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Case Number: 14-1297-EL-SSO

File Date: 9/21/2015

Section: 2 of 2

Number of Pages: 51

Description of Document: Exhibit:
Volume V

IV. ACCOUNTING ISSUES

In Written Comments filed on June 2, 2006 and at other times in this proceeding and in a related proceeding, DPUC Investigation Into the Financial Impact of Long-Term Contracts on Electric Distribution Companies, Docket No. 05-07-18, UI and CL&P indicated concern that the long-term capacity contracts could have negative impacts resulting from accounting treatments that: (1) require consolidation under FIN 46; (2) require treatment as a derivative; and (3) require that the CfD be recorded as a capital lease.

CL&P filed responses to Department interrogatories focused on accounting issues. Based on its preliminary review, CL&P has concluded that, if the Contract for Differences (CfD) is used to contract for capacity, the contract would not require consolidation under FIN 46(R) or treatment as a capital lease. CL&P Response to Department Interrogatory EL-8. CL&P concluded that it is a derivate, but its response does not clearly indicate if CL&P believes that accounting treatment as a derivative will cause costs that is seeks to recover and whether any actions can be taken now to mitigate against any such costs. Id. UI responded similarly. UI Response to Department Interrogatory EL-9. Both Companies said that they needed to review the financial information of selected bidders before they could make a final determination regarding accounting treatment of the contracts.

As described more fully below in Section V, the Department will provide CL&P and UI an opportunity to review the financial bid information of selected bidders for the purpose of identifying any negative accounting treatments that will cause costs for them. CL&P and UI will be given an opportunity in Docket 07-04-24, DPUC Review of Energy Independence Act Capacity Contracts, to identify any claimed negative accounting treatments and propose remedies. The Department can consider the proposed remedies or, without granting any remedy, approve the capacity contract and the electric distribution company can seek rate relief through a full rate proceeding pursuant to Conn. Gen. Stat. §§ 16-243m(l) and 16-19.

V. COST RECOVERY PROCESS ISSUES

CL&P has raised concerns about its ability to recover certain costs associated with negative credit rating and accounting treatment caused by being a counterparty to capacity contracts. CL&P appealed the Department's decision in Docket No. 05-07-18, DPUC Investigation Into the Financial Impact of Long-Term Contracts on Electric Distribution Companies addressing these issues. See Docket No. HHB-CV-06-4009637-S – The Connecticut Light and Power Company v. Connecticut Department of Public Utility Control, et al.

On April 16, 2007, CL&P filed a motion seeking that the Department make certain rulings regarding the process the electric distribution companies must follow to make cost recovery claims for costs resulting from being counterparties to capacity contracts required by Conn. Gen. Stat. §§ 16-243m(c), (g) and (i). CL&P represents that these rulings would mitigate against its accounting and balance sheet concerns. On April 16, 2007, the Department issued a ruling that it would address CL&P's motion in this decision and directed that any docket participants file comments by April 19, 2007.

In its motion, CL&P asks that the Department rule that:

1. Contracts for Differences (CfDs) are long-term capacity contracts within the meaning of Conn. Gen. Stat. § 16-243m(i) and will be used by the Department in the current capacity procurement (Requested Ruling 1);

2. entering into the capacity contracts is prudent and efficient management (Requested Ruling 2);

3. all of electric distribution companies' costs that are found to be prudently incurred by the Department and that are directly related to entering into, performing under and enforcing capacity contracts shall be recovered through non-bypassable federally-mandated congestion charge (NBFMCC) (Requested Rulings 2 and 3);

4. capacity contracts shall become effective upon approval by the Department in its final decision in the proceeding reviewing contracts required by Section 16-243m(i) (Requested Ruling 4);

5. electric distribution companies can seek to recover all prudently incurred costs directly caused by the capacity contracts even if the contracts are later invalidated unless the contracts were invalidated as a result of the electric distribution company's improper performance or failure to perform (Requested Rulings 2 and 5);

6. Section 16-243(l) authorizes the electric distribution companies to file for a full rate case, under Section 16-19, to recover on a going forward basis any costs associated with negative credit ratings resulting from capacity contracts (Requested Ruling 6);

7. the electric distribution companies can have time to review selected bidders' financial information to assess whether there is any negative accounting treatment that will result from capacity contracts and whether measures can be taken to mitigate against any such costs (Requested Ruling 7);

8. Section 16-243(l) authorizes the electric distribution companies to file for a full rate case, under Section 16-19, to recover on a going forward basis any costs associated with negative accounting treatment resulting from capacity contracts and, to the extent that the law prevents the filing of a rate case, the electric distribution company can file a notice of intent to seek the costs in a future rate case (Requested Rulings 8 and 9).

On April 19, 2007, the Office of Consumer Counsel (OCC) filed objections to CL&P's requested rulings. The OCC claims that 1) it would be ultra vires for the Department to make the requested rulings as it would bind the Department in the future to these rulings and 2) committing to use of specific regulatory procedures may impinge on the procedural rights of the OCC and other parties. The OCC incorporated by reference arguments made in a petition for reconsideration addressing the same issues in Docket No. 05-07-18.

Conn. Gen. Stat. §§ 16-243m(c), (g) and (i) require the CL&P and UI enter into long-term capacity contracts. On the issue of cost recovery, subsection (i) expressly provides that the costs of these contracts shall be recovered through federally mandated congestion charges (FMCCs). In addition to this express provision in Section 16-243m(i) regarding the Companies' entitlement to recover contract-related costs, it is a fundamental principle of constitutional law that it could result in an unconstitutional taking to require the Companies to spend money on these contracts and to incur costs performing services related to these contracts without, at the same time, allowing for appropriate cost recovery. Duquesne Light Co. v. Barasch, 488 U.S. 299 (1989).

CL&P filed written exceptions seeking clarification of several rulings made in the Draft Decision and providing suggested language to clarify the Department's intent. The Department adopts the requested language. The OCC filed written exceptions reiterating its objections described above. The Department rejects those objections for the reasons discussed below.

The Department makes the following rulings regarding the process for electric distribution companies to recover their costs associated with being counterparties to capacity contracts required by Conn. Gen. Stat. §§ 16-243m(c), (g) and (i). As a general matter, the rulings proposed by the CL&P do not guarantee any future cost recovery, but rather, clarify the process by which the Companies can seek recovery subject to a prudency review by the Department of the evidence regarding any claimed costs. Moreover, the proposed rulings are consistent with the express language of Section 16-243m, which provides that the costs of these contracts shall be recovered through FMCCs. The Department addresses below each of CL&P's requested rulings. These rulings will also apply to the electric distribution companies entering into, performing under and enforcing any cost sharing agreement, described more fully above in Section III, entered into between UI and CL&P.

With respect to the OCC's objections, the Department rules as follows. First, it is not ultra vires for the Department to perform its function of interpreting and applying the statutes that govern this proceeding. Section 16-243m addresses the issue of cost recovery by indicating that capacity contract costs shall be recovered through the FMCC. CL&P has requested rulings from the Department regarding the specific process by which it can seek to recover capacity contract costs. The Department's current Commissioners, and any future Commissioners, are and will continue to be bound by Section 16-243m until such statute is repealed or changed. To suggest that the Department cannot interpret the statutes relating to this proceeding and make rulings on relevant issues raised by parties to this proceeding based on its interpretation of relevant statutes is wholly without merit.

Second, the Department is not impinging on the procedural rights of the OCC and other parties. CL&P seeks a ruling regarding the process that it must follow to recover costs it may incur as a result of being a counterparty to capacity contracts. The Department is interpreting, applying and making rulings on the issues raised based on relevant statutes.

Third, the OCC incorporated by reference arguments it made in a petition for reconsideration addressing the same issues in Docket No. 05-07-18. CL&P also made a request for the same rulings it seeks here in Docket No. 03-07-17RE03, <u>DPUC Review of Long-Term Renewable Energy Contracts – Round 1 Results and Contract, Accounting and Allocation Issues</u>. The OCC raised all of the same objections in its petition for reconsideration in Docket No. 05-07-18 as objections to CL&P's request for cost recovery process rulings in Docket No. 03-07-17RE03. The Department, in a letter order dated April 9, 2007 in Docket No. 03-07-17RE03, adopted CL&P's proposed rulings and rejected all of the OCC's objections. The Department affirms its rejection of OCC's objections in this proceeding as well and makes the rulings requested by CL&P subject to some modifications described below.

CL&P requests that the Department rule that Contracts for Differences (CfDs) are long-term capacity contracts within the meaning of Conn. Gen. Stat. § 16-243m(i) and will be used by the Department in the current capacity procurement (Requested Ruling 1). The Department previously made this ruling in its September 13, 2006 Interim Decision in this proceeding at Section IV.B.1 and, for the same reasons stated therein, the Department affirms that ruling again in this decision.

CL&P requests that the Department rule that entering into the capacity contracts is prudent and efficient management for cost recovery purposes. As the Companies are required by statute and Department decisions implementing the same, to enter into capacity contracts and the cost sharing agreement, the Department finds that the Companies are acting prudently in obeying these legal directives. The Department does not see how it could legally rule otherwise.

CL&P requests that the Department rule that all of the electric distribution companies' costs that the Department finds (1) were directly related to entering into, performing under and enforcing capacity contracts and (2) were prudently incurred shall be recovered through a NBFMCC and Section 16-19b. The Department believes that this criteria and process for cost recovery is required by Sections 16-243m(i) and 16-19b(e) and (h). As such, only the contract price, administrative, and other direct costs can be collected through a NBFMCC and Section 16-19b. In its written exceptions, UI claims that any claimed negative credit rating and accounting treatment costs should be collected through the NBFMCC. The Department will withhold ruling on this issue until such time such costs are actually claimed. The Department views costs associated with negative credit rating and accounting treatment as being indirect costs distinguishable from direct costs, such as administrative and contract price costs. As described more fully below, the electric distribution companies must file a full rate case pursuant to Sections 16-19 and 16-243m(I) to recover these indirect costs, i.e. any negative credit rating and accounting treatment costs.

The OCC and others will have the right to review and contest UI's and CL&P's claimed costs. Section 16-19b(d) provides that the "Department of Public Utility Control shall adjust the retail rate charged by each electric distribution company for electric transmission services periodically to recover all transmission ***costs prudently incurred*** by each electric distribution company." [emphasis added].

Section 16-19b(h) requires that

> [t]he department shall ***hold a public hearing*** thereon whenever the department deems it necessary, but ***no less frequently than once every six months***, and undertake such other proceeding thereon to determine whether charges or credits made under such clauses reflect the actual prices paid for purchased gas or energy and the actual transmission costs and are computed in accordance with the applicable clause. ***If the department finds that such charges or credits do not reflect the actual prices paid for purchased gas or energy, and the actual transmission costs or are not computed in accordance with the applicable clause, it shall recompute such charges or credits and shall direct the company to take such action as may be required to insure that such charges or credits properly reflect the actual prices paid*** for purchased gas or energy and the actual transmission costs and are computed in accordance with the applicable clause for the applicable period. [emphasis added].

There are at least two opportunities, one in a contested case under Section 16-19b(h) and one in an administrative setting under Section 16-19b(e), for the Department, the OCC and others to examine and comment on the Companies' requested cost recovery related to the capacity contracts. The first opportunity arises in an administrative proceeding when the Companies seek to pass through the costs in the NBFMCC. At that time, the persons can comment on the Companies' submissions. The second opportunity arises at least twice a year, when persons, in the contested case conducted pursuant to Section 16-19b(h), can challenge any of the electric distribution companies' claimed capacity contract-related administrative costs that they believe are imprudent or not caused by the capacity contracts. If persons are correct that certain costs are not properly recoverable, the Department has the authority to require rate adjustments to address any over recovery.

CL&P asks that the Department rule that capacity contracts shall become effective upon approval by the Department in its final decision in the proceeding reviewing contracts required by Section 16-243m(i). In its written exceptions, UI requested that capacity contracts be considered effective (1) if no appeal is taken, forty six days after the Department Decision approving the contract or (2) if any appeal is taken regarding the contract, the date the on which all appeal issues are finally resolved. The Department will make CL&P's requested ruling as the express language of Section 16-243m(i) states that capacity contracts are effective upon Department approval. Also, this concept is reflected in Section 5.1(b) of the Master Agreements approved by the Department. Section 5.1(b) states that contracts will be effective upon approval in the docket required by Section 16-243m(i) which has now been opened and is identified as Docket No. 07-04-24, DPUC Review of Energy Independence Act

Capacity Contracts. UI did not file written exceptions to either the September 13 or November 16, 2006 Decisions objecting to the Master Agreement's provision regarding the effective date. UI should be indifferent to when Master Agreements become effective because, as described below, it will be able to recover all of its prudently incurred capacity contract costs even if the capacity contract is later invalidated on appeal. Delaying the effective date until resolution of appeals would unnecessarily delay the construction and operation of capacity projects and result in loss of benefits to consumers and increased costs for procuring the capacity if the RFP's November 2007 deadline for project approval is not met.[2]

CL&P requests that the Department rule that electric distribution companies can seek to recover all prudently incurred costs directly caused by the capacity contracts even if the contracts are later invalidated unless the contracts were invalidated as a result of the electric distribution company's improper performance or failure to perform. The Department believes that this request is consistent with basic ratemaking and cost recovery principles and the constitutional law regarding takings. If the electric distribution companies are prudently performing as counterparties under the capacity contracts as ordered by statute and the Department, and the contracts are later invalidated through no fault of their own, they are entitled to recover prudently incurred costs.

CL&P requests that the Department rule that Section 16-243(l) authorizes the electric distribution companies to file for a full rate case, under Section 16-19, to recover on a going forward basis any costs associated with negative credit ratings resulting from capacity contracts. The Department believes that the plain language of this provision and Section 16-243m(i), permitting capacity contract cost recovery through FMCC, provide clear legislative intent that the electric distribution companies could recover prudently incurred capacity contract costs on a going forward basis without any risk that electric distribution companies could be locked out from seeking to recover these costs or that these costs would somehow become unrecoverable. Unlike direct costs (such as administrative and contract price costs) that are directly related to entering into, performing under, and enforcing capacity contracts, which can be collected through a NBFMCC and Section 16-19b, for costs due to negative credit ratings, the electric distribution companies must file a full rate case under Section 16-19 and 16-243m(l), in which all of its costs and revenues can be examined and contested.

CL&P requests that the Department rule that the electric distribution companies can have time to review selected bidders financial information to assess whether there is any negative accounting treatment that will result from capacity contracts and whether measures can be taken to mitigate against any such costs.

The Department makes the requested ruling with modifications. Provided that CL&P and UI have provided signed nondisclosure agreements, the RFP Coordinator

2 Under the terms of the RFP, if projects do not receive final approval by November 2007, they can withdraw their bids or have their bid price adjusted using a utility price index. The Department assumes conservatively that any adjustment to the bid price based on the utility price index will result in a price increase as the cost of labor and commodities necessary to construct and operate the projects is not likely to become cheaper going forward.

will provide CL&P and UI with the financial bid information for winning bidders on May 4, 2007. In Docket No. 07-04-24, DPUC Review of Energy Independence Act Capacity Contracts, the Department will provide CL&P and UI until July 3, 2007, sixty days from May 4, 2007, to review the financial bid information of selected bidders for the purpose of identifying any negative accounting treatments that will cause costs for them as well as any proposed remedies for mitigating against any such costs. CL&P can request additional financial information from selected bidders and the Department will resolve any disputes pertaining to such requests. On July 3, 2007, CL&P and UI shall file a report with the Department in Docket No. 07-04-24 providing the results of their financial accounting review. If CL&P or UI claims there are costs due to accounting treatment, they shall promptly make a filing with the Department that 1) identifies the specific aspect or aspects of the Capacity Contract or counterparty structure that causes or contributes to the impact, together with citations to the applicable GAAP or FASB pronouncements, 2) provides a fair and reasonable estimate of the financial impact on CL&P of the GAAP treatment showing a material adverse impact 3) provides support reflecting CL&P's consultation with its outside auditor or consultant that the GAAP treatment is required for a fair presentation of its financial statements[3], and 4) identifies any proposed remedy. The Department will not make it mandatory, as requested by CL&P, to have a 30-day negotiation process between, the electric distribution company, the bidder and a Department prosecutorial unit. Rather, if CL&P or UI proves that negative accounting treatment of any of the capacity contracts will cause them costs, the Department can consider and adopt proposed remedies, or, without approving any remedies, approve the capacity contract and the electric distribution company can then seek rate relief through a full rate proceeding pursuant to Conn. Gen. Stat. §§ 16-243m(l) and 16-19. In order to bring timely closure to this proceeding, the Department is not inclined to give any more time for review beyond sixty days, given that the electric distribution companies can file a rate case at any time to seek cost recovery if they believe that negative accounting treatment of a capacity contract is causing increased costs.

CL&P requests that the Department rule that Section 16-243(l) authorizes the electric distribution companies to file for a full rate case, under Section 16-19, to recover on a going forward basis any costs associated with negative accounting treatment resulting from capacity contracts and, to the extent that the law prevents the filing of a rate case, the electric distribution company can file a notice of intent to seek the costs in a future rate case. The Department believes that the plain language of Section 16-243m(l) provides clear legislative intent that the electric distribution companies could recover these types of capacity contract costs on a going forward basis. The Department believes that it would be illegal, in contravention of Conn. Gen. Stat. § 16-243m(i) and may be in violation of the Takings Clauses of the United States and Connecticut Constitutions to bar the electric distribution companies from seeking cost recovery for capacity contract costs as a result of following mandates of the statute and Department decisions. Unlike costs that are directly related to entering into, performing under, and enforcing capacity contracts, which can be collected through a NBFMCC and Section 16-19b, for costs associated with negative accounting treatment of capacity

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[3] If CL&P seeks rate recovery for costs associated with GAAP treatment of a Capacity Contract, CL&P will then provide support, e.g., a report, letter, etc, prepared by its outside auditor or consultant to the DPUC that the GAAP treatment is required for a fair presentation of its financial statements.

contracts, the electric distribution companies must file a full rate case, in which all of its costs and revenues can be examined and contested, under Sections 16-9 and 16-243(l). In its written exceptions, CL&P requested clarification that the electric distribution companies can seek recovery for any accounting related-costs occurring during the term for the capacity contracts. The Department finds that, at any time during the term of the capacity contracts, the electric distribution companies can seek to recover any accounting-related costs that they can prove were caused by capacity contracts.

The Department believes that it is consistent with the cost recovery language of Sections 16-243m(i) and (l) to permit CL&P or UI, if they are legally barred from filing a rate case during the time they are incurring costs related to negative accounting treatment of capacity contracts, to defer those costs they seek to recover. If either company seeks such treatment, it must file written notice at the time it wishes for cost recovery to begin with the Department and the OCC. Any such requested deferral would be subject to Department review of the appropriateness of the deferral, including whether or not the company was overearning at the time of the deferral, and a prudency review of the costs. Office of Consumer Counsel v. Department of Public Utility Control et al, 279 Conn. 584 (2006).

The Department has not addressed all of the issues raised in the written exceptions. Most of the issues related to the consultant's bid evaluation method and are addressed in the attached revised Report and the nonpublic Report containing confidential bid information which was provided to the OCC. A tabular summary of how those issues were addressed is attached as Attachment 5.

VI. DESCRIPTION OF NEXT STEPS

In his written exceptions, the Attorney General requested that the Department suspend the completion of the procurement process until the end of the legislative session, June 6, 2007, to see, what, if any, energy bills see the General Assembly passes so the Department can assess whether the projects selected in this proceeding are appropriate in light of any new legislative mandates. On May 1, 2007, the AG and OCC filed a motion making the same request. For the reasons set forth in the Department's ruling on that motion, which are incorporated by reference into this decision, the Department rejects the request.

The following is a description of upcoming events in this and Docket No. 07-04-24, DPUC Review of Energy Independence Act Capacity Contracts. On or before May 4, 2007, CL&P and UI shall provide Kleen Energy, Waterside Power, Waterbury Generation, Ameresco, the Department and the RFP Coordinator with the signed nondisclosure agreements for each person it wishes to have access to the confidential financial bid information. The Companies should use the protective order and nondisclosure agreement approved by the Department on November 27, 2006. Consistent with the Code of Conduct outlined in the RFP and Master Agreements, CL&P and UI must limit access to the protected information to only those persons performing the financial accounting review. Upon receipt of the nondisclosure agreement, the RFP Coordinator will send CL&P and UI an electronic version of the selected bidders financial information on CD-ROM. CL&P and UI shall only use the financial bid information for the limited purpose of analyzing it to identify if there any actual financial accounting issues that raise cost recovery issues so that CL&P and UI may file a rate case seeking recovery for any claimed costs.[4] UI and CL&P shall have sixty days to review this information. In Docket No. 07-04-24, DPUC Review of Energy Independence Act Capacity Contracts, UI and CL&P shall report to the Department if there are any negative accounting treatments that will cause costs and propose remedies, including any agreements with bidders, for resolving any negative accounting issues. If the Department agrees that there is a problem, the Department will then consider whether it will address it through adopting a proposed remedy or through a rate case filing by UI or CL&P.

In Docket No. 07-04-24, DPUC Review of Energy Independence Act Capacity Contracts, on or before May 18, 2007, CL&P shall file signed executed Master Agreements with Kleen Energy and Waterside Power and UI shall file signed executed contracts with Waterbury Generation and Ameresco.[5]

In its written exceptions, UI claims that it is not required to file executed Master Agreements, but only a draft contract because Section 16-243m(i) states that the electric distribution companies shall have thirty days to negotiate a draft contract with each selected project. UI's analysis is incorrect for several reasons. First, the Department already has finalized standard contracts, i.e. the Master Agreement, so that there is no need to negotiate a draft contract. The first sentence of Section 16-243m(i) regarding the negotiation of a draft contract is, therefore, inapplicable to the circumstances of this proceeding. Additionally, the Department does not interpret Section 16-243m(i) as bestowing any substantive or procedural right on UI or CL&P to negotiate contract terms and conditions. The Department believes that Section 16-243m(e), which provides that the capacity contracts shall contain such provisions as the Department directs, is controlling. To that end, the Department conducted an extensive stakeholder process over the course of a year to develop the standard Master Agreements. The Department received input from numerous and diverse stakeholders, including UI, in the form of testimony at hearings and thousands of pages of written comments. The Department believes that the terms and conditions of the Master Agreements ultimately approved by it are commercially reasonable and fairly balance the interest of consumers, the buyers (UI and CL&P) and the capacity suppliers.

Second, from a process standpoint, it would be unfair to change the contract terms and conditions or to allow UI to file unexecuted contracts in the Section 12(i)

[4] In its written exceptions, UI indicated that it intends to use the financial bid data to assess whether the selected projects meet the criteria of Section 16-243m(i). The OCC has all of the financial bid data for all bidders and is, therefore, better equipped to perform that function in Section 16-243m(i) proceeding, Docket No. 07-4-24. The Department will provide CL&P and UI a limited set of confidential financial bid data needed to evaluate financial accounting issues. The Companies will be provided with information supplied by bidders on Appendices G and I of their bid submissions describing the bidders' financial capabilities and proposed project financing structures. The Companies can request additional information from the Department and selected bidders, but must justify how the additional information relates to the financial accounting review.

[5] In its written exceptions, CL&P asked about who should prepare the execution copy of each capacity contract. CL&P and UI, in consultation with the selected bidders and, if needed the RFP Coordinator, shall prepare the execution copies.

proceeding. Winning bidders bid into this process under the belief, based on language in the Department's September 13, 2006 and November 16, 2006 decisions in this proceeding, that the Master Agreements were final and that they would be required to sign those Master Agreements if selected. UI never raised an objection to this ruling after either decision on the basis that it had a right to negotiate different terms and conditions. Furthermore, the Next Steps sections of both of those decisions clearly described that UI and CL&P would be required to file executed contracts to be reviewed in the proceeding required by Section 16-243m(i). UI also never objected to this ruling after either decision. If UI had objected to either of these rulings in a timely manner back in September or November 2006, the Department would have been in a position to grant the requested relief as bidders could have incorporated this change into their Financial Bids, which were submitted to the Department on December 13, 2006. However, the Department declines to grant that requested relief now because doing so would constitute material changes that could negatively impact the timing and cost of financing, constructing and operating the selected projects.

Third, after conducting an extensive stakeholder process to develop the Master Agreements' terms and conditions, the Department will not now permit UI or CL&P to unilaterally (or bilaterally with the consent of a winning bidder) delete, add to or change the terms and conditions of the Master Agreement. The Department wanted all projects to sign contracts with identical terms so that it could evaluate them on an equal basis. The Department evaluated and selected projects based on the assumption that they agreed to the terms and conditions of the Master Agreements. Altering any of the terms and conditions of the Master Agreements post project selection would be unfair because projects may have been evaluated differently if they each had different contract terms and conditions at the time of evaluation and selection.

Finally, under Section 16-243m(e), the Department, not UI, has the ultimate authority to determine the terms and conditions of the capacity contracts. There are only very limited circumstances under which the Department will entertain proposals to revise the Master Agreements. If a provision is proven to be illegal, the Department will examine alternative language. Also, if UI or CL&P can prove that a provision will work an unintended unforeseen economic hardship on UI or CL&P, that was only detectable upon review of the selected bidders confidential financial bid data, and for which UI or CL&P cannot be made whole through the cost recovery processes set forth in this decision, the Department will examine alternative language. Section 12.6 of the Master Agreements and page 6 of the November 16, 2006 Decision provide for other circumstances justifying changes to the terms and conditions. Absent any of these justifications, the Department will not entertain any proposed revisions at this time and UI and CL&P are directed to file executed contracts with the Department on May 18, 2007 in Docket No. 07-04-24.

The schedule for Docket No. 07-04-24 is attached as Attachment 3. The Department will conduct this one proceeding to review all of the selected projects and the executed contracts and will issue a Decision approving or rejecting the contracts.

As discussed more fully above, pursuant to Section 16-243m(i), each contract will become effective upon approval by the Department.

The scope of review in the contested case proceeding will be limited to assessing whether there is substantial evidence to support the Department's preliminary finding in this proceeding that the projects selected meet the three criteria listed in Section 12(i) of the EIA, notably whether the project(s): (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. The scope of the proceeding will not include presentation of evidence about whether the Department or its consultants could have reached different conclusions using different methods for evaluating bids.

CL&P and UI shall use the Letter of Credit (LOC) template attached to this Draft Decision (Attachment 4, the same template the Department used for the RFP process) as a basis for the LOC to be signed by winning bidders electing to use an LOC to fulfill their Completion and Performance Security requirements. CL&P and UI may make amendments to the template if needed though such amendments should be commercially reasonable and acceptable to the Department and selected bidders. CL&P and UI shall submit the final LOC template to be used by the winning bidders for approval to the DPUC on or before May 7, 2007. Winning bidders should file comments on the draft LOCs on or before May 10, 2007.

Winning bidders will have until May 18, 2007, the date upon which the executed Master Agreements are submitted to the Department, to post their increased project security deposits (from \$10/kW to \$25/kW for generation from \$2/kW to \$5/kW for DR) with their respective electric distribution company). Upon notification that the electric distribution company has received the increased security deposit, the Department will return the original security deposit posted on December 13, 2006 to the bidder. For bidders that submitted an LOC, the Department will send the bidder the LOC within 2 days of notification by the electric distribution company that the increased security deposit has been received.

For those bidders that submitted a wire transfer of cash as their project security deposit, within 2 days of notification by the electric distribution company that the full Completion and Performance Security has been received, the Department will direct the Connecticut State Treasurer to issue a check for the original project security deposit, plus accrued interest, and to send that check to the bidder. We have been informed that it takes the Treasurer approximately seven business days to cut the check from the date of notification.

Bidders whose projects were not selected will have their project security deposit refunded to them. Bidders who posted a Letter of Credit will receive that LOC via express mail, sent out by April 24, 2007. Bidders who posted cash will receive a check from the Connecticut state Treasurer. Bidders who submitted bids using a wire transfer need to complete the vendor form that was distributed by the RFP Coordinator and submit that form to the DPUC as per the RFP Coordinator's instructions. It takes the State Treasurer about seven business days to process and send the check from the date that the Department issues the request for repayment of the project security deposit.

VI. CONCLUSION AND ORDERS

A. CONCLUSION

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 constituting 787 MW, provides the largest net benefit to Connecticut ratepayers as compared to other individual projects and portfolios of projects.

B. ORDERS

1. In this proceeding, if they have not already done so, CL&P and UI shall submit nondisclosure agreements to selected bidders, the RFP Coordinator and the Department on or before May 7, 2007.

2. In this proceeding, if they have not already done so, CL&P and UI shall submit the final LOC template to be used by the winning bidders for approval to the DPUC on or before May 7, 2007.

3. In this proceeding, winning bidders should file any comments they have on the LOC template on or before May 10, 2007.

4. In this proceeding, if they have not already done so, CL&P and UI shall file on or before May 10, 2007 a modified version of the cost sharing agreement already approved by the Department in Docket No. 03-07-17RE03, for use for in this proceeding.

5. In Docket No. 07-04-24, CL&P and UI shall file executed Master Agreements with their respective counterparties on or before May 18, 2007.

6. In Docket No. 07-04-24, CL&P and UI shall file their report or reports on financial accounting issues on or before July 3, 2007

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

This Decision is adopted by the following Commissioners:

Donald W. Downes

John W. Betkoski, III

Anne C. George

CERTIFICATE OF SERVICE

The foregoing is a true and correct copy of the Decision issued by the Department of Public Utility Control, State of Connecticut, and was forwarded by Certified Mail to all parties of record in this proceeding on the date indicated.

Louise E. Rickard

Louise E. Rickard
Acting Executive Secretary
Department of Public Utility Control

May 4, 2007

Date

Table of Contents of Attachments to Interim Decision

2015 Winter Report

May 13, 2015
PJM Interconnection

pjm

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Executive Summary

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

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

Key points from the report are summarized below.

Temperatures and Peaks

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

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

Generator Performance

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

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

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

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

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

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

Operations

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

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

Gas/Electric Coordination

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

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

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

Impact on Market Operations

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

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

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

2015 Recommendations

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

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

Report Organization

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

Weather and Load

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

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

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

Figure 1. 2015 Lowest Temperatures (Fahrenheit)

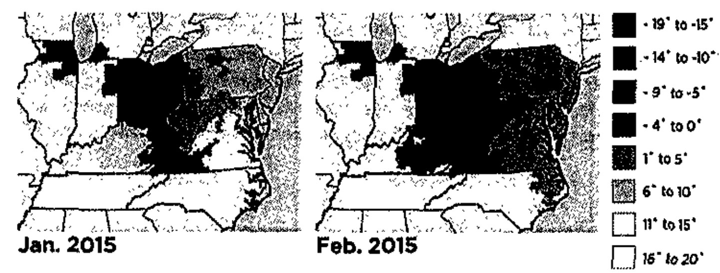
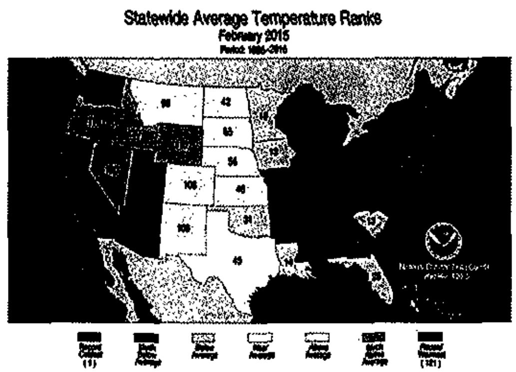
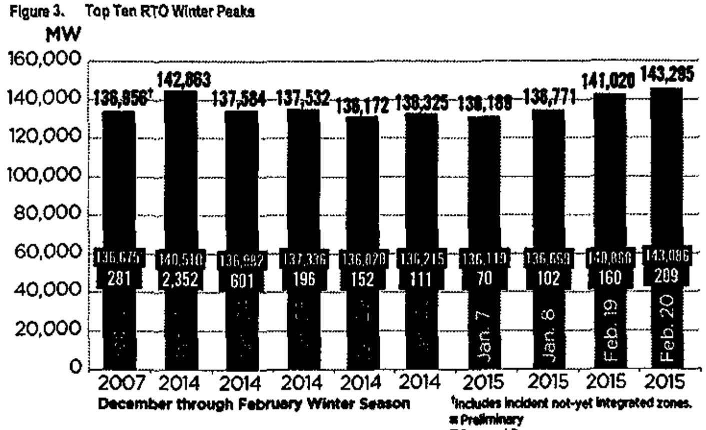


Figure 2. Statewide Average Temperature Ranks February 2015



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

Figure 3. Top Ten RTO Winter Peaks



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

Figure 4. Zones with All-Time Winter Peaks

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

Load Forecasting

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

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

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

Figure 5. 2015 Peak Error

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

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

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

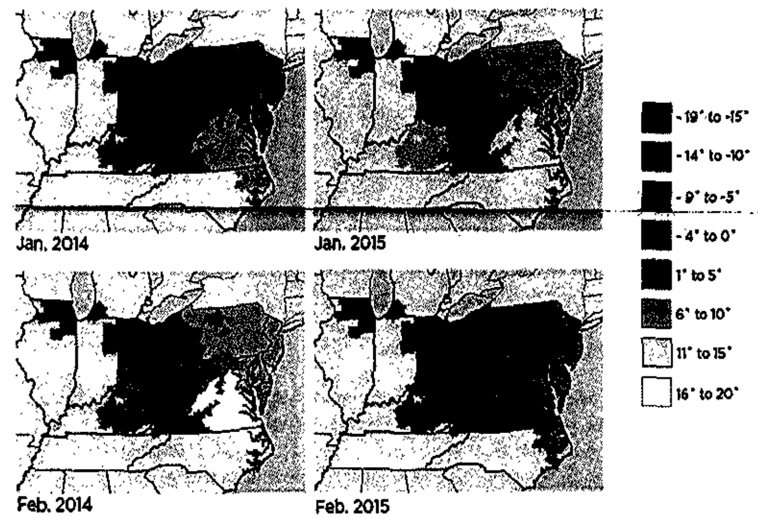
2014 Compared to 2015

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

Temperatures by Month

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

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



Wind Chill

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

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

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

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

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

Extreme Cold Weather Days and Persistence of Cold Weather

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

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

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

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

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

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

Temperature and Peak Load Progression

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

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

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

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

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

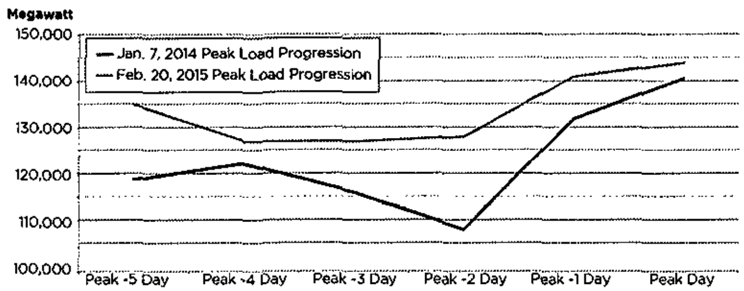


Figure 11. 2014 Temperature Drops (Fahrenheit)

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

Figure 12. 2015 Temperature Drops (Fahrenheit)

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

2015 Generator Performance

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

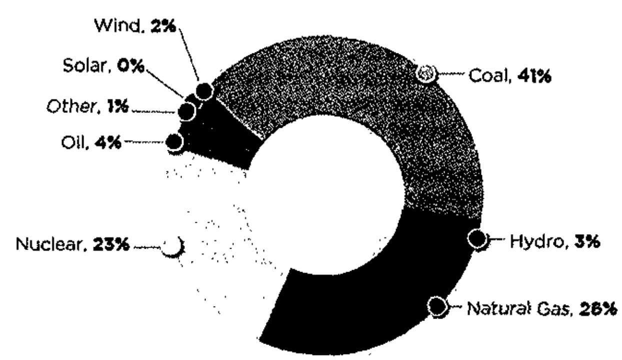
Generation Online

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

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

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

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

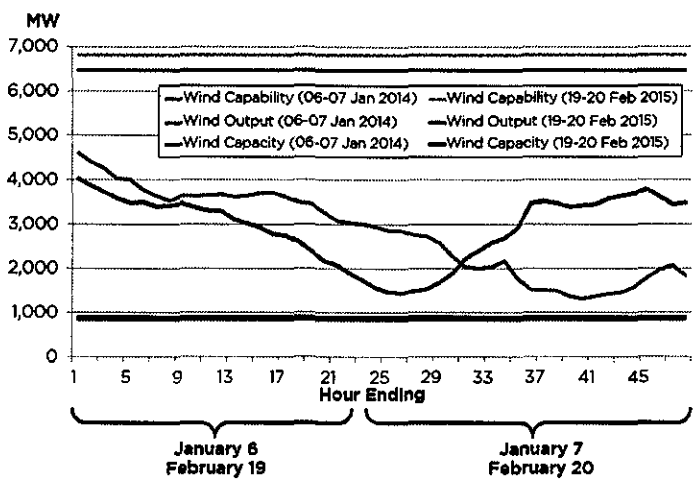


This generation mix is similar to the generation mix that was online at the peak in 2014 with a small increase in coal generation output in 2015.

Performance of Wind Units

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

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



Performance of Retiring Generation

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

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

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

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

Generator Outages

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

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

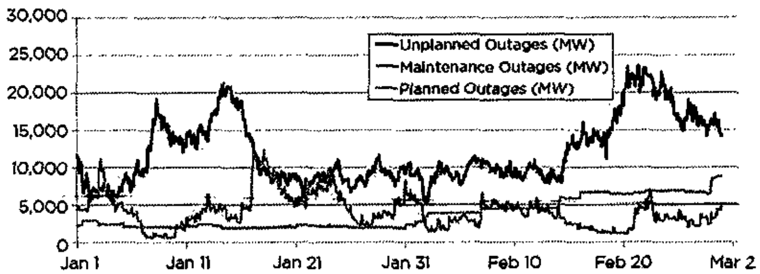
[2] Planned Outage - The scheduled removal from service, in whole or in part, of a generating unit for inspection, maintenance or repair with approval of PJM. Planned outages may last for several weeks and usually occur only once or twice per year.

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

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

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

Figure 16. Forced Outage Peaks: January – February 2015



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

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

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

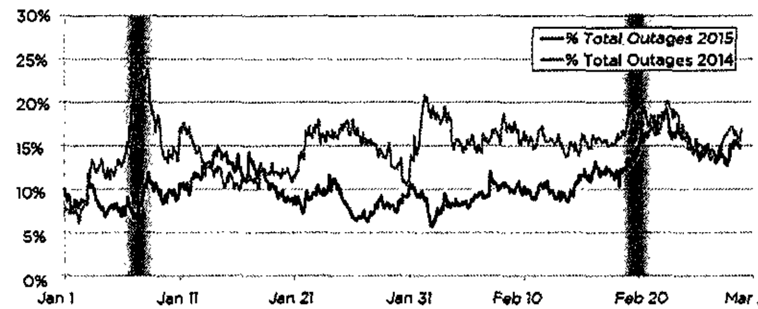
Another way to look at generator performance is by the number of hours during which forced outages were equal to, or greater than, 10 percent of the installed generation. Seven percent is the historical average winter outage rate. Using 10 percent as a threshold is a statistically significant amount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

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

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

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

Figure 18. Total Outage Rate



Forced Outage Causes

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

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

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

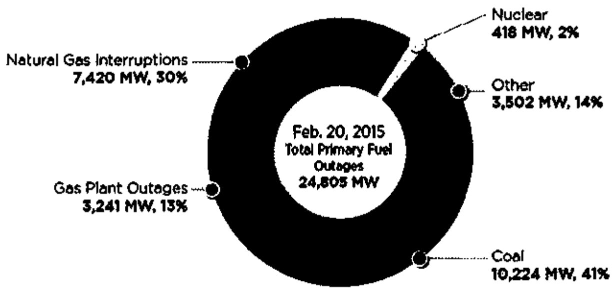
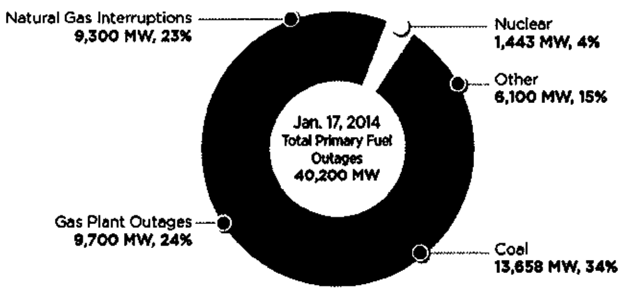


Figure 20. Outages by Primary Fuel Jan. 7, 2014



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

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

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

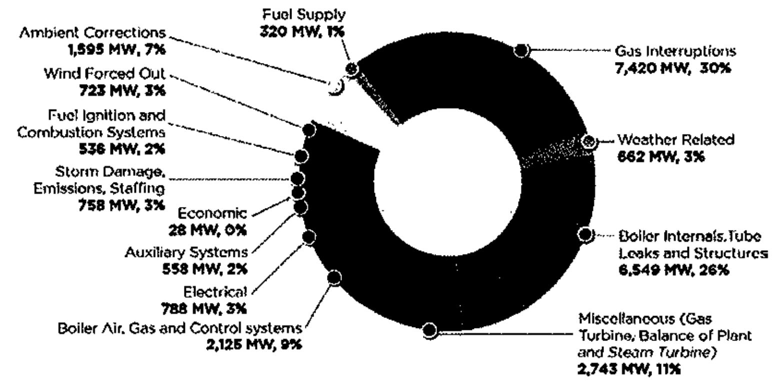
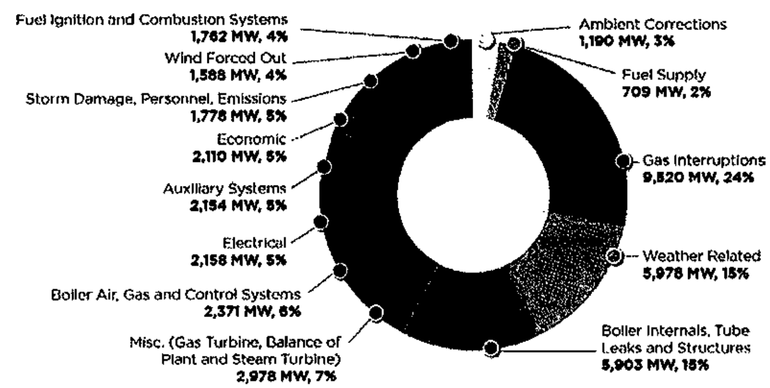


Figure 22. Causes of Forced Outages (MW) Jan. 7, 2014, 19:00



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

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

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

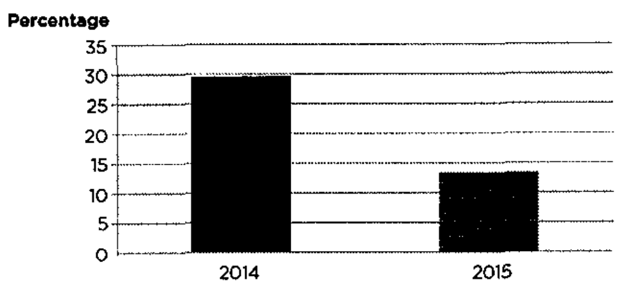
Although the amount of gas interruptions still was significant in 2015, several factors contributed to the better management of these interruptions over the peaks. These contributing factors include enhanced communications among PJM, the gas pipelines and the natural gas plant owner/operators; better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

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

Dual-Fuel Unit Performance

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

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



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

Reasons for this change include:

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

Contractual Constraints

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

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

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

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

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

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

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

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

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

Combustion Turbine Availability

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

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

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

Reporting of Unit Availability

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

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

Cold Weather Operational Exercise

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

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

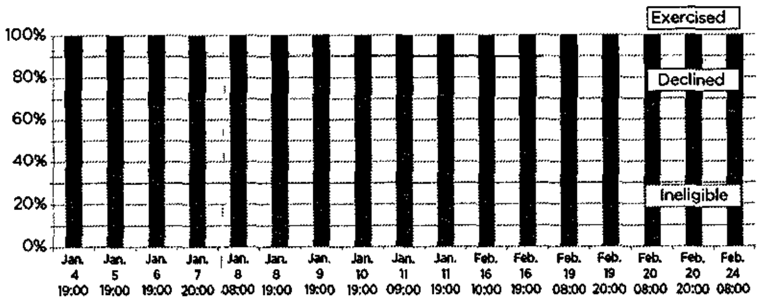
In total, 168 units with a combined 9,919 MW (11,054 MW ICAP) performed the cold weather generation operational exercise. The total cost of these tests was approximately $4,883,000.

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

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

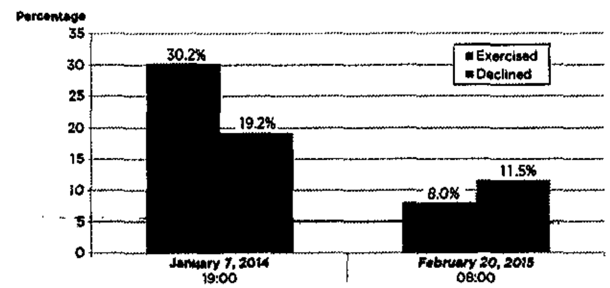
To determine the exercise's impact, PJM analyzed unit winter performance in 2014 and 2015 relative to participation in the cold weather operational exercise. The chart below shows a percentage breakdown of forced outages for January and February 2015 by megawatts and shows that eligible units that performed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

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



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

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



Cold Weather Resource Preparation Checklist

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

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

Summary of Generation Owner Outreach

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

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

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

Natural Gas Conditions 2015

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

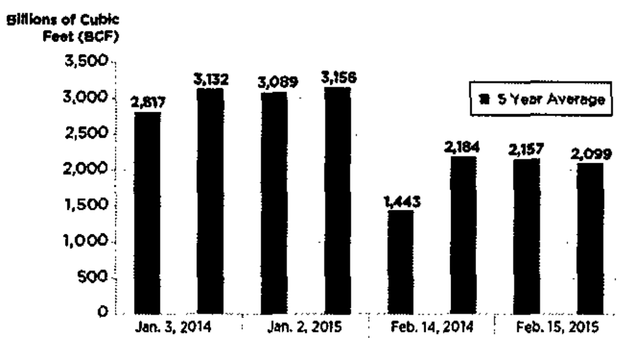
Natural Gas and Liquid Natural Gas Availability and Storage

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

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

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

Figure 26. Storage Comparison



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

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

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

Gas Restrictions

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

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

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

Figure 27. Number of Effective Operational Flow Orders in PJM

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

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

On forecast peak load days, there were consistent constrained areas that limited the ability to get gas to some units in the PJM footprint. These areas tended to persist throughout the winter and became effective starting in the December timeframe as temperatures dropped. Most at-risk generation was geographically located in areas behind local distribution companies or constrained by the physical pipeline limits. The northeastern part of the PJM footprint tends to be where most of the constrained areas occur, and will most likely continue to occur, until additional pipeline capacities are added. This is an area of concern as more generation within PJM is projected to use natural gas as its primary fuel.

In reviewing specifically the peak load days in January and February 2015, the split between interstate pipeline and local distribution companies' restrictions was nearly even with respect to installed capacity megawatts. Another observation in 2015 was that the same units were consistently affected throughout the cold days.

Natural Gas and Heating Oil Prices

The prices of natural gas and heating oil for 2015 were approximately 50 percent lower than in 2014 when compared to the average. The chart below shows the prices of natural gas and heating oil for the past two years for comparison purposes.

Figure 28. Prices of Natural Gas and Heating Oil

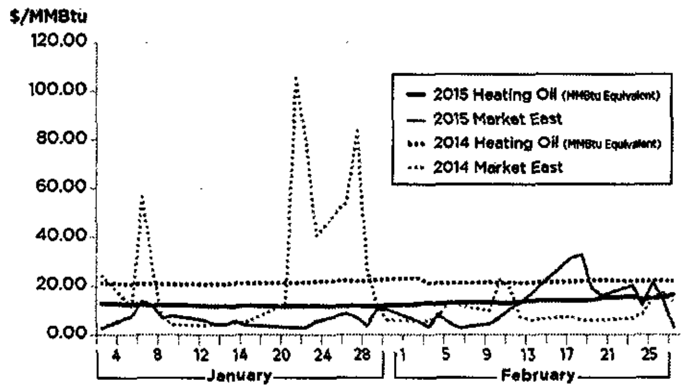
Year	Natural Gas Spot Price ($/MMBtu)	Natural Gas Daily Max ($/MMBtu)	Natural Gas Daily Average $MMBtu	Heating Oil Prices (equivalent $/MMBtu)
2015	75	30	10	13
2014	125	100	20	22
Percent Change	-40%	-70%	-50%	-41%

The following trends were noted in comparing prices to the winter of 2014 to the winter of 2015:

- 2015 natural gas spot prices did not reach the 2014 levels. (In 2014 spot prices were greater than $125/MMBtu; in 2015 the highest price observed was approximately $75/MMBtu.)
- The 2015 natural gas daily average for Market East[7] prices did not reach 2014 levels as shown in the figure below. (In 2014 the highest daily average was a little over a $100 dollars; in 2015, slightly over $30 dollars.)
- 2015 heating oil prices were lower this year than the winter of 2014. In 2014, the price for oil was around $22/MMBtu gas equivalent; in 2015, the price was closer to $13/MMBtu gas equivalent prices.

[7] Market East is an average of the following receipt locations: TETCO-M3, TRANCO-Z6 (NY) and TRANSCO-Z5 (non-WGL); heating oil is the daily heating oil average converted to MMBtu.

Figure 29. 2014 vs. 2015 Oil and Gas Comparison



The difference in natural gas prices between the winters of 2014 and 2015 was primarily driven by the relationship between supply and demand. In 2014, natural gas was in high demand and there was less supply; as mentioned above, supply was more in abundant in 2015. Generator dispatch changed in 2015 as well, which could have put a downward pressure on gas prices. For example, in 2014, lower oil prices offered dual-fuel capable generators a less-expensive fuel supply option. PJM also called on fewer units outside of the Day-Ahead Market with long lead unit times, and less flexible unit parameters such as minimum run times, which may have contributed to more stable and lower prices.

2014 Compared to 2015

To summarize the observations from the previous section, there seemed to be more natural gas and LNG available in the PJM market area in 2015 compared to 2014. There was an increase in storage in 2015. Prices for both natural gas and heating oil were lower than 2014 prices. There were just as many (comparing January 2014 / 2015) if not more (comparing February 2015 / 2014) restrictions issued by the pipelines, however.

The gas industry may have done some things differently both in preparations for and during real-time operations for the winter of 2014 / 2015 that had an impact on generators. For example, they added operational flow orders to reinforce firm transportation contractual rights on the pipeline and to manage pressure on the pipelines more actively. In 2014, the pipelines also limited the withdrawal from storage because of the effect on the operations of the storage facilities. In 2014, the pipelines required their customers to first fill their firm capacity from wellhead supply points, then from storage. This past winter that was not a requirement because of increased natural gas storage levels. When the pipelines require their customers take from the wellhead first, it limits the amount of capacity for generators to get access to supplies.

So while there were some actions taken by the pipelines to maximize capacity, there were also actions taken to ensure the capacity and pressure was available for firm transportation contractual rights. PJM units, particularly those who had non-firm service or were in operational flow order situations, were still impacted.

Units that had gas supply restricted by their pipelines either had to make themselves unavailable, ask for an exception to some of their unit parameters (e.g. minimum run time), or run on an alternate fuel, if the unit was capable and the alternate fuel available. As mentioned in the Generation section, there were approximately 7200 MWs of gas units that were unavailable because of their inability to get gas. This was less than the 9,300 MW forced out for the same reasons in 2015, but still 30 percent of the total forced outages for gas units in 2015.

Parameter Limited Schedules and Exceptions

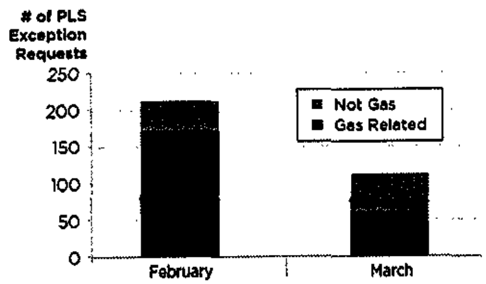
Generators have the ability to request exceptions to parameter limited schedule values due to conditions that impact the operations of their plant. This process is explained in detail in Section 6.6(f) of Attachment K-Appendix of the PJM Tariff, Section 6.6(f) of Schedule 1 of the Operating Agreement and Manual 11, but in summary, a generation resource may request an exception to certain parameters, such as minimum run time and turn down ratio, when conditions impact a unit's physical operational parameters.

One of the recommendations coming out of the winter 2014 operations was to allow generators, under a pipeline operational flow order or critical notice to use the unit parameters and parameter limited schedule exception process to communicate their operational conditions to PJM. PJM stakeholders approved this recommendation as part of the Gas Unit Commitment Coordination stakeholder group under the Operations Committee[8]. Units that elected to use this process could request a temporary exception to certain unit parameters to reflect their operational conditions because of pipeline constraints.

The primary reason for the exceptions requested during the winter of 2015 were due to ratable takes, or a pipeline restriction requiring units to take gas at an equal amount for every hour of the gas day. The number of parameter limited schedule exceptions requested because of gas restrictions is shown below. This information is not available for 2014 because gas-related parameter limited schedule exceptions were not permitted at that time.

[8] Link to Gas Unit Commitment Coordination Problem Statement http://www.pjm.com/~/media/committees-groups/committees/oc/20140603/20140603-item-09-gas-fired-unit-committment-coordination-problem-statement.ashx

Figure 30. Number of Parameter Limited Schedule Exception Requests for Winter 2015



Approving a unit's exception request allowed a unit to remain available that otherwise may have been forced out or unavailable to produce MWs to serve load. The process also increased the transparency to PJM dispatchers of the unit's true operational parameters, which allowed for more informed PJM Dispatch scheduling decisions.

Dual-Fuel Units

The high forced outage rates in winter of 2014 were a catalyst for PJM to better understand primary and secondary fuel types as well as more details about gas units and their gas supply, such as natural gas pipeline connection, location relative to a local distribution company, fuel supply contract (e.g. firm or interruptible), and dual-fuel capability. Implementing a 2014 winter recommendation, generators were required to provide this information to PJM.

As of March 1, 2015, approximately 40,000 MW's of generation within the PJM footprint were connected to interstate pipelines, and 22,000 MW's of generation were connected to a local distribution company. These numbers represent generation capable of burning natural gas as the primary fuel; they do not include generation that requires gas to start, typically large coal units that use natural gas as an igniter source.

Approximately 14 percent of the PJM fleet is dual-fuel capable, which means the unit is capable of running on a primary or alternative fuel source. Almost 60 percent of the generation located behind a local distribution company is capable of burning an alternate fuel. PJM observed that, during the cold weather peaks in January and February of 2015, a significant percentage of units located on a pipeline or behind a local distribution company that were at risk of getting gas *because of pipeline or local distribution company-issued restrictions, were*, in fact, able to run at some point during the cold weather events. (See the Generation section for outage information for dual-fueled units.) At the time of the report, there was no way to determine what type of fuel units were running on because the eMKT application change requiring units to designate fuel type on each schedule was not implemented until April 1.

While there is no direct *measurement of the number of units running on their alternate fuel at this time, several* indirect measurements point to improved generator performance for reasons that could include running on an alternate fuel. Those measurements include reduced forced outage rates and sufficient reserves, leading to a reduced number of emergency procedures. During informal interviews conducted by PJM, generation owners also

shared information that pointed to low oil prices, their own proactive oil inventory and emissions management, more prudent start-up procedures, and additional testing on alternate fuels, facilitated by the cold weather testing exercise, as reasons they elected to run more often on their alternate fuel when gas availability was restricted.

PJM Gas-Electric Coordination Team

One other change from 2014 that PJM believes contributed to improving the overall performance of the RTO this winter was the establishment of a PJM gas-electric coordination team. PJM established the team in response to a 2014 winter recommendation to improve PJM's tools and processes for two-way communication with the gas industry. Its mission is to enhance situational awareness and better understanding the impact of gas conditions to PJM generation.

The team provides regular communication to PJM Dispatch about natural gas-fired generation units that are at risk of obtaining gas based on available pipeline capacity. The team summarizes this unit and pipeline information daily and communicates to PJM markets, operations and dispatch groups. Additionally, as system and gas conditions change, the team conducts further analysis, examining scheduled gas on pipelines for the multiple nomination cycles throughout the day.

Another primary function of the team is to improve communication with the natural gas pipelines so the pipelines and PJM are more aware of grid conditions, estimated gas demands, and availability. Since the winter of 2014, PJM has established communication protocols with the majority of the pipelines located within the PJM footprint. This protocol allows for the exchange of non-pubic information between the gas and electric industries, under FERC Order 787 and subject to the No-Conduit rule, which prohibits disclosing non-public transmission-function information (e.g. day-ahead commitments) to marketing-function employees.

Acting on this newly established protocol, the team conducted regular calls with all the major pipelines to discuss gas conditions and generator impacts. Included in these discussions are any effective critical notices, capacity constraints or operational flow orders, units located in those constrained areas with Day-Ahead Energy Market commitments, and natural gas scheduled quantities by generator by gas pipeline nomination cycle. This information helps determine whether *generation, potentially needed for the morning and/or evening peak, has* purchased the required fuel to burn for their day-ahead unit commitment, and thus the risk to unit availability.

The team also monitors natural gas prices throughout the trading day as well as the daily average gas prices for key hubs and receipt points in order to determine the fuel supply risk. The higher the prices, the more constraints expected, and the higher the risk to generators *with non-firm gas contract to procure gas.*

The goal of this analysis is to determine the risk level of available units to meet the RTO load. PJM Dispatch will conduct analysis to determine the impact of the at-risk generation units and then reach out to generators that may be required for additional discussion on availability. PJM believes the daily risk profile of gas-fired generation units improved dispatcher scheduling decisions, enabled well-informed *discussions with generation owners about unit* flexibility, and contributed to improved generator availability and performance.

An important note is that generators located behind a local distribution company are much less transparent to PJM and, unless dual-fuel capable, are much more at risk of not being available during emergency conditions. Of the 7,420 MW of forced outages on the morning of Feb. 20, 2015, 60 percent of the units were located behind a local distribution company. PJM currently does not have any communication protocol in place with any local distribution companies in the PJM footprint. PJM is unable to see which generators behind a local distribution company have scheduled gas. Local distribution companies have a policy which gives higher priority to heating customers on extreme cold days. The "priority on human needs" policy was utilized to prioritize residential heating over gas-fired generators. For these reasons, a recommendation for this team is to work on increasing transparency and coordination with local distribution companies in the PJM footprint so PJM can better forecast local distribution company gas generator curtailments.

2015 Market Outcomes

In the winter of 2015, locational marginal prices (LMPs) and ancillary service market clearing prices (MCP) reflected systems conditions throughout the duration of the winter. Increased LMPs and MCPs for regulation, non-synchronized reserve and synchronized reserve occurred close to the winter peak periods. During the winter of 2015, there were no shortage pricing or emergency demand response events.

Locational Marginal Pricing

LMPs are determined based on the cost to provide the next increment of energy while respecting the primary and synchronized reserve requirements, congestion and marginal losses. PJM's real-time dispatch and LMP calculation systems jointly optimize energy, reserves and regulation to ensure that all system requirements are met using the least cost resource set. This construct allows accurate reflection of price signals with a higher degree of consistency between ancillary services and prevailing energy prices.

The chart below show the real-time and day-ahead energy prices during January 2015.

Figure 31. Locational Marginal Pricing Jan. 7 and Jan. 8, 2015

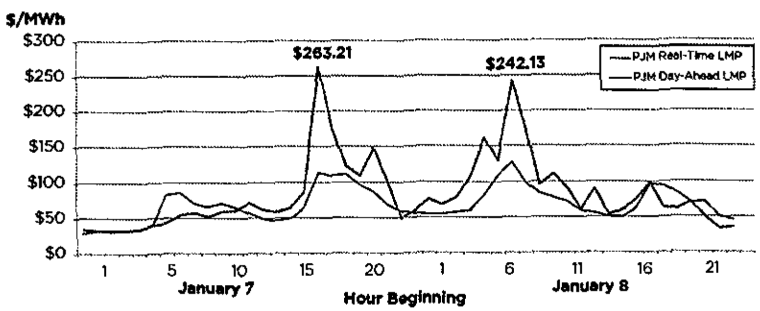
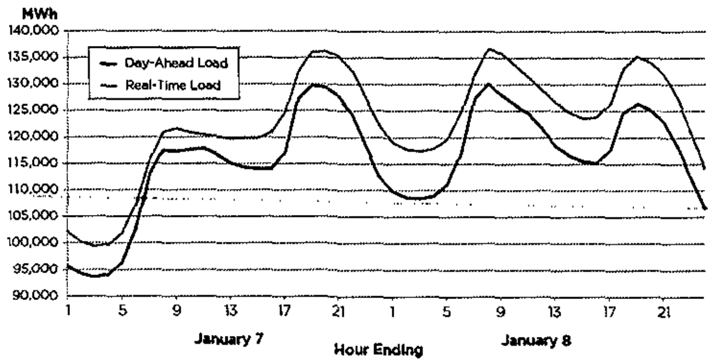


Figure 2 Day-Ahead versus Real-Time Megawatts Jan. 7 and Jan. 8 2015



The average RTO real-time energy market prices exceeded the average RTO day-ahead energy market prices consistently for the evening peak on Jan. 7, 2015, and the morning peak on Jan. 8, 2015. The highest RTO real-time LMP during the evening peak on Jan. 7 was $263.21 per megawatt-hour (hour beginning 1700), which exceeded RTO day-ahead LMP by $149.88 per megawatt-hour. The trend continued during the morning peak of Jan. 8, 2015, as RTO real-time LMPs exceeded day-ahead LMPs, which peaked at $242.13 per megawatt-hour (hour beginning 0700). For both Jan. 7, 2015, and Jan. 8, 2015, generation was the marginal resource setting prices. On average, RTO real-time LMP exceeded that of RTO day-ahead LMP consistently from Jan. 1, 2015, through Jan. 14, 2015, while this pattern reversed itself during the second half of January 2015 with RTO day-ahead LMP exceeding RTO real-time LMP

In January, the culmination of under-bid load, lower fuel prices in the day-ahead market and increased constraints in the eastern portion of the PJM system lead to the differences in the RTO real-time and the RTO day-ahead prices. Under-bid load and lower fuel prices in the PJM Day-Ahead Market could have dampened the day-ahead prices while an increase in congestion in the PJM Real-Time Market would have the effect of increasing prices. Real-time prices were lower in PJM's western area compared to the eastern area due to congestion on the bulk power system, a result of heavy transfers of energy across the RTO from the western portion of the footprint to the eastern portion. This necessitated the operation of more resources on the margin in the Eastern Region resulting in higher prices in that region compared to the rest of the footprint.

Figure 32. Locational Marginal Pricing Feb. 19 and 20, 2015

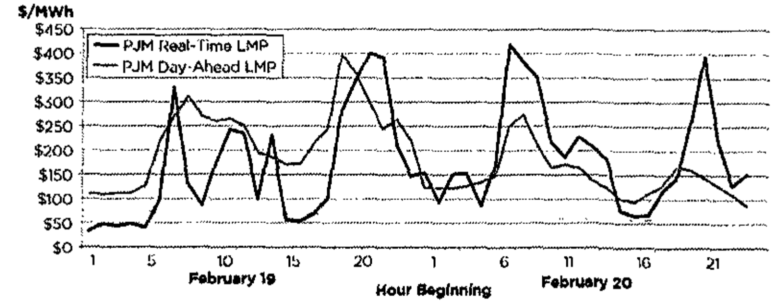
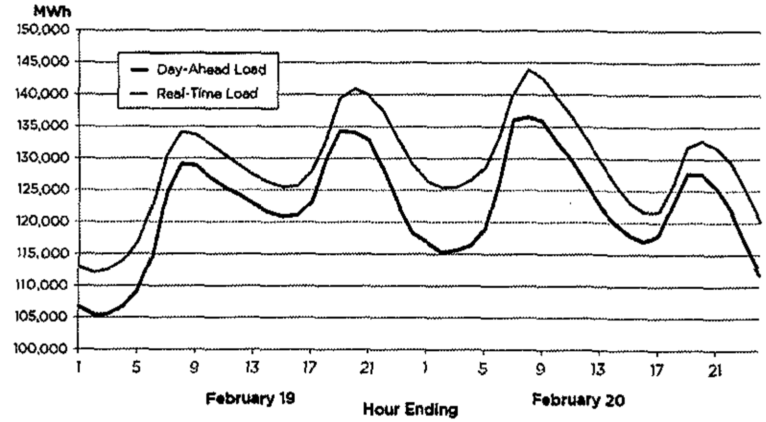


Figure 33. Day-Ahead versus Real-Time Megawatts Feb. 19 and 20, 2015



During the evening peak of Feb. 19, 2015, the RTO real-time LMP reached $399.76 per megawatt-hour (hour beginning 2000). Subsequently, on the morning of Feb. 20, 2015, the RTO real-time LMP, due to the record setting winter peak, hit a high of $418.67 per megawatt-hour (hour beginning 0600). On the other hand, from the evening peak on Feb. 19, 2015, to the morning peak on Feb. 20, 2015, the RTO day-ahead LMP decreased by 30.78 percent (maximum price of $396.89 per megawatt-hour (hour beginning 1800)).

The reduction of day-ahead LMP during the evening peak of Feb. 19, 2015, to the morning peak of Feb. 20, 2015, could be attributed to the lower fuel costs, under- bid load and units back in service from outages. Also contributing to lower day-ahead prices was the low number of long lead units that needed to be called outside of the Day-Ahead Market. The reduced number of long lead units that needed to be called outside of the Day-Ahead Market was attributed by the increased amount of day-ahead self-scheduled units that were available during this period.

Ancillary Services: Regulation, Synchronized and Non-Synchronized Reserve

During the peaks in January and February 2015, high prices for regulation, synchronized and non-synchronized reserves occurred around the same time as the real-time energy LMPs peak. The simultaneous pricing of these products with energy leads to a harmonized set of prices that are reflective of actual system conditions.

During both the winter of 2015 and 2014 Polar Vortex, the high clearing prices for regulation, synchronized and non-synchronized reserves occurred around the same time as real-time energy LMPs peaks. During these stressed conditions, ancillary service prices increased as the reserve margin decreased, and system capacity competed to meet the ancillary services requirements while maintaining power balance. Unlike 2014, PJM did not experience extreme ancillary services prices during the winter of 2015; the regulation price was just over $500 per megawatt-hour for two hours during the extreme winter periods in 2015, compared to approximately $3,300 per megawatt-hour during the 2014 Polar Vortex.

Figure 34. January 2015 Ancillary Service Price and Energy Price

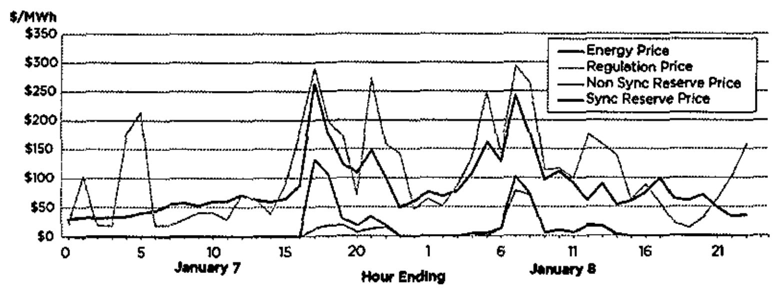
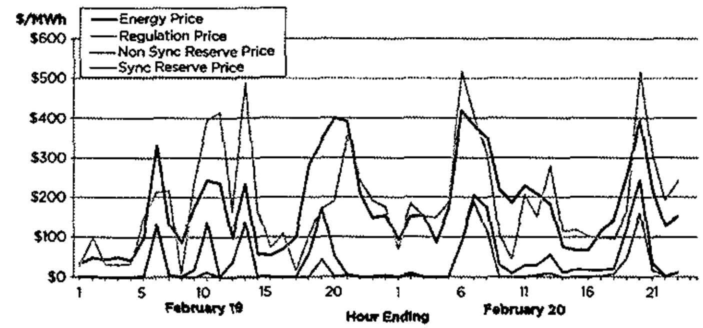


Figure 35. February 2015 Ancillary Service Price and Energy Price

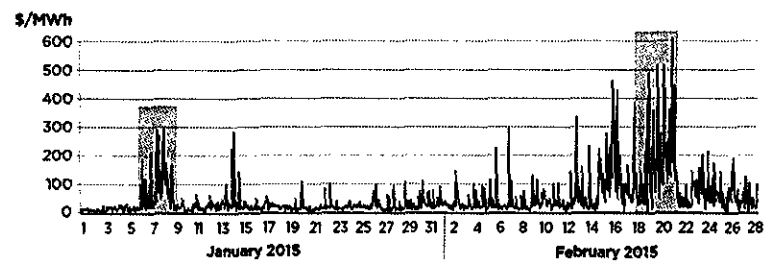


Regulation

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

During the winter of 2015, the top three highest regulation market clearing prices were $289.51 per megawatt-hour (hour beginning 1700) on Jan. 7, $293.34 per megawatt-hour (hour beginning 0700) Jan. 7, and $516.13 per megawatt-hour (hour beginning 0600) on Feb. 20. All three of these high-regulation market clearing price spikes occurred close to the real-time energy price peaks.

Figure 36. Regulation Market Clearing Price for January and February 2015



The spike in the regulation market clearing price on the morning of Jan. 7, 2015, of $214.03 per megawatt-hour (hour ending 0600) was due to a localized transmission constraint that occurred in the Jersey Central Power & Light zone. Real-time LMP for that zone reached a high of $175.69 per megawatt-hour (hour beginning 0600) on the morning of Jan. 7, 2015.

The spike in the regulation market clearing price on the morning of Feb. 20, 2015, of $516.13 per megawatt-hour (hour beginning 0600) was in part a combination of higher load and increased in regulation lost opportunity cost. Regulation lost opportunity cost is the revenue foregone or increase in costs relative to the energy market for providing regulation service.

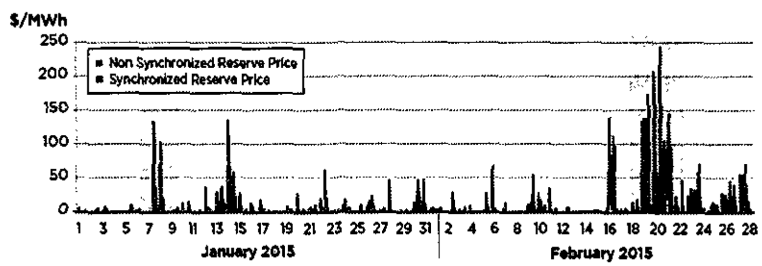
Regulation lost opportunity cost was the primary contributing factor to the increase of the regulation prices during the winter of 2015. During the 2014 Polar Vortex, the increase of regulation prices was due to the poor performance factor in the regulation market as high-performing generators were used for energy or reserves instead of regulation. Performance-based regulation was designed to calculate and include resource specific regulation lost opportunity cost in the regulation market clearing price on a real-time five-minute basis (similar to real-time LMPs).

Reserves Pricing

Reserve market clearing prices trended with energy prices during the winter of 2015 without any unanticipated excursions.

In January, both synchronized and non-synchronized reserves saw relatively small spikes in prices and volatility for both Jan. 7, 2015, and Jan. 8, 2015. *Synchronized reserve prices hit a maximum of $132.10 on Jan. 7, 2015, (hour* beginning 1700), coinciding with rising real-time energy prices. The rising energy prices were a result of the high loads and a reserve event that occurred during this hour. Reserve events typically produce higher energy prices due to the short-term need for more energy on the system.

Figure 37. Synchronous and Non-Synchronous Reserve Prices



During February, prices for both synchronized and non-synchronized reserves peaked on Feb. 20, 2015, along with the morning and evening peak cycle. *Synchronized reserve prices hit a maximum of* $243.14 on Feb. 20, 2015, (hour beginning 2000), and the non-synchronized reserve prices hit a maximum of $189.24 on Feb. 20, 2015, (hour beginning 0700), *both coinciding with rising real-time energy prices during* the respective timeframes. In anticipation of high loads for the morning of Feb. 20, PJM carried excess reserves on the system to ensure system reliability. These excess reserves resulted in lower synchronized reserve prices during the morning peak. *During the evening* peak, because of lower forecasted demand, PJM did not need to carry excess reserves. This had the effect of slightly increasing the reserve prices.

Uplift

To incent generators and demand response resources to operate as requested by PJM, resources that are scheduled by PJM and follow PJM dispatch instructions are guaranteed to fully recover their costs of operation. *Uplift* cost is created when market revenues are insufficient to cover the costs of the resources following PJM's direction.

The level of uplift for the combined months of January and February 2015 was $150.5 million, compared to the $653 million for the same period in 2014. The latter part of February 2015 *brought an increase in the amount of uplift as* PJM forecasted a greater need for generation in the day ahead, given load demand and extreme weather, to supply consumers and ensure adequate operating reserves to *mitigate risk from unscheduled generator outages and natural* gas uncertainty.

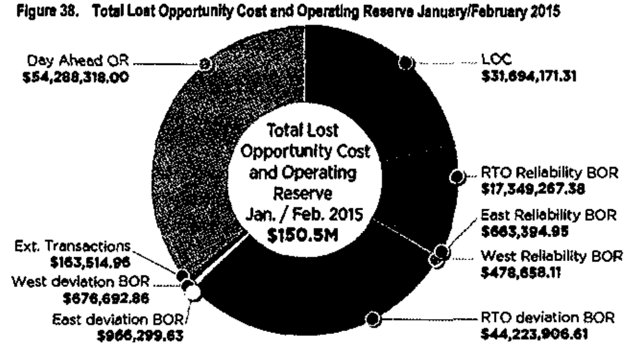
January 2015 and February 2015 experienced a noticeable uplift reduction compared to the same period in 2014. The uplift *reduction can be attributed to numerous factors: improved generator performance* and flexibility, improved communication and transparency with the natural gas pipelines, improved data accuracy from generators about their *operational flexibility, and lower fuel prices that enabled dual-fuel* units to run on oil during times of gas pipeline restrictions. These improvements provided PJM the ability to enhance energy scheduling accuracy and minimize the *need to commit long-lead, large combined-cycle resources* as was done in 2014.

Uplift incentivizes appropriate behavior from all supply resources and aids PJM in maintaining system control because only resources that operate at PJM's direction are eligible for uplift payments. For reliable operation, PJM requires supply resources to follow directives without hesitation. When resources follow dispatch instructions, uplift is sometimes necessary to guarantee that supply resources cover the total value of their energy offer. These payments are outside of the market and are not included in the pricing signals that are visible and transparent to market participants. Therefore, PJM strives to minimize uplift costs and operate the system so that the vast majority of a *resource's costs of operation are reflected in transparent market clearing prices.*

Some scenarios that lead to increased uplift involve PJM committing resources for expected extreme system conditions. As a result, more expensive resources are sometimes required to cover reserves and operate at their minimum output levels. In such cases, these resources are placed at the bottom of the supply stack and sometimes suppress LMPs. PJM may need to schedule additional generation to be available to mitigate any potential power *shortfalls* due to generator forced outages. The additional generation needed and committed after the execution of the Day-Ahead Energy Market increases the differences between day-ahead and real-time energy prices, but also creates situations where the resources called to supply reserves are not marginal, causing them to operate at their economic minimums. This may require uplift payments to these generators when LMPs are not adequate to cover their operational costs.

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

Figure 38. Total Lost Opportunity Cost and Operating Reserve January/February 2015



There can be various scenarios in which market revenues are insufficient to cover generators' costs. The drivers that contributed to high levels of uplift particularly during February 2015 included:

- Contractual Constraints – At times, due to gas delivery operation inflexibility restrictions, some resources operated within strict megawatt output levels during periods when they were uneconomic to ensure they were available during peak conditions. The winter of 2015 experienced less contractual constraints than the winter of 2014.

- Prudent Operations – During February 2015, based on the extreme weather forecast and expected system conditions, PJM committed resources to meet the forecasted load and maintain system reserve requirements. Such operations are typical during cold weather alerts, resulting in the scheduling of reserves to account for increased load demand. Additional resources that were committed to meet the increased load demand plus planned outages, unplanned outages and expected transmission congestion resulted in elevated balancing operating reserve deviation charges.

  In addition, the lower fuel prices seen in 2015 compared to 2014 prompted some generation owners to start their resources early and self-scheduled those resources in the PJM market prior to the anticipated extreme weather conditions to ensure their availability in the PJM market. Throughout February, particularly the latter part of the month, PJM procured adequate generation to meet forecasted load and maintain system reserve requirements. The Day-Ahead Market committed much of this generation in the Western Region of PJM in the form of combustion turbines based on the market-clearing engine. In real-time operations, there was a large amount of energy imports across the western border, resulting in heavy west-to-east transfers across the PJM system. These energy imports displaced the need for the combustion turbines committed in the Day-Ahead Market, which then were de-committed in real time. The heavy transfers across the system also caused the real-time LMPs to be higher in the Eastern Region of PJM. These issues contributed to the overall total energy uplift credits.

Uplift is an important feature in the PJM Energy Market design due to the number of variables associated with dispatching the system and maintaining control. While there is a tradeoff between lower energy prices and uplift because, generally, as uplift is reduced, energy prices will rise, and vice versa. No solution eliminates uplift

completely. Through the Energy Market Uplift Senior Task Force, PJM and its stakeholders have made progress to provide solutions for the reduction of uplift. The task force has focused on uplift credit methodology and specific units parameters that would enable the reduction of uplift.

Balancing Operating Reserve Credits

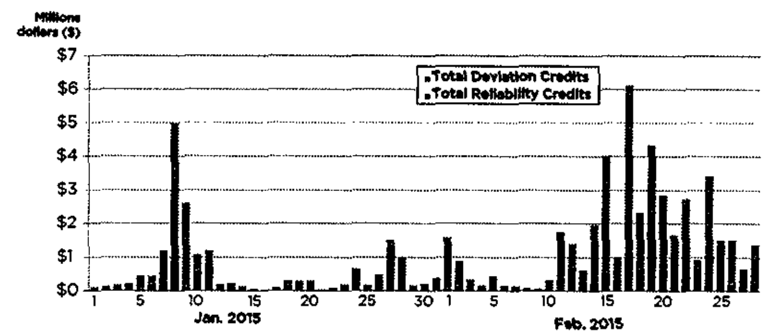
There are two general types of balancing operating reserve charges. If a generator is called to run after the close of the Day-Ahead Market and during the reliability assessment commitment performed after the Day-Ahead Market results are posted, it is either dispatched for prudent operations or "load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

If a generator is dispatched for prudent operations, the uplift cost associated with the generator running is categorized as a reliability credit. If a generator is dispatched for 'load plus reserves', the uplift cost is categorized as a deviation credit. When a generator is committed to run during the operating day, if its cost is greater than locational marginal prices most of the time, the uplift credit for the generator also is categorized as a deviation credit. During the operating day, if a generator is not economical (i.e. its cost-based offer is higher than the current LMP), its associated uplift cost is categorized as a reliability credit. This is summarized in the table below.

Figure 39. Balancing Operating Reserve Credits

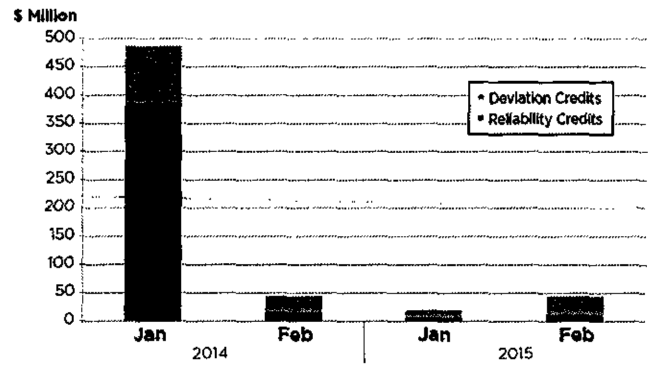
Reliability Credits	• Generator committed in advance of the operating day and outside of the Day-Ahead Market • Generator committed during the operating day and is out of the economic merit order
Deviation Credits	• Generator is needed to meet anticipated load plus reserves • Generator is committed during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

Figure 40. Balancing Operating Reserve Credits for the months of January and February 2015



PJM did experience higher-than-average operating reserve credits this winter. However, in comparison, February 2015's operating reserve credits were less than 20 percent of the credits for January 2014.

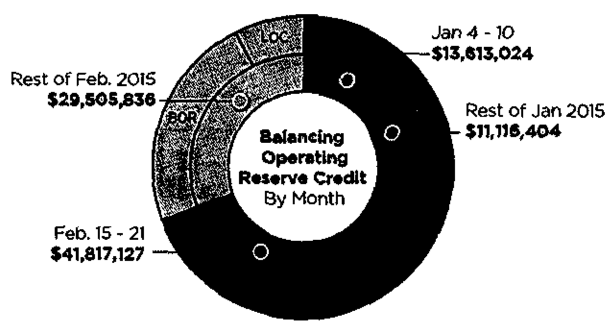
Figure 41. Comparison of 2014 to 2015 Operating Reserves Credits



Large contributing factors to the decreased operating reserve dollars, despite the similar weather conditions, were the improved unit performance, a result of winter readiness and preparation activities, as well as more informed dispatched scheduling decisions, a result of improved communications, better coordination with generators and gas pipelines and improved data accuracy.

The majority of the *balancing operating reserve credits incurred during* February 2015 were for deviation credits. Units that are called on by PJM can incur balancing operating reserve costs that can either be allocated as part of the reliability analysis or as part of the operating day. During the latter part of February, *the majority of balancing* operating reserve credits was allocated as part of the reliability assessment and specifically under load plus reserves deviation credits.

Figure 42. *Balancing Operating Reserve Credits in January and February 2015*



Time Period	Balancing Operating Reserve	Lost Opportunity Cost
Jan 4 - Jan 10	$11,045,414.00	$2,567,610.00
Total Month Jan 2015	$19,355,493.00	$ 5,373,935.00
Feb 15 - Feb 21	$ 22,649,517.00	$19,167,610.00
Total Month Feb 2015	$45,002,726.00	$26,320,236.00

The cold weather spikes Jan. 4-10, 2015, and Feb. 15-21, 2015, represented the majority of *balancing operating* reserve credit and lost opportunity cost credit for each respective month. February 2015 exhibited a high amount of lost opportunity costs, as resources scheduled in the Day-Ahead Market were not *run in real time and subsequently* compensated via lost opportunity cost based on the existing market rules.

Lost Opportunity Cost

Lost opportunity cost is an uplift cost and results primarily from PJM scheduling a resource to operate in the Day-*Ahead Energy Market* but then not calling the resource to operate in real time. For example, a resource may be committed in the Day-Ahead Energy Market to operate during specified times but is not needed in real time due to *factors* such as anticipated lower demand, increased supply from interchange transactions, or increased self-scheduled generation that was not modeled in the Day-Ahead Energy Market.

A resource is compensated for lost opportunity cost if it received a Day-Ahead Energy Market award but was not run in real time. This payment covers the resource's Day-Ahead Energy Market position and any Real-Time Energy Market charges the resource would have to pay. A generation resource's output could be also reduced in real time due to an operational issue on the system. In these cases, if the real-time LMP does not reflect the resource's offer during the time its output is reduced, the resource is made whole to the amount it could have earned had it operated *at a level of output corresponding* to the real-time LMP.

Figure 43. Lost Opportunity Cost in January and February 2015

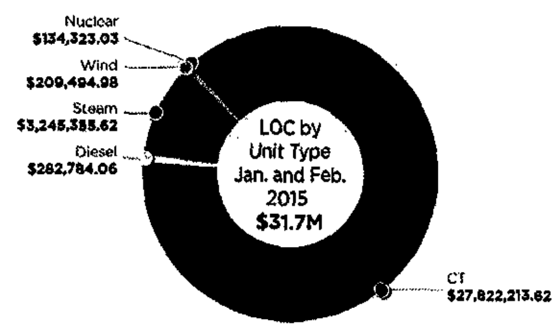
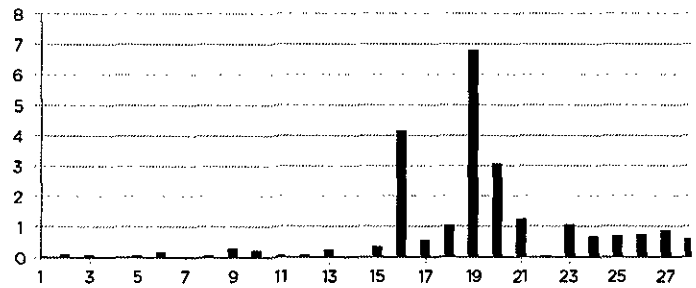


Figure 44. February 2015 CT Lost Opportunity Cost



The majority of lost opportunity cost expense was during the end of February 2015. The cause of the increase in lost opportunity cost expense was a combination of prudent operations and challenging load projections. Heavy west-to-east transfers across the system restricted the ability for PJM to load already committed internal western generation. The impact of not being able to run these generators impacted both real-time LMPs and lost opportunity cost for those generators.

Figure 45. Balancing Operating Reserve Credit by Unit Type

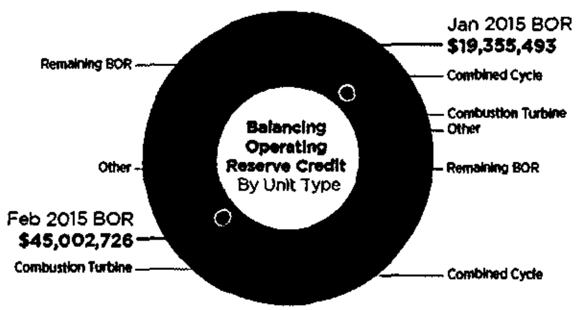


Figure 46. Balancing Operating Reserve by Unit Type in January 2015

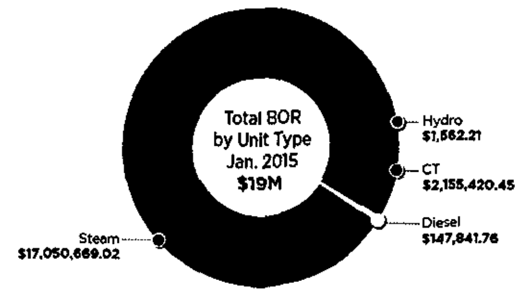
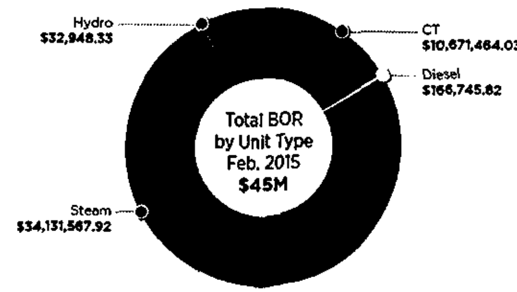


Figure 47. Balancing Operating Reserve by Unit Type in February 2015



Offer Cap

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

During the winter of 2014, PJM market participants experienced excessive high spikes of natural gas prices that could make electricity generation costs that could exceed the $1,000/MWh offer cap. To help alleviate this issue, PJM filed a temporary waiver with the Federal Energy Regulatory Commission (FERC) on Feb. 10, 2014, that allowed cost-based offers to exceed the $1,000/MWh offer-price cap. The FERC approved the waiver.

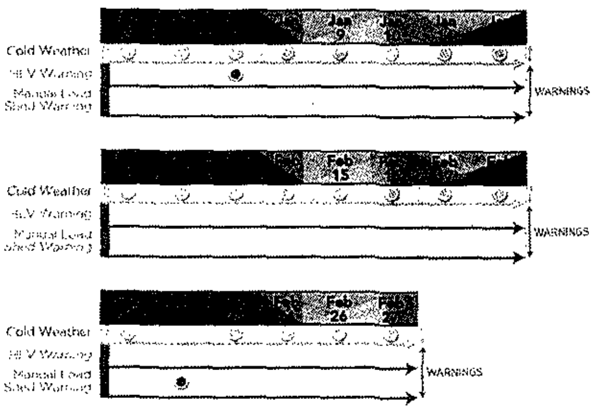
In preparation for the winter of 2015, on Dec. 15, 2014, PJM filed a temporary waiver with FERC that allowed cost-based offers to exceed the $1,000/MWh offer-price cap but capped at $1,800. On Jan. 16, 2015, FERC accepted the filling which was effective through March 31, 2015.

During the winter period from January 16 through March 31, PJM received 54 cost-based offers that were greater or equal to $1,000/MWh. All 54 cost-offers were submitted to PJM between Feb. 17 and March 6, 2015. None of the offers received were accepted, as the system conditions did not warrant running those units.[9]

Emergency Procedures

PJM did not need to take any emergency actions during the winter of 2015. At the highest peak periods, PJM needed only to issue alerts and warnings, which are designed to increase awareness and readiness for weather conditions. The cold weather alert was the most-frequently issued emergency procedure during January and February. PJM issues a cold weather alert in advance of an actual operating day when forecasted temperatures are 10 degrees Fahrenheit or lower, so market participants can prepare for the extreme weather conditions. There were 27 cold weather alerts[10] issued in January and February.

Figure 48. Emergency Procedures in January and February 2015



One of the most significant actions PJM takes in response to a cold weather alert is the deferment of scheduled transmission and generation outages and the commitment of long-lead generating units as needed. Once PJM issues a cold weather alert, it reviews scheduled outages and contacts transmission and generation owners to defer maintenance on an as-needed basis. During the winter of 2015, some transmission owners were able to defer transmission system maintenance once PJM issued the cold weather alert.

[9] Link to the IMM Informational Filing re: Offer Caps Docket EL13-31-000
http://www.monitoringanalytics.com/reports/Reports/2015/IMM_Informational_Filing_Docket_No_EL15-31-000_20150505.pdf

[10] This total includes alerts called for the entire RTO and separate regions in the RTO

PJM also reviews generating units with long lead times to assess if there is a need to commit those units to ensure availability during the peak. There were very few units called on for this reason in 2015.

PJM issued two other emergency procedures during the winter of 2015 to prepare for weather conditions. They were:

Heavy Load Voltage Schedule Warning

PJM issued a heavy load voltage schedule warning[11] for the afternoon of Jan. 7, 2015, (at 1505). This emergency procedure is designed to improve the voltage profile on the extra high voltage (345 kV and above) system and prompts transmission and generation owners to take the following actions:

- Transmission owners take all appropriate actions on distribution and sub-transmission systems in order to support system voltages. This includes energizing all available capacitor banks.
- Generation owners, working with transmission owners, increase reactive power on all units connected to the 230 kV and below voltage levels. All units connected to the 345 kV and higher voltage levels adjust reactive power accordingly.
- Generation owners report reactive capability and voltage regulator status changes to transmissions owners. There are no costs with taking this action.

As the load came down and system conditions normalized, PJM cancelled the heavy load voltage schedule warning at 2116. PJM did not need to take any further emergency action.

Manual Load Dump Warning

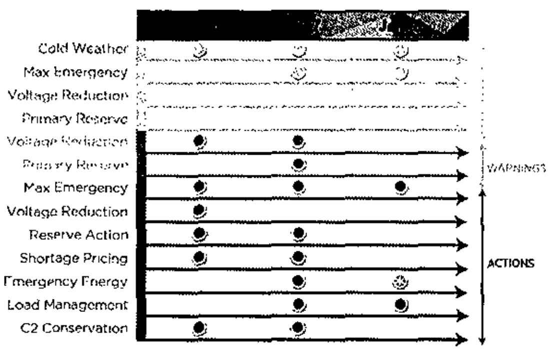
On Saturday, Feb. 21, 2015, PJM issued a manual load dump warning for the AEP transmission zone. This action was taken due to a contingency on the Cloverdale T-10, 765/345 kV transformer for the loss of Joshua Falls T-1, 165/138 kV transformer. PJM and AEP developed a contingency plan and had the Joshua Falls T-1 765/138 kV transformer relayed out of service. The manual load dump warning was in effect from 0624 to 2205 when the contingency cleared. No further action was required.

2014 Compared to 2015

The winter of 2014 was drastically different in the severity and use of emergency procedures. The chart below highlights the peak days in early January 2014 and the different types of emergency procedures that were required. They ranged from alerts to actions, including voltage reduction, emergency demand response, shortage pricing, and public appeals for conservation.

[11] Manual 13, Section 5.1.2

Figure 49. Emergency Procedures During the Polar Vortex 2014



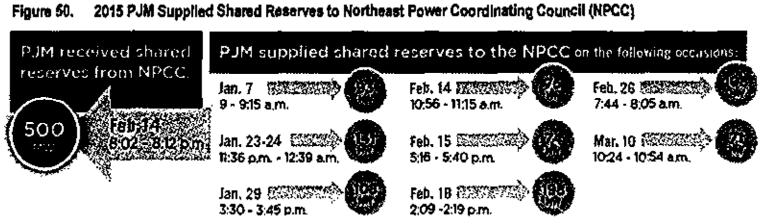
There were several reasons for the differences in number, severity, and type of emergency procedures needed in 2014 versus 2015, despite the all-time peak load being set in 2015. Those reasons include better generator performance, lower forced outages and more available generation, both internally and externally. PJM did not need to rely on emergency procedures in 2015 to reduce the load or call on more capacity; it relied on the generation available, either online or as reserves.

Shared Reserves

PJM participates in two shared reserves groups, Northeast Power Coordinating Council (NPCC) and the Virginia-Carolinas Reliability Agreement (VACAR). PJM supplies shared reserves when requested by those groups, and PJM requests shared reserves to help recover from the loss of internal PJM generation. PJM did not experience an activation of VACAR shared reserves during the winter of 2015. However, PJM activated NPCC shared reserves on one occasion for the loss of a PJM unit: On Wednesday, Feb. 14, 2015, from 2002-2012, PJM received 500 MW from NPCC.

PJM supplied shared reserves to the NPCC on the following occasions:

Figure 50. 2015 PJM Supplied Shared Reserves to Northeast Power Coordinating Council (NPCC)



Shared Reserves in 2014 v. 2015

During the peak of January 2014, PJM relied more heavily on energy imports from NPCC to meet its own energy needs. PJM received between 700 and 800 MW on two different occasions in early January 2014. On one occasion, PJM provided about 150 MW of shared reserves to NPCC.

While shared reserves were not needed with VACAR in 2015, work had been done throughout the year with VACAR's reliability coordinator, transmission operators and the reserve sharing group members to improve emergency procedures and protocols, data sharing, and communication between entities as far as expectations of roles and responsibilities. This helped to improve the overall communication and understanding of the VACAR sharing agreement, particularly when the parties were in tighter capacity situations.

Reserves

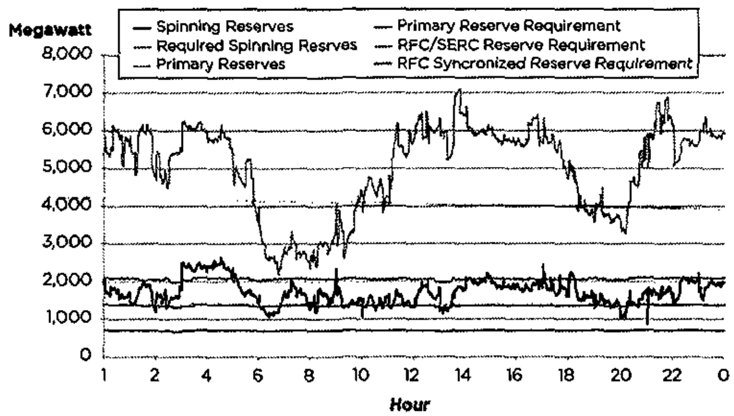
PJM maintains sufficient reserves to handle unexpected conditions on the system. Reserves are defined as capacity that is not currently being used but can be quickly available for an unexpected loss of generation or a grid contingency. To ensure the reliable operation of the grid, as well as to maintain compliance with North American Electric Reliability Corporation, ReliabilityFirst (RF) and SERC Reliability Corporation standards, PJM established a primary (contingency) reserve requirement[12] and a synchronized reserve requirement[13] as further detailed in the PJM Manual 13 - Emergency Operations. If the reserve requirements are not met, emergency procedures and shortage pricing, as indicated in PJM Manual 11 - Energy & Ancillary Services Market Operations, may be implemented.

During the winter of 2015, PJM maintained the primary (contingency) and synchronized reserves estimates above NERC/RF/SERC requirements at all times, and no emergency procedures were required. The graph below shows the primary reserve and synchronized reserves for the 24-hour period during which the new all-time winter peak was set (1200 Feb. 19–1200 Feb. 20).

[12] The Primary Reserve Requirement is capability, consisting of synchronized and non-synchronized resources, which can be converted fully into energy within 10 minutes from the request of PJM. The current PJM value for this objective is 150 percent of the largest single contingency in the RTO.

[13] The Synchronized Reserve Requirement is capability, comprised only of synchronized resources, which can be fully converted into energy within 10 minutes from the request of PJM. The current PJM value for this objective is 100 percent% of the largest single contingency in the RTO.

Figure 51. RTO Reserves



The graph shows the PJM primary and synchronized reserves estimates and their associated requirements. While the primary and synchronized reserves estimates remained above the NERC/RF/SERC requirements at all times, there were *brief periods when the synchronized reserves* estimates dipped below the PJM requirement, which is higher than the NERC/RF/SERC requirements. No emergency procedures were triggered during these transient periods as the synchronized reserves remained above the *ReliabilityFirst requirement.*

These transients occur mainly because of the look-ahead nature of the PJM Reserves Market, which schedules generation in advance to meet both the energy and system reserve requirements. In real time, as system conditions change (e.g. a brief *load spike, a sudden swing in interchange*, unit trips, failed unit start, or a unit starting later than scheduled), synchronized reserves may be used for short periods of time until additional generation is brought online or catches up. For this reason, PJM sets its reserve requirements higher than *the compliance standards dictate.*

2014 Compared To 2015

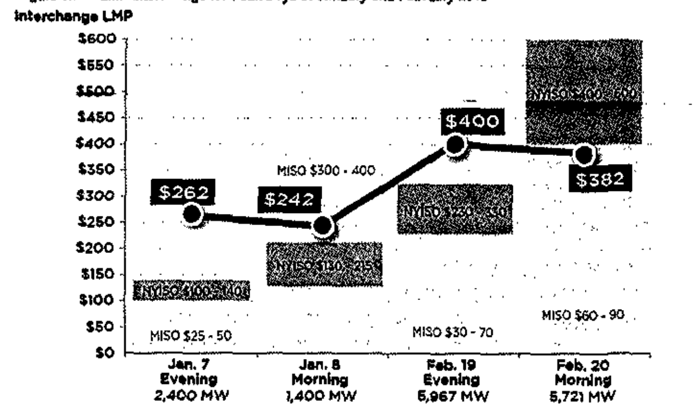
System conditions in January 2014 were significantly worse than the winter of 2015; at times, the reserves requirements were not met. As a result, PJM issued several emergency procedures in January 2014, including a primary reserve warning, voltage reduction warning and action, and a maximum emergency generation action, and triggered shortage pricing. PJM also relied on shared reserves from neighbors.

Improved generator performance was the key contributing factor to the improved reserves condition in 2015, *despite* the higher load value on Feb. 20, 2015. With 50 percent fewer outages, more generation online and more generation available than 2014, the primary and synchronized reserve requirements were met without *implementing any* emergency procedures.

Interchange

Managing interchange (energy transfers across the RTO) *was not operationally challenging or* significant for PJM on the peak winter days in 2015. Interchange for the peak days of January and February are reviewed below as well as a comparison with conditions in 2014.

Figure 52. **LMP Interchange for Peak Days of January and February 2015**



2014 Compared To 2015

Managing interchange during the peak winter days of 2015 was much less challenging than the winter of 2014. The *key difference was interchange volatility during peak hours.* While loads were high in 2015, emergency procedures, such as shortage pricing and demand response, were not needed, which had a dramatic impact on energy prices. While PJM LMPs were high compared to neighbors', the *difference in prices was not as extreme as when PJM* implements emergency procedures.

PJM's unit commitment decisions are made based on expected interchange. The lack of emergency procedures meant that *prices were more stable, more expensive internal units were not needed*, and in turn, interchange was more manageable.

By contrast, during the evening peak on Jan. 7, 2014, actual interchange into PJM increased 3,000 MW above the *forecasted interchange*, which was the result of high LMPs set by the call for emergency demand response. While interchange volatility can make operations more challenging, the impact is greater on the economics of the system.

The sudden increase in less-expensive supply, resulted in PJM operators releasing very expensive committed units, before meeting their minimum run times, causing uplift payments to the generators. PJM did not have this same issue in 2015 during the peak.

A recommendation from the winter of 2014 was to implement an interchange volatility cap that gives PJM the ability during emergency procedures to restrict the amount of interchange into PJM in advance of the operating hour. The cap gives PJM a better way to control the system economics and reduce uplift without compromising reliability.

PJM did not need to use the interchange volatility cap in 2015, as there was no real need for emergency procedures during the peak days. PJM did not experience the volatility because system prices overall were lower in 2015 and price spikes were not caused by emergency procedures – which points back to more available generation and better unit performance.

Bulk Electric System Status – Transmission

Just as PJM did in 2014, PJM prepared for 2015 winter peak operations by analyzing winter transmission outage requests to understand impacts to reliability and congestion. The PJM Peak Period Outage Scheduling Guidelines indicate transmission owners should avoid scheduling transmission outages that may result in increased risk to system reliability during the winter peak periods.[14]

For outages that transmission owners needed to schedule over the 2015 winter peak, PJM performed a detailed analysis on each outage request, under winter peak system conditions, to ensure system reliability could be maintained before approving the outage. The detailed analysis also included an assessment of congestion impacts. If there was a significant congestion impact for the outage, considering things like the amount of off-cost operations and number of units and megawatts impacted, PJM suggested that the outage be rescheduled. PJM also communicated long-duration 500 kV or above transmission outages (e.g. those scheduled for the entire season), and projected impacts to PJM members through the PJM committee process.

Prior to the 2015 winter season, PJM performed a winter operations study with the transmission owners as part of the Operations Assessment Task Force. The study results indicated the PJM RTO bulk power transmission system could be operated reliably during the 2015 winter peak load period in accordance with the operating principles and guidelines contained in the PJM manuals. The task force also performed sensitivity studies to simulate extreme system conditions that PJM might encounter during the winter season. The 2015 winter sensitivity studies included the following scenarios: gas pipeline restrictions, high winter loads close to the peak experienced in 2014, and high generation outages. The study results showed all contingencies identified in the sensitivity studies were controllable.

Key Transmission Outages in 2015: Planned and Unexpected Outages

PJM's analysis of transmission outages in this report did not directly correlate to any operational events in 2014 or 2015. However, for completeness, the impacts of the outages over the winter period are reviewed. In January and February 2015 there were 36 outages on 500 kV or above transmission lines and transformers. Twenty-six of the outages were planned outages, and 10 were unplanned emergency outages. Sixteen of the outages, mostly planned, lasted more than five days.

The three transmission outages with the most operational impacts during the winter of 2015 were:

[14] Manual 3: Transmission Operations, Section 4: Reportable Transmission Facility Outages, 4.2.6 Peak Period Outage Scheduling Guidelines

2015 Scheduled Outage:

The Dooms - Lexington 500-kV line (Sept. 8, 2014-June 15, 2015)

This scheduled outage is to rebuild the 500-kV line to accommodate Chesapeake and Yorktown generation deactivation in the Dominion control zone. The required rebuild project completion date is June 1, 2016. Originally, Chesapeake Units 3 and 4 were scheduled to deactivate in December 2015, but it was later decided to advance the deactivation to December 2014. The Dooms - Lexington project now is scheduled to be completed in December 2015. The major impact of this outage is restrictions on Bath County pump-storage hydro plant operations due to stability concerns. PJM implemented a special protection scheme (SPS)[15] to minimize the stability impact on Bath County operations during the Dooms-Lexington outage.

2015 Emergency Outages:

The Keystone #3 500/230/20-kV transformer (Nov. 3, 2014-Feb.6, 2015)

On Nov. 3, 2014, a relay operation took out of service the Keystone #3 500/230/20-kV transformer, which is located in the Pennsylvania Electric zone. The transformer remained out of service until Feb. 6, 2015. This emergency outage required PJM to increase the reserve requirement by about 400 MW to cover the potential loss of both the Keystone #1 and Keystone #2 units. The reserve requirement increased from approximately 1,300 MW to 1,700 MW. During this emergency outage, PJM also was required to monitor and control the single contingency loss of both Keystone units, the Juniata-Keystone (5004) 500-kV line and the Conemaugh-Keystone (5003) 500-kV line. This contingency restricted energy transfer into the eastern portion of the RTO and required more frequent off-cost operations, especially on the Bedington-Black Oak transfer interface.

The Black Oak-Hatfield 500-kV line Feb. 9, 2015-Feb. 12, 2015)

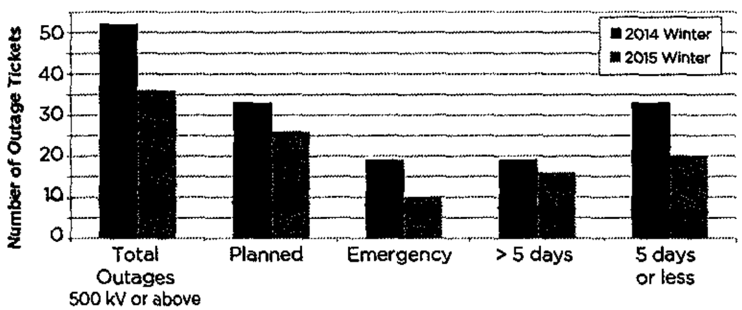
The Black Oak-Hatfield 500-kV line, located in the FirstEnergy – South control zone, was removed from service due to emergency overhead bus work at the Hatfield substation. This outage reduced energy transfer capability across the PJM footprint and required more frequent off-cost operations.

2014 Compared to 2015

There were fewer winter transmission outages of 500 kV or above in 2015 than in 2014. There were 36 outages on 500 kV or above transmission in January and February 2015, compared with 52 outages in January and February 2014. In 2014, 33 of the outages were planned outages and 19 were unplanned emergency outages. Nineteen of the outages lasted more than five days.

[15] Glossary of Terms Used in NERC Reliability Standards – SPS is an automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability. Such action may include changes in demand, generation (MW and Mvar), or system configuration to maintain system stability, acceptable voltage, or power flows.

Figure 53. Winter Peak 500 kV or above Transmission Outage Comparison for January and February, 2014 and 2015



Many of the planned outages in 2014 were to upgrade the infrastructure to support generator retirements occurring by April 2015. There were fewer of these types of outages in 2015. There were also fewer long-term outages in 2015. The reduction of long-term outages is a trend PJM anticipates continuing during future winter peak periods as *Regional Transmission* Expansion Plan (RTEP) upgrades required for generation retirements are completed.

The impact to congestion of the 2014 transmission outages with the most operational impacts was about three times greater than the congestion impact observed for the 2015 outages. The lower price of fuel contributed to this difference, as did the greater number and duration of outages in 2014.

The four 500 kV or above transmission outages with most operational impacts during the winter of 2014 include:

2014 Scheduled Outages:

Doubs-Mt. Storm 500-kV line (Sept. 3, 2013-June 3, 2014)
The Doubs-Mt. Storm 500-kV line is an internal tie-line between the Dominion and FirstEnergy-South control zones. This 500 kV or above transmission line reconstruction project was a PJM RTEP backbone project required due to aging infrastructure. The original outage schedule spanned 2012 to 2015. The approval of the requested 2014 winter outage allowed the line reconstruction work to be completed one year ahead of the original schedule. This outage reduced the energy transfer capability across the PJM footprint, causing congestion and requiring more frequent off-cost operations.

Branchburg-Ramapo 500-kV line (Feb. 7, 2014-Feb. 23, 2014)
Branchburg-Ramapo is an external tie-line between PJM and New York. Branchburg substation is located in the northern Public Service zone in New Jersey. This outage was necessary to install a new 500-kV Hopatcong substation, which is part of the Susquehanna-Roseland RTEP backbone project. This outage caused some local transmission constraints in the Public Service zone.

Bath County-Lexington 500-kV line (Feb. 2, 2014-March 21, 2014)
The Bath County-Lexington line is located in the Dominion control zone. The outage was necessary due to a

circuit breaker replacement project at the Lexington substation. This outage caused some operational restrictions on the Bath County pump storage hydro plant due to stability concerns.

Keeney AT50 500/230-kV transformer (Feb. 9, 2014-June 18, 2014)
Keeney substation is located in the Delmarva Power zone in Delaware. The four-month outage was necessary to replace the AT50 500/230-kV transformer. The outage started in February to ensure the new transformer could be ready for service before the 2014 summer peak season. The outage did not affect reliability during the peak days of 2014.

2014 Recommendations and Impacts to Operations

In May 2014, PJM published a list of recommendations stemming from the report of the winter of 2014. This is a high-level summary of the results of those recommendations and their impact on 2015 operations

ID	Category	Recommendation	Actions	Impact on 2015 Operations
1	Unit Performance	PJM, in conjunction with members, should consider the following topics and develop adjustments to improve unit performance: **1.** Review the penalties for non-performance during peak days and/or days when emergency procedures are issued for capacity emergencies **2.** Review incentives for performance during peak days **3.** Investigate a process for unit testing and preparation of resources in advance of winter operations, including testing dual-fuel capability **4.** Review generator outage rates outlined in PJM Manual 13: Emergency Operations.	• The Capacity Performance filing was developed through the Enhanced Liaison Stakeholder Committee process. PJM and stakeholders developed incentives for peak period performance as well as penalties for underperformance. The FERC has approved a one-time waiver of PJM's tariff to allow a short delay in the annual Reliability Pricing Model capacity auction for the 2018/2019 delivery year to allow the FERC to consider PJM's responses to questions from the FERC. If approved by the FERC, Capacity Performance would begin to impact units in the 2015 / 2016 transition year. • A voluntary winter testing program was developed and approved through a stakeholder process. This program identified units that had not run in more than eight weeks and made them eligible for cost-capped testing. • Manual 13-Emergency Operations was updated to reflect unit outage triggers for peak period operations.	• Heightened awareness and stakeholder engagement in discussions on improving generator performance. • Eligible units that performed the exercise had a lower magnitude of forced outages compared to those that did not test. • Manual 13 updates for Emergency Operations allowed for advanced warning to owners to stop maintenance outages during emergency operations.
2	Unit Characteristics	Work with generation owners to identify opportunities to create or improve information sharing. Consider including the following: **1.** Sharing of fuel source and emission limitations by schedule submitted and fuel limitations/certainty of supply **2.** Streamlining and standardizing the outage cause types in eDART with additional specificity that provides more insight and consider methods for	• Conducted generator survey to collect important generation data such as fuel type and inventory, dual fuel capability, and operational restrictions in PJM tools. • Enhancements to and member training about PJM's operations and markets tools to capture important, updated unit information. • Internally, completed automation of outage causes in eDART by implementing coding for frequently used outage ticket descriptions.	• This additional data provided PJM Dispatch increased understanding of unit status and flexibility in real-time. • More accurate reporting of unit status and performance improved dispatcher scheduling decisions as well as after-the-fact analysis. • Faster (next morning compared to days later in 2014) data analysis provided to Dispatch regarding unit performance which allowed for much more informed dispatcher scheduling

ID	Category	Recommendation	Actions	Impact on 2015 Operations
		validation **3.** Clarify the rules by which a generator can claim an Outside Management Control event for taking an outage	• Update the OMC guidelines posted for GADs reporting	decisions. • The streamlined outage data was aggregated for more accurate assessment of forced outage closer to real time.
3	Gas/Electric Coordination	PJM, in conjunction with stakeholders, should consider the following topics and develop appropriate industry recommendations and PJM rule changes. **1.** Investigate opportunities for better harmonization of the timing of the gas and electric operating days **2.** Consider potential market rule changes that would allow generators to better include natural gas costs in their energy or capacity market offers, including review of offer caps, and to make changes to energy market offers during the operating day **3.** Consider potential market rule changes that would allow generators to reflect fuel availability in their start-up and notification times **4.** Improve the tools and processes for two-way communication with the gas industry to enhance situational awareness and better evaluate impact to PJM generation **5.** Improve reporting of availability for units that are not committed day-ahead to include access to fuel and consider methods for validation.	In progress. Gas/electric coordination is an active discussion among PJM and stakeholders and across the energy industry. Work is in progress to address the two proposals adopted by the FERC (submitted by the North American Energy Standards Board) to revise the interstate natural gas nomination timeline and make conforming changes to standards. Most of the improvements to this area involved PJM specific business rules, tools or process changes that were developed through the PJM stakeholder process: • Generators were given some ability to change their cost offers intraday. • The offer cap was increased to $1,800 through March 31, 2015. • Procedures for communicating gas availability between generator operators and PJM operators were improved to include emphasis on use of data fields in the PJM tools. • Procedures were approved for generators to reflect gas availability and restrictions through a combination of notification time, or Parameter Limited Schedule exceptions. • In addition, PJM established an internal gas electric coordination team to provide PJM operations information and analysis to assess the impact of natural gas fuel supply on generator availability. • PJM and stakeholder operating training was conducted to review all processes, procedures, and tool changes made in	• Daily risk profile for gas-fired generation units provided to Dispatch improved scheduling decisions and enabled more informed communication with generation owners. • More informed communication with generation owners about the gas supply status as well as unit capability – from the generator survey results mentioned above – facilitated more detailed discussions about generator flexibility. • More information about generator status captured in tools ensured consistency, transparency and availability of information to PJM Operations and Markets staff. • More detailed and weekly conversations with gas pipelines provided the PJM gas/electric coordination team more insight into pipeline restrictions, durations, forecasts and overall status

ID	Category	Recommendation	Actions	Impact on 2015 Operations
			preparation for winter operations.	
4	*Fuel Limited* Resources	*For those units with fuel limitations look to:* **1.** Improve tools that allow sharing of fuel-limited details with PJM including tracking dual-fuel capability and availability **2.** *Review operator communications with respect to* fuel-limited generation commitment decisions for accuracy and consistency **3.** Confirm mechanism by which resources seek waivers for fuel emission limitations and better understand conditions under which relief may be granted	• *Conducted generator survey to collect* important generation data such as fuel type and inventory, dual fuel capability, and operational restrictions in PJM tools. • Enhancements to PJM's operations and *markets tools to capture important, updated* unit information. • Procedures for communicating gas availability between generator operators and PJM operators were improved to include *emphasis on use of data fields in the PJM* tools. • PJM and stakeholder operating training conducted to review all processes, procedures and tool changes made in *preparation for winter operations.* • Changes were made to PJM manuals (M13) and training to confirm roles and responsibilities and the procedures resources may use to seek waivers.	• *Reduced phone calls to PJM Dispatch* communicating information that was more appropriately input into the PJM tools. • More informed communication with generation owners about the fuel supply status as well as *unit capability, facilitated more detailed* discussions about generator flexibility. • More information about generator status captured in tools ensured consistency, transparency and availability of information to *PJM Operations and Markets staff.*
5	Fuel Specific Limitations	Examine difficulties experienced by generators during natural gas emergency procedures and consider: **1.** Methods to call on long lead generation based on fuel procurement limitations during extreme conditions **2.** Changes to allow adjustment of start times based on changes in fuel utilized **3.** Requirements for generation units whose primary fuel may not be natural gas but that require gas to operate	In addition to the actions taken for the gas / electric recommendation, PJM also: • Improved internal tools and processes for dispatching units with notification times that were outside of the Day-Ahead Market timeframe. • Market changes implemented to include long-lead units, committed in advance of the Day-Ahead Market because of their notification times in the Day-Ahead Market.	• PJM Dispatch had better visibility into megawatts available with notification times greater than 24 hours, which better informed scheduling decisions.
6	Energy Market Uplift	PJM, in conjunction with stakeholders, should consider the following topics and develop appropriate recommendations and PJM rule changes: **1.** Review the cost allocation of energy market uplift charges **2.** Investigate potential mechanism to allocate uplift	• In progress. The PJM Energy Market Uplift Senior Task Force (EMUSTF) worked through this issue without coming to consensus. *The EMUSTF continues to work* through business rule changes to allocate uplift.	• The EMUSTF is in progress. No recommendations have been implemented so there is no impact to operations to document.

ID	Category	Recommendation	Actions	Impact on 2015 Operations
		during emergency operations when rates are extreme **3.** Investigate methods and procedures for reducing the amount of uplift to be paid	• PJM staff also implemented internal metrics and goals to reduce overall uplift.	
7	Interregional Coordination	In order to increase situational awareness with the VACAR Reserve Sharing Group and VACAR Reliability Coordinator: **1.** Define and review PJM emergency procedures and overall communications. Review operating agreements (including VACAR Reserve Sharing Group Agreement) **2.** Include language regarding coordination of emergency procedures	• PJM worked closely with VACAR over the past year to improve the procedures with VACAR Reliability Coordinator, the VACAR transmission operators, and the VACAR Reserve Sharing Group members. • Updated and improved emergency procedures and protocols, data sharing and communication between entities and expectations of roles and responsibilities. • PJM conducts seasonal meetings with neighboring entities to share winter/summer outlooks and emergency procedures updates.	• These changes were extremely helpful for improved coordination and operations during the winter of 2015 because of consistent terminology and data use and understanding. • The seasonal meetings have led to greater understanding of actions taken during real-time operations.
8	Unit Commitment	Evaluate provisions in Manual 11 to determine where changes may be appropriate such as clarification and training regarding: **1.** *Start-up costs and cancelled dispatch provisions* in Attachment C **2.** *Switching schedules*	• In progress. Member waiver requests for gas balancing costs have been filed with the FERC; no FERC ruling has been made. • *PJM with stakeholders updated Manual 11* and improved training related to switching schedules and cancelled dispatch instructions. • Generators were given some ability to *change their cost offers intraday.* • The gas balancing waiver requests are still under review with the FERC	• More informed communication with generation owners about the fuel supply status as well as unit capability, facilitated more detailed discussions about *generator flexibility.* • More information about generator status captured in tools ensured consistency, transparency and availability of information to PJM Operations and Markets staff.
9	Voltage Reduction *Emergency* Procedure	Review the voltage reduction capabilities of transmission owners to better understand current *capabilities and determine if there are additional* requirements that need to be developed: **1.** Survey transmission owners to understand existing voltage reduction capabilities (amount, time frame, etc.) **2.** Enhance Manual 13 with specifics on Voltage Reduction Warnings for TOs without supervisory control and data acquisition (SCADA) control	• PJM worked with transmission owners to better understand their voltage reduction *capabilities. Voltage reduction plans have* been added to the PJM Dispatcher SharePoint site. • Manual 13 – Emergency Procedures was updated to specify voltage reduction expectations for those transmission owners without automated SCADA control.	• PJM did not need to invoke the voltage reduction emergency procedure during the *winter of 2015.*

ID	Category	Recommendation	Actions	Impact on 2015 Operations
10	Emergency Energy Bids	Review and enhance the tools and processes for accepting Emergency Energy Bids	• PJM updated the procedures and the Emergency Procedure tool to improve the communication of and procurement method for emergency energy bids.	• PJM did not need to use emergency procedure bids during the winter of 2015.
11	Regulation Market Rules	PJM stakeholders should consider reexamining the performance of the Regulation Market during January. Specifically: **1.** Investigate whether the division by the performance score is appropriate **2.** Investigate whether the minimum participation requirements are adequately high enough **3.** Investigate the possibility of going short regulation during system peaks	In progress. PJM is reviewing the market rules for regulation service to include performance scoring, minimum participation requirements and regulation during system peaks. PJM will take this issue to stakeholders in spring of 2015.	• The regulation problem statement is going through the stakeholder process. No recommendations have been implemented so there is no impact to operations to document.
12	External Capacity	Develop processes and tools that will: **1.** Confirm that external capacity resources either bid into the day-ahead market or submitted eDart tickets that they are unavailable **2.** Track the output of external capacity resources to ensure they are not submitting an outage into eDart and selling energy into a different market **3.** Track the real-time output of external units cleared in the day-ahead market to confirm they are meeting obligations (tag validation versus commitment) **4.** Develop ability to notify, track and confirm units that have not cleared in the day-ahead market but are recalled by PJM due to a capacity emergency such as Max Emergency	PJM updated internal procedures and tools to improve the tracking of external capacity resources.	• If required, the most up to date information on external capacity resources and contact information is captured in one place. External capacity availability was not called in the winter of 2015.
13	Communications & Procedures	Review and improve how the Emergency Procedures tool is used to communicate, both internally and externally, and develop solutions to address the following topics: **1.** Consider adjustments to the roles and responsibilities for communications during emergency procedures	• PJM developed procedures and implemented tool enhancements to improve how the Emergency Procedures tool is used to communicate both internally and externally with stakeholders. • PJM improved internal support procedures during operational events to ensure clear roles and responsibilities for	• During the winter peaks, PJM operations was able to quickly staff the operational readiness team to provide Dispatch the extra analysis and support required.

ID	Category	Recommendation	Actions	Impact on 2015 Operations
		2. Refine training to reinforce processes and tools	communications. • These procedures were developed during the winter of 2014, drilled during the 2014 summer and winter emergency procedure drills. • These changes improved operations in the winter of 2015.	
14	Public Appeals	In order to better implement and use public appeals for conservation, PJM should: **1.** Evaluate and consider the impact of calls for conservation and investigate where or how to use the data **2.** Improve process for public notification during emergency procedures (C1/C2) **3.** Review triggers for public notifications and associated transmittal protocols **4.** Review both the content and processes for public appeals in Manual 13	• PJM reviewed the use of public appeals for conservation and updated the procedures and details in Manual 13, Attachment A. • PJM continues to look for ways to quantify the impacts of calls for consumer conservation for future operations.	• PJM did not need to use these procedures in the winter of 2015.

2015 Recommendations and Lessons Learned

The recommendations identified in 2015 are a continuation of some recommendations identified in 2014 as well as some new recommendations.

ID	Category	Recommendation	Status
1	*Capacity Performance*	*Continue with the implementation of the Capacity Performance proposal to address* resource performance incentives on a sustained basis.	*On May 13, 2015, PJM answers protests regarding PJM's* April 10 response to FERC's March 31 Deficiency Notice.
2	Gas / Electric Coordination	Continue to improve coordination between the gas and electric industries: 1. Based on the FERC's Final Rule in Docket No. RM14-2-000, Coordination of the Scheduling Processes of Interstate Natural Gas Pipelines and Public Utilities, implement changes to better align the scheduling processes. A consideration could be moving the times of the Day-Ahead Market. 2. Offer even more flexibility in changing unit offers during the electric day, as has been discussed in the Gas Unit Commitment Coordination working group. 3. Improve transparency of generation within gas local distribution companies.	PJM has 90 days from Federal Register publication of the April 16, 2015, Final Rule to respond regarding how it intends to meet the requirements.
3	Generator Operational Parameters	Continue to improve the ability for generators to communicate operational parameters to PJM. 1. Improve the ability for PJM tools (e.g. eDART, eMKT, DMT) to better capture and log generator flexibility and unit status information for use in real-time operations as well as after-the-fact analysis. 2. Improve PJM processes (e.g. PLS exception process) to review and assess generator parameters, particularly when they may differ from financial or settlements parameters.	PJM members recently proposed a problem statement to better address generator offer flexibility.
4	Cold Weather Unit Preparation	Build upon the success of the cold weather unit exercise and preparation checklist to improve the value while balancing the costs. Consider: 1. Modifying the criteria for eligibility 2. Refining the testing conditions and timeframe	PJM is discussing next steps for Cold Weather Preparation in the Operating Committee.
5	Energy Market Uplift Reduction	Continue to investigate methods and procedures for reducing the amount of uplift to be paid.	Through the existing Energy Market Uplift Senior Task Force, PJM and its stakeholders continue to work on solutions to reduce uplift.

Appendix

Appendix 1: Capacity Performance

Capacity Performance, currently under consideration by the FERC, would create stronger performance incentives for committed capacity resources. The incentives would ensure more operational availability and flexibility during peak power system conditions.

Generator performance issues during peak conditions in the winter of 2014 identified the need for a more robust capacity product to ensure system reliability. Capacity Performance addresses issues of generation fuel security, performance, winter peak operations and operational characteristics of resources needed to ensure that system reliability will be maintained throughout the current industry transformation and beyond.

While generator performance improved during the winter of 2015, many of the improvements were voluntary, such as winter testing and preparation. Improvements also were a result of lower fuel prices.

To ensure performance, a Capacity Performance resource must deliver energy in all hours if scheduled by PJM, or if self-scheduled, when PJM declares a Hot or Cold Weather Alert and/or a Maximum Emergency Generation Alert.

Had the Capacity Performance Construct Been in Place

PJM provides the following high-level information relative to the winter of 2015 to help understand impacts of the Capacity Performance construct had it been in place during this winter.

A cold weather alert was issued on 19 days during January and February 2015.

Based on the filed Capacity Performance rules for a unit's total start time (notification time plus start time), a unit must be available for scheduling with a maximum of a 14-hour total start time. Had the Capacity Performance rules been in place for the winter of 2015, based on current data:

- Approximately 1,123 units would have had total start times of 14 hours or less.
- Approximately 162 units would have had total start times greater than 14 hours. The impact of this could have been more units self-scheduling, units starting themselves earlier, unit parameter changes or potential forfeiture of uplift payments.

There were five hours that would have qualified as Performance Assessment Hours under the currently filed version of Capacity Performance[16]. On Feb. 21, 2015, PJM issued a manual load dump warning in the AEP transmission zone that was effective from 1842 to 2205. This action was taken due to a contingency on the Cloverdale T-10.

[16] *Performance Assessment Hours are delineated by* PJM's declaration of Emergency Actions, which are defined as, any emergency action for locational or system-wide capacity shortages that either utilizes pre-emergency mandatory load management reductions or other emergency capacity, or initiates a more severe action including, but not limited to, a Voltage Reduction Warning, Voltage Reduction Action, Manual Load Dump Warning or Manual Load Dump Action.

765/345 kV transformer for the loss of the Joshua Falls T-1, 165/138 kV transformer because PJM would have required a reduction in load to control the facility post-contingency.

PJM may issue a manual load dump warning in all or a portion of the footprint for two primary reasons.

1) If there is a system-wide capacity shortage such that either the primary reserve quantity is less than the largest single generator contingency, or, the loss of a transmission facility jeopardizes reliable operations after all possible measures are taken to increase reserves, PJM will issue a manual load dump warning to notify members that a manual load dump action may be necessary to maintain reliability.

2) If there is a transmission facility that is greater than 230 kV that cannot be controlled post-contingency after without a reduction in load in the affected area after all other measures are taken, PJM will issue a manual load dump warning in particular transmission zones that will relieve the overloaded facility.

Because the manual load dump warning was issued only in the AEP zone due to the post-contingency overload, only capacity resources in the AEP zone would have been eligible for over-performance credits or under-performance charges under the Capacity Performance rules. Under Capacity Performance, the under-performance charges could have been assessed against any units in the zone on a forced outage or units not following PJM dispatch instructions.

Appendix 2: Typical Preparation for an Operating Day

This section provides context and details about the processes, tools, and timelines for the operational actions taken prior to an operating day.

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

In the winter of 2015, PJM began conducting weekly calls with six interstate pipelines. The pipeline discussions revolved around pipelines status and how it could impact the natural gas supply to PJM generation.

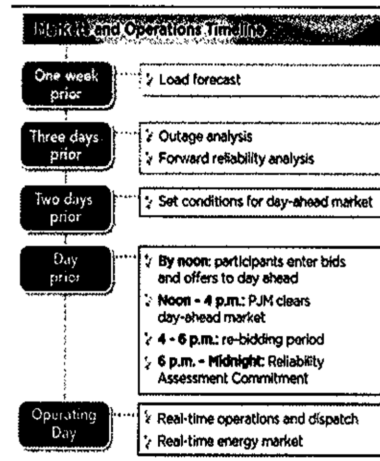
Approximately three days prior to an operating day, PJM's planning becomes more detailed. To prepare for expected conditions during the operating day, PJM staff begins studying transmission and generator outages, load forecasts, natural gas supply, weather and other expected factors. The expected system conditions dictate the amount of preparation required. PJM analyzes, communicates, studies and revises its analysis and operating strategy multiple times as needed as more information about an operating day becomes available. For example, PJM may request that transmission outages in progress be restored as quickly as possible to prepare for extreme weather conditions and then will update the analysis to reflect these conditions.

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

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

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

Figure 54. Market and Operations Timeline



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

On a typical winter day, PJM's peak load for the day averages approximately 106,000 MW. Beyond the expected ~~demand, PJM also will commit approximately~~ 4,000 MW of reserves [17]. Leading up to and throughout the operating day, PJM examines updated information and system conditions and acts to continually balance generation with the need for electricity and maintain adequate reserves to prepare for unexpected issues. PJM manages changes from day-ahead commitments and schedules in the Real-Time Energy Market using the offers from generation resources and demand resources to jointly minimize the cost of energy and reserves while maintaining energy balance and respecting the limits of the transmission system. Any differences in generation or demand from the Day-Ahead Energy Market commitments are cleared at price levels determined by the Real-Time Energy Market.

Appendix 3: Locational Marginal Pricing – Marginal Unit Type Intervals

Figure 55. Type of Marginal Resources in the Day-Ahead Energy Market

	Generation	Dispatchable Transaction	Up-to Congestion Transaction	Decrement Bid	Increment Offer	Price-Sensitive Demand
Jan	14.2%	0.5%	71.9%	6.9%	6.3%	0.1%
Feb	13.1%	0.4%	73.1%	7.7%	5.6%	0.1%
Mar*	10.2%	0.6%	73.5%	10.7%	5.1%	0.0%

* March 1 through March 11

[17] To provide a sense of scale, the combination would be enough power to serve about 91,200,000 homes. (One megawatt is enough power to serve about *800 homes. A typical large nuclear power plant provides 1,000 MW of energy.)*

Appendix 4: Natural Gas System Critical Notices

In addition to the individual gas pipeline websites listed below, PJM also has a tool which provides a summary of the Critical Notices. Please see the following website on pjm.com: https://gaspipe.pjm.com/gaspipe/pages/dashboard.jsf

Pipeline	Website
Columbia	http://www.columbiapipeinfo.com/infopost/
Dominion	http://escript.dom.com/jsp/info_post.jsp?&company=dti#
Texas Eastern	https://infopost.spectraenergy.com/infopost/TEHome.asp?pipe=TE&mode=1
Natural Gas Pipeline of America	http://pipeline.kindermorgan.com/infoposting/notices.aspx?type=RECENT
~~ANR~~	~~http://anrebb.transcanada.com/~~
Tennessee Gas	http://webapps.elpaso.com/PortalUI/DefaultKM.aspx?TSP=TGPD
Nicor	https://www.nicorgas.com/
National Fuel	http://sbsprd2.natfuel.com/supply/infopost/infopost_frame.htm

Appendix 5: Emergency Procedures

Please see Emergency Procedures page on pjm.com for a description of the message and further details.

https://emergencyprocedures.pjm.com/ep/pages/dashboard.jsf

Message ID	Start Time	End Time	Region
94390	3/4/2015 - 8:53	3/6/2015-23:31	Western - Region
94389	3/4/2015 - 8:44	3/5/2015 - 23:30	ComEd - Control Zone
94238	2/24/2015 – 9:45	2/27/2015 – 23:53	Western - Region
94214	2/23/2015 – 12:55	2/27/2015 – 3:17	DLCO - Control Zone ATSI - Control Zone
94190	2/22/2015 – 10:25	2/24/2015 – 23:56	PJM - RTO
94161	2/20/2015 – 9:01	2/24/2015 – 0:00	Western - Region
94071	2/17/2015 - 9:11	2/21/2015 – 0:44	PJM - RTO
94058	2/16/2015 – 9:08	2/20/2015 – 0:41	PJM - RTO
94057	2/16/2015 – 9:08	2/19/2015 – 0:19	AEP - Control Zone AP - Control Zone ComEd - Control Zone DAYTON - Control Zone DLCO - Control Zone Western – Region ATSI - Control Zone CPP - Control Zone DEOK - Control Zone EKPC - Control Zone
93973	2/12/2015 – 8:31	2/18/2015 – 0:00	Mid-Atlantic - Region
93972	2/12/2015 – 8:31	2/17/2015 – 0:01	PJM - RTO
93971	2/12/2015 – 8:29	2/16/2015 – 0:00	Mid-Atlantic – Region Western - Region
93970	2/12/2015 – 8:21	2/15/2015 – 0:00	AEP - Control Zone AP - Control Zone ComEd - Control Zone

Message ID	Start Time	End Time	Region
			DAYTON - Control Zone DLCO - Control Zone ATSI - Control Zone CPP - Control Zone DEOK - Control Zone EKPC - Control Zone
93969	2/12/2015 – 8:17	2/14/2015 – 0:50	AP - Control Zone DLCO - Control Zone ATSI - Control Zone
93849	2/5/2015 – 12:10	2/6/2015 – 11:53	Mid-Atlantic - Region
93829	2/4/2015 – 10:02	2/5/2015 – 23:19	ComEd - Control Zone DLCO - Control Zone
93811	1/30/2015 – 15:21	2/1/2015 – 19:48	PJM - RTO
93810	1/30/2015 – 10:24	2/1/2015 – 19:48	PJM - RTO
93809	1/30/2015 – 10:21	1/30/2015 – 15:39	PJM - RTO
93649	1/14/2015 -10:02	1/15/2015 – 11:30	ATSI - Control Zone
93630	1/13/2015 – 10:06	1/14/2015 – 9:55	Western - Region
93629	1/13/2015 – 10:06	1/14/2015 – 23:59	Western - Region
93580	1/8/2015 – 8:21	1/11/2015 – 0:58	Western - Region
93578	1/8/2015 – 8:21	1/10/2015 - 4:36	Western - Region
93551	1/7/2015 – 9:15	1/8/2015 - 23:43	PJM - RTO
93530	1/6/2015 – 7:44	1/7/2015 - 9:15	AEP - Control Zone AP - Control Zone ComEd - Control Zone DAYTON - Control Zone DLCO - Control Zone Western – Region ATSI - Control Zone CPP - Control Zone DEOK - Control Zone EKPC - Control Zone
93529	1/6/2015 – 7:43	1/8/2015 - 0:35	AEP - Control Zone AP - Control Zone ComEd - Control Zone DAYTON - Control Zone DLCO - Control Zone Western – Region ATSI - Control Zone CPP - Control Zone DEOK - Control Zone EKPC - Control Zone
93509	1/5/2015 – 9:05	1/7/2015 – 0:05	ComEd - Control Zone
93489	1/4/2015 – 9:05	1/6/2015 – 0:12	ComEd - Control Zone

Appendix 6: Cold Weather Operational Exercise

As described in the 2015 Generator Performance section, PJM also implemented the 2014 recommendation to develop a cold weather exercise designed to give generators that run infrequently or have dual fuel capability the opportunity to test their units prior to the onset of cold weather. In total, 168 units with a total of amount of 9,919 MW (11,054 MW ICAP) performed the cold weather generation operational exercise.

Total Units Exercised		Success Rate (By Unit Count)
168 Units	9,919 MW	94%

A summary of eligible units and their participation is below. Of the 214 units initially eligible and interested in participating in the exercise, 46 units were unable to participate either because of warm weather on the day scheduled or subsequent ineligibility because they ran in real-time during the cold days during the month of December 2014. The final number of units exercised this test was 168.

Figure 56. 2014 Winter Exercise Participation Unit Counts

	Total Eligible Units As Of Dec. 1, 2014	Eligible Units That Wanted To Participate	Eligible Units That Declined To Participate	Eligible Units That Did Not Respond
Unit Count	443	214	210	19
Total ICAP MW	45,604	14,558	29,598	1,448

Figure 57. Exercise results were analyzed and the success / failure analysis

	[illegible]		Failures		Success						[illegible]	[illegible]
	[illegible]	[illegible]	Failures by Unit Count	Failures by MW	Success		[illegible]		Total Success			
					[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]		
Total	168	9,919	10	397	142	8,541	16	981	158	9,522	94%	96%

26 units out of 168 units experienced initial failures, or failed to complete the exercise ('Failures by Unit Count + Initial Failure ; Success by Unit Count) 16 (Initial Failure; Success by Unit Count) of those 26 units, were able to correct the issue and subsequently successfully completed the exercise. The total unit success rate of 94 percent includes these corrected failures. Causes of failures were also analyzed and are summarized below. The percentages are based on a total of 26 exercise failures. The types of failures include control system, liquid handling, supporting diesel, and electrical failures. Examples of "Miscellaneous" failures include: failed to fire, water injection problems, failed to synchronize, high temperature, vibration, lube oil leak, and thermocouple failures. The majority of units that failed were repaired and retested on the same day or within the same week. Several of the units that failed asked for a retest later during the program. Many other generation owners elected to self-schedule shortly after the repairs were made, which means they were compensated for the MWs but not for the test.

Figure 58. Cold Weather Operational Exercise – Causes of Failures