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Case Number: 14-1297-EL-SSO

File Date: 9/21/2015

Section: 1 of 2

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Volume V

FILE

# PUCO EXHIBIT FILING

Date of Hearing: 9/4/2015

Case No. 14-1297-EL-SSO

PUCO Case Caption: In the Matter of the Application of Ohio Edison, The Cleveland Electric Illuminating Company, and The Toledo Edison Company for Authority to Provide for a Standard Service Offer Pursuant to R.C. 4928.143 in the Form of an Electric Security Plan.

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Reporter's Signature: Karen Gibson
Date Submitted: 9-18-15

BEFORE THE PUBLIC UTILITIES COMMISSION OF OHIO

- - -

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|---|---|
| In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company for Authority to Provide for a Standard Service Offer Pursuant to R.C. 4928.143 in the Form of an Electric Security Plan. | Case No. 14-1297-EL-SSO |

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PROCEEDINGS

before Mr. Gregory Price, Ms. Mandy Chiles, and Ms. Megan Addison, Attorney Examiners, at the Public Utilities Commission of Ohio, 180 East Broad Street, Room 11-A, Columbus, Ohio, called at 9:00 a.m. on Friday, September 4, 2015.

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VOLUME V

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- - -

# DECLARATION OF AUTHORITY

This Declaration of Authority ("Declaration") is made ________________ [Add Date] by the following:

PRINCIPAL: ________________________________ ("Principal – PJM Member")

AGENT: ___________________________________ ("Agent")

## RECITALS:

WHEREAS, PJM is a Regional Transmission Organization ("RTO") subject to the jurisdiction of the Federal Energy Regulatory Commission ("FERC");

WHEREAS, PJM Settlement, Inc. ("PJM Settlement") is a Pennsylvania Non-Profit Corporation, incorporated for the purpose of providing billing and settlement functions and credit and risk management functions for PJM. References to "PJM" in this Declaration are intended to apply to PJM and/or PJM Settlement, as appropriate, with regard to their respective functions;

WHEREAS, PJM and PJM Settlement administer centralized markets that clear various electric energy and energy-related products among multiple buyers and sellers;

WHEREAS, PJM additionally exercises operational control over its members' transmission facilities whereby PJM provides open-access transmission service and control area functions, including economic dispatch and emergency response to ensure reliability;

WHEREAS, Principal is a PJM Member and seeks to obtain, or is obtaining, services provided or administered by PJM, seeks to participate, or is participating in, markets administered by PJM, or seeks to engage in, or is engaging in, operations that use or affect the integrated transmission system operated by PJM;

WHEREAS, such activities or contemplated activities by Principal and Agent are governed by rights and obligations established by or under the PJM Open Access Transmission Tariff ("Tariff"), the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. ("Operating Agreement"), the Reliability Assurance Agreement Among Load-serving Entities in the MAAC Control Zone ("RAA"), and other agreements, manuals, and practices of PJM (the Tariff, the Operating Agreement, the RAA, and such other agreements, manuals, and practices of PJM, the "PJM Agreements"); and

WHEREAS, Principal and Agent desire to declare to PJM their respective authorities concerning such rights and obligations, intend that PJM rely upon such declaration, and acknowledge that PJM may rely upon such declaration to its detriment.

## DECLARATION:

NOW, THEREFORE, acknowledging that PJM will rely on the truth, accuracy, and completeness of the declarations made below, Principal and Agent, as identified below, makes the following declarations:

**1. Exclusivity of Agent's Authority.**

Pursuant to a binding, legally enforceable agreement, Principal has authorized Agent to act for Principal with respect to certain rights and responsibilities as specified in Section 2 of this Declaration ("the Authorized Rights and Responsibilities"). With respect to the Authorized Rights and Responsibilities, Agent is authorized to communicate and transact with PJM as Principal's sole and exclusive agent, and PJM is authorized to communicate and transact directly and exclusively with Agent as Principal's agent. With respect to Authorized Rights and Responsibilities, Principal will abide by any direction issued by PJM to Agent.

**2. Specification of Authorized Rights and Responsibilities.**

In the following subparts (a) through (h), Principal and Agent specify the rights and responsibilities with respect to which Agent is authorized to act for Principal. Specification shall be effective only if both Principal and Agent have placed the initials of their authorized representatives in the space provided for each applicable right or responsibility from among the options provided below:

(a) Load Server Responsibilities.

___ ___ Agent is authorized to satisfy Principal's obligations as a Load-Serving Entity under the RAA, including, without limitation, its obligations to provide Unforced Capacity, submit capacity plans, provide or arrange for Capacity Resources, satisfy Accounted-for Obligations and Peak Season Maintenance Obligations, comply with any capacity audits, make payment of all deficiency, data submission, and emergency procedure charges incurred, coordinate planning and operation of Capacity Resources with other parties, and develop and submit planned outage schedules.

___ ___ Agent is authorized to satisfy Principal's obligations under the Tariff, RAA and to provide or arrange for transmission service to its loads; provide or arrange for sufficient reactive capability, voltage control facilities, and black start capability for service to its loads; submit firm transmission service schedules and designate Network Resources and other points of receipt and delivery for transmission service.

___ ___ Agent is authorized to request changes to the transmission service required for service to Principal's loads, and to enter into on Principal's behalf, any feasibility, system impact, facilities study, or other agreements required to process such request for a change in service.

___ ___ Agent is authorized to satisfy Principal's rights and obligations under the Tariff and Operating Agreement to submit bids on, obtain, administer, and receive payments or credits for Financial Transmission Rights and Auction Revenue Rights with respect to service to Principal's loads.

___ ___ Agent is authorized to provide data required by PJM with respect to service to Principal's loads, including, but not limited to, data required for coordination of operations, accounting for all interchange transactions, preparation of required reports and maintenance schedules, and analysis of system disturbances.

___ ___ Agent is authorized to provide the facilities and personnel required to coordinate operations with PJM and other PJM Members.

(b) <u>Electric Distributor Responsibilities.</u>

___ ___ Agent is authorized to satisfy Principal's rights and obligations as an Electric Distributor under the Operating Agreement, including, but not limited to, assuring the continued compatibility of its local energy management, monitoring, and telecommunications systems with PJM's technical requirements; providing or arranging for the services of a 24-hour local control center to coordinate with PJM; providing to PJM all system, accounting, customer tracking, load forecasting, and other data necessary or appropriate to implement or administer the Operating Agreement, RAA; shedding connected load, initiating active load management programs, and taking such other coordination actions as may be necessary in accordance with PJM's directions in Emergencies; maintaining or arranging for a portion of its connected load to be subject to control by automatic under-frequency, under-voltage, or other load-shedding devices; and complying with the under-frequency relay obligations and charges specified in the Operating Agreement.

(c) <u>Generator Responsibilities.</u>

___ ___ Agent is authorized to operate the Principal's generation resources in all events, including, but not limited to, emergencies, and shall operate such resources in a manner that is consistent with the standards, requirements, or directions of PJM and that will permit PJM to perform its obligations under the Operating Agreement, Tariff, RAA, and other applicable agreements, manuals, and practices.

___ ___ Agent is authorized to ensure that the required portion of Principal's Capacity Resources have the ability to go from a shutdown condition to an operating condition and start delivering power without assistance from the power system;

– or –

___ ___ Agent is authorized to direct the operation of Principal's generation resources by relaying PJM's instructions to the resource in all events, including, but not limited to, emergencies, and shall direct such resources in a manner that is consistent with the standards, requirements, or directions of PJM and that will permit PJM to perform its obligations under the Operating Agreement, Tariff, RAA, and other applicable agreements, manuals, and practices.

___ ___ Agent is authorized to communicate and act on behalf of Principal with PJM in all matters concerning the provision of capacity from Principal's generation resources.

___ ___ Agent is authorized to communicate and act on behalf of Principal with PJM in all matters concerning the provision of energy from Principal's generation resources.

___ ___ Agent is authorized to communicate and act on behalf of Principal with PJM in all matters concerning the provision of ancillary services from Principal's generation resources, including, without limitation, information required in Resources, dispatch of any unit, provision of reactive power, regulation, synchronous condensing, spinning, or other reserves, establishment or maintenance of a unit as a Black-Start Unit, satisfaction of must-run obligations, and costs or revenue requirements for any product or service offered by any such unit.

___ ___ Agent is authorized to provide information on outages of Principal's generation facilities, whether planned, forced, or for maintenance, and to coordinate such outages with PJM.

___ ___ Agent is authorized to act on behalf of Principal with respect to Principal's rights and obligations under any Feasibility Study, System Impact Study, or Facilities Study Agreements.

___ ___ Agent is authorized to act on behalf of Principal with respect to Principal's rights and obligations under any Construction Service Agreements.

___ ___ Agent is authorized to act on behalf of Principal with respect to Principal's rights and obligations under any Interconnection Service Agreements.

___ ___ Agent is authorized to receive from PJM historic and real time data collected by PJM from, or provided to PJM by Principal, with respect to Principal's generation resources.

___ ___ Agent is authorized to act on behalf of Principal for the following specific unit(s) in Principal's primary and subaccounts.

| Resource Name: | Resource I.D.: |
|---|---|
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Market Buyer/ Market Seller Responsibilities.

___ ___ Agent is authorized to satisfy Principal's rights and obligations as a Market Buyer or Market Seller under the Operating Agreement, including, but not limited to, arranging for a Market Operations Center capable of real-time communication with PJM during normal and emergency conditions; reporting to PJM sources of energy available for operation; providing to PJM scheduling and other information, including, but not limited to, maintenance and other anticipated outages of generation or transmission facilities, scheduling and related information on bilateral transactions and self-scheduled resources, and implementation of active load management, interruption of load, and other load reduction measures; obtaining Spot Market Backup for bilateral transactions; submitting to PJM binding offers to purchase or sell energy and ancillary services in compliance with all applicable Offer Data specifications; responding to PJM's directives to start, shut down, or change output levels of generation units, or change scheduled voltages or reactive output levels; responding to PJM's directives to schedule delivery or change delivery schedules for external resources; and following PJM's directions to take actions to prevent, manage, alleviate or end an emergency.

(d) Billing and Payment Responsibilities.

___ ___ In connection with all rights and responsibilities specified by Principal and Agent in any of the subparts (a) through (d) of this Section, or as specified in the attached Addendum, Agent shall be billed for and shall make payment to PJM for, all charges, penalties, costs, and fees. (If this option is not specified, PJM will issue billings to and collect amounts due from Principal.)

___ ___ In connection with all rights and responsibilities specified by Principal and Agent above, Agent is entitled to receive from PJM, in Agent's account, all credits, revenues, distributions, and disbursements. (If this option is not specified, PJM will pay such amounts to Principal.)

General Membership Responsibilities.

___ ___ Agent is authorized to participate and vote in all PJM committees, working groups, and other stakeholder bodies on Principal's behalf.

___ ___ Agent is authorized to participate on Principal's behalf in the regional transmission expansion planning process.

___ ___ Agent is authorized to provide information or otherwise cooperate on Principal's behalf in connection with any investigation or request for information by PJM or the PJM Market Monitoring Unit in accordance with the Operating Agreement and Attachment M to the Tariff. (If this option is specified, PJM and the PJM Market Monitoring Unit shall have the right to request and obtain such information from Agent and/or Principal.)

___ ___ Agent shall be billed for and shall make payment of Principal's costs of membership in PJM, including payment of the Membership fee and payment of any other general assessments on the PJM members, including, but not limited to, amounts assessed as a consequence of defaults by other Members.

(e) Additional Responsibilities.

___ ___ Agent has been Authorized other rights and responsibilities of Principal as specified on Attachment "A" to this Declaration.

(f) Limitation on Responsibilities.

___ ___ The rights and responsibilities specified in subparts (a) through (f) above apply to a limited portion of Principal's facilities or loads located in the PJM Region, as specified on Attachment "B" to this Declaration, and to no other facilities or loads of Principal.

**3. Continuing Responsibilities and Liabilities of Principal.**

(a) The Authorized Rights and Responsibilities are the only rights and responsibilities under the PJM Agreements for which Agent is authorized to act for Principal and Principal retains all rights and responsibilities under the PJM Agreements not specified by Principal and Agent in Section 2.

(b) With respect to the Authorized Rights and Responsibilities, and notwithstanding any other provision of this Agreement, Principal shall remain liable to PJM for all amounts due or become due to PJM under the PJM Agreements, and Agent's authorization to make payment of any such amounts hereunder (if specified in Section 2) shall not release Principal from liability for any financial obligations to PJM not satisfied by Agent.

**Reliance and Indemnity, Duty to Inform, Liability Waiver, Termination, and Rules of Construction.**

(a) Principal and Agent each recognizes, accepts, and intends that PJM will rely upon on the truth, accuracy, and completeness of the declarations herein in matters including, but not limited to, creditworthiness and in assuring compliance with the PJM Agreements. Principal and Agent each recognizes and accepts that PJM or its members may suffer losses and damages if any declaration is or becomes untrue, inaccurate, or incomplete and each agrees to indemnify PJM for any such losses and damages.

(b) Principal and Agent each has a continuing duty to notify PJM if and when any declaration herein ceases to be truthful, accurate, or complete. Until such time as PJM receives written notification of any change to any declaration, in accordance with the terms contained herein, PJM shall be entitled to rely perpetually on this Declaration, as governing its relationship with Principal and Agent, as to the subject matter of this Declaration. Written notice of changes to the declarations contained herein must be provided by Principal (a PJM Member) to PJM at least thirty (30) days in advance of their effectiveness. If Agent is also a PJM Member, then both parties will be required to provide thirty (30) days prior written notification in order for such changes to be effective.

(c) Termination- Principal (a PJM Member) may, for its sole convenience, terminate this Declaration by providing at least thirty (30) days prior written notification to PJM. If Agent is also a PJM Member, both parties will be required to provide at least thirty (30) days prior written notification in order for termination to become effective. Upon such termination, all rights, responsibilities, and accounts will revert back to the original status quo prevailing before the Declaration became effective.

(d) Nothing in this Declaration shall be construed to create or give rise to any liability on the part of PJM and Principal and Agent expressly waive any claims that may arise against PJM under this Declaration. This Declaration shall not be construed to modify any of the PJM Agreements and in the event of conflict between this Declaration and a PJM Agreement, the applicable PJM Agreement shall control.

(e) Capitalized terms used herein that are not defined herein have the meanings given in the PJM Agreements, as applicable.

(f) The Recitals are hereby incorporated into the body of this Declaration.

IN WITNESS WHEREOF, Principal and Agent execute this Declaration to be effective as of the date written above or upon receipt of a fully executed original by PJM, whichever date is later.

| **PRINCIPAL (PJM Member):** | **AGENT:** |
|---|---|
| **Signature:**____________________ | **Signature:**____________________ |
| **Name:** ____________________ | **Name:** ____________________ |
| **Title:**____________________ | **Title:**____________________ |
| **Company Name:**________________ | **Company Name:**________________ |

EXHIBIT
PENGAD 800-631-6989
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Sierra Club

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

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| Petition for Initiation of Proceeding to Examine Proposal for Continued Operation of R.E. Ginna Nuclear Power Plant | Case 14-E-________ |

**PETITION FOR INITIATION OF PROCEEDING TO EXAMINE PROPOSAL FOR CONTINUED OPERATION OF R.E. GINNA NUCLEAR POWER PLANT**

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*Attorneys for Exelon Corporation, Constellation Energy Nuclear Group, LLC, and R.E. Ginna Nuclear Power Plant, LLC*

Dated: July 11, 2014

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

| | |
|---|---|
| Petition for Initiation of Proceeding to Examine Proposal for Continued Operation of R.E. Ginna Nuclear Power Plant | Case 14-E-________ |

# PETITION FOR INITIATION OF PROCEEDING TO EXAMINE PROPOSAL FOR CONTINUED OPERATION OF R.E. GINNA NUCLEAR POWER PLANT

## INTRODUCTION

R.E. Ginna Nuclear Power Plant, LLC ("GNPP") hereby petitions the New York State Public Service Commission (the "Commission") to initiate a proceeding to examine a proposal for the continued operation of the R.E. Ginna Nuclear Power Plant (the "Ginna Facility").

GNPP, which is a subsidiary of Constellation Energy Nuclear Group, LLC ("CENG"), owns the Ginna Facility. Prior to expiration on June 30, 2014, the Ginna Facility was operating under a purchase power agreement (the "PPA") with Rochester Gas and Electric Corporation ("RG&E") for a majority of its output. The Ginna Facility is now a fully merchant generator in the wholesale market. On a forward-looking basis, CENG management has analyzed the revenues the Ginna Facility would expect to receive for energy and capacity sales in the New York Independent System Operator ("NYISO") markets following the PPA's expiration. CENG management determined that the expected revenues from the Ginna Facility's sale of capacity and energy into the NYISO markets will not be sufficient to cover its costs of continued operation, including required new capital investment.

In January 2014, CENG management representatives met separately with individual Commissioners, Department of Public Service Staff ("Staff"), RG&E, and the NYISO to discuss

CENG's management's determination that market revenues will be insufficient to cover the Ginna Facility's costs going forward following the PPA's expiration and that, as a result, the Ginna Facility's retirement was under consideration by CENG management. CENG management advised RG&E that, to the extent that it was subsequently determined that the Ginna Facility was needed to support electric system reliability, CENG management was willing to continue the Ginna Facility's operations upon negotiation and approval by the board of directors of CENG and by the Commission of an acceptable Reliability Support Services Agreement ("RSSA").

On February 21, 2014, GNPP, RG&E, and the NYISO entered into a Reliability Study Agreement to determine the potential reliability impacts of retiring the Ginna Facility. On May 12, 2014, the NYISO produced the final results of its independent reliability study, attached as *Exhibit 1 (the "Reliability Study"), confirming the need for the Ginna Facility's continued* operation at least through October 1, 2018, to avoid adverse impacts to electric system reliability. RG&E also conducted a local reliability analysis, the results of which are included in the NYISO study, which confirms the need for the Ginna Facility's continued operation to support local electric reliability in RG&E's service area.

Given this reliability need, CENG management is willing to continue the Ginna Facility's operations upon negotiation and approval by the board of directors of CENG and by the Commission of an acceptable RSSA. RG&E is making a concurrent filing with the Commission recognizing there would be a reliability need in the NYISO control region for the greater Rochester area if the Ginna Facility ceased operations. In the absence of this confirmed reliability need and an acceptable RSSA, and given CENG's management's conclusion that projected market revenues are insufficient to support the Ginna Facility's continued operation, CENG management would recommend to CENG's board to authorize the Ginna Facility's retirement as soon as practicable. The execution of an RSSA would, however, forestall the Ginna Facility's retirement during the agreement's term.

GNPP respectfully requests that the Commission: (1) find that the Ginna Facility's continued operation is necessary to assure electric service reliability; (2) find that CENG management's communications with individual Commissioners and Staff, RG&E, and the NYISO, including, but not limited to, this Petition and the attached Reliability Study, constitute full and sufficient notice to the Commission to satisfy the advance notice requirements with respect to consideration of retirement generally and the Ginna Facility specifically; and (3) direct RG&E and GNPP to negotiate and file an RSSA for the Ginna Facility's continued operation to support electric system reliability in RG&E's service territory by December 1, 2014.[1]

## BACKGROUND

### A. The Ginna Facility is a Critical Baseload Power Resource and Provides 581 MW of Reliable and Clean Energy to New York

The Ginna Facility is a 581 MW single-unit pressurized water reactor located on 426 acres along the south shores of Lake Ontario in Ontario, N.Y., about 20 miles northeast of Rochester, N.Y. In 2004, the Ginna Facility's license to operate was extended until September 2029.[2]

Following Commission approval, CENG, through its subsidiaries, acquired the Ginna Facility from RG&E on June 10, 2004.[3] CENG, a joint venture between Exelon Corporation

[1] In making this filing with the Commission, GNPP reserves its right to take any alternative actions and make other filings in connection with recovery of GNPP's costs, including, but not limited to, filing of a Reliability-Must Run Agreement with the Federal Energy Regulatory Commission.

[2] *See* Issuance of Renewed Facility Operating License No. DPR-18 for R.E. Ginna Nuclear Power Plant, Operating License, Nuclear Regulatory Commission, issued May 19, 2004 (Adams Accession No. ML041330109).

[3] *See* Case 03-E-1231: *Petition of Rochester Gas and Electric Corporation, Constellation Generation Group, LLC, and R.E. Ginna Nuclear Power Plant, LLC for Authority Under Public Service Law Section 70 to Transfer by Auction Sale the R.E. Ginna Nuclear Generating Plant and Related Assets and for Related Approvals*, Order Approving Transfer, Subject to a Modification (May 20, 2004).

("Exelon") and EDF Group ("EDF"), owns 100% percent of GNPP and, in turn, the Ginna Facility.[4] Exelon, through its subsidiaries, owns 50.01% of CENG. EDF, through its subsidiaries, owns 49.99% of CENG.

On May 20, 2004, the Commission approved the transfer of the Ginna Facility and the related PPA and Interconnection Agreement.[5] In a companion order, the Commission directed that "owners of nuclear wholesale generating facilities must file a notice of termination of operations at least six months prior to a shutdown for economic reasons, unless the generator can demonstrate that a shorter period for notice was unavoidable."[6] The Commission reasoned that the "notice would allow time to devise measures for mitigating [generation planning and community impacts] of a shutdown."[7]

### B. Market Revenues are Insufficient to Cover the Ginna Facility's Expected Operating Costs

In recent years, the Ginna Facility's revenues from the sale of capacity and energy have not been sufficient to cover the costs of operation.[8] In the two preceding calendar years (*i.e.*,

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[4] In 2012, Exelon acquired Constellation Energy Group, Inc. *See* Case 11-E-0245: *Exelon Corporation, Constellation Energy Group, Inc., Constellation Energy Nuclear Group LLC, Nine Mile Point Nuclear LLC, and R.E. Ginna Nuclear Power Plant LLC – Joint Petition for a Declaratory Ruling Regarding a Stock Transaction or, In the Alternative, An Order Approving the Stock Transaction*, Declaratory Ruling on Review of a Stock Transfer Transaction (Dec. 20, 2011).

[5] *See* Case 03-E-1231: *Petition of Rochester Gas and Electric Corporation, Constellation Generation Group, LLC, and R.E. Ginna Nuclear Power Plant, LLC for Authority Under Public Service Law Section 70 to Transfer by Auction Sale the R.E. Ginna Nuclear Generating Plant and Related Assets and for Related Approvals*, Order Approving Transfer, Subject to a Modification (May 20, 2004).

[6] Case 04-E-0030: *Petition of R.E. Ginna Nuclear Power Plant, LLC for a Declaratory Ruling on Regulatory Regime*, Order Providing for Lightened Regulation of Nuclear Generation Facility Owner (May 20, 2004)("*Lightened Regulation Order*").

[7] *Id.*

[8] It is well documented in various analyst reports (*e.g.* UBS, Credit Suisse) and analyses by the Nuclear Energy Institute that small, single-unit reactors such as the Ginna Facility are facing considerable economic challenges. For example, the shutdown of the Kewaunee and Vermont Yankee nuclear generating facilities can be attributed to the same economic challenges that the Ginna Facility faces. *See e.g.* Nuclear Energy Institute, NUCLEAR INDUSTRY CITES 'PRESSING NEED' FOR ELECTRICITY MARKET REFORMS (May 21, 2014), *available at*: http://www.nei.org/News-Media/News/News-Archives/Nuclear-Industry-Cites-Pressing-Need-for-Electrici; UBS, SOME MERCHANT NUCLEAR PLANTS COULD FACE EARLY RETIREMENT (Jan. 9, 2013), *available at*:

2012 and 2013), CENG has sustained cumulative losses at the Ginna Facility of nearly $100 million (including the allocation of CENG corporate overhead). Over the last three calendar years (*i.e.*, 2011-2013), losses have significantly exceeded $100 million (including the allocation of CENG corporate overhead). Further, in addition to incurring these losses, CENG has not been compensated for any operational risk or an appropriate return on its investment over this period.

On a forward-looking basis, CENG management analyzed the revenues the Ginna Facility would expect to receive for energy and capacity sales in the NYISO markets following the PPA's expiration. CENG management determined that the expected revenues from the Ginna Facility's sale of capacity and energy into the NYISO markets will not be sufficient to cover its costs of continued operation, including required new capital investment.

Despite the Ginna Facility's losses, at no point has CENG decreased its emphasis on safety, reliability, or commitment to the environment.

In January 2014, CENG management met separately with individual Commissioners, Staff, RG&E, and the NYISO to discuss CENG management's conclusion that market revenues will be insufficient to cover the Ginna Facility's costs going forward and that, as a result, its retirement was under consideration. CENG management advised RG&E that, to the extent that it was subsequently determined that the Ginna Facility was needed to support electric system reliability, CENG management was willing to continue the Ginna Facility's operation upon negotiation and approval by the board of directors of CENG and by the Commission of an acceptable RSSA.

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http://www.platts.com/latest-news/electric-power/newyork/some-merchant-nuclear-plants-could-face-early-6007202.

### C. The Ginna Facility is Needed for Reliability and Other Benefits

On February 21, 2014, GNPP, RG&E, and the NYISO entered into a Reliability Study Agreement to determine the potential reliability impacts on the New York State Transmission System and the local transmission system of retiring the Ginna Facility. The NYISO assessment of the retirement of the Ginna Facility was performed in accordance with applicable North American Electric Reliability Corporation Reliability Standards, Northeast Power Coordinating Council Design Criteria, New York State Reliability Council Reliability Rules and Procedures, and NYISO planning and operation practices. On May 12, 2014, the NYISO produced the final results of its independent Reliability Study, attached as Exhibit 1, confirming a reliability need at least through October 1, 2018, were the Ginna Facility to retire. RG&E also conducted a local reliability analysis, which is included in the NYISO study, and confirms the local electric reliability need in RG&E's service area.

The need for the Ginna Facility is partially tied to the in-service date for RG&E's proposed Rochester Area Reliability Project (the "RARP").[9] As described in RG&E's application, the RARP includes 1.9 miles of new 345 kV transmission line, 23.6 miles of new or rebuilt 115 kV transmission line, a new 345 kV/115 kV substation, and equipment upgrades at several existing substations in Monroe County, and equipment upgrades at two substations in Niagara County.[10] The RARP was proposed, in part, to address a possible long-term outage of the Ginna Facility, which is the largest single source to the Rochester system.[11]

[9] *See* Case 11-T-0534: *Application of Rochester Gas and Electric Corporation for a Certificate of Environmental Compatibility and Public Need*, Application (Filed Sep. 30, 2011).
[10] *See id.* p. 1.
[11] *See id.* p. 7.

No alternatives have been identified, including merchant generation or transmission, to replace the full output of the Ginna Facility and address the reliability need that would result from its retirement between now and October 2018. GNPP is unaware of any proceeding or publicly-announced alternative designed to fill the generation shortfall created by the Ginna Facility's retirement. Although the risk of an extended outage at the Ginna Facility formed the basis for the RARP, no formal consideration or long-term planning analysis has specifically evaluated the impact of the Ginna Facility's retirement or otherwise solicited supply or demand-side alternatives that might mitigate the reliability consequences of such an early retirement. Given this established reliability need and lack of any alternatives, CENG management is willing to continue the Ginna Facility's operations upon negotiation and approval by the board of directors of CENG and by the Commission of an acceptable RSSA.

In addition to alleviating adverse electric system reliability impacts in RG&E's service territory, the Ginna Facility's continued operation will provide further benefits at the state and local level. For example, the Ginna Facility employs about 700 people during normal operations and an additional 800 - 1,000 people during refueling outages. Further, the Ginna Facility is the largest taxpayer in Wayne County, contributing more than $10 million in state and local property taxes in 2012. Additionally, the Ginna Facility provides significant environmental benefits for the state. Electricity generated by the Ginna Facility rather than by fossil-fueled generators prevents the release of 2 million tons of carbon dioxide annually – a significant amount compared to the 30 million tons of total carbon dioxide emissions produced annually by New York's electric sector. Nuclear facilities, like the Ginna Facility, provide nearly 60% of New York's carbon-free electricity, helping New York meet its RGGI carbon-reduction goals. In the absence of the Ginna Facility's output, increased RGGI costs would likely result in higher electricity prices statewide. Also, the Ginna Facility's operation, rather than fossil-fueled generators' operation, prevents the emission of more than 1,000 tons of nitrogen oxide and 1,040 tons of sulfur dioxide annually. Sulfur dioxide and nitrogen oxide are precursors to acid rain and smog. Finally, the Ginna Facility's continued operation greatly assists in maintaining the critically-important balanced electric portfolio in New York. Nuclear facilities produce approximately 30% of New York's electricity. Over the past 10 years, the Ginna Facility has operated at over 95% capacity, and its reliable production has also assisted in offsetting price volatility of other generation sources. As demonstrated by the recent 2014 winter impacts, the Ginna Facility provides a substantial stabilizing effect against volatile and expensive natural gas prices, particularly in the winter.

Despite the Ginna Facility's many benefits, CENG management has concluded that projected market revenues are insufficient to cover the Ginna Facility's operating costs going forward. As a result, in the absence of a confirmed reliability need and acceptable RSSA, CENG management would recommend to CENG's board that the Ginna Facility cease operations and retire as soon as practicable. In light of the established reliability need for the Ginna Facility, however, CENG management is willing to continue the Ginna Facility's operations subject to the negotiation and approval by the board of directors of CENG and by the Commission of an acceptable RSSA.

**PETITION**

GNPP respectfully requests that the Commission promptly consider this Petition and issue an order consistent with this Petition.

Specifically, GNPP requests that the Commission find that the NYISO and RG&E Reliability Study establishes the need for the Ginna Facility's continued operation. GNPP requests that the Commission direct RG&E and GNPP to negotiate and file by December 1, 2014, an RSSA of an appropriate duration and with a commencement date of no earlier than January 11, 2015, to provide for continued electric system reliability.

GNPP also requests that the Commission find that GNPP's communications with individual Commissioners and Staff, RG&E, and the NYISO, including, but not limited to, this Petition and the attached Reliability Study, constitute full and sufficient notice to the Commission to satisfy the advance notice requirements with respect to consideration of retirement generally and the Ginna Facility specifically. The intent behind the Commission's *Generation Unit Retirement Order* and *Lightened Regulation Order* is to ensure that the Commission and interested parties be given sufficient notice of a possible retirement so that system reliability and community impacts can be identified and addressed, respectively.[12] Since January 2014, GNPP has been working with RG&E and the NYISO to study the reliability impacts associated with long-term shut down of the Ginna Facility. The proposed RSSA between GNPP and RG&E addresses and resolves the reliability impacts identified in the attached Reliability Study and forestalls any community impacts. Accordingly, the procedural requirements in and intent behind these Commission orders for advance notice of generator unit retirements have been fully satisfied.

[12] *See* Case 05-E-0889: *Proceeding on Motion of the Commission to Establish Policies and Procedures Regarding Generation Unit Retirements*, Order Adopting Notice Requirements for Generation Unit Retirements (Dec. 20, 2005), p. 14; Case 04-E-0030: *Petition of R.E. Ginna Nuclear Power Plant, LLC for a Declaratory Ruling on Regulatory Regime*, Order Providing for Lightened Regulation of Nuclear Generation Facility Owner (May 20, 2004).

## CONCLUSION

Based on the foregoing, GNPP respectfully requests that the Commission consider the instant Petition and issue an order:

(1) finding and determining that the NYISO and RG&E Reliability Study establishes the need for the Ginna Facility's continued operation;

(2) directing RG&E and GNPP to negotiate and file by December 1, 2014, an RSSA of an appropriate duration and with a commencement date of no earlier than January 11, 2015, along with supporting documentation, to provide for continued electric system reliability in RG&E's service territory; and

(3) finding that GNPP's communications with individual Commissioners and Staff, RG&E, and the NYISO, including, but not limited to, this Petition and the attached Reliability Study, constitute full and sufficient notice to the Commission to satisfy the advance notice requirements with respect to consideration of retirement generally and the Ginna Facility specifically.

Respectfully submitted,

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Dated: July 11, 2014
Albany, New York

EXHIBIT
PENGAD 800-631-6989
3
Sierra Club

BEFORE THE
NEW YORK STATE
PUBLIC SERVICE COMMISSION

| | |
|---|---|
| Petition Requesting Initiation of a Proceeding to Examine a Proposal for Continued Operation of the R.E. Ginna Nuclear Power Plant, LLC. | Case 14-E-0270 |

**ROCHESTER GAS AND ELECTRIC CORPORATION'S RESPONSE TO ORDER DIRECTING NEGOTIATION OF A RELIABILITY SUPPORT SERVICE AGREEMENT AND PETITION FOR APPROVAL OF COST ALLOCATION AND COST RECOVERY SURCHARGE MECHANISM**

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February 13, 2015

BEFORE THE
NEW YORK STATE
PUBLIC SERVICE COMMISSION

| | |
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| Petition Requesting Initiation of a Proceeding to Examine a Proposal for Continued Operation of the R.E. Ginna Nuclear Power Plant, LLC. | Case 14-E-0270 |

**ROCHESTER GAS AND ELECTRIC CORPORATION'S RESPONSE TO ORDER DIRECTING NEGOTIATION OF A RELIABILITY SUPPORT SERVICE AGREEMENT AND PETITION FOR APPROVAL OF COST ALLOCATION AND COST RECOVERY SURCHARGE MECHANISM**

## I. INTRODUCTION

Rochester Gas and Electric Corporation ("RG&E" or the "Company") submits this Response to the Order Directing Negotiation of a Reliability Support Service Agreement and Making Related Findings issued on November 14, 2014 ("November Order") by the New York State Public Service Commission ("Commission") in the above-referenced matter. Pursuant to Ordering Clause 1 of the November Order, attached hereto as Exhibit A is an executed Reliability Support Services Agreement ("RSSA") between RG&E and R.E. Ginna Nuclear Power Plant, LLC ("GNPP," and together with RG&E, the "Parties").[1] As discussed in more detail below, RG&E respectfully requests that the Commission: 1) accept the attached RSSA without modification; and 2) approve full and immediate cost recovery by RG&E from its customers of all amounts payable to GNPP under the RSSA utilizing the cost recovery surcharge mechanism proposed herein.[2]

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[1] Contemporaneous with this filing, GNPP is submitting the RSSA to the Federal Energy Regulatory Commission ("FERC") and requesting that FERC accept the RSSA as GNPP's Electric Rate Schedule FERC No. 1 effective April 1, 2015, as agreed to by the Parties, without suspension, hearing or settlement judge proceedings.

[2] As indicated in Section III below, while the Parties have executed the attached RSSA, various conditions to payment obligations exist.

## II. BACKGROUND

GNPP, which is a subsidiary of Constellation Energy Nuclear Group, LLC ("CENG"), owns and operates the R.E. Ginna Nuclear Power Plant ("Ginna Facility"), a 581 MW single-unit pressurized water reactor located in Ontario, New York.[3] In 2004, the Ginna Facility's license to operate was extended until September 2029.[4] Prior to expiration in June 2014, GNPP sold a majority of the Ginna Facility's output to RG&E under a power purchase agreement ("PPA"). Since then, the Ginna Facility has continued to operate as a merchant generator selling into the wholesale markets operated by the New York Independent System Operator ("NYISO"). On a forward-looking basis, CENG's "management determined that the expected revenues from the Ginna Facility's sale of capacity and energy into the NYISO markets [would] not be sufficient to cover its costs of continued operation...."[5] As a result, in January 2014, "CENG management representatives met separately with individual Commissioners, Department of Public Service Staff, RG&E and the NYISO" to inform them that "the Ginna Facility's retirement was under consideration by CENG management."[6]

CENG's management informed RG&E that if it was determined that the Ginna Facility was required to support electric system reliability in RG&E's service territory, CENG's management was willing to continue operating the Ginna Facility upon implementation of an acceptable RSSA.[7]

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3 Case 14-E-0270 – Petition Requesting Initiation of a Proceeding to Examine a Proposal for Continued Operation of the R.E. Ginna Nuclear Power Plant, LLC, Petition for Initiation of Proceeding to Examine Proposal for Continued Operation of R.E. Ginna Nuclear Power Plant, at 1 and 3 (July 11, 2014) ("Petition").

4 Id. at 3.

5 Id. at 1.

6 Id. at 1-2.

7 Id. at 2.

On February 21, 2014, GNPP, RG&E and the NYISO entered into a Reliability Study Agreement to assess the potential reliability impacts of retiring the Facility. On May 12, 2014, the NYISO produced the 2014 Reliability Study, confirming that the Ginna Facility's retirement would result in bulk transmission and non-bulk local distribution system reliability violations in 2015 and 2018.[8]

On July 11, 2014, GNPP filed a petition requesting that the Commission initiate a proceeding to examine a proposal for the continued operation of the Ginna Facility.[9] Ginna asserted that "[i]n the two preceding calendar years (i.e., 2012 and 2013), CENG has sustained cumulative losses at the Ginna Facility of nearly $100 million (including the allocation of CENG corporate overhead)" and that "CENG has not been compensated for any operational risk or an appropriate return on its investment over this period."[10] Based on the results of the 2014 Reliability Study, GNPP requested that: 1) the Commission determine that the continued operation of the Ginna Facility is required to preserve system reliability; and 2) the Commission issue an Order directing RG&E to negotiate and file an RSSA for the continued operation of the Ginna Facility.[11] Concurrent with the filing of the Petition and the 2014 Reliability Study by GNPP, RG&E filed a letter indicating that it supported the 2014 Reliability Study analysis, which demonstrated that permanently retiring the Ginna Facility would threaten local reliability needs in RG&E's service territory.[12]

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8 Case 14-E-0270, Additional Reliability Study for Exelon Corporation at 17 (May 12, 2014) ("2014 Reliability Study"). GNPP filed the 2014 Reliability Study with the Commission on July 11, 2014.

9 Petition at 1.

10 Id. at 4-5.

11 Id. at 10.

12 Case 14-E-0270, Response of RG&E to Petition (July 11, 2014).

On October 6, 2014, RG&E issued a Request for Proposals ("RFP") soliciting alternatives to meet the reliability need that would result from the potential retirement of the Ginna Facility. RG&E received six responses to the RFP. RG&E submitted its analysis of the RFP responses to the Commission on December 23, 2014 (the "RFP Report").[13] In addition, RG&E identified a set of transmission solutions, the Ginna Retirement Transmission Alternative ("GRTA"), that could shorten the duration of the RSSA and allow for the retirement of the Ginna Facility.[14] The GRTA also mitigates the urgency of RG&E's Rochester Area Reliability Project and addresses other system reliability matters, such as stuck breaker contingencies.[15]

In the November Order, the Commission ruled that GNPP had demonstrated that the Ginna Facility is required to maintain system reliability and that its actions with respect to meeting the relevant retirement notice requirements were satisfactory.[16] The Commission also accepted the findings of the 2014 Reliability Study and stated that it established "the reliability need for continued operation of the Ginna Facility that is the essential prerequisite to negotiating an RSSA."[17] As such, the Commission ordered RG&E and GNPP to negotiate an RSSA.[18]

[13] RG&E submitted both a confidential and public version of the RFP Report.

[14] Case 11-T-0534 – Application of Rochester Gas and Electric Corporation for a Certificate of Environmental Compatibility and Public Need for the Construction of The Rochester Area Reliability Project, Letter from John D. Draghi to Administrative Law Judges Liebschutz and Phillips, at 3 (December 23, 2014). The GRTA consists of upgrades at Station 122 and uprates to certain 34.5 kV and 11.5 kV underground transmission lines. In addition, RG&E will construct a fifth bay of 345 kV circuit breakers at Station 80. Id. at 3-4.

[15] Id. at 2.

[16] November Order at 15, 24-25. Although GNPP did not cite a specific retirement date for the Ginna Facility, the Commission ruled that GNPP provided proper notice pursuant to the Commission's Order Adopting Notice Requirements of Generation Unit Requirements issued on December 20, 2005 in Case 05-E-0889, imposing a 180-day retirement notice requirement, and the Order Providing for Lightened Regulation of Nuclear Generation Facility Owner issued on May 20, 2004 in Case 04-E-0030, imposing a six-month retirement notice requirement. Id. at 21-22. In reaching this determination, the Commission reasoned, in part, that because the 2014 Reliability Study was filed on the same date as the Petition, no additional time was required for the preparation and examination of such a reliability study. Id. at 18-19. As such, the Commission found that the purpose of the notice requirement, which was to provide sufficient time to assess whether adverse impacts on reliability might arise from the retirement of a generation facility, and to afford time to develop and implement alternatives, had been satisfied. Id. at 21-22.

[17] Id. at 17.

Per the November Order, the Parties entered into negotiations. The Parties reached an agreement in principle on an RSSA. On February 13, 2015, GNPP filed the executed RSSA with the FERC, along with a copy of its cost of service study and supporting materials. The terms of the RSSA are summarized below.

## III. THE RSSA

The term of the RSSA runs from the start of the hour ending 0100 EPT on April 1, 2015 and remains in effect through the hour ending 2400 EPT on September 30, 2018 (the "Initial Term"), thus matching the time period of the 2014 Reliability Study that establishes the reliability need for the Ginna Facility.[19] While the RSSA has a term of three and a half years, RG&E may, in its sole discretion, terminate the contract prior to the expiration of the Initial Term.[20] Pursuant to Section 2.2(c) of the RSSA, RG&E can terminate the agreement by providing twelve months' prior written notice and making a "Settlement Payment."[21] The RSSA also provides for the possibility of a "Necessary Extension" of the RSSA should the continued operation of the Ginna Facility be required for reliability purposes after the expiration of the Initial Term and any such extension shall be for a period of eighteen (18) months.[22] Notice of a Necessary Extension shall be provided no later than January 31, 2017.[23]

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18 Id. at 27. With respect to RSSA costs, the Commission stated that "RG&E and Ginna are expected to support their positions on an RSSA with the economic analysis that will enable the Commission to determine the extent to which RSSA pricing is required. Additionally, it is expected that any RSSA resulting from these negotiations should address impacts of changes in economic circumstances and concomitant market electric prices on Ginna over time." Id. at 23. As noted in Section III herein, the RSSA responds to changes in market revenues by providing RG&E customers with 85% of the energy and capacity market revenues. Should there be a substantial increase in market prices, RG&E customers would receive 85% of the increase.

19 RSSA § 2.2(a). The RSSA is subject to certain termination provisions.

20 Id. § 2.2(c). GNPP does not have an early termination option.

21 The settlement payment compensates Ginna for the unrecovered portion of costs incurred by Ginna that would have been fully recovered had the RSSA run to term.

22 RSSA § 2.3.

23 Id.

As indicated, while the RSSA became effective upon execution on February 13, 2015, no payment obligation commences under the RSSA until: 1) the issuance by FERC of an order accepting the RSSA under Section 205 of the Federal Power Act, 16 U.S.C. § 824d and the regulations promulgated thereunder, without modifying or imposing any term or condition in a manner that is adverse in any material respect to a Party as determined in the affected Party's reasonable discretion; and 2) the issuance by the Commission of an order (A) accepting the RSSA and (B) approving full and immediate cost recovery by RG&E through a surcharge mechanism (without offset or deferral including with respect to items unrelated to the RSSA) of all amounts payable to Ginna under the RSSA on a substantially current basis that coincides with the timing of all payments made by RG&E to Ginna under the RSSA, in each case without modifying or imposing any term or condition in a manner that is adverse in any material respect to a Party as determined in the affected Party's reasonable discretion.[24] Assuming such conditions are satisfied, pursuant to the proposed RSSA, RG&E would compensate GNPP through a Monthly Fixed Amount of approximately $17.5 million,[25] net Applicable Revenues for each month.[26] In the RSSA, GNPP expressly agrees to accept the risk that GNPP may perform the reliability support obligations in accordance with the RSSA without any compensation from RG&E, or with reduced compensation, if the aforementioned conditions are not satisfied.[27]

In the event that the Acceptance Date is achieved after April 1, 2015, the RSSA allows Ginna to recoup payments that it would have been owed under the RSSA had the Acceptance

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24 Id. § 2.1(a)(i) and (ii). The RSSA defines the date, if any, upon which each of the foregoing conditions precedent above are satisfied or waived by the Parties as the "Acceptance Date." Id.

25 Id. §§ 1.1(ff) and 4.1(a).

26 The RSSA defines "Applicable Revenues" as "RGE's eighty-five percent (85%) share of any Energy Revenues, RGE's eighty-five percent (85%) share of any Capacity Revenues and one hundred percent (100%) of any Ancillary Service Revenues…." Id. § 1.1(e).

27 Id. § 2.1(d).

Date been achieved by April 1, 2015. Specifically, the RSSA states that GNPP shall track the net amount that would have been owed to GNPP under the RSSA had the Acceptance Date been achieved by April 1, 2015 (i.e., the Monthly Fixed Amount, net of Applicable Revenues, any Unplanned Outage Performance Adjustments, any Force Majeure Event Performance Adjustments and any other amounts payable by GNPP under the RSSA) for each calendar month (or any partial month) until the day immediately prior to the Acceptance Date (such cumulative net amount for such calendar months, the "Deferred Collection Amount").[28] RG&E would pay the Deferred Collection Amount, plus interest on the unpaid balance thereof at the Commission-published interest rate for customer-provided capital that is applicable to investor-owned utilities, in equal monthly installments as part of GNPP's monthly invoice amounts such that the final monthly installment of the Deferred Collection Amount would be paid on the invoice relating to March 2017.[29]

Section 4.3 of the RSSA also provides for the possibility that market conditions could change sufficiently such that GNPP may elect to stay operational after the expiration of the Agreement, in which case it would be appropriate for GNPP to repay RG&E customers for a portion of the RSSA costs. Specifically, the RSSA requires that if the Ginna Facility delivers energy to the NYISO transmission system or makes available capacity to the NYISO markets after seventy-five days following the end of the RSSA term, GNPP will pay RG&E the Capital Recovery Balance and the Capital Recovery Quarterly Return, as specified in the RSSA, via

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28 Id. § 4.1(b).

29 Id. In light of these aspects of the RSSA, RG&E and GNPP respectfully request that the Commission grant a make-whole provision as necessary, when it suspends the attached tariff pages.

quarterly payments over six or seven years.[30] The exact term over which the quarterly payments will be made is based on the total amount due to RG&E customers.[31]

The RSSA is the result of lengthy and carefully considered negotiations between GNPP and RG&E. The RSSA contains concessions from both sides, and is intended to be treated as a package. The RSSA is cost-justified because the payments required by the agreement are within the range of just and reasonable outcomes and are significantly lower than GNPP's claimed full cost of service, as demonstrated by the GNPP cost-of-service analysis filed at FERC. As indicated in its FERC filing, GNPP is willing to accept the lower rate in the interest of avoiding litigation and establishing a just and reasonable rate for reliability service in a timely manner. The RSSA is also narrowly tailored to address the reliability need identified in the 2014 Reliability Study. At the same time, it performs the essential function of such an RSSA agreement, in that it maintains reliability in the Rochester, New York area. Thus, the RSSA is just and reasonable, in the public interest and should be accepted by the Commission.

## IV. REQUEST FOR APPROVAL OF COST ALLOCATION AND COST RECOVERY SURCHARGE MECHANISM

RG&E hereby respectfully requests Commission approval to recover all costs it incurs pursuant to the RSSA through an RSS Tariff Surcharge mechanism ("the RSS Surcharge"), thereby satisfying an RSSA condition precedent. RG&E's proposed RSS Surcharge is set forth in Exhibit B hereto.[32] The proposed RSS Tariff is nearly identical to the NYSEG RSS Tariff approved in Case 12-E-0400.[33]

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30 Id. § 4.3(a).

31 Id.

32 The proposed tariff pages were also filed with the Commission via the Electronic Tariff System. In addition, a draft State Administrative Proceeding Act notice is attached hereto as Exhibit C.

33 Case 12-E-0400 - Petition of Cayuga Operating Company, LLC to Mothball Generating Units 1 and 2, Order Deciding Reliability Issues and Addressing Cost Allocation and Recovery (Dec. 17, 2012).

The RSS Surcharge would allow RG&E to recover costs incurred pursuant to the RSSA, including monthly fixed payment costs; outside service and consultancy costs; applicable capital expenditures; any other costs passed on by any third-party to ensure local reliability needs; and the Deferred Collection Amount. Any payments or credits received by the Company for energy and ancillary service revenues, any payments or credits received by the Company for capacity revenues, and any other applicable payments or credits by third parties (e.g., other utility payments) will offset these costs.

RG&E proposes to allocate the RSSA costs to the respective service classes based on the Company's embedded cost of service study from the Company's last rate proceeding.[34] Specifically, the RSSA costs would be allocated based upon the transmission plant allocation factors contained in that study. For non-demand billed service classifications, the resulting surcharge rates are on a cent per kWh charge, and for the demand billed service classifications, the resulting surcharge rates are on a dollar per kW charge, with the exception of Service Classification No. 14. For customers taking service under Service Classification No. 14, the RSS Surcharge will be collected through an As Used Demand charge. Any RSSA agreement costs incurred prior to the implementation of the RSSA Surcharge would be deferred, and recovered via the RSSA Surcharge over the remaining billing months through March 31, 2017.

RG&E has estimated that, over the term of the agreement, the average residential customer using 600 kWh per month will incur an approximately 4.2% rate increase ($3.89/month) on its overall electric bill. The actual amount will vary monthly depending on the market price of energy supply and capacity. As a result, RG&E estimates that the rate change constitutes a "major change" under Section 66(12)(c) of the New York State Public Service Law

[34] Case 09-E-0717 - Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Rochester Gas and Electric Corporation for Electric Service.

("PSL"). PSL § 66(12)(f) provides that, when a utility files a schedule stating a new rate or change that is a "major change," a hearing must be held "concerning the propriety of a change proposed by the filing." Pending such a hearing, the Commission is authorized to suspend the effective date of a tariff that results in a major change for an initial 120 days, followed by an additional 6-month suspension period if the hearing cannot be concluded within the initial suspension period.

RG&E has filed the proposed RSS Surcharge effective April 1, 2015 with the expectation that the Commission will suspend the tariff's effective date pending a hearing in this matter. However, the suspension periods authorized by PSL § 66(12)(f) are permissive, not mandatory. PSL Section 66(12)(f) states: "[p]ending such hearing and decision thereon, the [C]ommission, upon filing with such schedule and delivering to the utility, a statement in writing of its reasons therefor, may suspend the operation of such schedule, but not for a longer period than one hundred and twenty days beyond the time when it would otherwise go into effect." PSL § 66(12)(f) (emphasis added). Pursuant to the same PSL section, "the Commission may extend the suspension for a further period not exceeding six months" if the hearing cannot be held within the initial one hundred and twenty day period. Id. (emphasis added). The time frames referenced in the statute set an outer limit on the length of the suspension period (i.e., one hundred and twenty days and six months), but do not set a minimum period. The use of the word "may" in the statute and the lack of a minimum period make the statutory suspension periods permissive rather than mandatory. See N.Y. Stat. Law 177(b), cmt. (McKinney) ("Generally speaking, permissive or discretionary words in a statute are to be given a permissive interpretation...."). Given the permissive nature of the statutory language, the Commission is not required to suspend RG&E's tariff filing to the full extent allowed by law[35] and the Company respectfully requests that the Commission take prompt action with respect to RG&E's proposed cost allocation and cost recovery surcharge mechanism such that the Commission can take final action in this matter at or prior to its April 2015 session.

Moreover, full and immediate recovery of any costs incurred under the RSSA is appropriate and necessary. Once the FERC and the Commission accept the RSSA and the Commission approves a cost recovery mechanism, the RSSA costs will be incurred by RG&E immediately - as it will require RG&E to submit monthly payments to GNPP for its continued operation of the Ginna Facility. Matching cost recovery with cost incurrence is appropriate to ensure that the cash flows of RG&E are not negatively impacted, which would have detrimental impacts on financial and credit metrics of the Company. Customers will receive the benefits of the RSSA immediately through continued reliability and it is therefore appropriate for customers to incur the costs concurrently with the benefits. Recovery of the RSSA costs on a current basis properly matches the reliability benefits with cash flows of the Company, therefore mitigating any potential harm to its credit rating and resulting cost to customers. Thus, RG&E requests approval of its proposed cost allocation and cost recovery surcharge mechanism.

## V. CONCLUSION

As the November Order concluded, retiring the Ginna Facility would create a reliability need. GNPP has stated that the RSSA is needed to keep the Ginna Facility operational and

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[35] See MCI Telecommunications Corp. v. Pub. Serv. Comm'n of N.Y., 231 A.D.2d 284, 293 (3d Dep't 1997) (stating "[w]hile new service offerings are generally subject to PSC investigations and suspensions, we note first that this suspension power is purely discretionary") (internal citations omitted); Case 08-E-0539, et al. - Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service, Ruling on Motion to Strike at 12 (Nov. 4, 2008) (stating "[t]urning to PSL § 66(12)(f), this statute affords the Commission discretion to suspend rate case filings and to take up to approximately eleven months for the hearing process to run its course and for the Commission to render a decision.") (emphasis added).

maintain electric system reliability within RG&E's service territory. RG&E respectfully requests Commission acceptance of the RSSA without modification.

RG&E also requests approval to implement an RSS Surcharge mechanism in the manner described herein to allow for full and immediate recovery of costs incurred pursuant to the RSSA.

Dated: February 13, 2015

Respectfully submitted,

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EXHIBIT
4
Sierra Club
PENGAD 800-631-6989

*** PUBLIC VERSION ***

# Exhibit A

# Reliability Support Services Agreement
# Between
# R.E. Ginna Nuclear Power Plant, LLC and
# Rochester Gas and Electric Corporation

Execution Version

# RELIABILITY SUPPORT SERVICES AGREEMENT

dated as of February 13, 2015,

between

R.E. Ginna Nuclear Power Plant, LLC

and

Rochester Gas and Electric Corporation

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EXHIBITS

# RELIABILITY SUPPORT SERVICES AGREEMENT

Pursuant to the rates, terms and conditions of this Reliability Support Services Agreement (this "Agreement"), dated as of February 13, 2015 (the "Effective Date"), R.E. Ginna Nuclear Power Plant, LLC ("Ginna") shall provide reliability support services to Rochester Gas and Electric Corporation ("RGE," and together with Ginna, the "Parties") from the R.E. Ginna Nuclear Power Plant which is interconnected with RGE's transmission system.

## RECITALS

WHEREAS, Ginna owns the R.E. Ginna Nuclear Power Plant, a nuclear generating station located in Ontario, New York, which consists of one (1) pressurized water reactor unit (PTID 23603) with a capacity of 581 MW (the "RSS Unit," and together with all appurtenant facilities, the "Facility"). Since being placed into service, the RSS Unit has supplied energy, capacity and ancillary services in New York;

WHEREAS, RGE is the transmission owner to which the Facility is interconnected;

WHEREAS, in January 2014, Ginna communicated to the New York State Independent System Operator ("NYISO") and RGE its intent to potentially retire the RSS Unit due to insufficient revenues projected to be earned by the Facility;

WHEREAS, the NYISO and RGE conducted a reliability study, dated as of May 12, 2014, which determined that retirement of the RSS Unit would result in bulk transmission system and non-bulk local distribution system reliability violations in 2015 and 2018;

WHEREAS, on July 11, 2014, Ginna submitted a petition to the New York State Public Service Commission ("NYPSC") requesting that the NYPSC direct RGE and Ginna to negotiate and file an agreement by which Ginna would provide Reliability Support Services from the RSS Unit to Ginna;

WHEREAS, on November 14, 2014, the NYPSC ordered RGE and Ginna to negotiate and file an agreement with the NYPSC by which Ginna would provide Reliability Support Services from the RSS Unit to RGE; and

WHEREAS, both Parties desire to ensure that the RSS Unit remains available to support system reliability in New York until certain transmission upgrades are completed or other reliability remedies are identified and implemented.

NOW THEREFORE, in consideration of the mutual agreements and covenants set forth herein, and other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, and intending to be legally bound by this Agreement, the Parties covenant and agree as follows:

## ARTICLE I
## DEFINITIONS

**1.1 Definitions.** Unless otherwise stated in this Agreement, the following terms shall have the following meanings:

(a) "**Acceptance Date**" shall have the meaning set forth in Section 2.1(a).

(b) "**Agreement**" shall have the meaning set forth in the Preamble.

(c) "**Ancillary Service Revenues**" shall have the meaning set forth in Section 3.2(d).

(d) "**Applicable Laws**" shall mean all applicable provisions of all constitutions, treaties, statutes, laws (including the common law), rules, regulations, ordinances, and codes and any order, writ, injunction, decree, judgment, award, decision or determination of any court or any federal, state, municipal or other governmental department, commission, board, bureau, agency, authority or instrumentality.

(e) "**Applicable Revenues**" shall mean RGE's eighty-five percent (85%) share of any Energy Revenues, RGE's eighty-five percent (85%) share of any Capacity Revenues and one hundred percent (100%) of any Ancillary Service Revenues, subject to Ginna's right to retain such Applicable Revenues under the circumstances described in Section 5.3(b) and in Section 7.1(b).

(f) "**Capacity Revenues**" shall have the meaning set forth in Section 3.2(c).

(g) "**Capital Recovery Balance**" shall mean the applicable amount set forth in Exhibit 5 for the applicable date of termination or expiration of this Agreement, as such amount may be adjusted pursuant to the last sentence of Section 4.3(a).

(h) "**Confidentiality Agreement**" shall have the meaning set forth in Section 10.14.

(i) "**Deferred Collection Amount**" shall have the meaning set forth in Section 4.1(b).

(j) "**Effective Date**" shall have the meaning set forth in the Preamble.

(k) "**Energy Revenues**" shall have the meaning set forth in Section 3.2(b).

(l) "**Environmental Laws**" shall mean any and all federal, state, or local, statutes, laws, judicial decisions, regulations, ordinances, rules, judgments, orders, decrees, plans, injunctions, permits, concessions, grants, franchises, licenses, agreements and other governmental restrictions relating to (i) the protection of the environment, (ii) the effect of the environment on human health, (iii) emissions, discharges or releases of hazardous materials or wastes into surface water, ground water or land, or (iv) the manufacturing, processing, distribution, use, treatment, storage, disposal, transport or handling of hazardous materials or wastes or the cleanup or other remediation thereof.

(m) "**EPT**" shall mean the prevailing time in the eastern time zone of the United States.

(n) "**Excess Force Majeure Outage Hour**" shall have the meaning set forth in Section 7.1(b)

(o) "**Facility**" shall have the meaning set forth in the Recitals.

(p) "**FERC**" shall mean the Federal Energy Regulatory Commission.

(q) "**FERC Authorization**" shall have the meaning set forth in Section 2.1(a).

(r) "**Force Majeure Event**" shall have the meaning set forth in Section 7.1(a).

(s) "**Force Majeure Outage**" shall mean the condition, other than during any period of Planned Outage or Unplanned Outage, in which due to a Force Majeure Event the RSS Unit is unavailable or available at an hourly average capacity level that is less than 400 megawatts.

(t) "**Force Majeure Performance Adjustment**" shall mean, for a given hour in a month, an amount equal to the pro-rata portion of the Monthly Fixed Payment, equivalent to the ratio of one (1) hour to the total amount of hours in such month.

(u) "**FPA**" shall mean the Federal Power Act.

(v) "**GAAP**" shall mean the generally accepted accounting principles in the United States, as in effect from time to time.

(w) "**Generation Attributes**" means any and all attributes associated with the capability of the RSS Unit or the Facility to produce capacity, energy or ancillary services or the generation of energy by the RSS Unit, including current or future credits, credit privileges, emissions reductions, offsets, allowances and other benefits, rights, powers or privileges, however denominated, including as such may be provided for in any currently existing or subsequently enacted Applicable Laws, attributable to the RSS Unit or the Facility. Examples of Generation Attributes include, but are not limited to: (i) renewable energy credits, offsets or other similar benefits allocated, assigned or otherwise awarded by any Governmental Authority, program administrator or other certification board and (ii) the avoidance of the emission of any gas, chemical or other substance into the air, soil or water, or the reduction, displacement or offset of emissions resulting from fuel combustion at another location pursuant to any federal, state or local legislation or regulation addressing "greenhouse gases" or similar emissions as well as environmental or renewable energy credit trading program or any similar program currently existing or subsequently enacted under Applicable Laws. "Generation Attributes" shall not include energy, capacity and ancillary services produced by the RSS Unit.

(x) "**Ginna**" shall have the meaning set forth in the Preamble.

(y) "**Ginna UCAP**" shall mean the RSS Unit's "Unforced Capacity" as determined in accordance with the NYISO Tariffs.

(z) "**Good Utility Practice**" shall mean any of the practices, methods or acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods or acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice or method, or act to the exclusion of all others, but rather to delineate acceptable practices, methods, or acts generally accepted in the region. Without limitation of the foregoing, "Good Utility Practices" shall include the applicable operating policies, standards, criteria, practices and/or guidelines of FERC, NERC, NYISO, NYSRC, NPCC, NRC and any other Governmental Authority, including those practices required by FPA Section 215(a)(4).

(aa) "**Governmental Authority**" shall mean the government of any nation, state or other political subdivision thereof, including any entity lawfully exercising executive, military, legislative, judicial, regulatory, or administrative functions of or pertaining to a government, including FERC, NERC, NYISO, NYSRC, NPCC and NRC.

(bb) "**Initial Term**" shall have the meaning set forth in Section 2.2(a).

(cc) "**Interconnection Agreement**" means the Interconnection Agreement, dated November 24, 2003, as amended, restated or supplemented, between RGE and Ginna (as successor to Constellation Generation Group, LLC by assignment).

(dd) "**Interest Rate**" shall have the meaning set forth in Exhibit 2.

(ee) "**Market or Regulatory Change**" shall mean any action by the NYPSC, NYISO, FERC or any successor Governmental Authority that is not subject to a stay and would cause supplemental capacity payments or other additional payments, revenues or credits to be provided with respect to the RSS Unit or the Facility due to (i) the RSS Unit being deemed to run partly or wholly for the benefit of additional constituencies (e.g., the State of New York or the region) and not exclusively for the benefit of RGE's customers or (ii) the RSS Unit's status as a nuclear generator or the nature of its energy, capacity, ancillary services or other Generation Attributes having been generated by a nuclear generator.

(ff) "**Monthly Fixed Amount**" shall mean $17,504,118.25 for each month during the Initial Term and $18,402,166.16 for each month during any Necessary Extension, in each case, prorated for any partial month, as such amounts may be adjusted in accordance with Section 4.1.

(gg) "**Necessary Extension**" shall mean, if elected by RGE in accordance with a Notice of Necessary Extension pursuant to Section 2.3, the period of time from the start of the hour ending at 0100 EPT on October 1, 2018 through the hour ending at 2400 EPT on March 31, 2020.

(hh) "**NERC**" shall mean the North American Electric Reliability Corporation.

(ii) "**Notice of Necessary Extension**" shall have the meaning set forth in Section 2.3.

(jj) "**NPCC**" shall mean the Northeast Power Coordinating Council, Inc.

(kk) "**NRC**" shall mean the Nuclear Regulatory Commission.

(ll) "**NYISO**" shall mean the New York Independent System Operator, Inc., or successor organization charged with operating the transmission system and markets in the State of New York.

(mm) "**NYISO Day-Ahead Energy Market**" shall mean the NYISO-administered day-ahead energy market.

(nn) "**NYISO ICAP Spot Market Auction**" shall mean the "ICAP Spot Market Auction" as defined in the NYISO Tariffs.

(oo) "**NYISO Outage Scheduling Manual**" shall mean the "Outage Scheduling Manual" published by the NYISO.

(pp) "**NYISO Tariffs**" shall mean, collectively, the published tariffs of the NYISO, including the Open Access Transmission Tariff and the Market Administration and Control Area Services Tariff, as such tariffs may be amended by the NYISO.

(qq) "**NYPSC**" shall have the meaning set forth in the Recitals.

(rr) "**NYSRC**" shall mean the New York State Reliability Council, L.L.C.

(ss) "**Party**" shall mean either Ginna or RGE. "**Parties**" means both Ginna and RGE.

(tt) "**Planned Outage**" shall mean a planned interruption, in whole or in part, in the electrical output of a generating unit to permit Ginna to perform maintenance and repair of the RSS Unit, pursuant to the process for providers and suppliers of installed capacity set forth in the NYISO Tariffs and NYISO Outage Scheduling Manual.

(uu) "**Property Taxes**" shall have the meaning set forth in Section 4.1(d).

(vv) "**Quarterly Installment Payment**" shall have the meaning set forth in Section 4.3(a).

(ww) "**Rate Recovery Order**" shall have the meaning set forth in Section 2.1(a).

(xx) "**Reliability Support Services**" shall mean the services required to be provided by Ginna to RGE pursuant to this Agreement and shall include but not be limited to Ginna (a) keeping the RSS Unit available, capable of being committed and operating for reliability purposes as requested by RGE or the NYISO, (b) offering the RSS Unit's energy into the NYISO Day-Ahead Energy Market and capacity into NYISO ICAP Spot Market Auctions, and (c) providing reactive power consistent with the capability of the RSS Unit pursuant to the Interconnection Agreement and the procedures specified under voltage support service provisions of the NYISO Tariffs.

(yy) "**RGE**" shall have the meaning set forth in the Preamble.

(zz) "**RSS Unit**" shall have the meaning set forth in the Recitals.

(aaa) "**Scheduling, System Control and Dispatch Charge**" shall mean the charges attributable to the RSS Unit for scheduling, system control and dispatch service calculated in accordance with Schedule 1 of the NYISO Open Access Transmission Tariff and Schedule 1 of the NYISO Market Administration and Control Area Services Tariff.

(bbb) "**Settlement Payment**" shall mean the applicable amount set forth in Exhibit 1 for the applicable date of early termination of this Agreement plus any unpaid balance of any Deferred Collection Amount.

(ccc) "**Staff**" shall mean the staff of the New York State Department of Public Service.

(ddd) "**Term**" shall mean the Initial Term, together with any Necessary Extension unless such period is decreased upon the termination of the Agreement pursuant to Section 2.1(c), Section 2.2(c) or Section 9.1.

(eee) "**Unplanned Outage**" shall mean the condition, other than during any period of Planned Outage or Force Majeure Outage, in which due to unanticipated failure the RSS Unit is unavailable or available at an hourly average capacity level that is less than 400 megawatts.

(fff) "**Unplanned Outage Performance Adjustment**" shall mean, for a given hour in a month, an amount equal to the pro-rata portion of the Monthly Fixed Payment, equivalent to the ratio of one (1) hour to the total amount of hours in such month.

## ARTICLE II
## CONDITIONS TO PAYMENT OBLIGATIONS; TERM; SURVIVAL OF OBLIGATIONS

### 2.1 Conditions to Payment Obligations

(a) The Parties' obligations with respect to payment of the Monthly Fixed Amount (including the obligation to net Applicable Revenues, any Unplanned Outage Performance Adjustments, any Force Majeure Event Performance Adjustments and any other amounts payable by Ginna under this Agreement) shall be subject to the Parties obtaining the following:

(i) the issuance by FERC of an order accepting this Agreement under Section 205l of the Federal Power Act, 16 U.S.C. §824d and the regulations promulgated thereunder, without modifying or imposing any term or condition in a manner that is adverse in any material respect to a Party as determined in the affected Party's reasonable discretion ("FERC Authorization"); and

(ii) the issuance by the NYPSC of an order (A) accepting this Agreement and (B) approving full and immediate cost recovery by RGE through a customer surcharge (without offset or deferral including with respect to items unrelated to this Agreement) of all amounts payable to Ginna under this Agreement on a substantially current basis that coincides with the timing of all payments made by RGE to Ginna hereunder, in each case, without modifying or imposing any term or condition in a manner that is adverse in any material respect to a Party as determined in the affected Party's reasonable discretion (the "Rate Recovery Order").

The date, if any, upon which each of the foregoing conditions precedent set forth in clauses (i) and (ii) above are satisfied or waived by the Parties shall be referred to herein as the "Acceptance Date."

(b) Each of the Parties shall use commercially reasonable efforts to take, or cause to be taken, all actions, and to do, or cause to be done, all things necessary, proper or advisable under Applicable Laws to cause the FERC Authorization and the Rate Recovery Order to be obtained as expeditiously as possible. Each of the Parties shall cooperate with each other, and execute and deliver such additional documents, as may be reasonably required in order to achieve the Acceptance Date in accordance with Section 2.1(a) as expeditiously as possible.

(c) Ginna shall have the right to terminate this Agreement without liability upon ten (10) days' prior written notice if the Acceptance Date is not achieved by July 1, 2015, but such a termination notice may not be issued later than August 1, 2015. Without limiting the immediately foregoing sentence, during the process to obtain the FERC Authorization or the Rate Recovery Order, if a Governmental Authority modifies or imposes any term or condition that is adverse in any material respect to a Party, as determined in the affected Party's reasonable discretion, then such adversely affected Party shall have the right to terminate this Agreement without liability upon ten (10) days' prior written notice, but such a termination notice may not be issued later than thirty (30) days after the date of such final modification or imposition by a Governmental Authority. Without limiting the foregoing sentences of this Section 2.1(c), RGE shall have the right to terminate this Agreement without liability upon ten (10) days' prior written notice if RGE reasonably determines that the Rate Recovery Order does not provide full and immediate cost recovery to RGE through a customer surcharge (without offset or deferral including with respect to items unrelated to this Agreement) of all amounts payable to Ginna under this Agreement on a substantially current basis that coincides with the timing of all payments made by RGE to Ginna hereunder, but such a termination notice may not be issued later than thirty (30) days after the date of the issuance by the NYPSC of the Rate Recovery Order; provided, that RGE's failure to exercise such termination right within such thirty (30) day period shall be deemed to constitute RGE's acknowledgement that the Rate Recovery Order satisfies the condition precedent set forth in Section 2.1(a)(ii).

(d) The Parties expressly acknowledge, except for the payment obligations described in Section 2.1(a), the other rights and obligations of the Parties under this Agreement, including Ginna's obligation to provide the Reliability Support Obligations during the Initial Term, are not contingent upon satisfaction of the conditions precedent set forth in Section 2.1(a). In consideration for RGE executing this Agreement prior to the Acceptance Date, Ginna expressly agrees to accept the risk that, unless and until this Agreement is terminated in accordance with Section 2.1(c) or otherwise, Ginna may perform the Reliability Support Obligations in accordance with this Agreement without any compensation, or with reduced compensation, if the FERC Authorization or Rate Recovery Order are not received in accordance with Section 2.1(a). Ginna hereby waives to the fullest extent possible any rights under this Agreement and at law and in equity (including under any theory of unjust enrichment, restitution, quantum meruit or similar legal theory or any claim under the Federal Power Act, the New York Public Service Law or the rules and regulations of the NYPSC) to recover the Monthly Fixed Amount from RGE with respect to the Term in the event that this Agreement is terminated without achievement of the Acceptance Date. This Section 2.1(d) shall survive any termination of this Agreement.

### 2.2 Term

(a) Reliability Support Services shall be provided commencing at the start of the hour ending 0100 EPT on April 1, 2015 and remain in effect through the hour ending 2400 EPT on September 30, 2018, unless the Agreement is otherwise terminated pursuant to Section 2.1(c), Section 2.2(c) or Section 9.1 (the "Initial Term").

(b) This Agreement shall be effective as of the Effective Date and no provision of this Agreement shall terminate earlier than the expiration of the Initial Term, except as otherwise provided in Section 2.1(c), Section 2.2(c) or pursuant to the provisions relating to Termination for Default (Section 9.1).

(c) Upon at least twelve (12) months' prior written notice, RGE, in its sole discretion, may terminate this Agreement prior to the expiration of the Initial Term. Upon the provision of such written termination notice, RGE no longer shall have the right to require a Necessary Extension pursuant to Section 2.3. Upon the termination date specified in such notice, RGE shall pay to Ginna the Settlement Payment and shall have no further liability to Ginna under this Agreement except for liabilities incurred prior to such termination date.

## 2.3 Necessary Extension

RGE may provide written notice to Ginna ("Notice of Necessary Extension") indicating that RGE has reasonably determined, in consultation with the NYISO and the NYPSC and subject to any order or requirement of the NYPSC, that the continued operation of the RSS Unit is required for reliability purposes after the expiration of the Initial Term and any such extension shall be for a period of eighteen (18) months ("Necessary Extension"). Such Notice of a Necessary Extension shall be provided no later than January 31, 2017. Ginna shall acknowledge receipt of the Notice of Necessary Extension in writing to RGE within five (5) business days of receipt. Upon RGE sending such Notice of Necessary Extension, the Term shall be extended by a period of eighteen (18) months through the hour ending at 2400 EPT on March 31, 2020.

## 2.4 Survival of Obligations

Notwithstanding the termination of this Agreement, the Parties shall continue to be bound by the provisions of this Agreement that by their nature are intended to, and shall, survive such termination.

# ARTICLE III
# OBLIGATIONS AND OPERATIONS

## 3.1 Scheduling and Bidding

(a) Ginna shall cause the RSS Unit and the Facility to be fueled, operated and maintained in accordance with Good Utility Practice and the NYISO Tariffs and with due regard for the reliability purpose of this Agreement.

(b) Ginna shall interface and comply with NYISO scheduling deadlines and requirements for maintaining the Facility and the RSS Unit as eligible energy, capacity and ancillary services providers, as well as comply with the NYISO's dispatch instructions and the Interconnection Agreement. The Parties acknowledge that the Reliability Support Services shall not include the purchase by RGE of any physical energy-related products or services (energy, capacity or ancillary services); provided that Ginna shall be obligated to provide such energy products and services to the NYISO as described in this Agreement, with the Applicable Revenues derived therefrom to be applied as a credit against RGE's obligation for the Monthly Fixed Amount in accordance with Section 3.2.

(c) The Parties acknowledge that as a consequence of the provision of the Reliability Support Services under this Agreement, Ginna will need to run the RSS Unit for testing and diagnostic purposes, including for demonstrating the RSS Unit's Dependable Maximum Net Capability (as defined in the NYISO Tariffs) and relative accuracy test audit testing, reactive capability testing, environmental compliance testing, or as otherwise required by plant management for health, safety, environmental or operational reasons. As permitted under the NYISO Tariffs and as warranted by system conditions, the Parties shall coordinate the scheduling of the RSS Unit for these purposes so that RGE will either designate the related RSS Unit as the Day-Ahead Reliability Unit (as defined in the NYISO

Tariffs) or commit that RSS Unit pursuant to the Supplemental Resource Evaluation (as defined in the NYISO Tariffs). Such designation shall be coordinated between the Parties so that the most appropriate designation is selected. Ginna shall use reasonable best efforts to perform these tests during periods already scheduled by RGE or the NYISO. Ginna shall coordinate with RGE to schedule any testing required to meet operational requirements. In the event that such testing cannot be accomplished during a period of time the RSS Unit is in operation, Ginna shall provide RGE with at least fourteen (14) days advance written notice requesting written authorization from RGE for Ginna to self-commit the RSS Unit. Authorization by RGE shall not be unreasonably withheld.

**3.2 Energy, Capacity and Ancillary Services**

(a) Ginna shall at all times bid the RSS Unit in compliance with NYISO market rules.

(b) Ginna shall offer the full amount of the RSS Unit's expected hourly output into the NYISO Day-Ahead Energy Market consistent with past practice, subject to compliance with NYISO market rules. Ginna shall comply with any dispatch instruction issued by the NYISO under established NYISO protocols or by RGE under the Interconnection Agreement, to the extent such dispatch instructions are consistent with the operating parameters of the RSS Unit and are in accordance with the NYISO Tariffs. All monthly energy revenues, net of the Scheduling, System Control and Dispatch Charge, paid by the NYISO for the account of the RSS Unit ("Energy Revenues") shall be shared such that RGE shall be entitled to eighty-five percent (85%) of Energy Revenues and Ginna shall be entitled to fifteen percent (15%) of Energy Revenues, subject to Ginna's right to retain all Energy Revenues under the circumstances described in Section 5.3(b) and Section 7.1(b).

(c) Ginna shall offer Ginna UCAP into the NYISO ICAP Spot Market Auction; such offers shall be consistent with Ginna's prior offers into such auction and be subject to compliance with NYISO market rules. All monthly capacity revenues paid by the NYISO for the account of the RSS Unit ("Capacity Revenues") shall be shared such that RGE shall be entitled to eighty-five percent (85%) of Capacity Revenues and Ginna shall be entitled to fifteen percent (15%) of Capacity Revenues, subject to Ginna's right to retain all Capacity Revenues under the circumstances described in Section 5.3(b) and Section 7.1(b).

(d) RGE shall be entitled to one hundred percent (100%) of any ancillary service (including reactive power) revenues paid for the account of the RSS Unit ("Ancillary Service Revenues"), subject to Ginna's right to retain all Ancillary Service Revenues under the circumstances described in Section 5.3(b) and Section 7.1(b).

(e) Ginna shall use commercially reasonable efforts, consistent with Good Utility Practice, to maximize the Energy Revenues, Capacity Revenues and Ancillary Service Revenues.

(f) The Applicable Revenues shall be (i) credited against the Monthly Fixed Amount for the applicable delivery month, with any Applicable Revenues in excess of the Monthly Fixed Amount paid to RGE, and (ii) reflected on the monthly invoice relating to such delivery month in accordance with Section 4.1(a).

(g) The Parties shall credit or otherwise reimburse each other for any under or overpayments of Energy Revenues, Capacity Revenues and/or Ancillary Service Revenues if any such revenues for any month are modified in the NYISO's close-out invoicing process. This provision shall survive termination of this Agreement until the NYISO has issued a final close-out invoice for every month of the Term.

(h) Ginna (or its affiliates with respect to any portion of the Facility owned by affiliates of Ginna) shall be solely responsible, without contribution from RGE, for any penalties, fines or imbalance charges that relate to the bidding, scheduling and operation of the RSS Unit or the operations of the Facility.

(i) During the Term, Ginna shall not engage in any hedging activities other than non-speculative hedging activities relating to the projected volumes associated with Ginna's fifteen percent (15%) share of any Energy Revenues and fifteen percent (15%) share of any Capacity Revenues. No revenues or losses from any such hedging activities shall be included in the calculation of Energy Revenues, Capacity Revenues or Ancillary Service Revenues. Notwithstanding the foregoing, the provisions of this Section 3.2(i) shall not serve to limit the ability of Ginna's affiliates to enter into any hedging activities so long as Ginna is not obligated under or financially impacted by such hedging activities.

(j) Each Party shall bear its own bad debt losses under the NYISO Tariffs.

### 3.3 Generation Attributes

Any Generation Attributes and revenues (including any revenues paid by the NYISO) associated therewith (other than energy, capacity and ancillary services and revenues and losses resulting from hedging activities), whether financially settled or otherwise, shall accrue to RGE's benefit, either as a credit to the Monthly Fixed Amount or as a transfer of title of such Generation Attributes to RGE for the duration of the Term, as Ginna may elect. Ginna shall use commercially reasonable efforts, consistent with Good Utility Practice, to maximize such Generation Attributes and revenues associated therewith.

### 3.4 Operating Characteristics and Environmental Compliance

Ginna shall have no obligation to cause the RSS Unit to be operated in a manner that would be inconsistent with or in violation of the NYISO Tariffs, NERC, NPCC, NRC or NYSRC rules or would cause Ginna to violate the terms of any applicable environmental regulations, restrictions, orders or decrees or any operating permit, which determination shall be made by

Ginna in its reasonable discretion. Ginna shall have the obligation to ensure that the RSS Unit is operated in accordance with the NYISO Tariffs, NERC, NPCC, NRC or NYSRC rules and consistently with the terms of any applicable environmental regulations, restrictions, orders or decrees or any required operating permits.

**3.5 Reactive Power**

Except when the RSS Unit is unavailable, the RSS Unit shall provide reactive power consistent with the capability of the RSS Unit and in accordance with the Interconnection Agreement and the procedures specified under the NYISO's Voltage Support Service.

**3.6 Retirement of RSS Unit**

Ginna shall be entitled to undertake any actions during the Term that are necessary or advisable to retire the RSS Unit after the Term so long as such actions do not unreasonably interfere with, limit or diminish Ginna's provision of the Reliability Support Services during the Term.

## ARTICLE IV
## PRICING

**4.1 Monthly Fixed Amount**

(a) The billing period during the Term shall be each calendar month. Not later than the twentieth ($20^{th}$) day of each month, Ginna shall prepare and provide to RGE an invoice showing for the preceding month the Monthly Fixed Amount (prorated for any partial month), the Applicable Revenues, any Unplanned Outage Performance Adjustments, any Force Majeure Event Performance Adjustments and any other amounts payable by either Party under this Agreement, together with reasonable documentation supporting the invoiced amounts (including the relevant NYISO invoices detailing the revenues and charges related to the RSS Unit). RGE shall pay Ginna the Monthly Fixed Amount (net of Applicable Revenues, any Unplanned Outage Performance Adjustments, any Force Majeure Event Performance Adjustments and any other amounts payable by Ginna under this Agreement) for each month during the Term.

(b) In the event that the Acceptance Date is achieved after April 1, 2015, (i) Ginna shall track the net amount that would have been owed to or by Ginna under this Agreement had the Acceptance Date been achieved by April 1, 2015 (*i.e.* the Monthly Fixed Amount, net of Applicable Revenues, any Unplanned Outage Performance Adjustments, any Force Majeure Event Performance Adjustments and any other amounts payable by Ginna under this Agreement) for each calendar month (or any partial month) until the day immediately prior to the Acceptance Date (such cumulative net amount for such calendar months, the "Deferred Collection Amount"), (ii) Ginna shall prepare and provide to RGE as soon as reasonably practicable, but not later than the twentieth ($20^{th}$) day of the month after the Acceptance Date is achieved, a calculation of the Deferred Collection Amount, together with reasonable documentation supporting such amount and

(iii) RGE or Ginna, as the case may be, shall pay the Deferred Collection Amount, plus interest on the unpaid balance thereof at the NYPSC-published interest rate for customer-provided capital that is applicable to investor-owned utilities, in equal monthly installments as part of Ginna's monthly invoice amounts such that the final monthly installment of the Deferred Collection Amount is scheduled to be paid on the invoice relating to March 2017. Ginna shall recalculate the Deferred Collection Amount and the monthly installment payments thereof if any component of the Deferred Collection Amount is subsequently adjusted by any final close-out invoice issued by the NYISO. For the avoidance of doubt, any Deferred Collection Amount shall not be considered to be part of the Monthly Fixed Amount for purposes of determining any Unplanned Outage Performance Adjustments or any Force Majeure Event Performance Adjustments for periods on and after the Acceptance Date.

(c) In the event that the nuclear waste fee established under the Nuclear Waste Policy Act of 1982 is reinstated during the Term (including the establishment of a fee covering time periods prior to the Term that is payable based upon the operation of the RSS Unit during the Term), the Monthly Fixed Amount shall be increased during the period during the Term in which such nuclear waste fee is in effect by the monthly amount of the nuclear waste fee applicable to the RSS Unit, as calculated based on the actual monthly generation output of the RSS Unit. For the avoidance of doubt, no amount shall be payable by RGE for any such nuclear waste fee that is reinstated after the Term that applies retroactively to the Term.

(d) In the event that Ginna pays (i) annual property tax payments or (ii) in lieu of tax payments applicable to the Facility ((i) and (ii) defined herein as "Property Taxes") in amounts that are lower than $8.41 Million in 2015, $7.25 Million in 2016, $7.39 Million in 2017 or $7.54 Million in 2018, respectively, then the Monthly Fixed Amount shall be decreased during the applicable calendar year in the Initial Term by an amount equal to one-twelfth (1/12) of the difference between the amount set forth above for such year and the paid Property Taxes applicable to such year.

**4.2 Capital Expenditures and Operating Costs**

In consideration of the Monthly Fixed Amount and the revenues retained by Ginna pursuant to Section 3.2, Ginna shall be responsible, at its sole cost and without additional payment from RGE, for all capital expenditures and operating costs (including fuel), whether or not currently anticipated, required to operate and maintain the RSS Unit in accordance with Good Utility Practice, including, but not limited to the projected expenditures described in Exhibit 6 (if required) and any capital expenditures or operating costs (including fuel) attributable to the enactment of any Applicable Laws, or any changes in existing Applicable Laws, after the date hereof. The Parties acknowledge that the economic terms of this Agreement, including the Fixed Monthly Amount and the revenues retained by Ginna pursuant to Section 3.2, have been established based upon an estimate of such capital expenditures and operating costs (including fuel) and the Parties have agreed that Ginna shall bear the risk and retain the benefit of any savings related to estimated capital expenditures and operating costs during the Term.

### 4.3 Payment of Capital Recovery Balance

(a) If the RSS Unit delivers energy to the NYISO transmission system or makes available capacity to the NYISO markets after seventy-five (75) days following the end of the Term, Ginna shall pay RGE the Capital Recovery Balance as more particularly described in this Section 4.3(a). The quarterly installment payments of the Capital Recovery Balance shall be calculated according to the following formula:

$$\text{Quarterly Installment Payment} = (i \times B \times (1+i)^n) / ((1+i)^n - 1)$$

<u>Where</u>:

i = the quarterly compounded equivalent of RGE's then-NYPSC approved weighted average cost of capital

B = the applicable Capital Recovery Balance as specified in Exhibit 5

n = the total quarters over which the Capital Recovery Balance is to be recovered (i.e., 24 if the capital recovery balance is less than $50M, 28 if the capital recovery balance is greater than $50M)

Such payments (i) shall only include periods after the seventy-five (75) day period following the end of the Term and (ii) shall be prorated for any partial calendar quarter. Ginna's payment obligation under this Section 4.3 shall survive the termination of this Agreement until the earlier of (i) the completion of twenty-four (24) Quarterly Installment Payments, if the Capital Recovery Balance is less than or equal to $50 million, or twenty-eight (28) Quarterly Installment Payments, if the capital recovery balance is greater than $50 million, and (ii) such time that the RSS Unit permanently ceases delivering energy to the NYISO transmission system and making available capacity to the NYISO markets. Ginna shall invoice amounts due by Ginna to RGE under this Section 4.3(a) on the tenth ($10^{th}$) business day following the end of each calendar quarter. Ginna shall be entitled to remit prepayments of all or any portion of the Capital Recovery Balance, foregoing the requirement to pay any interest on such amount, and, upon such prepayment, (w) the Capital Recovery Balance shall be decreased by the prepayment amount, (x) Ginna shall not be required to resume making Quarterly Installment Payments until after the equivalent number of prepayment amount quarters has passed, (y) the Quarterly Installment Payment shall be recalculated in accordance with the above formula such that the remaining, post-prepayment Capital Recovery Balance will be recovered over the remaining number of Quarterly Installment Payments after Ginna is required to resume making Quarterly Installment Payments and (z) the remaining Capital Recovery Balance shall continue to accrue interest until repaid.

(b) If the RSS Unit permanently ceases delivering energy to the NYISO transmission system and making available capacity to the NYISO markets prior to seventy-five (75) days following the end of the Term, Ginna's compensation and payment obligations set forth in Section 4.3(a) shall not apply, but such obligations shall be reinstated if the RSS Unit subsequently resumes delivering energy to the NYISO transmission system or making available capacity to the NYISO markets.

(c) For each hour in a given month in which an Unplanned Outage Performance Adjustment or Force Majeure Performance Adjustment amount is credited against the Monthly Fixed Amount as specified in Section 5.3(b) or Section 7.1(b), the Capital Recovery Balance shall be reduced by the following amount:

Capital Recovery Balance Reduction = (FH/H) * (P - R) * RATIO

Where:

FH = hours in such month that are subject to an Unplanned Outage Performance Adjustment or a Force Majeure Performance Adjustment
H = total hours in a given month
P = Fixed Monthly Payment
R= The amount of Applicable Revenues retained by Ginna applicable to such hour, pursuant to Section 5.3(b) or Section 7.1(b)
RATIO = 4.21% for the period April 1, 2015 – September 30, 2018 and 2.66% for the period October 1, 2018 – March 31, 2020

The Capital Recovery Balance Reduction shall never be less than zero (0).

### 4.4 Billing and Payment

Billing and payment terms for invoices issued under Sections 4.1 and 4.3(a) shall be as set forth in Exhibit 2.

### 4.5 Other Costs

Each Party shall bear its own attorneys' and consultants' fees incurred in connection with the preparation, negotiation, regulatory approval and administration of this Agreement.

### 4.6 Books and Records

RGE shall have the right to reasonable access to, review of, and audit of Ginna's books and records for the purpose of proper administration of this Agreement, including the satisfaction of any inquiry of RGE by a Governmental Authority relating to this Agreement, subject to Applicable Laws. Notwithstanding the foregoing, RGE shall not be entitled to review any Safeguards Information (as defined in 10 C.F.R. §73.2) relating to the Facility or any information relating to the Facility that is classified as National Security Information or Restricted Data or information or records concerning the Facility's physical protection, classified matter protection, or material control and accounting program for special nuclear material not otherwise designated as Safeguards Information or classified as National Security Information or Restricted Data (as discussed in 10 C.F.R. § 2.390(d)(1)) unless (a) Ginna determines in its reasonable discretion that RGE has reason to know such information and the requested information is related to the administration of this Agreement and (b) each individual determined by RGE to have reason to know such information satisfies any security checks required by and other regulatory requirements of any Governmental Authority or generally required by the Facility prior to and/or as a condition of being granted access to, review of, or audit of such information.

## ARTICLE V
## OUTAGES AND MAINTENANCE; ACCESS

### 5.1 Planned Outages

(a) The schedule of Planned Outages for the Term is set forth in Exhibit 3. Ginna shall provide to RGE a detailed major outage plan and schedule involving maintenance or restoration of the RSS Unit from a Planned Outage. Upon reasonable notice to RGE, Ginna may alter the commencement and/or completion dates for Planned Outages, provided that increasing the duration of a Planned Outage beyond the applicable duration set forth in Exhibit 3 shall be subject to Section 5.3(a).

(b) Ginna shall be permitted to take the RSS Unit out of operation, or reduce the capability of the RSS Unit, during Planned Outages as permitted by the NYISO Tariffs and policies and the Interconnection Agreement.

(c) Ginna shall provide RGE a monthly report on the tenth ($10^{th}$) business day of each successive month of the Term on the current and projected operating status of the RSS Unit and any upcoming items of note, including any forecasted changes to the Planned Outage schedule, substantially in the form set forth in Exhibit 4. Such reports shall not serve to amend Exhibit 3 for purposes of determining Unplanned Outage Performance Adjustments in accordance with Section 5.3.

### 5.2 Unplanned Outages

In the event of an Unplanned Outage, Ginna shall notify RGE, pursuant to established practice under the NYISO Outage Scheduling Manual, of the nature and expected duration of such Unplanned Outage as soon as practicable and shall keep RGE timely advised of any developments associated with such Unplanned Outage and the estimated timing of the return of the RSS Unit to full capability. Ginna shall use commercially reasonable efforts to remedy and to mitigate the consequences of an Unplanned Outage as soon as reasonably practicable. An Unplanned Outage that occurs and continues for a period of ninety (90) consecutive days or more shall be considered a failure to perform a material obligation under this Agreement by Ginna that is subject to termination for default pursuant to Section 9.1.

## 5.3 Unplanned Outage Performance Adjustment

(a) Ginna's failure to return the RSS Unit to service from a Planned Outage within the allotted duration set forth in Exhibit 3 shall result in the excess hours associated with such Planned Outage being treated as an Unplanned Outage and the application of the Unplanned Outage Performance Adjustment as set forth in Section 5.3(b) below, but shall not be deemed a failure to perform a material obligation under this Agreement under Section 9.1 unless Ginna fails to exercise Good Utility Practices and act in accordance with the NYISO Tariffs in returning the RSS Unit to service.

(b) For each hour (or portion thereof) of an Unplanned Outage that exceeds a total of 195 hours for a calendar year (pro-rated for any partial years) during the Term, (i) an Unplanned Outage Performance Adjustment amount shall be credited against the Monthly Fixed Amount on the monthly invoice that is issued for the month in which such hour occurs and (ii) Ginna shall be entitled to retain, without credit to RGE, the Applicable Revenues relating to such hour.

## 5.4 Access

RGE shall be entitled to have one individual who shall serve as RGE's representative or agent and who shall not be an employee of Ginna or its affiliates located in a work space at the Facility's training building, with badge access (*i.e.* authorized access at all times without escort) to the training building. Such RGE representative or agent shall be given access to the internet at such work space, if so requested, but shall not be entitled to access to any computer system of Ginna or its affiliates. RGE shall be entitled to have its on-site representative or agent given visitor (escorted) access to the other areas of the Facility and a reasonable number of additional representatives or agents given visitor (escorted) access to the Facility, subject to such representatives' or agents' satisfaction of any security and regulatory requirements and other protocols generally required of visitors to the Facility and upon reasonable advance notice to Ginna. RGE's representatives and agents shall at all times comply with all requirements and instructions of Facility personnel while present at the Facility, including but not limited to any requirements of any Governmental Authority. Such access to the Facility shall not unreasonably interfere with the operations of the Facility. RGE shall be solely responsible for, and shall indemnify and hold harmless Ginna for, the acts of or any employment related claims or other claims brought by RGE's employees, representatives or agents, including any loss, claim, action or suit for or on account of injury or death of persons, or for damage to, or destruction or economic loss of, property associated with any (a) injury sustained by RGE's employees, representatives or agents or (b) acts or omissions of any of RGE's representatives or agents while present at the Facility's training building or at the Facility.

## ARTICLE VI
## REPRESENTATIONS AND WARRANTIES

### 6.1 Representations and Covenants of Ginna

Ginna hereby represents and warrants to RGE as of the Effective Date and covenants to RGE that:

(a) Ginna is a limited liability company duly organized, validly existing and in good standing under the laws of the State of Maryland. Ginna has full limited liability company power and authority to own and lease all of the properties and assets it now owns and leases and to carry on its business as now being conducted. To the knowledge of Ginna, Ginna is in substantial compliance with Applicable Laws.

(b) Ginna has full power and authority (limited liability company and otherwise) to execute, deliver and perform this Agreement (including execution, delivery and performance of the operative documents to which Ginna is a party) and to consummate the transactions contemplated herein, subject to the conditions set forth in this Agreement. The execution and delivery by Ginna of this Agreement and the operative documents, and the consummation of the transactions will not violate Ginna's organizational documents or other obligations, and no other proceedings on the part of Ginna are necessary with respect thereto and no additional consents or approvals other than those provided for herein are required. This Agreement has been duly and validly executed and delivered by Ginna and constitutes the legal, valid and binding obligation of Ginna enforceable against Ginna in accordance with its terms except as the same may be limited by bankruptcy, insolvency, reorganization, arrangement, fraudulent conveyance, moratorium or other similar laws relating to or affecting the rights of creditors generally, or by general equitable principles (regardless of whether enforcement is considered in a proceeding at law or in equity). Ginna shall take, and cause to be taken, all action that is necessary for Ginna to complete the actions to be completed by Ginna pursuant to this Agreement.

(c) There are no known issues, defects, problems or other issues involving or related to the ownership and/or operation of the RSS Unit and the Facility as a whole that would preclude or prevent Ginna from fully performing its duties and obligations in accordance with this Agreement.

(d) The calculation of operating and maintenance costs and capital expenditures anticipated to be incurred by Ginna over the Term included in the cost of service materials and supporting data referenced in the affidavit submitted by Ginna to FERC in connection with its application for approval of this Agreement, attached hereto as Exhibit 6, (i) have been prepared by Ginna in good faith consistent with its historical practices, (ii) represent Ginna's best estimate of such costs consistent with historical practices and the projected operations of the Facility during the Term and (iii) are consistent with the prevailing cost estimates and operating plans presented to the board of directors of Constellation Energy Nuclear Group, LLC on December 9, 2014.

(e) No citations, fines, or penalties have been asserted against Ginna under any Environmental Law or by the regulatory authority or jurisdiction in which Ginna operates. Ginna has not received notice (verbal or written) of, nor is it aware of, any person making allegations that all or any part of the RSS Unit or the Facility as a whole, or the use, operation or ownership thereof, are in violation of any applicable Environmental Law.

(f) Ginna shall keep in force all existing policies of insurance, or comparable replacement policies of insurance at existing levels of coverage related to the RSS Unit and the Facility, including the ownership and operation thereof, throughout the duration of the Term.

(g) Ginna is in compliance with or has performed all agreements, representations and warranties, and conditions in this Agreement that are required to be performed and complied with by Ginna before or coincident with the Effective Date.

**6.2 Representations and Covenants of RGE**

RGE hereby represents and warrants to Ginna as of the Effective Date and covenants that:

(a) RGE is a corporation duly organized, validly existing and in good standing under the laws of the State of New York, with full corporate power and authority to own property and carry on its business as now being conducted.

(b) RGE has full power and authority (corporate and otherwise) to execute, deliver and perform this Agreement (including execution, delivery and performance of the operative documents to which RGE is a party) and to consummate the transactions contemplated herein, subject to the conditions set forth in this Agreement. The execution and delivery by RGE of this Agreement and the operative documents, and the consummation of the transactions will not violate RGE's organizational documents or other obligations, and no other corporate proceedings on the part of RGE are necessary with respect thereto and no additional consents or approvals other than those provided for herein are required. This Agreement has been duly and validly executed and delivered by RGE and constitutes the legal, valid and binding obligation of RGE enforceable against RGE in accordance with its terms except as the same may be limited by bankruptcy, insolvency, reorganization, arrangement, fraudulent conveyance, moratorium or other similar laws relating to or affecting the rights of creditors generally, or by general equitable principles (regardless of whether enforcement is considered in a proceeding at law or in equity). RGE shall take, and cause to be taken, all corporate action that is necessary for RGE to complete the actions to be completed by RGE pursuant to this Agreement.

(c) RGE is in compliance with or has performed all agreements, representations and warranties, and conditions in this Agreement that are required to be performed and complied with by RGE before or coincident with the Effective Date.

## ARTICLE VII
## FORCE MAJEURE EVENTS

### 7.1 Force Majeure Event

(a) Any delay or failure in the performance by a Party, other than payment of undisputed amounts, shall be excused if and to the extent caused by the occurrence of a Force Majeure Event. A "Force Majeure Event" means acts of God, fires, floods, explosion, riots, wars, unusually inclement weather, sabotage, vandalism, terrorism, terroristic acts, restraint of government, governmental acts, changes in laws, regulations or orders or injunctions, labor strikes, breakage or accident of machinery or equipment resulting from an event or circumstance that would otherwise constitute a Force Majeure Event hereunder, and other like events or circumstances that are beyond the reasonable control of the Party affected thereby, despite such Party's commercially reasonable efforts to prevent, avoid, delay, or mitigate the effect of such acts, events or occurrences, and which events or the effects thereof are not attributable to a Party's negligence or failure to perform its obligations under this Agreement. In no event shall "Force Majeure Event" include economic hardship of any kind.

(b) RGE's obligation to pay Ginna the Monthly Fixed Amount shall not be affected by the occurrence of a Force Majeure Event, but the amount of the Monthly Fixed Amount may be adjusted for a Force Majeure Outage pursuant to this Section 7.1(b). For each hour (or portion thereof) of a Force Majeure Outage (other than due to a Force Majeure Event with respect to the transmission or distribution systems of RGE or by equipment owned by RGE) that exceeds a total of seven hundred twenty (720) hours for the Initial Term (such hour defined herein as an "Excess Force Majeure Outage Hour"), (i) a Force Majeure Performance Adjustment amount shall be credited against the Monthly Fixed Amount on the monthly invoice that is issued for the month in which such hour occurs and (ii) Ginna shall be entitled to retain, without credit to RGE, the Applicable Revenues relating to such hour. Upon the commencement of a Necessary Extension, the amount of Force Majeure Outage hours that can occur prior to the occurrence of an Excess Force Majeure Outage Hour shall be reset to the higher of (i) an amount equal to (x) seven hundred twenty (720) hours *minus* (y) the number of hours during which Force Majeure Outage(s) occurred during the Initial Term and (ii) three hundred and nine (309) hours.

(c) The Party unable to perform by reason of a Force Majeure Event shall use commercially reasonable efforts to remedy its inability to perform and to mitigate the consequences of the Force Majeure Event as soon as reasonably practicable; <u>provided</u> that (i) no Party shall be required to settle any strike, walkout, lockout, or other labor dispute on terms which, in the Party's sole discretion, are contrary to its interests and (ii) the Party unable to perform shall, as soon as practicable, advise the other Party of the reason for its inability to perform, the nature of any corrective action needed to resolve performance, and its efforts to remedy its inability to perform and to mitigate the consequences of its inability to perform and shall advise the other Party of when it estimates it will be able to resume performance of its obligations under this Agreement.

## ARTICLE VIII
## LIMITATIONS OF LIABILITY

### 8.1 Indemnification, Limitation of Liability

(a) Each Party shall release, indemnify and hold harmless the other Party and its directors, managers, officers, agents, contractors, sub-contractors and representatives against and from any and all loss, claims, actions or suits, including costs and attorneys' fees, both at trial and on appeal, resulting from, or arising out of or in any way, the negligence or willful misconduct related to this Agreement or breach of this Agreement of the indemnifying Party and its directors, managers, officers, agents, contractors, sub-contractors and representatives, including, but not limited to, any loss, claim, action or suit, for or on account of injury or death of persons, or for damage to, or destruction or economic loss of, property, excepting only such loss, claim, action or suit as may be caused solely by the negligence or willful misconduct or breach of this Agreement of the Party seeking indemnification or its directors, managers, officers, agents, contractors, sub-contractors or representatives.

(b) Nothing in this Agreement shall be construed to create any duty to, any standard of care with reference to, or any liability to any person not a party to this Agreement. No undertaking by one Party to the other under any provision of this Agreement shall constitute the dedication of that Party's system or any portion thereof to the other Party or to the public.

(c) Neither Party shall be liable to the other for incidental, consequential, special, indirect, multiple or punitive damages, loss of revenue, profits, fees or costs arising out of, or connected in any way to the performance or non-performance of a Party under this Agreement, whether arising from contract, tort (including negligence), strict liability or otherwise, unless such damages are the result of a Party's gross negligence or willful misconduct and except as may be included in the calculation of Unplanned Outage Performance Adjustments or Force Majeure Event Performance Adjustments.

## ARTICLE IX
## REMEDIES

### *9.1 Termination for Default*

If any Party shall fail to perform any material obligation imposed on it by this Agreement, and that obligation has not been suspended pursuant to the terms of this Agreement, the other Party, at its option, may terminate this Agreement by giving the Party in default written notice setting out specifically the circumstances constituting the default and declaring its intention to terminate this Agreement. If the Party receiving the notice does not within thirty (30) days after receiving the notice, remedy the default, the Party not in default shall be entitled by a further written notice to terminate this Agreement; provided that, if the default is reasonably expected to take more than thirty (30) days to remedy, the defaulting Party shall notify the non-defaulting Party of its plan for remedying the default and must take actions to begin remedying the default within thirty (30) days. The Party not in default shall have a duty to mitigate damages. If RGE terminates this Agreement pursuant to this Section 9.1, then no Settlement Payment shall be owed to Ginna except that any unpaid balance of any Deferred Collection Amount shall, at RGE's option, (a) continue to be repaid by RGE in monthly installments in accordance with Section 4.1(b) or (b) be repaid in full upon termination of this Agreement. If Ginna terminates this Agreement pursuant to this Section 9.1, its damages shall be limited to the Settlement Payment. Notwithstanding anything to the contrary in this Section 9.1, termination of this Agreement pursuant to this Section 9.1 shall be without prejudice to the right of any Party to collect any amounts due to it prior to the time of termination.

### 9.2 Waiver

The failure to exercise any remedy or to enforce any right provided in this Agreement or Applicable Law shall not constitute a waiver of such remedy or right or of any other remedy or right. A Party shall be considered to have waived any remedies or rights only if the waiver is in writing and signed by the Party against whom such waiver is to be enforced.

### 9.3 Beneficiaries

Except as is specifically set forth in this Agreement, nothing in this Agreement, whether express or implied, confers any rights or remedies under, or by reason of, this Agreement on any persons other than the Parties and their respective successors and assigns, nor is anything in this Agreement intended to relieve or discharge the obligations or liability of any third-party, nor give any third-person any rights of subrogation or action against any Party.

## ARTICLE X
## MISCELLANEOUS PROVISIONS

### 10.1 Assignment

Neither Party shall assign its rights or delegate its duties under this Agreement without the prior written consent of the other Party, which consent shall not be unreasonably withheld, conditioned, or delayed; provided that, upon the occurrence of a Market or Regulatory Change, RGE may assign this Agreement to one or more parties that are the beneficiaries identified in the appropriate Governmental Authority's determination of benefits, subject to Ginna's approval of such party's creditworthiness, which shall not be unreasonably withheld, conditioned or delayed and need not be equivalent to RGE's creditworthiness. Any such assignment or delegation made without such written consent shall be null and void. Upon any assignment made in compliance with this section, the assigning Party shall be relieved of liability under this Agreement and this Agreement shall inure to and be binding upon the successors and assigns for the assigning

Parties. Without limiting the foregoing, Ginna may not sell or transfer the assets comprising substantially all of the RSS Unit unless the purchaser or transferee agrees in writing with RGE to assume all rights, obligations and liabilities under this Agreement.

**10.2 Market or Regulatory Change**

Upon the occurrence of a Market or Regulatory Change, the Parties shall modify the economic terms of this Agreement (which may include adjusting the Monthly Fixed Amount, the revenue sharing percentages set forth in Section 3.2, Exhibit 1 and/or Exhibit 5, as applicable) to preserve, to the maximum extent possible, each Party's economic bargain under this Agreement. Such modifications shall only serve to reallocate, but not limit, the economic costs covered by this Agreement in accordance with the appropriate Governmental Authority's determination of benefits. Any additional revenues received by Ginna due to a Market or Regulatory Change that do not constitute Ginna's entitlement to Energy Revenues and/or Capacity Revenues described in Section 3.2(b) and (c) shall be for RGE's account and shall be credited against the Monthly Fixed Amount, with any such revenues in excess of the Monthly Fixed Amount paid to RGE. Upon notice of a Market or Regulatory Change by one Party to another, the Parties shall negotiate in good faith to determine the required modifications to this Agreement.

**10.3 Cost Recovery**

(a) In the event that, after the Rate Recovery Order is obtained, the NYPSC or other Governmental Authority subsequently disallows the recovery from RGE's customers of any amounts paid to Ginna under this Agreement due to the breach or inaccuracy of Ginna's representations and warranties set forth in Section 6.1(d), the Parties shall negotiate in good faith to address the basis for such disallowance and to mitigate the economic impact of such disallowance on RGE. If the Parties fail to agree upon and implement a mechanism or adjustment to this Agreement to fully mitigate the economic effects of such disallowance on RGE, then Ginna shall refund to RGE any such disallowed amount to the extent such disallowance was not a direct result of the willful misconduct or gross negligence of RGE. Any such refund shall be payable by Ginna, at Ginna's option, by means of a cash payment to RGE or by crediting such amount against the next succeeding Fixed Monthly Amount(s).

(b) If the NYPSC or other Governmental Authority implements a rate recovery mechanism that does not allow RGE to fully recover through a customer surcharge (without offset or deferral including with respect to items unrelated to this Agreement) amounts paid to Ginna under this Agreement on a substantially current basis that coincides with the payments made by RGE to Ginna hereunder, then (i) the Monthly Fixed Amount shall be immediately reduced to be equal to the monthly amount that RGE is reasonably anticipated to recover through such surcharge on a substantially current basis and (ii) the Parties shall modify the other economic terms of this Agreement (which may include adjusting Exhibit 1 and/or Exhibit 5, as applicable) to allow for payment of the unpaid balance of the Monthly Fixed Amount as such amounts are reasonably anticipated to be recovered by RGE through such surcharge (which may include payments made to

Ginna after the expiration or termination of the Term). Such modifications shall only serve to modify the timing of, but not limit, the amounts payable to Ginna by RGE under this Agreement. Ginna shall be entitled to financing or carrying costs in connection with such modifications only to the extent that RGE is permitted by the NYPSC or other Governmental Authority to recover such financing or carrying costs through such surcharge.

**10.4 Notices and Correspondence**

Except as otherwise expressly provided in this Agreement, permitted by NYISO rules or required by law, all invoices, notices, consents, requests, demands, approvals, authorizations and other communications provided for in this Agreement shall be in writing and shall be sent by email, followed by personal delivery, certified mail, return receipt requested, facsimile transmission, or by recognized overnight courier service, to the intended Party at such Party's address set forth below. All such notices shall be deemed to have been duly given and to have become effective: (i) upon receipt if delivered in person or facsimile; (ii) two (2) days after having been delivered to a courier for overnight delivery; or (iii) seven (7) days after having been deposited in the United States mail as certified or registered mail, return receipt requested, all fees pre-paid, addressed to the applicable addresses set forth below. Each Party's address for notices shall be as follows (subject to change by notice in accordance with the provisions of this Section):

TO GINNA:

R.E. Ginna Nuclear Power Plant, LLC
100 Constellation Way, Suite 500C
Baltimore, MD 21202
Attention: Senior Vice President
Telephone No.: 410-470-5133
Facsimile No.: 410-470-2600

With copies to:

R.E. Ginna Nuclear Power Plant, LLC
4300 Winfield Road
Warrenville, IL 60555
Attn: Brad Fewell, Senior Vice President and General Counsel
Telephone No.: 630-657-3752

And

R.E. Ginna Nuclear Power Plant, LLC
c/o Exelon Generation Company, LLC
100 Constellation Way, Suite 500
Baltimore, MD 21202
Attention: General Counsel
Telephone No.: 410-470-3121
Facsimile No.: 410-470-2600

TO RGE:

Rochester Gas and Electric Corporation
James A. Carrigg Center, 18 Link Drive
P.O. Box 5224
Binghamton, New York 13902-5224
Attention: David Kimiecik, Vice President - Energy Services
Telephone No.: (607) 762-8701

with a copy to:

Iberdrola USA Management Corporation
99 Washington Ave, Suite 2018
Albany, NY 12210
*Attention: Noelle Kinsch, Deputy General Counsel*
Telephone No.: (518) 434-4977

**10.5 Parties' Representatives**

Each Party to this Agreement shall ensure that throughout the Term duly appointed representatives are available for communications between the Parties. The representatives shall have full authority to deal with all day-to-day matters arising under this Agreement. Ginna and RGE shall be entitled to assume that the duly appointed representatives of the other Party are at all times acting within the limits of the authority given by the representatives' Party.

**10.6 Taxes**

(a) Each Party shall use reasonable efforts to implement the provisions of and to administer this Agreement insofar as it applies to the Reliability Support Services in accordance with the intent of the Parties to minimize all taxes, so long as neither Party is materially adversely affected by such efforts. If any of the transactions hereunder are to be exempted from or not subject to any particular taxes, the Parties shall cooperate in good faith to promptly provide each other with all necessary documentation to evidence and qualify for such exemption.

(b) RGE shall pay or cause to be paid all taxes, if any, on or with respect to the sale of the Reliability Support Services (other than ad valorem, franchise or income taxes, or similar taxes measured by or based upon net income, which are related to the sale of the Reliability Support Services and are, therefore, the responsibility of Ginna). In the event Ginna is required by Applicable Law to remit or pay taxes which are RGE's responsibility hereunder, RGE shall promptly reimburse Ginna for such taxes. If RGE is required by Applicable Law to remit or pay taxes which are Ginna's responsibility hereunder, RGE may deduct the amount of any such taxes from the sums due to Ginna under this Agreement. Nothing shall obligate or cause a Party to pay or be liable to pay any taxes for which it is exempt under Applicable Law.

### 10.7 Independent Parties

Nothing contained herein shall constitute the Parties as joint venturers, partners, employees or agents of one another, and neither Party shall have the right or power to bind or obligate the other. Nothing herein will be construed as making either Party responsible or liable for the obligations and undertakings of the other Party. Except for provisions herein expressly authorizing a Party to act for another, nothing in this Agreement shall constitute a Party as a legal representative or agent of the other Party, nor shall a Party have the right or authority to assume, create or incur any liability or any obligation of any kind, express or implied, against or in the name or on behalf of the other Party unless otherwise expressly permitted by such other Party. Except as otherwise expressly provided in this Agreement, no Party undertakes to perform any obligation of the other Party.

### 10.8 Choice of Law

This Agreement shall be interpreted and enforced in accordance with the laws of the State of New York, excluding any choice of law provisions or rules which may direct the application of the laws of another jurisdiction.

### 10.9 Effect of Invalidation, Modification, or Condition

Each covenant, condition, restriction, and other term of this Agreement is intended to be, and shall be construed as, independent and severable from each other covenant, condition, restriction, and other term. If any covenant, condition, restriction, or other term of this Agreement is held to be invalid or otherwise modified or conditioned by any Governmental Authority, the invalidity, modification, or condition of such covenant, condition, restriction, or other term shall not affect the validity of the remaining covenants, conditions, restrictions, or other terms hereof. If an invalidity, modification, or condition has a material impact on the rights and obligations of the Parties, the Parties shall make a good faith effort to renegotiate and restore the benefits and burdens of this Agreement as they existed prior to the determination of the invalidity, modification, or condition. If the Parties fail to reach agreement, then the Party whose rights and obligations have been adversely affected may, in its sole discretion, terminate this Agreement.

### 10.10 Amendments

Any amendments or modifications of this Agreement shall be made only in writing and duly executed by all Parties to this Agreement. Such amendments or modifications shall become effective only after the Parties have received any authorizations required from FERC for the amendment or modification. The Parties agree to negotiate in good faith any amendments to this Agreement that are needed to reflect the intent of the Parties as expressed herein and to reflect any changes to the design of the New York markets that are approved by FERC from time to time.

**10.11 Dispute Resolution**

Except where otherwise provided for in this Agreement, disputes under this Agreement shall be submitted to representatives of each Party for resolution. If the dispute remains unresolved after forty-five (45) days, either Party may pursue any legal remedies available to it by law.

**10.12 Injunctive Relief**

In addition to any other remedy to which a Party may be entitled by reason of the other Party's breach of this Agreement, the Party not in default shall be entitled to seek temporary, preliminary and permanent injunctive relief from any court of competent jurisdiction restraining the other Party from committing or continuing any breach of this Agreement.

**10.13 Entire Agreement**

This Agreement consists of the terms and conditions set forth herein, as well as the Exhibits hereto, which are incorporated by reference herein and made a part hereof. This Agreement contains the entire agreement between the Parties with respect to the matters set forth herein and supersedes all prior negotiations, undertakings, agreements and business term sheets.

**10.14 Confidentiality**

Information provided by any Party to the other pursuant to this Agreement may, at the Party's discretion, be provided subject to the terms of the Confidentiality Agreement dated January 23, 2014, between Exelon Generation Company, LLC, an affiliate of Ginna, and RGE ("Confidentiality Agreement"). RGE may disclose information provided under Section 4.6 to the NYPSC and Staff pursuant to regulatory requests received in the ordinary course of RGE's business, and shall use at least the same degree of care (which in no event shall be less than reasonable care) in connection with demands or requests for the disclosure of any confidential information of Ginna as RGE uses to protect its own similar confidential information in connection with similar regulatory requests. Disclosure of such information pursuant to regulatory requests not received in the ordinary course of business shall remain subject to all of the terms and conditions of Section 4 of the Confidentiality Agreement. All information provided to either Party in connection with the negotiations regarding this Agreement shall remain subject to the provisions of such Confidentiality Agreement.

**10.15 Communications; Press Releases**

The Parties shall reasonably cooperate and coordinate with each other with regard to any communications in respect of the Reliability Support Services or the transactions contemplated by this Agreement with state and local community organizations and groups or the public generally, whether through press releases or otherwise. Each Party agrees to inform the other Party with respect to all such matters and shall promptly provide the other Party with copies of any communications sent, delivered or received; provided that nothing in the foregoing shall operate to prevent a Party from complying with Applicable Law or the requirements of any Governmental Authority concerning such matters.

**10.16 FERC Proceedings**

Ginna agrees to not seek a reliability must-run agreement (or similar agreement) from FERC with respect to the RSS Unit during the Term. Notwithstanding the foregoing, the Parties agree that Ginna will seek the FERC Authorization in accordance with Section 2.1.

**10.17 Standard of Review**

The standard of review for any modifications to this Agreement requested by a Party will be subject to the "public interest" standard of review set forth in United Gas Pipe Line Company v. Mobile Gas Service Corporation, 350 U.S. 332 (1956), and Federal Power Commission v. Sierra Pacific Power Company, 350 U.S. 348 (1956). See also Morgan Stanley Capital Group Inc. v. Public Util. Dist. No. 1 of Snohomish County, 554 U.S. 527 (2008). The standard of review for any modifications to this Agreement requested by a non-party to this Agreement or initiated by FERC will be the most stringent standard permissible under applicable law. See NRG Power Mktg., LLC v. Maine Pub. Utils. Comm'n, 558 U.S. 165 (2010).

**10.18 Counterparts**

This Agreement may be executed in several counterparts, each of which is an original and all of which constitute one and the same instrument. Facsimile or PDF signature shall be an acceptable form of execution.

(SIGNATURE PAGE FOLLOWS)

IN WITNESS WHEREOF, the Parties have executed this Agreement as of the Effective Date.

**ROCHESTER GAS AND ELECTRIC CORPORATION**

By: [signature]

Name: MARK S LYNCH
Title: PRESIDENT & CEO

By:______________________________

Name:
Title:

**R.E. GINNA NUCLEAR POWER PLANT, LLC**

By:______________________________

Name:
Title:

IN WITNESS WHEREOF, the Parties have executed this Agreement as of the Effective Date.

**ROCHESTER GAS AND ELECTRIC CORPORATION**

By:__________________________________

Name:
Title:

By: Joseph J. Syta

Name: Joseph J. Syta
Title: Vice President, Controller & Treasurer

**R.E. GINNA NUCLEAR POWER PLANT, LLC**

By:__________________________________

Name:
Title:

IN WITNESS WHEREOF, the Parties have executed this Agreement as of the Effective Date.

**ROCHESTER GAS AND ELECTRIC CORPORATION**

By:________________________________

Name:
Title:

By:________________________________

Name:
Title:

**R.E. GINNA NUCLEAR POWER PLANT, LLC**

By: Mary G. Korsnick

Name: Mary G. Korsnick
Title: Senior Vice President and Chief Nuclear Officer

[Signature Page to Reliability Support Services Agreement]

**Exhibit 1**
**to**
**Reliability Support Services Agreement**
**Between Rochester Gas and Electric Corporation and R.E. Ginna Nuclear Power Plant, LLC**

**Settlement Payment**

| Termination Announcement | Termination Date | Settlement Payment |
|---|---|---|
| Apr-15 | Apr-16 | $ 43,604,186.91 |
| May-15 | May-16 | $ 41,036,836.08 |
| Jun-15 | Jun-16 | $ 38,089,342.20 |
| Jul-15 | Jul-16 | $ 35,479,110.20 |
| Aug-15 | Aug-16 | $ 32,846,981.24 |
| Sep-15 | Sep-16 | $ 30,044,584.25 |
| Oct-15 | Oct-16 | $ 27,613,402.77 |
| Nov-15 | Nov-16 | $ 24,610,419.03 |
| Dec-15 | Dec-16 | $ 22,006,732.50 |
| Jan-16 | Jan-17 | $ 18,671,045.00 |
| Feb-16 | Feb-17 | $ 14,092,324.63 |
| Mar-16 | Mar-17 | $ 11,458,030.70 |
| Apr-16 | Apr-17 | $ 55,220,372.72 |
| May-16 | May-17 | $ 55,045,483.09 |
| Jun-16 | Jun-17 | $ 52,185,430.19 |
| Jul-16 | Jul-17 | $ 49,030,608.43 |
| Aug-16 | Aug-17 | $ 45,845,195.62 |
| Sep-16 | Sep-17 | $ 42,255,186.15 |
| Oct-16 | Oct-17 | $ 39,033,331.04 |
| Nov-16 | Nov-17 | $ 35,381,359.62 |
| Dec-16 | Dec-17 | $ 32,096,975.27 |
| Jan-17 | Jan-18 | $ 29,066,148.93 |
| Feb-17 | Feb-18 | $ 24,487,197.52 |
| Mar-17 | Mar-18 | $ 21,164,488.51 |
| Apr-17 | Apr-18 | $ 17,344,839.27 |
| May-17 | May-18 | $ 14,510,011.86 |
| Jun-17 | Jun-18 | $ 10,685,706.68 |
| Jul-17 | Jul-18 | $ 7,282,019.75 |
| Aug-17 | Aug-18 | $ 3,844,384.87 |

**Exhibit 2**
**to**
**Reliability Support Services Agreement**
**Between Rochester Gas and Electric Corporation and R.E. Ginna Nuclear Power Plant, LLC**

**Billing and Payment**

Billing Period. As designated in Section 4.1 or Section 4.3(a), as applicable.

Timeliness of Payment. Unless otherwise agreed by the Parties in a transaction contemplated by this Agreement, all invoices under this Agreement shall be due and payable in accordance with each Party's invoice instructions on or before the later of the last 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. Each Party shall make payments by electronic funds transfer, or by other mutually agreeable method(s), to the account designated by the other Party. Any amounts not paid by the due date will be deemed delinquent and will accrue interest at the 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.

Interest Rate. "Interest Rate" shall mean, for any date, the lesser of (a) the per annum rate of interest equal to the prime lending rate as may from time to time be published in *The Wall Street Journal* under "Money Rates" on such day (or if not published on such day on the most recent preceding day on which published), plus two percent (2%) and (b) the maximum rate permitted by applicable law.

Disputes and Adjustments of Invoices. A Party may, in good faith, dispute the correctness of any invoice or any adjustment to an invoice, rendered under this Agreement or adjust any invoice for any arithmetic or computational error within twelve (12) months of the date the invoice, or adjustment to an invoice, was rendered. In the event an invoice or portion thereof, or any other claim or adjustment arising hereunder, is disputed, payment of the undisputed portion of the invoice shall be required to be made when due, with notice of the objection given to the other Party. Any invoice dispute or invoice adjustment shall be in writing and shall state the basis for the dispute or adjustment. Payment of the disputed amount shall not be required until the dispute is resolved. Upon resolution of the dispute, any required payment shall be made within two (2) Business Days of such resolution along with interest accrued at the Interest Rate from and including the due date to but excluding the date paid. Inadvertent overpayments shall be returned upon request or deducted by the Party receiving such overpayment from subsequent payments, with interest accrued at the Interest Rate from and including the date of such overpayment to but excluding the date repaid or deducted by the Party receiving such overpayment. Any dispute with respect to an invoice is waived unless the other Party is notified in accordance with this section 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 of a transaction contemplated by this Agreement occurred, the right to payment for such performance is waived.

Netting of Payments. The Parties hereby agree that they shall discharge mutual debts and payment obligations due and owing to each other on the same date pursuant to all transactions applicable to this Agreement through netting, in which case all amounts owed by each Party to the other Party for the purchase and sale of products during the monthly billing period under this Agreement, 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.

Payment Obligation Absent Netting. If no mutual debts or payment obligations exist and only one Party owes a debt or obligation to the other during the monthly billing period, that Party shall pay such sum in full when due.

US Federal Tax Forms. Each Party to this Agreement shall upon signing provide the other Party a completed W-9.

Dollars. Unless otherwise stated all dollars in this Agreement refer to U.S. Currency.

**Exhibit 3**
**to**
***Reliability Support Services Agreement***
**Between Rochester Gas and Electric Corporation and R.E. Ginna Nuclear Power Plant, LLC**

**Planned Outage Schedule**

[redacted]

**Exhibit 4**
**to**
**Reliability Support Services Agreement**
**Between Rochester Gas and Electric Corporation and R.E. Ginna Nuclear Power Plant, LLC**

## Monthly Report

*R.E. Ginna Nuclear Power Plant LLC*

| **Historical Information** | Past Month Daily Average | Past Month | Year-to-Date |
|---|---|---|---|
| **Generation (Historical)** | | | |
| Gross Generation | | | |
| Net Generation | | | |
| Station Service | | | |
| Station Service as % of Generation | | | |
| Fuel Consumption | | | |
| **Availability (Historical)** | | | |
| Equivalent Availability Factor | | | |
| Capacity Factor | | | |

| **Projections** | Current Month | [+ 1] | [+ 2] | [+ 3] | [+ 4] |
|---|---|---|---|---|---|
| **Generation** | | | | | |
| Gross Generation | | | | | |
| Net Generation | | | | | |
| Station Service | | | | | |
| Station Service as % of Generation | | | | | |
| Fuel Consumption | | | | | |
| **Availability** | | | | | |
| Equivalent Availability Factor | | | | | |
| Capacity Factor | | | | | |

**Planned Outage Schedule (current month plus next six months):**

**Other Items of Note:**

**Exhibit 5**
**to**
**Reliability Support Services Agreement**
**Between Rochester Gas and Electric Corporation and R.E. Ginna Nuclear Power Plant, LLC**

**Capital Recovery Balance**

| Date of Agreement Expiration or Termination | Capital Recovery Balance |
|---|---|
| Apr-16 | $ 47,171,814.97 |
| May-16 | $ 44,988,890.37 |
| Jun-16 | $ 42,439,709.70 |
| Jul-16 | $ 40,240,300.88 |
| Aug-16 | $ 38,031,964.40 |
| Sep-16 | $ 35,677,111.03 |
| Oct-16 | $ 33,717,350.03 |
| Nov-16 | $ 31,204,487.16 |
| Dec-16 | $ 29,110,989.71 |
| Jan-17 | $ 26,273,952.76 |
| Feb-17 | $ 22,208,206.23 |
| Mar-17 | $ 20,140,090.97 |
| Apr-17 | $ 64,581,539.99 |
| May-17 | $ 65,266,227.71 |
| Jun-17 | $ 63,315,124.89 |
| Jul-17 | $ 61,077,979.80 |
| Aug-17 | $ 58,820,241.06 |
| Sep-17 | $ 56,171,301.91 |
| Oct-17 | $ 53,905,809.85 |
| Nov-17 | $ 51,227,769.98 |
| Dec-17 | $ 48,937,658.66 |
| Jan-18 | $ 46,977,224.76 |
| Feb-18 | $ 43,517,902.17 |
| Mar-18 | $ 41,379,654.89 |
| Apr-18 | $ 38,813,619.77 |
| May-18 | $ 37,435,063.36 |
| Jun-18 | $ 35,188,156.89 |
| Jul-18 | $ 33,540,151.32 |
| Aug-18 | $ 32,135,490.83 |
| Sep-18 | $ 30,952,564.39 |
| Mar-20 | $ 39,773,599.49 |

**Exhibit 6**
**to**
**Reliability Support Services Agreement**
**Between Rochester Gas and Electric Corporation and R.E. Ginna Nuclear Power Plant, LLC**

**Ginna Affidavit**

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

| | | |
|---|---|---|
| R.E. Ginna Nuclear Power Plant, LLC | ) ) ) | Docket No. ER15-____-000 |

STATE OF MARYLAND

BALTIMORE CITY

## ATTESTATION

I, the undersigned, being duly sworn, depose and say that I am Senior Vice President and Chief Nuclear Officer for R.E. Ginna Nuclear Power Plant, LLC ("Ginna" or the "Company") and that to the best of my knowledge, information and belief, the cost of service materials and supporting data submitted by Ginna as part of this filing are true, correct, accurate and complete, and current representations of the Company's actual historical costs for the years 2011, 2012 and 2013, and estimated costs for the years 2014, 2015, 2016, 2017 and 2018.

Mary G. Korsnick
Mary G. Korsnick
Senior Vice President and Chief Nuclear Officer

Subscribed and sworn to before me
this 12 day of February, 2015

Catherine Stanley
Notary Public

CATHERINE A. STANLEY
COMMISSION EXPIRES
NOTARY PUBLIC
MAR 29, 2016
BALTIMORE CITY, MD

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

CASE 12-E-0577 - Proceeding on Motion of the Commission to Examine Repowering Alternatives to Utility Transmission Reinforcements.

# ORDER ADDRESSING REPOWERING ISSUES AND COST ALLOCATION AND RECOVERY

Issued and Effective: June 13, 2014

TABLE OF CONTENTS

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

At a session of the Public Service Commission held in the City of Albany on June 12, 2014

COMMISSIONERS PRESENT:

Audrey Zibelman, Chair
Patricia L. Acampora
Garry A. Brown
Gregg C. Sayre
Diane X. Burman

CASE 12-E-0577 - Proceeding on Motion of the Commission to Examine Repowering Alternatives to Utility Transmission Reinforcements.

ORDER ADDRESSING REPOWERING ISSUES AND COST ALLOCATION AND RECOVERY

(Issued and Effective June 13, 2014)

BY THE COMMISSION:

## INTRODUCTION

By Order dated January 18, 2013, Niagara Mohawk Power Corporation d/b/a National Grid (National Grid) was directed to "examine the relative costs and benefits of repowering the [Dunkirk generating facility], and to compare those costs and benefits to the costs and benefits of alternative transmission upgrades over the long term."[1] On February 13, 2014, National Grid filed a "Term Sheet," contemplating the addition of natural gas capability for refueling the currently coal-fired Dunkirk generating facility, and allowing National Grid to defer some transmission upgrades. The Dunkirk facility is located in

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[1] Case 12-E-0577, Repowering Alternatives to Utility Transmission Reinforcements, Order Instituting Proceeding and Requiring Evaluation of Generation Repowering (issued January 18, 2013), p. 3 (January 2013 Order).

Dunkirk, New York and is owned by Dunkirk Power LLC (Dunkirk), which is a subsidiary of NRG Energy, Inc. (NRG). National Grid requests two forms of relief (the Dunkirk Proposal) -- that the Term Sheet be approved, and that the allocation and recovery from ratepayers of the costs that would be incurred under a contract between National Grid and Dunkirk implementing the Term Sheet be authorized

Moreover, pursuant to Chapter 57 of the Laws of 2013, Part Y (the Part Y legislation), enacted on March 29, 2013, the Legislature declared that "it is in the public interest to develop clean power generation near energy demand." As a result, "repowering existing power generation facilities can produce significant benefits in terms of enhanced system reliability, electric market competitiveness, and emissions reductions." Consequently, we must evaluate National Grid's actions to determine whether the Dunkirk proposal is in the public interest, as defined in the Part Y legislation.

As discussed below, the Term Sheet provisions supporting the repowering of the Dunkirk facility and the proposed allocation and recovery of the costs that will be incurred in implementing the Term Sheet are consistent with National Grid's obligations to ensure "safe and adequate service;" with the public interest objectives identified in the January 2013 Order; and, with the Part Y legislation. Accordingly, the Term Sheet repowering provisions are approved as in conformance with the Part Y legislation, and the proposed allocation and recovery of the costs that will be incurred in implementing the Term Sheet are authorized.

BACKGROUND

The January 2013 Order recognized that National Grid has entered into short-term Reliability Support Services (RSS) agreements with NRG in order to keep the Dunkirk facility available to meet local reliability needs.[2] The current RSS Agreement provides for National Grid to procure RSS from the Dunkirk generating station from May 31, 2013, until June 1, 2015.[3] National Grid initially proposed to pursue transmission reinforcements as a long-term solution to the reliability needs created by the unavailability of the Dunkirk facility. While National Grid was urged to continue developing the transmission proposals in the January 2013 Order, it was also directed to evaluate repowering over a long-run horizon of at least ten years, as an alternative to the transmission upgrades designed to address the retirement of the Dunkirk facility.

The January 2013 Order directed National Grid to prepare a report analyzing the repowering alternatives in terms of the impacts on reliability and other factors, including: 1) the effectiveness in alleviating the identified reliability problems, and in reducing the risk of load shedding; 2) ratepayer costs; 3) environmental factors; 4) the economy (e.g., temporary and permanent jobs, economic development, and tax revenue); 5) the competitiveness of the electric market; and, 6)

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[2] According to NRG, it intended to "mothball" the Dunkirk facility due to presently unfavorable economic conditions (i.e., lower revenue margins due to natural gas prices). "Mothballing" would remove the unit from operating, but maintain the ability to return the facility to service if economic conditions improved.

[3] Case 12-E-0136, Petition of Dunkirk Power LLC and NRG Energy, Inc. for Waiver of Generator Retirement Requirements, Order Deciding Reliability Need Issues and Addressing Cost Allocation and Recovery (issued May 20, 2013) (Dunkirk Reliability Order).

those additional factors National Grid believes should be considered in weighing the costs and benefits of the alternatives.

On March 29, 2013, the Part Y legislation was enacted. It specifically acknowledges and codifies the January 2013 Order, regarding the examination of repowering alternatives and their comparison to transmission reinforcements.

In response to the January 2013 Order, National Grid solicited bids from NRG on scenarios for repowering the Dunkirk generating facility. On April 1, 2013, NRG filed three proposed plant configurations at various cost levels addressing repowering.

On May 17, 2013, National Grid submitted a response to NRG's proposal and recommended that the transmission solutions be implemented as being less risky and less costly to ratepayers than any of NRG's proposals. National Grid proposed to develop and install three transmission projects by June 1, 2015, which avoid the need for continued reliance on the RSS agreement with Dunkirk Power, and two transmission projects to address the longer-term reliability needs that would exist after that date.[4] National Grid indicated that these two projects could be placed into service no later than the 2018-2019 timeframe, and that it would "rely upon operational measures to address any reliability

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[4] The five projects that National Grid identified included: 1) two new 33.3 MVAr capacitor banks on the two Dunkirk 115 kV bus sections; 2) one new 75 MVAr capacitor bank at the Huntley 115 kV switchyard; 3) reconductoring of two 115kV lines between the Five Mile Road and the Homer Hill substations, each approximately 7.4 miles in length; 4) reconductoring one mile of the Niagara - Gardenville #180 115 kV line; and, 5) reconductoring 14 miles of the Packard - Erie #181 115 kV line.

issues" during the period "following completion of the first three projects...and before the completion of the [other two]."[5]

On July 15, 2013, a public information forum was held in Fredonia, New York to receive input on the options available to National Grid for addressing the electric reliability concerns associated with "mothballing" the Dunkirk facility. Following the public information forum, a public statement hearing was conducted and various public comments were received.[6]

National Grid subsequently indicated that it had revised its local transmission plans based on its periodic review of its reliability needs. NRG also reported a finding made in certain New York Independent System Operator, Inc. (NYISO) studies showing that the shutdown of the Dunkirk units had created congestion on the transmission system leading to increased costs to electric customers.

On August 23, 2013, a Notice Requiring Additional Information and Technical Conference (Notice) was issued. The Notice advised that Staff of the Department of Public Service (Staff) would coordinate with NRG, the NYISO, National Grid, New York State Electric & Gas Corporation, and the New York Power Authority to analyze the impacts of the system congestion NRG claimed to have identified. In addition, the Notice directed National Grid to file the final results of its system review and planning process analyzing the transmission and generation needed to address reliability issues. On September 5, 2013, National Grid submitted its "Transmission Reliability Report, Western Division Area Review, Needs Assessment Report (August 31, 2013)" in response to the Notice. On October 23, 2013, the

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[5] National Grid Filing May 17, 2013, p. 7.

[6] A transcript of the comments received during the public statement hearing was posted on our website on July 22, 2013.

NYISO filed an analysis of the congestion impacts NRG had identified.

On October 31, 2013, Staff hosted a technical conference to discuss the non-confidential aspects of the information submitted by National Grid and the NYISO, and the studies conducted by a consultant, PowerGem, that NRG had retained. During the technical conference, National Grid presented its 2013 update to its western area reliability analysis, which indicated that reconductoring the #181 line was needed in order to serve increased load forecasts, regardless of whether Dunkirk was available. National Grid also advised of the need to reconductor a portion of another line (#182) if Dunkirk was unavailable.

On December 15, 2013, Governor Andrew M. Cuomo announced that NRG and National Grid had developed a framework for an agreement that would permit NRG to repower the Dunkirk station. On December 23, 2013, a Notice of Filing Deadline was issued, indicating that National Grid and NRG should file, by January 30, 2014, the terms of the proposed agreement, with documentation supporting the evaluation of the costs and benefits of the repowering solution, taking into account the reliability, economic, and environmental benefits identified in the January 2013 Order. The Notice also advised that if the parties were unable to identify such a proposal by that date, they should file, either jointly or separately, their recommendations for any further action in this proceeding. The deadline for the National Grid and NRG filings was subsequently extended until February 13, 2014, when the Dunkirk Proposal was filed.

## THE DUNKIRK PROPOSAL

### The Term Sheet Agreement

The Term Sheet agreement filed by National Grid on February 13, 2014 provides for payments to Dunkirk of $20.41 million per year for ten years (approximately $150 million on a Net Present Value (NPV) basis),[7] while Dunkirk would add approximately 435 MW of gas-fired capability to Units 2, 3, and 4 at the Dunkirk generating facility. The Term Sheet contemplates that commercial operation of the first refueled unit would commence on or about September 1, 2015. National Grid maintains that this agreement would ensure the availability of the Dunkirk generating facility for ten years and allow National Grid to continue to provide reliable electric service, while yielding positive economic and environmental benefits.[8]

According to National Grid, the agreement would afford sufficient flexibility for it to defer some transmission reinforcements, estimated to range in cost between $33.7 million to $68.3 million, which would otherwise be needed for reliability if the Dunkirk facility were shut down. National Grid calculates that these reinforcements would produce an approximate annual revenue requirement of $5.6 million to $11.4 million, or $37.7 million to $76.4 million on a ten-year NPV basis. Moreover, National Grid advises that the availability of the Dunkirk units would enhance the capability to dispatch hydroelectric generation from the Niagara Power Project or to import power from the Ontario control area for reliability or economic purposes.

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[7] Staff's Report, which is discussed below, estimated that the NPV of the Term Sheet was approximately $140 million.

[8] Refueling the Dunkirk facility is expected to reduce local plant emissions of $CO_2$, $SO_x$, and $NO_x$ compared with burning coal.

National Grid also expects that keeping the Dunkirk facility operational would reduce transmission constraints and result in reducing congestion-related costs by between $8.8 million and $161.1 million in 2014, while allowing for greater production of renewable, emission-free hydroelectric energy. National Grid also suggests that certain indirect electric market benefits would accrue to its customers, including lower NYISO Installed Capacity (ICAP) costs and Locational-Based Marginal Prices (LBMP).[9]

NRG estimates that the Dunkirk Proposal will support 100 construction jobs during the construction period, and $25 million in operation and maintenance spending annually.[10] NRG estimates investing about $300 million over the 10-year term of the agreement, while supporting over 200 jobs in the region.[11] In addition, NRG projects contributing $8 million in annual property tax payments, which would assist in sustaining essential services in the local community.

National Grid indicates that closure of the Dunkirk plant would reduce the City of Dunkirk's local budget by about 42%, and the City School District's budget by 30%. This would require a property tax increase of $1,000 for the average Dunkirk homeowner to replace the lost revenue. National Grid states that continued operation of the plant at Dunkirk helps support local and state tax revenue stability and promotes

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9 National Grid estimates that the NPV of ICAP payments to the State would fall by $841 million, with $271 million accruing to National Grid customers. National Grid also notes that annual LBMP "payment" savings due to reduced congestion costs in the western New York portion of the bulk electric system were estimated in a range of $7 million to $161 million.

10 NRG Filing April 7, 2014, p. 5.

11 Id.

economic opportunity. The net impact of this spending, it asserts, is expected to create an average of 175 jobs per year, $31 million in additional Gross Domestic Product, and almost $15 million in higher personal income between 2015 and 2025.[12]

Cost Allocation and Recovery

National Grid proposes that the costs incurred in implementing the Term Sheet be allocated and recovered using an approach equivalent to that used for the current RSS agreements approved in the Dunkirk Reliability Order.[13] Specifically, all National Grid customer service classifications, except those within the Empire Zone and Excelsior Jobs Program qualifying loads, would be allocated costs based on its most recent transmission plant allocator, which, in turn, is based on the respective contribution of each service class to National Grid's coincident peak demand, as approved in its most recent rate case. The costs would then be recovered from each class on a volumetric basis (kW for demand classes and kWh for non-demand classes). Because the anticipated monthly payments under an agreement implementing the Term Sheet, at $1.7 million per month, would be less than the monthly costs expected to be recovered in connection with the current RSS agreement, at $2.83 million per month, National Grid states that implementing the Term Sheet will result in lower surcharges for customers than they presently incur.

## THE STAFF REPORT

On May 16, 2014, following the filing of the Dunkirk Proposal, a Staff Report was issued analyzing the potential

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[12] Dunkirk Proposal, p.10.

[13] Case 12-E-0136, supra, Order Deciding Reliability Need Issues and Addressing Cost Allocation and Recovery.

costs of the Dunkirk Proposal relative to the potential impacts on reliability. In its Report, Staff estimated that the NPV of the agreement, on a ten-year basis, is about $140 million, although these costs could be reduced based on the potential for capacity revenue sharing provided for under the Term Sheet.[14] Staff also concluded that the Dunkirk Proposal offers several reliability benefits, such as fuel diversity and flexibility in the operation and maintenance of the transmission system. While Staff noted that many of these benefits could not be quantified exactly, Staff developed estimates for some, including deferred transmission investments ($37.7 - $76.4 million) and avoided RSS payments ($50 million).

Staff also found that the Dunkirk Proposal would create direct economic benefits. These benefits ($21 million for labor only and $34 million for labor and material and service (M&S) expenditures at the plant), along with maintaining property tax payments ($8 million), would address the significant and inordinate negative impact on the local economy that would attend the mothballing of the Dunkirk facility. In addition, Staff estimated that the Dunkirk Proposal could result in significant production cost savings ($31 million).

Responding to NRG's analysis, Staff noted the Dunkirk Proposal would facilitate the dispatch of the Niagara generating facility, increasing the output of a renewable, zero-emission hydroelectric facility, to the benefit of the environment. Moreover, the capability of the Dunkirk facility to generate electricity using natural gas would present additional opportunities to use a fuel source with reduced emissions

[14] Staff's estimate of the NPV was computed using National Grid's discount rate of 7.36%. National Grid, however, did not discount the first year of the agreement and thus overstated the NPV by $10 million.

compared to the existing coal-fired units. Based on the combination of qualitative and quantifiable benefits, Staff recommended that the cost allocation and recovery associated with the Dunkirk Proposal be approved.

## COMMENTS

In conformance with State Administrative Procedure Act (SAPA) §202(1), notice of the Dunkirk Proposal was published in the State Register on February 19, 2014. The SAPA §202(1)(a) period for submitting comments in response to the petition expired on April 7, 2014. Comments were timely filed by various interested individuals, elected officials, and municipal entities, as well as Multiple Intervenors (MI), Entergy,[15] NRG, and Earthjustice and Sierra Club, on behalf of Ratepayer and Community Intervenors, Citizens Campaign for the Environment, and Environmental Advocates of New York (collectively, Earthjustice).

Moreover, comments were solicited on the Staff Report at the time of its issuance, with a deadline for filing set at May 27, 2014. In response to that solicitation, additional comments were received from MI, Entergy, NRG, National Grid, and Earthjustice.

### Multiple Intervenors

While it neither supports nor opposes the Dunkirk Proposal and the attending Term Sheet Agreement, MI nonetheless advises that it believes a shut-down of the Dunkirk generating facility would create unacceptable reliability problems. Consequently, MI believes that a regulated long-term solution

[15] Entergy Nuclear FitzPatrick, LLC, Entergy Nuclear Indian Point 2, LLC, Entergy Nuclear Indian Point 3, LLC, and Entergy Nuclear Operations, Inc. (collectively, "Entergy").

would be in the public interest as a replacement for the existing RSS agreement with Dunkirk. MI notes that it is unable to determine whether the Term Sheet agreement is preferable to the alternative transmission upgrades given that it does not have access to sufficiently detailed information and was not privy to the negotiations between National Grid and Dunkirk.

MI seeks policy guidance regarding the allocation of costs for reliability solutions and regulated infrastructure projects that are likely to result in benefits beyond a single utility's service territory. MI supports a cost allocation approach based on the "beneficiaries pay" principle, and suggests that a material share of the Term Sheet costs should be allocated on a statewide basis because a majority of ICAP cost savings would accrue to ratepayers outside of National Grid's service territory. MI points to Case 12-E-0503,[16] where a statewide allocation of transmission costs was justified based on economic benefits beyond a single service territory.

Lastly, in responding to the Staff Report, MI encourages the Commission to ensure that utilities are conducting appropriate transmission planning activities where they know of "at risk" generation facilities that may result in reliability concerns. MI notes that the Staff Report did not address its earlier comments and urges that a decision be issued consistent with those comments.

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[16] Case 12-E-0503, Generation Retirement Contingency Plans, Order Accepting IPEC Reliability Contingency Plans, Establishing Cost Allocation and Recovery and Denying Request For Rehearing (issued November 4, 2013) and Order Denying Request For Rehearing and Motion For Clarification (issued April 1, 2014.

Entergy

Entergy argues that the Federal Energy Regulatory Commission (FERC) has exclusive jurisdiction over the Term Sheet agreement, and that the Commission cannot therefore act on the Term Sheet. Entergy also maintains that the Term Sheet agreement would lead to the submission of zero bids, or near zero bids, for ICAP and would lead to artificially suppressed prices that will adversely affect competitive markets.

Entergy contends that the reliability need is limited to 150 MW and that repowering a total of 435 MW would exceed that reliability need. Based on these factors, Entergy asserts that the identified transmission solutions would be less costly and that, therefore, the refueling proposal should not be pursued.

Reiterating the above contentions in response to the Staff Report, Entergy maintains the Report should have also examined the costs and benefits of National Grid's alternative transmission upgrades. According to Entergy, the record is inadequate absent this information. In addition, Entergy claims that the emissions associated with the Dunkirk Proposal should be compared to the emissions associated with a transmission alternative, rather than with the coal-fired Dunkirk facility.

NRG

NRG supports the Dunkirk Proposal and highlights various reliability, economic, and environmental benefits, including those identified in the Staff Report. NRG also emphasizes that the tax payment under the Payment-In-Lieu-of-Taxes (PILOT) agreement for the Dunkirk generating facility constitutes 18.2% of the City of Dunkirk's revenues and 29% of the Dunkirk City School District's revenues.

Earthjustice

In filing a motion for an evidentiary hearing, discussed further below, Earthjustice also presented comments on substantive issues. Earthjustice also responded to the Staff Report and reiterated its request for an evidentiary hearing on the entire record before the Commission, including the Staff Report. It argues that the transmission reinforcements represent a lower cost and more effective reliability solution than the Dunkirk Proposal. They also claim the agreement to refuel 435 MW is not justified because the capacity needed to avoid transmission upgrades is 150 MW.[17]

Contending that the benefits estimated by Staff are overstated, uncertain, and unsupported, and that the Dunkirk Proposal is not just and reasonable, Earthjustice disputes Staff's estimated RSS savings on the grounds that they are speculative. Earthjustice also requests that a modeling study be performed with respect to the potential production cost savings associated with dual-fuel capability, and questions the value to ratepayers of that capability during cold weather events. According to Earthjustice, it is "imprudent for a company to take actions on the assumption that circumstances such as those that existed during the polar vortex will occur again anytime soon."[18]

Finally, Earthjustice raises concerns with the potential environmental impacts associated with the use of coal.

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[17] Comments similar to those filed by Earthjustice were also submitted by Carol Chock and other members of the Ratepayer and Community Intervenors, which are represented by Earthjustice. Ms. Chock adds her concerns that the Term Sheet will lead to higher fees for homeowners and businesses, and harm the environment through the use of both natural gas and coal. She seeks a transition to renewable technologies.

[18] Earthjustice Filing (filed May 27, 2014), p. 6.

Earthjustice seeks to compare the emissions impacts associated with a refueled Dunkirk facility with a shutdown of the facility and construction of the transmission upgrade alternative, rather than assuming continued operation of the facility using coal. At a minimum, Earthjustice seeks an enforceable condition that would limit the use of coal at the Dunkirk facility only to those specific time periods when it is needed as an emergency backup fuel due to the unavailability of natural gas.

National Grid

National Grid submitted comments supporting the analysis and conclusions reached in the Staff Report. National Grid also clarified that it intends to proceed with installing capacitor banks at Dunkirk and Huntley and reconductoring the Five Mile to Homer Hill 115 kV lines.

Other Public Comments

Numerous comments were submitted by residents, businesses, labor representatives, and elected officials strongly supporting the Dunkirk Proposal.[19] Congressman Tom Reed noted that the Dunkirk Proposal "ensures that the facility continues to play an important role in the tax base of the county, local government and school district, provide reliability to the grid and promote efficiency and reduce emissions statewide."

State Senator Catharine M. Young indicated that the Term Sheet agreement meets the requirements of the Part Y legislation, which requires examination of various factors

[19] While not opposing the Dunkirk Proposal outright, one interested individual questioned how the Dunkirk facility would fit into the NYISO marketplace, and suggested the proposal would result in ratepayers paying increased power bills and other generators seeking similar arrangements. Comments of Steve Wible, filed May 19, 2014.

associated with the issue of repowering the Dunkirk facility, including impacts on temporary and permanent jobs, economic development and tax revenue, and effects on the environment. Senator Young also points out that the Dunkirk Proposal avoids the prospect of massive property tax hikes and cuts in services and job losses.

The Chautauqua County Executive, Vincent Horrigan, cited the loss of revenue from the Dunkirk facility, which would amount to a 58% tax increase for City of Dunkirk residents, and a 42% tax increase for Dunkirk City School District residents. Mr. Horrigan's comments, and various statements from other interested members of the public, highlight strong community support for the Dunkirk Proposal to help as a means for promoting economic stability, job growth, economic development, and a cleaner environment.

## DISCUSSION

### Procedural Issues

#### A. Motion for Evidentiary Hearing

By motion dated April 7, 2014, Earthjustice seeks, pursuant to Public Service Law (PSL) §22 and 16 NYCRR §3.6 and §3.7(a), an Order directing that a "public adjudicatory hearing presided over by an administrative law judge (ALJ) be held" to determine whether the Dunkirk Proposal is just, reasonable, and in the public interest. Earthjustice requests that a schedule be established for the parties in this proceeding to conduct discovery, present testimony, and cross examine witnesses regarding the Dunkirk Proposal and that the ALJ be directed to make a recommendation to the Commission, based upon the evidence adduced, as to whether the Dunkirk Proposal is just, reasonable, and in the public interest.

1. The Earthjustice Argument

Earthjustice presents four arguments in support of its claim that an evidentiary hearing on the Dunkirk Proposal must be held in this proceeding. First, it claims that an evidentiary hearing is required as a matter of law. Earthjustice points out that PSL §66(12)(f) requires that a hearing be held for "major" rate changes, defined in PSL §66(12)(c) as a change in rates that would increase the aggregate revenues of the utility more than the greater of $300,000 or 2.5%. According to Earthjustice, the $20.41 million in annual costs over a period of 10 years is in excess of a "major change" as defined in the PSL. Earthjustice further maintains that the hearing is necessary to fully evaluate the Dunkirk Proposal to ensure that the "least cost option is pursued" and that the rates "…resulting from the agreement are just and reasonable".[20]

As its second argument, Earthjustice asserts that an evidentiary hearing is also necessary to protect the public's interest in an open and transparent process. Earthjustice explains that the "abrupt" announcement of the Dunkirk Proposal presupposes a review of the issues repowering raises, consequently depriving Earthjustice and the public of an opportunity to examine the assumptions underlying the Dunkirk Proposal and to evaluate the economic, environmental, and other representations made in support of the Dunkirk Proposal. Earthjustice protests that the 45-day comment period, required pursuant to SAPA §202(1)(a) before the Dunkirk Proposal may be acted upon, does not afford a meaningful opportunity for public participation. It adds that the complex issues involved here do not lend themselves to decision by notice and comment.

[20] Motion at 11-12.

The SAPA notice itself, Earthjustice maintains, was deficient as no notice was provided to the parties through the Commission's electronic Document and Matter Management system (DMM). According to Earthjustice, the absence of electronic notice through DMM deprived them of adequate notice of the SAPA comment period concerning the potential action on the Dunkirk Proposal, notwithstanding that notice was published in the State Register on February 19, 2014. The electronic notice provided through DMM of the procedural and substantive decisions reached in the proceeding, Earthjustice contends, should also extend to notice of the comment period. Earthjustice also complains that because Dunkirk did not file a Full Environmental Assessment Form until April 1, 2014, the public had only four business days to review, evaluate and comment on the critical environmental issues presented. That time, it contends, was insufficient for meaningful input on the environmental review.

In its third argument, Earthjustice addresses what it characterizes as technically deficient and often conflicting analyses in the record. Those shortcomings, it argues, can only be resolved through an evidentiary hearing, where the question of whether the Dunkirk Proposal is the most cost-effective means to address the reliability impacts resulting from the closure of the Dunkirk facility could be thoroughly considered. In support of its argument, Earthjustice claims that National Grid's prior statements and studies are in conflict with the Dunkirk Proposal and its Statement in Support on the issues of: 1) the cost of transmission upgrades compared to the cost of repowering the Dunkirk facility; 2) the impact of repowering on the energy and capacity markets; and, 3) the impact of repowering on reliability and whether the same benefits could be achieved through cheaper transmission upgrades.

As its fourth and final point, Earthjustice contends the environmental impacts associated with the repowering of the plant can only be explored adequately through the evidentiary hearing. Earthjustice believes that the environmental benefits posited -- reductions to emissions of carbon dioxide, sulfur dioxide, and nitrogen oxides -- are overstated because the Dunkirk facility retains coal-burning capability notwithstanding the addition of gas-burning capability. As a result, Earthjustice protests that there is no guarantee that the plant will end its coal-burning operations. It also points out that the National Grid and Dunkirk statements in support compare emissions from a 435 MW plant that is gas-fired to emissions from the same sized coal-fired plant, yet only a single coal-fired unit is currently operating and it is scheduled to cease operations in May 2015. The proper baseline, Earthjustice insists, is to compare the repowering project to one where the plant is not operating at all.

2. Replies to the Motion

NRG and Dunkirk, together, and National Grid filed letters in opposition to Earthjustice's request for an evidentiary hearing. In opposing the Motion, both NRG and National Grid calculate that the "major changes" mandatory hearing requirement under PSL §66(12)(f) is not triggered by the Dunkirk Proposal. Citing National Grid's Annual Report filed on September 9, 2013 pursuant to PSL §66(6), NRG notes National Grid's aggregate electric revenues for 2012 were approximately $2.7 billion. Therefore, a $20.41 million increase in annual revenue resulting from the Dunkirk Proposal is less than 1%, and the statutory threshold for "major changes" requiring a hearing is not met.

Confirming NRG's analysis, National Grid states that it projects annual aggregate revenue for the rate year running from April 1, 2015 to March 31, 2016 of approximately $2.55 billion.[21] Multiplying that amount by the 2.5% figure from PSL §66(12)(f), National Grid notes, results in an annual amount of $63,853,225. That amount, National Grid points out, is significantly more than the $20.41 million in annual revenue needed to recover the annual costs that would be incurred under the Dunkirk Proposal.

Contending that Earthjustice has failed to identify specific material questions of fact that require an evidentiary hearing, NRG maintains that Earthjustice's mere presentation of policy arguments and unsubstantiated attacks on the credibility of National Grid's Statement in Support are insufficient to warrant examination at an evidentiary hearing. NRG argues that the process developed in this proceeding is both open and transparent and that the existing evidence on the record is adequate to support a determination on whether the Dunkirk Proposal is in the public interest.

Consistent with NRG, National Grid notes that an evidentiary hearing is not necessarily justified simply because parties may have conflicting positions. National Grid emphasizes that the process and scope of this proceeding were clearly established in the January 2013 Order. In that Order, National Grid continues, it was directed to evaluate how transmission and generation alternatives may affect reliability, customer costs, the environment, the economy (e.g., job impacts, economic development, tax revenues, etc.), electric market

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[21] Case 12-E-0201, National Grid - Electric Rates, Joint Proposal, Appendix 1, p. 17.

effects, and other potentially relevant factors.[22] National Grid maintains it has fully complied with that Order and that Earthjustice has failed to support its allegations to the contrary.

According to National Grid, the parties and the public have been afforded ample opportunity to participate in the process, and there is a full record on which a determination may be based. This proceeding, National Grid recounts, has been ongoing for over 14 months. Over a dozen parties have participated; thousands of pages of material have been generated, all of which is in the record; over 7,000 comments from the public have been received; and, a public statement hearing, attended by an estimated 3,000 people, has been held on the record. In addition, a technical conference has been conducted where parties were afforded the opportunity to discuss the respective analyses of National Grid, NRG, and the NYISO.

Finally, National Grid dismisses Earthjustice's assertion that a hearing is necessary to sort out what Earthjustice perceives as conflicting analyses. That perception, National Grid maintains, is inconsistent with the ample evidence on the record regarding the estimated costs of the various proposals and solutions. National Grid also characterizes as misplaced Earthjustice's argument that the Commission is constrained to selecting the lowest-cost solution presented on the record. The January 2013 Order, National Grid believes, clearly indicates that non-cost factors will be considered in evaluating the Dunkirk Proposal. As a result, it concludes, the mere fact that the Dunkirk Proposal may not

[22] January 2013 Order at 3-4.

represent the lowest cost solution does not give rise to a need for an evidentiary hearing.[23]

3. Discussion

We deny Earthjustice's motion for an evidentiary hearing. As an initial matter, Earthjustice's reliance on PSL §22 and 16 NYCRR §3.7(a) as the procedural vehicle for bringing their motion is misplaced. Those provisions of law address the process for requesting rehearing. Since Earthjustice does not point to a prior Order as the subject for rehearing, their filing is not a request for rehearing. Instead, it is best categorized as a motion seeking an evidentiary hearing.

As properly considered, the motion lacks merit. Contrary to Earthjustice's contention, a hearing is not required by statute. As National Grid and NRG point out, the Dunkirk Proposal would impose on National Grid's ratepayers an annual cost increase forecast at $20.41 million. That amount falls well below the "major changes" threshold defined in PSL §66(12)(c), which, as National Grid correctly calculates, amounts to $63,853,225 annually under these circumstances.[24] Thus, an evidentiary hearing is not required by law.

Consequently, the question presented by Earthjustice's motion is whether an evidentiary hearing should be held as a matter of discretion. To determine if an evidentiary hearing should be held where one is not required by law, we look to whether there are contested matters where additional facts need to be elicited or technical matters that might be better

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[23] Id.

[24] Earthjustice presents no reasoning in support of its contention that the amount to be tested against the threshold is the 10 year cumulative payment under the Agreement instead of the annual figure traditionally used to perform the test.

developed and tested through testimony and the cross examination of witnesses.[25]

Here, the record is sufficiently developed.[26] To reiterate National Grid's points, this proceeding has been on-going for over 14 months. Over a dozen parties have participated; thousands of pages of material have been generated, all of which is in the record; over 7,000 comments from the public have been received; and, a public statement hearing, attended by an estimated 3,000 people, was held on the record. Staff also hosted a technical conference where parties were afforded the opportunity to discuss the analyses that had been presented. Moreover, a Staff Report was provided on the proposed Dunkirk Proposal for comment by the parties and the public.

Contrary to Earthjustice's assertions, we are not bound to allow cost recovery for only the "lowest cost" option for addressing the Dunkirk facility's closure.[27] The January 2013 Order did not call for an analysis limited to only the

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[25] Case 94-E-0098, et al., Niagara Mohawk Power Corporation, Order Denying Interlocutory Appeal (issued February 26, 1996) at 10.

[26] Given the extraordinary interest in the issues raised by this proceeding, nothing prevents us from adopting such additional procedures as may be appropriate to provide an opportunity for additional comment beyond that required by SAPA, such as the opportunity to submit comments on the Staff Report, notwithstanding that evidentiary hearings are not necessary or appropriate.

[27] Tele/Resources, Inc. v. PSC, 58 A.D.2d 406, 401 (1977), citing Matter of New York Tel. Co. v. PSC, 309 N.Y. 569 (1956); Matter of Consolidated Edison Co. of N.Y. v. PSC, 53 A.D.2d 131 (1976), mot for lv to app den, 40 N.Y.2d 803 (1976). The Commission is not bound to entertain or ignore any particular factor in discharging its primary responsibility to determine rates that are just and reasonable.

costs to ratepayers of the repowering and transmission options. Instead, the January 2013 Order sought assessments of impacts on system reliability over the long-run, ratepayer costs, the environment, the economy (e.g., temporary and permanent jobs, economic development, and tax revenue), and the operation of competitive electric markets, and consideration of any other factors that might weigh on the costs and benefits of the alternatives.[28] Furthermore, the Part Y legislation enacted on March 29, 2013 established a policy on repowering electric generation that values the development of clean power sited near energy demands in order to meet the needs of ratepayers, support local and state tax revenue stability, promote economic opportunity, and enhance the state's environment.

In light of those policies, the extensive proceedings already conducted, and the substantial discretion we exercise when reviewing requests that evidentiary hearings be held other than as a matter of law, Earthjustice's request that such hearings be conducted here is denied. Under these circumstances, evidentiary hearings are unlikely to elicit additional material facts regarding contested matters, better develop technical analyses, or be needed to evaluate the benefits and burdens of the Dunkirk Proposal. Earthjustice's allegations that National Grid's prior positions deviate from those it takes in the Dunkirk Proposal do not justify evidentiary hearings, when the facts relevant to both the positions themselves and the change in position are already on the record. Therefore, National Grid's change in position is

[28] January 2013 Order at 3-4.

not, standing alone, a sufficient justification for requiring evidentiary hearings.[29]

Earthjustice's other arguments similarly lack merit. Earthjustice claims a hearing is necessary because notice of the statutory deadline for submitting comments under SAPA was not given electronically through the DMM document system. SAPA, however, does not require the posting of a notice on DMM. Moreover, given that Earthjustice is a sophisticated entity represented by counsel, the claim that SAPA was unfairly applied to them also cannot be sustained. The same result adheres to the implication that, because notice of decisions is supplied through DMM, notice of the comment deadline should have been furnished as well.

Earthjustice's argument that it had insufficient time to comment on the Environmental Assessment Form (EAF) was filed on April 1, 2014 is similarly unavailing. Notwithstanding Dunkirk's submission of an EAF, Earthjustice is incorrect to suggest that the State Environmental Quality Review Act (SEQRA) requires the solicitation of comments on the EAF. Finally, we note that Earthjustice does not claim that the record on the environmental impacts of the proposed refueling is insufficient. It merely claims that the arguments of National Grid and NRG concerning the environmental benefits of refueling are "flawed." Indeed, nothing prevented Earthjustice from presenting this argument, which it could appropriately have done on the existing notice and comment record. Therefore, Earthjustice's argument is unpersuasive.

For the above reasons, the evidentiary hearing Earthjustice requests is neither legally required nor would it result in material contributions to the existing and already

[29] Case 94-E-0098, supra, at 8.

adequate record. Therefore, Earthjustice's motion for an evidentiary hearing is denied in its entirety.

B. Motion for Severance

1. The Motion

On April 21, 2014, Earthjustice filed a motion pursuant to 16 NYCRR §3.6, seeking an order severing this proceeding for the purpose of "separately and independently evaluat[ing] transmission and repowering alternatives at the Cayuga and Dunkirk plants."[30] According to Earthjustice, evaluating both plants in the same proceeding "leads to a muddled public docket and creates confusion among the public."[31] Earthjustice claims that evaluating the Cayuga and Dunkirk facilities in the same proceeding increases the size and complexity of the public docket.

2. Discussion

Notwithstanding that the record in this proceeding is extensive, including documentation concerning both the Dunkirk and Cayuga facilities, severance is unnecessary and unwarranted at this time. With the review of the Dunkirk Proposal decided here, the evidentiary record as to it is complete and few, if any, filings that would expand the evidence on that record are expected. Thus, there is no reason to assign a new case number at this point to the Dunkirk Proposal,[32] and the Cayuga process may continue under that docket without undue confusion. Accordingly, Earthjustice's motion to sever the Cayuga and Dunkirk matters into separate proceedings is denied.

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[30] Dunkirk Motion, p. 3 (filed April 21, 2014).

[31] Id.

[32] Regardless of whether a new case is established, the evaluations of the Dunkirk and Cayuga repowering/refueling proposals are independent from each other and will be decided on a case-by-case basis.

The Dunkirk Proposal

As stated in the January 2013 Order, "[r]epowering existing generation facilities can produce significant benefits in terms of enhanced system reliability, electric market competitiveness, and emissions reductions."[33] These potential benefits have been embodied in the Part Y legislation, which declares that "it is in the public interest to develop clean power generation near energy demand to meet the needs of ratepayers, support local and state tax revenue stability, promote economic opportunity, and enhance the state's environment."[34] The Dunkirk Proposal properly implements these principles in response to the impacts on reliability posed by the proposed mothballing of the Dunkirk facility.

The January 2013 Order was designed to ensure that adequate consideration is given to repowering alternatives for ensuring reliability. As noted above, the January 2013 Order sought a filing from National Grid analyzing various factors, including: 1) the effectiveness in alleviating the identified reliability problems, and in reducing the risk of load shedding; 2) the ratepayer costs; 3) environmental factors; 4) the economy (e.g., temporary and permanent jobs, economic development, and tax revenue); 5) the competitiveness of the electric market; and, 6) other factors National Grid believes should be considered in weighing the costs and benefits of the alternatives.

In its filing of the Dunkirk Proposal prepared in response to the January 2013 Order, National Grid has undertaken the consideration of Dunkirk facility repowering alternatives and has addressed the factors identified above. The Dunkirk

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[33] January 2013 Order, p. 1.

[34] Part Y legislation, §3.

Proposal raises two issues -- approval of the Term Sheet provisions supporting the repowering of the Dunkirk facility and the authorization of the allocation and recovery of the Term Sheet costs.

A. Environmental Quality Review

Under the State Environmental Quality Review Act (SEQRA), Article 8 of the Environmental Conservation Law, and its implementing regulations (6 NYCRR §617 and 16 NYCRR §7), we must determine whether the actions we approve may have a significant impact on the environment. Other than our approval of the action proposed here, no additional state or local permits are required, so a coordinated review under SEQRA is not needed. We will assume Lead Agency status under SEQRA and conduct an environmental review.

The proposed action does not meet the definition of Type I or Type II actions listed in 6 NYCRR §§617.4, 617.5 and 16 NYCRR §7.2, so it is classified as an "unlisted" action requiring SEQRA review. SEQRA requires applicants to submit a complete EAF describing and disclosing the likely impacts of the actions they propose.[35] Dunkirk has submitted a narrative and a long-form EAF Part 1 that substantially comply with this requirement. Staff has completed the long-form EAF Part 2.

As our first action, after review of the EAF, we conclude, based on the criteria for determining significance listed in 6 NYCRR §617.7(c), that our approval of the Term Sheet supporting the repowering of the Dunkirk facility will have no significant adverse environmental impacts. We therefore adopt a negative declaration pursuant to SEQRA.

The information provided in the EAF supports this conclusion. The proposed refueling involves minor physical

[35] 6 NYCRR §617.6(a)(3).

alterations at the existing plant site, which has been operated as a coal powered power plant for over fifty years, and some disturbances related to the construction of the gas fuel pipeline, which we will review pursuant to Article VII of the PSL and its exemption from SEQRA. The work at the plant site will not involve any change in land use or impacts to surface or groundwater or any other environmental receptors.

While SEQRA does not require us to find specific benefits to an action, we note that the option of refueling the facility with gas offers potential environmental enhancements, as opposed to countering the effects of mothballing through transmission upgrades or continued coal-fueled operation of the plant. Retaining generation at the Dunkirk location mitigates the impacts that would attend constructing additional transmission, opens existing transmission capacity to greater generation from renewable-fueled hydro facilities at Niagara Falls and in the Province of Ontario, and allows for greater flexibility in operating the transmission system in ways that are more efficient.

Besides meeting reliability needs, reducing emissions, and relieving transmission congestion in western New York, the Term Sheet reduces costs for consumers, assists in retaining local jobs, creates temporary construction jobs, stabilizes the local property base, and improves the local economy. Notwithstanding that coal capability will be retained as a source of a back-up fuel, the capability to use gas generally will reduce use of coal, thereby replacing it with a cleaner, more environmentally-beneficial fuel. Finally, the Term Sheet stabilizes the grid, facilitating planning for upgrading it over a period of years and eliminating the need to complete multiple projects in a compressed period, which would adversely affect the environment.

As Lead Agency, we determine that the proposed action will not have a significant adverse impact on the environment and adopt a negative declaration pursuant to SEQRA. A Notice of Negative Declaration concerning this unlisted action is attached. The completed EAF will be retained in our files.

As our second action, we authorize National Grid to recover the costs of the Term Sheet in rates. National Grid proposes that the allocation and recovery of costs under the Term Sheet be accomplished under Rule 50 (Reliability Support Services (RSS) Surcharge) of its retail tariff for RSS contracts. This is listed as a Type II action pursuant to SEQRA.[36] Type II actions have been determined not to have a significant impact on the environment or are otherwise precluded from environmental review under Environmental Conservation Law, article 8.[37] Therefore, no further review under SEQRA of the rate recovery authorization is required.[38]

B. Reliability Needs

In conformance with the January 2013 Order, National Grid has properly evaluated reliability impacts and the effect of the Dunkirk Proposal in alleviating those impacts. In its initial response to NRG's proposed mothballing of the Dunkirk facility, National Grid identified adverse reliability consequences associated with the potential action, and accordingly entered into an RSS agreement with Dunkirk in order

[36] 16 NYCRR §7.2(b).

[37] 6 NYCRR §617.5.

[38] To the extent an application may come before us in order to supply the natural gas needed to refuel the Dunkirk facility, such applications pursuant to PSL Article VII are not subject to review under SEQRA. 6 NYCRR §617.5(c)(35).

to keep the facility available during an interim period to ensure safe and adequate service.[39]

National Grid's decision to implement the Term Sheet for refueling the Dunkirk facility would ensure the continued availability of that facility over the long-term, while obviating some transmission upgrades. Adding natural gas fueling capability at the facility while supporting its continued operation resolves the adverse reliability impacts that would be experienced if the plant were mothballed. As National Grid states, "refueling the Dunkirk facility units mitigates [the] potential reliability risk that may arise between 2015 and 2017 such as reliability impacts that may result from other generator shutdowns in the region."[40] Further, the availability of the Dunkirk facility will "provide greater operational flexibility at the Niagara Power Project and allow for more power imports from the Ontario control area (IESO), which would provide the NYISO increased opportunity to call on these resources for economic or emergency energy during high load conditions."[41] These reliability assessments are supported by the record in this proceeding.

Having the Dunkirk units available will provide for increased flexibility and reliability in responding to transmission maintenance outages, and will guard against long-term outages of transmission lines and transmission level transformers. Further, installing dual-fuel capability at the facility will enhance reliability because coal can act as a

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[39] Letter from C.E. Root, National Grid Sr. V.P., Network Strategy to T.G. Dvorsky, DPS Director, Office of Electric, Gas and Water, dated March 30, 2012.

[40] Dunkirk Proposal, p. 8.

[41] Id.

back-up fuel source during limited periods when natural gas may be unavailable or in short supply. As pointed out in the Staff Paper, this enhanced capability has significant value during periods when high natural gas demands result in gas pipeline constraints and gas unavailability for electric generators. During these periods, reducing natural gas consumption at the Dunkirk facility should also increase the availability of natural gas for residential heating purposes.

National Grid stated that the estimated total costs of the deferred transmission projects range between $33.7 million to $68.3 million, which equates to a ten-year NPV of approximately $37.7 million to $76.4 million. Although National Grid subsequently indicated that it intends to pursue some of the projects it included in these estimates, the need for those transmission projects it proposes has not been sufficiently justified. Additional analysis on the need for these projects is therefore required. It is expected that National Grid will prepare an updated reliability analysis in support of its continued development of these transmission projects, in light of the continued operation of the Dunkirk facility over the longer term. The recovery of any transmission project costs can then be addressed in the next National Grid rate proceeding.

While the existing RSS Agreement expires May 31, 2015, National Grid concedes that the longer term transmission upgrades it plans to implement to ensure reliability in the absence of the Dunkirk facility would not have been completed until 2017. As a result, without the Term Sheet, it would have been necessary to extend the existing RSS Agreement to at least September 30, 2017. While National Grid did not reflect the value of these avoided RSS payments in its report, Staff estimates the value at approximately $50 million.

C. Economics and Economic Development

The National Grid Report identifies various economic development and other economic benefits of the Term Sheet agreement, which we are encouraged to consider under the Part Y legislation. *These economic development and other economic* benefits are significant and lend support to making a finding that the Dunkirk Proposal in the public interest.

The Term Sheet results in net positive impacts to the local economy between September 2015 and 2019. The direct benefits of labor and materials and service (M&S) spending to the Dunkirk area, during September 2015 to the middle of 2019 period, from the income and benefits received by labor and some or all of the M&S payments is estimated to range between $21 million (for labor only) and $34 million (for labor and M&S) on an NPV basis.[42] In addition, the plant will continue its property tax payments of approximately $8 million per year to the Dunkirk area, which is inordinately dependent on the plant for tax revenues.

While National Grid calculates the electric market impact benefits of the refueled Dunkirk facility, a better estimate of the benefits utilizes the "production cost savings" associated with relieving congestion in western parts of the State provided by the availability of the Dunkirk facility, especially when congestion could block the flows from NYPA's Niagara Hydroelectric plant and imports from Ontario. NYISO and NRG both presented production cost estimates at the Staff-

[42] These benefits were estimated by Staff using the pro forma specifications for various upstate NY generator types filed at FERC by the NYISO. Attachment I - C. Class Average Avoidable Costs, Annual Report in Docket ER01-3001 and ER03-647, filed at FERC 12/20/2011, p. 36. "Class G, Steam Electric, Natural Gas" is the relevant column for this purpose.

sponsored technical conference on October 31, 2103. NYISO's estimate of annual production cost savings for 2019 and 2022 are $1.6 million and $8.6 million, respectively. On the other hand, NRG presented annual production cost savings of $40.4 million by 2023. These results were produced using different computer software modeling tools, with NYISO using General Electric's MAPS software and NRG using PowerGem's PROBE market model tool. Although both models produced different quantitative results, qualitatively they showed similar trends in increased production cost savings over time. To place these modeling results on a comparable basis, Staff devised a methodology that indicated a ten year NPV in the range of $31 million to $81 million.

D. Environmental Factors

National Grid describes the environmental benefits of refueling the Dunkirk facility. In particular, refueling Dunkirk Units 2, 3, and 4 would create additional opportunities to avoid adverse environmental impacts by reducing the local emission of $CO_2$, $SO_x$ and $NO_x$ from the plant compared to burning coal. Although statewide emissions of these pollutants are expected to remain relatively unchanged, local emissions from the plant itself are expected to be significantly reduced.[43]

In addition, the NYISO found that the availability of generation at the Dunkirk facility would relieve certain system constraints in western New York that otherwise limit the output from the Niagara Power Project. With some relaxation of the system constraints, a greater proportion of the energy produced in NYISO Zone A would be renewable, emissions-free hydropower than would be the case if the Dunkirk facility were not operating.[44]

[43] Dunkirk Proposal, p. 12.

[44] Dunkirk Proposal, pp. 12-13.

While we share Earthjustice's concern with the air emissions associated with the use of coal, we expect the future use of coal at the Dunkirk facility will be limited to periods of natural gas shortage or unavailability, which will be the times when the plant's dual-fuel capability will help relieve the natural gas shortage and help avoid potential curtailments of firm gas customers. Moreover, the use of coal will be subject to the limitations specified in Dunkirk's air emissions permits.

Accordingly, the Dunkirk Proposal and its attendant Term Sheet meet the objectives and policies established in the Part Y legislation and the January 2013 Order. National Grid has appropriately balanced the factors it was required to evaluate under the legislation and the Order, and has arrived at a result that furthers the policies established therein. Therefore, we approve the Term Sheet supporting the repowering project as in the public interest.

E. Cost Allocation and Recovery

Without the Dunkirk facility, National Grid would have incurred costs to reinforce its transmission system to meet its reliability needs. Moreover, the Term Sheet is intended to ensure that National Grid continues to deliver reliable electric service to its customers. As a result, the allocation and recovery of the costs incurred to implement the Term Sheet should be done in a manner consistent with the other approaches for allocating costs associated with maintaining reliability, such as the cost of necessary transmission upgrades.

The existing RSS surcharge tariff mechanism is therefore an appropriate cost recovery mechanism. Under the RSS Surcharge, costs are allocated to service classifications based on National Grid's most recent transmission plant allocator and are recovered from each class on either a kWh basis for non-demand classes or a kW basis from demand classes.

MI's suggestion that the costs of the Term Sheet should be allocated statewide, given the potential ICAP savings, is rejected. Those market savings are uncertain and difficult to quantify. Accordingly, they are an inadequate basis for determining with the necessary specificity costs that should be recovered, or for allocating those costs to ratepayers outside of the responsible transmission owners' service territory. Our rationale in approving the allocation and recovery of costs associated with the refueling is similar to the approach we take with respect to RSS agreements, since both those costs and the Term Sheet costs were to solve a local transmission security reliability violation, as identified by the host utility on its transmission system. We presume that the reliability benefits fall predominately, if not exclusively, to the host utility, while also providing local economic and tax benefits in the host utility's franchise territory.

F. PSL Statutory Authority

For the purpose of cost recovery, Entergy argues that we lack authority to take action with respect to the Term Sheet and are preempted by FERC. Entergy's arguments are rejected. We find that sufficient authority exists under the PSL to establish a retail cost allocation and recovery mechanism related to the Term Sheet.

Authority exists under the PSL to require National Grid to consider alternatives. In particular, PSL §5(2) provides authority to "encourage all persons and corporations subject to its jurisdiction to formulate and carry out long-range programs, individually or cooperatively, for the performance of their public service responsibilities with economy, efficiency, and care for the public safety, the preservation of environmental values and the conservation of natural resources."[45] The broad language of PSL §5(2) encompasses the authority to direct electric utilities, which include National Grid, to study various alternatives to meeting future electric system needs, including transmission, generation and/or demand-side management options. That broad authority, as it applies to repowering efforts, was specifically recognized in the Part Y legislation.

Moreover, PSL §65(i) provides that "[a]ll charges made or demanded by any...electric corporation or municipality for…electricity or any service rendered or to be rendered, shall be just and reasonable and not more than allowed by law or by order of the commission."[46] Accordingly, we may develop retail rate recovery mechanisms that provide for jurisdictional utilities to collect payments from their ratepayers for needed infrastructure.

G. Federal Preemption

We disagree with Entergy's argument that the FPA precludes us from accepting the Term Sheet and authorizing

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[45] Section 5(2) of the PSL has been held to confer "broad discretion" to promote energy conservation. See Multiple Intervenors v. NYPSC, 166 A.D.2d 140 (3rd Dept. 1991). Furthermore, PSL §5(2) was determined to provide the Commission with jurisdiction to require utilities to file plans outlining how they would adapt to a competitive electric industry. See Energy Association of New York State v. NYPSC, 169 Misc. 2d 924 (Supreme Ct. 1996)(noting that PSL §5(2) transformed "the traditional role of the Commission from that of an instrument for a simple case-by-case consideration of rates requested by utilities to one charged with the duty of long-range planning for the public benefit").

[46] PSL §65(1).

National Grid to recover its costs from retail ratepayers.[47] The import of Entergy's argument is that the FPA precludes us from accepting utility agreements with generators for the purpose of preserving system reliability. But ensuring the safety and adequacy of electric service is a core function under the Public Service Law. The FPA expressly preserves such State authority from federal intrusion.

As the FPA states, FERC's authority to establish reliability standards "shall [not] be construed to preempt any authority of any State to take action to ensure the safety, adequacy, and reliability of electric service within that State, as long as such action is not inconsistent with any [FERC-approved] reliability standard, except that the State of New York may establish rules that result in greater reliability within that State, as long as such action does not result in lesser reliability outside the State than that provided by the [FERC-approved] reliability standards."[48] Since the Dunkirk Proposal defines measures needed to ensure safety, adequacy, and reliability, and can result in greater reliability in New York than would otherwise exist under the FERC-approved reliability standards, the Proposal falls within the ambit of the FPA provisions.

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[47] Entergy's argument is at odds with its own actions in entering into contracts whose costs are recovered from ratepayers, when such contracts further its pecuniary interests. See, e.g., Case 01-E-0040, Consolidated Edison Company of New York, Inc., Order Authorizing Asset Transfer (issued August 31, 2001)(approval of contract for Entergy's sale of capacity and energy).

[48] 16 U.S.C. §824o(i)(3). FERC's reliability jurisdiction expressly reserves state authority to "order the construction of additional generation or transmission capacity or to set and enforce compliance with standards for adequacy or safety of electric facilities or services." 16 U.S.C. §824o(i)(2).

5. This proceeding is continued.

By the Commission,

Kathleen H. Burgess

KATHLEEN H. BURGESS
Secretary

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

CASE 12-E-0577 - Proceeding on Motion of the Commission to Examine Repowering Alternatives to Utility Transmission Reinforcements.

NOTICE OF DETERMINATION OF
NON-SIGNIFICANCE

NOTICE is hereby given that an Environmental Impact Statement will not be prepared in connection with the approval by the Public Service Commission of the Term Sheet proposed by Niagara Mohawk Power Corporation d/b/a National Grid for the addition of natural gas capability for refueling the currently coal-fired Dunkirk generating facility, and allowing for the deferral of some transmission upgrades, based on our determination, in accordance with Article VIII of the Environmental Conservation Law, that such action will not have a significant adverse affect on the environment. The exercise of this approval constitutes an "unlisted" action, as is defined in 6 NYCRR §617.2(ak).

Based on our review of the record, we find that The approval of the Term Sheet for refueling the Dunkirk facility with natural gas results in environmental benefits as opposed to countering the effects of mothballing through transmission upgrades or coal-fueled operation. Retaining generation at the Dunkirk location mitigates the impacts that would attend constructing additional transmission, opens existing transmission space to greater generation from renewable-fueled hydro facilities, and allows for greater flexibility in operating the transmission system in ways that are more efficient. Moreover, refueling the facility with gas diminishes the possibility that it will be returned to service as a coal-fueled plant either to mitigate the effects of mothballing or if economic considerations were to warrant, thereby substituting a cleaner, more environmentally-beneficial fuel than was previously used.

The address of the Public Service Commission, the Lead Agency for the purposes of the environmental quality review of this project, is Three Empire State Plaza, Albany, New York 12223-1350. Questions may be directed to Dean Long at (518) 474-9870 or at the address above.

KATHLEEN H. BURGESS
Secretary

# Where does Ohio's electricity come from?

In Ohio, the majority of our electricity is generated using nonrenewable resources like coal, natural gas, nuclear and petroleum. While these resources are found naturally in the earth and produce large amounts of electricity, nonrenewable resources take a long time to form, and there is a limited supply available for people to use for power generation.

Renewable resources including hydropower, wind, biomass and solar energy are also used to produce electricity, but often on a smaller scale. These resources are readily available in nature and can be replenished relatively quickly.

The PUCO supports a mix of generation resources in order to minimize the risks, including price spikes, associated with an exclusive reliance on any one type of electric generation. Below are brief descriptions of the generation resources currently used in Ohio.

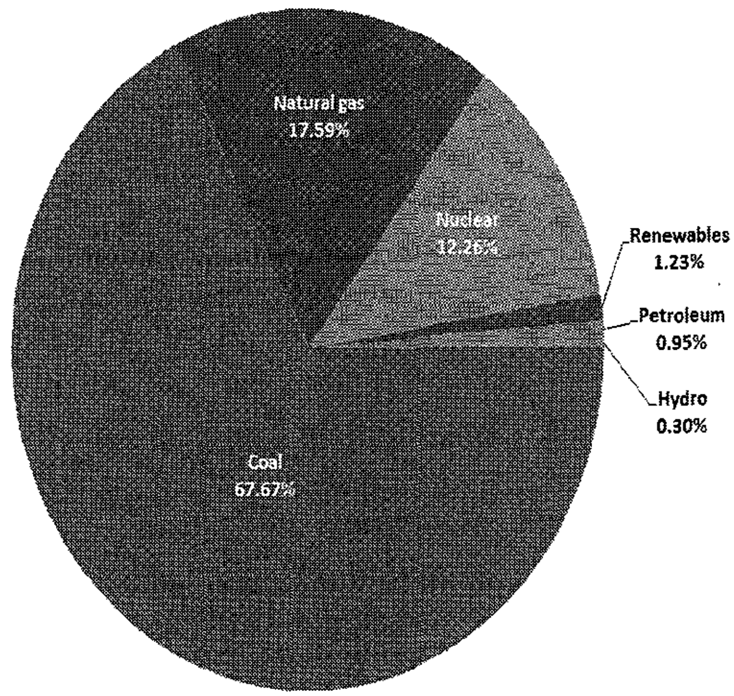
**Coal,** a nonrenewable fossil fuel, is used to generate 67.67 percent of the electricity in Ohio. Coal is burned to produce heat, which converts water into high-pressure steam. The steam turns the blades of a turbine that is connected to a generator. The generator spins and converts mechanical energy to electricity.

**Natural gas**, a nonrenewable fossil fuel, can either be burned to produce steam or to produce hot combustion gas that passes through the turbine blades. Approximately 17.59 percent of the electricity in Ohio is produced using natural gas and other gases.

**Petroleum**, a nonrenewable fossil fuel, is burned to create steam to turn the turbine blades. The most common form of petroleum used to make electricity is fuel oil, a type of oil that is refined from crude oil. Petroleum generates approximately one percent of Ohio electricity.

**Nuclear** power involves a process called fission in which the atoms of the element uranium split, releasing heat to turn water into steam and rotate the turbine blades. Nuclear power is nonrenewable and is used to generate about 12.26 percent of Ohio electricity.

**Ohio generation output 2014**




*Source: EIA*

In **hydropower** generation, flowing water is used to spin the turbine connected to the generator. Hydropower plants can use the current from a river or falling water that has accumulated in a dam to create the force needed to turn the turbine blades.

**Wind** turbines harness the force of the natural wind to turn the generator turbine.

**Solar** power uses photovoltaic cells to harness the energy of the sun to produce energy.

**Geothermal** energy involves the heat buried beneath the surface of the earth. This heat transforms water into steam, which is then tapped to be used at steam-turbine plants.

**Biomass** energy resources include wood and wood wastes, landfill gas, biogas from food processing waste, animal waste, sewage sludge, and potential energy crops. The **Ohio Biomass Energy Program** (OBEP) works to promote the use of biomass in Ohio.

# Snapshot of existing and planned renewable energy facilities in Ohio

## Wind

- Timber Road Wind Farm II, 55 turbines, 100 MW*
- Blue Creek Wind Farm, 160 turbines, 350 MW*
- Northwest Ohio Wind, 59 turbines, 100 MW**
- Buckeye Wind Farm, 54 turbines, 135 MW***
- Buckeye II Wind Farm, 56 turbines, 140 MW***
- Hardin Wind Farm, 132 turbines, 211 MW***
- Hog Creek Wind Farm I & II, 43 turbines, 67 MW***
- Timber Road Wind Farm I & III, 60 turbines, 99 MW***
- Black Fork, 91 turbines, 200 MW***
- Scioto Ridge, 176 turbines, 300 MW***

* Operational
**Under construction
***Approved (not yet under construction)

**More information on wind**

## Solar

- Wyandot Solar Energy Generation Facility, 12 MW
- BNB Napoleon Solar, 9.8 MW
- First Solar Perrysburg Array, 2.4 MW
- Bryan Municipal Utilities, 2 MW
- Melink Solar Canopy at the Cincinnati Zoo, 1.6 MW
- Yankee Station Solar Generating Facility, 1.1 MW
- Centerburg High School Solar Array, 1 MW

## Hydro and Other

- 130 MW hydroelectric capacity statewide
- 19 landfill gas projects of which nine generate electricity for a total capacity of 50 MW
- Biomass generation using waste residue to generate heat and power onsite in the wood manufacturing and paper industries

# Ohio's renewable energy portfolio standard

Ohio law contains an alternative energy portfolio standard that requires that 12.5 percent of electricity sold by Ohio's electric distribution utilities or electric services companies must be generated from renewable energy sources by 2027

The law sets annual benchmarks, or incremental percentage requirements for renewable energy, through 2027. Each utility and electric services company is subject to compliance payments if the annual benchmarks are not met. Utilities and electric services companies may purchase renewable energy credits to meet the renewable energy standard.

pjm

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

May 8, 2014

PJM Interconnection

## 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.

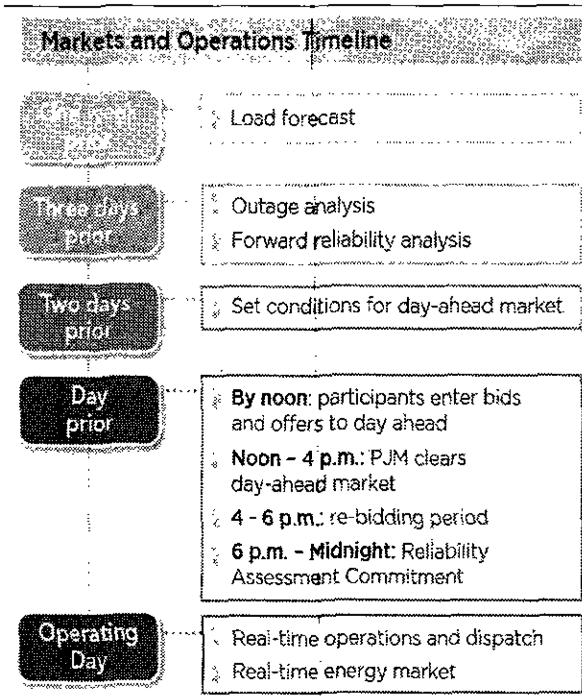
Two days prior to an operating day, PJM will begin to set up the conditions such as the expected outages and conditions for the operating day in the model for the Day-Ahead Energy Market. (The Day-Ahead Energy Market offers an opportunity for market participants to lock in their positions in advance 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.

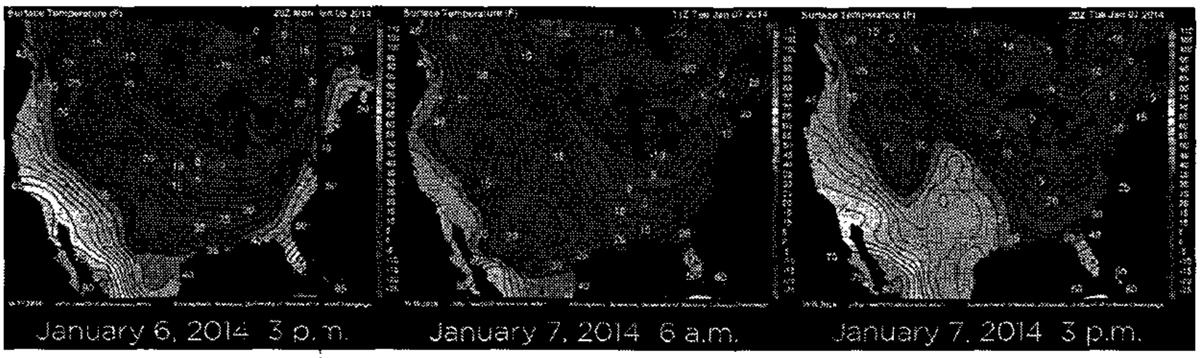
One lesson PJM implemented from the September 2013 Heat Wave[4] was to alert PJM's load forecasting experts when the temperature forecast, an input into the load forecasting engine, changes more than 8-10 degrees from the previous day. In such scenarios PJM can experience corresponding load forecast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

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.

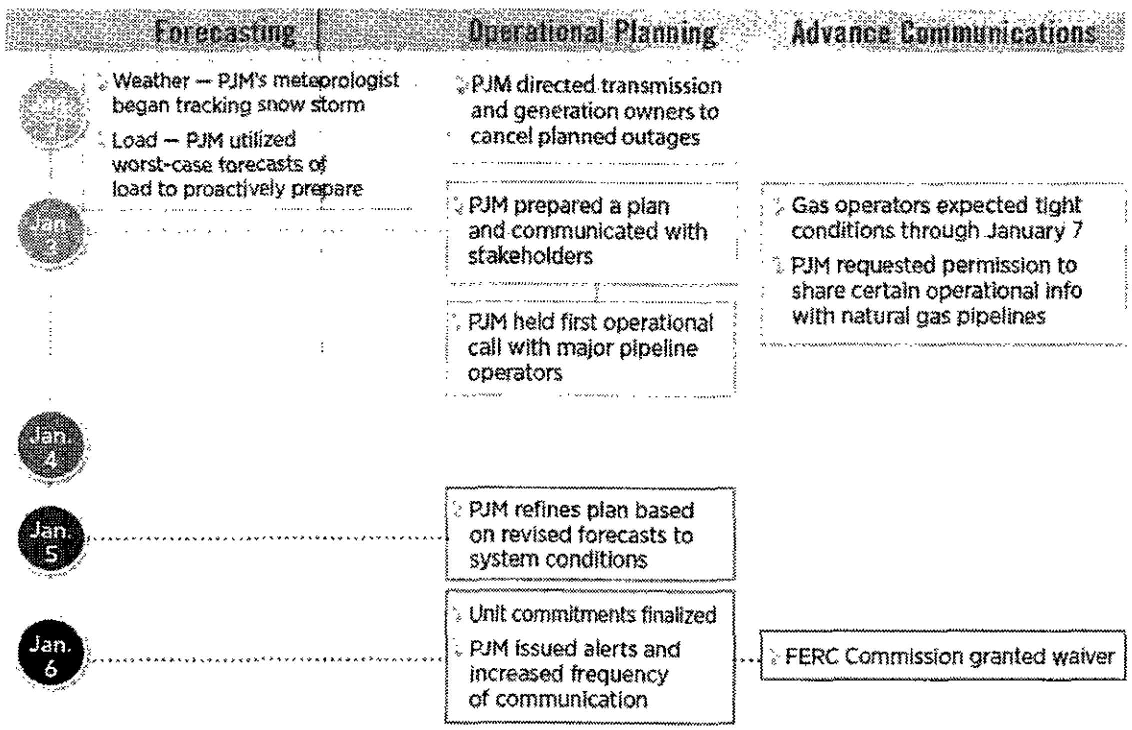
*to the Federal Energy Regulatory Commission for waivers of certain provisions of PJM's governing documents that* would permit PJM to share certain non-public information with natural gas pipeline operators during the forecasted extreme weather conditions. The waivers, the first covering one week in 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**

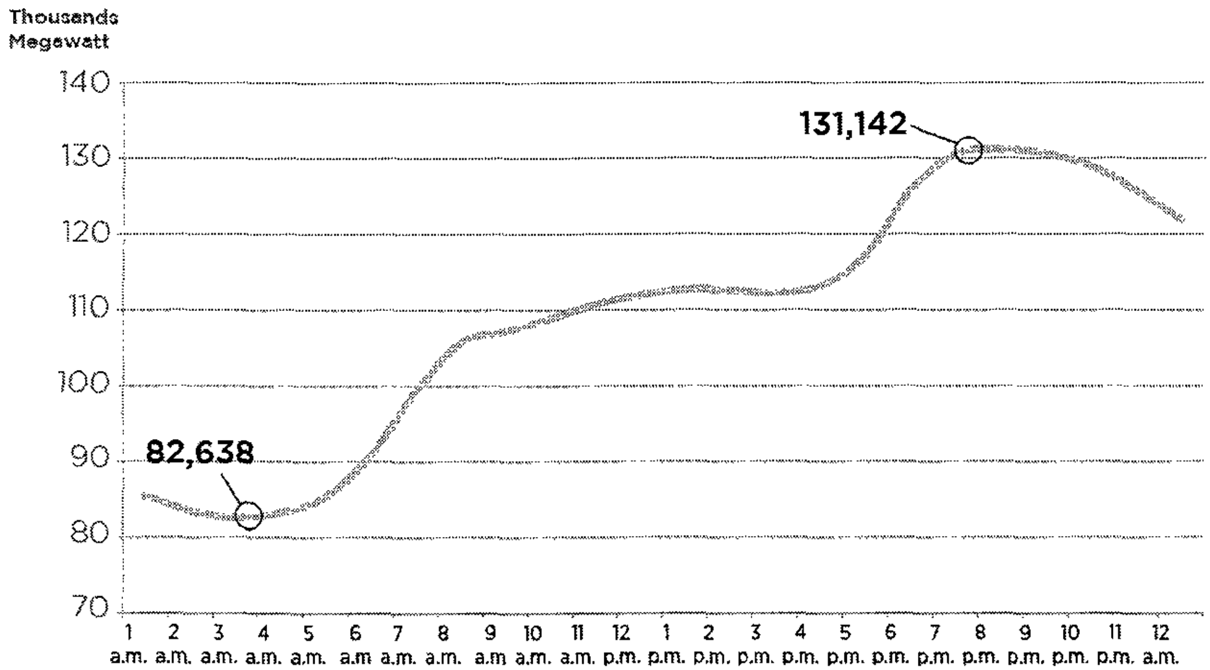
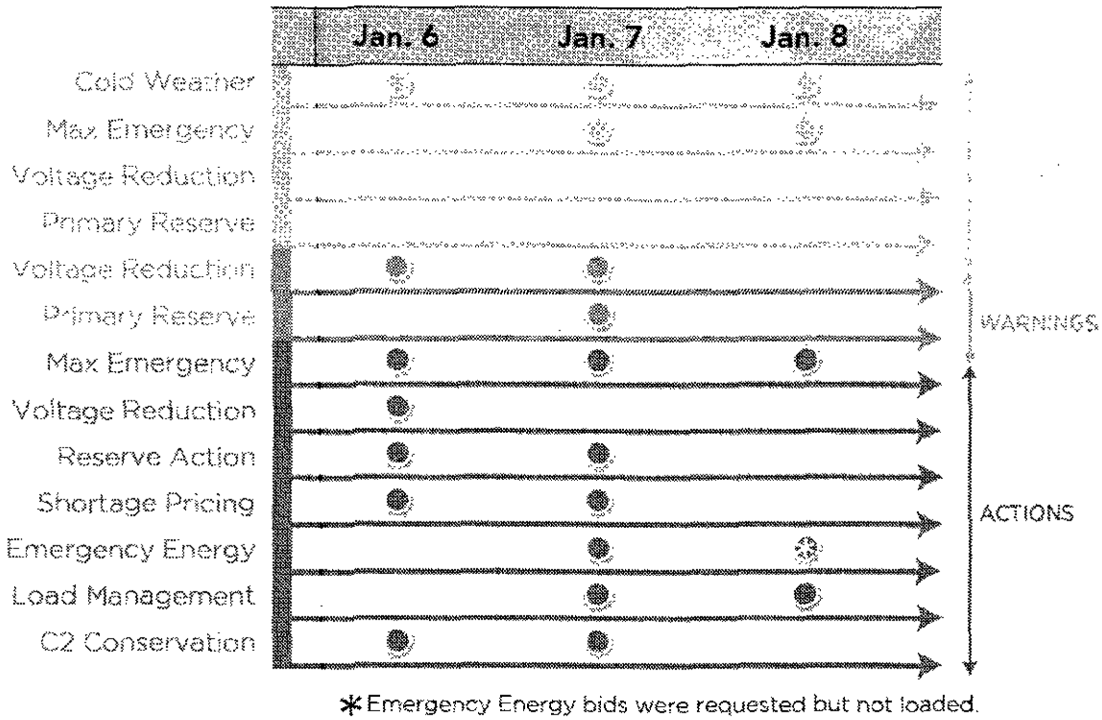

Thousands
Megawatt
140
130
120
110
100
90
80
70
131,142
82,638
1 a.m. 2 a.m. 3 a.m. 4 a.m. 5 a.m. 6 a.m 7 a.m. 8 a.m. 9 a.m 10 a.m. 11 a.m. 12 p.m. 1 p.m. 2 p.m. 3 p.m. 4 p.m. 5 p.m. 6 p.m. 7 p.m. 8 p.m. 9 p.m. 10 p.m. 11 p.m. 12 a.m.

**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.

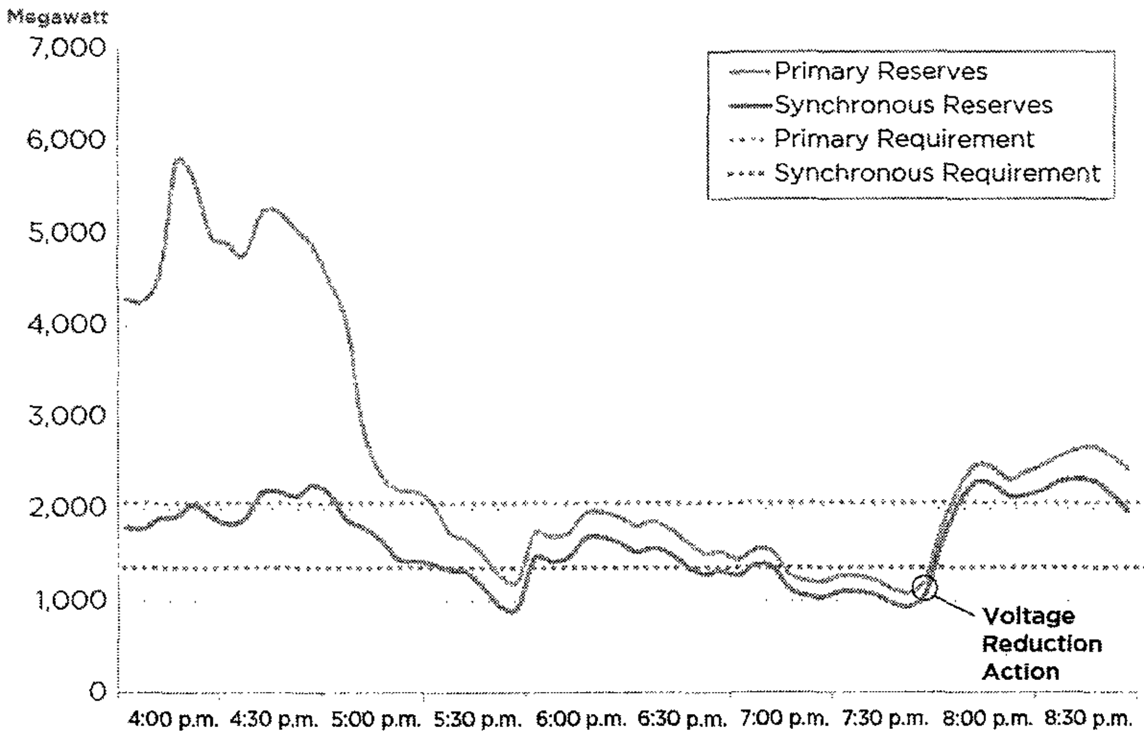
At just about 5 p.m. on Monday, January 6, PJM initiated a synchronized reserve event to maintain system reliability in response to the nearly concurrent, but unrelated, loss of two large generating units totaling 1,562 MW.[7] The Northeast Power Coordinating Council provided 775 MW of shared reserves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

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.

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[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**

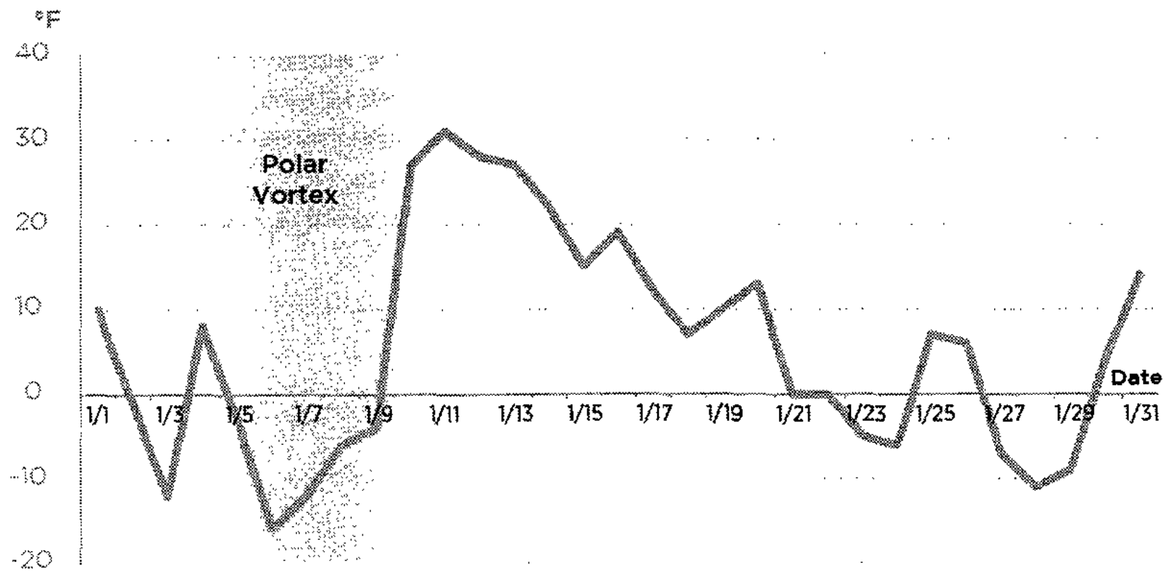
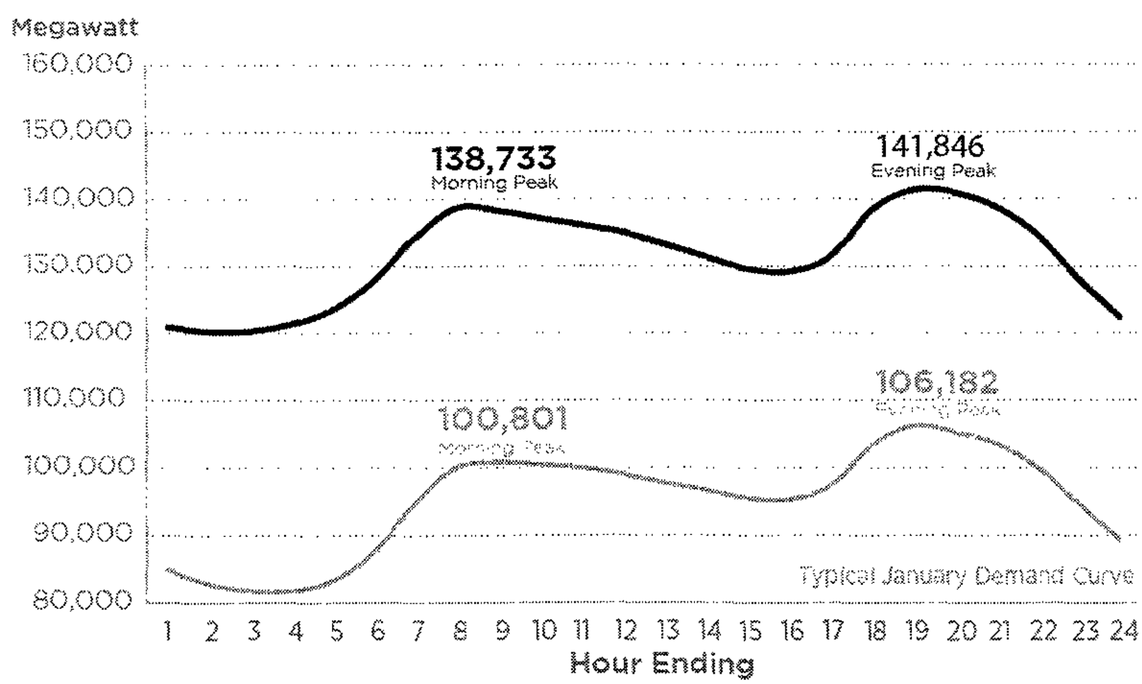



**Figure 8: January 7 – Peak Load vs. Typical Load (Winter load peaks twice each day.)**

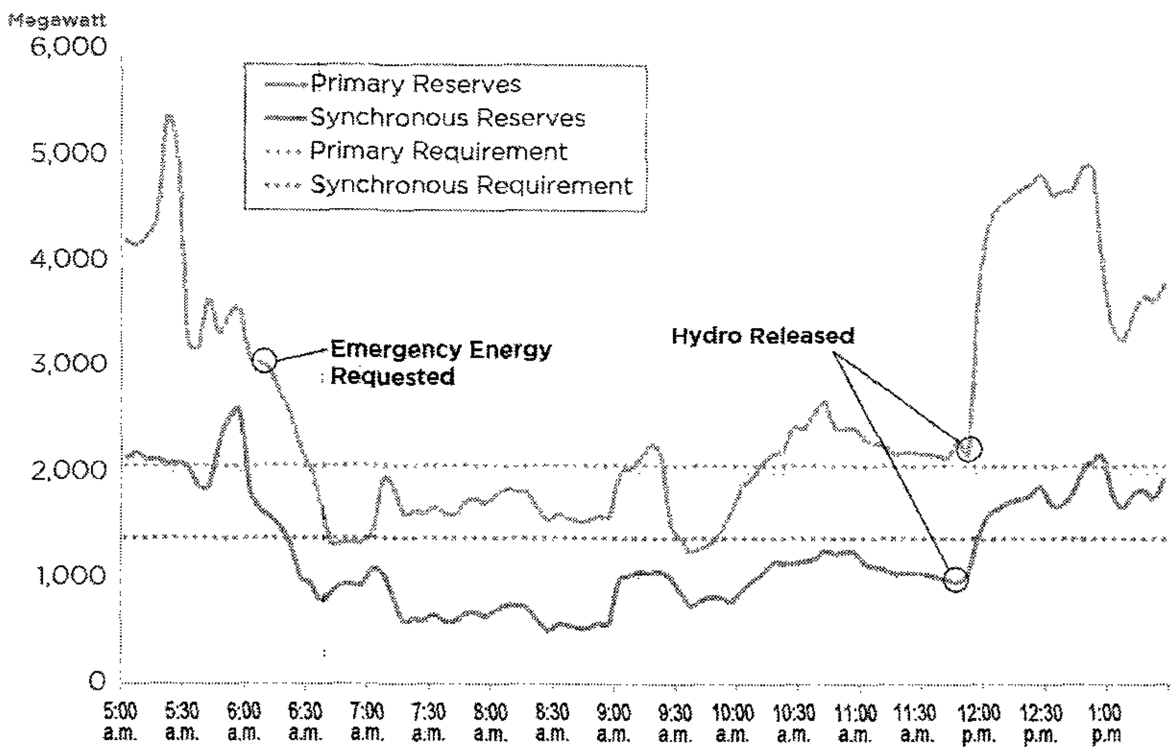



*The PJM demand curve for January 7, 2014, was 35,000 MW higher than typical of a January peak load.*

### 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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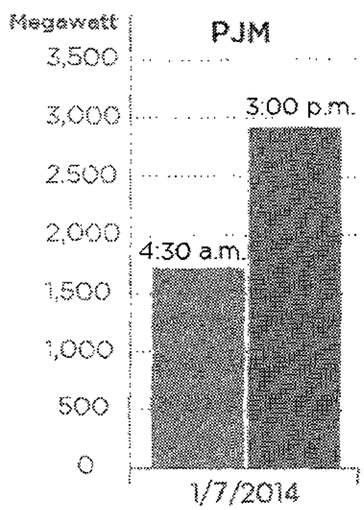
12 The purpose of a Primary Reserve Warning is to warn the members that the primary reserve is less than required and operations are getting critical. It is issued when the primary reserve is less than the primary reserve requirement but greater than the synchronized reserve requirement. Transmission 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.

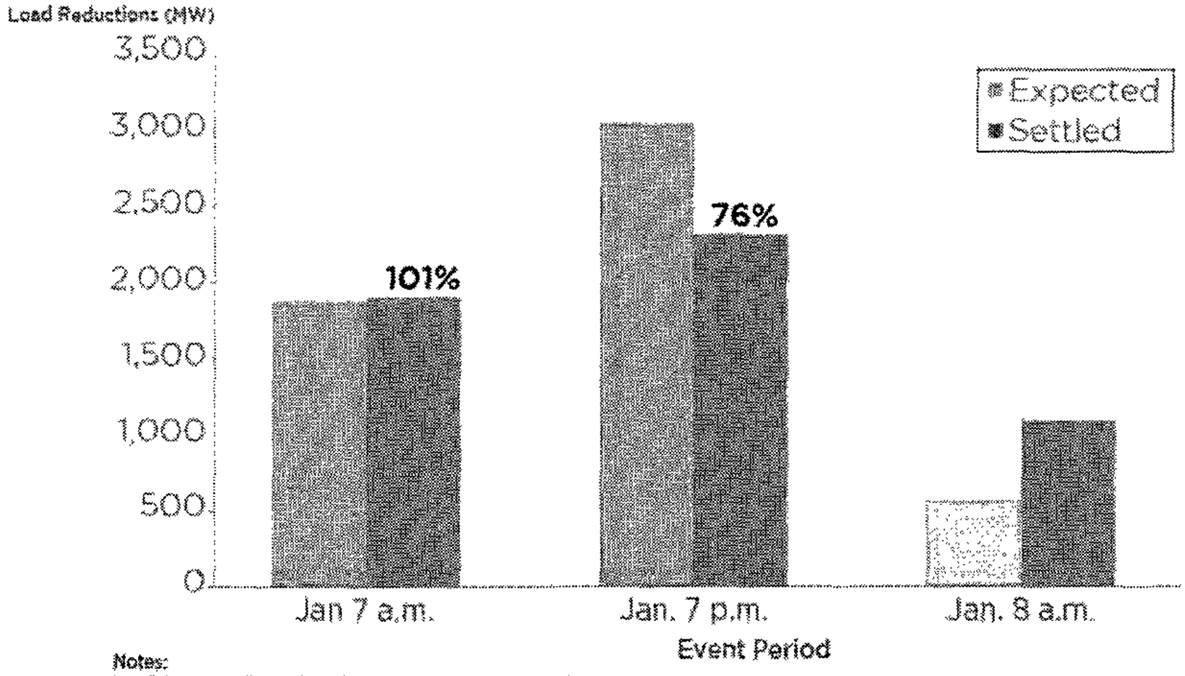
## *Operational Observations and Challenges*

### 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**



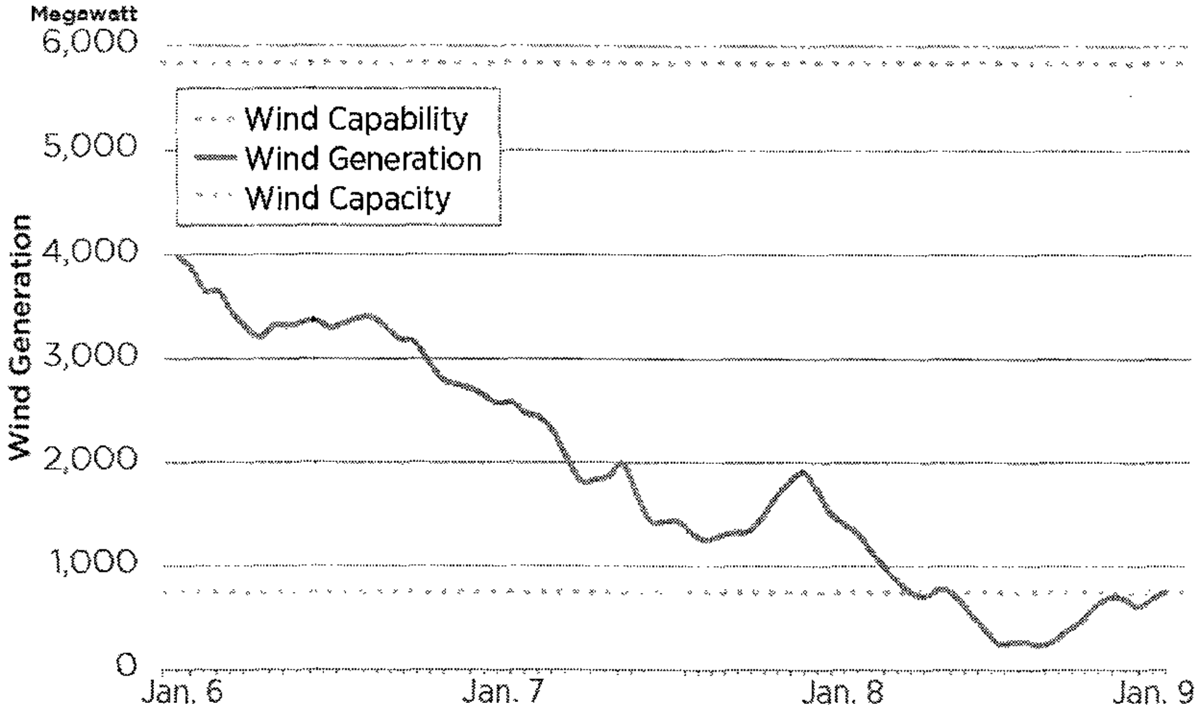

Notes:

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**



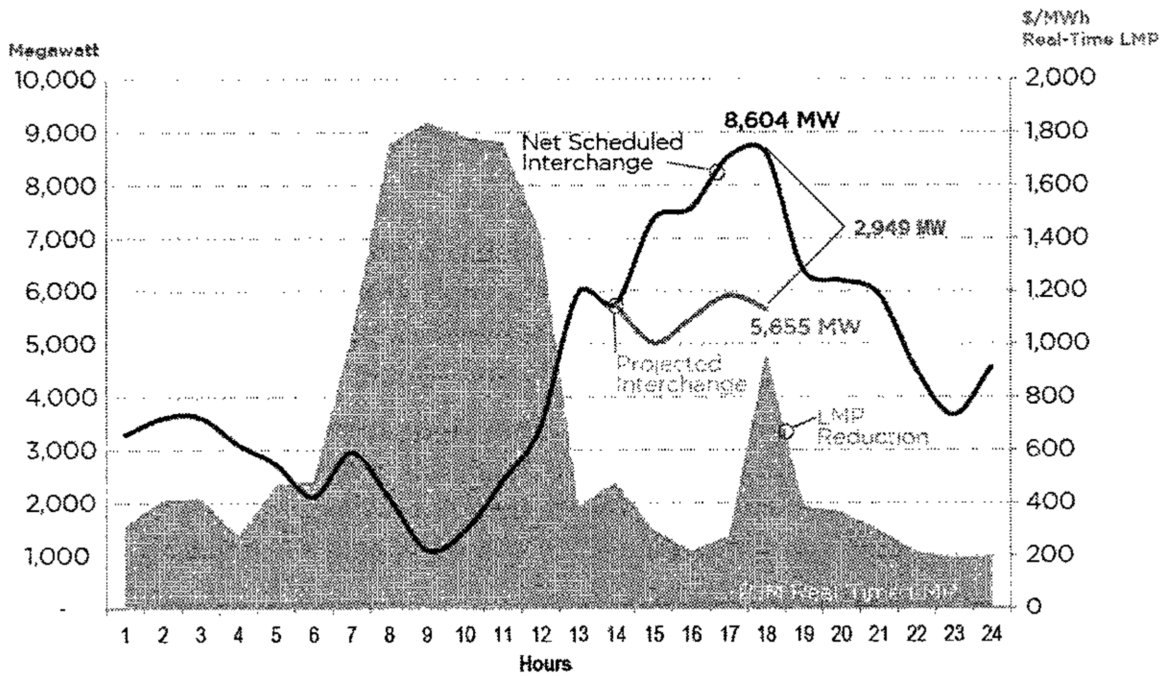

### Managing Interchange

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.

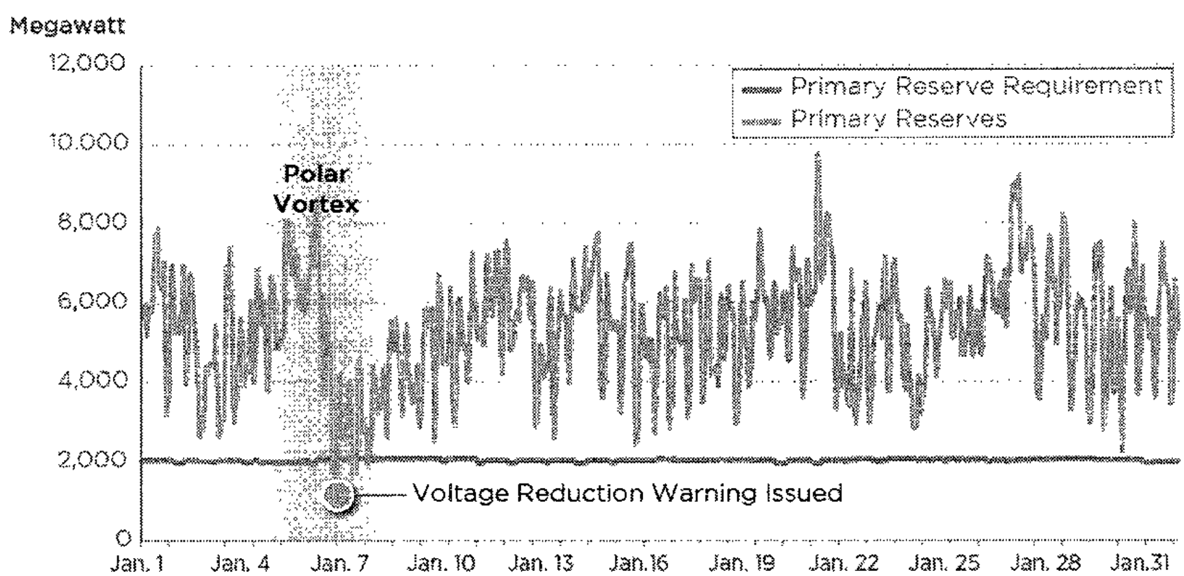
**Figure 13: Interchange and Locational Marginal Prices on January 7, 2014**




## 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**



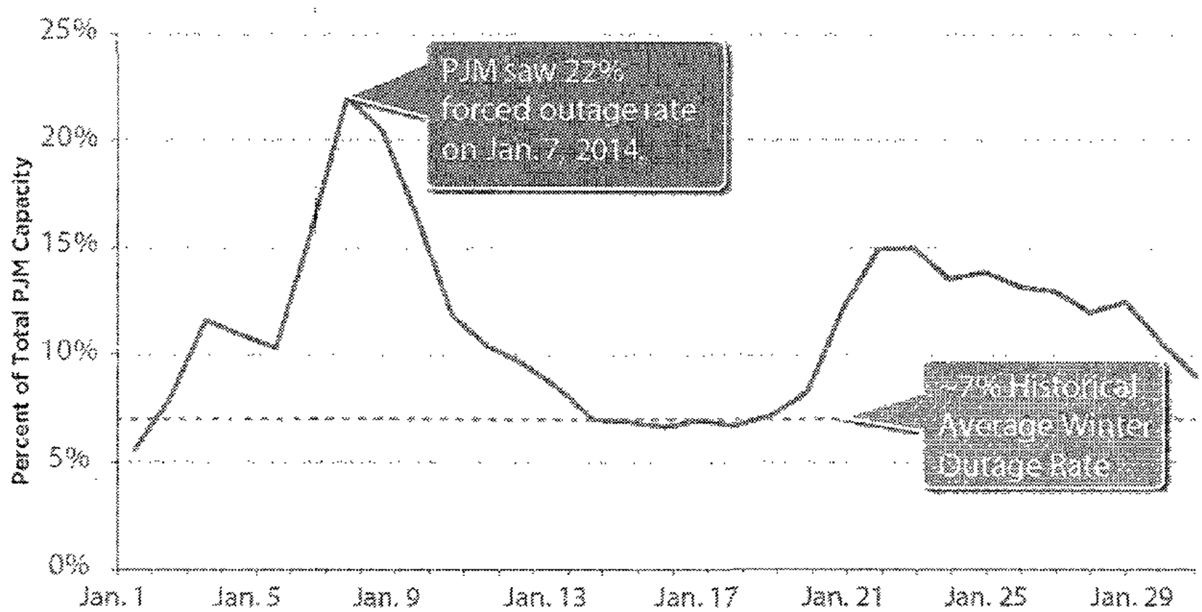
When PJM has a sustained shortfall of its primary reserve capability, a Primary Reserve Warning is issued as notification of the reserve shortage. On the evening of January 6, PJM additionally issued a Voltage Reduction Warning and Action to maintain reliability. If needed, PJM could have initiated additional 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.

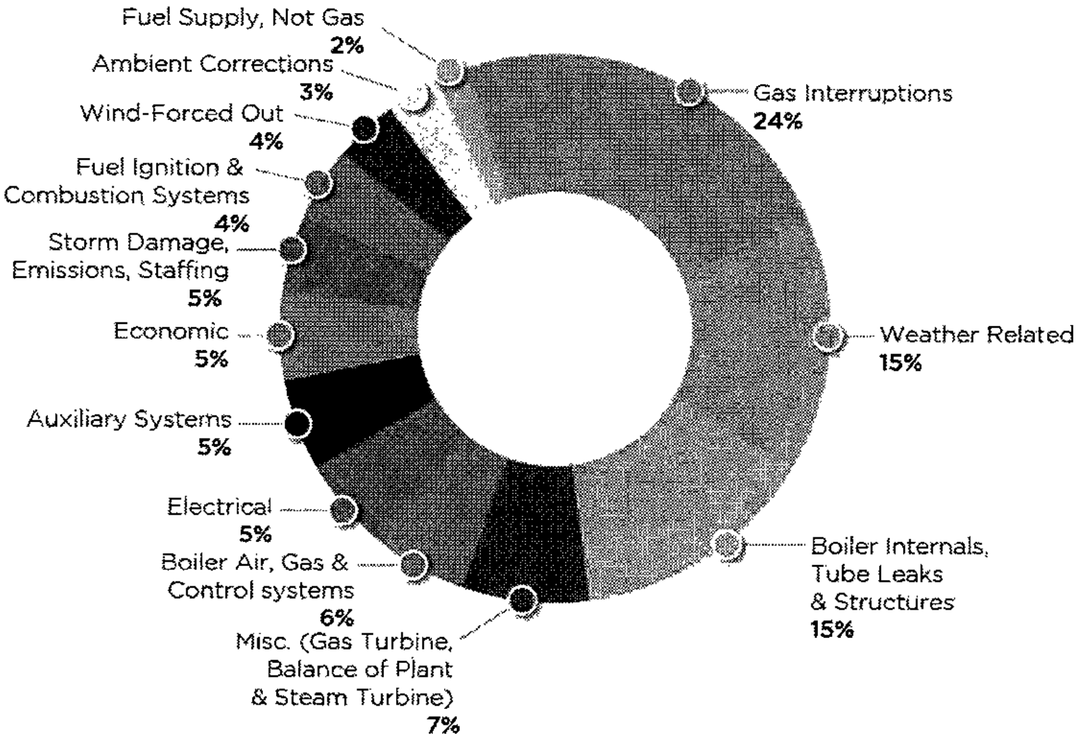
PJM experienced very tight operational conditions and a significantly higher number of forced outages, due to both mechanical problems and natural gas deliverability, throughout January 2014 as compared to a more typical January. At the all-time winter peak at 7 p.m. on January 7, PJM experienced a 22 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.

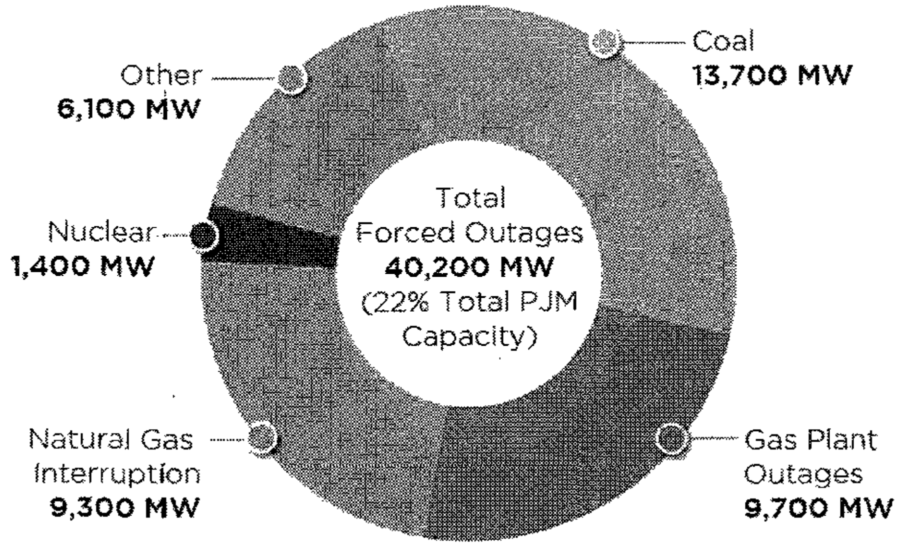
**Figure 16: Causes of Forced Outages – January 7, 7:00 p.m.**




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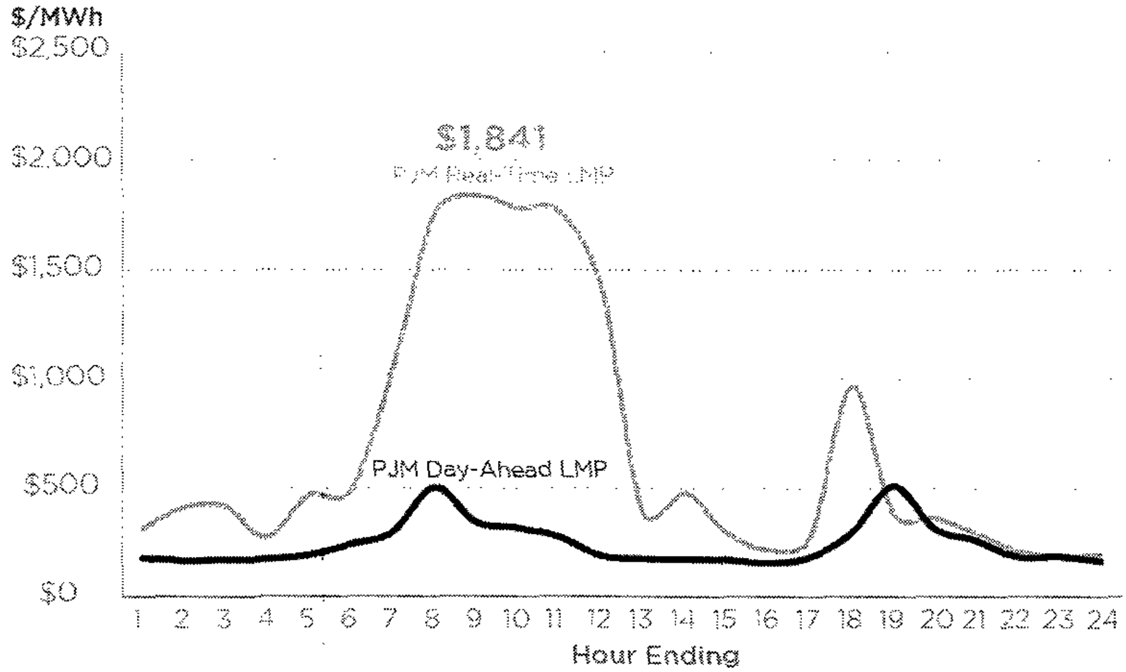
16 For more information on the shortage pricing rules, view training material PJM previously has provided at http://www.pjm.com/markets-and-operations/energy/shortage-pricing.aspx.

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**

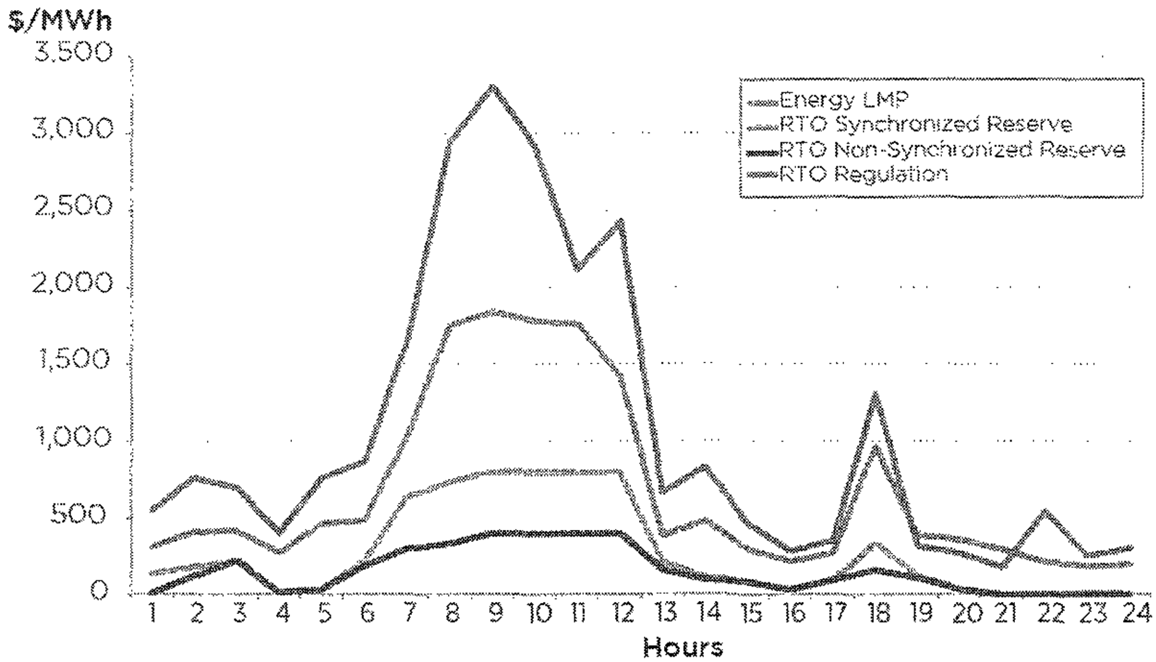



Real Time Locational Marginal Prices are calculated based on five minutes intervals. Although generation usually is the marginal resource setting the price, on January 7, demand response set prices for 63 five-minute energy pricing intervals during the day. Additional information on interval analysis 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**

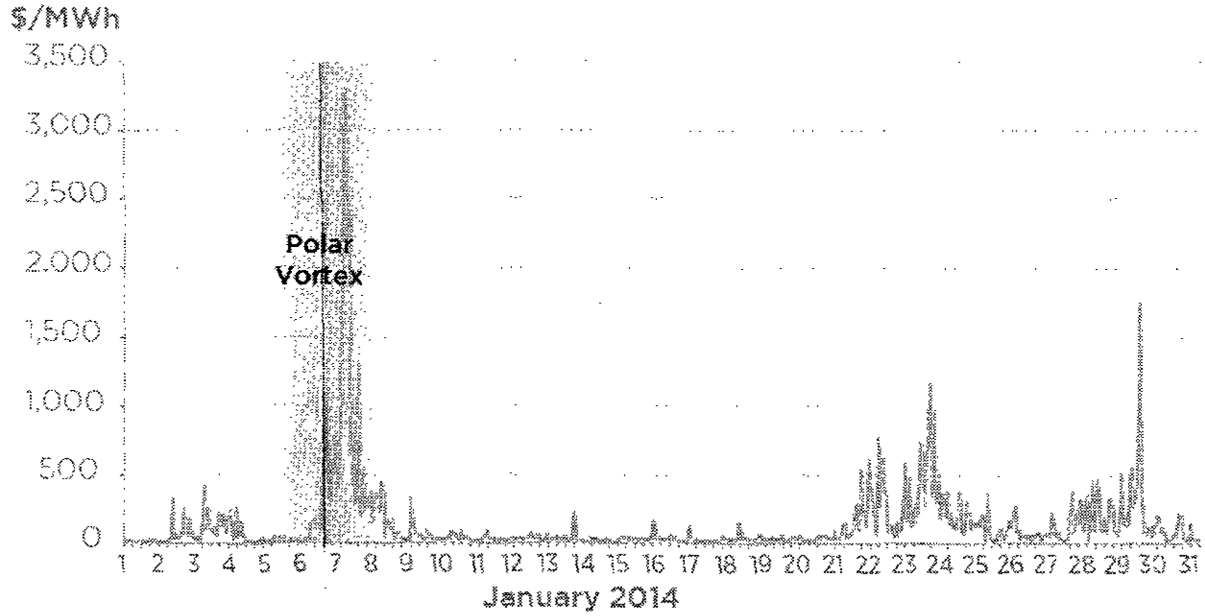



### Regulation

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



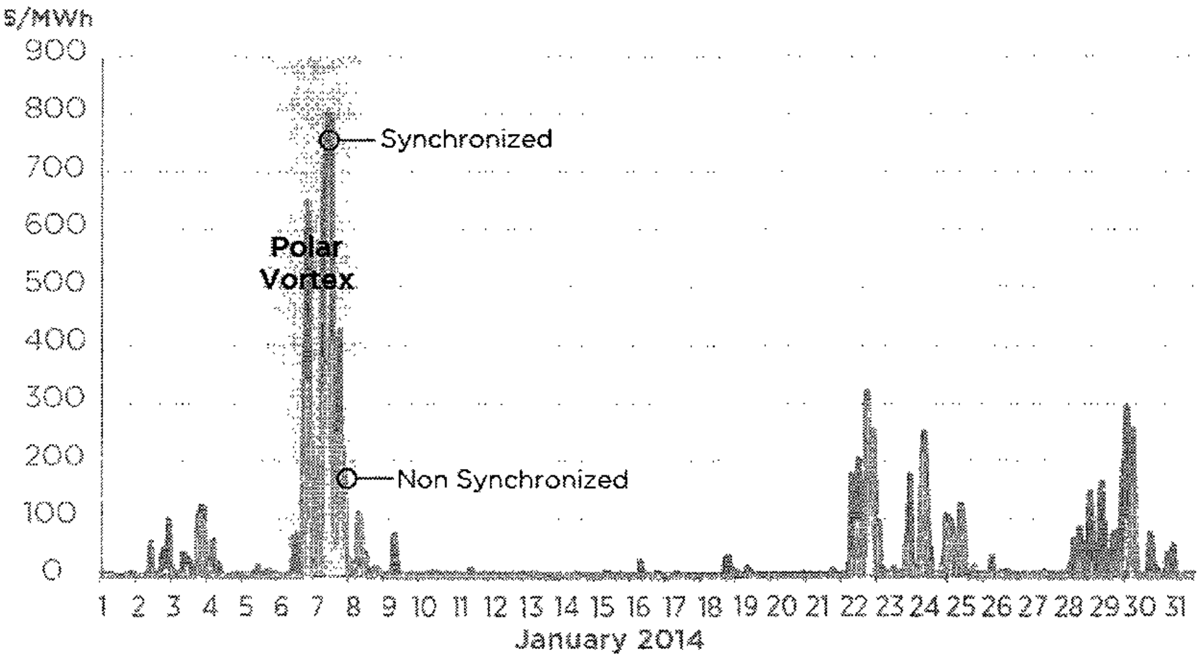

Regulation lost opportunity cost is the revenue foregone or increase in costs relative to the energy market for providing regulation service. Performance Based Regulation was designed to calculate and include resource specific regulation lost opportunity cost in the regulation market clearing price on 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.

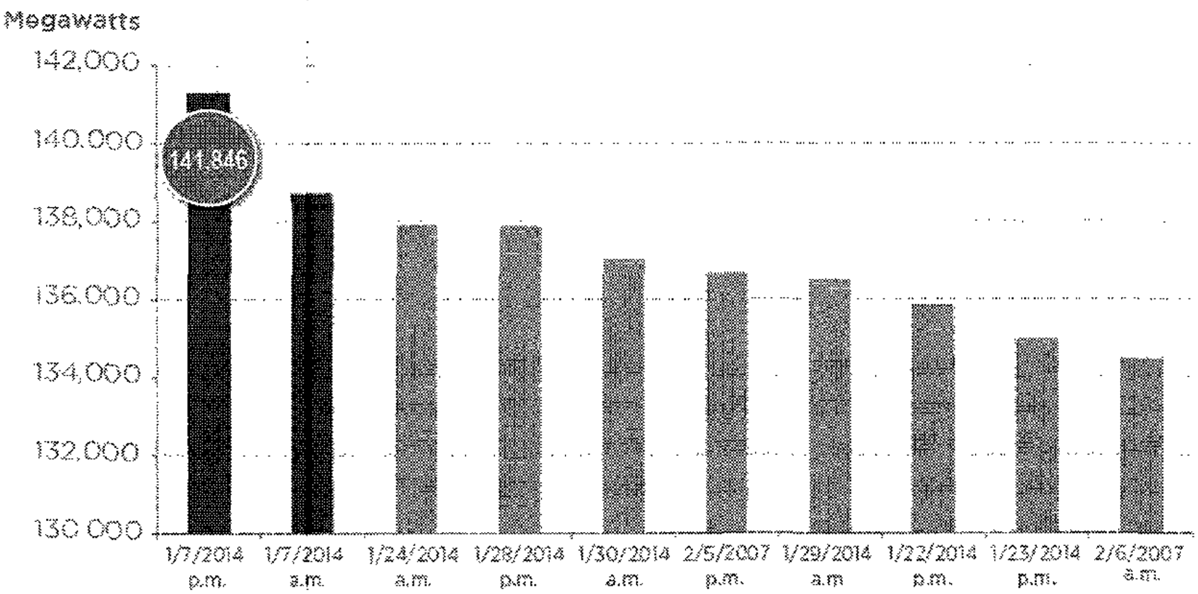
Meanwhile, spot natural gas prices soared; for example, on January 22 spot natural gas prices were 27 times the previous four months' average. Alternative fuels (usually oil) were a challenge for dual-fuel units for reasons that included fuel deliverability or minimum allowed run times because of emission 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)

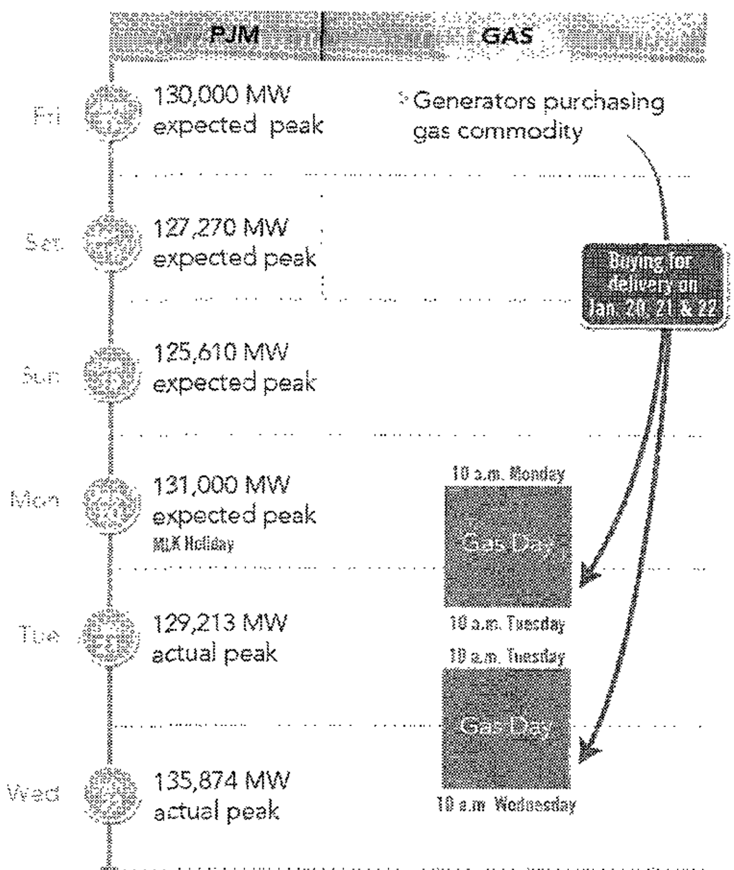
A timeline of critical notices on the natural gas pipelines in the PJM footprint can be found in

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**

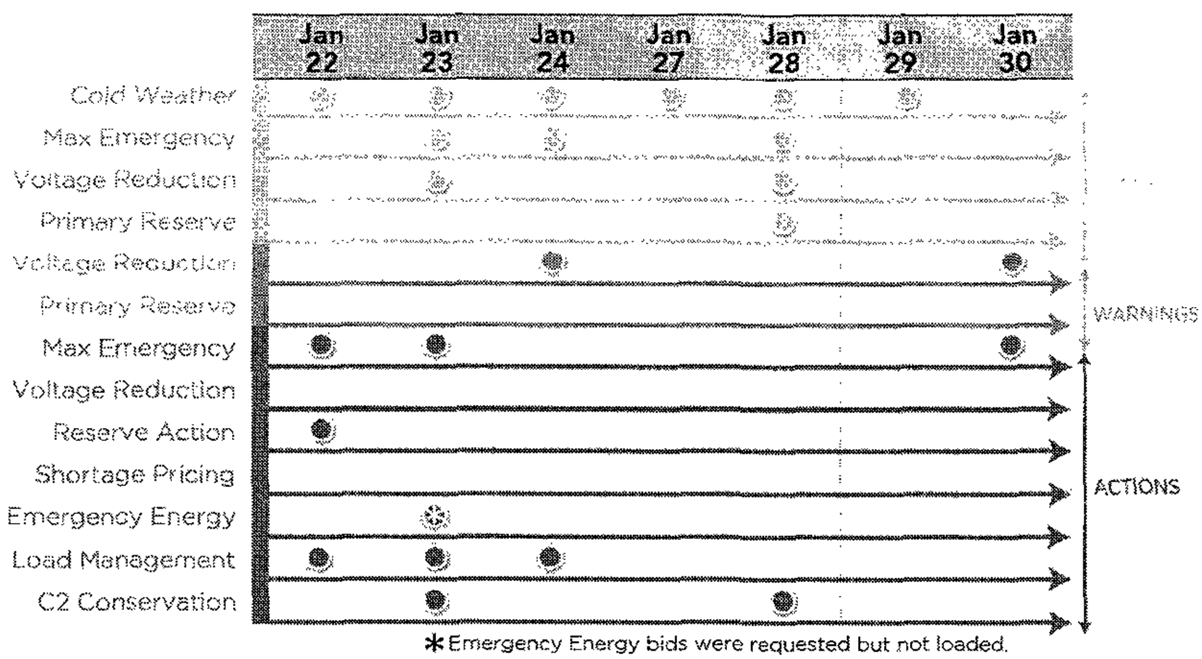


The market timing issues were further exacerbated by the three-day Martin Luther King Jr. Day holiday weekend. High electricity demand for was expected the Tuesday and Wednesday mornings after Martin Luther King Jr. Day, January 20, which coincided with the Tuesday-Wednesday 10 a.m. to 10 a.m. gas day. 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.

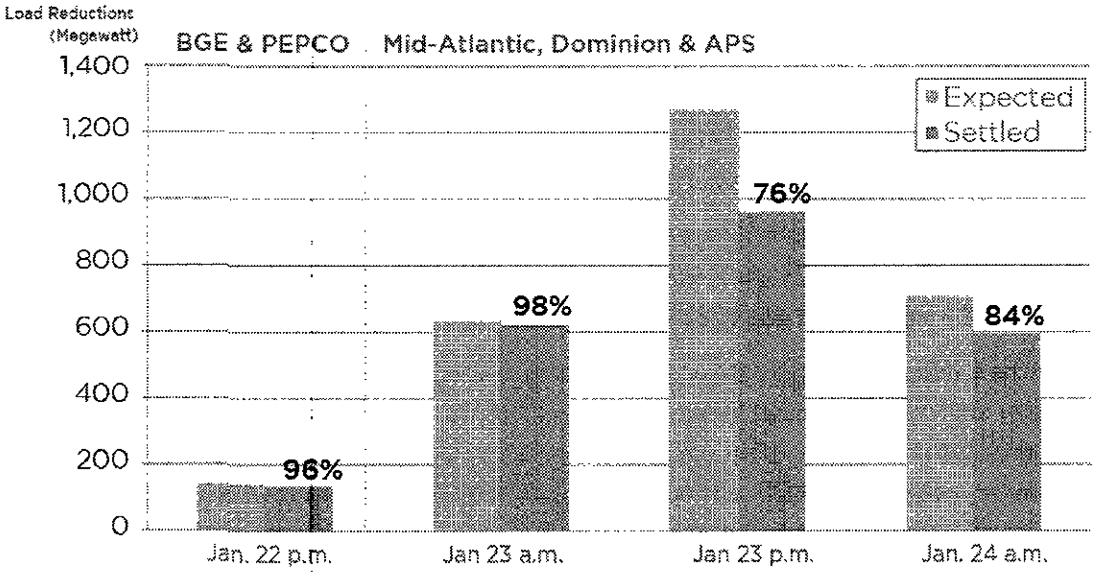
### *Demand Response*

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**

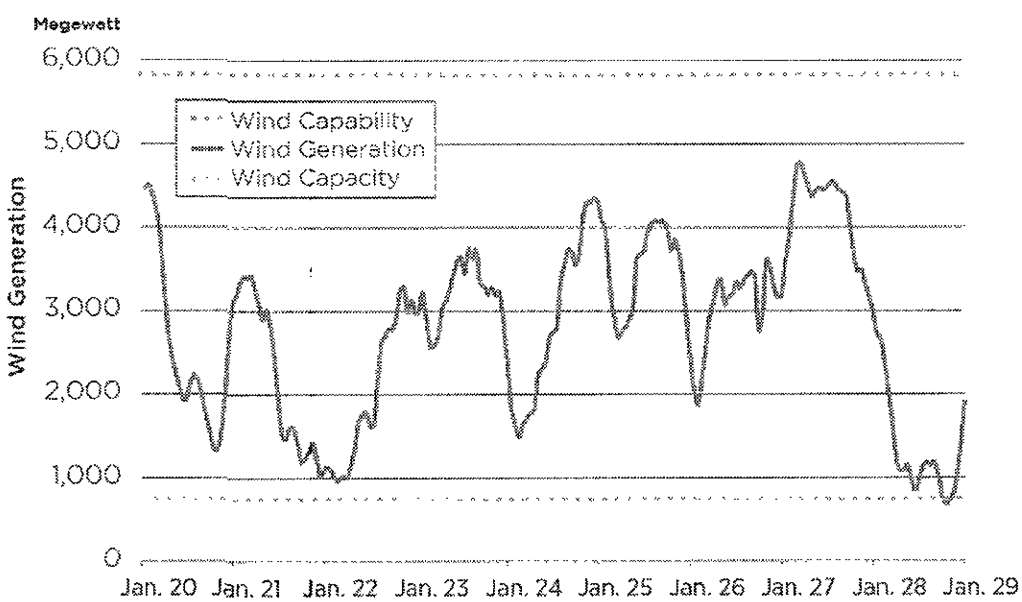



Notes:
1. DR events dispatched during non-compliance period.
2. Expected Energy Load Reductions (MW) - CSP reported estimate based on current market rule.
3. MW value is average hourly load reduction for non-ramp in hours.

### 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.

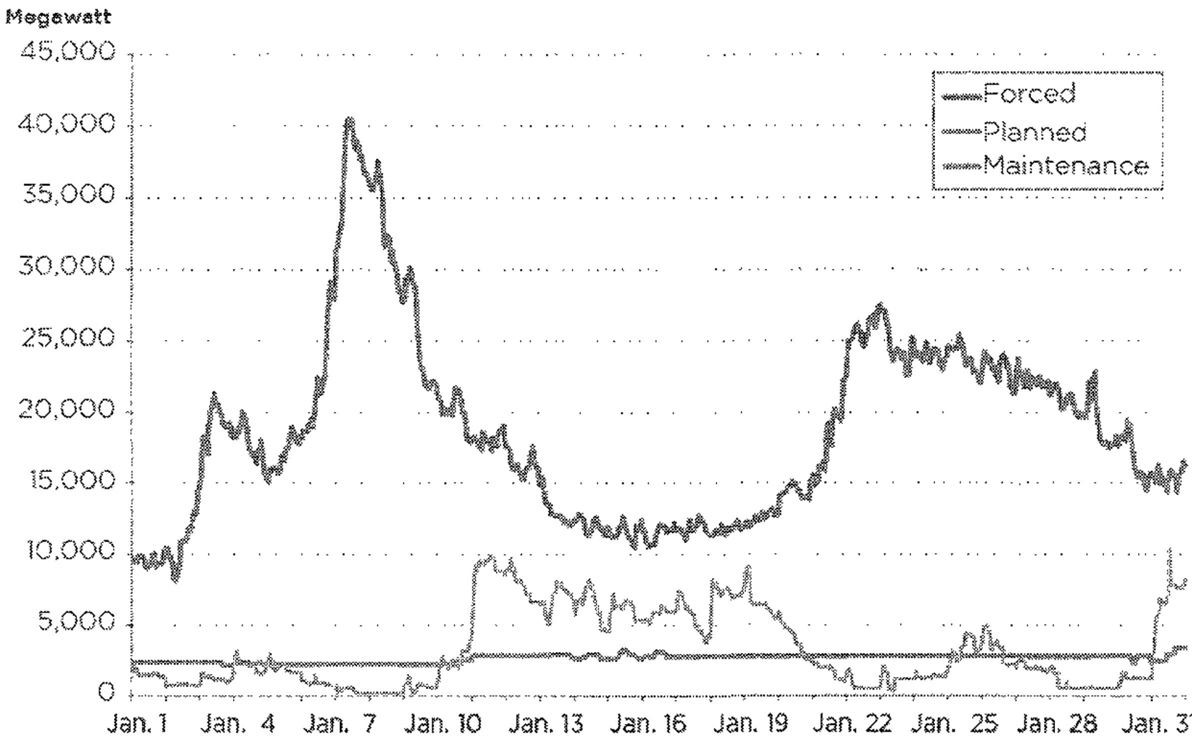
**Figure 26: Winter Storm Wind Generation**



### 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:

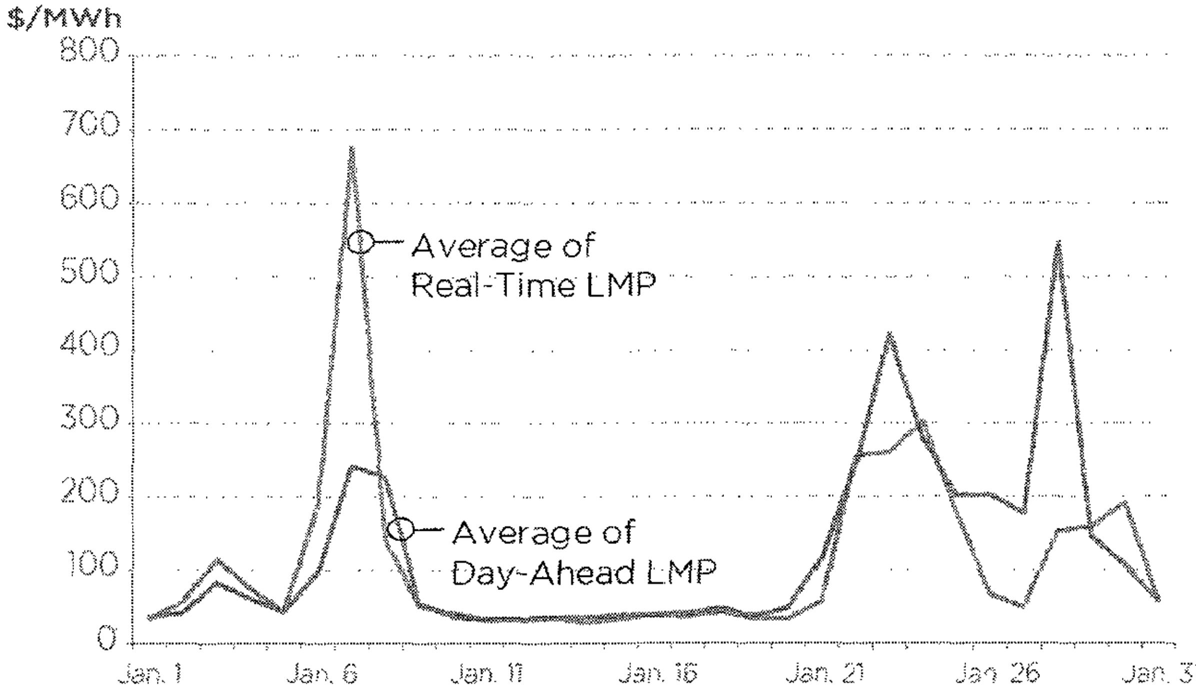
- the need for early commitment, days ahead of the Day-Ahead Energy Market, to ensure fuel deliverability;
- inflexible scheduling criteria such as 24-hour and multi-day commitment; and,
- *purchase of gas for an entire weekend.*

## *Market Outcomes: Winter Storm*

### Energy Prices

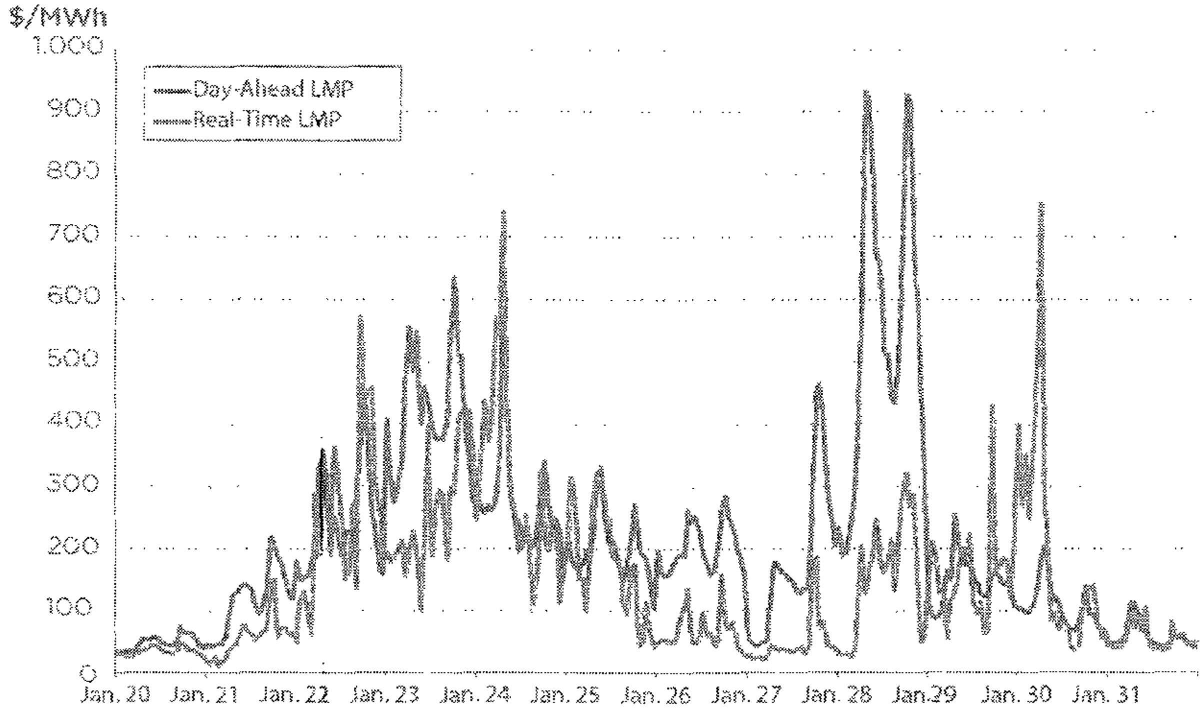
Energy prices were high during the Winter Storm but not as high as during the Polar Vortex. Shortage pricing conditions were not present during the Winter Storm because sufficient generation was available to meet the forecasted demand. Day-Ahead Energy Market prices were higher than real-time prices 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**



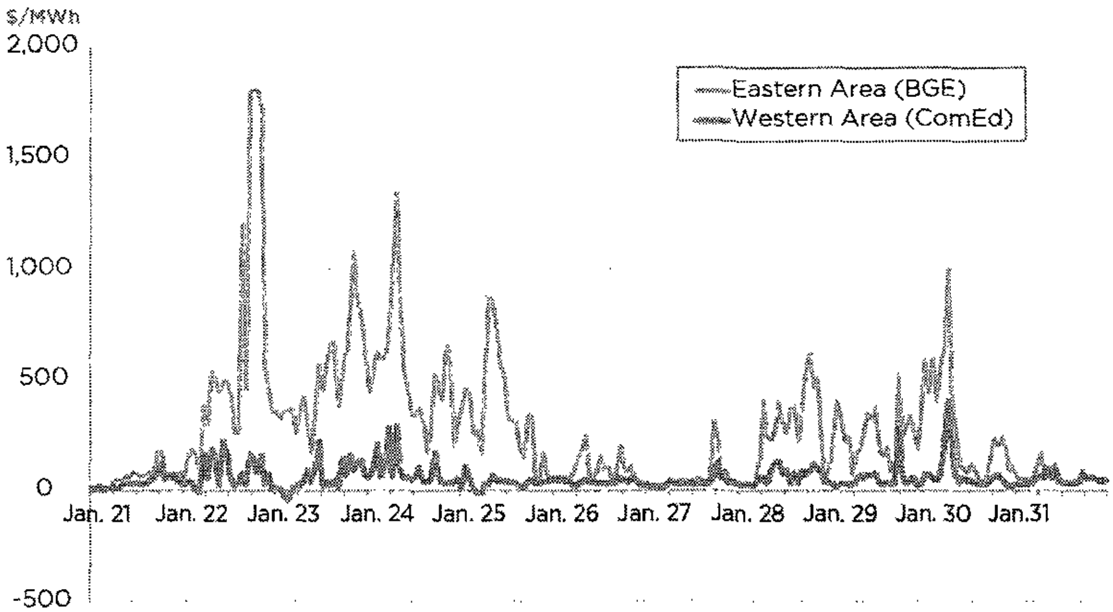

During January 22-25 real-time and day-ahead prices were more closely aligned. During January 27-29, day-ahead prices were higher than real-time prices – an indication of market participants' expectation that conditions would follow the Polar Vortex pattern. Real-time LMPs were lower than day-ahead LMPs 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.

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

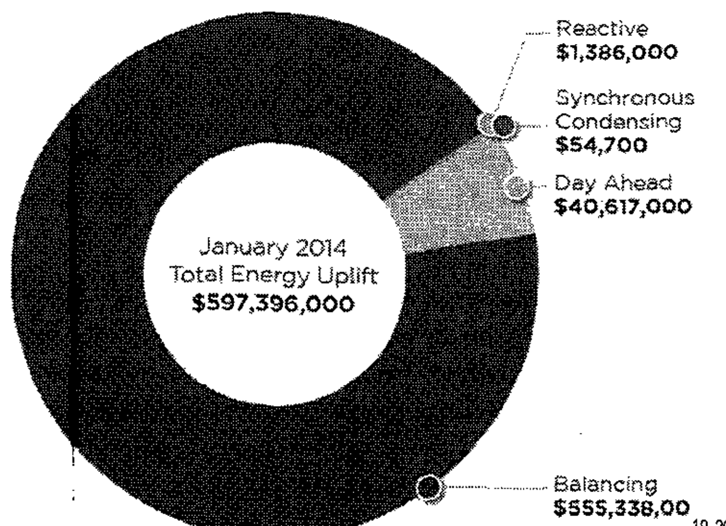
**Uplift**

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.*

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[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.

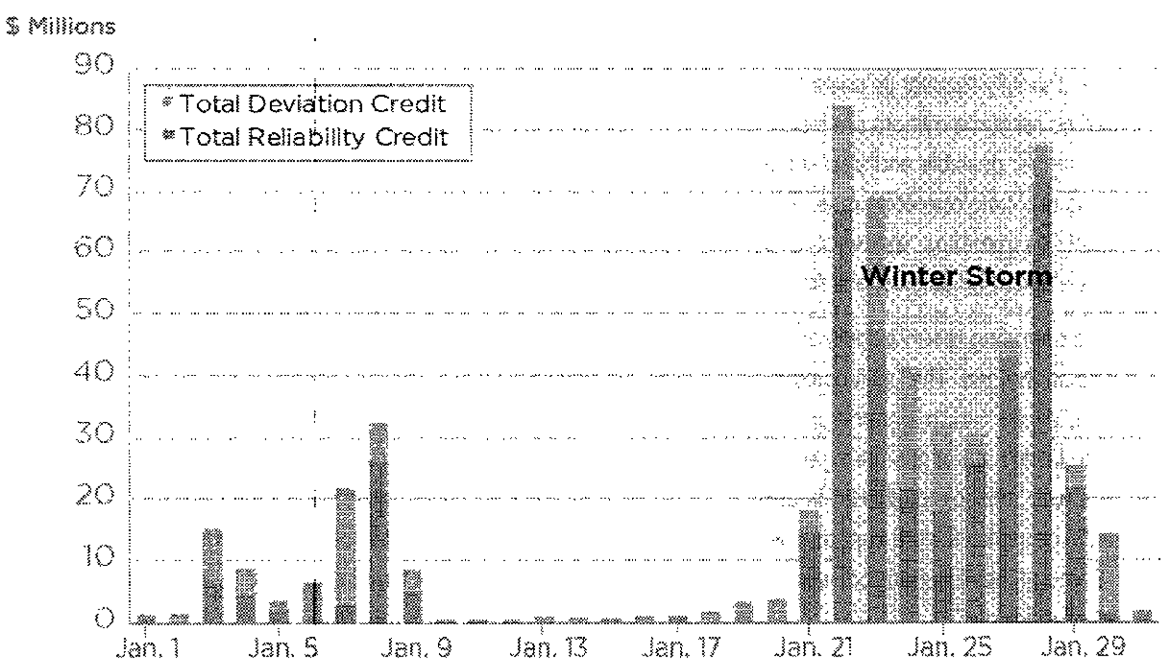
Increased operating reserve costs are a side effect of running additional generation to support outages or other situations on the grid. The uplift costs are high when the primary fuel of additional generation being run is high priced. During the Winter Storm, generation was needed specifically in the 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.<br>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.<br>Generator is committed during the operating day and cost is greater than locational marginal prices most of the time. |

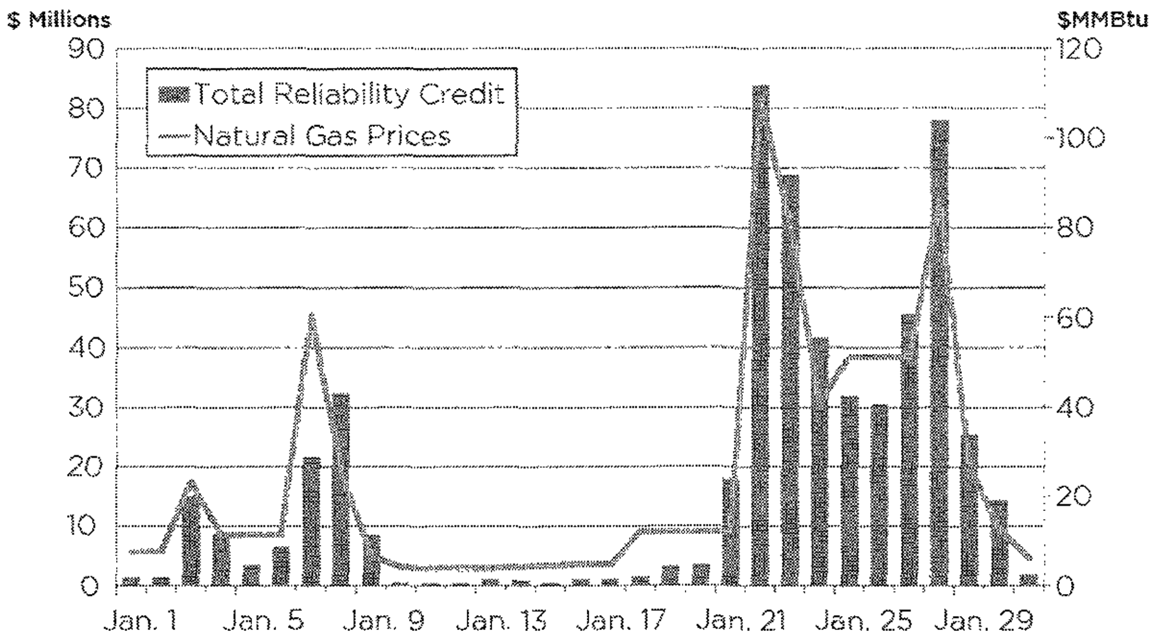
There are two general types of balancing operating reserve charges. If a generator is called to run after the close of the Day-Ahead Market and during the Reliability Assessment Commitment performed after the Day-Ahead Market results are posted, it is dispatched either for prudent operations or "load 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**

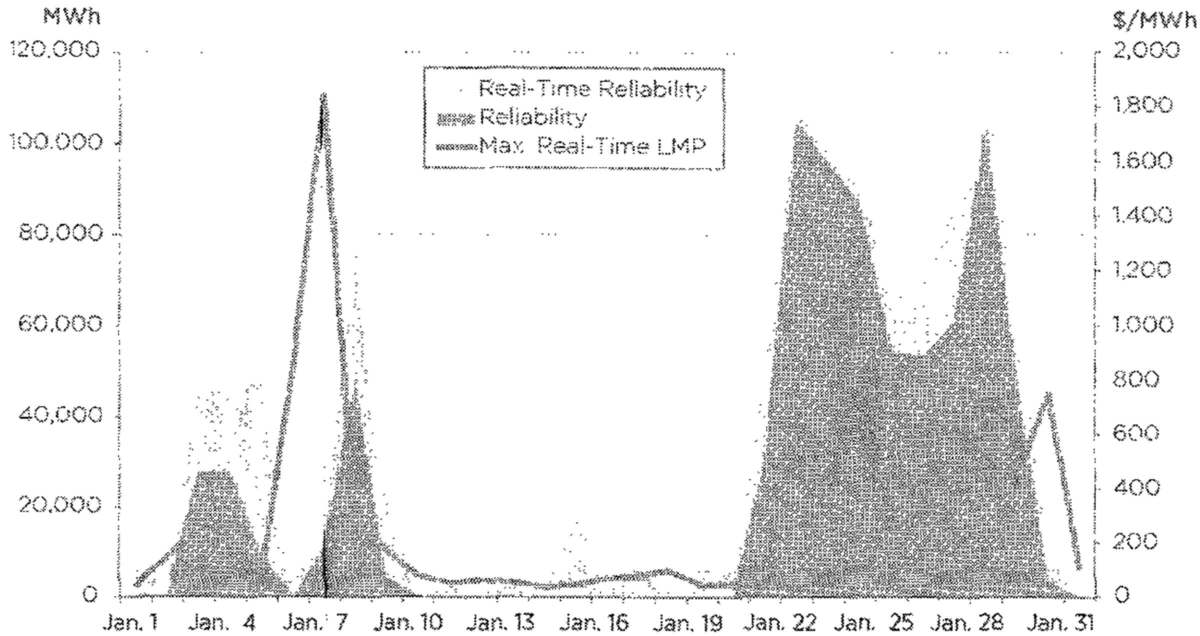



PJM worked in advance of the Winter Storm to mitigate the risk of losing generators and worked with generators which had inflexible parameters to keep them online to ensure reliability would be maintained. An example of inflexible parameters is a long minimum run time. PJM may need a generator only for 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**



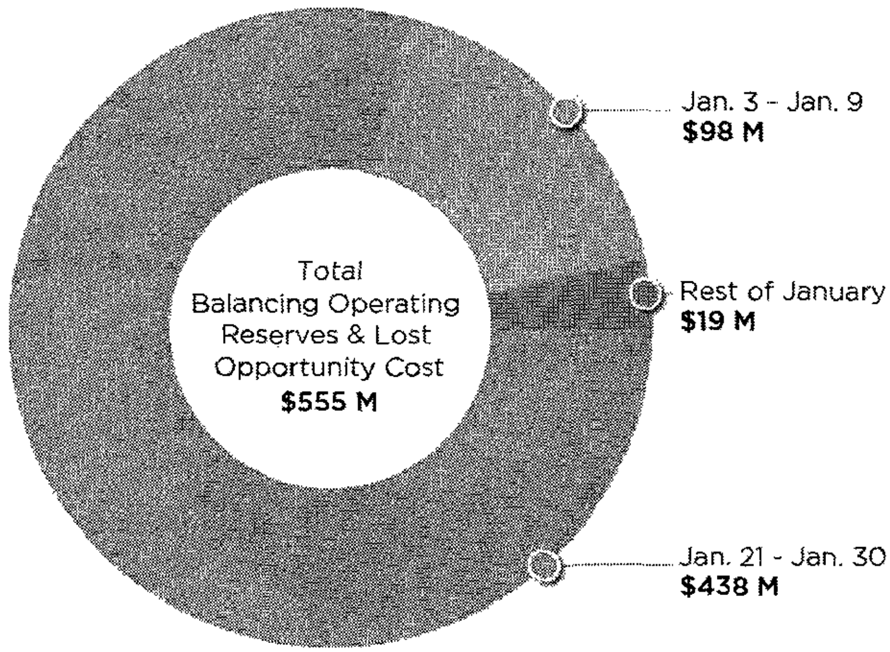

*The megawatt-hours associated with real-time reliability credits are shown in the light blue added on top of the megawatt-hours committed prior to the operating day, which are represented in dark blue. The maximum real-time locational marginal price is shown by the green line overlaid on the reliability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

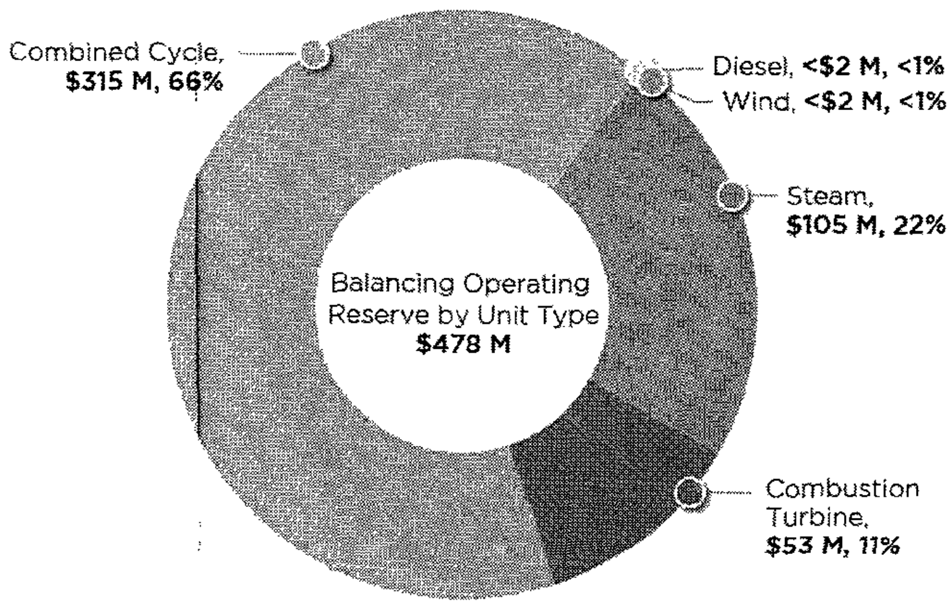
PJM works to run as few units as possible and minimize production cost, but operational parameters of individual generation units can limit flexibility. One reason for increased generation contractual constraints during January was natural gas pipeline operational orders. During January 2014 peak natural-gas 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

[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,

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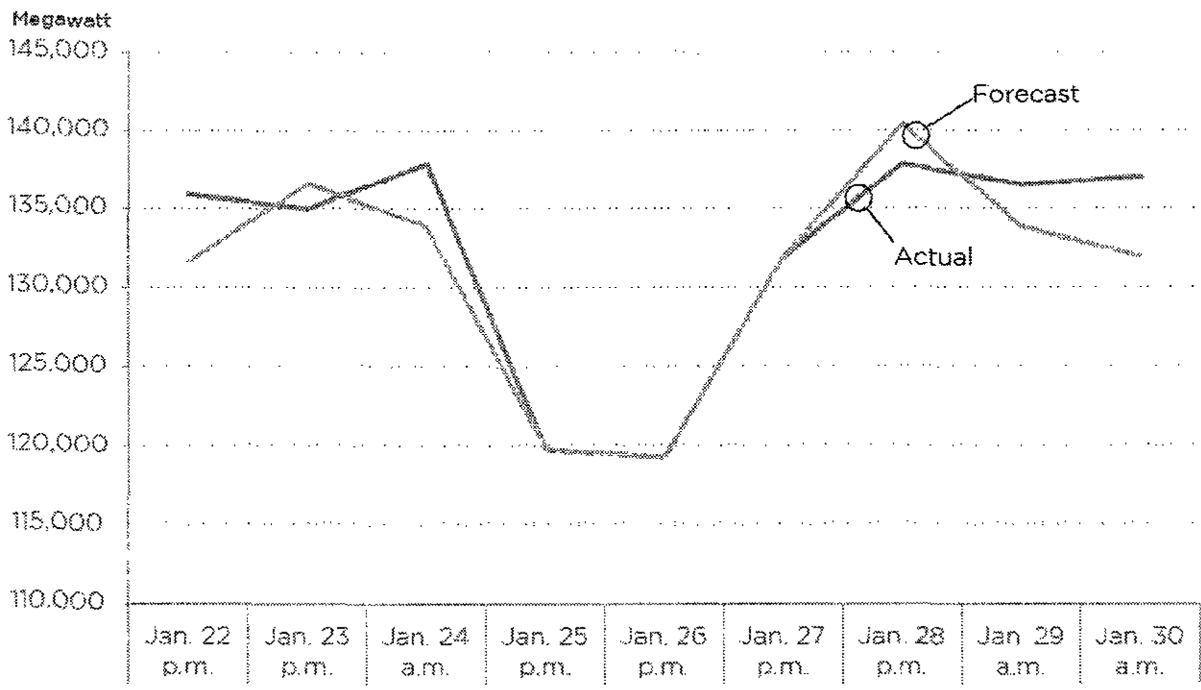
[22] Combined-cycle plants are natural gas-fired generators that typically consist of one or more combustion turbines that exhaust into a steam generator. Combined-cycle generators usually are larger and can produce more megawatts than individual combustion turbines alone; they also are generally used 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.

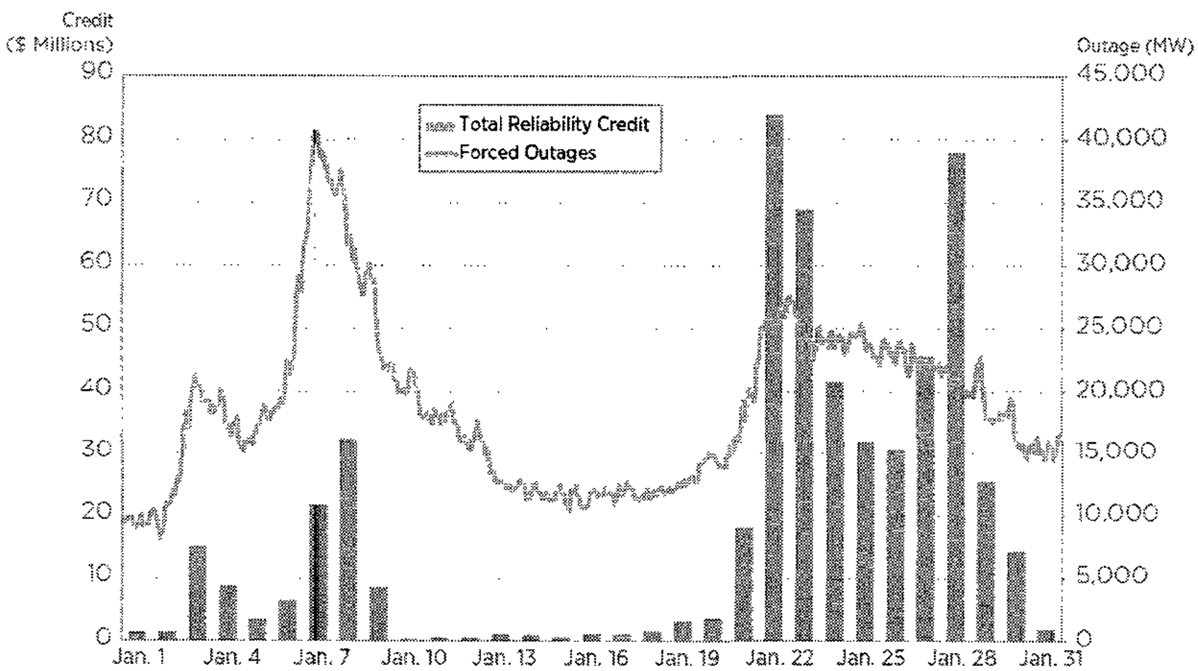
**Figure 38: Forecast and Actual Peak Load**



### 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:<br>1. Review the penalties for non-performance during peak days and/or days when emergency procedures are issued for capacity emergencies<br>2. Review incentives for performance during peak days<br>3. Investigate a process for unit testing and preparation of resources in advance of winter operations, including testing dual-fuel capability<br>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:<br>1. Sharing of fuel source and emission limitations by schedule submitted and fuel limitations/certainty of supply<br>2. Streamlining and standardizing the outage cause types in eDart with additional specificity that provides more insight and consider methods for validation<br>3. Clarify the rules by which a generator can claim an Outside Management Control event for taking an outage | Process Change or Addition<br>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:<br>1. Investigate opportunities for better harmonization of the timing of the gas and electric operating days<br>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<br>Process Change or Addition<br>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<br>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<br>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:<br>1. Improve tools that allow sharing of fuel-limited details with PJM including tracking dual-fuel capability and availability<br>2. Review operator communications with respect to fuel-limited generation commitment decisions for accuracy and consistency<br>3. Confirm mechanism by which resources' seek waivers for fuel emission limitations and better understand conditions under which relief may be granted | Technology<br>Process Change or Addition | New |
| 5 | Fuel Specific Limitations | Examine difficulties experienced by generators during natural gas emergency procedures and consider:<br>1. Methods to call on long-lead generation based on fuel procurement limitations during extreme conditions<br>2. Changes to allow adjustment of start times based on changes in fuel utilized<br>3. Requirements for generation units whose primary fuel may not be natural gas but that require gas to operate | Market Construct<br>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:<br>1. Review the cost allocation of energy market uplift charges<br>2. Investigate potential mechanism to allocate uplift during emergency operations when rates are extreme<br>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:<br>1. Define and review PJM emergency procedures and overall communications. Review operating agreements (including VACAR Reserve Sharing Group Agreement)<br>2. Include language regarding coordination of emergency procedures | Process Change or Addition<br>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:<br>1. *Start-up costs and cancelled* dispatch provisions in Attachment C<br>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:*<br>1. Survey transmission owners to understand existing voltage reduction capabilities (amount, time frame, etc.)<br>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<br><br>Process Change or Addition | In progress |
| 11 | Regulation Market Rules | PJM stakeholders *should consider reexamining the performance* of the Regulation Market during January. Specifically:<br>1. Investigate whether the division *by the performance score is appropriate*<br>2. *Investigate whether* the minimum participation requirements are adequately high enough<br>3. Investigate the possibility of going short regulation during system peaks | Market Construct | New |
| 12 | External Capacity | Develop processes and tools that will:<br>1. Confirm that external capacity resources *either bid into the day-ahead market or submitted eDart* tickets that they are unavailable<br>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*<br>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)<br>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:*<br>1. Consider adjustments to the roles and responsibilities for communications during emergency procedures<br>2. Refine training to reinforce processes and tools | PJM & Member Dispatcher Training<br><br>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:<br>**1.** Evaluate and consider the impact of calls for conservation and investigate where or how to use the data<br>**2.** Improve process for public notification during emergency procedures (C1/C2)<br>**3.** Review triggers for public notifications and associated transmittal protocols<br>**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*

**January 6, 2014**

**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.

**January 7, 2014**

**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.

**January 23, 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:**

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**

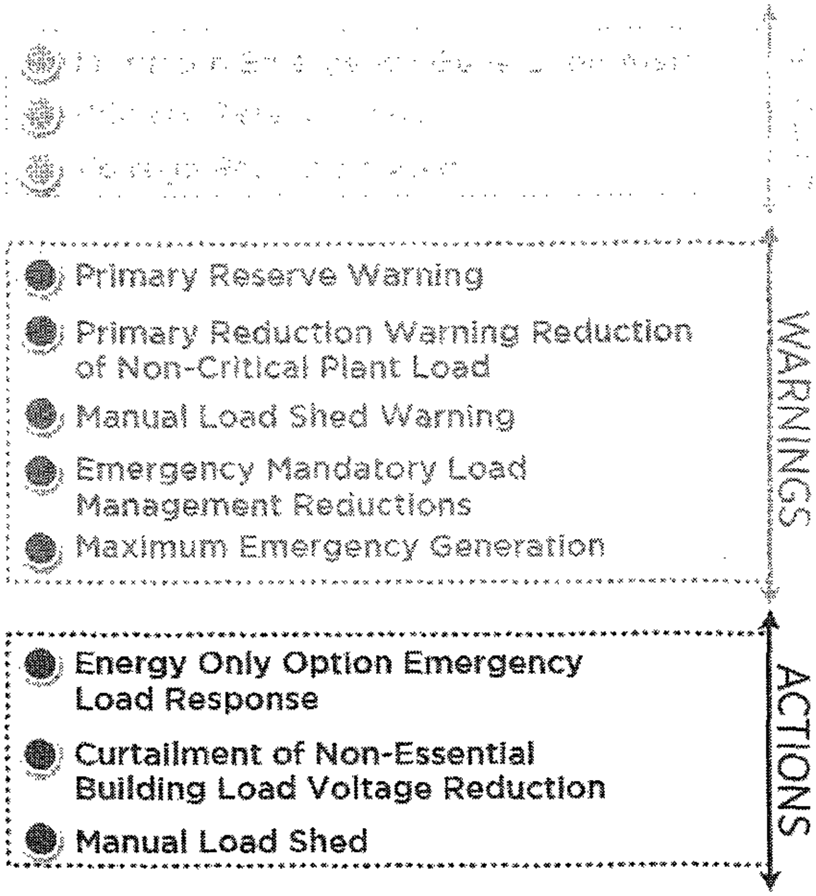
13/14 Preliminary Daily Peak-Hour Period Availability Charges: **$45,585.71**

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

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***




**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 |

# STATE OF CONNECTICUT

**DEPARTMENT OF PUBLIC UTILITY CONTROL**

**TEN FRANKLIN SQUARE**

**NEW BRITAIN, CT 06051**

**DOCKET NO. 05-07-14PH02 DPUC INVESTIGATION OF MEASURES TO REDUCE FEDERALLY MANDATED CONGESTION CHARGES (LONG TERM MEASURES)**

May 3, 2007

By the following Commissioners:

Donald W. Downes

John W. Betkoski, III

Anne C. George

## DECISION

# DECISION

## I. INTRODUCTION AND SUMMARY

Pursuant to General Statutes of Connecticut (Conn. Gen. Stat.) §§ 16-243m(c) and (g), the Department reviews and approves the recommendations of its consultants to select certain bidders for capacity contracts in response to the request for proposals (RFP) for new capacity conducted in this proceeding. The Department selects a seven hundred and eighty seven megawatt portfolio of projects consisting of one new highly efficient combined cycle gas-fired base load plant, two peaking plants located in the constrained Southwest Connecticut region, and one state-wide energy efficiency program. The Department also describes the next steps in the approval process for capacity contracts with selected bidders.

## II. BACKGROUND OF THE PROCEEDING

Pursuant to Conn. Gen. Stat. § 16-243m, also known as Public Act 05-01, An Act Concerning Energy Independence (EIA or Act), the Department opened the instant uncontested proceeding on its own motion. The purpose of this docket is to implement a competitive procurement process to solicit new capacity resources in order to reduce Federally Mandated Congestion Charges (FMCCs) for Connecticut ratepayers over the long term. On September 13, 2006, the Department issued the First Interim Decision approving the RFP for incremental or new capacity. On November 16, 2006, the Department issued the Second Interim Decision approving the capacity contracts, Master Agreements, that the electric distribution companies will use to contract for new capacity selected in this proceeding. On April 23, 2007, the Department issued a Draft Decision approving its consultant's recommendations. Participants filed written exceptions to the Draft Decision on April 26, 2007. Oral arguments were held at the Department on April 30, 2007.

### A. DESCRIPTION OF THE ENERGY INDEPENDENCE ACT (EIA)

The Connecticut legislature mandated that the Department issue a RFP to procure new or incremental capacity to reduce the impact of FMCCs on Connecticut ratepayers through the EIA. As defined in the Act, eligible capacity includes generation, demand response, and energy efficiency, thus this procurement process is similar to the Integrated Resource Planning processes undertaken under the previous era of electricity sector regulation.

According to subsection 12(c) of the Act, the RFP must identify "measures that would reduce FMCCs for the period commencing on May 1, 2006, and ending on December 31, 2010" and may include but shall not be limited to "(1) customer-side distributed resources, (2) grid-side distributed resources, [and] (3) new generation facilities, including expanded or repowered generation". Subsection 12(c) of the EIA further specifies that the RFP shall "encourage responses from a variety of resource types and encourage diversity in the fuel mix used in generation."

Under subsection 12(g), the Department must give preference to proposals that result in the greatest aggregate reduction of FMCCs, make efficient use of existing sites and supply infrastructure, and serve the long term interest of ratepayers.

Finally, Section 12(i) of the EIA lays out the criteria by which the Department should judge the project proposals and approve contracts. The Department can approve a contract if it determines that it will: (1) result in the lowest reasonable cost of such products and services; (2) increase reliability; and (3) minimize FMCCs to the state over the life of the contract.

### B. PARTICIPANTS

The Department designated the persons identified on the Service List, Attachment 1, as participants in the proceeding.

## III. SELECTION PROCESS AND SELECTED BIDDERS

The Department has reviewed a report entitled "Recommendations on Selection of Projects in the 2006 Connecticut RFP Process" dated May 3, 2007 (Attachment 2, LEI Report) prepared by London Economics International LLC. The Department incorporates the LEI Report's findings, analysis, conclusions and recommendations into this decision by reference. The attached Report is an updated version of the original Report dated April 20, 2007. The updates are made in response to issues raised in written exceptions. The updates expand on the description of the modeling approach and analysis conducted by LEI and reconcile conclusions in the RFP selection with the needs assessment.

Based on the content of the Report, the Department makes the following determinations. The Department finds that the RFP process was conducted in a fair and impartial manner, was commercially reasonable and was competitive. The Department also finds that the RFP process conformed to the principles and standards approved by the Department in Docket No. 05-07-20, Development of Process and Standards for Competitive Solicitation of Long-Term Projects to Reduce Federally Mandated Congestion Charges. The Department further finds that the selected projects meet the criteria of Conn. Gen. Stat. §§ 16-243m(c), (g) and (i).

The winning projects portfolio, consisting of four individual projects, provides the largest net benefit to Connecticut ratepayers as compared to other individual projects and portfolios of projects. The winning portfolio constitutes a total maximum capacity of 787 MW and consists of one 620 MW new highly efficient combined cycle gas-fired base load plant in Middletown offered by Kleen Energy Systems LLC (Project 409), one small, 66 MW, peaking plant located in the constrained Southwest Connecticut (Stamford) region offered by Waterside Power LLC (Project 851), one 96 MW new and highly efficient peaking unit also located in Southwest Connecticut (Waterbury) offered by Waterbury Generation LLC (Project 993), and one 5 MW energy efficiency program offered by Ameresco (Project 358). This portfolio is projected to create net economic benefits for Connecticut ratepayers totaling $509 million on a weighted average basis[1] because of its impact on wholesale costs of power, namely Locational Marginal Prices in the energy market, capacity clearing prices in the capacity market, and auction clearing prices in the Locational Forward Reserve Market.

The Department believes that the portfolio selected will provide much needed resources to supplement Connecticut's aging generation fleet. Included in the portfolio is a new efficient 620 MW base load generation plant which will help drive down energy prices, reduce emissions and add capacity to meet our growing demands. The addition of two peaking plants will help improve reliability and provide a foundation for fast start generation capacity which has been identified in the needs analysis. Although no demand response units have been selected through this solicitation, the Department believes that demand response and conservation are important components of the state's resource mix. The Department will continue to aggressively pursue demand response and conservation though other venues such as the distributed generation grant program, Energy Independence Act short-term measures and the conservation and load management program.

The DPUC directs that The Connecticut Light and Power Company (CL&P) serve as the counterparty to two contracts – with Kleen Energy and with Waterside Power. The DPUC directs that The United Illuminating Company (UI, together with CL&P, Companies) serve as the counterparty to two contracts – with Waterbury Generation and with Ameresco. The anticipated share of costs based on LEI's weighted average of all nine scenarios analyzed is 89% for CLP and 11% for UI.

| Bid ID # | Bidder | Location | EDC Counterparty | Weighted Cost ($MM) | EDC share of costs |
|---|---|---|---|---|---|
| 409 | Kleen | Middletown | CL&P | $ 304.52 | 89% |
| 851 | Waterside | Stamford | CL&P | $ 3.78 | |
| 993 | Waterbury | Ansonia | UI | $ 35.42 | 11% |
| 358 | Ameresco | CT State | UI | $ 2.29 | |
| TOTAL | | | | $ 346.02 | |

As all Connecticut customers will benefit from the capacity contracts regardless of what service territory a project is located in, all customers are responsible for paying the costs of all of the capacity contracts. In order to achieve the targeted 80-20 cost sharing ratio (which represents each Company's peak load share), it will be necessary to establish a cost sharing agreement between CL&P and UI similar to the one used for the Project 100 renewable energy contracts in Docket No. 03-07-17RE03. Therefore, the Department directs that CL&P and UI file on or before May 7, 2007 a modified version of the cost sharing agreement already approved by the Department in Docket No. 03-07-17RE03, for use in this proceeding.

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1 The range in net benefits is from $-66 to $1,679 million and is based on the results of nine different market scenarios, with differing supply-demand conditions, environmental regulations, and fuel prices.