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Final Report on Electricity Supply Conditions in New England During the January 14 - 16, 2004 "Cold Snap"

ISO New England Inc.

Market Monitoring Department

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FOREWORD

The Final Report on Electricity Supply Conditions in New England during the January 14 - 16, 2004 "Cold Snap" includes revisions and clarifications based on further review of the Cold Snap following the publication of an Interim Report in May 2004. A separate Management Response to the Final Report provides action steps to address each of the recommendations in the Final Report. ISO New England acknowledges the significant progress of the region's stakeholders to improve power system reliability for winter 2004/2005 and beyond.

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I. Executive Summary

In January 2004, New England experienced unusually severe weather and electricity demand conditions. In particular, extremely low temperatures and very high demand for electricity combined with tight conditions in the natural gas markets to stress-test the electricity system in New England during January 14 - 16, 2004 ("January 2004 Cold Snap" or the "Report Period"). This prompted concern by ISO New England Inc. (the "ISO") about market and system performance during the severe weather conditions, and a desire to improve market rules and operations as necessary to increase market efficiency and system reliability, especially during similar events in the future. These concerns were mirrored by stakeholders.

The Market Monitoring Department of the ISO performed a detailed investigation of the events and concluded that given the extreme circumstances during the January 2004 Cold Snap, New England's electricity system performed well in most respects. Despite record winter peak electricity demand, many unexpected generator outages, and projected capacity deficiencies, the ISO was able to avoid interruptions of electrical supply. Furthermore, the ISO's Market Monitoring Department has found no evidence of anti-competitive behavior by generators.

The January 2004 Cold Snap did, however, highlight vulnerabilities of the New England bulk power system, especially to capacity limitations of the natural gas pipeline network. While the gas system was able to meet the demand of its firm customers, many generators have interruptible service and thus have limited rights to delivery under tight conditions. While there was ample gas supply beyond the Northeast, the availability of gas transportation for non-firm customers within New England was a limiting factor and a root cause of both high gas prices and gas unit unavailability. Additionally, some generators with firm gas transportation engaged in fuel arbitrage, selling their firm gas supplies. This report makes several recommendations to address these vulnerabilities.

During the Report Period, New England experienced the coldest temperature at the time of the winter electricity demand peak in the last 20 years. The 2004 winter peak was well above the weather-normalized forecast of winter peak loads,[1] with a record peak hour demand of 22,817 megawatts (MW) on January 15, 2004. Load remained high by historical standards throughout the Report Period. While the January 2004 Cold Snap did not ultimately result in interruption of electrical demand, it did push the electricity system in New England close to its limits. Record high winter electricity demand coincided with the unavailability of substantial quantities of generating capacity, much of which was gas-fired. This combination of factors resulted in a deficiency of the contingency reserve margin the ISO normally maintains to ensure the reliability of the system.

New England's dependence on natural gas for electric power generation can cause acute problems during periods of extremely cold temperatures. Most of the new electric generation capacity added in New England since 1990 is fueled by natural gas, and currently over 30 percent of New England's winter capacity consists of gas-only units. Additionally, about 20 percent of New England's generation is gas-capable dual-fuel units. Extremely cold weather greatly increases the demand for natural gas in two ways: First, cold temperatures increase the demand for natural gas used for heating. Second, because large quantities of generation in New England depend on gas, the increased demand for electricity associated with cold weather

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[1] The weather-normalized forecast of winter peak loads for 2003/2004 was projected to be 22,085 MW.

requires more gas. Any shortfall in the availability of natural gas for power producers can cause a shortfall in power supply.

During the Report Period, the ISO received numerous reports of gas interruptions[2] from generating units, as well as reports of operational problems from units of all fuel types, including frozen fuel lines, air intakes clogged by ice, and a variety of other problems associated with the cold weather. As a result, at times during the Report Period the ISO faced projected capacity deficiencies. With extremely harsh and life-threatening weather conditions projected to continue, the ISO took various steps to address potential capacity deficiency problems. These included activating the ISO demand response program; directing the return to service of all units previously granted economic outages; canceling all work on critical transmission lines, generators, and communications links; arranging for transmission owners to staff key substations; implementing the steps of its emergency operating procedures; and notifying the public about the power supply situation.

The ISO's Market Monitoring Department has not found evidence of anti-competitive behavior associated with the January 2004 Cold Snap. It has closely reviewed generator offers during the Report Period and observed substantial increases in offers from gas-fired units. These increases are consistent with events in the gas market. The Report Period was characterized by high and extremely volatile gas prices, gas transportation limitations, thin gas liquidity, weather-related operating risks and outages, and other uncertainties. Hence, generators faced a

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[2] As discussed in greater detail throughout this report, many merchant generators rely on interruptible gas transmission capacity for their operation. In periods of peak demand, such as those faced during the Report Period, many of those generators were, indeed, interrupted pursuant to the terms of their contract. For the purposes of this analysis, the term "interruption" is defined as those instances where a merchant was unable to secure natural gas for purposes of power generation.

substantially more complex purchase environment than under normal conditions in addition to gas price increases. Electricity prices were generally below the variable costs, or break-even levels, for efficient gas-fired generators buying gas in the spot market. Under the conditions present during the Report Period, the rational economic choice even for a generator with a firm gas contract would typically be to sell gas for a certain high profit rather than to generate electricity for a potentially smaller and less certain profit. This behavior fosters efficient resource allocation and thus is permitted under the market rules. Evidence shows that some generators with firm gas arrangements did sell their fuel and transportation. Generally gas sold by generators went to other generators or local gas distribution companies, where it was most likely used for heating homes and businesses.

Analysis of the markets during the Report Period shows competitive benchmark results similar to those calculated during normal conditions, despite low Residual Supply Indices ("RSI").[3] The majority of load serving entities in New England, and the ultimate consumers of electricity, were insulated from electricity spot market prices during the period because of high levels of forward contracting. Analyses by the ISO's Market Monitoring Department specifically addressing both economic and physical withholding during the Report Period reveal no evidence of anti-competitive behavior. The ISO's Market Monitoring Department has concluded that generator offer behavior during the Report Period was generally consistent with expected competitive behavior given the market conditions. While offers from gas-fired units increased sharply, they were consistent with the underlying gas market.

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[3] The RSI measures the percentage of required capacity available if the largest generation owner is excluded. An RSI above 100 means that all energy and reserve needs can be met without the largest supplier, and reduces concerns about the possibility of the exercise of market power.

The ISO's Market Monitoring Department closely examined units that requested economic outages. Given that these units were not likely to have cleared in the day-ahead energy market or purchased day-ahead gas, and based on other information available to the ISO, economic outages granted by the ISO do not appear to have exacerbated reliability issues or resulted in increased electricity clearing prices. Sale of firm gas was unlikely to have been influenced by the granting of economic outages.

Due primarily to reductions in the capacity of units out of service due to fuel unavailability, gas unit availability improved each day of the Cold Snap despite decreasing temperatures. This suggests that the gas and electric markets were better able jointly to allocate fuel and maximize resource utilization as experience with the extreme conditions increased. Pivotal suppliers[4] had a greater proportion of generation available than non-pivotal suppliers, suggesting that the owners with the greatest incentive to physically withhold were not withholding. Dual fuel units experienced much lower unavailability than did gas-fired units.

This report provides many recommendations for improving the functioning of the New England electricity markets. The most important of these are:

- Improve ISO understanding of and coordination with the gas industry.
- Evaluate ways to better coordinate gas and electric market timing to allow maximum utilization of gas system infrastructure.
- Provide adequate market incentives and signals to ensure unit availability during critical periods of high electricity demand.
- Open a regional dialogue with regulators and electricity stakeholders about barriers to installation and use of dual-fuel capability.

[4] A pivotal supplier is a generation owner for whom at least a portion of their generation capacity is required to meet either system energy needs or reserve requirements.

Other recommendations include revising and clarifying economic outage approval criteria, reviewing forecasting assumptions of forced outages during extremely cold weather, updating the New England Gas Study to reflect the lessons learned from the January 2004 Cold Snap, evaluating increased supply offer flexibility, and changing or clarifying certain ISO procedures and protocols to improve ISO responses and actions during similar events.

II. Introduction: Background Information on the New England Bulk Power System, Gas System, and Summary of January 2004 Cold Snap Events

On January 14, 15, and 16, 2004 - the Report Period - severely cold temperatures affected the greater Northeast, and New England in particular, causing unprecedented winter demand on the region's electricity and gas systems. Electricity demand on January 14, Hour Ending 6:00 p.m., set a new record winter peak of 22,450 MW, which was superseded the next day by a new winter record of 22,817 MW during Hour Ending 7:00 p.m. On January 14, the ISO invoked Operating Procedure No. 4 ("OP4").[5] During the peak hour on that day, the hourly real-time price in the electricity market rose to nearly $1,000/MWh. In addition, day-ahead gas prices at a number of locations on the New England gas system increased to nearly ten times their normal levels.

This report provides a detailed summary of events, evaluates the performance of the electricity system, and examines generator behavior during the Report Period. In particular, it addresses questions that have been raised about whether generators' behavior complied with existing market rules, and whether physical or economic withholding of generation took place. The report reviews electricity system, weather, gas market, and gas transportation conditions and analyzes prices and behavior in the electricity market. The report also evaluates whether mitigation authority was applicable under the market rules. The report makes recommendations for short-term and long-term actions to be undertaken by the ISO to reduce the likelihood of recurring capacity shortages of the kind faced during the Report Period.

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[5] Operating Procedure No. 4 ("OP4") specifies 16 actions (including public notifications) that can be taken to address an imminent or actual operating reserve shortage (providing a total potential load relief of 3,000 to 4,000 MW). The occasional use of OP4 is an implicit part of the reliability design of the bulk power system.

A brief overview of New England's power system operations, wholesale electricity market, and natural gas markets provides context for the narrative of events and analysis that follow.[6]

Power System Operations

- The ISO uses detailed operating procedures and guidelines to operate the bulk power system in New England, and monitors and controls the real-time generation and flow of electricity on a continuous basis from its control center in Holyoke, Massachusetts.

- Satellite control centers, operated by transmission-owning companies, assist the ISO in its operating mission.

- The bulk electric power system in New England comprises more than 8,000 miles of high-voltage transmission lines and several hundred generating facilities. New England is interconnected with New Brunswick, Quebec, and New York.

- New England is a part of the Northeast Power Coordinating Council ("NPCC")[7] region of the North American Electric Reliability Council ("NERC").[8]

- The New England Power Pool ("NEPOOL")[9] has adopted the "one day in ten years" criterion for resource adequacy, meaning that the power system is designed in a manner that the likelihood of having to disconnect non-interruptible customers (based on a generation shortage) occurs on average no more than one day in ten years.

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[6] The ISO has provided more detailed background information in the following Appendices: (A) an overview of the manner in which the New England bulk power system is operated; (B) a brief discussion of the operation of the relevant electricity markets; (C) an overview of the New England natural gas markets and transportation, and increases in gas-fired generation; (D) a discussion of gas arbitrage; (E) a review of a similar extreme weather event in PJM in 1994; (F), a review of demand response; and (G) a detailed account of the events in the gas markets, January 7-17, 2004.

[7] NPCC's mission is to promote the reliable and efficient operation of the interconnected bulk power systems in northeastern North America through the establishment of criteria, coordination of system planning, design and operations, and assessment of compliance with such criteria. In the development of reliability criteria, NPCC, to the extent possible, facilitates attainment of fair, effective, and efficient competitive electric markets. *See* http://www.npcc.org.

[8] NERC's mission is to ensure that the bulk electric system in North America is reliable, adequate, and secure. Since its formation in 1968, NERC has operated successfully as a voluntary organization, relying on reciprocity, peer pressure and the mutual self-interest of all those involved. *See* http://www.nerc.com.

[9] NEPOOL was created in 1971, integrating the majority of New England's utilities and municipal systems, establishing a central dispatch system, and enhancing the region's overall system reliability. In 1996, the Federal Energy Regulatory Commission (FERC) deregulated portions of the industry, which changed NEPOOL's role and led to the creation of the ISO.

- In operating the system, the ISO continuously seeks to maintain operating reserves at levels required by NERC and NPCC, representing megawatts of generation that can be called on to produce electricity at a given time. Where operating reserves are tight (due, for example, to an unusually high number of units being out of service or an unusually high electricity demand due to extremely hot or cold weather), the ISO uses emergency operating procedures, including OP4.

New England's Wholesale Electricity Market

- The ISO operates markets for wholesale electric energy, regulation, and installed capacity ("ICAP"). In these markets, generators and other suppliers offer energy, and buyers submit bids to purchase energy, with a $1,000/MWh bid cap. The markets also accommodate direct bilateral energy contracts between sellers and buyers. The ISO develops a least-cost, security-constrained dispatch based on the offers and bids, and the system's transmission characteristics. The price paid to generators and the price paid by load varies by the location in New England at which the power is generated and consumed.

- The monthly ICAP market helps ensure the availability of sufficient generation and reserves. Generating units that are selected for payment as "ICAP Units" are required to obtain advance approval from the ISO to schedule any non-emergency outages and must offer their full capacity into the energy market. The ISO's Market Monitoring Department evaluates the supply offers of ICAP units for evidence of physical or economic withholding and has the authority to substitute a lower offer in certain instances.

- Once a unit is scheduled to run, it must do so unless permitted or required by the ISO to change its schedule, or if the unit experiences a forced outage. Otherwise, the generator is subject to penalties for failure to perform as dispatched.

- In addition to maintenance outages, a generator can request ISO permission to take an "economic outage." Economic outage requests are occasioned by a generator's belief that it will not be able to recover its costs of operation, including opportunity costs, by running in the electricity market. For example, if the cost of natural gas would require that a generator submit an energy offer exceeding $1000/MWh to recover its costs, the generator could request an economic outage because supply offers cannot exceed $1,000/MWh. The ISO may reject an economic outage request if it would cause an actual or projected capacity deficiency, reserve violation, or transmission problem.

New England's Natural Gas Markets

- Gas supplies for New England generators are primarily sourced from producing fields in the U.S. Gulf Coast, Western Canada, and the Canadian Maritime Provinces (offshore Nova Scotia). Distrigas also imports Liquefied Natural Gas ("LNG") at a large terminal in Everett, Massachusetts for re-gasification and delivery into the Algonquin and Tennessee pipelines as well as directly to the KeySpan distribution system, the largest gas utility in New England. Distrigas also supplies LNG to the New Mystic Station in Everett and to various LNG gas utility satellite tanks throughout New England via truck.

- Gas transportation by pipeline is generally purchased separately from the gas commodity, although gas marketers may re-bundle the commodity and transportation, and gas transportation rights may be required for certain commodity purchases. Each of the interstate pipelines serving New England has its own scheduling system and receives monthly and daily nominations from its customers (called "shippers") for the amounts of transportation they wish to schedule under their transportation contracts. The scheduling systems among New England pipelines are synchronized in accord with North American Energy Standards Board ("NAESB") standards. A range of transportation service options is available from the pipeline. Primary firm is the highest quality and most expensive. Secondary firm is subordinate to primary firm transportation and is scheduled after all primary firm transportation requests are fulfilled but before any interruptible transportation is scheduled. The last general category of pipeline transportation is interruptible transportation. It is scheduled after all firm transportation requests have been fulfilled and based on the availability of leftover pipeline capacity to accommodate additional requests for service. Many generators in New England use secondary firm transportation and interruptible transportation service for gas delivery.

- Firm capacity determines the size of a gas pipeline system. Interruptible capacity is that which is available only because the holders of firm capacity are not making use of that capacity. Pipelines are generally not designed to meet any demand for capacity beyond that which is firm. Pipelines have some discretion to build extra facilities (*e.g.* over-sizing a pipe) when they construct new facilities. However, typically pipelines do not wish to bear the economic uncertainty associated with such speculative capital expenditures. Pipelines are generally at risk for 100% of any excess capacity constructed.

- The market for natural gas comprises three segments: a long-term forward market, a short-term forward market and an intra-day market. The long-term market consists of seasonal, annual, or multi-year contracts. The short-term market typically involves monthly, weekly, or daily purchases and includes smaller quantities released by long-term purchasers in the week or days ahead of delivery, as well as the day-ahead market. The intra-day market involves commodity quantities and transportation made available after the day-ahead gas scheduling process. This is typically a small proportion of total gas consumed.

- Different types of users vary in their transportation entitlements, or lack thereof, and the sources and uses of gas. Local Distribution Companies ("LDCs")[10] have an obligation to serve, and therefore generally have primary firm entitlements to ensure continuous deliverability during harsh weather conditions. Manufacturing processes typically have steady demand, while heating and cooling uses vary with temperature. Generating plants that do not have long-term power sales contracts or thermal hosts requiring continuous steam production run only if their electricity supply offers are accepted on a day-to-day basis. Gas-fired generating plants are therefore less likely to enter into firm gas supply or transportation

[10] A Local Distribution Company is the company responsible for the local distribution of natural gas.

arrangements than are users with more stable usage patterns. The gas contracting patterns of generators vary within New England.

- LDCs are responsible for assuring the reliable delivery of retail gas to end customers. LDCs recover the fixed and variable costs of firm transportation from their customers. In addition, the LDCs recover the gas commodity costs from their customers. LDCs also build local peaking facilities to meet their obligation to serve. The gas customers of the LDCs provide the economic assurance for the LDC to contract for long-term firm services from the gas marketplace and build peaking facilities.

- Interstate pipelines receive a FERC regulated rate of return based upon their costs to provide services. A pipeline's rates are a function of its costs in addition to a return on equity. Pipelines periodically file with the FERC for the authority to establish new rates. However, the requirement that pipelines come in for periodic rate reviews varies from pipe to pipe and many have no filing requirements.

- New England's gas market is part of an integrated North American gas marketplace which is governed by the same gas day timelines. The entire North American gas marketplace utilizes the same gas day, in contrast with the electric industry which utilizes a regional calendar day based on the local time zone.

- Over the last four years, the ISO, through Levitan and Associates, Inc. ("Levitan"), conducted several studies of the New England interstate pipeline system's ability to serve the simultaneous requirements of the core LDC consumers and rapidly increasing demand from the electricity generating market. The studies analyzed interstate gas deliveries to merchant power plants on peak electric and peak gas days during the winter heating season using pressure/flow simulation models of New England's interstate gas pipelines. In addition, the studies evaluated several postulated gas and electric system contingencies.

    - The first study, completed in early 2001, indicated that about 3,230 MW of gas-fired generation would be "at-risk" of gas unavailability in 2004/05.

    - The second study, completed in early 2002, found that 3,900 MW of generation would be at-risk for the winter 2004/05 on a peak day, and that insufficient operational flexibility existed to satisfy the coincident peak demands of gas utilities and gas-fired generators, which often rely on interruptible capacity. These findings were reaffirmed in a broader regional study performed by Levitan in 2002 and 2003 for four independent system operators and NERC.[11]

    - In January 2004 the ISO asked Levitan to update the steady-state analysis of New England's consolidated pipeline deliverability to capture the actual operating

[11] *See Multi-Region Assessment of the Adequacy of the Northeast Natural Gas Infrastructure to Serve the Electric Power Generating Sector*, Levitan and Associates, July 2003.

> conditions on New England's pipelines during the Report Period. Levitan is using the ISO's consolidated regional pipeline model to simulate actual deliveries on the interstate pipelines during January 13 - 17. This study will be released by the ISO when completed. Any implications of the latest Levitan work for the recommendations in this report will beaddressed subsequent to the release of the Levitan report.[12]

The ISO responded to the results of the Levitan first studies by developing a fuel-diversity white paper[13] and subsequently establishing the Fuel Diversity Working Group in the summer of 2003. This group is focused on the problems identified in the Levitan study and determining the appropriate changes to the NEPOOL market rules, ISO procedures, or planning processes. In addition, the ISO anticipates that by sponsoring the various reports and disseminating their findings to the marketplace, it will stimulate investment and responses by market participants. This is an important avenue of response, as many of the issues identified by the study are outside the direct control of the ISO and are best resolved through market actions.

A brief summary of the weather-related events of January 7-9 and January 13-16, 2004 and their electricity supply impacts follows. These events and effects are described in more detail later in this report. During the January 2004 Cold Snap, New England experienced the coldest temperature at the time of the winter peak in the last 20 years, accompanied by exceptionally high electricity demand levels. LDCs throughout New England experienced record send-outs as demand exceeded peak day forecasts achieving levels that were not expected by some utilities until 2006.[14] Several pipelines issued Operational Flow Orders ("OFOs"),[15]

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[12] *See Post Operational Assessment of New England's Interstate Pipeline Delivery Capability During the January 2004 Cold Snap*, dated March 24, 2004. This report is posted on the ISO's website as a supplement to the Cold Snap report.

[13] *See Natural Gas and Fuel Diversity Concerns in New England and the Boston Metropolitan Electric Load Pocket*, ISO New England, July 2003.

[14] *Source:* Natural Gas Week.

which interrupted service to customers not holding firm transportation and tightened imbalance[16] tolerances for firm customers.

January 7-9. January 7-9 brought very cold weather and high demand. Unit availability was close to historical norms. New England was a net exporter of power to neighboring control areas during the peak hour on two of the three days. Several natural gas pipelines issued capacity constraint notices,[17] and Yankee Gas issued an OFO. On January 9, KeySpan's New England system experienced a record daily send-out of 1.2 Bcf .[18]

January 13. The ISO conducted its day-ahead forecast for January 14, expected to be an extremely cold day, and projected a surplus of 583 MW above reserve requirements. The ISO had previously approved economic outages for January 14, 15, and 16. Several pipelines issued capacity constraint notices[19] for January 14. During the night of January 13-14, generators reported unexpected outages and deratings that limited availability, including gas interruptions, frozen fuel lines, and ice clogging of air intakes. Hydro-Quebec requested that its customers conserve electricity.

January 14. In response to the overnight developments, the ISO revised its capacity forecast for the evening peak, calculating an 84 MW deficit based on an increase in unit outages.

(...continued)

[15] OFOs are formal notifications by the pipeline or LDC that require limitations on gas deliveries to ensure that the pipeline system maintains reliable operation.

[16] Imbalances occur when end of day gas metering indicates that the customer has physically taken more or less gas then was stated within his daily nomination.

[17] Capacity constraints are issued by pipelines whenever the total amount of gas nominated exceeds the physical delivery capability of the pipe.

[18] Billion Cubic Feet. 1 Bcf approximately equals 1 MMDth, 1 Dth = 1 MMBtu, 1 Giga-Joule (GJ) = 0.950 Dth.

[19] Capacity constraint notices are informational notices usually posted on a pipelines' Electronic Bulletin Board ("EBB") to notify shippers that capacity constraints are in existence.

The ISO cancelled all economic outages at about 10:00 a.m. and ordered those units online as soon as possible. Gas pipelines continued to issue capacity constraint notices. Algonquin and Tennessee (Zones 5 and 6) issued OFOs. The ISO also implemented an emergency procedure, Master/Satellite Procedure No. 2 ("M/S 2"),[20] at about noon. New York exported 350 MW to New England across the evening peak. Approximately 4,271 MW of New England gas units that had been ordered online made it online for the evening peak (out of a total of 10,332 MW of gas capable capacity). The remaining units were out of service because of a combination of fuel problems and various plant physical conditions. New England experienced OP4 conditions between 5:00 p.m. and 7:00 p.m., with about a 110 MW deficiency out of a 1,741 MW reserve requirement. The ISO activated its price-response program for January 14. Conditions were at or near emergency in New Brunswick and on the Hydro-Quebec system. The ISO issued a notice requesting conservation and briefed New England regulators and other government officials on the situation. The ISO's day-ahead forecast for January 15 projected a surplus of 1,568 MW, but this figure was highly uncertain, given concerns about equipment failure and fuel supply due to the severe cold.

January 15. During the night of January 14-15, over 2,000 MW of generating capacity became unavailable. Conditions were highly volatile, with many units experiencing weather-related operational difficulties. During the day on January 15, the ISO, in consultation with the master satellite heads, made the decision to staff electric substations to prepare for the potential

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[20] Master/Satellite Procedure No. 2 ("M/S 2") – Abnormal Conditions Alert. This procedure alerts power system operations, maintenance, construction, and test personnel as well as market participants when abnormal power system conditions exist or are anticipated. Once notified, these personnel are expected to take precautions so that routine maintenance, construction and test activities associated with generating stations, transmission lines, substations, dispatch computers, and communications equipment do not further jeopardize the reliability of the power system. If maintenance, construction or test activities could jeopardize the reliability of the power system, such activities are to be curtailed during the alert. *See* http://www.iso-ne.com/master_satellite_procedures/Ms02.doc.

of controlled load curtailment, and the public was urged to conserve energy. Pipeline companies issued capacity constraint notices for January 16. The Algonquin and Tennessee OFOs remained in effect. The ISO briefed New England regulators and other government officials.

New winter peaks were experienced by New York (25,262 MW) and Hydro-Quebec (36,274 MW). Some New York dual-fuel units converted from gas to fuel oil. New England experienced a new record winter peak of 22,817 MW during the evening but was able to avoid an OP4 declaration because of significant imports from New York - up to 1,100 MW - and because gas-fired plant availability improved in New England. The ISO's day-ahead forecast for the morning peak on January 16 indicated a zero surplus/deficit, but this was highly uncertain, given concerns about equipment failure and the extreme cold and high winds forecasted for the morning hours.

January 16. The ISO briefed New England regulators and government officials and again urged the public to conserve electricity. The level of available gas-fired generation significantly improved for Friday morning, avoiding the need to declare OP4 conditions. Load was below forecast. School closings helped reduce both electrical and gas loads. Temperatures moderated during the day, power supply conditions remained stable, and at the evening peak New England experienced a 2,184 MW surplus. While gas pipelines continued to experience constraints into January 17, the challenges facing the bulk electrical system had subsided by the end of the day on January 16. The reduction in electricity demand that reduced capacity requirements was the result of the normal weekend decrease in consumption due to closed schools, offices, and businesses. KeySpan's New England system reported another daily send-out record of 1.4 Bcf. The Algonquin and Tennessee OFOs remained in effect until January 17.

III. Summary of Events

A. Overview of Weather and Gas Issues

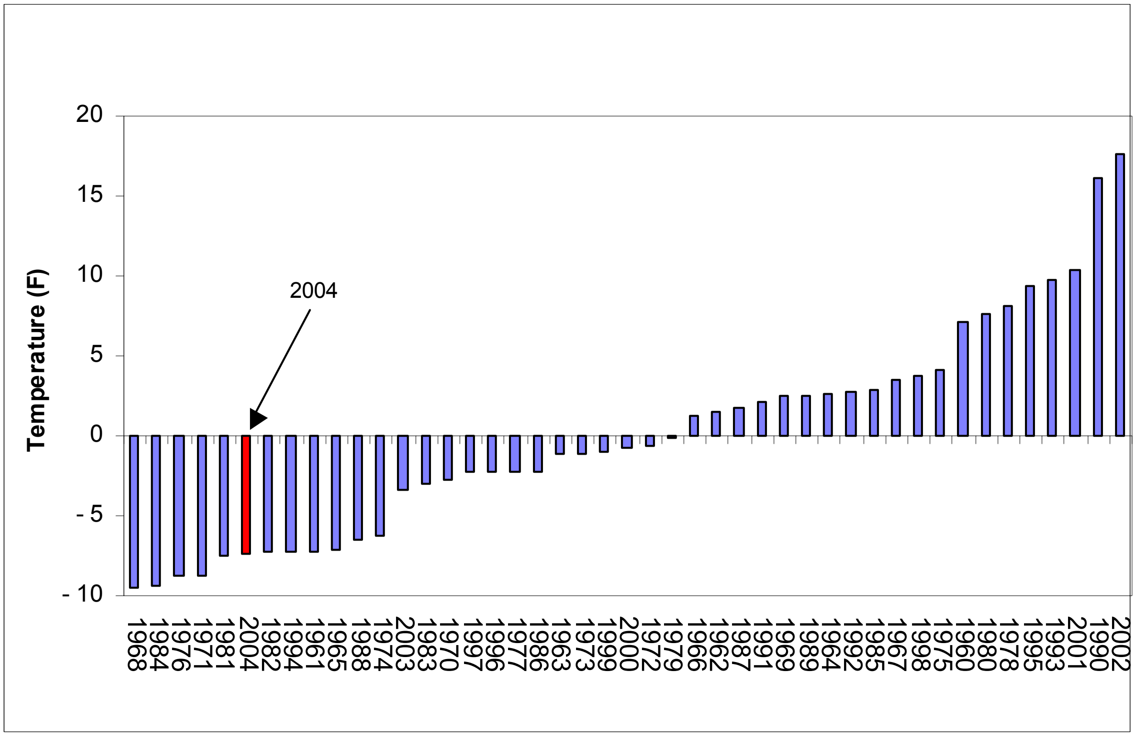
1. Weather

A primary cause of events in the power and natural gas markets in the middle of January 2004 was extremely cold weather across New England and the rest of the Northeast. By January 16, 2004, New England had experienced the coldest temperature in the last 20 years, and the sixth coldest temperature since 1960 (see Figure 1).[21]

[21] Comparing temperatures for the winter period 2004, January 2004 also had the lowest mean, minimum, and maximum temperatures. The mean and minimum for January 2004 were far below those for December 2003 and February 2004.

Month	*Mean*	*Minimum*	*Maximum*
December 03	33	14	54
January 04	21	(7)	50
February 04	33	13	54

Figure 1 - Coldest Hourly Temperatures for the Month of January (1960-2004) [22]



During the January 2004 Cold Snap, temperatures were unusually low with exceptionally high electricity demand. Figure 2 presents the growth in the New England hourly winter peak loads since 1980 and compares it with the annual weather-normalized forecast winter peak load. The winter peak in 2004 was above the weather-normalized forecast of peak load.

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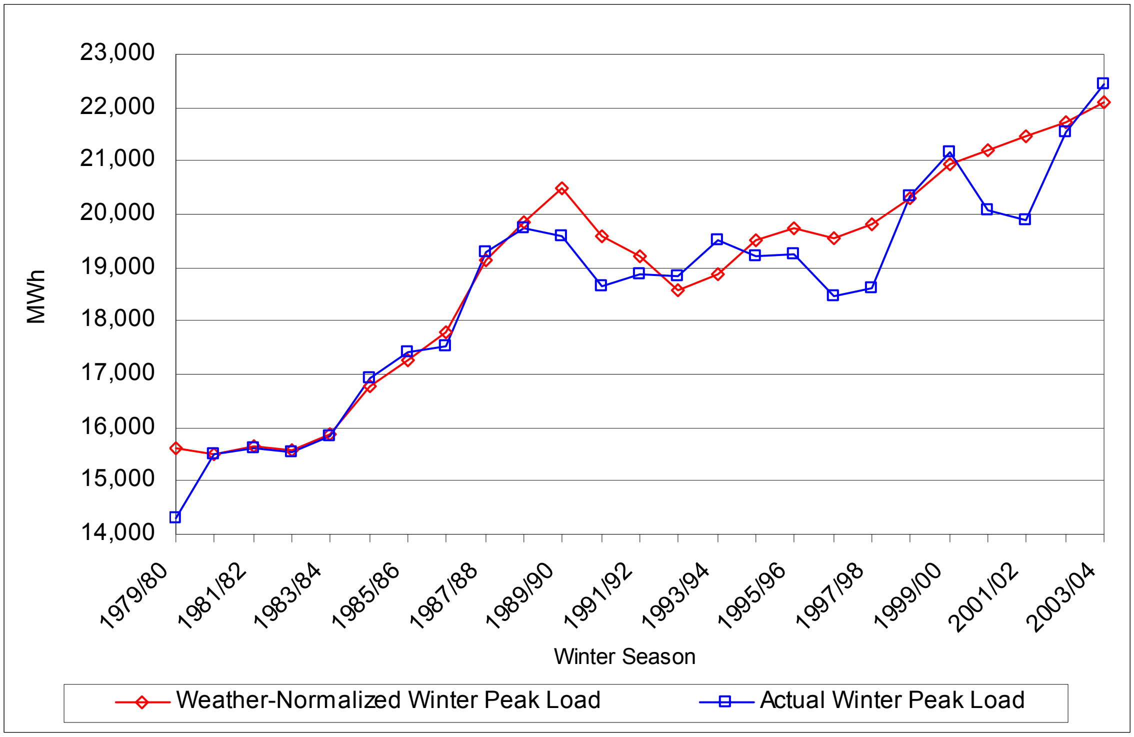
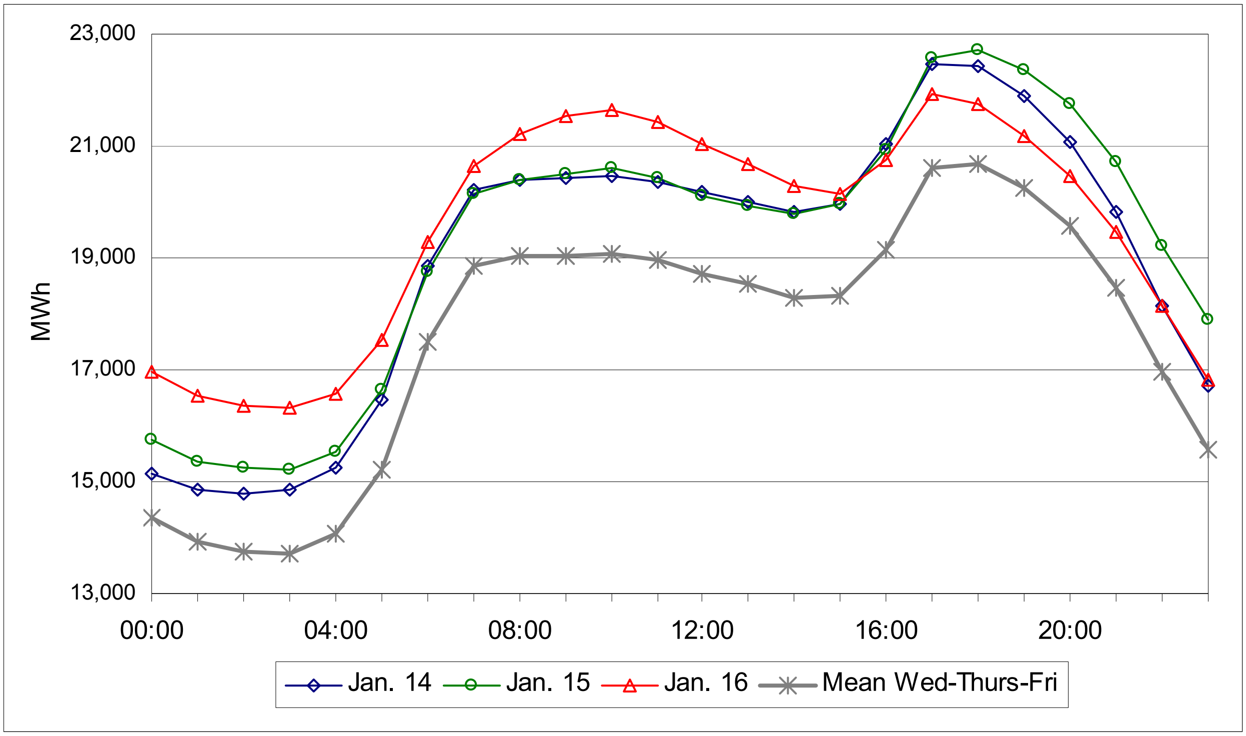
[22] Each value represents the lowest hourly load-weighted temperature at eight locations in New England for the month of January. *Source:* ISO weather data.

Figure 2 - Weather Normalized Forecast and Actual New England Winter Hourly Peak Loads from 1980-2004



The all-time winter peak of 22,817 MW occurred between 6:00 and 7:00 p.m. on January 15, 2004. Load remained high by historical standards during the entire Report Period (see Figure 3, where *Mean Wed-Thurs-Fri* is the average hourly load for all Wednesdays, Thursdays, and Fridays in January 2004, including the Report Period). Growing electricity consumption in New England, combined with the rapid growth of gas-fired installed electric capacity, has increased the interdependence of the electric and gas markets, with each more sensitive to fluctuations in the other, particularly during severe winter weather such as that experienced during the Report Period.

Figure 3 - Hourly New England Loads During January 14 - 16, 2004



2. <u>Fuel Mix</u>

New England's load is increasingly served by gas-fired generation. Natural gas has been the fuel of choice for most of the over 14,000 MW of total capacity added in New England since 1990.[23] Table 1 summarizes the percentage of gas and gas-capable units as a proportion of total installed capacity.

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[23] The total gas-fired capacity added since May 1, 1999, the opening of the interim markets, is nearly 8,000 MW (winter capability).

Table 1 - Seasonal Claimed Capability by Unit Fuel Type, January 2004

Fuel Type	Winter Claimed Capability	Summer Claimed Capability	Total Listed Units	
			WCC %	SCC %
Natural gas only	10,332	8,929	32%	30%
Primary natural gas with secondary fuel oil	3,032	2,664	9%	9%
Primary fuel oil with secondary natural gas	3,015	2,907	9%	9%
Total Gas Capable units	**16,379**	**14,500**	**50%**	**48%**
All Oil/Jet units	4,837	4,500	15%	15%
All Coal units	2,839	2,779	9%	9%
All Hydros	3,269	3,191	10%	11%
All Wood	888	863	3%	3%
All Others	17	17	0%	0%
Nuclear	4,411	4,347	13%	14%
Total Units	**32,640**	**30,197**	**100%**	**100%**

The data show that gas-only units constitute over 30 percent of New England's winter capacity, with more gas required for mixed fuel plants. New England has become highly dependent on natural gas for electricity generation. As discussed in the gas studies summarized in Appendix A, the inability of power producers to secure gas for their power plants can cause a shortfall in power supply.

The inability of power producers to secure gas for their power plants is a concern because, in winter, cold weather is the main driver for the consumption of both electricity and gas. Extremely cold weather affects gas consumption in two ways: increased demand for power requires gas-fired units to burn more gas, and cold weather also increases demand for gas for heating residential homes and for commercial customers.

This is most clearly evidenced by the need to invoke emergency operating procedures on January 14 during peak load hours. Peak load on January 14 was 22,450 MW. While this is high, it is well below the established summer peak of approximately 25,000 MW. Under normal summer conditions, a 22,450 MW load should be a routine, though high demand, day. However, with large amounts of gas-fired generation unavailable, emergency procedures were required during the Report Period.

The following section of the report describes the events during the Report Period in greater detail.

B. Day-by-Day Narrative

1. January 7-9

To understand the events of the Report Period, a review of conditions and actions during the prior week is helpful. During January 7-9, New England experienced single-digit temperatures. Conditions experienced across the peak hours of this period are summarized in Table 2 below:

Table 2 - Overview of System Conditions for January 7-9, 2004

Date	Temperature	Peak Demand (MW)	Out of Service (MW)	Surplus (MW)[24]
January 7 (Wednesday)	Boston 23°F Hartford 19°F	20,746	Gas 2,123 Other 1,160	2,138
January 8 (Thursday)	Boston 15°F Hartford 16°F	20,948	Gas 3,008 Other 830	2,739
January 9 (Friday)	Boston 6°F Hartford 7°F	21,409	Gas 2,806 Other 1,000	2,917

During this three-day period, the system experienced close to record demand, but unit outages remained close to historical winter[25] norms of approximately 3,100 MW unavailable for

[24] Surplus is capacity over and above load and reserves.

the winter conditions experienced. Economic outages by generators averaged 755 MW and no units on economic outage had to be recalled. New England was a net exporter to the New Brunswick and New York control areas on two of the three days across the peak hours (484 and 128 MW on January 8 and 9, respectively). Some pipelines issued Critical Notices[26], but did not impose penalties.

Summary for January 7-9:

- Peak demand conditions were experienced during January 7-9.
- Generation availability, including gas-fired plant availability, appeared to be in the "expected norm" for winter peak conditions during this operating period.[27]
- Several generating units were unavailable for gas supply reasons on January 10.

2. <u>Real-Time January 13, Day-Ahead Forecast for January 14</u>

On January 13, the ISO conducted its day-ahead forecast for January 14, presented in Table 3. Based on a review of the previous day's operation and comparison to similar winter

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(...continued)

[25] For this report, the winter period is defined as the months of December, January, and February.

[26] Critical Notices are warnings issued by the gas pipelines under unusual system conditions. They may be warnings, or they may announce the implementation of a range of operating restrictions and possible penalties.

[27] The Weighted Equivalent Availability Factor (WEAF) is the equivalent average availability factor of a specific group of generating units weighted by the capacity of each unit (a 100 MW unit has 10 times the weight of a 10 MW unit). The Equivalent Availability Factor can be viewed as the percent of time that the entire generator was available. The term *equivalent* means that unit deratings were taken into consideration.

The WEAF for all units for the last 4 winter periods are:
Winter 00/01 - .8855
Winter 01/02 - .9040
Winter 02/03 - .9129
Winter 03/04 - .8977

The WEAF for gas only units for the last 4 winter periods are:
Winter 00/01 - .9323
Winter 01/02 - .8307
Winter 02/03 - .8904
Winter 03/04 - .8176

days from 2003, System Operations projected a peak-hour demand of 22,075 MW, and committed resources designed to provide a generation surplus of 583 MW above operating reserve and replacement reserve requirements. For January 14, generating units with a total capacity of 2,327 MW had initially been granted economic outages.[28]

Table 3 - Day-Ahead Projections of System Conditions for January 14, 2004

Projection for	Projected Temperatures	Projected Peak Demand (MW)	Projected Out of Service (MW)	Projected Surplus/(Deficit) (MW)
January 14 (Wednesday)	Boston 8°F Hartford 5°F	22,075	8,400 (Gas: 6,832 Coal: 417 Nuclear: 12 Oil: 776 Hydro: 244 Other: 119) (Economic Outages: 2,327)	583

In the late afternoon of January 13, Hydro Quebec issued a press release requesting that its customers decrease electric consumption during the morning and evening peak hours (6:00-9:00 a.m. and 5:00-7:00 p.m.) of January 14 and 15, and during the morning peak on January 16. At around 11 p.m., the ISO sent an event notification for the real-time price response program for Hours Ending 8 a.m. through 6 p.m. on January 14.

Summary for Real-Time January 13, Forecast January 14:

- The unit commitment for January 14, based on day-ahead forecasts of generating unit availability and weather conditions, was expected to create an acceptable level of surplus.
- A neighboring electric system requested conservation from its customers for the Report Period.

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[28] For January 15, the figure was initially 3,287 MW; for January 16, the figure was initially 1,781 MW.

3. <u>January 14</u>

a) Overnight, January 13-14

During the period from midnight on January 13 through 10:00 a.m. on January 14, a large number of generating units (with a total capacity of 822 MW) experienced unexpected availability issues. Of the generating capacity that became unavailable during the night of January 13 to 14, 507 MW was gas-fired and 315 MW was not gas-fired. The ISO received numerous reports of gas curtailments from generating units, as well as a variety of weather-related operational problems. A sampling of outage reasons due to gas curtailments follows:

- "Change purge valve on gas manifold;"
- "Economic out-of-service - 24 hour notification;"
- "Economic Outage - gas prices."

b) Morning

The morning update to the previous day's capacity projection (Table 4) showed an 84 MW capacity deficiency due to a 400 MW increase in generator outages on peak and a 300 MW increase in the peak load forecast.

Table 4 - Updated Projections of System Conditions for January 14, 2004

Projection for	Projected Temperatures	Projected Peak Demand (MW)	Projected Out of Service (MW)	Projected Surplus/(Deficit) (MW)
January 14 evening peak (Wednesday)	Boston 7°F Hartford 8°F	22,375	8,806 (Gas: 7,114 Coal: 418 Nuclear: 12 Oil: 860 Hydro: 234 Other: 168) (Economic Outage: 0)	(84)

The sudden loss of natural gas at various generating stations across New England on the morning of January 14 became a great concern for power system operations. Between 9:00 a.m.

and 11:00 a.m. on January 14, approximately 1,400 MW of natural gas-fired capacity became unavailable for dispatch due to lack of natural gas availability. Complicating these events was the lack of advance notice to system operations at the ISO regarding the pending loss of generation. Of the 1,400 MW of losses, only 300 MW had provided advance notice of their inability to run on January 14, and that was given approximately 3 hours in advance. The remaining 1,100 MW was lost with little or no notice.

Based on the revised load forecast and concerns about supply resource reliability, at approximately 10:00 a.m. on January 14 the ISO notified all units that were previously granted an economic outage to be available for dispatch or to declare a forced outage. All of the units previously granted economic outages were gas-fired. Of the ten generators (2,327 MW) recalled,[29] none were able to return to service on January 14. Three of these units, totaling 675 MW, were unavailable due to start times that would not enable them to be on-line for the peak hours. The remaining units were unable to procure gas and were re-classified as forced outages. At 10:45 a.m., the ISO cancelled the prescheduled maintenance on the 342 transmission line (serving Cape Cod) and ordered the restoration of the line to service in anticipation of a declaration of M/S 2 in the afternoon.

c) Afternoon

At about noon, Hydro Quebec inquired about the availability of emergency energy from New England transmitted over the Phase I high voltage DC transmission facilities for the

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[29] As a result of reviewing the Interim Report, a participant questioned whether all of their units had been requested to return to service. Market monitoring was unable to confirm that one unit of approximately 250MW was asked to return to service. There is no recorded phone conversation, as some calls were made on an unrecorded line to accommodate the large call volume. The participant later claimed that it would have been able to get gas had it been called.

evening peak of January 14. The ISO indicated the possibility of providing up to 400 MW of emergency energy if Hydro Quebec was using its emergency procedures. Also at noon, the ISO declared M/S 2, notifying all power system personnel of the projected capacity deficiency and canceling all work on critical transmission lines, generators, and critical equipment. A continued decline in generating resource availability and record system demand led to OP4 conditions (Actions 1 and 6) between 5:00 and 7:00 p.m.

At 1:30 p.m., the ISO convened a NERC/NPCC conference call to determine the extent of power supply availability within the other Northeastern control areas. During the call, the ISO, New Brunswick, and Hydro Quebec all reported forecasted deficiencies in their 30-minute reserve requirements. The Independent Electricity Market Operator ("IMO") for Ontario reported "no surplus" available. The New York Independent System Operator ("NYISO"), the Midwest Independent System Operator ("MISO"), and PJM Interconnection ("PJM") reported normal conditions (although PJM subsequently reported about 2,500 MW of gas-fired units unavailable). New Brunswick and Hydro Quebec also projected deficiencies for the January 15 peak. In essence, the only interface into New England that could support substantial imports was the NYISO interface with a capability of about 600 MW.

At about 3:30 p.m., the ISO issued a request to market participants for Emergency Energy Transactions ("EETs")[30] for the Hours Ending 6:00 through 8:00 p.m.

At about 4:30 p.m., the ISO briefed New England regulators and government officials about power supply conditions for the evening peak and projections for the balance of the week.

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[30] These short-notice import transactions are called for before the ISO makes direct emergency purchases from neighboring power pools.

The ISO issued a press release at about 5:30 p.m. asking for conservation through the evening peak hours, and all day on January 15.

d) Evening

From 5:00 to 7:00 p.m. on January 14, the New England system experienced a capacity deficiency, triggering Actions 1 and 6 under OP4. The ISO issued a "Power Caution," and government officials and state regulators were notified of these actions under the OP4 notification provisions. By the evening hours, one of the gas-fired units recalled by the ISO from an economic outage had made it back online. At around 6:00 p.m., the ISO also "postured" some generation (restricted a unit's output) to maintain required levels of ten-minute operating reserves.

At the evening peak hour (Hour Ending 6:00 p.m.), the following conditions (Table 5) were experienced:

Table 5 - Actual System Conditions for January 14, 2004

Date	Actual Temperatures	Actual Peak Demand (MW)	MW Out of Service (MW)	Surplus/(Deficit) (MW)
January 14 (Wednesday: Hour Ending 6:00 p.m.)	Boston 7°F Hartford 8°F	22,450	8,927 (see details below)	(108)

The details of the capacity out of service at the evening peak are as follows in Table 6. Some causes of the outages and reductions reported by units during this time were "gas restrictions," "river conditions," "fuel leak," "steam leak," "vibrations," "freeze up problems," and "frozen controller."

Table 6 - Summary of Generation Outages (MW) on January 14, 2004[31]

Fuel Type	Forced Outage (MW)	Reductions in Capability of Online Units (MW)	Total (MW)
Gas Capable	5,883	1,335	7,238
Coal	415	15	430
Nuclear	0	12	12
Oil	660	182	842
Hydro	5	257	262
Other	30	113	143
Subtotal	**6,993**	**1,934**	**8,927**

During the peak hour, there was sufficient transmission capacity to import up to 600 MW from New York into New England. Actual imports were 350 MW from New York. Neither EETs nor emergency pool-to-pool transactions were required. The Cross Sound Cable was activated between 4:00 a.m. and midnight on January 14. The minimum flow during this period was 50 MW of exports to Long Island for Hour Ending 5:00 a.m. The maximum flow was 253 MW of exports to Long Island for Hour Ending 9:00 p.m. In accordance with NEPOOL Operating Procedure #9, Cross Sound Cable transactions that caused or exacerbated transmission restrictions, transmission interruptions, or system-wide reliability concerns would have been curtailed by the ISO prior to curtailing firm New England load. On January 14, NYISO experienced a new winter peak demand of 24,627 MW, and Hydro Quebec experienced a new winter peak demand of 35,601 MW.

Preliminary data indicate that the ISO demand response program produced an average hourly reduction of 18.2 MW on January 14.[32] The ISO activated the real-time price response

[31] Note that all units that failed to return from economic outages were re-classified as forced outages.

[32] *See* Section III for a further analysis of demand response.

program[33] on the evening of January 14 for Hours Ending 8:00 a.m. through 6:00 p.m. for January 15.

Summary for January 14:

- New England experienced a new winter peak
- An abnormal number of gas units reported gas and unit availability problems.
- Approximately 1,400 MW of gas-fired units declared outages at the beginning of the new gas day.
- The ISO cancelled all economic outages at about 10:00 a.m. and ordered those units online as soon as possible.
- The ISO implemented M/S 2 at about 12:00 noon.
- New York exported 350 MW to New England across the evening peak (600 MW of transmission capability was available).
- Approximately 4,271 MW of New England gas units were available for the evening peak out of a total 10,332 MW. The remaining units were out of service because of a combination of fuel problems and various plant physical conditions.
- The ISO experienced OP4 conditions between 5:00 and 7:00 p.m., with about a 110 MW deficiency out of a total 1,741 MW reserve requirement.
- Conditions were at or near emergency in New Brunswick and Hydro Quebec.
- A neighboring electric system requested conservation from its customers for the Report Period.

4. January 15

a) Day-Ahead Forecast

The ISO's day-ahead forecast (Table 7) for January 15 projected the following conditions:

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[33] Under this program, verified voluntary interruptions are paid the greater of the real-time price or $100/MWh.

Table 7 - Initial Projections of System Conditions for January 15, 2004

Projection for	Projected Temperatures	Projected Peak Demand (MW)	Projected Out Of Service (MW)	Projected Surplus/(Deficit) (MW)
January 15 Thursday	Boston 5°F Hartford 3°F	22,525	7,034 (Gas: 5,312 Coal: 418 Nuclear: 12 Oil: 877 Hydro: 289 Other: 126) (Economic Outage: 0)	1,568 (but highly uncertain due to concerns about equipment failure and fuel supply due to severe cold)

Temperatures were projected to be several degrees colder than those on January 14, with extremely high winds. All economic outages were cancelled for January 15 on January 14.

b) Overnight January 14-15

During the night of January 14-15, over 2,000 MW of generating capacity became unavailable. Conditions were highly volatile, with many units experiencing weather-related operational difficulties, while about 410 MW of generation previously on forced outage became available.

c) Morning and Afternoon of January 15

Weather conditions were predicted to deteriorate for the evening peak on January 15 and overnight into Friday, January 16. The daytime temperature for January 16 was forecast to be -9°F in Boston and Hartford, with high winds. Historically, experience had shown that under weather conditions less severe than those forecast for the evening of January 15, New England had experienced increased transmission facility breaker failures due to freezing and air leaks.

The ISO's system operations staff met with the master satellites at 9:00 a.m. to review the power supply situation and discuss the potential requirement to staff the New England substations across the evening peak and into the next day's peak. This action, which involves positioning operating personnel at key substations, permits quick response to equipment problems and enables manual curtailment and restoration of customer load (rotating blackouts), on short timelines and in a controlled fashion. It was agreed to make the final staffing determination before 2:00 p.m. to give the crews adequate notification time.

At 1:30 p.m., the ISO asked the master satellite heads to arrange for transmission owners to staff key substations across the evening peak as a precautionary measure. The decision to staff electric substations was based on the lessons learned from the August 14, 2003 Midwest/Northeast blackout and the extremely harsh and life-threatening conditions projected for the next two days. Early in the afternoon, the ISO determined that Southwest Connecticut could not maintain adequate second contingency reserves across the evening peak due to unexpected gas-related generator outages. The ISO coordinated with NYISO and the Connecticut Satellite (CONVEX) to arrange for post-contingency transfers over the 1385 cable (Northport, Long Island to Norwalk, Connecticut), if needed.

During the afternoon, some dual-fired generating units in New York began converting from gas to oil.[34] Coordination between the ISO and NYISO resulted in an increase of 800 MW, to 1,400 MW, in the New York to New England transfer capability.[35] During the afternoon, NYISO exported up to 1,100 MW to New England. At 4:30 p.m., the ISO briefed New England regulators and key government officials on the expected power supply conditions for the evening peak and the peak expected for Friday, January 16. School administrators across southern New England announced school closings for Friday due to cold temperatures. The ISO also

[34] This was an economic response, as opposed to curtailments based on gas availability.

[35] This report does not evaluate whether such an increase was possible on January 14, though it may have been desirable if feasible.

participated in a conference call with New England gas pipeline operators, the LNG importer, Distrigas, and several of the larger local gas utilities in the region to determine what actions could be taken to ensure that any available gas could be delivered to available generating plants. During this call, the ISO inadvertently released confidential information about the operating status of one specific generator in its attempts to understand which resources were likely to be available during the remainder of the Cold Snap. The gas industry representatives from New England (as well as gas control operational officials from Houston and Calgary) stated to the ISO on this call that some limited quantities of gas commodity and transportation could be made available if needed, but that gas companies needed to know where, when, and in what volumes. The ISO did not request action from the gas industry at that time.

d) Evening of January 15

At about 7:30 p.m., the ISO issued a press release warning the public of the power supply situation and the measures that were being taken, including the potential for rotating blackouts.

Conditions across the evening peak for the Hour Ending 7:00 p.m. were as follows in Table 8:

Table 8 - Actual System Conditions for January 15, 2004

Date	Actual Temperatures	Actual Peak Demand (MW)	Out Of Service (MW)	Surplus/(Deficit) (MW)
January 15 Thursday (Hour Ending 7:00 p.m.)	Boston 5°F Hartford 5°F	22,817	8,363 (see details below)	717

Table 9 provides details on the units out-of-service at the evening peak. These numbers are similar to those for January 14, with an improvement in the availability of gas units. Oil unit availability decreased. A 600 MW oil unit tripped with an equipment-related outage and an additional 100 MW in oil units declared outages due to lack of fuel. The increase in the capacity surplus over the peak hour is due to improved gas unit availability and increased import capability from NYISO.

Table 9 - Summary of Generation Outages in MW on January 15, 2004

Fuel Type	Forced Outage	Reductions in Capability of Online Units	Total
Gas Capable	5,648	1,172	**6,820**
Coal	310	34	**344**
Nuclear	0	12	**12**
Oil	558	188	**746**
Hydro	12	299	**311**
Other	30	100	**130**
Subtotal	**6,558**	**1,805**	**8,363**

Preliminary data indicate that the demand response program produced an average hourly reduction of 25.3 MW on January 15. The Cross Sound Cable was not activated on January 15. The ISO activated the real-time price response program on the evening of January 15 for Hours Ending 8:00 a.m. through 6:00 p.m. for January 16.

Summary for January 15:

- New England experienced a new winter peak for the second consecutive day.
- New England faced volatile power supply conditions, substations were staffed to prepare for rolling blackouts, and the public was urged to conserve energy.
- New winter peaks were experienced by New York (25,262 MW) and Hydro Quebec (36,274 MW).
- Some New York dual-fired units converted to oil use.
- NYISO provided significant imports into New England - up to 1,100 MW.
- Gas-fired plant availability improved in New England.
- The combination of increased imports and increased availability of gas-fired units produced a small generation surplus, and an OP4 declaration was not necessary across the evening peak.
- A neighboring electric system requested conservation from its customers for the Report Period.

5. <u>January 16</u>

a) Day-Ahead Forecast

The ISO's day-ahead forecast for the morning and evening peaks of Friday, January 16 projected the conditions shown in Table 10.

Table 10 - Initial Projections of System Conditions for January 16, 2004

Projection for	Projected Temperatures	Projected Peak Demand (MW)	Projected Out Of Service (MW)	Projected Surplus (MW)
January 16 Friday (morning peak)	Boston -9°F Hartford -9°F	21,600	5,327 (Gas: 4,027 Coal: 240 Nuclear: 16 Oil: 585 Hydro: 298 Other: 161) (Economic. Outage: 0)	0 (but highly uncertain due to concerns about equipment failure and fuel supply due to severe cold)
January 16 Friday (evening peak)	Boston 7ºF Hartford 10ºF	22,800	4,571 (Gas: 3,275 Coal: 240 Nuclear: 16 Oil: 588 Hydro: 308 Other: 144) (Economic. Outage: 0)	711

As indicated, system operations projected surplus conditions for the evening peak hour on January 16. However, a high degree of uncertainty was associated with this projection. Numerous schools in New England were reported to be closed for Friday due to the extreme weather conditions.

b) Overnight January 15-16

At 2:00 a.m. on January 16, a key Canadian transmission interface to Vermont - the Phase I Highgate Interconnection (with a rated transfer capacity of 225 MW) - was lost due to transformer problems in Southern Quebec. In addition, later that morning, a critical generation facility in Vermont suffered a forced outage. These two contingencies combined to significantly stress the Vermont transmission system. The interconnection could not be restored until 4:00 p.m. on Friday.

c) Morning and afternoon, January 16

The level of available gas-fired generation significantly improved for Friday morning compared with the previous day, as additional units came back on line. Imports from New York continued to be reliable. As a result, the ISO crossed the morning peak without the need to go into OP4 conditions. At about 10:00 a.m., the ISO briefed New England regulators and other key government officials on the expected power supply conditions for the evening peak. At 10:30 a.m. the ISO held a conference call with gas industry experts regarding the status of the electric and gas markets. At about 3:00 p.m., the ISO issued a press release to market participants and the media urging conservation.

Temperatures moderated during the day, and power supply conditions remained stable. By mid-afternoon, the ISO projected a surplus of up to 1,500 MW across the evening peak.

d) Evening of January 16

Conditions across the evening peak (Hour Ending 6 p.m.) are shown in Table 11.

Table 11 - Actual System Conditions for January 16, 2004

Date	Actual Temperatures	Actual Peak Demand (MW)	Out Of Service (MW)	Surplus/ (Deficit) (MW)
January 16 Friday (Hour Ending 6:00 p.m.)	Boston 11°F Hartford 12°F	21,885	6,328 (see details below)	2,184

The details of the units out of service at the evening peak are shown in Table 12.

Table 12 - Summary of Generation Outages on January 16, 2004

Fuel Type	Forced Outage (MW)	Reductions in capability of online units (MW)	Total (MW)
Gas Capable	3,099	1,842	4,941
Coal	163	3	166
Nuclear	0	16	16
Oil	427	390	817
Hydro	5	272	277
Other	30	81	111
Subtotal	**3,724**	**2,604**	**6,328**

Unit availability increased by approximately 2,000 MW from the previous day, with gas-fired units constituting much of the increase. The Cross Sound Cable was not activated on January 16. Preliminary data indicate that the demand response program produced an average hourly reduction of 21.5 MW on January 16.

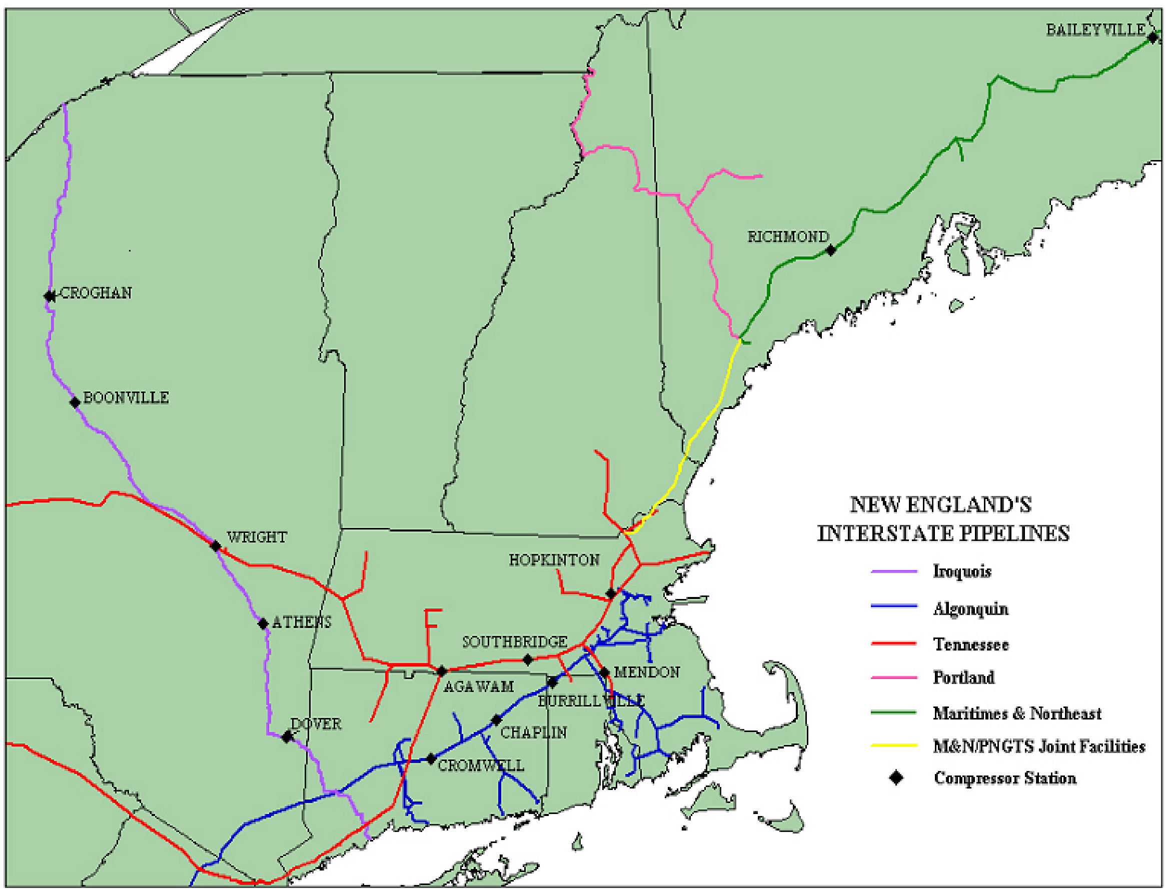
Summary for January 16:

- Friday's peak was lower than projected.
- More generation became available.
- Power supply conditions were stable across the evening peak.
- A neighboring electric system requested conservation from its customers for the Report Period.

C. <u>Timing of Events in the Gas Market</u>

Because of the extremely cold temperatures experienced during the Report Period, peak operating conditions on three of the five interstate gas pipelines systems serving New England (shown in Figure 4) left them with little or no operating flexibility. These conditions were limited to the Northeast, with most of the United States experiencing normal operating conditions. Gas availability for power generators in New England that did not hold firm interstate capacity was limited by the high gas demand due to extreme weather conditions.

Figure 4 - New England's Interstate Pipelines



Under tariffs approved by the FERC, New England's interstate pipelines typically issue two types of OFOs, generally through the posting of critical notices, which are formal notifications by the pipeline or LDC of limits on gas deliveries to ensure that the pipeline system maintains reliable operation. The lower level warning notice enforces daily balancing wherein a shipper's *daily* gas withdrawals cannot exceed certain tolerances from scheduled flows without incurring severe daily scheduling penalties. These penalties are defined in the pipeline's tariff. The higher level of capacity constraint notice imposes hourly balancing restrictions wherein a shipper's *hourly* gas flow is limited (typically to 1/24 of the scheduled daily flow), with hourly scheduling penalties in effect.

In the weeks leading up to the January 2004 Cold Snap, both the Tennessee and Algonquin pipelines had been issuing Critical Notices from time to time warning shippers to remain in daily balance. On January 14, both Tennessee and Algonquin issued Critical Notices in New England, which went a step further than prior constraints[36] by imposing severe tariff penalties to shippers deviating by more than 2 percent from their daily gas nominations. Neither Tennessee nor Algonquin posted a Critical Notice enforcing hourly flow restrictions. Algonquin and Tennessee did not enforce hourly flow restrictions because their existing OFO balancing penalty was sufficient to enforce conformance to daily tolerance requirements. Algonquin's penalty for imbalance gas is $15 per Dth.[37] Tennessee's penalty for imbalance gas is $15 per Dth plus the regional spot gas price. In addition to penalties on imbalances, generators directly connected to pipelines have automatic flow controls, providing pipeline operators the ability to ensure near uniform flows under tight operating conditions, or to completely shut off gas to generators over-pulling from the pipeline. Portland Natural Gas Transmission System

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[36] Prior constraints are earlier notices from the pipelines that inform shippers of pending or projected periods of constraint.

[37] Dth means dekatherm, which is equal to 1 MMBtu.

("PNGTS") also posted a Critical Notice during this period, limiting shippers to 105 percent of their confirmed daily nomination. Because Iroquois' throughput was below its maximum capacity during the January 2004 Cold Snap Iroquois did not post a Critical Notice.[38] Note that only a small portion of New England (southwestern Connecticut) is served by Iroquois. During the Cold Snap, Iroquois delivered natural gas to Tennessee and Algonquin at the Wright (New York) and Brookfield (Connecticut) interconnects along with gas to Tennessee through the Shelton (Connecticut) interconnect for redelivery to entitlement holders across each pipeline's route system in New England or if additional gas was available to be transported by Iroquois. While Iroquois may have been able to deliver more gas to the Tennessee and Algonquin pipelines, it is beyond the scope of this report to determine if Tennessee and Algonquin could have transported significantly more gas from Iroquois to the rest of New England. This will be addressed in the study by Levitan.

Figure 5 provides a summary time line of events in the gas market. A more detailed summary of press releases and Critical Notices of capacity constraints posted by the interstate pipelines and LDCs on their Internet websites is included in Appendix E.

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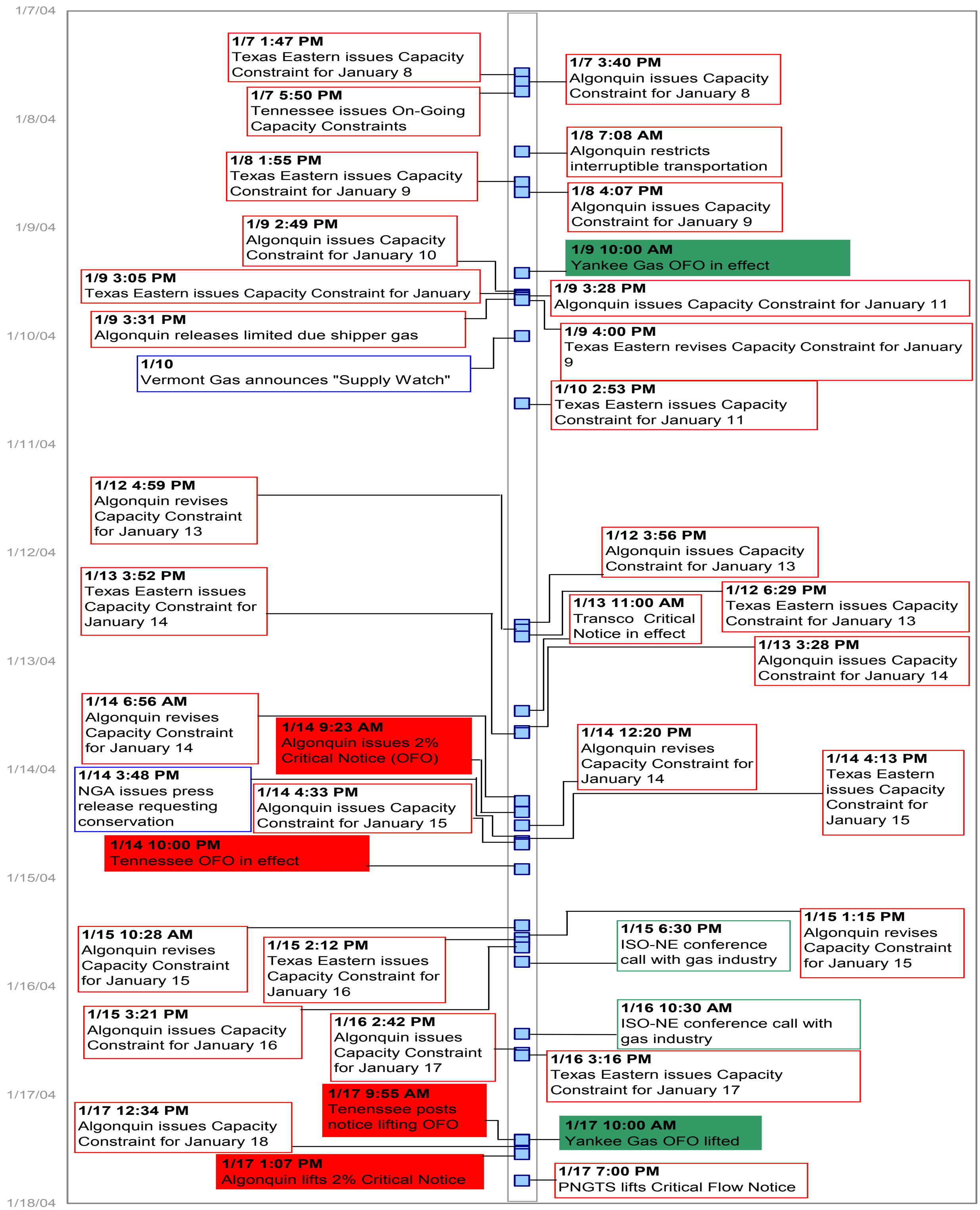
[38] Downstate NY spark-spreads were negative, meaning that LMPs were below the fuel costs of gas-fired generation, and thus gas-fired units in NY were not consuming sufficiently large quantities of gas to fully utilize the Iroquois pipeline. The difference between the market power price and the heat rate times the gas price is called the "spark spread", and it is a common electricity market metric. The unit-specific heat rate is a measure of its efficiency in converting fuel to electricity. The spark spread is often calculated and provided on a daily basis in trade publications. It is used by energy trading companies for market assessment, deal pricing, and risk management.

Figure 5 - Timeline of Gas Events, January 7-17, 2004



IV. Analysis of the Event

This section of the report analyzes the events described in Section II with three objectives:

- To understand the effects of the weather and gas supply situation on the electric markets;
- To determine whether generator behavior was consistent with the operation of a competitive market; and
- To identify and recommend changes in the market rules, operating procedures, and forecasting processes that could improve the functioning of the bulk power system in future events involving extremely cold weather or supply constraints.

Section IV.A provides an overview of market conditions during the Report Period. It also supports the analysis' focus on gas-fired units. Section IV.B discusses the effects of high gas prices, extreme gas price volatility, gas transportation limitations, and weather-related operating risks on supply offers and outages by gas-fired generators. The analysis concludes that generator behavior was generally consistent with competitive behavior given the market conditions.

Section IV.C examines the necessary conditions for the exercise of market power in the electricity markets and models market outcomes during the Report Period. Section IV.C concludes that the affected generators did not effectively exercise market power and that consumers were largely insulated from spot electricity prices during this period. Sections IV.D and E review the results of the ISO's ongoing market monitoring program during the Report Period. No mitigation actions were taken during the period, and the analysis does not suggest that any such actions were appropriate.

A final section (IV.F) analyzes certain other dimensions of the energy markets. Overall conclusions and recommendations for future action are discussed in Section V.

A. Background and Scope

1. Basis of the Analysis

The analysis discussed in this report is based on the following:

- The Market Monitoring Department's routine monitoring of Locational Marginal Prices ("LMPs"), supply offers, and demand bids;
- Evaluation of the gas markets during the Report Period by the Market Monitoring Department and Levitan;
- Analysis of outages, deratings,[39] and other data regularly collected by the Market Monitoring Department; and
- Targeted surveys of generation unit owners.

The surveys of generation unit owners were required because of the unit-specific nature of the problems and observed behavior during the Report Period. An initial round of information was obtained by telephone. The resulting explanations were divided into several categories, including economic outages, high offers, and forced outages, which include fuel-related and weather-related outages. For the purposes of the assessment, those terms were defined as:

- Economic outage - an outage requested by a participant to remove a generator from service because of market conditions;[40]
- High offers - offers from natural gas-fired units that exceed the unit-specific level adjusted by the average day-ahead gas price by $100/MWh;[41]
- Fuel-related outages - the inability to procure adequate fuel or transport fuel to plant gate, resulting in a unit being forced out-of-service or into a reduction of available capacity; and
- Weather-related outages - forced outages or reductions directly attributable to the unusually cold weather experienced during the January 2004 Cold Snap.

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[39] Deratings, for the purpose of this analysis, are defined as the inability to supply the full seasonal claimed capability of the unit.

[40] *See* Section I.

[41] Natural gas reference level is defined as the unit heat rate times fuel price plus variable costs, plus applicable environmental adders.

After evaluating the results of the phone interviews, the ISO's Market Monitoring Department developed a set of written questions specific to each outage type. This questionnaire was sent to the appropriate lead participants to elicit detailed information on gas contracting practices, expected operating conditions, gas market conditions, and plant operations during the Report Period. However, specific responses may inaccurately represent aspects of a generator's physical or financial position. At the request of other authorized authorities, the results of these responses have been provided and are being compared with independent additional data requests and analysis. At this time, no inconsistencies have been relayed to the ISO's Market Monitoring Department.

2. <u>Focus on Gas-Fired Units</u>

The analysis focuses principally on gas-fired units for three reasons. First, gas-fired units represented a disproportionate share of both fuel- and weather-related outages, and the absolute number of gas-fired MW unavailable was large. Second, as discussed above, New England's two main pipelines, Algonquin and Tennessee, as well as all of New England LDCs, experienced capacity constraints during the Report Period, thereby requiring the issuance of OFOs to ensure tight tolerances around daily confirmations. About 75 percent of the gas-fired generators in New England that are directly served by interstate pipelines rely on either Algonquin or Tennessee for transportation service. The operating restrictions (OFOs) on Algonquin and Tennessee, as well as at the local level, indicate tight system and market conditions that could have impaired the ability of gas-fired units to perform in accordance with ISO dispatch requirements (*i.e.* hourly variations). The operating restrictions on the pipelines also imposed difficult management decisions on units formulating offers in the electric markets. Third, regional gas prices were the highest in recent memory in New England and New York, and were extremely volatile in the daily markets. Energy supply offers from gas-fired units also increased rapidly.

For example, on January 14, 2004, during the OP4 conditions of Hour Ending 6:00 p.m., the New England control area experienced 8,927 MW of unavailable capacity (Table 13). These outages and reductions are categorized by both primary fuel and outage type. As indicated by Table 13, gas-capable units account for the largest category of outages, with 81 percent of the total unavailable capacity. This contrasts with the approximately 50 percent share of total capacity of gas-only and gas-capable generation in New England. This outage total of nearly 9,000 MW can be compared with the average December 2003 - February 2004 winter outage levels of approximately 5,110 MW, [42] and the 3,100 MW outage level used by ISO forecasters during winter peak load conditions. Gas-capable units alone, with 7,238 MW unavailable, experienced more than double the forecast level of outages. Overall outages were higher than normal, and gas-fired units accounted for a disproportionate share of outages.

Table 13 also categorizes the outages of New England generating units as pre-event (*i.e.*, started before January 14), equipment-related, weather-related, or fuel availability-related.[43] Partial reductions in output are shown in the same categories. Note that no economic outages were in effect for most of the Report Period, as all were cancelled on the morning of January 14.

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[42] This calculation excludes the Report Period.

[43] The pre-event outage category includes forced outages and ISO approved planned annual maintenance outages, but does not include economic outages. Fuel availability-related outages are outages caused by an inability to procure or transport fuel.

Table 13 - Generator Outages and Reductions, Hour Ending 6 p.m. on January 14, 2004

Unit Fuel Type	Forced Outage					Reductions in Capability of On-line Units						
	Pre-event Outage	Equipment Related Outage	Weather Related Outage	Fuel availability outage	Subtotal FO	Pre-event Reduction	Equipment Related	Weather Related	Fuel availability	Subtotal Reduction	Total	Percent
Gas Capable	1,824	893	674	2,492	5,883	415	240	136	564	1,355	7,238	81%
Coal	415	-	-	-	415	-	12	3	-	15	430	5%
Nuclear	-	-	-	-	-	-	12	-	-	12	12	0%
Oil only	-	427	233	-	660	-	25	157	-	182	842	9%
Hydro	5	-	-	-	5	117	-	15	125	257	262	3%
Other	30	-	-	-	30	34	79	-	-	113	143	2%
Outage Subtotal	**2,274**	**1,320**	**907**	**2,492**	**6,993**	**566**	**368**	**311**	**689**	**1,934**	**8,927**	**100%**

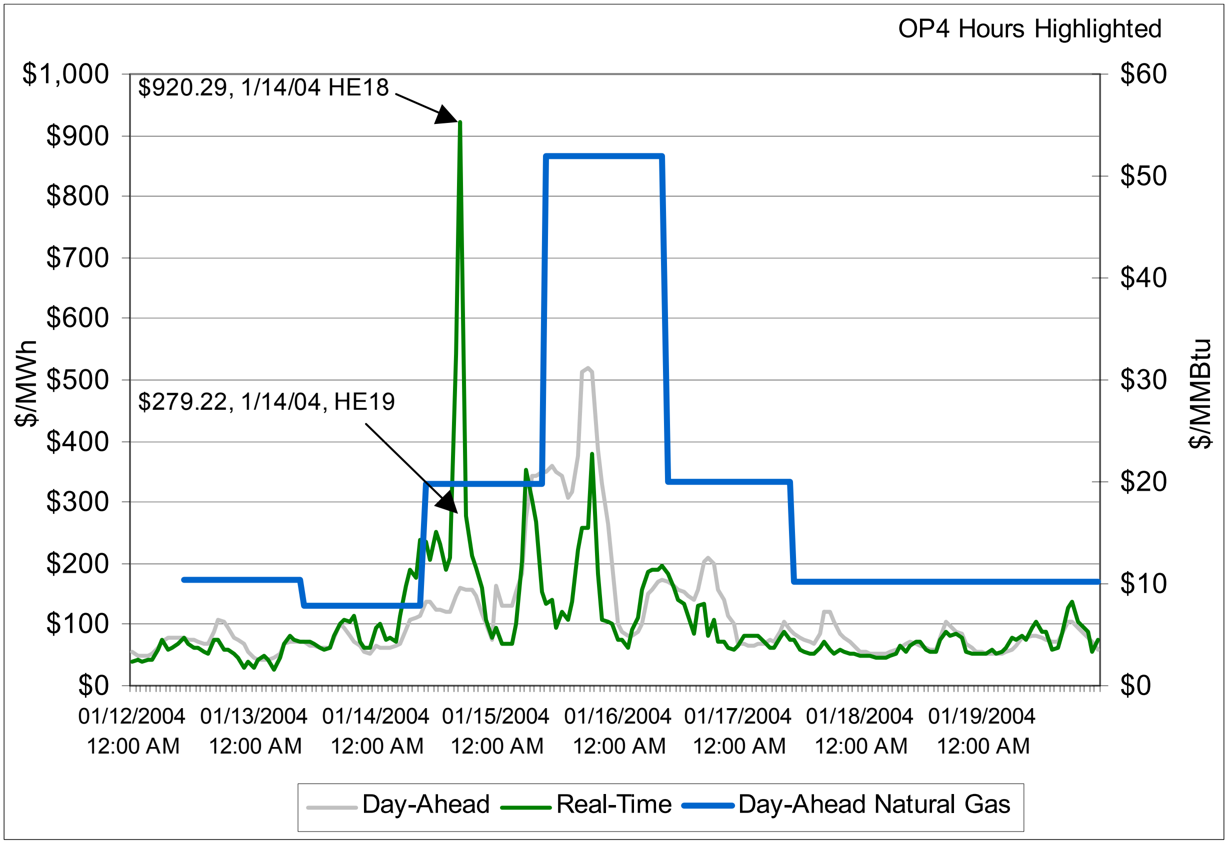
The pre-event outages and reductions, as reported, were within the normal range for the season. The only units in the pre-event category were those units out-of-service due to scheduled maintenance or equipment failures before the Report Period. Weather and fuel-related outages and reductions for gas-fired units are significant contributors to the high overall outage total. Outages are discussed in more detail in Section IV.D.

3. Power and Fuel Price Data

Figure 6 shows the hourly day-ahead and real-time electricity prices at the New England electricity trading hub plotted against the average New England day-ahead natural gas price. The average gas price is the average of prices at three important natural gas trading pricing points in New England: Algonquin Citygate, Dracut, and Tennessee Zone 6.

Figure 6 shows that both electricity and gas prices were highly volatile during the Report Period. Day-ahead gas prices increased dramatically; averages reached over $50/MMBtu during the Report Period, with a high trade of $74/MMBtu. During the same period, electricity prices also experienced significant increases; real-time hourly prices reached more than $900/MWh during OP4 conditions on January 14, and sustained prices above $100/MWh for the other days. While power prices during the Report Period exhibited high hourly volatility, the variation between the load zones in the day-ahead and real-time markets was small. Congestion was low, with much of the LMP variation due to losses. This is attributed primarily to the fact that oil-fired generation in import-constrained areas was operating in-merit, while gas-fired generation in export-constrained zones was out-of-merit and not fully loaded. A similar pattern was seen during the gas price spikes of March 2003. Because the need for congestion relief did not significantly affect LMPs, and unit dispatch more generally, the report does not address congestion issues in detail. In short, the LMPs suggest that New England was operating primarily as an unconstrained pool throughout the Report Period.

Figure 6 - Hourly Day-Ahead and Real-Time Power Prices at the ISO Hub and Daily Day-Ahead Natural Gas Prices in New England,[44] January 12-19, 2004



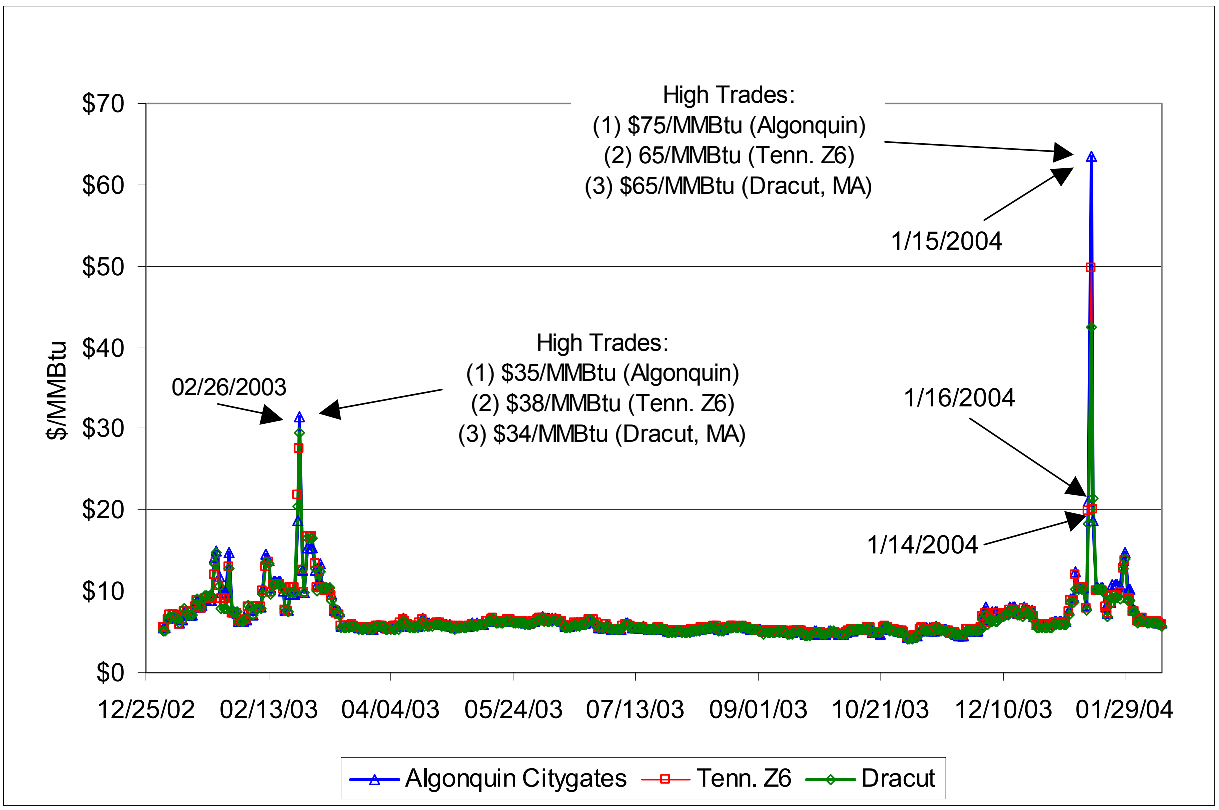
Note that each electricity price is plotted against the time for which the price is applicable. The average day-ahead gas price is plotted consistent with the gas operating and trading day for which it is applicable. The gas-operating day is a 24-hour interval from 10:00 a.m. to 10:00 a.m. The prices shown in Figure 6 are generally consistent with the underlying conditions in the electric and gas markets. The high gas prices occurred during a period of exceedingly high gas system utilization and extreme operating conditions. Given the sharp increase in regional gas prices and New England's dependence on gas-fired generation,

[44] Data on natural gas prices are obtained from Platts and Intercontinental Exchange (ICE). The natural gas price index shown in Figure 6 is an average of the Algonquin, Dracut, and Tennessee Zone 6 trading hubs in New England.

electricity prices should be expected to rise on average. However, the highest electricity prices (over $900/MWh) occurred as a result of a capacity deficiency, not because expensive gas units were setting LMPs. The following sections will examine the rise in electricity prices, and the behavior that caused it in greater detail.

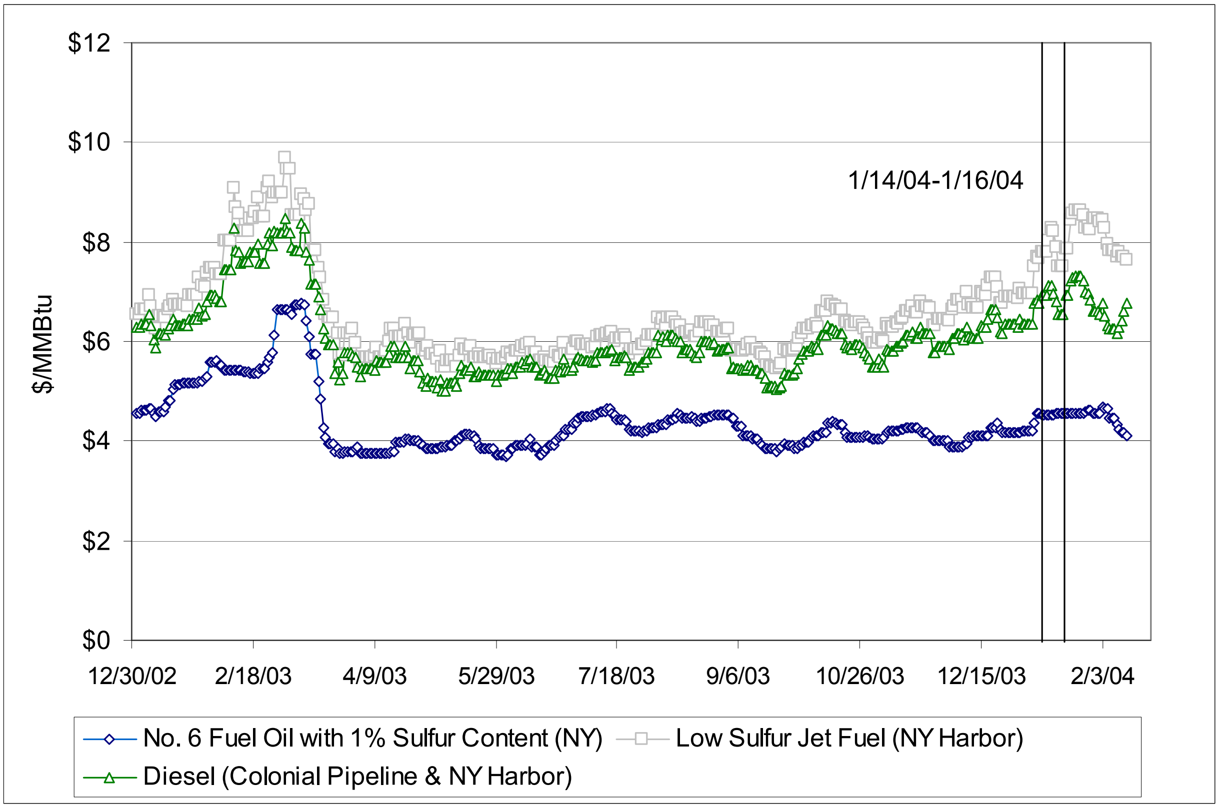
The price of natural gas at the Algonquin, Tennessee, and Dracut pricing points in New England over the last year is shown in Figure 7. Gas price volatility during the Report Period far exceeded average levels, and also exceeded the levels experienced in the winter of 2002-2003.

Figure 7 - Daily Average Day-Ahead Natural Gas Prices in New England at Selected Hubs



By contrast, as shown in Figure 8, prices for various types of fuel oil showed much less volatility than prices for gas during the January 2004 Cold Snap. Low-sulfur jet and diesel fuel prices (No. 2 fuel oil) rose during the Report Period, while No. 6 fuel oil prices remained essentially flat. The modest escalation of oil prices, as compared to the sharp rise in gas prices, most likely contributed to the relatively low prices in the electricity market during the Report Period, excluding the OP-4 hours. Oil-fired units dispatched in economic order displaced gas-fired units. Oil-fired units were on the margin for many of the on-peak hours during this period.

Figure 8 - Daily Oil Price Indexes at Selected Locations



The next section examines how a natural gas-fired generator might evaluate participation in the electricity market when gas prices are both high and highly uncertain.

B. Pricing of Supply Offers by Gas-Fired Generation

1. Effects of Gas Price Volatility

This section of the analysis addresses the effect of gas price volatility on generator supply offers during the Report Period.

Under typical system conditions, the forward market prices for power and gas imply a heat rate that allows efficient gas-fired units to operate profitably (*i.e.*, infra-marginally) during on-peak hours.[45] However, during extreme weather events, the price of gas and power may "decouple." That is, the price of gas may rise significantly more than the power price. In such a case the cost of fuel for gas plants rises disproportionately compared to the market price of electricity. Above some level, even the most efficient gas plants are unable to produce electricity and break even or earn a profit.

[45] A generator's heat rate is the rate at which it converts gas (MMBtu) to electricity (MWh) and measures the thermal efficiency of the conversion process. The implied heat rate for any day can be calculated as the ratio of forward power and forward gas prices for that day, which approximates the thermal efficiency that would be required to break even on the conversion of fuel to electricity. VOM and emissions are not considered.

Figure 9 - Daily Average Implied Forward Heat Rates in New England, Based on Day-Ahead Average On-Peak Electricity and Gas Prices

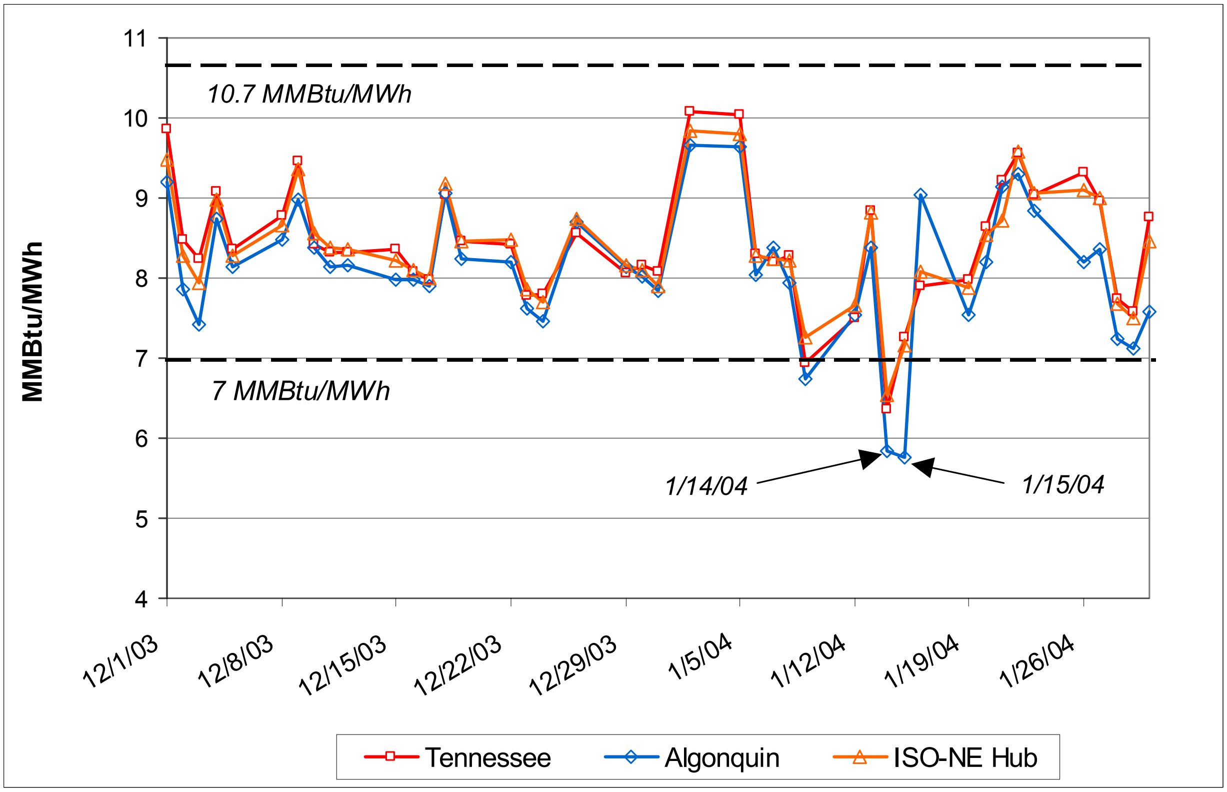


Figure 9 illustrates this point. It plots the day-ahead implied heat rates for two pipelines, which is the ratio of the representative day-ahead price of power to the day-ahead price of gas at these locations, along with lines showing the efficiencies of a state of the art combined cycle plant (7 MMBtu/MWh) and a more typical combustion turbine (10.7 MMBtu/MWh). The day-ahead price of power is an average of the on-peak LMPs at the node of each generator that runs on natural gas delivered by either the Algonquin or Tennessee pipelines. Also plotted is the implied heat rate at the New England hub, using the day-ahead prices for gas and power in Figure 6. During the Report Period, the implied heat rate at the New England hub closely tracked the implied heat rate at Tennessee. Note that using average on-peak electricity prices for the implied heat rate calculation is appropriate because the most efficient gas-fired generators (combined-cycle units) have minimum run times of eight hours or more. When combined with daily operating reserve calculations that apply infra-marginal revenues from some hours to out-of-merit operating costs in others, the substantial minimum run times of these units suggest that average on-peak prices would produce implied heat rates that best indicate which units can operate profitably during a given day, given their thermal heat rates and other operating characteristics.

The spot market implied heat rate shows how efficient a generator buying gas and selling electricity in the spot market must be, ignoring non-fuel variable costs and start-up and no-load costs. Generators with a thermal heat rate of less than the implied heat rate on any given day would find it profitable to convert natural gas into electricity (positive spark-spread). Those with heat rates above the implied heat rate would be unprofitable (negative spark-spread) and perhaps choose to shut down (to the extent permitted by the applicable market rules) in the absence of other arrangements such as reliability must-run contracts, forward reserve commitments or operating reserve payments. Given that a state-of-the-art gas plant typically has a heat rate of about 7 MMBtu/MWh at full load, Figure 9 suggests that it was not optimal for any gas-fired generator connected to Algonquin to be online on January 14 or 15 in the day-ahead electricity market.[46] On Tennessee and at the hub, no gas-fired generators would be profitable on January 14, and only under unrealistic assumptions (zero start-up and no-load costs, no fuel penalties, etc.) would a state-of-the-art gas unit be expected to break even on January 15. Only the most efficient gas-fired generators using day-ahead gas would have been able to operate economically

[46] At 50 percent load, the heat rates are about 10 to 25 percent higher, depending on the specific equipment design. Minimum load varies widely depending on air permit restrictions and unit specific emissions control equipment, and other physical characteristics.

on January 16. This suggests that most gas-fired generators would not have expected to be infra-marginal during much of the Report Period.

This has implications for evaluating the possible exercise of market power by gas-fired units. Given that even the most efficient gas-fired generators were "out-of-the-money" on January 14 and 15, any attempts at economic withholding would not have raised LMPs. Economic withholding would have influenced only Operating Reserve payments. A unit with costs above the prevailing LMP could not influence LMPs by "withholding," because it is not infra-marginal in any event, even with offers "at cost." On January 16, some portion of gas-fired generators was infra-marginal.

The spark spread relationships do not capture a generator's exposure to costly imbalance penalties when OFOs are posted, and which are not known until after the gas day has ended. Interstate pipelines from time to time issue and implement system-wide, market area or local OFOs in the event of deliverability constraints to protect the physical integrity of the pipeline. Left unchecked, shippers over-pulling gas from the pipeline could reduce delivery pressures to below contract minimums. Flow orders are uniformly applicable to all volumes received at all receipt points under all rate schedules. Issuance of the flow order as a Critical Notice on a pipeline's Electronic Bulletin Board ("EBB") puts shippers on notice that they must conform to their Maximum Daily Quantity ("MDQ") or Maximum Hourly Gas Quantity ("MHQ") flow rates as defined in the pipeline's tariff.

The pipeline's OFO daily or hourly tolerance is a percentage established by the pipeline. This percentage is generally +or - 2 %.[47] Shippers are obligated to take their daily or hourly gas supply within these tariff-defined percentages. Failure to stay in conformance with the daily or hourly flow limitation, often referred to as the "ratable-take provision," can cause the shipper to incur expensive penalties for unauthorized contract over-pulls. Ratable takes result in proportioning the granted nominations to twenty-four equal volumes metered over the full gas day instead of allowing the consumption of the nominated volume at any point during the day. Table 14 summarizes each pipeline's OFO penalty. Note that LDC penalties are not shown in Table 14, but in New England those penalties can be five times the applicable daily spot gas price.

Table 14 - Summary of New England Interstate Pipeline OFO Penalties

Pipeline		OFO Overrun Penalty
Algonquin		\$15 / Dth
Iroquois		\$2.50 / Dth, up to 50 Dth \$25 / Dth, for additional overruns
Maritimes & Northeast		\$50 / Dth
Portland Natural Gas Transmission System		\$2.50 / Dth, up to 50 Dth \$25 / Dth, for additional overruns
Tennessee	Action Alert	Twice the otherwise applicable daily charges
	Balancing Alert	\$15 + Regional Daily Spot Price / Dth

When pipelines issue OFOs, transportation to non-LDC shippers who are interruptible have usually been interrupted. In accord with FERC tariffs, secondary firm arrangements out of the primary contract path are subordinated to primary firm transportation arrangements. Many gas-fired generators do not have any primary firm rights across the Algonquin or the Tennessee

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[47] In Algonquin's case, the FERC has allowed the pipeline to differentiate the hourly tolerance for different contract customers. A substantial portion of Algonquin's entitlement holders in Connecticut and Massachusetts receive an extra 6 percent hourly tolerance. This sub-group of benefited entitlement holders are all gas utilities. All other firm transportation shippers are subject to a 2 percent daily tolerance requirement when Algonquin posts an OFO.

route system, let alone MDQs equal to *expected* winter loadings. Some have primary firm transportation rights for a portion of the daily requirement or for a lateral only, however. Of critical concern in light of the OFOs posted on Algonquin and Tennessee is that generators holding firm transportation entitlements would be able to exercise their respective contract rights, but not necessarily in conformance with the daily and/or hourly restrictions given the dispatch pattern of the unit(s). Failing to comply with the ratable-take provision incorporated in each pipeline's general terms and conditions is a costly option for a merchant generator. If an OFO is posted and the merchant generator takes gas in excess of the daily and/or hourly limit applicable to his delivery point(s), the merchant generator would be liable for unauthorized overrun daily penalty charge(s) *plus* any unauthorized overrun hourly penalty charge(s) *plus* applicable penalties billed to the delivering pipeline by any upstream supply pipelines, if any. In the extreme, over-pulls could result in an immediate curtailment of gas supply via automatic flow control valves. This would cause the unit to trip, possibly necessitating costly repairs. The pipeline penalty alone is expensive, particularly since there is no existing market mechanism for a generator to "socialize" the cost of the infraction after the fact. For any generator not located on a main pipeline, the penalties can "pancake"; that is, the cost of the infraction would be additive. For example, a merchant generator served by a Massachusetts LDC receiving upstream transportation from Tennessee could have been exposed to penalty gas for imbalance resolution equal to $387 per Mcf[48] on January 15: a $15/MMBtu imbalance penalty plus the $62/MMBtu spot price of gas plus $310/MMBtu in LDC penalties (5 x $62/MMBtu).[49]

The implied heat rate concept can also be applied to fuels other than natural gas. Given the prices of jet fuel and No. 2 fuel oil, an implied heat rate calculation can be performed. This is shown in Figure 10. The dramatic rise in implied heat rates for jet fuel and No. 2 oil units suggests that most units burning these fuels were infra-marginal during the Report Period.

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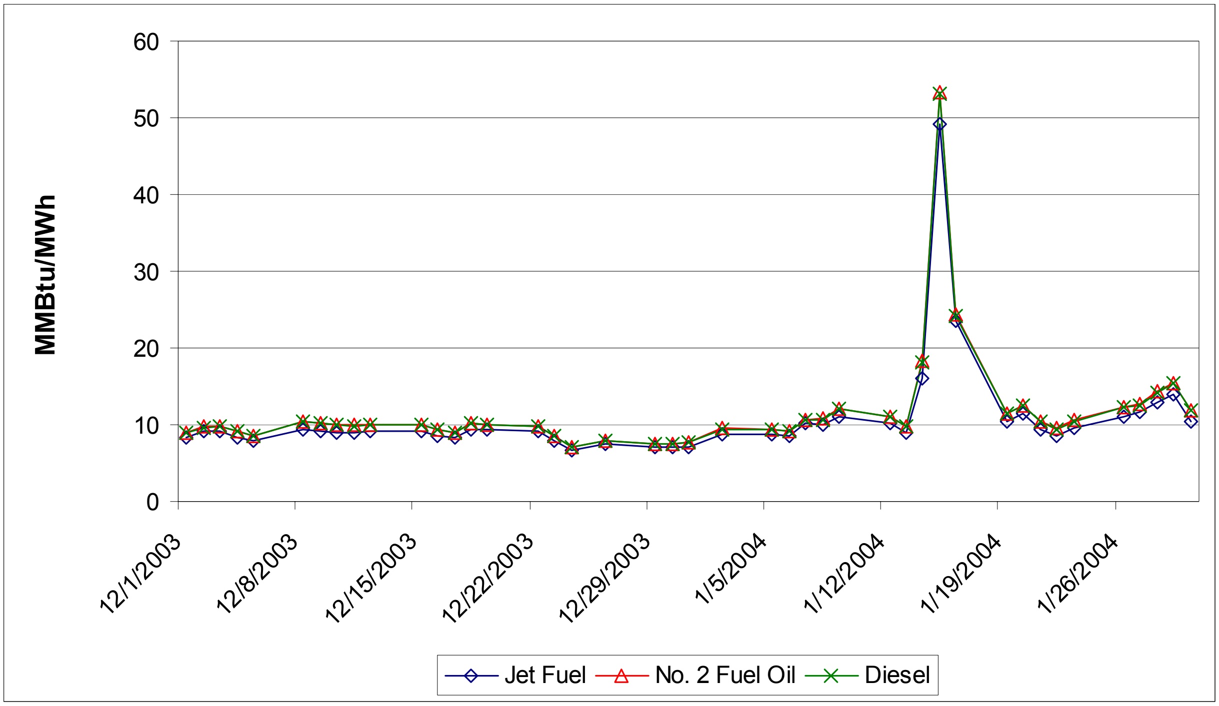
[48] Thousand Cubic Feet. 1 Mcf is approximately equal to 1 MMBtu = 1 Dth, approximately equals .95 Giga-Joule (GJ).

[49] To understand the impact of "pancaking" penalties, assume average generation of 250 MW, about 76% of the seasonally claimed capability of the unit. This equates to 36,000 Mcf/d. If only 5% of total gas use is above the 2% tolerance, the imbalance quantity = 1,800 Mcf, or $696,600 for the day. If no LDC penalties apply, but the infraction occurs on Tennessee, the imbalance decreases to $138,600.

Figure 10 - Implied Heat Rate for Peaking Unit Liquid Fuels, December 1, 2003 - January 31, 2004



2. Hourly LMPs versus Variable Costs

Related to the spark-spread concept, marginal costs can be calculated for a generator with an assumed heat rate at the applicable gas price, and compared with actual LMPs. Figure 11 shows an example of a power plant with the heat rate of 8 MMBtu/MWh offered with the underlying fuel price equal to the observed day-ahead average gas trade.[50] Whenever the power price is above the unit's heat rate times gas costs, it is profitable for this unit to commit, assuming no start-up or no-load costs and a one-hour minimum run time. The most efficient plants (those with heat rates below roughly 9 MMBtu/MWh) are not this flexible.

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[50] As in the earlier examples, variable operations and maintenance and environmental costs are not included to be consistent with industry conventions. For most units, these costs are small relative to fuel costs.

Figure 11 - Variable Production Costs of Gas Plant with a Heat Rate of 8 MMBTU/MWh, Based on Average Day-Ahead Gas Prices and Day-Ahead and Real-Time Electricity Prices, for January 11 - 17, 2004

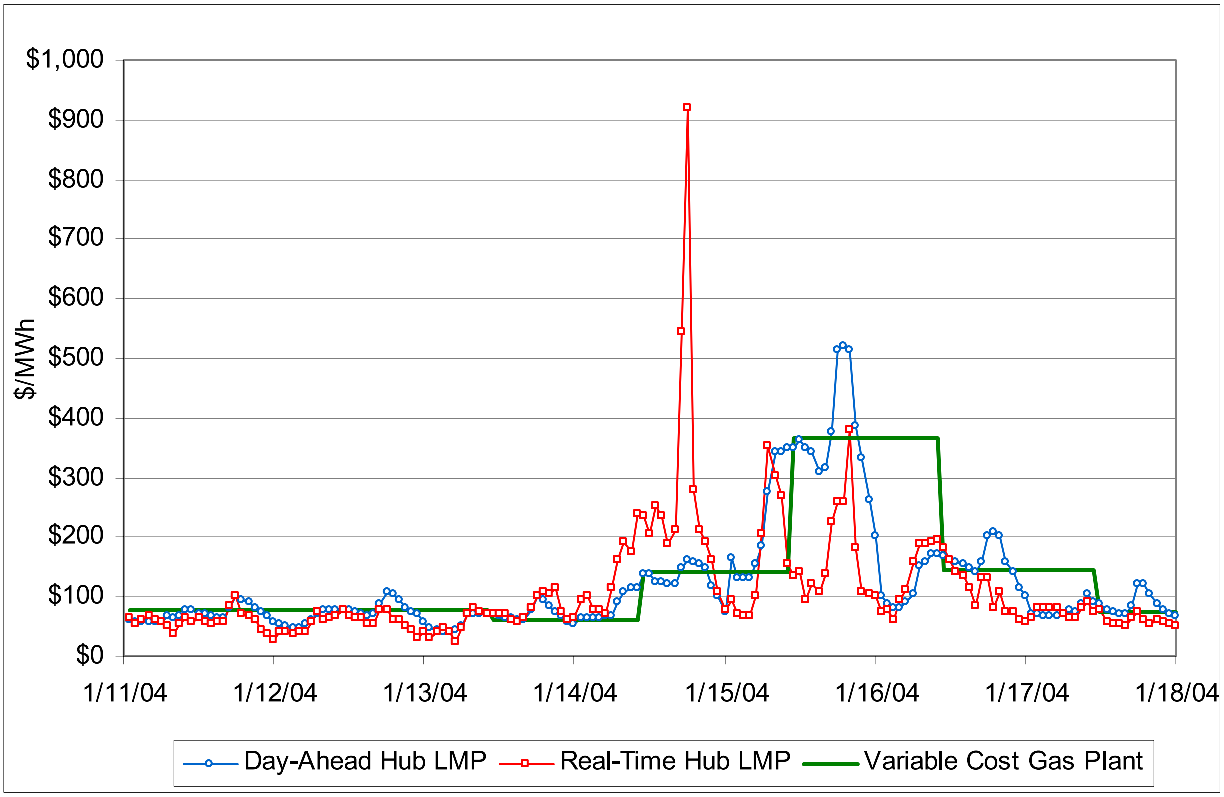
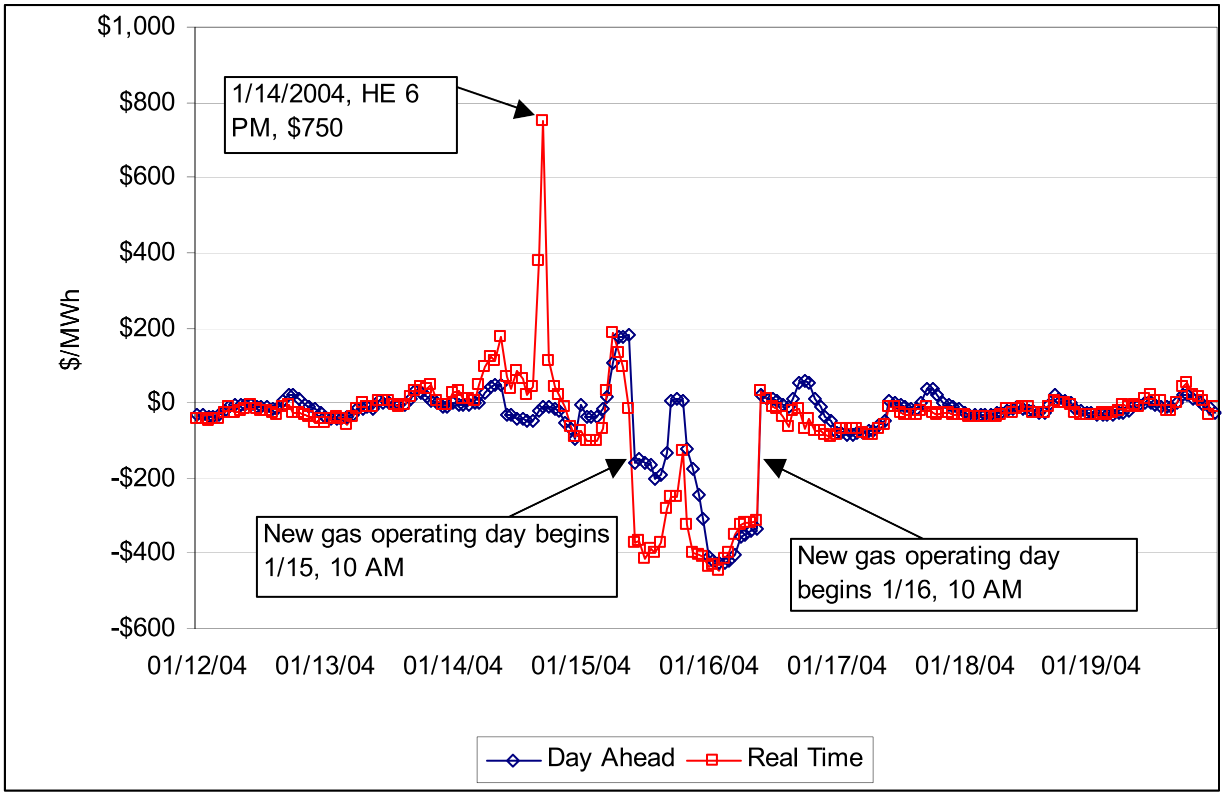


Figure 11 shows that even for a reasonably efficient gas plant paying day-ahead gas prices, it was only sporadically profitable to produce electricity during the Report Period. The time intervals for such profitable electricity production by a unit are shown by a positive spark spread. Figure 12 plots the day-ahead and real-time spark spreads for the unit characterized in Figure 11.

Figure 12 - Day-Ahead and Real-Time Spark Spreads for a Gas-Fired Unit with an 8MMBtu/MWh Heat Rate, January 12 - January 19, 2004



When the spark spread is positive, the production of electricity is profitable. We observe that both day-ahead and real-time spark spreads are only occasionally positive and that the volatility of those profits, and therefore the uncertainty associated with them, are very high during the Report Period. Also note that non-fuel variable costs and start-up and no-load costs are ignored. These costs would further reduce a unit's profitability. For less efficient plants, those facing higher gas costs, or those that are not flexible on an hourly basis (which is most plants in New England), even these hours might be unprofitable.

3. <u>Gas and Power Markets Trading and Scheduling Timelines</u>

The gas prices described and used above are generally day-ahead gas prices that are reported after the closing of day-ahead gas trading. While these prices are widely reported, they may not reflect either the actual or the expected cost of gas for a generator submitting a supply offer. This section shows why this is the case.

Generators have a range of gas supply options that include: long-term and short-term purchases in the gas producing regions, at major continental market centers, at regional market hubs, or at the citygate. These purchases can be tied to spot market prices or can use some other agreed upon pricing mechanism, such as fixed price contracts. Firm and non-firm transportation options can be used for delivery. Non-firm transportation - both secondary firm transportation and interruptible transportation - is typically at risk of interruption during periods of extremely cold weather. Under typical conditions, generator supply offers are usually based on the day-ahead market price for gas. Gas supply and transportation nominations are typically done on a day-ahead basis. Some gas supply is purchased in day-ahead and intra-day markets. Intra-day transaction volumes are comparatively thin, however.

Four distinct scheduling windows during the gas scheduling and operating day. They are listed in Table 15. The first two are day-ahead windows for Timely Gas and Evening Gas. The majority of gas trading in the day-ahead market is consummated between 8:00 a.m. and 10:00 a.m. one business day ahead of the operating day. The other two products are intra-day gas, scheduled to begin delivery on the same day. The trading of intra-day gas continues around the clock. Firm capacity can "bump" interruptible capacity for the first three of these scheduling windows, adding further uncertainty to holders of non-firm capacity.

Table 15 - Scheduling Timeline for Day-Ahead and Intra-Day Gas[51]

Gas	Nomination Deadline for Shippers	Point Operator Confirmation Deadline	Receipt of Final Scheduled Quantities by Shippers & Point Operators	Effective Start Time for Gas Flow
Timely Gas (day-ahead)	12:30 p.m.	4:30 p.m.	5:30 p.m.	10:00 a.m. [52]
Evening Gas (day-ahead)	7:00 p.m.	10:00 p.m.	11:00 p.m.	10:00 a.m. [53]
Gas 1 (intra-day)	11:00 a.m.	2:00 p.m.	3:00 p.m.	6:00 p.m.
Gas 2 (intra-day)	6:00 p.m.	9:00 p.m.	10:00 p.m.	10:00 p.m.

The timeline of decisions in the day-ahead and real-time gas market is shown against the power markets timeline in Figure 13. The key points are that the various deadlines and inflexibilities in the two markets combine to limit the ability of participants to update offers in the electricity market, and implicitly require that participants either take a position in the gas market while uncertain of their electricity market obligations or reflect uncertain gas prices and availability in their electricity market offers. [54]

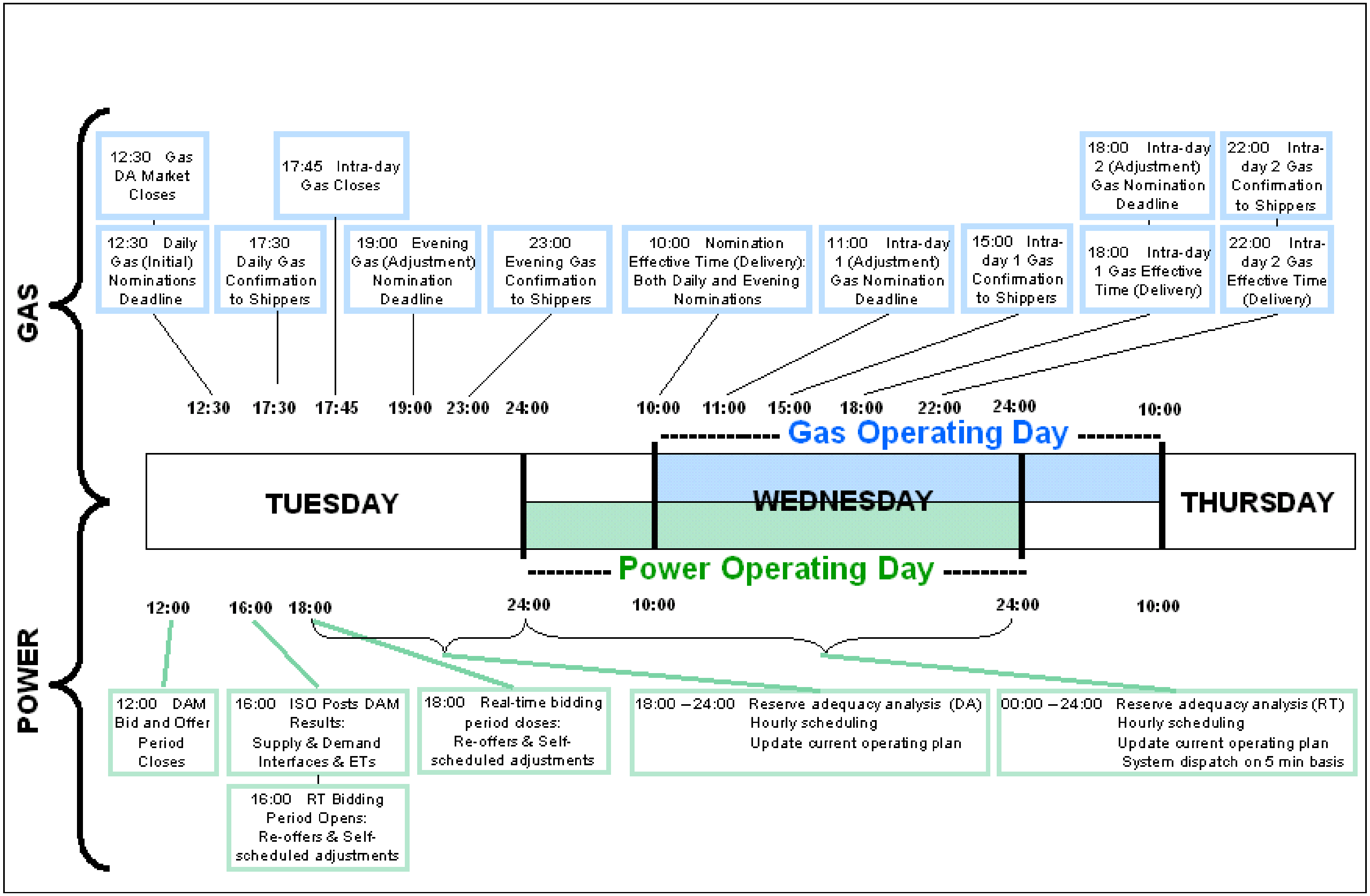
[51] All times are EST (Eastern Standard Time)

[52] On the next day.

[53] On the next day.

[54] For a more detailed discussion of the gas-electric timelines, see Appendix A.

Figure 13 - Gas and Power Markets Trading and Scheduling Timeline



To better understand the decisions facing gas-fired units, it is necessary to first examine the decision faced by generators offering in the day-ahead electricity market. Generators anticipating gas requirements for the next power day must make day-ahead commodity purchases and submit their daily transportation nomination to their respective shippers no later than 12:30 p.m. for the day-ahead gas market. In the electricity market, offers are submitted at noon, with day-ahead electricity schedules released at 4:00 p.m. Thus to pay day-ahead gas prices, generators must nominate their gas supply well before knowledge of their day-ahead electricity schedule at 4:00 p.m. In fact, nominations of transportation quantities must be made at nearly the same time as the day-ahead electricity offer submittal deadline. When expected day-ahead prices make it likely that a generator will be dispatched, they may seek to line up gas in the day-ahead gas market. If expected day-ahead electricity prices are relatively low, and the generator does not anticipate economic dispatch, it is unlikely that the generator will seek to nominate and gain delivery of day-ahead gas. A generator committed in the day-ahead market that does not have day-ahead gas would seek to line up gas during the evening day-ahead gas adjustment period.

The above discussion ignores the fact that a generator receiving day-ahead dispatch between midnight and 10:00 a.m. of the operating day would necessarily need to buy intra-day gas for that portion of its electric schedule or use day-ahead gas arranged for on a previous day. This is because the gas day runs from 10:00 a.m. to 10:00 a.m., while the electricity market runs from midnight to midnight.

In comparison with the above, a generator not committed in the day-ahead market faces different decisions. Between 4:00 and 6:00 p.m., the ISO accepts re-offers from generators not committed day-ahead. Between 6:00 p.m. and midnight, the ISO performs the day-ahead

Reserve Adequacy Analysis ("RAA") to determine what additional generators will be required for system reserves and capacity requirements to maintain real-time system and sub-area reliability. Generators not committed day-ahead may be committed or scheduled to be committed during the day-ahead RAA or later during the dispatch day. Re-offers must reflect the gas market conditions expected in the event of dispatch during the day-ahead RAA process or in real-time. Final gas nomination adjustments are required before the ISO's reliability commitment. Thus, any gas units selected during the day-ahead RAA or in real-time must buy intra-day gas, not day-ahead gas. This would be reflected in their re-offers. While this works reasonably well under normal conditions, it does not work as well when pipelines are at or near their capacity limits.

It is generally expected that under normal circumstances the expected price of intra-day gas is higher than that of the day-ahead gas, with only a modest difference. The volatility (price uncertainty) of the intra-day product is also higher.[55] Under unusual conditions, like the ones experienced during the Report Period, the liquidity in the intra-day gas market may be extremely thin, thereby heightening price volatility. One manifestation of this volatility is large bid-ask spreads. Another manifestation is large spreads between the intra-day price and the day-ahead price. It is also possible for liquidity to "dry-up" under the extremely tight gas system conditions of January 14-16; *i.e.*, it may not be possible to obtain intra-day gas or transportation at the desired delivery point to meet the scheduled start time for the generating unit at any price. The reduced liquidity, high volatility, and potentially high prices in the intra-day gas market during

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[55] Unfortunately systematic and publicly available price and volume information for the intra-day market is not available so these assertions are based on a general understanding and conventional wisdom of the marketplace, not reliable data.

extreme periods would reasonably be reflected in the electricity supply offers of units not anticipating a day-ahead schedule.

As noted earlier, under extremely cold conditions such as those during the Report Period, gas system operators may implement specific operational restrictions (OFOs and ratable takes) on gas consumption that further complicate offer formulation by gas-fired units. The combination of these two restrictions, enforced by significant penalties, up to and including instant curtailment of gas shipments, can dramatically increase gas costs and risk to generators. These restrictions essentially impose a requirement to take (and pay for) gas during hours when the generator does not anticipate being scheduled to run in merit. These penalty costs may also be incorporated into a generator's offer.

This discussion shows the complicated decisions facing gas-fired units formulating electricity supply offers. Assuming that gas-fired generators expect to pay the average day-ahead gas price may be inappropriate during periods of tight gas supply. A rational generator might base its supply offers on a much higher assumed gas price, reflecting price uncertainty, liquidity, pipeline penalties, and restrictions. This suggests that the spark-spread calculations in the previous section overstate a units true expected profitability.

One concern raised by a comparison of the electric and gas market timelines is that the failure to purchase day-ahead gas and make transportation nominations reduces the amount of gas ultimately available for consumption in real-time under tight gas system conditions. This could be caused either by low day-ahead electricity prices or the timing of the electricity market day-ahead clearing process. If the pipelines were at capacity, then this may not be relevant as the additional nominations could not be accommodated. However, if the pipelines were underutilized day-ahead, it could be that spare transport capacity could have been available if generators sought to make additional nominations day-ahead. Such an analysis is beyond the scope of this report, but should be considered when evaluating any market timeline changes.

4. Economic Outages, Gas Unit Availability, and Gas-Fired Unit Contracting Practices

During the Report Period, all economic outages[56] requested by gas-only units were in the Southeastern Massachusetts (five units), Maine (one unit), Northeastern Massachusetts and Boston (one unit), and Rhode Island (three units) load zones, totaling 2,327 MW. Each unit is an ICAP resource. Two of the ten units had returned to service by January 15.

The economic outage provisions of the NEPOOL market rules are intended in part to allow gas-fired generators to manage their fuel costs. Natural gas purchase and delivery arrangements can be complex. Generators must buy the gas itself (commodity) and reserve space (capacity) on a pipeline or local gas distribution facility to have it delivered (transportation). Commodity contracts may be firm (guaranteed delivery) or interruptible and may be at fixed prices or at prices tied to one or more market indices. Transportation arrangements may also be firm or interruptible. By accepting interruptible contracts for either the commodity or transportation (arrangements that allow their supplier or transporter to curtail gas supply when the commodity or transportation is in short supply) merchant generators can lower their fuel procurement costs under typical conditions. But this may also limit their ability to produce electricity in times of pipeline capacity constraints or high commodity prices.[57]

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[56] Economic outages are requested when a generator believes that it will not be able to recover its costs of operation, including opportunity costs, by running in the electricity market. For example, if the cost of natural gas would require that a generator submit an energy offer exceeding $1,000/MWh to recover its costs, the generator could request an economic outage because supply offers cannot exceed $1,000/MWh. The ISO may reject an economic outage request if it would cause an actual or projected capacity deficiency, reserve violation, or transmission problem.

[57] Negative spark spreads.

These types of arrangements will tend to lower electricity prices, on average, while also making them more volatile in occasional periods of more limited gas availability. In times of more limited availability (either commodity or transportation), generators without firm contracts must compete with industrial, commercial, and home heating demand for limited spot market gas, and spot gas prices may spike to levels that would not permit generators to recover their fuel costs when competing against oil-fired and other generating resources.

Table 16 - Gas-Fired Available MW (Winter Claimed Capability) for the Peak Hours, January 14-16, 2004

Market Day	Total MW	Total Available MW	% of Total MW	Fuel Availability Related Outage – MW	% of Total MW	Weather or Equipment related Outage - MW	% of Total MW
January 14, 2004 HE 6 pm	10,332	4,271	41%	2,964	29%	3,097	30%
January 15, 2004 HE 7 pm	10,332	5,066	49%	1,907	18%	3,359	33%
January 16, 2004 HE 6 pm	10,332	6,323	61%	1,462	14%	2,546	25%

Table 16 shows, for the peak hour of each day of the Report Period, the total MW of gas-fired installed capacity, the total MW and percentage available, and the total MW and percentage unavailable. The unavailable amounts are divided into fuel-availability related outages and weather or equipment related outages. Fuel-availability related outages steadily declined over the Report Period, while weather and equipment related outages were roughly constant. The fuel-availability related outages decreased despite weather conditions that got progressively worse, suggesting that fuel availability improved as the gas and electricity markets adjusted to the Cold Snap.

During the Report Period, of 39 gas-only units in New England, only nine did not experience some period of outage with two others suffering only minor degradation of output.

Tables 17 through 20 demonstrate that the status of a unit's gas transportation arrangements (firm vs. non-firm) had some, though limited, bearing on the capacity unavailable due to outages. Tables 17 through 20 show, for the peak hour of the day, the total available gas-fired capacity during the Report Period. This capacity is divided into capacity with firm and non-firm transportation arrangements. Data on transportation arrangements are from the FERC staff report, *New England Gas Infrastructure*.[58] They were spot-checked with the results of the ISO survey responses. Within firm and non-firm transportation, the capacity in each load zone is classified as available, unavailable due to lack of gas, or unavailable due to weather- or equipment-related outages. Table 17 provides pool-wide availability data for each day of the Report Period. Tables 18-20 show availability by load zone, with a separate table for each day.

Table 17 allows the comparison of gas unit availability by day and type of fuel transportation arrangements. Gas unit availability improved each day of the Report Period regardless of type of fuel transportation arrangements. Weather- and equipment-related outages were very similar across days for units with firm transport. These outages were more variable for units without firm transport. The percentage of gas-availability related outages was uniformly lower for units with firm gas transportation arrangements than for units without firm gas transportation arrangements. Overall, availability for units with firm gas transport averaged 56 percent, while availability for units without firm gas transport averaged 42 percent. Much of this difference is due to differences in gas-availability related outages, suggesting that having firm gas arrangements did increase unit availability.

[58] Docket No. PL04-01-00, December 2003.

Table 17 - Gas Unit Availability by Day, With and Without Firm Transportation, January 14-16, 2004, Peak Hour

Market Day	Total Zonal MW	With Firm Transport							Without Firm Transport						
		Total Firm MW	Firm Available MW	% of Firm MW	Gas Related Outage - MW	% of Firm MW	Weather or Equipment related Outage - MW	% of Firm MW	Total Non-Firm MW	Non-Firm Available MW	% of Non-Firm MW	Gas Related Outage - MW	% of Non-Firm MW	Weather or Equipment related Outage - MW	% of Non-Firm MW
January 14, 2004 HE 6 pm	**10,332**	**5,899**	2,879	49%	1,512	26%	1,508	26%	**4,433**	1,393	31%	1,451	33%	1,589	36%
January 15, 2004 HE 7 pm	**10,332**	**5,899**	3,291	56%	1,101	19%	1,507	26%	**4,433**	1,776	40%	806	18%	1,851	42%
January 16, 2004 HE 6 pm	**10,332**	**5,899**	3,837	65%	554	9%	1,507	26%	**4,433**	2,487	56%	908	20%	1,039	23%

Table 18 - Available Gas MW by Load Zone January 14, 2004 Peak Hour (Hour Ending 6 p.m.)

Zone	Location	Zonal Gas MW	January 14, 2004, Peak Hour (Hour Ending 6 p.m.)											
			With Firm Transport						Without Firm Transport					
			Available MW	% of Total Zonal MW	Gas Related Outage - MW	% of Total Zonal MW	Weather or Equipment related Outage MW	% of Total Zonal MW	Available MW	% of Total Zonal MW	Gas Related Outage - MW	% of Total Zonal MW	Weather or Equipment related Outage MW	% of Total Zonal MW
4001	MAINE	1,372	270	20%	0	0%	0	0%	538	39%	2	0%	562	41%
4002	NEW HAMPSHIRE	792	0	0%	0	0%	792	100%	0	0%	0	0%	0	0%
4004	CONNECTICUT	1,488	48	3%	1	0%	0	0%	270	18%	559	38%	610	41%
4005	RHODE ISLAND	2,046	638	31%	852	42%	165	8%	388	19%	3	0%	0	0%
4006	SEMASS	2,185	246	11%	603	28%	415	19%	0	0%	504	23%	417	19%
4007	WCMASS	173	117	68%	56	32%	0	0%	0	0%	0	0%	0	0%
4008	NEMASSBOST	2,276	1,560	68%	0	0%	136	6%	197	9%	383	17%	0	0%
Total		**10,332**	**2,879**		**1,512**		**1,508**		**1,393**		**1,451**		**1,589**	

Table 19 - Available Gas MW by Load Zone January 15, 2004 Peak Hour (Hour Ending 7 p.m.)

Zone	Location	Zonal Gas MW	January 15, 2004, Peak Hour (Hour Ending 7 p.m.)											
			With Firm Transport						Without Firm Transport					
			Available MW	% of Total Zonal MW	Gas Related Outage - MW	% of Total Zonal MW	Weather or Equipment related Outage MW	% of Total Zonal MW	Available MW	% of Total Zonal MW	Gas Related Outage - MW	% of Total Zonal MW	Weather or Equipment related Outage MW	% of Total Zonal MW
4001	MAINE	1,372	0	0%	270	20%	0	0%	540	39%	0	0%	562	41%
4002	NEW HAMPSHIRE	792	0	0%	0	0%	792	100%	0	0%	0	0%	0	0%
4004	CONNECTICUT	1,488	48	3%	1	0%	0	0%	545	37%	21	1%	872	59%
4005	RHODE ISLAND	2,046	1,165	57%	326	16%	165	8%	61	3%	330	16%	0	0%
4006	SEMASS	2,185	412	19%	436	20%	415	19%	250	11%	255	12%	417	19%
4007	WCMASS	173	105	61%	68	39%	0	0%	0	0%	0	0%	0	0%
4008	NEMASSBOST	2,276	1,561	68%	0	0%	135	6%	380	17%	200	9%	0	0%
Total		**10,332**	**3,291**		**1,101**		**1,507**		**1,776**		**806**		**1,851**	

Table 20 - Available Gas MW by Load Zone January 16, 2004 Peak Hour (Hour Ending 6 p.m.)

Zone	Location	Zonal Gas MW	January 16, 2004, Peak Hour (Hour Ending 6 p.m.)											
			With Firm Transport						Without Firm Transport					
			Available MW	% of Total Zonal MW	Gas Related Outage - MW	% of Total Zonal MW	Weather or Equipment related Outage MW	% of Total Zonal MW	Available MW	% of Total Zonal MW	Gas Related Outage - MW	% of Total Zonal MW	Weather or Equipment related Outage MW	% of Total Zonal MW
4001	MAINE	1,372	270	20%	0	0%	0	0%	813	59%	290	21%	0	0%
4002	NEW HAMPSHIRE	792	0	0%	0	0%	792	100%	0	0%	0	0%	0	0%
4004	CONNECTICUT	1,488	48	3%	1	0%	0	0%	796	54%	21	1%	622	42%
4005	RHODE ISLAND	2,046	1,187	58%	303	15%	165	8%	66	3%	325	16%	0	0%
4006	SEMASS	2,185	666	30%	182	8%	415	19%	252	12%	252	12%	417	19%
4007	WCMASS	173	105	61%	68	39%	0	0%	0	0%	0	0%	0	0%
4008	NEMASSBOST	2,276	1,561	68%	0	0%	135	6%	560	25%	20	1%	0	0%
Total		**10,332**	**3,837**		**554**		**1,507**		**2,487**		**908**		**1,039**	

Tables 18-20 show gas unit availability and transportation arrangements by load zone. The performance of units with firm transportation in Western Central Massachusetts and Northeast Massachusetts/Boston was comparatively good. Overall performance of units in Maine was also good, and Rhode Island had approximately 50 percent availability. Every other region had relatively low availability. Connecticut had a relatively high proportion of forced outages for units without firm transportation. In Maine, units without firm transportation were comparatively successful in producing during the Report Period relative to units with firm transportation. By contrast, units in Southeastern Massachusetts and Maine with firm transportation were more available than those with non-firm transportation.

On average, 40 percent of New England's gas-fired capacity is associated with some type of firm gas delivery contract. Other than Rhode Island, with 83 percent of capacity tied to firm gas contracts, each state with significant gas-fired MW has between 25 percent and 40 percent firm gas. Often the owner of a group of gas-fired units will purchase enough firm gas and transportation for only one unit while depending on interruptible supplies for other units.

5. <u>Gas Arbitrage</u>

During the Report Period, some generators sold firm gas back into the gas market rather than use it to generate electricity. This behavior is generally called arbitrage. If expected power prices are lower than the production costs of a unit with firm gas, this presents an opportunity for a generator to sell gas back into the gas market for a profit greater than the expected profit in the electricity market. Generally, arbitrage improves market efficiency by allocating resources to those who value them most highly. If gas, for example, is more highly valued for home heating than for electric production, sale of the gas to a local gas distribution company allows that company to resell to customers who are undertaking a more highly valued activity.[59] The long-term purchase price is a sunk cost for purposes of the analysis. The electricity market responds by substituting electricity from other, cheaper sources. Gas sold by generators in New England might be sold to other, more efficient generators, or sold to local gas companies seeking alternate supply sources on the open market. All of these examples are desirable, with higher prices acting as the incentive to find such trades. In the case of electricity, fuel arbitrage (selling fuel if it is priced higher than electricity) is accepted practice, codified in the market rules of most independent system operators.[60] Note that whether or not a generator has sold its output has little bearing on this decision, because a generator could fulfill its obligations by purchasing from the spot electricity market.

Arbitrage allocates resources more efficiently and is appropriate market behavior. Even generators that do not sell available gas may appropriately reflect the foregone revenue opportunity in their supply offers. The foregone revenues from the sale of gas are a cost (known to economists as an opportunity cost) of a decision to generate electricity. Opportunity costs are included in the calculation of submitted offers just like any other costs, and help to ensure that the electricity price reflects the true value of the resources used in the production of electricity. This also explains why the day-ahead/intra-day prices of gas are used throughout this report

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[59] Whether such a sale earns a profit or reduces a loss depends on the cost of the gas to the generator under its long-term contract. The profit or loss is irrelevant to the arbitrage. It makes sense to sell if the price is higher in the gas market no matter whether the result is a profit or a loss.

[60] *See* Market Rule 1, Appendix B, § 3.2.1 – "Certain Economic Decisions Excused" and NEPOOL Operating Procedure No.5: Generation Maintenance and Outage Scheduling, http://www.iso-ne.com/smd/operating_procedures/OP5_SMD_FIN.doc. Discussions with market monitors at other ISOs confirm that it is accepted practice elsewhere, with ICAP deratings and lost power market revenues being the penalties. Arbitrage provisions are explicit in the rules of the California ISO (§ 2.4.3 of the market monitoring rules), Midwest ISO (§ 2.4.c of the market mitigation measures), and NYISO (§ 2.4 (2) of the market mitigation rules). They do not appear to be explicit in PJM.

without reference to any long-term gas contracts. A rational owner of long-term gas will reflect any opportunity costs in its supply offers to reflect the mark-to-market value of natural gas in the regional marketplace. Appendix C provides additional discussion of fuel arbitrage and a further discussion of the risks faced by gas-fired generators.

6. <u>Conclusions</u>

Gas unit availability during the Report Period was relatively low, caused by a combination of fuel availability and increases in other types of conditions that may cause an outage. Availability improved as participants gained experience with the extreme conditions of the Report Period. Units with firm gas transportation had higher levels of availability. Gas prices were high and highly volatile, rendering gas generators uneconomic much of the time, especially when risk and uncertainty are considered. Day-ahead gas prices likely understated the expected costs of generating during the period. Under the circumstances, gas arbitrage was rational and efficient.

C. <u>Potential for the Exercise of Market Power</u>

1. <u>Purpose of the Analysis</u>

This section of the analysis examines the possibility that generators may have sought to take advantage of unsettled conditions in the gas and power markets to exercise market power. While the analysis in the preceding section suggests that it is difficult to estimate a generator's actual or expected costs during the Report Period, the ISO performed a variety of different analyses to examine the potential for the exercise of market power and to detect particular behaviors that would suggest market power actually was exercised during the Report Period.

The results of those analyses, presented below, do not suggest that an exercise of market power in New England's wholesale electricity markets was likely or was attempted.[61]

2. <u>Resource Concentration</u>

While the results of an evaluation of the potential to exercise market power will not be sufficient to determine whether or not the exercise of market power has taken place, the evaluation is a useful indicator. This is especially true when evaluating market outcomes under extreme conditions, because there are less likely to be definitive conclusions from other analytical results. Under these circumstances, both *ex ante* indicators and *ex post* results can be used to produce an overall evaluation of market and participant performance.

Before evaluating market outcomes, it is useful to examine the underlying market structure. A review of the distribution of generating resources in New England reveals low concentration of ownership. A widely used measure of market concentration is the Hirschman-Herfindahl Index ("HHI"), calculated as the sum of the squares of the market shares of the firms in a market. Although a low concentration index does not guarantee that a market is competitive, higher values are indicative of greater potential for the exercise of market power by participants. The HHI for the winter of 2003–2004 is approximately 600. This is quite low relative to other organized wholesale markets, and well below the 1,800 "rule of thumb" threshold for a reasonable expectation of competitive markets.

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[61] The conclusions regarding market competitiveness in this report are limited to the wholesale electricity market. The ISO does not have sufficient information to draw any conclusions about the competitiveness of the natural gas market.

3. Residual Supply Index

The Residual Supply Index (RSI) is a measure of market competitiveness that calculates the degree of hourly supply and demand balance considering the largest supplier's market share of available capacity, *i.e.*,

$$\text{RSI} = \frac{\text{Total Supply - Largest Seller's Supply}}{\text{Total Demand}}$$

The RSI measures an individual bidder's potential influence on the market-clearing price. Residual supply is the amount of generation capacity remaining in the market after subtracting the capacity of an individual bidder. The RSI is the ratio of residual supply to total market demand. If the RSI exceeds 100 percent, then suppliers other than that bidder have sufficient capacity to meet market demand, and that bidder has relatively little influence on the market-clearing price for a given hour. On the other hand, if the RSI is below 100 percent, that bidder's capacity is needed to meet market demand, and that bidder becomes "pivotal" in determining the market-clearing price for that hour. The bidder can thus set the price as high as possible, subject to prevailing bid caps, although the profit-maximizing bid may be below the bid cap if the residual supply is price-elastic. The RSI is closely related to the HHI, discussed in the previous section, as an indicator of market competitiveness, but it is regarded as a more robust indicator for electricity markets, which are characterized by rapidly changing market conditions with continuous balancing of (non-storable) supply and demand.

Although there is no universally accepted threshold for the RSI in measuring market competitiveness, there is general agreement that the RSI must be significantly above 100 percent (usually at least 120 percent) for the market to be fairly competitive. Table 21 shows the number of hours during which the RSI was below 100 percent and 110 percent during selected summer and winter months, and during the 72-hour period covering January 14-16, 2004.[62] It also shows the minimum and maximum RSIs during each period.

Table 21 - RSI Comparison

Time Period	Number of hours RSI < 110	Number of hours RSI < 100	Average RSI	Maximum RSI	Minimum RSI
Beginning of Markets: May 1999	248	18	121%	169%	95%
July 2002	263	169	116%	174%	83%
August 2002	165	82	123%	184%	87%
January 2002	8	0	136%	177%	107%
January 2003	113	4	126%	185%	99%
January 2004	75	24	133%	194%	88%
January 14-16, 2004	49	24	106%	131%	88%
Aggregate of 14 Days with OP4 hours in 2001-2003 (excluding August 15, 2003 Northeast blackout)[63]	205	146	107%	163%	77%

The average RSI during the Report Period was lower than during typical peak months, although the index was in line with historical average RSI values during time periods containing OP4 conditions. The month of January 2004 compares favorably with other months under most of the metrics. These results suggest that the ability of any participants to profitably withhold capacity during the Report Period was similar to other OP4 periods in the past three years.

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[62] For this RSI analysis, total supply was defined as the month's Seasonal Claimed Capability (SCC) derated by 8 percent + net imports. Total demand was defined as Real-Time Adjusted Load Obligation + regulation (Automatic Generation Control) + requirements for reserves (Ten Minute Non Spinning Reserve, Ten Minute Spinning Reserve, and Ten Minute Operating Reserve). The 8 percent deration was an average 5-year Equivalent Forced Outage Rate ("EFOR") deration for the entire system.

[63] These days are:

2001: July 23-25, August 7-10. August 8 did not have OP4 hours but had load conditions similar to the adjacent days.

2002: June 26, July 23, August 5, August 13-14, and August 19.

2003: December 5

Table 22 provides a more detailed summary of the 24 hours during the Report Period for which the RSI fell below 100.

Table 22 - Summary of Hours where the RSI Fell Below 100, January 14-16, 2004

Hour	January 14	January 15	January 16	Total	Hours RSI < 95%	Hours RSI< 90%
12:00 a.m.- 5:59 a.m.	0	0	0	0	0	0
6:00 a.m.- 11:59 a.m.	3	2	4	9	2	0
12:00 p.m. - 5:59 p.m.	6	2	0	8	3	1
6:00 p.m. - 11:59 p.m.	4	3	0	7	6	0
TOTAL	13	7	4	24	11	1

The only hour in which the RSI fell below 90 percent was January 14 Hour Ending 6:00 p.m., when the NEPOOL system load reached its then-record winter peak. There were 10 other hours during which the RSI fluctuated between 90 and 95 percent.

4. Competitive Benchmark Analysis

Another way of measuring energy market competitiveness during the Report Period is to compare the real-time LMP at the electricity trading hub with a benchmark clearing price ("competitive benchmark") obtained when participants offer generation at their units' estimated short-run marginal costs. Short-run marginal costs are defined as fuel costs[64] plus variable O&M plus environmental costs. In other words, the benchmark analysis compares actual LMPs (or submitted offers) with estimated LMPs (or offers) that would have occurred if every unit offered at its estimated marginal cost. Because estimating costs is difficult and entails measurement

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[64] The fuel costs are based on data from the Platts and Energy Argus external subscription services. Natural gas prices are the average of three New England gas hub prices: Algonquin Citygate, Tennessee Zone 6 delivered and Dracut into Tennessee.

error, not all, or even most, of any mark-up can necessarily be attributed to attempts to exercise market power.[65]

The benchmark analysis focuses on the spread between the LMP and the marginal cost of generation. If the real-time LMP and the aggregate bid intercept significantly exceed the competitive benchmark, they may indicate market-power exercise requiring further analysis. An important attribute of competitive benchmark analyses is that results may be analyzed and compared over time and even across power pools. These results are generally expressed as Quantity-Weighted Lerner Indices ("QWLI").[66] The higher the QWLI, the greater the concern about the exercise of market power. Studies conducted by the California Independent System Operator have indicated a strong inverse relationship between the QWLI and the RSI; taken together, these market metrics are a powerful initial diagnostic tool for assessing market power in electricity markets.

The competitive benchmark analysis for the Report Period indicates that the excess of market price over the benchmark ("markup") during this period is quite small. Table 23 summarizes the QWLI calculations for this 72-hour period using both the aggregate bid intercept, an unconstrained offer-based dispatch price, and the real-time LMP at the electricity

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[65] *See* http://www.iso-ne.com/smd/market_analysis_and_reports/public_forum_and_annual_report/2002_Annual_Forum/_Toc19356583, (Annual Market Report for FY 2001) pages 30-37 and http://www.iso-ne.com/smd/market_analysis_and_reports/public_forum_and_annual_report/2003_Annual_Forum/2002_Annual_Market_Report_Final.pdf, (Annual Market Report for FY 2002) pages 46-48 for prior benchmark analyses conducted by ISO New England.

[66] The QWLI is calculated as a sum of ((Price – Marginal Cost)*Quantity)/sum of (Price * Quantity) over hourly data.

trading hub as market-price measures and comparing them to the benchmark results obtained under the following scenarios:[67]

(a) All units available at Economic Maximum ("EcoMax"), the maximum generating capacity of the generating unit under non-emergency conditions, except those taking outages/reductions preceding January 14 and equipment outages.[68]

(b) All units available at EcoMax, except those taking outages/reductions preceding January 14, equipment-related, and weather-related outages.

(c) All units available at EcoMax, except those taking outages/reductions preceding January 14, equipment-related outages, weather-related outages, and gas-related outages.

The scenarios produce the expected result; namely, outages of units that are generally in merit when available will increase the benchmark price and decrease the markup, all else being equal.

Table 23 - Benchmark Analysis Results and Comparison

Time Period	QWLI: Day-Ahead Hub LMP over Benchmark	QWLI: Real-Time Hub LMP over Benchmark	QWLI: Aggregate Bid-Intercept over Benchmark
(a)January 14-16, 2004: only pre-event and equipment forced outages in benchmark	20%	8%	13%
(b)January 14-16, 2004: pre-event, equipment and weather forced outages in benchmark	15%	4%	9%
(c)January 14-16, 2004: pre-event, equipment, weather, and gas forced outages in benchmark	11%	0%	5%
May 1999 –December 2002	N/A	14%	6%

In reviewing these results, the following should be considered:

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[67] These scenarios are consistent with the outage classifications used throughout this Report: (a) pre-Report Period, (b) equipment-related, (c) weather-related, and (d) gas-related. The outage classification is performed for each asset for each hour during the Report Period.

[68] Note that this does not include economic outages.

- A benchmark analysis is typically conducted over a longer time period than the 72-hour Report Period, usually spanning several months or even years. This allows assessments of competitive conditions across a variety of load and capacity conditions.

- The gas prices used in the marginal cost benchmark are day-ahead forecasts of spot gas prices, and are constant for each day. They do not reflect the actual intra-day spot price volatility that occurred during the Report Period. Thus the marginal cost benchmark may understate units' actual or expected marginal costs, thereby overstating the QWLI, all else constant.

- The real-time hub LMP is reduced by commitment of out-of-merit resources for reliability. This would understate the QWLI, all else equal.

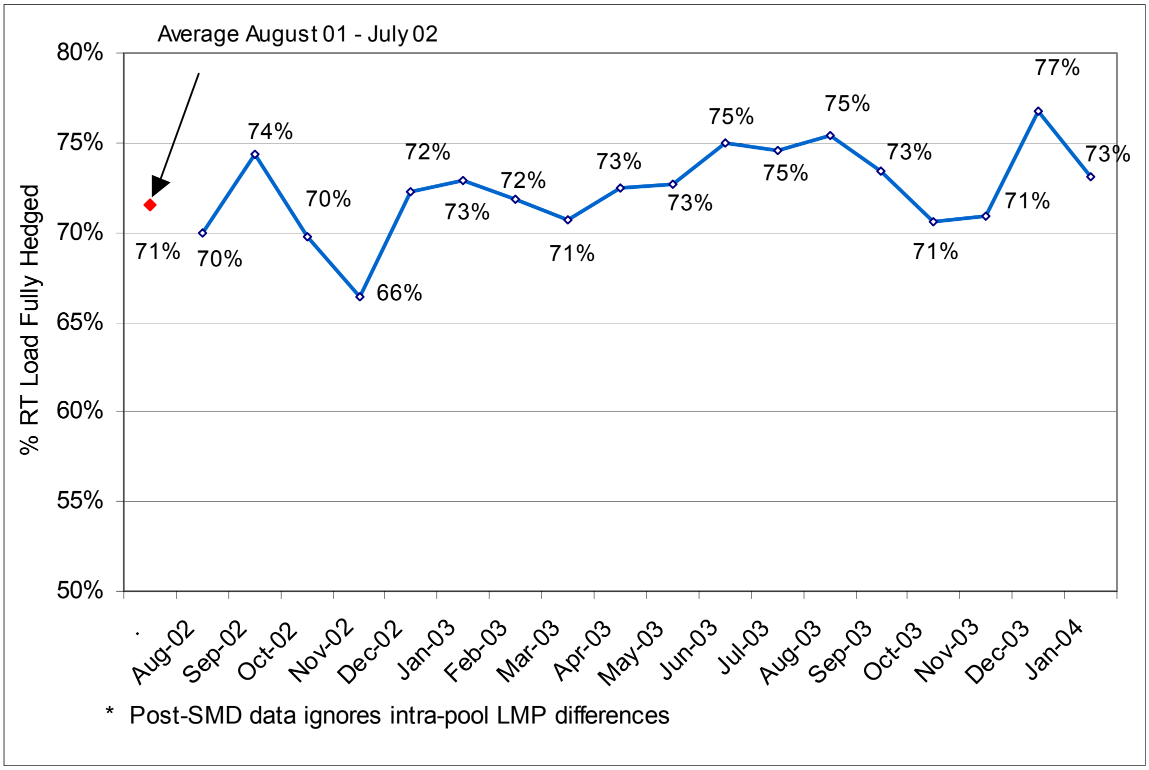
- The aggregate bid-intercept, which does not reflect this unusually high amount of out-of-merit commitment, exceeds the real-time hub LMP in 24 of 44 hours during which hourly loads exceeded 20,000 MW, and is more than twice the real-time hub LMP in 3 hours. The aggregate bid-intercept QWLI thus exceeds the real-time hub QWLI in each Report Period scenario.

Real-time hub QWLI's were below historical norms, while the bid-intercept benchmark QWLI was near historical levels. The results of this benchmark analysis indicate that any attempt to exercise market power did not unduly influence electricity prices during the Report Period. The results are also consistent with the observation that gas-fired units were not infra-marginal during much of the Report Period so that attempted withholding would not have been profitable. Because gas-fired units were often out of the money when day-ahead gas prices are assumed, any increase in supply offers due to risk or different gas price expectations, or outages due to fuel availability, would not influence the benchmark.

5. Forward Contracting

The New England market also demonstrates a high degree of forward contracting. As Figure 14 suggests, the percentage of real-time load fully hedged through the ISO's settlement system has generally been between 70 and 75 percent, with forward contracting for January 2004 at 73 percent. Note that these data present only a partial picture of the forward contracting arrangements in New England; they most likely understate the true extent of forward contracting because they omit contracts not settled through the ISO's settlement system.

Figure 14 - Percentage of Real-Time Wholesale Load Fully Hedged Through the ISO Settlement System



Forward contracting is important for two reasons. First, generators that are forward contracted have strong incentives to offer their resources at marginal costs to ensure that they run and meet their contractual commitments. Second, to the extent that load is contracted forward, it is insulated from short-term price effects such as those that might occur during a period of cold weather. The level of forward contracting in New England suggests that load was largely insulated from these unexpected events. Generators that enter into these long-term forward contracts are not necessarily gas-fired, and therefore may not be exposed to the gas purchase and delivery risks. Also, companies that hold the short position in these forward contracts often have diverse portfolios of generators. In such cases, gas-unit outages do not limit the company's ability to fulfill its forward obligation.

6. **Conclusions**

Each of these indicators suggests that the New England electricity market is generally competitive. Market concentration is low, reserve margins are robust with no pivotal suppliers under normal winter conditions, and there is a high degree of forward contracting. *A priori*, there is little reason to be concerned about the competitiveness of the New England market for wholesale electricity. The specific calculations for the Report Period show mixed results. RSIs were low during the period. However, competitive-benchmark results were similar to those obtained during normal conditions and the degree of forward contracting was high. These results are consistent with other studies favorably evaluating the general performance of the NEPOOL market.[69]

D. **Analysis of Market Conduct**

The previous section shows that the New England electricity markets generally do not exhibit the structural preconditions for the exercise of market power. This section analyzes the observed behavior of gas-fired generators in the market during the Report Period to determine if there is evidence of efforts to exercise market power.

1. **Economic Withholding Analysis**

Economic withholding entails submitting a supply offer for a resource that is unjustifiably high so that (i) the resource will not be dispatched or scheduled, or (ii) the bid or

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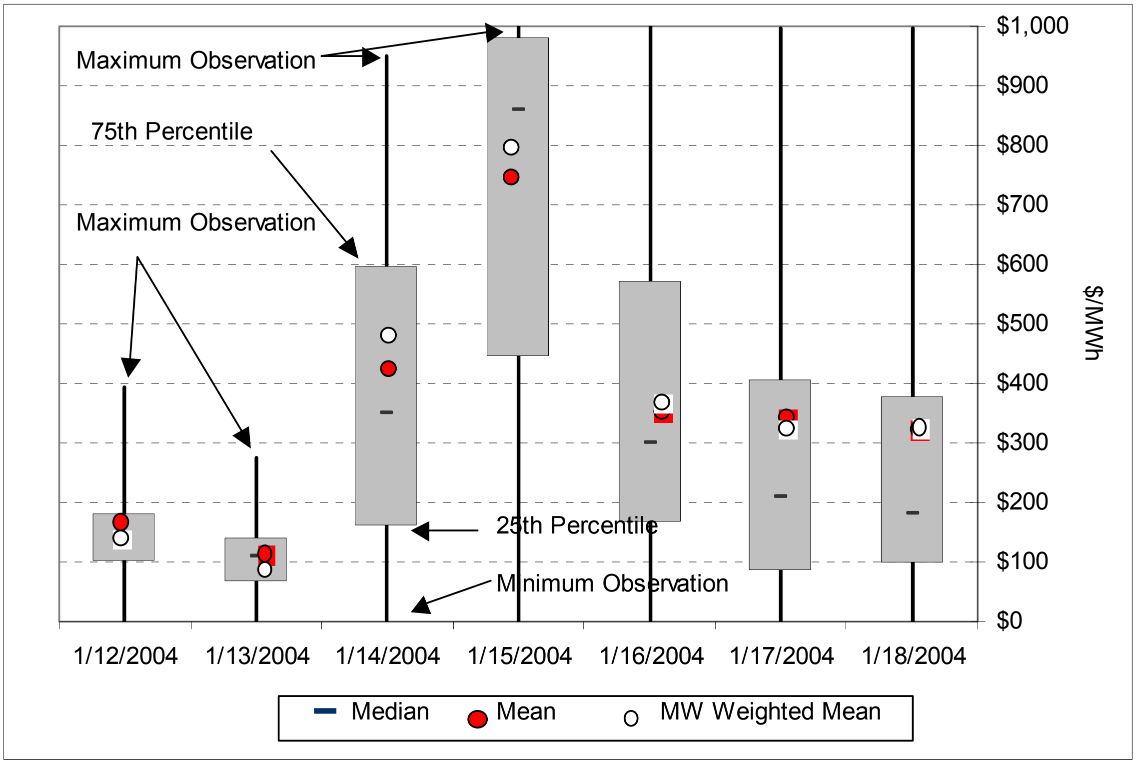
[69] *See* Patton, David B., Sinclair, Robert A. and Lee VanSchaick, Pallas M., (May 2002), *A Competitive Assessment of the Energy Market in New England*, Potomac Economics Ltd., *and* Bushnell, James and Saravia, Celeste (2002), *An Empirical Assessment of the Competitiveness of the New England Electricity Market* University of California Energy Institute Working Paper CSEM WP-101.

offer will set an unjustifiably high market-clearing price. A first step in evaluating unit offers is to plot them over time. Figure 15 shows the offers of natural gas-fired units at their seasonal claimed capability for the week of the Report Period. The figure shows the arithmetic and MW weighted mean and median offers, the maximum and minimum offers, and the inter-quartile range of offers in the shaded box. The inter-quartile range, the area between the 25th percentile and 75th percentile, provides a summary indicator of both the variation of gas unit offers and their average level. A figure calculated using offers at economic minimums would show similar results, though average prices would be lower.

As Figure 15 shows, during the Report Period offers from gas units were high relative to offers from gas units in earlier and later periods. This is consistent with trends in published gas price data over the same period. The variation in submitted offers from gas units also increased significantly during this time period, especially on January 15, as shown by the relatively large inter-quartile range (shaded box). The supply offer increase and increase in offer variance is consistent with the increased uncertainty in the gas market during the Report Period.

Figure 15 - Gas Unit Offers at Maximum Normal Output (Economic Maximum), January 12 - 18, 2004



The ISO calculated the amount of capacity from gas-fired units offered at high offer prices. A "high" offer price, for the purpose of evaluating economic withholding in this section, is defined as a supply offer greater than the unit's estimated marginal cost plus $100/MWh.[70] For gas-fired units, a unit's marginal cost would equal the assumed gas price times its unit-specific heat rate.[71] Figure 16 shows the amount of offers (in MW) that would qualify as "high offers" under a range of gas price assumptions.[72] Those assumptions are the composite average regional

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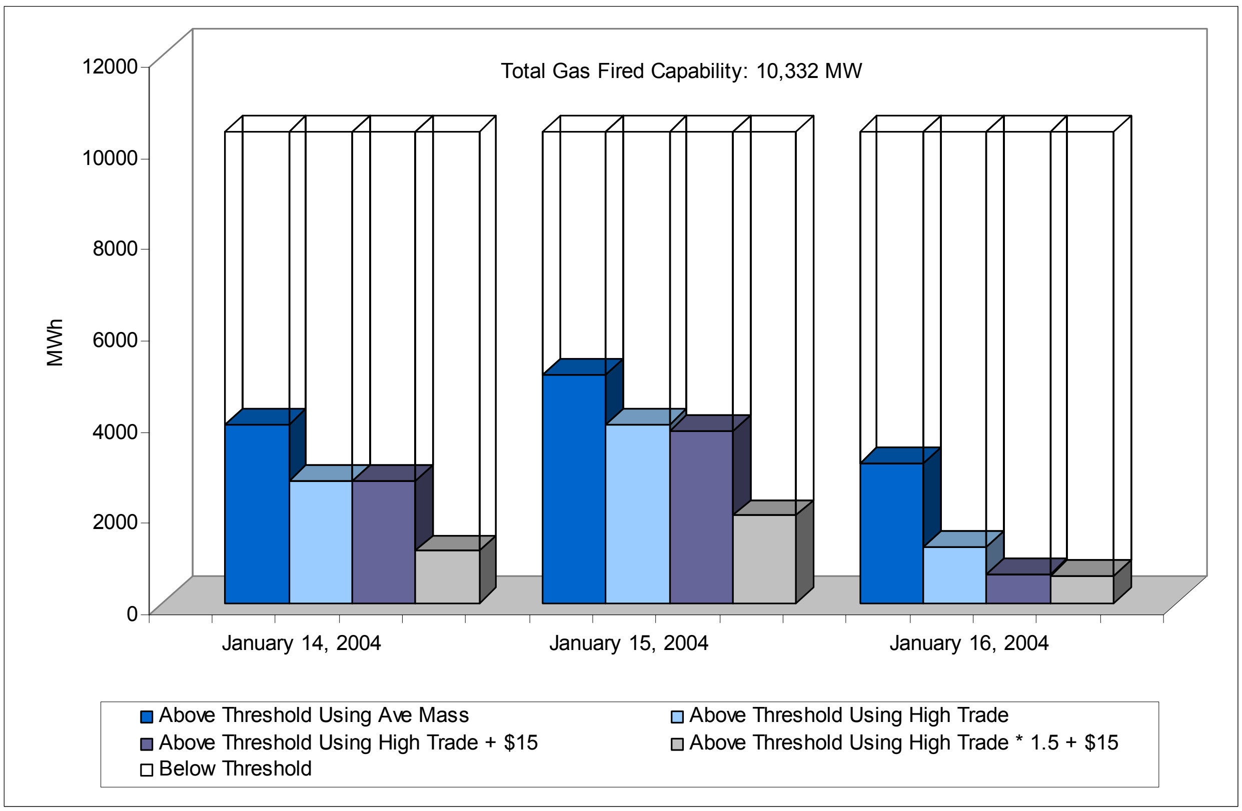
[70] The $100 threshold is the same as that used for the general market power mitigation screen in Market Rule 1, Appendix A.

[71] Note that because start-up and no-load costs vary with gas prices but cannot be changed daily, generators may have also reflected increases in their costs in their incremental energy offers. No attempt was made to adjust for these possibilities.

[72] Many generators have gas supply arrangements / entitlements that embed defined prices linked to liquid dailies such as AECO-C, Dawn, Henry, TETCO M3, or Transco Z6 NY. Algonquin citygates, Boston citygate, Tennessee (continued...)

gas prices at the Algonquin, Dracut, and Tennessee pricing points (the average day-ahead gas price), the high trade at these pricing points for each of the three days of the Report Period, the high trade plus a $15 imbalance charge, and the high trade with a 50 percent intra-day premium plus a $15/MMBtu imbalance charge.

Figure 16 - Total Gas MW That Exceeded the $100 Threshold Test, Based on Different Day-Ahead Gas Prices, January 14 - 16, 2004



The key to this calculation is the assumed regional gas price. As discussed earlier, volatility in the natural gas market may make the average day-ahead gas prices reported in Platts,

(...continued)

Zone 6 and Dracut are not nearly as liquid but are relevant for setting marginal cost in the day-ahead or real-time market. Iroquois Gas Transmission System ("IGTS") Zone 2 also is not as liquid. Generators mark to market based on the value of natural gas in New England / New York. In discussing "marginal cost," it is the opportunity cost that drives the determination of marginal cost based on mark to market even though the amount of gas trading relative to total gas use in New England is small.

The Intercontinental Exchange ("ICE"), or other industry publications inappropriate to use when calculating marginal costs for all gas units. The owners of many gas-fired generators in New England could not reasonably expect to pay the day-ahead gas price. As noted earlier, day-ahead LMPs were often below the marginal costs of all gas-fired generators in New England, so that before the close of the day-ahead gas day, most gas-fired generators may not have been expecting to be dispatched. If a generator did not expect to be dispatched on an economic basis, it most likely would not have purchased gas at day-ahead prices.

A generator facing uncertain dispatch most likely would consider the anticipated cost of procuring natural gas in the intra-day market in its offer to the ISO. When OFOs are in effect, the intra-day cost of gas has the potential to vary greatly from the average day-ahead prices. Bid-ask spreads often sharply diverge when OFOs are posted. As noted earlier, the intra-day gas market is comparatively thinly traded, and often reflects a premium over the day-ahead market. For example, a generator may anticipate that intra-day gas prices will more closely follow the high day-ahead trade, that they may incur daily or hourly penalties associated with the OFOs posted on Algonquin or Tennessee, or that intra-day gas may be available only at a significant premium to the high day-ahead trade. In addition, generators faced the risks and uncertainties noted in the previous sections and detailed in Appendix C, including the risk of imbalance charges, the risk of ratable takes, and the risk of being curtailed.

Figure 16 shows the amount of offers (in MW) that exceed the $100/MWh threshold (shaded portion of the bar) and the amounts that are within the threshold (unshaded portion). At least one-half of gas generator supply offers each day are consistent with day-ahead gas prices, because more than half of the offers are under the $100/MWh threshold under any of the gas price scenarios. These quantities necessarily increase as the assumed gas price increases. Under the fourth scenario, over 80 percent of offers from gas-fired capacity are under the $100/MWh threshold each day.

Given the offer deadlines in the New England electricity market, a participant is unlikely to know what the gas price will be if it is dispatched, so it must base its offer on expectations. Under normal gas market conditions, this is not problematic. Under the type of gas market conditions experienced during the Report Period, these concerns become paramount.

Many responses to the generator questionnaire confirm that submitted offers often reflect costs and risks beyond those suggested by day-ahead gas prices. Some concerns communicated to the ISO's Market Monitoring Department included:

- The "LMP forecasted price below actual cost of generation."
- "Forecast of electricity prices compared to the forecasted gas prices produced a very large negative spark spread in which the projected electric energy prices would not cover the cost of fuel."
- "Offers were based on expected intra-day prices for gas, which were expected to be more volatile than day-ahead prices."
- "The largest risk premium that we must factor in is that we must commit to purchase gas before we know whether the electric offer is accepted in the day-ahead market."
- "The primary risks associated with intra-day gas that needs to be accounted for in the generator bids are the price volatility, commodity availability and deliverability."

Given the considerations faced by a gas-fired unit during the Report Period and the explanations provided in part above, there is insufficient evidence to conclude that generators, through high offers, were seeking to manipulate the market. Generally, the data are consistent with risk-averse generators seeking to incorporate the high levels of risk and uncertainty present in the gas market in their electricity offers. However, the analysis cannot rule out the possibility that specific generators may have inflated offers to raise LMPs and operating reserve payments.

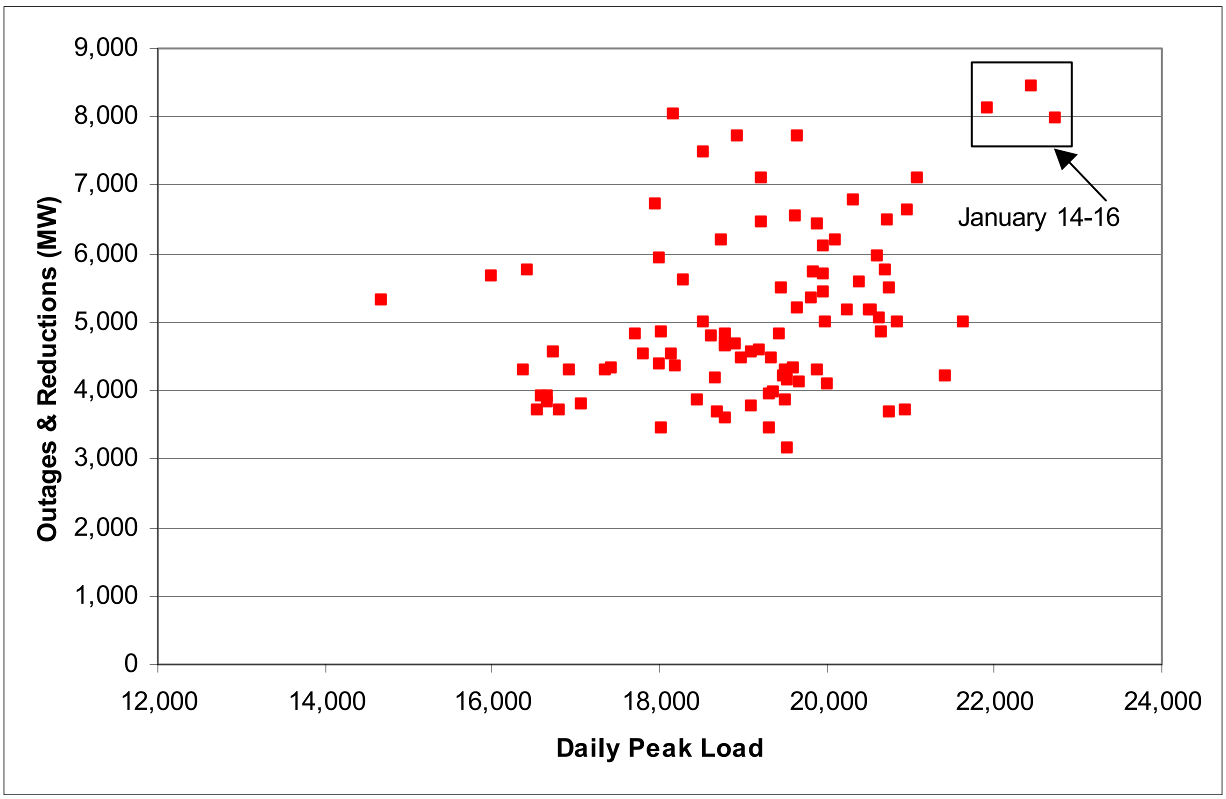
As related earlier, any attempted withholding by gas-fired generators is unlikely to have influenced LMPs because these units were not infra-marginal in any event.

2. Physical Withholding Analysis

a) *Outages and Reductions*

Figure 17 shows total generating unit capability reductions and outages for the peak hour versus actual peak load for December 2003 - February 2004. This time frame was chosen because it is homogeneous with respect to capacity availability (*i.e.,* there are few planned outages during the winter months).

Figure 17 - Outages and Reductions (MW) vs. Daily Peak Load (MW), Winter Period 2004



The scatter plot in Figure 17 shows that during the three days of the Report Period, loads as well as reductions and outages were high. This is not a desirable relationship and is the opposite of what has been observed during the summer months.[73] This relationship raises the concern that the markets may not be providing the proper incentives to make units available when they are most needed in the winter months.

During the events of the Report Period, the system experienced an unusually high number of outages and reductions when compared with recent history, as shown in Figure 18. These data also suggest that outages generally increase as winter temperatures fall. The Report Period is consistent with that pattern, though both the temperatures and number of outages are extreme. This suggests either that cold temperatures cause an increase in forced outages, or that attempted physical withholding increases at low temperatures (which also correspond to relatively high loads).

A number of mechanisms could result in an increase in forced outages as temperatures fall. Equipment could be more likely to break or fail at low temperatures; fuel could become unavailable (gas) or compromised (frozen coal piles, ice in rivers). Each of these would increase the number of outages relative to those that might occur during more typical temperatures. On the other hand, cold temperatures and the accompanying high winter loads could increase incentives to physically withhold. This warrants investigation. However, experience during high load periods during the summer months shows that unit availability generally improves during these periods. In addition, the withholding incentives during summer are likely to be

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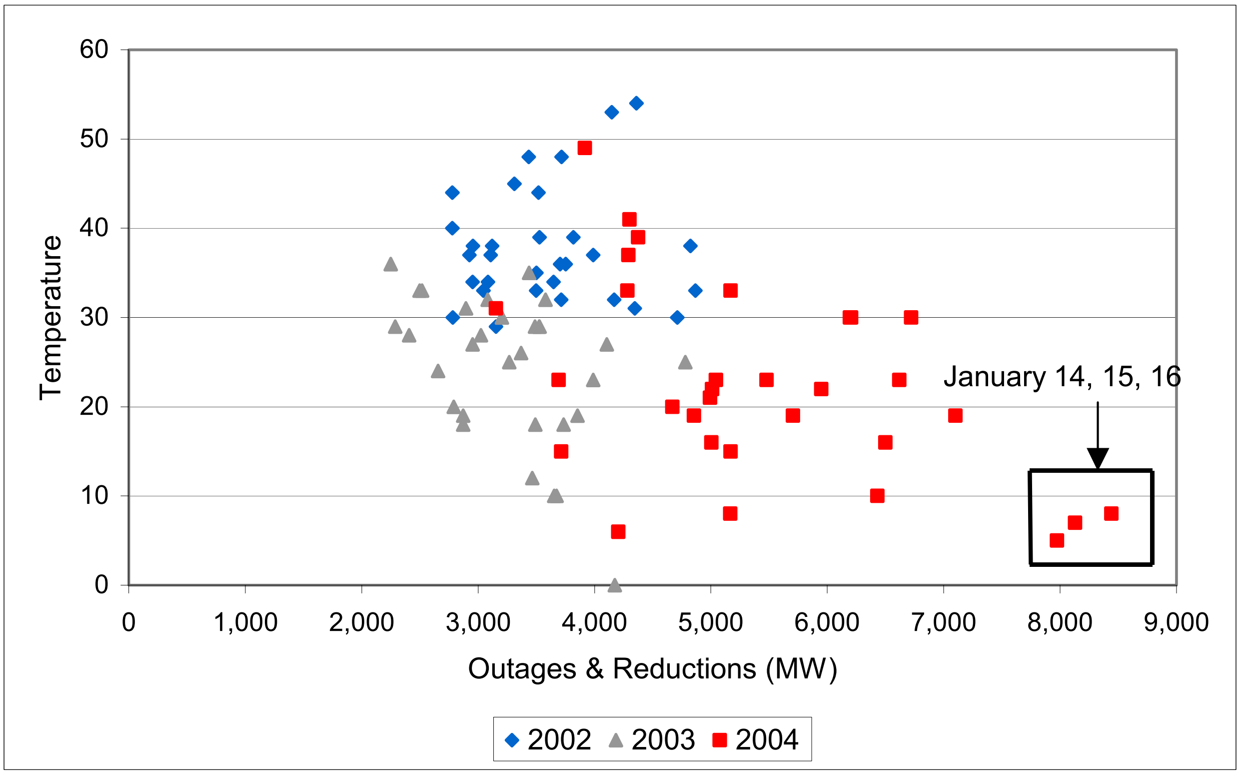
[73] *See* 2002 Annual Market Report, http://www.iso-ne.com/smd/market_analysis_and_reports/public_forum_and_annual_report/2003_Annual_Forum/, pp. 40-41.

stronger as loads are generally higher, and overall pool capacity is lower under summer output ratings.

The next set of tables gives a detailed look at outages by fuel type. Participant justifications for the outages are also presented, providing further insight on the cause of outages during the Report Period.

Figure 18 - Total Outages and Reductions (MW) vs. Temperature (Fahrenheit) for the Month of January 2002, 2003, 2004



Tables 24 through 26 provide outage details by fuel type and cause for each day of the Report Period, with the average hourly unavailable capacity and the unavailable capacity for the peak hour. As shown, January 14 and 15 experienced approximately 8,500 MW of average hourly unavailable capacity, over 80 percent of which were from gas-capable units. On January 16, the average hourly amount of unavailable capacity fell to 6,360 MW, with gas units again accounting for over 80 percent of all outages.

Outages and reductions[74] in the Tables are divided into four categories: pre-event, equipment-related, weather-related, and fuel availability. Pre-event outages are those that began before the Report Period and continued through it. The remaining categories capture outages that began during the Report Period. Equipment-related outages are events such as a tube leak that have no clear cause related to the conditions of the Report Period; these are the same sorts of outages that are categorized as pre-event outages. Weather-related outages are those that appear to be directly related to the extreme cold of the Report Period, and they include events such as frozen pipes or iced-over intake ducts. Fuel-availability outages are those directly related to lack of fuel for the facility. Each of these outage categories is broken down by fuel type.

A review of the pre-event outages showed that their aggregate quantity was normal for the winter period. The capacity out of service or reduced in this category approximates the outages anticipated during winter peak periods by ISO forecasting (about 3,100 MW). The bulk (nearly 60 percent) of the pre-event outages (about 1,600 MW) is accounted for by two large gas-fired generators. One outage commenced five days before the Report Period. Since this outage began well in advance of the Report Period and constitutes the vast majority of the participant's capacity, withholding is an unlikely strategy. The other outage occurred in two parts. Half of the unit was scheduled out for maintenance in advance and approved by the ISO a week before the Report Period. Again, the timing of the outage makes withholding an unlikely cause. The other half of the unit tripped out of service the morning of January 13, and stayed out for maintenance until January 23. Neither of these unit outages appears abnormal. The remaining outages were comparatively small, spread across a number of units and owners, and

[74] A unit reduction is the inability to supply the higher of (a) offered MWs or (b) the seasonal claimed capability of the unit.

began at various times before the Report Period. For these reasons, the pre-event outages are considered normal.

The equipment-related outages were reviewed and considered typical events for the reported failures during the period. In combination with the pre-event category, the number of megawatts out of service or reduced were within the average norms as indicated above. The failures reported included pump-seal failures, tube leaks, relay malfunctions, and combustion problems. The average of equipment-related outages and reductions during the Report Period was approximately 1,524 MW.

Weather-related outages and reductions were between 1,100 MW and 1,800 MW throughout the Report Period. Fuel-availability outages and reductions were between 2,300 MW and 3,100 MW on January 14 and 15, dropping to about 1,800 MW on January 16. Gas-capable units account for the largest share of outages. Each outage category type for gas-capable units includes a significant amount of capacity.

Table 24 - January 14 Outages and Average Hourly Outages by Category

For the Peak hour: January 14, 2004 Hour Ending 6 p.m. Outages – MW by Category

Unit Fuel Type	Forced Outage					Reductions in Capability of On-line Units					Total	% of Total
	Pre-event Outage	Equipment Related Outage	Weather Related Outage	Fuel availability outage	Subtotal FO	Pre-event Reduction	Equipment Related Reduction	Weather Related Reduction	Fuel availability Reduction	Subtotal Reduction		
Gas Capable	1,824	893	674	2,492	5,883	415	240	136	564	1,355	7,238	81%
Coal	415	-	-	-	415	-	12	3	-	15	430	5%
Nuclear	-	-	-	-	-	-	12	-	-	12	12	0%
Oil only	-	427	233	-	660	-	25	157	-	183	843	9%
Hydro	5	-	-	-	5	117	-	15	125	257	262	3%
Other	30	-	-	-	30	34	79	-	-	113	143	2%
Subtotal	**2,274**	**1,320**	**907**	**2,492**	**6,993**	**566**	**368**	**311**	**689**	**1,934**	**8,927**	**100%**

Overall Average for the 24 hour period: January 14, 2004 Average Hourly Outages – MW by Category

Unit Fuel Type	Forced Outage					Reductions in Capability of On-line Units					Total MW	% of Grand Total MW
	Pre-event Outage	Equipment Related Outage	Weather Related Outage	Fuel availability outage	Subtotal FO	Pre-event Reduction	Equipment Related Reduction	Weather Related Reduction	Fuel availability Reduction	Subtotal Reduction		
Gas Capable	1,895	928	701	2,588	6,112	302	175	99	410	986	7,096	82%
Coal	415	-	-	-	415	-	5	1	-	6	422	5%
Nuclear	-	-	-	-	-	-	11	-	-	11	11	0%
Oil only	-	318	174	-	492	-	20	125	-	145	637	7%
Hydro	55	-	-	-	55	112	-	15	120	247	302	3%
Other	35	-	-	-	35	47	111	-	-	158	193	2%
Subtotal	**2,400**	**1,246**	**875**	**2,588**	**7,109**	**461**	**322**	**240**	**530**	**1,552**	**8,662**	**100%**

Table 25 - January 15 Outages and Average Hourly Outages by Category

For the Peak hour: January 15, 2004 Hour Ending 7 p.m. Outages – MW by Category

Unit Fuel Type	Forced Outage					Reductions in Capability of On-line Units					Total MW	% of Grand Total MW
	Pre-event Outage	Equipment Related Outage	Weather Related Outage	Fuel availability outage	Subtotal FO	Pre-event Reduction	Equipment Related Reduction	Weather Related Reduction	Fuel availability Reduction	Subtotal Reduction		
Gas Capable	1,824	1,312	936	1,576	5,648	415	16	136	605	1,172	6,820	82%
Coal	163	147	-	-	310	-	-	34	-	34	344	4%
Nuclear	-	-	-	-	-	-	12	-	-	12	12	0%
Oil only	-	248	310	-	558	-	25	163	-	188	746	9%
Hydro	5	7	-	-	12	117	-	57	125	299	311	4%
Other	30	-	-	-	30	34	66	-	-	100	130	2%
Subtotal	**2,022**	**1,714**	**1,246**	**1,576**	**6,558**	**566**	**119**	**390**	**730**	**1,805**	**8,363**	**100%**

Overall Average for the 24 hour period: January 15, 2004 Average Hourly Outages - MW by Category

Unit Fuel Type	Forced Outage					Reductions in Capability of On-line Units					Total MW	% of Grand Total MW
	Pre-event Outage	Equipment Related Outage	Weather Related Outage	Fuel availability outage	Subtotal FO	Pre-event Reduction	Equipment Related Reduction	Weather Related Reduction	Fuel availability Reduction	Subtotal Reduction		
Gas Capable	1, 715	1,233	880	1,481	5,309	302	125	337	761	1,525	6,834	81%
Coal	168	152	-	-	320	-	-	58	-	58	378	4%
Nuclear	-	-	-	-	-	-	12	-	-	12	12	0%
Oil only	-	219	274	-	492	-	30	195	-	225	718	9%
Hydro	15	21	-	-	35	111	-	78	136	325	360	4%
Other	30	-	-	-	30	35	68	-	-	103	132	2%
Subtotal	**1,928**	**1,625**	**1,154**	**1,481**	**6,188**	**448**	**235**	**668**	**897**	**2,248**	**8,436**	**100%**

Table 26 - January 16 Outages and Average Hourly Outages by Category

For the Peak hour: January 16, 2004 Hour Ending 6 p.m. Outages - MW by Category

Unit Fuel Type	Forced Outage					Reductions in Capability of On-line Units					Total MW	% of Grand Total MW
	Pre-event Outage	Equipment Related Outage	Weather Related Outage	Fuel availability outage	Subtotal FO	Pre-event Reduction	Equipment Related Reduction	Weather Related Reduction	Fuel availability Reduction	Subtotal Reduction		
Gas Capable	1,262	468	676	693	3,099	415	104	3	1,320	1,842	4,941	78%
Coal	163	-	-	-	163	-	-	3	-	3	166	3%
Nuclear	-	-	-	-	-	-	16	-	-	16	16	0%
Oil only	-	423	4		427	-	51	339	-	390	817	13%
Hydro	5	-	-	-	5	117	-	41	114	272	277	4%
Other	30	-	-	-	30	34	47	-	-	81	111	2%
Subtotal	**1,460**	**891**	**680**	**693**	**3,724**	**566**	**218**	**386**	**1,434**	**2,604**	**6,328**	**100%**

Overall Average for the 24 hour period: January 16, 2004 Average Hourly Outages – MW by Category

Unit Fuel Type	Forced Outage					Reductions in Capability of On-line Units					Total MW	% of Grand Total MW
	Pre-event Outage	Equipment Related Outage	Weather Related Outage	Fuel availability outage	Subtotal FO	Pre-event Reduction	Equipment Related Reduction	Weather Related Reduction	Fuel availability Reduction	Subtotal Reduction		
Gas Capable	1,615	599	317	887	3,418	228	106	637	808	1,779	5,197	83%
Coal	163	-	-	-	163	-	-	15	-	15	178	3%
Nuclear	-	-	-	-	-	-	18	-	-	18	18	0%
Oil only	-	203	2	-	205	-	42	280	-	322	527	8%
Hydro	8	-	-	-	8	105	-	65	123	293	301	4%
Other	30	26	-	-	56	35	48	-	-	83	139	2%
Subtotal	**1,816**	**828**	**319**	**887**	**3,850**	**368**	**214**	**997**	**931**	**2,510**	**6,360**	**100%**

b) Pivotal Suppliers and Physical Withholding

The results of the pivotal supplier analysis can be combined with data on unit outages and reductions to compare the outages reported by pivotal suppliers with those reported by non-pivotal suppliers. If outages reported by pivotal suppliers are less than or approximately equal to those experienced by non-pivotal suppliers, it suggests that pivotal suppliers were not seeking to exercise market power by physically withholding, because their availability was at least as good as that of other suppliers. This is important because generally pivotal suppliers have the greatest incentive and ability to attempt to exercise market power.

Table 27 compares outages and reductions for all pivotal suppliers with all non-pivotal suppliers. There are five pivotal suppliers evaluated for each day of the Report Period, selected because they were each pivotal in at least one non-OP4 hour of the Report Period.[75] These are essentially the five largest generation owners. For both pivotal and non-pivotal suppliers, the Table provides total MW in the joint portfolio, the unavailable MW, the percentage of unavailable MW, the gas MW in portfolio, the unavailable gas MW, and the percentage of gas MW unavailable, for the peak hour of each day of the Report Period.

For January 14 and 15, pivotal suppliers had a greater percentage of total capacity available, and a greater percentage of gas-fired capacity available than did non-pivotal suppliers. This difference was large, especially for gas units, with non-pivotal suppliers reporting approximately 65 percent unavailability for each day. On January 16, the percentage of total unavailable capacity for pivotal and non-pivotal suppliers was essentially the same, while gas units controlled by pivotal suppliers were twice as available.

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[75] Technically all generators are pivotal in OP4 hours.

Pivotal suppliers in aggregate also had many fewer MW unavailable, both total MW and gas MW, on each day than did non-pivotal suppliers. Not only were the relative unavailable amounts smaller, the absolute amounts were smaller, too, which means that the unavailable amount from non-pivotal suppliers had a greater withholding effect than did the unavailable amount from pivotal suppliers. Note that no supplier was actually pivotal on January 16. These results show that pivotal suppliers had better availability than non-pivotal suppliers, and suggest that pivotal suppliers were not attempting to exercise market power by physically withholding capacity.

Table 27 - Pivotal Supplier Outage Summary, January 14 - 16, 2004, Peak Hour

	Total Portfolio MW	Actual Participant Offer	Unavailable Portfolio	% of Portfolio Unavailable	Total Gas MW in Portfolio	Unavailable Gas - MW	% of Gas Portfolio Unavailable
Pivotal Suppliers							
January 14, 2004 Hour Ending 6 p.m.	15,102	12,115	2,987	20%	4,109	1,809	44%
January 15, 2004 Hour Ending 7 p.m.	15,102	12,122	2,980	20%	4,109	905	22%
January 16, 2004 Hour Ending 7 p.m.	15,102	12,052	3,050	20%	4,109	749	18%
Non-Pivotal Suppliers							
January 14, 2004 Hour Ending 6 p.m.	17,538	11,598	5,940	34%	6,223	3,995	64%
January 15, 2004 Hour Ending 7 p.m.	17,538	12,127	5,411	31%	6,223	4,145	67%
January 16, 2004 Hour Ending 6 p.m.	17,538	14,275	3,263	19%	6,223	2,811	45%

c) Gas vs. Dual Fuel Outages and Reductions during the Cold Snap

Table 28 summarizes the total capacity and the outages and reductions of gas-fired and dual-fuel units for the peak hours of each day of the Report Period. Outages and reductions have been characterized as fuel availability outages and reductions or other outages and reductions. Other outages and reductions include pre-event outages, weather-related outages, and equipment-related outages.

Table 28 - Actual Gas and Dual-Fuel Unit Outages and Reductions over the Peak Hours, January 14-16, 2004

		MW			As a % of Winter Claimed Capability		
Unit Type	**Winter Claimed Capability (MW)**	**Fuel Availability Outages & Reductions (MW)**	**Other Outages & Reductions (MW)**	**Total (MW)**	**Fuel Availability Outages & Reductions (%)**	**Other Outages & Reductions (%)**	**Total (%)**
Gas Only, January 14 Hour Ending 6pm	10,332	2,964	3,097	6,061	29%	30%	59%
Dual Fuel, January 14 Hour Ending 6pm	6,047	292	1,085	1,177	2%	18%	19%
Gas Only, January 15 Hour Ending 7pm	10,332	1,907	3,359	5,266	18%	33%	51%
Dual Fuel, January 15 Hour Ending 7pm	6,047	274	1,280	1,554	5%	21%	26%
Gas Only, January 16 Hour Ending 6pm	10,332	1,462	2,546	4,008	14%	25%	39%
Dual Fuel, January 16 Hour Ending 6pm	6,047	225	706	931	4%	12%	15%

For each day of the Report Period during the peak hour, fuel availability outages and reductions for dual-fuel units were less than 5 percent of the units' total winter claimed capability. In comparison, the fuel availability outages and reductions for gas-only units ranged from 29 percent of winter claimed capability on January 14 to 14 percent of winter claimed capability on January 16. This suggests that adding dual-fuel capability to gas-fired units would improve availability. Other outages and reductions for dual-fuel units were also systematically lower than for gas-fired units, though it is unclear how this is related to fuel type. One hypothesis is that, because gas-only units tend to be the newest units, they have not experienced extremely cold weather before, and thus the Cold Snap revealed unit vulnerabilities to be addressed by the unit owners. Older units may have already been through this cycle.

d) Participant Questionnaire Responses

To further investigate weather-related and fuel-related reductions and outages, the ISO's Market Monitoring Department sent a series of questions to the appropriate lead participants. Not surprisingly, the responses and documentation from the participants in response to the questionnaire supported the need for the outages. The surveys were sent to lead participants of units with a range of fuel types.

Representative responses concerning weather related outages and reductions include:

- "Forced out of service because of damaged expansion joint."
- "Frozen conveyer."
- "Fly ash recovery system was in-operable due to extremely cold temperature."
- "Freezing temperatures caused damaged on the reheat, high pressure and low pressure drain lines. The extreme cold was deemed the major factor in this failure."

Representative responses concerning fuel availability outages and reductions included:

- "Outage due to gas procurement issues and gas company restrictions."
- "Outages and or reductions were a direct result of gas supply restrictions imposed by the gas company."
- "Gas prices high - restrictions on the pipeline."

The information obtained from the questionnaires is consistent with the initial outage reports to ISO operations and follow-up phone calls by the Market Monitoring Department. The weather-related outages are consistent with the extreme cold experienced during the Report Period. In some cases, generators provided clear documentation (*e.g.*, pictures of ice build-up on intakes) of the conditions experienced because of the extreme cold that prevented operation of the unit or caused a reduction in capacity. The unavailability of gas is consistent with the pipeline notices and documentation provided with the questionnaire responses. The analysis of the Report Period and documentation received do not indicate that physical withholding of resources occurred during the Report Period. Despite these general conclusions, it is not possible to say with certainty that each forced outage was justified without a substantially more thorough investigation, which might also be inconclusive. These conclusions do not suggest that such efforts are warranted given the results to date and the difficulty of gathering significant additional evidence. Coordination and review of survey responses by other authorized entities is on-going. Comparison with parallel investigation results is a useful check on ISO results.

3. Economic Outages: Conduct of Generating Units

Economic outages are allowed under the market rules when a generator reasonably expects it to be more profitable to sell available fuel than to produce electricity, absent the exercise of market power. In practice, most economic outages are requested by gas-fired units. Selling available natural gas is explicitly allowed as a reason for an economic outage under OP5[76] and Appendix B to Market Rule 1.[77] An approved economic outage is not a requirement for the sale of natural gas. However, a generator on an economic outage is obligated to make "best efforts" to return to operation if called back by the ISO. Economic outages are used throughout the year, especially when natural gas prices rise. Economic outages were unusually high during the Report Period.

Table 29 shows that 10 units, totaling 2,327 MW, were on economic outage entering the operating day of January 14. However, at 10:00 a.m. on that day, generators were called back from economic outage by the ISO because of forecast capacity shortages over the evening

[76] *See* NEPOOL Operating Procedure No. 5, Generation Maintenance and Outage Scheduling, Part II - Definitions, Economic Request, p.5.

[77] *See* Market Rule 1, Appendix B, § 3.2.6, "Certain Economic Decisions Excused."

peak.[78] The economic outages were re-classified as forced outages when the units failed to return to service as requested. The failures to return to service suggest that these outages initially may have been more appropriately categorized as forced outages. The ISO was not able to confirm whether generators used "best efforts" to return to service when the economic outages were cancelled. Three of the 10 units, totaling 675 MW, had sufficiently long start-times that recall from outage on the morning of January 14 would not have allowed them to be available for the evening peak. These units were not recalled for that day. Therefore, the actual number of MW that could have been expected to return from economic outage on January 14 was 1,652 MW. Of the three units with long start-times, one unit returned to service on January 15. The remaining two units (approximately 504 MW) were not recalled by the ISO during the Cold Snap period due to start-times that made them unavailable until the weekend. From 10:00 a.m. on January 14 through the remainder of the Report Period, the ISO did not permit any economic outages. All newly unavailable units were categorized as forced outages.

[78] As noted earlier above, Market Monitoring was unable to verify that one of the units had been called back to service. After a review of the Interim Cold Snap Report, the participant stated that gas was available for the unit during the Cold Snap period.

Table 29 - Status of Units that Declared Economic Outages[79]

Unit Status	Cumulative Units	Cumulative MWs
Units with Economic Outages granted January 13	10	2,327[80]
Economic outages recalled January 14 at approximately 10 a.m.		
Units that returned to service on January 14	-	-
Units that returned to service on January 15	2	423
Units that returned to service on January 16	4	1,145
Units that returned to service on January 17	7	1,817
Units that returned to service after January 17	10	2,327

Although all economic outages were cancelled on the morning of January 14 and all units that could be available for the evening peak were requested to return to service, it is possible that the granted requests for economic outages represent attempted withholding. Similarly, the granting of the economic outages, which were subsequently cancelled, could have reduced the affected units' ability to get fuel and operate on or after January 14.

The ISO's evaluation of the circumstances and timing of economic outages suggests that the outages were most likely not used to withhold capacity from the market, though the outages may have been mis-categorized. Ten different generating units declared economic outages before January 14. These ten units are owned by four different owners, and represent 51 percent, 79 percent, 12 percent, and 12 percent of their owner's total capacity. These owners control between 1,100 and 4,100 MW of total generation. The generation owner with 51 percent of its

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[79] The amount of economic outages is somewhat lower than the amount reported by the ISO during and immediately after the Report Period. Further investigation determined that a number of forced outages had been incorrectly characterized as economic outages in preliminary data.

[80] The units with economic outages include two units with start times that made them effectively unavailable until after the Cold Snap period. Therefore, eight units totaling approximately 1,800 MW could reasonably have been expected to return to service from economic outages during the Cold Snap period. During the relevant period, four units totaling 1,145 MW did return to service. The units that did not return to service remained on forced outage for the entire Cold Snap period because they were unable to procure fuel.

capacity out had one economic outage that significantly pre-dated the Report Period. The owner with 79 percent of its capacity on economic outage requested this outage mainly due to gas prices. The owner with 12 percent of its capacity on economic outage stated that credit restrictions significantly influenced its decision to request an economic outage. The other owner with 12 percent of its capacity on economic outage stated that no gas was physically available to its facility.

The requests for economic outages were consistent with the events of the gas market during the period. With one exception, all of the economic outages were requested during or after the morning of January 13, indicating that unit owners were able to anticipate or experience the tight gas market before requesting an economic outage. Most of the economic outages were requested by midday on January 13, with day-ahead gas prices around $19.00/MMBtu.[81] That both large and small owners took outages and that independent information shows that the regional gas markets were highly volatile is consistent with the explanation that owners requesting economic outages were seeking to avoid participating in the risky gas market, characterized by high and volatile prices. However, economic outages are intended for units for which operation is uneconomic, not for units for which fuel is unavailable. To reliably operate the system, the ISO must have accurate information about each generating unit's operating status. The delayed return of most of the units on economic outage suggests that fuel was not available and that they should have been initially categorized as unplanned outages, assuming that best efforts were made to return to service. As with the review of physical withholding, the

[81] Average trades were: Algonquin: $23.36, Dracut: $18.30, Tennessee Zone 6: $16.33. Average of prices for these hubs = $19.33. Maximum day-ahead trades were: Algonquin: $35.00, Dracut: $21.00, Tennessee Zone 6: $21.50.

ISO was not able to verify that each request for an economic outage was not an attempt to withhold from the market, or that best efforts were made to return to service.

Economic outages are not likely to be the best mechanism to withhold from the market. First, they are reviewed and approved by the ISO. When a system or sub-area capacity deficiency is anticipated, they are denied, yet this is the time when withholding is most likely to be profitable. Second, offering at a very high price is likely to be a better withholding strategy. With an offer cap, there is no value to withhold via an economic outage if you could be paid at the offer cap. When LMPs are less than $1,000/MWh, economic outages and $1,000/MWh offers have the same effect on LMPs. When LMPs reach $1,000/MWh, high offers earn revenue while economic outages would earn none. There does not seem to be an advantage to withholding through an economic outage as opposed to submitting a high offer price.

Economic outages also could have affected the electricity market or reliability by creating the expectation that the units granted economic outages were not going to operate on January 14, thereby shrinking the windows in which owners could buy fuel once the outages were cancelled. Including the units on economic outage in the day-ahead market would not be likely to have induced these units to buy day-ahead gas. LMPs in the day-ahead market for January 14 would generally not have supported a gas-fired unit, even one that was highly efficient. Prices at the electricity trading hub exceeded $150/MWh during only three hours. With average day-ahead gas prices on Algonquin, for example, exceeding $21/MMBtu, even a very efficient unit would need to earn approximately $150/MWh over its entire minimum run time (generally over six hours) to break even, assuming no imbalance charges or other penalties.[82] Thus it is unlikely that units on economic outage would have cleared in the day-ahead market and been better able to procure natural gas as a result, even when potential imbalance charges are ignored.

Because these units had been granted outages and had seen relatively low day-ahead electricity prices for January 14, gas-fired units that had their outage requests approved on January 13 would not have purchased gas prior to the outage cancellations on January 14. Given the timing of the economic outage cancellations and the intra-day gas market, the granting of economic outages to these units does not seem to be an important concern. These units would not have sought to purchase gas until asked to run by the ISO in real-time, and these units would likely not have been asked to run by the ISO before the outage cancellation. In addition, these units were not essential for reliability until the peak evening hours, which allowed substantial time to procure gas during January 14 after the cancellation of economic outages at 10:00 a.m.

Economic outages, by removing the unit from the market for a long time, may have reduced the likelihood that the units could find and purchase available gas. The timing of the economic outage cancellations (early on the January 14 dispatch day) means that it is not likely that the requests for these outages had significant effects on unit availability beyond January 14. This is because the outage cancellation came well before the close of the day-ahead gas trading day for January 15, providing units sufficient time to purchase available day-ahead gas. These units would also have been able to participate in the day-ahead electricity market. While the units did not all return by January 15, it is likely that factors beyond having been on economic outage contributed to this, such as unavailability of non-firm regional gas transportation.

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[82] Example: failure to stay within the 2% tolerance on Algonquin triggers a $15 / Dth imbalance charge, but the generation company doesn't discover how much money it owes Algonquin until the market has settled.

No economic outages were in effect after 10:00 a.m. on January 14. Given the available data, it does not appear that the granting of economic outages contributed significantly either to high real-time prices or to the capacity shortage on January 14, because generators had adequate notice to procure available intra-day gas. Their lack of participation in the day-ahead market is not material because, given the realized LMPs, they were not likely to have received a day-ahead commitment or sought day-ahead gas. The evidence also does not suggest that economic outages contributed to the tight capacity situations on January 15 and 16, as the units had ample opportunity to find any available gas. Further work is required to evaluate the usefulness of allowing units to declare economic outages.

4. Economic Outages: ISO Scheduling

NEPOOL Operating Procedure 5 governs outage scheduling. Section II.D.2 states that "a Maintenance Outage (of which Economic Outages are a subset) request for the next day or an overnight Maintenance Outage must be submitted by 9:00 a.m. of the preceding day." The primary purpose of OP5 is to define a set of capacity requirements that must be considered in the maintenance approval process. The submittal deadline was developed to ensure that the ISO has the time to perform the required reliability assessment before approving the outage request. Requests that do not meet the assessment criteria are denied. It has been standard practice to relax the deadline when the required reliability assessment can be performed before the start of the requested outage. This practice provides added flexibility to generators while ensuring that the reliability assessments are performed.

All but 180 MW of the 2,327 MW of economic outages granted for January 14 were requested and granted after the 9:00 a.m. day-ahead deadline on January 13. The bulk of the economic outages were requested and granted by noon on January 13. All were cancelled at 10:00 a.m. on January 14, and the available units with sufficiently short start-up times were requested to return to service. As discussed above, it is not clear that the granting of these outages affected the ability of these units to ultimately acquire gas and operate on January 14. As part of the Cold Snap review, OP5 and Market Rule 1 will be reviewed regarding the submission of maintenance and economic outages.

E. Market Monitoring Activity

1. Overview

Under Market Rule 1, Appendix A, the ISO, in consultation with the Independent Market Advisor, can mitigate the market effects of any conduct that would substantially distort competitive outcomes in the wholesale electricity market while it seeks to avoid unnecessary interference with competitive price signals and normal market operations. The ISO has the authority to monitor, and potentially to mitigate, conduct that is anti-competitive or that evidences physical or economic withholding. The ISO's authority to mitigate for potential economic withholding falls under two categories: congestion mitigation and general market power mitigation.

a) Congestion Mitigation

Congestion mitigation authority arises when a unit needs to be committed out of pool-wide merit order to relieve a transmission constraint. For such a unit to be mitigated in the day-ahead and real-time markets, it needs to fail two tests: one for conduct (generally, an increase in energy offer price of $25 or 50 percent above the reference level[83]/ marginal cost, whichever is lower) and one for impact (generally, an increase of $25 or 200 percent above the price at the electricity trading hub, whichever is lower). To be mitigated, offers must fail both the conduct

[83] *See* Market Rule 1, Appendix A, § 5.6.1.

and impact tests and also fail to be supported by an adequate explanation. Mitigation is applied *ex ante* in the energy market.

Congestion mitigation can also occur in the operating reserve settlement evaluation. In general, the daily operating reserve payment to each resource is subject to conduct and impact tests. The impact test compares the actual operating reserve credits for each resource to the operating reserve credits that the resource would have been paid at its reference levels for startup, no load, and energy offers. If the actual operating reserve credits are 100 percent greater or more than the operating reserve credits at a unit's reference level, and the increases exceed $10/MWh, the resource is subject to mitigation if it is operated in a constrained area. Mitigation is applied *ex post* for the operating reserve evaluation.

b) General Market Power Mitigation

An assessment of market conditions and the applicability of general market mitigation is conducted daily for the day-ahead market, the re-offer period, and real-time operation. General market power mitigation in an unconstrained area applies only to pivotal suppliers. The ISO investigates pivotal supplier energy offers at or above $25 that exceed a 300 percent increase or an increase of $100/MWh above the reference level; whichever is lower. As defined in Appendix A, Section 5.2.2, a "pivotal supplier" is a participant whose aggregate energy supply offers (up to and including Economic Maximum) are greater than the NEPOOL supply margin.[84] If a pivotal supplier is identified, and the general thresholds in §5.3.1 of Appendix A apply, the Market Monitoring Department will evaluate the conduct of the pivotal supplier and the market

[84] From Market Rule 1, Appendix A, § 5.2.2, the NEPOOL supply margin is the total energy supply offers (up to and including Economic Max) for an hour, less total system load (as adjusted for net interchange with other control areas and including operating reserve).

impact of their supply offers on LMPs. Mitigation is applied *ex ante* in the general market power assessment. The results of ISO's mitigation evaluation for economic withholding, under congestion mitigation and general market power, during the Report Period are presented below.

2. Congestion Mitigation Activity Results

The ISO's authority to mitigate for economic withholding under its congestion mitigation authority in the energy market applies only if there is congestion on the system, either in the day-ahead or real-time market. It is applied at generator nodes, applicable to the generator setting the LMP (the marginal unit). To be mitigated, the unit must fail the $25/MWh conduct test and the $25/MWh market impact test.

The Market Monitoring Department reviewed whether or not there was congestion during the Report Period and whether or not marginal generators at nodes with "high" congestion (over $25/MWh) were compliant. Only 1.44 percent (1,889 of 131,328) of all LMPs, both day-ahead and real-time, exceeded the relevant congestion threshold of $25/MWh.[85] Generator nodes with congestion account for 0.45 percent of all LMPs. Six of the LMPs at nodes of marginal generators occurred in the real-time market (see Table 30). The remainder were in the day-ahead market. There was very little congestion during the Report Period.

Table 30 - Generator LMPs with Congestion by DA/RT, by Day

Day	Day-Ahead	Real-Time	Grand Total
1/14/2004	117	6	123
1/15/2004	93	-	93
1/16/2004	372	-	372
Grand Total	**582**	**6**	**588**

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[85] The 50 percent above the Reference Level was irrelevant.

The Market Monitoring Department found that all marginal generators were compliant with the $25/MWh conduct threshold based on Reference Prices and submitted explanations of behavior. There were no LMPs to be mitigated under the congestion mitigation rules.

3. Evaluation of General Market Power Mitigation

Table 31 shows that there were only three pivotal suppliers in the day-ahead market during the Report Period. Mitigation was not applicable given the unit offer prices, LMPs, and applicable reference levels. This is not surprising given that day-ahead LMPs only slightly exceeded $500/MWh, approximately the cost of an efficient gas-fired unit at the average day-ahead gas price on January 15. Day-ahead market prices were lower on January 14 and 16. These results are consistent with the implied heat rate discussion earlier in this section.

Table 31 - Number of Pivotal Suppliers in the Day Ahead Market by Day, January 14-16, 2004

Date	Number of Pivotal Suppliers
January 14, 2004	0
January 15, 2004	3
January 16, 2004	0

The Market Monitoring Department also performed a real-time pivotal supplier assessment using the real-time supply margin. Real-time prices are evaluated at non-compliant generator nodes to determine any real-time market impact using a $100/MWh threshold. Table 32 shows the number of pivotal suppliers in the real-time market that also failed the $100/MWh threshold test for the Report Period. There were pivotal suppliers on each of the days in the Report Period.

Table 32 - Number of Pivotal Suppliers in the Real-Time Market that failed the $100/MWh Threshold Test during the Report Period

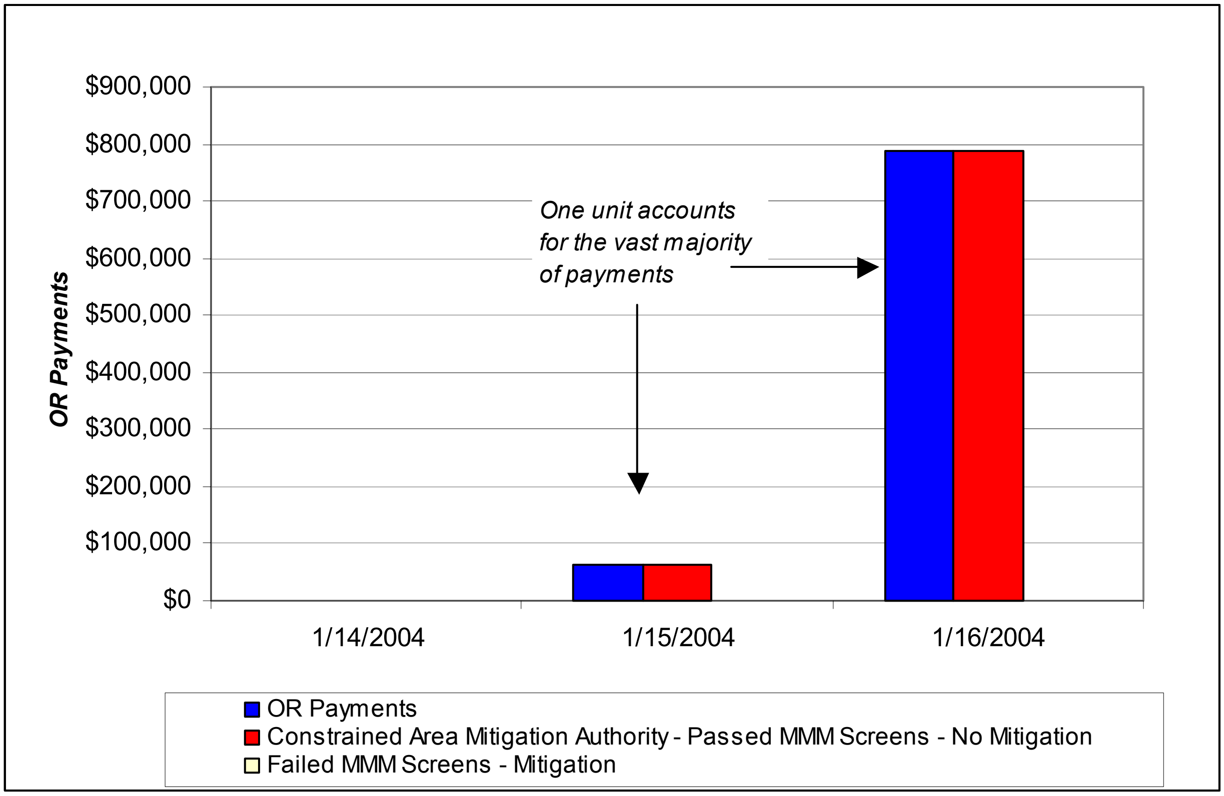
Date	Number of Pivotal Suppliers
January 14, 2004	ALL
January 15, 2004	5
January 16, 2004	1

For the identified pivotal suppliers mitigation was not applicable under the $100/MWh thresholds. Again, this is not surprising given that for most hours real-time prices were well below $200/MWh. Oil was often the marginal fuel, with gas-fired units out of the money. With prices below $200/MWh and a $100/MWh market-impact threshold, it is unlikely that any market participant had a market impact that would exceed the threshold. The OP4 hours are examined separately in Section IV.F.

4. Evaluation of Operating Reserve Mitigation for Units Running Out of Merit

Resources receiving operating reserve credits were also evaluated for possible mitigation during the Report Period. Figure 19 shows that, for the day-ahead market, all of the payments passed the operating reserve test. One unit accounted for the majority of these payments. This unit was evaluated by the Market Monitoring Department and its offers were consistent with the conduct test.

Figure 19 - Day-Ahead Operating Reserve Payments in New England



Real-time operating reserves accounted for the bulk of all operating reserve payments during the Report Period and were substantial, as illustrated in Figure 20. These payments are almost entirely attributable to the relatively large quantities of gas-fired generation operating out of merit for much of the operating day. This out of merit operation is explored further in Section IV.F. Because LMPs were low relative to the operating costs, or as-offered costs, of gas-fired generation, the amount of operating reserve charges is large.

Figure 20 - Real-Time Operating Reserve Payments in New England, January 14-16, 2004

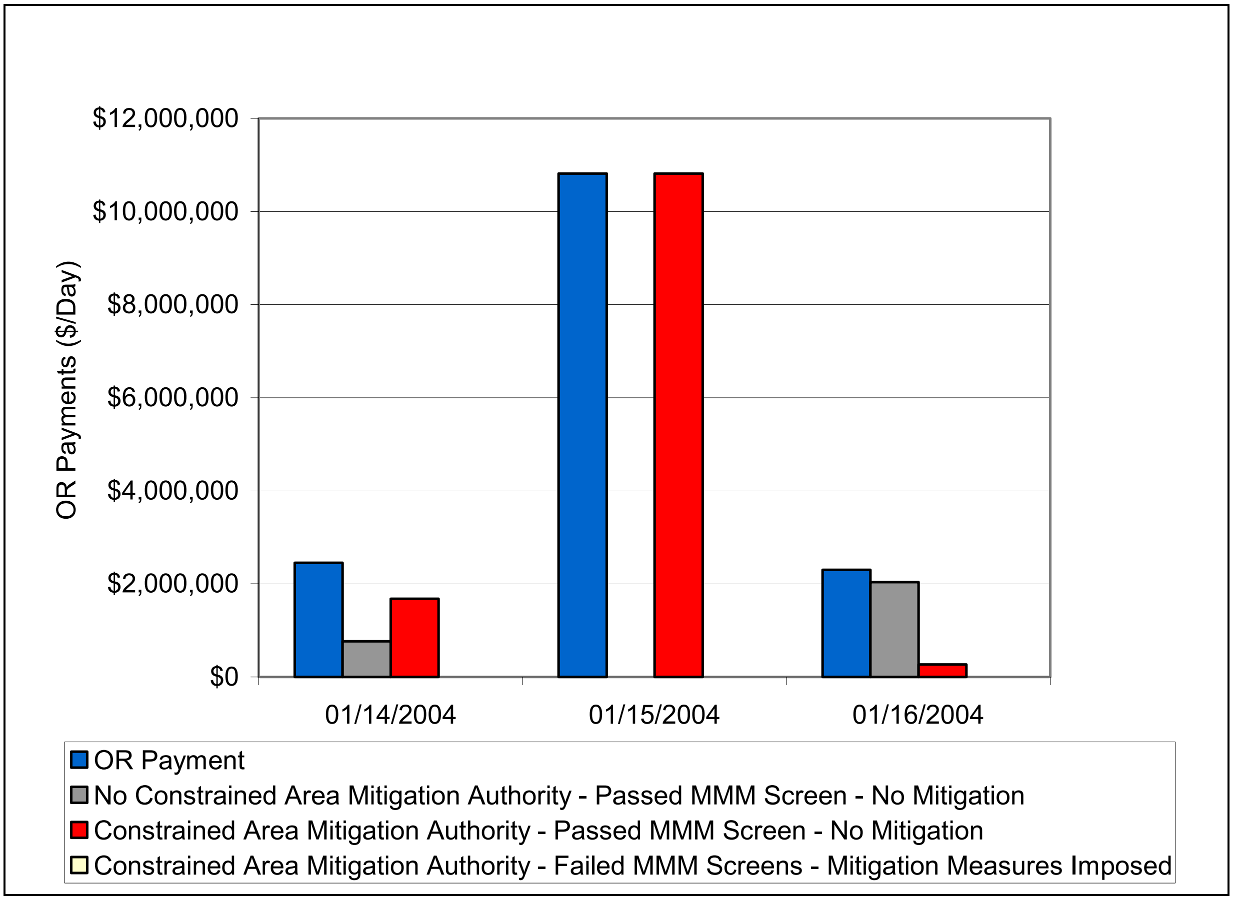


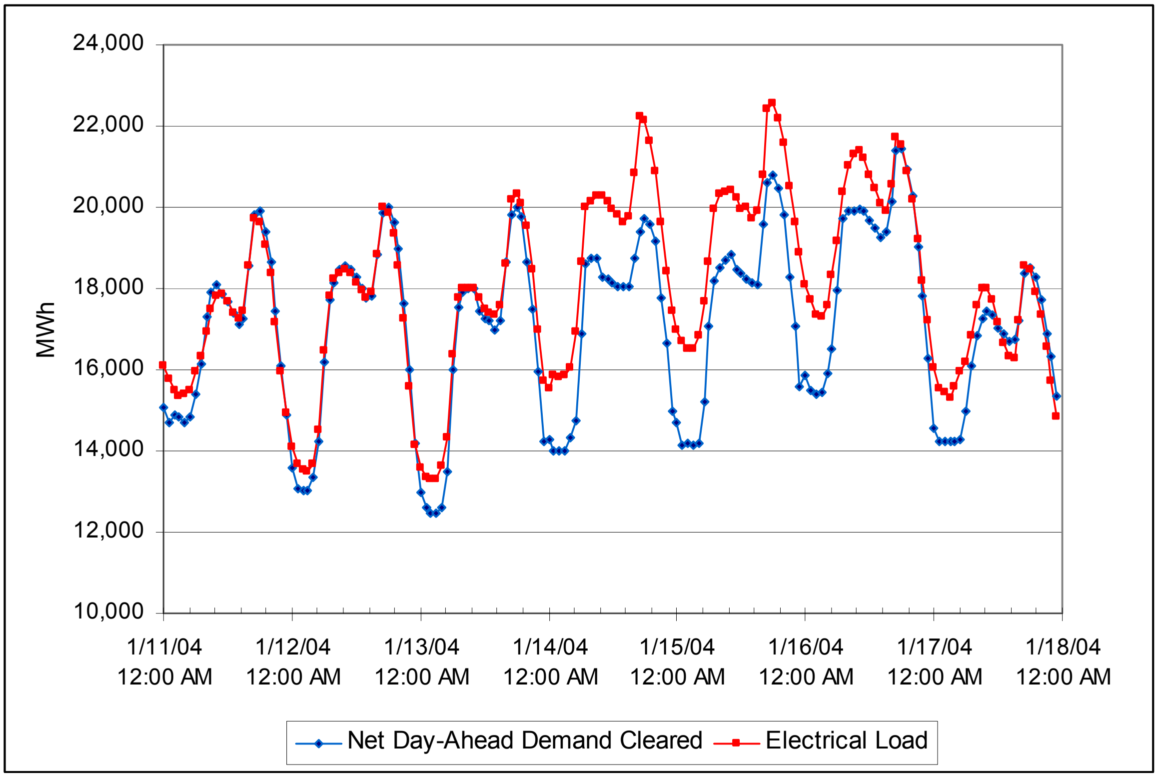
Figure 19 and Figure 20 show that no mitigation measures were imposed during operating reserve settlement. The units receiving operating reserve payments did not exceed the relevant thresholds.

F. Other Market Analysis

1. Load Behavior During the Report Period

This section of the report analyzes the behavior of load during the Report Period. Relatively low levels of day-ahead cleared bids can lead to increased real-time operating reserve charges, and may reduce unit availability if gas units that are unable to find gas intra-day would have been more likely to find gas if scheduled day-ahead. As Figure 21 suggests, the real-time electrical load was noticeably higher than the day-ahead cleared demand during the Report Period.

Figure 21 - Net Day-Ahead Demand Cleared and Real-Time Load January 11 - 17, 2004



The average daily relationship between day-ahead demand cleared and real-time forecast load during the Report Period for the day and for the peak hour is shown in Table 33. These values are somewhat lower than the average ratio of day-ahead demand cleared to real-time load for January 2004 of 98 percent, though only about 6 percentage points lower. On January 14, only 89 percent of the load forecast cleared in the peak hour. During the peak-load hours of January 14 and 15, over 1,100 MW more would have cleared day-ahead had the days during the Report Period followed the monthly average.

Table 33 - Average Day-Ahead Demand Cleared as a Percent of Real-Time Load Forecast, January 11-17, 2004

Market Day	Day	Daily Average	Peak Hour
1/11/2004	Sunday	99%	98%
1/12/2004	Monday	100%	100%
1/13/2004	Tuesday	98%	98%
1/14/2004	Wednesday	92%	89%
1/15/2004	Thursday	92%	92%
1/16/2004	Friday	94%	94%
1/17/2004	Saturday	97%	92%

The average daily relationship between day-ahead generation cleared and real-time forecast load for the day and for the peak hour for the week of the Report Period is shown in Table 34. The difference between Table 33 and Table 34 is virtual trades. While the daily averages are close to the monthly averages, the peak hour percentages are lower still, especially on January 14. These values can be compared with the average for January 2004 of 92 percent. The lowest average day-ahead demand cleared as a percent of real-time load forecast was 87 percent since the implementation of SMD, and the smallest average day-ahead generation cleared as a percent of real-time load forecast was 78 percent.[86]

While the amount of day-ahead load cleared was somewhat lower than typical levels, the total amount of demand submitted day-ahead during the Cold Snap, as a percentage of both forecast and actual real-time load, was approximately 110%. This is consistent with submitted demand both immediately before and immediately after the Cold Snap period. The exception occurred during the overnight hours (1:00 a.m. – 5:00 a.m.) of January 16, when submitted demand fell below 100% of actual load. Hence while demand submitted day-ahead was relatively constant relative to expected real-time load, cleared day-ahead demand was lower.

[86] Both of these events happened in March 2003, the first month of Standard Market Design.

The lower than average amounts of generation cleared during the peak hour in the day-ahead market, especially on January 14, is consistent with the sharp rise in gas prices and imperfect adjustment by demand bidders and virtual traders. This adjustment improved as the Cold Snap progressed. However, this imperfect adjustment likely contributed to the lack of day-ahead clearing by gas units during the Report Period.

Table 34 - Average Day-Ahead Generation Cleared as a Percent of Real-Time Load Forecast, January 11-17, 2004

Market Day	Day	Daily Average	Peak Hour
1/11/2004	Sunday	94%	93%
1/12/2004	Monday	95%	96%
1/13/2004	Tuesday	96%	96%
1/14/2004	Wednesday	88%	83%
1/15/2004	Thursday	88%	85%
1/16/2004	Friday	89%	87%
1/17/2004	Saturday	94%	89%

The next two figures show that load responded to higher fuel prices and higher expected electricity prices by increasing its willingness-to-pay in the day-ahead market during the Report Period, especially on January 15. The figures show price-sensitive demand bids display a pattern similar to the corresponding generator offer figures provided earlier. The variance of price-sensitive demand bids increased as well. This effect is more pronounced in the peak hour. However, this did not prevent relatively low levels of day-ahead clearing.

Figure 22 - Willingness to Pay for the Peak Hour of Each Day

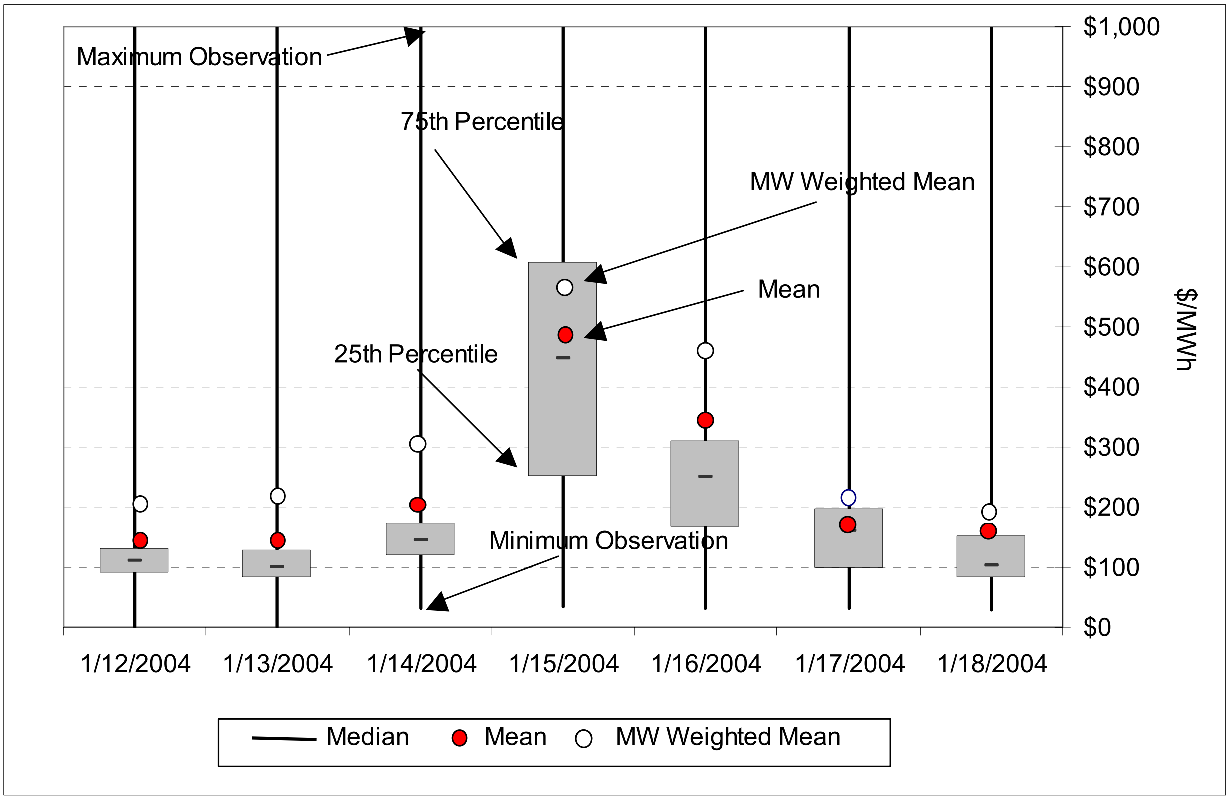
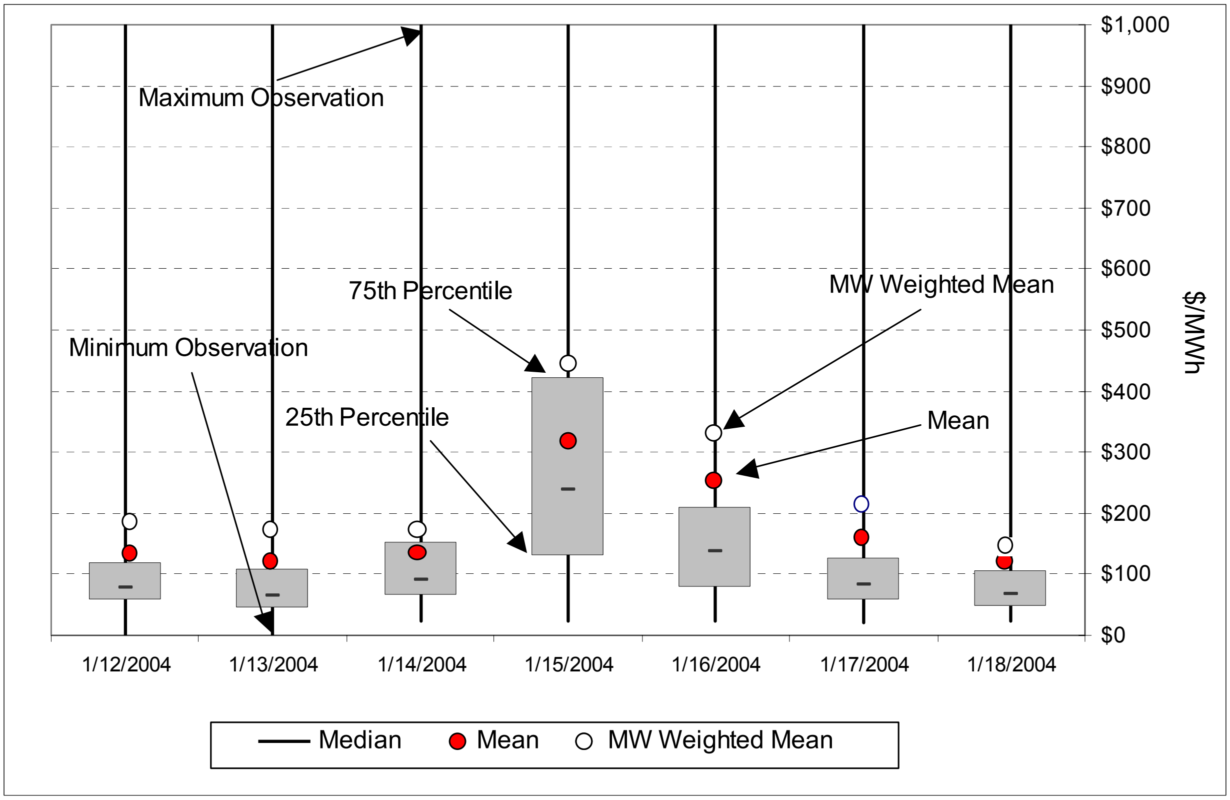


Figure 23 - Willingness to Pay Average for all Hours



Day-ahead cleared bid amounts are a function of participant-submitted demand bids and supply offers, not the ISO's load forecasting. These data suggest that some combination of increased price uncertainty and load uncertainty caused load to clear lower amounts in the day-ahead market. This most likely affected real-time operating reserve charges and may have somewhat reduced the ability of the gas units that otherwise would have cleared day-ahead to procure gas for the operating day though the market timing incompatibilities discussed earlier make this effect unclear. However, these results are not sufficient to conclude that the day-ahead markets are not working as intended. This is because the amounts cleared day-ahead are still within the normal range of day-ahead cleared amounts versus real-time loads. Day-ahead cleared amounts still averaged over 90 percent of the real-time forecast. As noted above, submitted day-ahead demand was consistent with levels immediately before and after the

January 2004 Cold Snap period. In addition, it is not surprising that load did not instantly replicate results obtained during typical load and price conditions under the extreme conditions of the Report Period.

2. Day-Ahead Market Clearing

Figure 24 shows the volume of gas-only offers that cleared in the day-ahead market for each hour and the number of MWh produced by gas-only generators in the real-time market from January 11 – January 17. The volume of cleared gas-only MWh in the day-ahead market on January 14 and 15 was much lower than on other days during the period, while the amount produced in real-time was similar. Day-ahead cleared amounts increased on January 16. The larger amount of gas-only MWh generated in real-time is caused by gas units committed to meet real-time reliability needs. These results are consistent both with the moderate increase in under-scheduling of load in the day-ahead market on January 14 and 15 and with relatively high real-time reserve charges on these days.

Figure 24 - Day-Ahead Gas-Only MWh Cleared in the Day-Ahead Market and Actual Gas-Only MWh Generated in the Real-Time Market, January 11-17, 2004

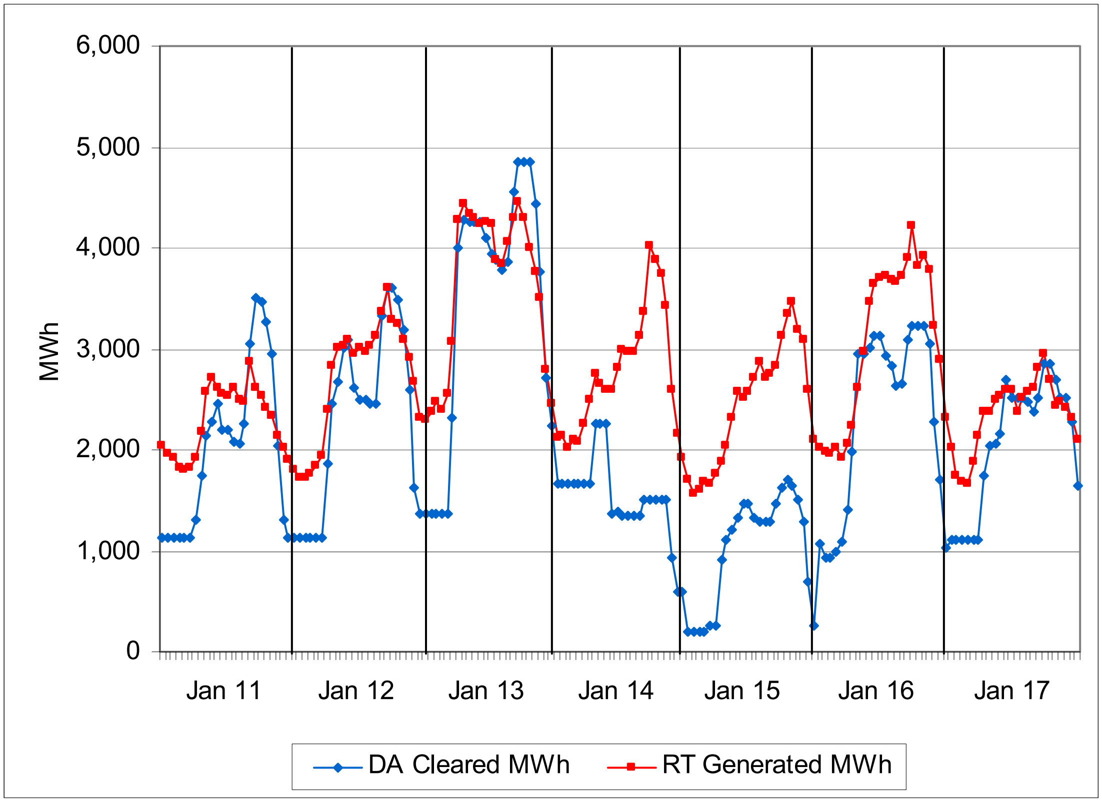


Figure 25 shows the MWh of increment offers[87] and decrement bids[88] that cleared in the day-ahead market from January 11 to January 17. The volume of incs cleared increased on January 14 and 15, especially during the peak load hours of the day, while the volume of decs fell on January 14 and 15 relative to surrounding days. Cleared virtual trades approached more typical levels on January 16. These results are consistent with higher than expected day-ahead prices on January 14 and 15, resulting in more incs cleared and decs not cleared.

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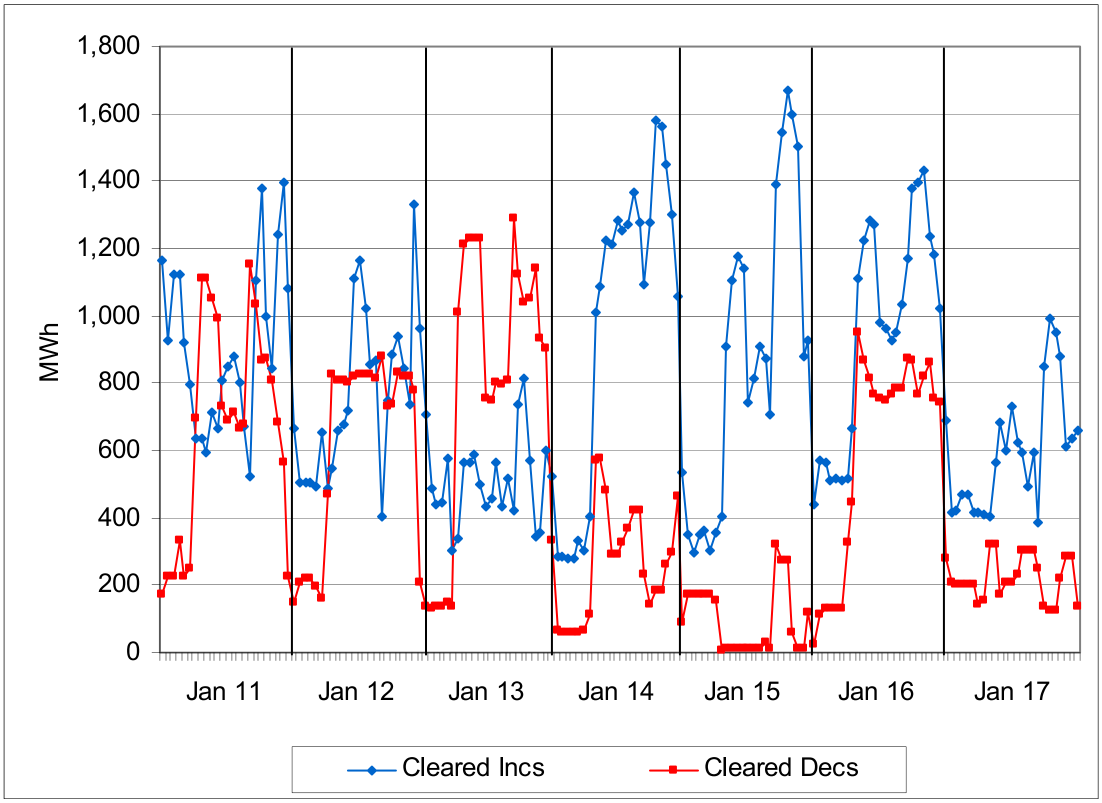
[87] From Market Rule 1, an increment offer ("inc") is an offer to sell energy at a specified location in the day-ahead energy market. An accepted increment offer results in scheduled generation at the specified location in the day-ahead energy market.

[88] From Market Rule 1, a decrement bid ("dec") is a bid to purchase energy at a specified location in the day-ahead energy market that is not associated with a physical load. An accepted decrement bid results in scheduled load at the specified location in the day-ahead energy market.

Figure 25 - Cleared Increment Offers and Decrement Bids, January 11-17, 2004



3. Review of Demand Response During the Report Period

The demand response program consists of two kinds of programs: (1) the reliability programs (real-time demand response, 30-minute demand response, two-hour demand response and the profiled-response program), in which response is mandatory, and (2) the real-time price program, in which the response of subscribers is voluntary based on price signals. During the Report Period, only the price-response program was activated,[89] and it was called from 7:00 a.m. to 6:00 p.m. on each day. Table 35 summarizes the response in terms of the total energy (MWh)

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[89] The reliability programs are activated only when certain OP4 actions are called. During January 14-16, the OP4 actions associated with the activation of the real-time demand response programs and the profiled response program were not called. The demand response programs tend to receive much higher MWh response rates than the price response program. The demand response programs were only called once (August 15, 2003), and some of these programs achieved response rates of over 90 percent.

for each day, by load zone, and provides the grand total for all three days. Table 35 also compares the response with total capacity enrolled in the program.[90]

Table 35 - Demand Response by Day and Zone, January 14 - 16, 2004[91]

Zones	ME	NH	VT	CT	RI	SEMA	WCMA	NEMA	Grand Total
Total Contracted	4.4	2.2	78.1	297	23.1	86.9	102.3	691.9	1,285.9
Response on January 14	0.0	0.3	15.1	53.4	4.2	39.6	27.1	156.7	296.6
Response Percentage on January 14	0%	15%	19%	18%	18%	46%	27%	23%	23%
Response on January 15	0.0	0.4	17.5	54.6	5.0	40.5	31.7	230.4	380.1
Response Percentage on January 15	0%	20%	22%	18%	22%	47%	31%	33%	30%
Response on January 16	0.0	0.1	23.7	54.9	6.8	79.6	51.3	220.0	436.5
Response Percentage on January 16	0%	5%	30%	18%	29%	92%	50%	32%	34%

The price-response program is voluntary; there is no penalty for failing to provide a load reduction.[92] Participation by subscribers (customers) is based on the average price for the load zone at the time of the activation of the program. Subscribers are eligible to receive a minimum payment of $100/MWh for each hour for which they provide interruptions. The level of response illustrated in Table 35 should be considered in terms of the information about energy market prices available to the program subscribers at the time of the activation of an event. The

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[90] The total contracted energy (MWh) is the capacity (MW) level that subscribers have contracted to provide for each hour during a price response event. This figure is then multiplied by the number of hours in the event. In this instance there were 11 hours in the event each day.

[91] The overall MWh response rate for the price program resources for hour ending 8 a.m. – hour ending 6 p.m. for March – December 2003 was 15 percent.

[92] In addition, some of the customers provide load reductions by controlling loads that are available only during the summer season (*e.g.*, air conditioning levels). Thus, some participants are not able to respond during a winter price event.

program participants are mostly retail customers that do not continuously monitor wholesale prices.[93]

Table 36 - Demand Response by Asset, January 14 - 16, 2004

Zones	ME	NH	VT	CT	RI	SEMA	WCMA	NEMA	Grand Total
Total Ready to Respond Assets	1	1	13	44	14	76	82	105	336
Responded on January 14	0	1	10	30	11	60	65	83	260
Response Percent	0%	100%	77%	68%	79%	79%	79%	79%	77%
Responded on January 15	0	1	11	31	11	68	67	87	276
Response Percent	0%	100%	85%	70%	79%	89%	82%	83%	82%
Responded on January 16	0	1	11	33	12	71	76	96	300
Response Percent	0%	100%	85%	75%	86%	93%	93%	91%	89%

In terms of number of participants, a total of 336 assets were enrolled and ready to respond in the price program on these days. Table 36 details response percent that represents the total number of assets that responded on each day. "Responded" in this context means any capacity reduction by an asset in any hour for any duration on that day. For example, on January 14 not all 260 assets responded in every hour nor did all 260 assets respond at the same time.[94]

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[93] If prices going into the event were relatively modest, then chances are that these customers will not respond if, at some point during the day, the prices spiked to high levels.

[94] A detailed analysis of demand response in terms of assets responded and demand reduced (MW) during the Report Period during Hour Ending 6:00 p.m. is presented in Appendix D.

4. Evaluation of Price Setting Eligibility and Out of Merit Operation During the Report Period

a) Unit Eligibility and Operating Reserve Payments

Under the market rules, units running out-of-merit at their economic minimum are eligible to receive operating reserve credits or uplift payments. How much operating reserve credit a unit receives depends on the hourly LMP and the unit's offers. If a unit needed for reliability submits a relatively high offer price and the LMP is relatively low, the resultant operating reserve credit can be substantial. Figure 26 presents total day-ahead and real-time operating reserve payments for January 11-17.[95] There were high operating reserve payments (over $2 million) in the real-time market on January 14, 15 and 16. These payments have been a source of concern for participants, including one participant that stated that it thought that it had profitably exported energy to New England to help alleviate a capacity shortage but ultimately lost money when its share of operating reserve payments was assigned. This analysis focuses on January 15, as operating reserve payments for that day totaled over $10 million, by far the largest of the Report Period.

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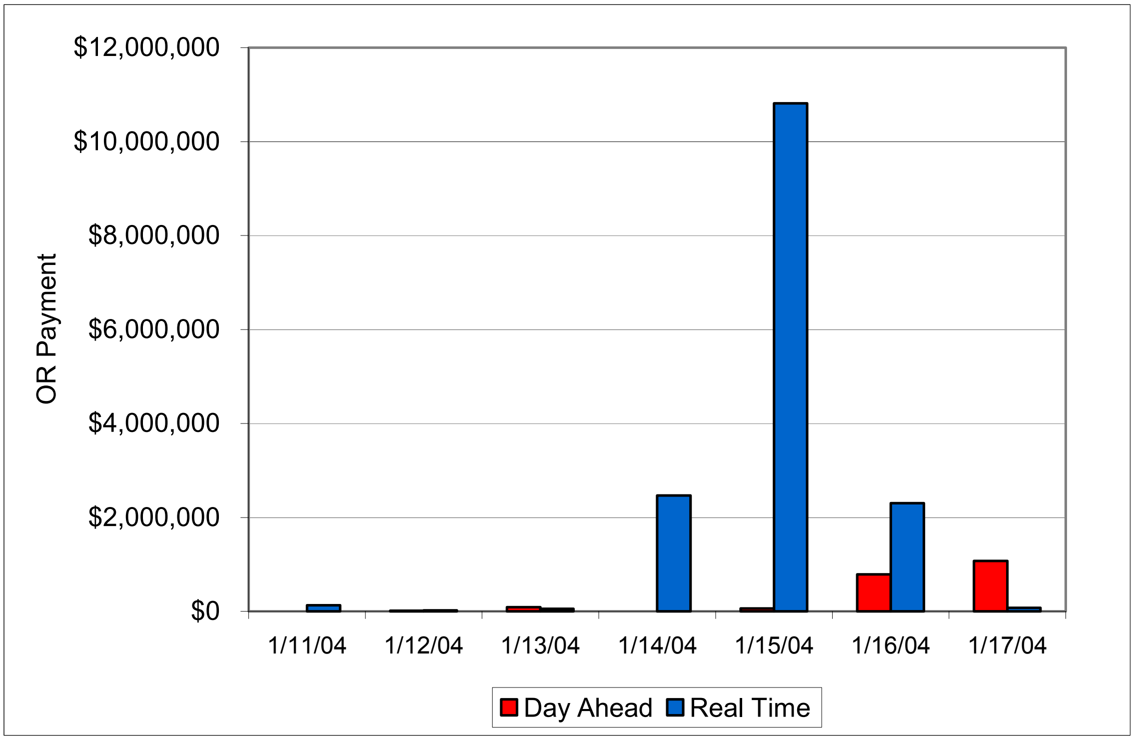
[95] There are four types of operating reserve credits: Economic, paid to generating units committed to ensure pool reliability (*e.g.*, to supply replacement reserves) whose decommitment would pose a threat to that reliability; Reliability Must Run (RMR), paid to units that are required for reliability within a particular reliability region; Voltage Ampere Reactive (VAR), paid to units providing VAR support to the transmission system; and Special Constraint Resources (SCR), paid to units that provide SCR Service for local reliability under Schedule 19 of the NEPOOL Tariff.

Figure 26 - ISO New England Operating Reserve Payments



b) Price Setting On January 15

Table 37 provides a detailed breakdown of all energy generated (MWh) in the real-time market on January 15. Energy is categorized broadly as "Not Eligible to Set the LMP at Dispatch Point" or "Eligible to Set LMP." Units are not eligible to set the LMP when they are operated at or below their economic minimum output, when they are self-scheduled, or when they are not dispatchable. Units might be non-dispatchable because of operating characteristics, unit-offer characteristics or, in some limited cases, ISO dispatch for reliability. Units able to respond to offer-based dispatch signals and not ramp-constrained are eligible to set the LMP. Table 37 shows that only 10 percent of all energy was marginal or infra-marginal and eligible to set the LMP on January 15. A unit is infra-marginal when the LMP at the unit's node is higher than the unit's offer at the current output level and a more expensive resource sets the dispatch rate.[96] The most striking result is that 70 percent of energy was self-scheduled. While in one sense these MWh are infra-marginal, as they were offered as zero price takers, they are not eligible to set LMPs.

Table 37 - Unit Operation LMP Setters by Operating Category, January 15, 2004, All On-Peak Hours

Not Eligible to Set the LMP at Dispatch Point						Eligible to Set LMP	TOTAL
Special Constrained Resources[97]	Self Scheduled	At EcoMin	Below EcoMin	On Manual Dispatch	On Regulation	Marginal or Infra-Marginal	
0.10%	70.24%	10.94%	0.88%	1.56%	5.96%	10.31%	100.00%

c) Change in Fuel Mix of Price Setters on January 15 in the Real-Time Market

On January 15 in the real-time market, there was a change in the fuel mix of the generators setting the LMP relative to earlier periods. Under typical system conditions, gas-only units are on the margin about 43 percent of the time.[98] On January 14 in the real-time market, for example, gas-only units on the margin totaled 96 of 246 of the ISO's Scheduling, Pricing, and Dispatch software ("SPD") runs, or 39 percent of the time. On that day gas units were marginal at many different price points, as illustrated in Figure 27.

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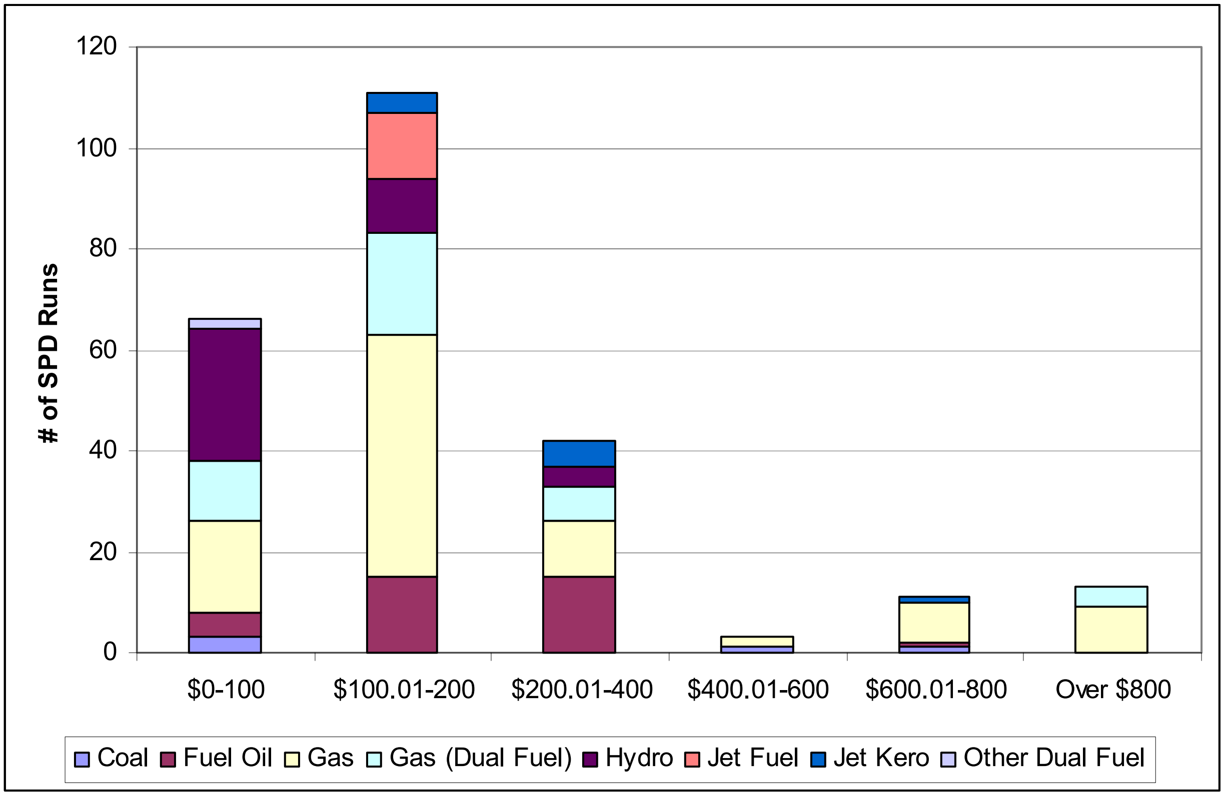
[96] The Dispatch Rate is the price set in the *ex ante* dispatch software and is essentially the marginal price in an area of the transmission system.

[97] A small portion of the energy (MWh) (0.10 percent) was dispatched and flagged in response to a SCR dispatch request. The SCR flag identifies units requested by a transmission owner to operate to support the local transmission and distribution systems, below the bulk power system operated by the ISO. That is, these units would not have operated, but for the specific local needs of a transmission owner. They are ineligible to set price at their required dispatch level, but are eligible to set price if dispatched economically above the level require by the transmission owner.

[98] *See* ISO Quarterly Report, 4th Quarter 2004.

Figure 27 - SPD Price Setters By Fuel Type in the Real-Time Market, January 14, 2004[99]

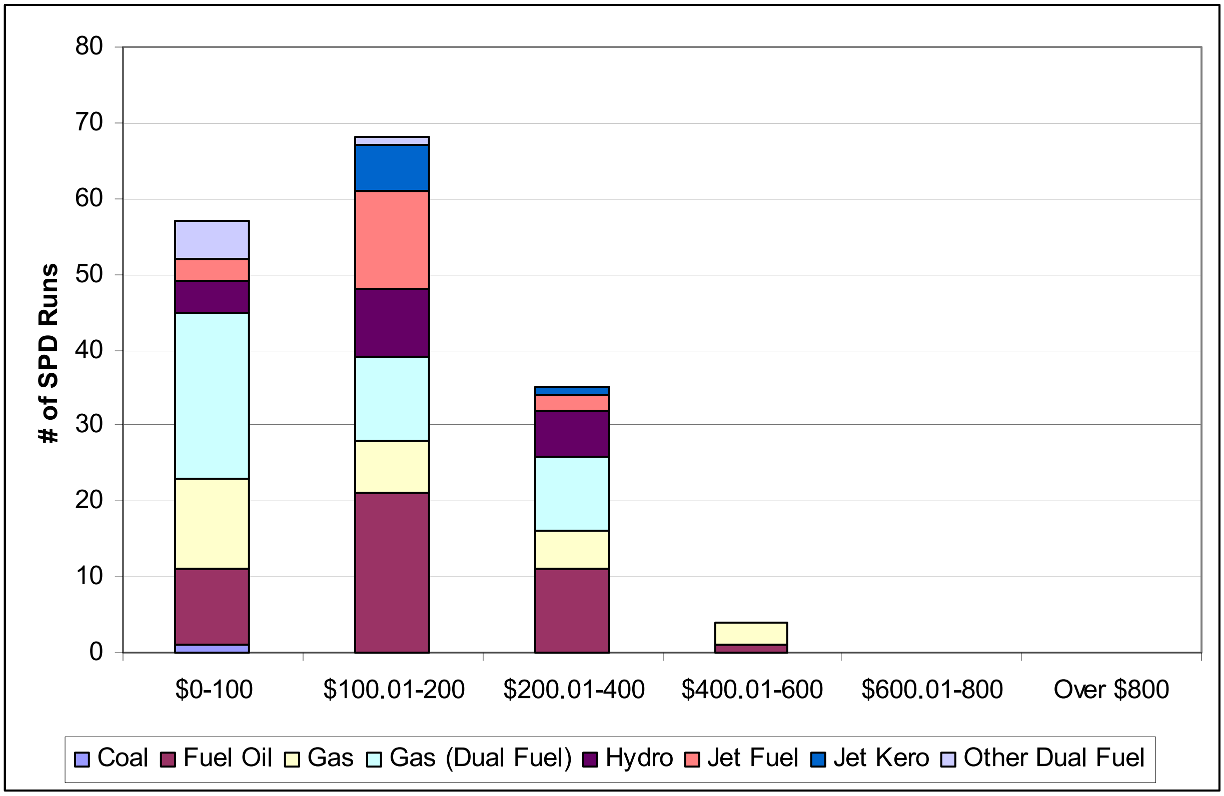


The January 15 real-time market shows a large decrease in price setting by gas units. Figure 28 shows number of SPD runs that each fuel type set price in the real-time market on January 15, and the price ranges in which the prices were set. Gas units on the margin accounted for only 27 of 164 SPD runs, or 16 percent, compared with 43 percent of the time under typical system conditions. Figure 28 shows that dual fuel[100] and oil units were on the margin for 85 of 164 SPD runs, or 52 percent. This compares with 35.8 percent of SPD runs during typical system conditions. This is consistent with economic dispatch: relatively cheap fuels (oil) were substituted for relatively expensive fuels (natural gas).

[99] This exhibit does not include data for units that were marginal that were backed down for transmission that created negative price separation on January 14.

[100] Dual fuel units are capable of burning two types of fuel.

Figure 28 - SPD Price Setters by Fuel Type in the Real-Time Market, January 15, 2004



d) Units Providing Operating Reserve in the Real-Time Market During the Report Period

While LMPs were generally low to moderate during the Report Period, a number of gas units were dispatched out of merit order for reliability. In these cases, the units were dispatched at their economic minimums for long portions of their minimum run times and were not eligible to set LMPs. These units are generally eligible for operating reserve payments. As noted in Section IV.E, most of the operating reserve payments during the Report Period were in the real-time market.

Table 38 shows total operating reserve (MWh) and payments for the Report Period by fuel type in the real-time market for January 14, 15 and 16. For the Report Period, gas-fired units produced the majority of operating reserves and received the greatest proportion of operating reserve payments. In addition, other gas units operated out-of merit for many hours, yet were ineligible to receive operating reserve payments under NEPOOL settlement rules. These rules have since been revised.[101]

Table 38 - Operating Reserve MWhs and Payments by Fuel Type in the Real-Time Market, January 14 - 16, 2004

Fuel Type	January 14				January 15				January 16			
	Units	OR MWh	OR Payment	$/MWh	Units	OR MWh	OR Payment	$/MWh	Units	OR MWh	OR Payment	$/MWh
Fuel Oil	1	51	$9,418.20	$184.67	1	1,013	$617,918.59	$609.99	4	3,842	$313,060.83	$81.48
Gas	9	13,878	$2,247,318.76	$161.93	8	16,096	$10,104,213.09	$627.75	7	10,052	$1,932,075.13	$192.21
Gas (Dual Fuel)	3	1,984	$174,632.22	$88.02	3	2,524	$91,305.52	$36.17	-	-	-	N/A
Hydro	-	-	-	N/A	-	-	-	N/A	1	1,077	$37,537.75	$34.85
Jet Fuel	-	-	-	N/A	-	-	-	N/A	2	154	$19,529.76	$126.82
Jet Kero	2	130	$21,407.40	$164.67	-	-	-	N/A	-	-	-	N/A
Total	**15**	**16,043**	**$2,452,776.58**	**$152.89**	**12**	**19,632**	**$10,813,437.20**	**$550.81**	**14**	**15,125**	**$2,302,203.47**	**$152.21**

Table 39 presents the total number of units by fuel type that were providing operating reserve and the percentage of operating reserve payments for each fuel type in the real-time market. On each day, gas-fired units accounted for the bulk of all units providing operating reserve and the majority of all operating reserve payments. Gas units accounted for over 80 percent of total operating reserve payments on all three days.

[101] The rules in effect during the Report Period prevented a unit from receiving operating reserve credits if it had been self-scheduled at any point during its current period of on-line operation, even if the self-scheduling occurred weeks or even months earlier but the unit had operated continuously since that time.

Table 39 - Total Units Receiving Operating Reserve Credits and Percentage of Total Operating Reserve Credits by Fuel Type in the Real-Time Market, January 14 - January 16

Fuel Type	January 14		January 15		January 16	
	# of Units	% of OR Payment	# of Units	% of OR Payment	# of Units	% of OR Payment
Fuel Oil	1	0.38%	1	5.71%	4	13.60%
Gas	9	91.62%	8	93.44%	7	83.92%
Gas (Dual Fuel)	3	7.13%	3	0.85%	-	0.00%
Hydro	-	-	-	0.00%	1	1.63%
Jet Fuel	-	-	-	0.00%	2	0.85%
Jet Kero	2	0.87%	-	0.00%	-	0.00%
Total	**15**	**100.00%**	**12**	**100.00%**	**14**	**100.00%**

Operating reserve charges and related data for December 2003 and January and February 2004 were compared with those of the Report Period. While total operating reserve charges during the Report Period were much higher than typical levels, the two primary determinants of these charges, in number of units and amount of MWh receiving operating reserves, were within normal ranges.

The daily numbers of units receiving Operating Reserve credits, while slightly above normal, were not even the largest in January. January 14, 15, and 16 had 15, 12, and 14 units eligible to receive operating reserve credits. The previous week had days with 15 and 17 eligible units, but with much lower charges. January 15, with 12 eligible units, had the highest charges but the fewest eligible units during the Report Period. The energy produced by these units, while high, was similar to other days during the winter months examined with large amounts of energy paid operating reserve.

The chief determinant of the high operating reserve charges during the Report Period was the large gap between LMPs and the offer prices of the units receiving operating reserve credits. The $/MWh paid to capacity generated by units eligible for operating reserve credits during the Report Period was much higher than for any other day during the three winter months examined, excluding a handful of days with very low numbers of MWh generated by units eligible for operating reserve credits.

To obtain a better understanding of the high operating reserve payments, the ISO evaluated the physical characteristics of the gas-fired units that provided operating reserves in the real-time market during the Report Period as well as system needs for capacity on those days. The physical assessment of these units consisted of an evaluation of offers, operational flags, and as-offered physical characteristics. The system operational assessment consisted of an evaluation of the capacity margin over the peak hour of each day of the Report Period and an illustrative evaluation of the supply offer stack for two SPD runs on January 15. The results of these evaluations are presented below.

(1) Physical Assessment

The ISO reviewed the economic minimum as a percentage of the economic maximum over the peak hour for each gas-fired unit that provided operating reserve in real-time for the Report Period. Table 40 presents the sum of the economic minimums, economic maximums, average ratio of economic minimum to economic maximum, and the number of gas-fired units providing large quantities of operating reserve in real-time during the Report Period. The average ratio of economic minimum to economic maximum is greater than 60 percent for each day of the Report Period. This ratio is important because if the unit is selected to provide operating reserve, the ISO must commit the unit and pay operating reserves based on the unit's economic minimum. The higher the economic minimum, the more energy that must be paid operating reserves, whether or not that energy is needed. High economic minimums also have implications for a unit's ability to set LMPs and their effect on LMPs when dispatched at economic minimum. For these reasons, units with high economic minimums have been a focus of attention since the Interim Markets.

Table 40 - Physical Characteristics of Gas-Fired Units Receiving Large Quantities of Operating Reserve Credits, January 14-January 16, 2004

Day	Total Economic Minimum MW	Total Economic Maximum MW	Average EcoMin/EcoMax	# Gas Units
January 14	1,211	1,829	66.21%	9
January 15	1,137	1,791	63.49%	8
January 16	715	1,180	60.58%	7

All of the units receiving at least a $500,000 operating reserve payment in real-time per day in the Report Period were gas-fired, with one exception. Consistent with the high operating reserve payments, the gas units providing operating reserve reflected gas market conditions in their energy offer prices. The offer prices were well above average LMPs. However, as noted in Section III, all of these units passed both the operating reserve conduct and impact screens and, as a result, were not subject to mitigation. During the Report Period, two units that received operating reserve credits were designated SCR. All other units were used to provide pool-wide capacity.

The ISO evaluated the eligibility of the gas units that were providing operating reserve to set the LMP in real-time during the Report Period and examined whether or not there were any hours that the units were operating in merit. Table 41 presents the number of hours that gas units providing operating reserve were operating or offline for the on-peak hours of the Report Period. Table 41 also presents the number of hours that the units, when operating, were at economic minimum, above economic minimum but offered above the hourly LMP,[102] and running in merit. Table 41 shows that during a large majority of operating hours, the gas units providing operating reserve were operating at economic minimum. These units operated a large majority of on-peak hours, but seldom operated above economic minimum. When above economic minimum they were in merit or eligible to set price about half the time. The in-merit operations on January 14 occurred during the high-priced OP4 hours. The units running in-merit on January 15 and 16 were primarily units with relatively "low" offer prices.

Table 41 - Gas Units Providing Operating Reserve by Operating Category During On-Peak Hours, January 14 -16, 2004

Day	# Units	On-Peak Hours Offline	On-Peak Hours Operating	Operating Hours at EcoMin, Not Eligible to Set Price	Operating Hours Above EcoMin	Operating Hours Above EcoMin, Above LMP	Operating Hours Above EcoMin, In Merit or Marginal
January 14	9	46	98	77	21	6	15
January 15	8	12	116	101	15	13	2
January 16	7	10	102	78	24	13	11

(2) System Operational Assessment

The system capacity margin is calculated by subtracting the forecast load, reserve requirements, replacement reserve requirements, and net imports/exports from all capacity available in 30 minutes over the peak hour of the day. As noted in Section II, due to high loads and generator outages and reductions the projected capacity margin over the peak hours was projected to be less than 2,000 MW for each day of the Report Period. This is less than would be available on a typical day. Projected and actual capacity margins over the peak hour, along with

[102] Because this analysis was done at the hourly level, unit ramping constraints could show hourly generation above economic minimum but with the hourly LMP below the unit's offer price.

outages for each day in the Report Period, are presented in Table 42. On January 14 and 15 the actual capacity margin was lower than the projected capacity margin. This is consistent with the high degree of capacity volatility on the system on these days, and suggests that committing the system so that it had a positive capacity margin was appropriate and prudent. However, additional commitments typically run out of merit at the unit's economic minimum. Any excess capacity may contribute to lower LMPs and higher operating reserve payments. On January 16, the actual capacity margin was much higher than forecast.

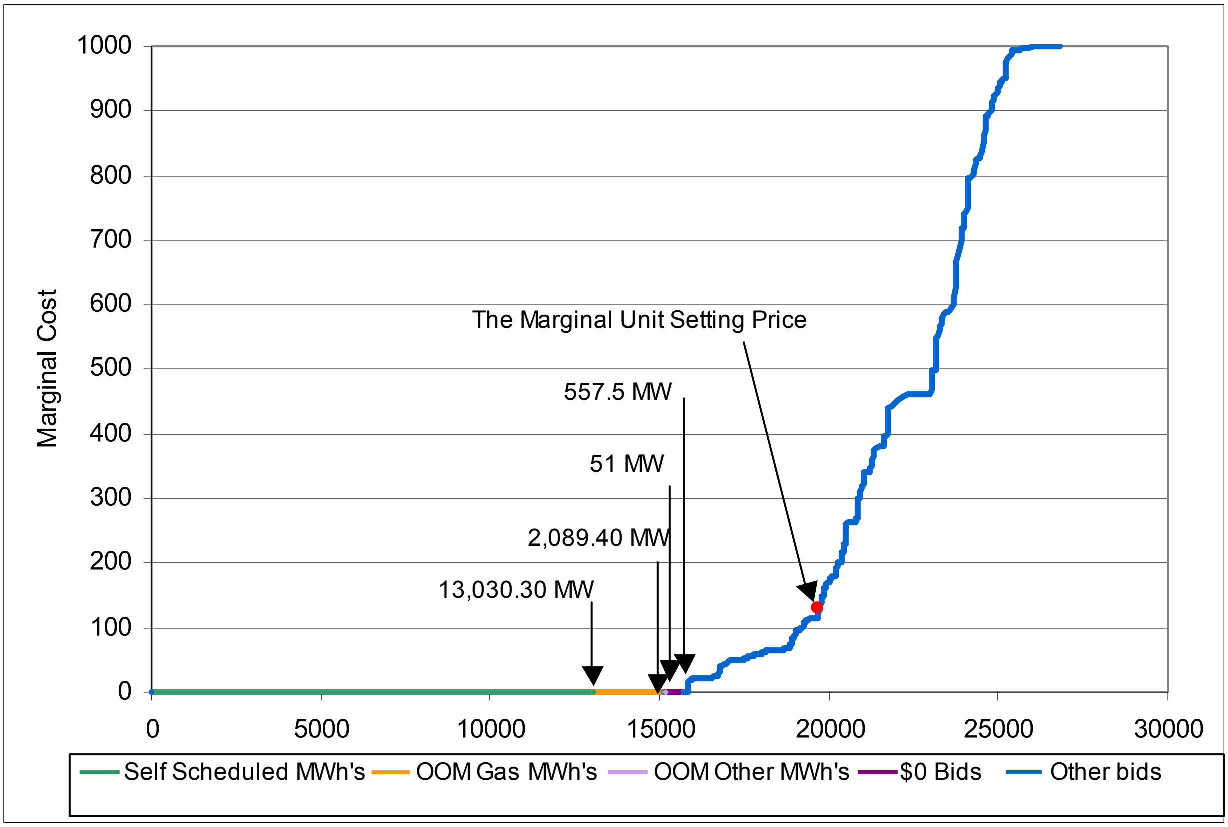
Table 42 - Projected v. Actual Capacity Margin over the Peak Hour and MW Outages, January 14 - 16, 2004

Day	Projected Surplus/(Deficit) MW	Actual Surplus/(Deficit) MW	Actual Outages MW
January 14	(84)	(108)	8,927
January 15	1,568	717	8,363
January 16	711	2,184	6,328

(3) Supply Stack Evaluation

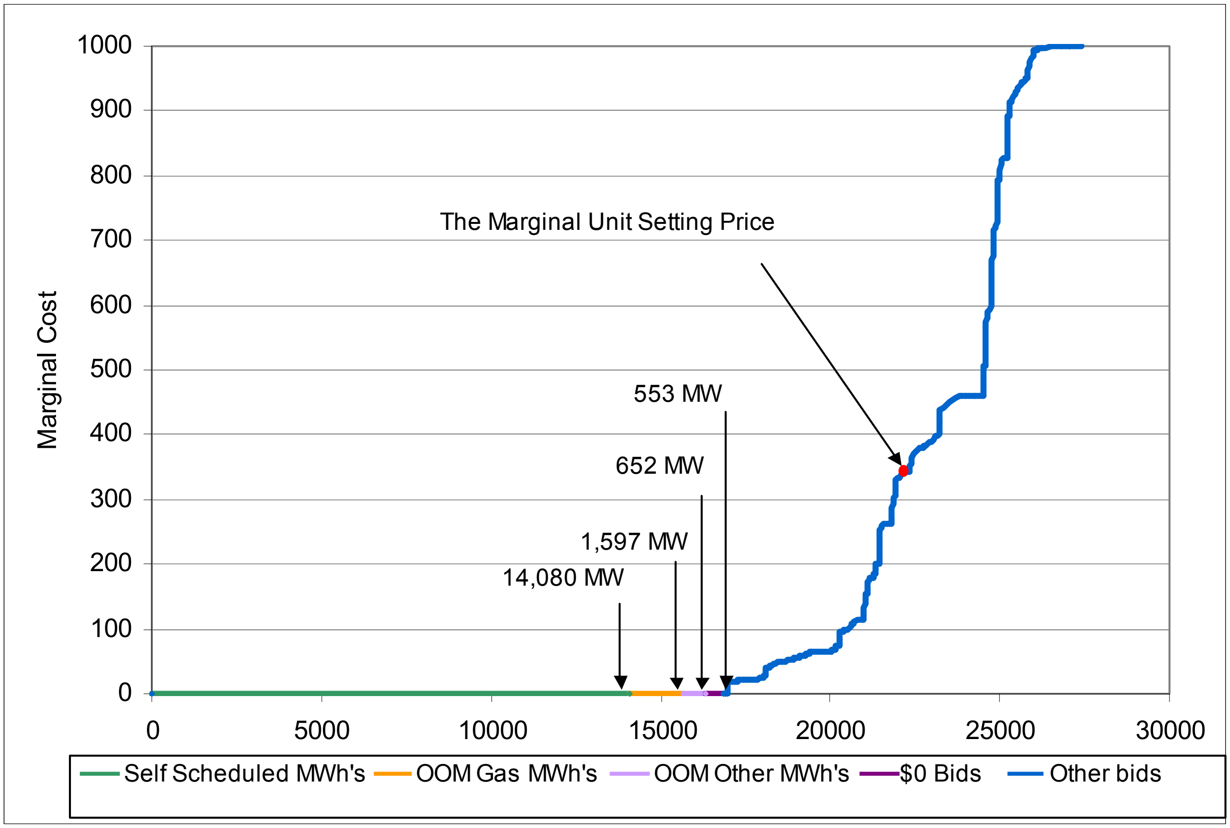
The ISO reviewed the supply stack for two SPD runs on January 15. Hour Ending 2:00 p.m. was selected because it has an especially low-priced interval. Hour Ending 7:00 p.m. was chosen because it was at the peak hour of the day. The supply stacks are presented below in Figures 29 and 30. In Hour Ending 2:00 p.m., a dual fuel (oil/gas) unit was setting the dispatch rate at $109/MWh. Almost 2,100 MW of gas units were providing operating reserve and running at their economic minimums, which made them ineligible to set the LMP. Without this 2,100 MW, the price would have been approximately $380/MWh. The average EcoMin/EcoMax ratio for gas units running out of merit on January 15 was 63.49%. If this average could have been cut in half for these units, removing 1,048 MW of essentially zero priced generation, the price for the SPD run in Figure 29 would have moved up to $261.89 in Hour Ending 2:00 p.m.

Figure 29 - Supply Stack for 1 SPD run, January 15, Hour Ending 2:00 p.m.



The supply stack presented in Figure 30 for January 15 Hour Ending 7 p.m. shows a jet unit setting the dispatch rate at $349.35/MWh. Almost 1,600 MW of gas units were running at their economic minimum providing operating reserve. Without this 1,600 MW, the price would have been approximately $460/MWh. The average EcoMin/EcoMax ratio for gas units running out of merit on January 15 was 63.49%. If this average could have been cut in half for these units, removing 799 MW of essentially zero priced generation, the price for the SPD run in Figure 30 would have moved up to $389.21 in Hour Ending 7:00 p.m. While the amount out-of-merit gas MW is less in this case, the problem of out of merit generation still exists at the peak hour.

Figure 30 - Supply Stack for 1 SPD Run, January 15, Hour Ending 7 p.m.



These figures show that out-of-merit operation can have a significant effect on LMPs; high economic minimums exacerbate this problem. While this sort of problem may occur during more typical system conditions, the effect is more pronounced on these days because of the operation on the steep portion of the supply stack. This issue warrants continued efforts toward resolution.

e) Conclusion

The combination of high economic minimums for units selected for operating reserve, a change in fuel mix in LMP price setters on January 15 and 16, and excess system capacity during non-peak hours all contributed to lowering LMPs in the real-time market during the Report Period. These factors thus increased operating reserve payments, which were exacerbated by high gas prices and resulting high offers from gas units. The Market Monitoring Department evaluated all operating reserve payments and found that all payments were compliant under the Market Rules. At least one participant noted that the high operating reserve charges caused an export to New England to become unprofitable. They suggested revisiting the assignment of operating reserve charges to external transactions in real-time.

5. **OP4 Price Setters**

In OP4 hours, a general concern is the composition of the generators that set prices during the period because the exercise of market power is most likely during such periods of capacity deficiency. During such hours it is especially important to evaluate whether high prices were set appropriately. If prices are being set at high levels, there are many potential reasons. It may be that the unit setting price is a PUSH[103] unit with high costs, a unit the ISO is having generate in its emergency range, or that a unit has inflated its offers to economically withhold or set high LMPs.

For the OP4 period, Hours Ending 5:00 p.m. and 6:00 p.m. on January 14, Table 43 shows the number of SPD runs and percentage of SPD runs for which each unit type set price. The data show that a mix of thermal, PUSH, and hydro units setting price in these hours. Some transmission constraints were activated during the period, and this resulted in multiple price setters for many SPD runs. Some of these prices were at relatively low levels.

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[103] On June 1, 2003, the ISO implemented Peaking Unit Safe Harbor ("PUSH") offer rules, allowing owners of low capacity-factor units (less than 10 percent annual capacity factor) in Designated Congestion Areas to include levelized fixed costs in their energy offers without risk of mitigation. The rules are intended to increase opportunities for fixed cost recovery and to produce signals for investment through higher LMPs in these areas during periods of scarcity.

Table 43 - OP4 Price Setters by Unit Type

Unit Type	Hour Ending 6 p.m. # of SPD Runs	Hour Ending 7 p.m. # of SPD Runs	Hour Ending 6 p.m. % of SPD Runs	Hour Ending 7 p.m. % of SPD Runs
Combine Cycle	10	4	43%	40%
Combine Cycle - PUSH	1		4%	
Hydro	2	4	9%	40%
Jet		1	0%	10%
Jet - PUSH	9		39%	
Thermal - Emergency Range	1		4%	
Thermal		1		10%

The ISO evaluated general and local market power for the units setting price during the OP4 hours. All units that set price were evaluated for mitigation and passed the mitigation screens. Prices in OP4 hours appear to have been set appropriately.

V. Conclusions and Recommendations for Action

The January 2004 Cold Snap significantly stressed both the New England electricity market and the electricity production and delivery system. Generally, the markets worked well and reliability was maintained. New England's electricity system successfully met the challenges of extremely cold weather and highly volatile fuel prices. However, the ISO's analysis also reveals areas for improvement. These conclusions are organized into the following categories: System Operations and Reliability, Market Timelines and Flexibility, ISO Operations and Implementation, and Market Monitoring and Analysis. Each section includes recommendations for action to be considered. The initial recommendations are intended to be a starting point for further consideration in the broader stakeholder discussion currently underway in New England. Final recommendations will be developed after the conclusion of the stakeholder process.

System Operations and Reliability

The events of the January 2004 Cold Snap highlight the vulnerability of the New England electricity grid to significant reductions in available generator capability on peak days. System reliability was maintained during the January 2004 Cold Snap, but a combination of record winter electricity demand and dramatically reduced availability of generating units put reliable operation of the electric system at risk. The reduced unit availability was caused by a combination of weather-induced outages and unavailability of fuel, primarily natural gas. There were two primary reasons for the unavailability of fuel: certain generators engaged in fuel arbitrage, which is allowed by the market rules, and other generators had not procured firm gas. In each case generators ultimately depended on the spot gas market. The spot gas market is subject to the capacity limitations of the natural gas pipeline network, which is built to serve firm gas load and which severely reduces the availability of non-firm gas transportation service during periods of high gas demand. The spot gas market was illiquid, volatile, and experienced high prices during the Report Period. The electricity market did not provide sufficient incentives for units relying on the spot gas market to contract for and hold firm gas, or even to nominate available gas day-ahead. These issues are discussed more fully below.

The electricity system became much more difficult to forecast and operate during the January 2004 Cold Snap due to the increased uncertainty of unit availability. Units became unavailable more frequently than under normal conditions, though these outages were often of short duration. This volatility meant that timely information from generators about unit availability was critical. Outage reporting appeared to be linked to the beginning of the new gas day, especially on January 14, consistent with reported gas-availability problems.

Participants need to provide ample notice to the ISO of expected outages due to fuel unavailability. In addition, improved coordination with the natural gas pipelines could significantly improve the ISO's ability to forecast and manage such situations. No formal coordination process currently exists between the electricity and natural gas industries.

The analysis suggests that additional dual-fuel capability and greater fuel diversity would reduce vulnerability to gas availability problems. Dual-fuel units were more available than gas-fired units, although many dual-fuel units failed to convert from gas to oil, for reasons including interpretation of air quality permits. As a group, dual-fuel units had a much lower percentage of unavailability due to fuel procurement problems and also had fewer weather-related outages. The latter is likely due to the fact that dual-fuel units tend to be older than gas-only units and have most likely experienced severe weather conditions in the past, allowing owners to correct any design problems and improve operations under such conditions. Survey responses suggest that the same learning can and should occur by recent-vintage gas-only units to rectify identified cold-weather operations problems. The ISO should consider following up with units experiencing weather-related outages to determine whether preventive measures have been taken.

More widespread dual-fuel capability and greater fuel diversity have other advantages, primarily by reducing New England's exposure to: a) gas price fluctuations, b) nationwide shortages of gas, and c) regional gas transportation disruptions. In the absence of more dual-fuel capability, a reduction in weather-related outages may not have improved gas-unit availability because it may not have been possible to procure sufficient gas to operate existing units, had the units been available.

Some stakeholders have suggested that the ISO should establish requirements that generators purchase firm gas supply arrangements that ensure gas delivery. Such requirements would assure that generators are ready and able to commit units provided the incentives are appropriate. The analysis shows that although units with firm gas transportation were somewhat more likely to be available than units without firm arrangements, a firm supply contract requirement would not necessarily ensure that units did not sell firm gas when doing so was more profitable than producing electricity.

Prohibiting fuel arbitrage is both difficult to enforce and economically inefficient. Instead, adequate market incentives should ensure that unit availability and electricity production are adequately rewarded and, thereby, create incentives for necessary participation in the electricity market. Evidence of LMPs below the incremental costs of gas-fired units during the Report Period suggests the absence of these incentives.

Economic outages were a source of concern during the January 2004 Cold Snap because of both their perceived reliability impact and a concern that outages were used to manipulate the market. It is not clear that economic outages had a significant impact on system reliability. Economic outages are also not likely to be the best mechanism by which to withhold capacity from the market. Denial of economic outages is not likely to have prevented units that wished to sell firm gas from doing so, and there is no requirement that generators selling firm gas seek an economic outage. But it also is not clear that economic outages are a necessary tool for generators except under more limited circumstances. Economic outages are appropriate when generators are prevented by the $1,000/MWh offer cap from reflecting their costs in their supply offers.[104] The failure of those units granted economic outages to return to service immediately upon the ISO's cancellation of those outages suggests that these units would have been more accurately characterized as experiencing unplanned outages, not economic outages. The ISO should consider narrowing the circumstances under which economic outages are allowed, as most economic outages might be more appropriately effected through either higher offer prices, or lengthened notification times, or should be classified as forced outages.

Imports from other control areas can be crucial during tight system conditions. The ISO should continue to improve coordination with neighboring control areas to maximize utilization of interface capability, particularly under emergency conditions. Also, the market rules assign a portion of certain operating reserve charges to real-time imports as deviations from day-ahead

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[104] Economic Outages may also be appropriate when a generation owner expects to save more by reducing staffing or other cost-cutting measures and becoming temporarily unavailable than by operating in the market. This is especially so if taking economic outages enables an owner to reflect this reduced availability through longer notification and start-up times, which could not be done under normal market conditions. An economic outage under these circumstances would be preferable to a forced outage when a unit is truly available.

schedules. Large operating reserve charges were assigned to real-time imports during the Report Period, especially on January 15. This can reduce the incentive to schedule such imports and result in inefficient use of interface capability.

Recommendations to address these conclusions are:

- The ISO should increase coordination with gas industry representatives and continue to support the activities of the Fuel Diversity Working Group. The ISO should increase its understanding of the gas transportation system and improve its working relation with key members of the gas industry. This should include development of an explicit coordination process between the ISO and the gas industry that facilitates information exchange and resolution of operational issues. Gas utilities are for-profit market participants, and some own generation assets. Hence, any coordination process must ensure appropriate treatment of confidential market information in accordance with the NEPOOL Information Policy, FERC Standards of Conduct for Transmission Providers, and anti-trust law provisions.

- The ISO should initiate an update of the New England Gas Study to reflect lessons learned from the January 2004 Cold Snap. Updating the studies will help the ISO better plan for future problems and may inform and motivate stakeholders to seek resolutions to problems identified in the updated report. It may be appropriate to include the updated study as an annual component of the Regional Transmission Expansion Plan (RTEP). The updated study should include:

    - A determination as to whether or not the existing pipeline capacity could have been better utilized. Although the ISO cannot directly affect pipeline utilization, data on utilization can help to determine the degree to which market-timing issues impaired the efficient allocation of supply-side resources.

    - An identification of feasible gas infrastructure capacity improvements in electricity-critical areas. Identification of gas system upgrades that would directly improve electricity system reliability can help guide investment and improve the probability of regulatory approval of specific projects.

- The ISO should review generators that provided operating reserve during the Report Period and evaluate, through follow-up with the plant operators, whether the operating reserves identified by the ISO dispatch software were actually available for dispatch in the event of a contingency. If they were not actually available, the ISO must seek ways to improve units' availability and to identify units actually unavailable in real time so that they are not counted as reserve providers. Coupled with this should be an evaluation of the reliability of quick-start units called on during the Report Period. Given the increased forced outages due to cold weather, the ISO should evaluate whether quick-start resources faced similar degradations in availability and whether this warrants revised operating procedures.
- The ISO should review the outage notifications provided by generators. The ISO should have follow-up discussions clarifying market rule obligations to provide notice of outages.
- The ISO should encourage consideration of the feasibility and usefulness of having the gas utilities provide "peaking gas" capability on gas pipelines in New England. Under emergency operating conditions, peaking gas might allow the provision of gas to peaking or quick-start units, enabling them to reliably provide critical operating reserves. Many details of operation and implementation would need to be resolved.
- The ISO should inventory dual-fuel units and their ability to burn each fuel. One focus should be to assess the regulatory barriers, if any, to operating on secondary fuels. The ISO should open a dialogue with state and local regulators about permitting of dual-fuel units. In addition, the ISO should evaluate the economic incentives to install dual-fuel capability, including whether permitting restrictions reduce those incentives.
- To increase incentives for unit availability during peak periods, the ISO should evaluate modifications to the ICAP rule. These modifications might include adjusting the UCAP

calculations to weigh outages during peak periods more heavily or imposing penalties on ICAP units that are unavailable during peak periods.

- The ISO should carefully reevaluate commitment practices and price-setting methodology to ensure appropriate price signals.

- The ISO should review and clarify OP5 economic outage documentation requirements and the criteria for evaluation and acceptance of economic outage requests. It may be appropriate to narrow the circumstances under which economic outages are granted. In addition, the ISO should clarify generator obligations, the linkage to ICAP payments, and the meaning of making "best efforts" to return from economic outages when requested to do so.

- Although congestion was not significant during the January 2004 Cold Snap, additional operational concerns might arise if the system were congested during an event similar to the January 2004 Cold Snap. The ISO should consider the implications of significant transmission system congestion during events similar to the January 2004 Cold Snap.

- The ISO should seek to maximize available imports during critical periods. It should review procedures for establishing transfer limits during critical periods and evaluate current disincentives to scheduling imports during such periods.

Market Timelines and Flexibility

During the Report Period, the electricity market was affected by the high degree of price volatility and limited liquidity at some regional gas market hubs. These effects, through high supply offers, were exacerbated by the apparent incompatibility between the natural gas and electricity market timelines, which forces generation owners to reflect a potentially large degree of risk in their offers to account for gas price volatility and penalty exposure. The inability of generation owners to update offers in the electricity market to reflect new information about gas prices makes the timing problems even worse. In addition, the timing of the day-ahead electricity market means that most gas units, even those clearing in the day-ahead market, must rely on purchasing intra-day gas or risk holding gas with no dispatch schedule. Units cleared day-ahead do not receive their schedules until after the day-ahead gas nomination deadline. It is unclear whether the lack of day-ahead gas purchases and transportation nominations reduced the non-firm and intra-day gas ultimately available for generation in real-time.

Revisions to the day-ahead electric market timeline could provide unit schedules prior to the day-ahead gas nomination deadline. While in theory revised electricity market timing will help to ensure that available gas and transportation are more fully utilized, during periods of tight demand day-ahead market commitment for gas-fired generation is uncertain. Based on evidence from the Report Period, when prices are high, few gas units might clear in the day-ahead electricity market. Thus the electricity market timeline could be revised, but gas units would not clear day-ahead and any advantages of the revised timeline would be lost. The ISO should consider ways to signal gas-fired generators that they will be needed for reliable bulk power system operation during the next operating day regardless of whether they would naturally clear in the day-ahead electricity market. This is likely to be a difficult task, as it would need to be done in a way that does not distort day-ahead market clearing or the offer incentives of gas-fired units.

Gas prices and gas market uncertainty contributed to a sharp run-up in supply offers from gas-fired units. Reducing the risk and uncertainty faced by gas-fired units would be expected to reduce the risk premiums in supply offers from gas units, which are ultimately borne by consumers. This risk reduction could be accomplished through a combination of increased electricity-market offer flexibility and revised electricity-market timing.

Gas units were generally uneconomic during the Report Period given their input prices, operating constraints, gas market deadlines, and uncertainty. Many gas units that were dispatched operated out of merit for large portions of the day, though over-commitment during the peak hours on January 14 and 15 did not appear to be a problem. These out of merit costs were reflected in high operating reserve charges, especially on January 15. This suggests that the market prices did not reflect the true marginal costs of power during the January 2004 Cold Snap. Ensuring that electricity market prices reflect the costs of marginal needed capacity is essential. Efficient prices signal generators to make themselves available and to compete with other users of gas to secure adequate supplies for electricity production, and it signals the value of dual-fuel or oil-fired capability.

Recommendations to address these conclusions are:

- The ISO should quantify the additional gas that could have been made available, if any, had gas-fired units that were ultimately committed in real time made day-ahead gas purchases and transportation nominations.
- The ISO should investigate enhanced coordination of gas and electric trading through synchronization of the respective trading deadlines. The ISO should support efforts (*e.g.* NAESB) to coordinate the trading days for gas and electricity. One example of better synchronization is the timing of the NYISO day-ahead market, which clears by approximately 10:00 a.m. day-ahead, before the end of the day-ahead gas trading day. Such timing might better enable day-ahead gas purchases and transportation nominations to ensure maximum gas availability in real-time.
- The ISO should evaluate increasing supply-offer flexibility in the real-time market. This would improve participants' ability to more accurately reflect current gas-market conditions in

their offers. This, in turn, would allow electricity end-users to compete more effectively with residential heating for scarce gas resources and may also work to reduce the risk premiums reflected in gas-unit offers under extreme conditions.

- The ISO should consider how to ensure that sufficient gas-fired capacity is incented to make day-ahead gas purchases and transportation nominations. This would be complemented by any revisions to the market timelines that better synchronize the electric and gas markets.

ISO Operations and Implementation

The January 2004 Cold Snap review has identified specific areas where ISO operations can be improved by modifying internal procedures and processes. These are listed below:

- The ISO lacks a formal mechanism and protocols for communicating with the gas industry in general and especially during tight system conditions. As a result the ISO is not as fully informed as possible about expected operating conditions. In addition to the emergency conditions, this also contributed to the inadvertent release of confidential generator information relating to one generator.

- Consistent with past operating practice, economic outages were granted by the ISO after the procedural deadline in OP5. The ISO must eliminate inconsistency between operating practices and procedures.

- Despite a more conservative forecast and unit commitment, the ISO's anticipation of unit availability underestimated the many unit outages experienced during the January 2004 Cold Snap. Forecasting methods need to incorporate the experience gained during the January 2004 Cold Snap to anticipate better the volatility of unit availability during similar conditions.

- The ISO briefed state regulators and public officials on a daily basis throughout the Report Period. During the January 15 briefing, the ISO notified public officials that because of highly volatile and uncertain conditions it had requested that transmission owners staff their substations as a precautionary measure should rolling blackouts become necessary. The ISO also issued a press release containing this information. Because the situation was so uncertain, this information was received with a varying degree of urgency resulting in an inconsistent message about the actual state of the bulk electricity system.

Recommendations to address these conclusions are:

- The ISO, jointly with the Northeast Gas Association, should develop a protocol for gas pipeline/ISO communications and establish a formal coordination mechanism between the ISO and the natural gas industry.
- The ISO should evaluate revisions to the NEPOOL Information Policy to allow limited sharing of confidential data as necessary for the purpose of maintaining system reliability. These revisions should allow communications with the natural gas pipeline system as necessary to ensure system reliability.
- The ISO should revise the economic outage provisions of OP5 or operating practice to ensure consistency between the practices of ISO operators and the written procedures.
- The ISO should review the assumptions used to forecast forced outages during extremely cold weather. The Report Period experience suggests that extremely cold weather can directly cause unit failures and indirectly cause outages due to fuel unavailability. Fuel availability may be better anticipated through improved monitoring of gas pipeline status.

- The ISO should review established procedures and protocols for communicating with state officials and announcing unusual emergency actions and should engage state agencies to refine these procedures.

<u>Market Monitoring and Analysis</u>

The ISO reviewed the available data and conducted a survey of market participants about events during the Report Period. The resulting analysis confirmed the lack of synchronization of the gas and electricity market timelines and the risks this creates for gas-fired generating units. Generators, including those with firm gas contracts, engaged in fuel arbitrage; they sold natural gas rather than use it to generate electricity because it was more profitable to do so. Such behavior is allowed under the NEPOOL market rules and is consistent with the relative prices in the two markets. Arbitrage improves market efficiency and resource allocation. Practically, it helped to ensure that LDCs had sufficient gas for residential and commercial heating purposes during the January 2004 Cold Snap.

The ISO evaluated whether economic and physical withholding had occurred during the Report Period. Many gas generators submitted high offers. Those offers were consistent with the prices, risks and uncertainties present in the natural gas markets at the time. Since LMPs were generally below the marginal costs of gas-fired units during the period, LMPs would have been unaffected had gas-fired generators attempted to withhold. LMPs may not have accurately reflected the marginal costs of generation. This conclusion is supported by the analysis of out of merit operations and large operating reserve credits to gas fired resources.

The relatively high level of generator outages was generally consistent with the unusually cold weather and tight gas system conditions, and units with firm gas were somewhat more available. Pivotal supplier analysis shows that it is unlikely that those participants most likely to benefit from the exercise of market power tried to exercise it through physical withholding. Unit availability improved each day of the Report Period despite worsening weather conditions, which suggests that generation owners learned how to cope with the market and weather as they gained experience with the extreme conditions. It does not appear that economic or physical withholding directly contributed to either high prices or reliability problems during the Report Period. This conclusion is supported by the ISO's competitive benchmark analysis.

High offers and a greater variation in offer prices from gas-fired units were generally consistent with the market environment and reflected both higher gas prices and increased uncertainty. However, it is difficult for a market monitor to distinguish between participants who submit high offers reflecting genuine risk and uncertainty, and participants who have better information about fuel prices and availability but are inflating their offers to take advantage of volatile market conditions. This difficulty is especially acute when risk and uncertainty are relatively large components of a unit's supply offer as any quantification of risk and uncertainty is the direct result of assumptions, perceptions, and modeling decisions that inherently involve a large degree of participant discretion and judgment.

The difficulty in evaluating unit offers can be addressed by:

a) reducing the risk that must be incorporated in a supply offer by increasing market flexibility and improving market coordination;
b) increasing market competition and contestability; and,
c) continuing to coordinate market monitoring efforts with the Federal Energy Regulatory Commission.

Coordination with regulators is especially important given that the scope of the ISO market monitor is inherently limited to investigation of electricity markets and that the ultimate penalties available to government entities (*e.g.,* revocation of market-based rates) are the most severe. Coordination with regulators can result in better, more thorough data gathering and analysis and also reveal inconsistencies in data and responses from participants.

Recommendations that follow from these conclusions are:

- The ISO's Market Monitoring Department should seek to incorporate lessons learned from its review of the January 2004 Cold Snap events into the monitoring of future events, including evaluation of participant explanations of behavior under similar circumstances.
- The ISO should further investigate out-of-merit operations during the Report Period. It should also evaluate rule changes necessary to reflect more fully in LMPs the cost of dispatched units.
- The ISO should continue and improve coordination with regulators or other monitoring entities to ensure adequate monitoring and information exchange during critical periods.

VI. Appendix A - Fundamentals of New England Power System Operations

A. The Electric Power Grid

New England's bulk electric power system is designed and operated to reliably meet the electricity needs of the region in accordance with established industry criteria. The system is comprised of more than 8,000 miles of high voltage transmission lines and several hundred generating facilities, of which 292 units are subject to central dispatch control.

There are also several interconnecting transmission lines to bulk power transmission systems in New York and the provinces of Quebec and New Brunswick in Canada. The interconnections with neighboring systems allow for both the import and export of electricity between regional power systems. These interconnections are used for both reliability purposes and for the sale and purchase of electricity between regions.

The bulk power systems operating in the northeastern United States were designed and built to standards developed in response to the Northeast Blackout of 1965 and have evolved over time. The fundamental goal of the system's design and operations is to minimize the likelihood of experiencing a major disruption in the future.

B. North American Reliability Requirements

To provide uniform design and operating standards for electricity generation and delivery systems, the industry created NERC, which was given the responsibility to establish electric system reliability and operating performance standards. In turn, NERC coordinates its activities with ten regional reliability councils that provide oversight at the regional level. The New England bulk power system is a part of the NPCC region.[105]

NEPOOL has adopted the bulk power supply resource adequacy standard commonly known as the "one day in ten years" criterion. This standard is widely used by the electric industry[106] and requires that the bulk power system be designed and operated in a manner that the likelihood of having to disconnect non-interruptible customers, resulting from a lack of generating resources, occurs on average no more than one day in ten years.

C. Operating Procedures and Guidelines

The ISO has detailed operating procedures and guidelines that govern the day-to-day dispatch and operation of the bulk power system. At its control center in Holyoke, Massachusetts, system operators continuously monitor the real-time generation and flow of electricity across the region's interstate high voltage transmission system.

The ISO uses both electronic and verbal communications to provide centrally located, real-time dispatch directions on the electrical output of each of 292 generating resources. ISO also coordinates maintenance activities of the generators and the transmission system to ensure that the flow of electricity is not disrupted by a planned or unexpected outage of a facility.

To assist the ISO in operating the New England bulk power system, there are four sub-regional control centers, called Satellite Control Centers, operated by transmission companies. Like the ISO's master control center, the satellite facilities are staffed 24 hours a day by system operators who monitor the real-time generation, transmission and distribution of electricity. The

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[105] The NPCC is comprised of the following regions: New Brunswick & Maritimes Provinces, New England, New York, Quebec and Ontario.

[106] Both NPCC and NEPOOL have adopted the "one day in 10 year" resource adequacy criterion.

satellite facilities work in conjunction with the ISO to ensure reliable transmission and distribution operations within their sub-regions. The satellite facilities also serve as backup to perform certain critical ISO operational functions. The ISO also coordinates its activities with neighboring bulk power system operators to protect the overall reliability of the interconnected systems.

D. Operating Reserves

To ensure minute-to-minute reliability of the bulk power system, there are requirements for maintaining a continuous and adequate reserve of electricity supply, commonly referred to as operating reserves. The ISO ensures that there is enough electricity to meet the real-time demand of the New England region while constantly maintaining an adequate amount of reserves to be called upon to replace any generating source or transmission line that is forced out of service unexpectedly. Electricity is generated on demand since it cannot be stored. Once power is generated, it must flow to a demand source. Operating reserves can be defined as a specific amount of megawatts that could be called upon to generate at any given time.

The ISO maintains operating reserves to provide the capability to replace, within ten minutes, the sudden loss of energy production from the largest source of power, and to restore, within 30 minutes, a subsequent loss of the second largest source of power. Typically, the ISO maintains an operating reserve margin of about 1,700 MW. Resources designated to provide operating reserves are identified in advance of the operating day, and the ISO closely monitors these resources to ensure that they will be able to generate electricity within the prescribed time frames necessary to ensure a constant balance between supply and demand.

Due to a variety of circumstances, there are times when the required operating reserves are jeopardized. Circumstances could include having an unusually high number of generating units out of service due to mechanical problems or experiencing unexpected high demand due to extremely hot or cold weather. To respond to such conditions, the ISO has special operating procedures that address a variety of such scenarios or contingencies. These procedures were developed during the original design of the New England bulk power system, and work to maintain system reliability. Operating procedures have been enhanced over the course of the 31-year existence of central dispatch in New England.

E. <u>NEPOOL Operating Procedure No. 4 (OP4)</u>

OP4 is invoked whenever a deficiency to the required operating reserves has occurred or is proposed to occur. OP4 specifies 16 actions that the ISO can take to either increase the available supply or reduce the actual real-time demand for electricity. These actions can be implemented in any order depending on the circumstances of the capacity deficiency. In addition, some of the steps can be implemented in advance of an anticipated capacity deficiency situation. The potential load relief resulting from implementing all 16 steps of OP4 is between 3,000 MW and 4,000 MW.

It is important to note that OP4 is an implicit part of the reliability design of the bulk power system in New England. OP4 anticipates that there may be instances when required operating reserves can not be maintained and appropriate remedial measures need to be taken.

F. <u>Public Notifications</u>

The ISO uses a public notification system when the invocation of OP4 requires the ISO to request customers to conserve electricity. Modeled after advisories used by the National Weather Service, the ISO's public notification system has three levels of appeals: Power Caution, Power Watch and Power Warning.

- A Power Caution (Action 1 of OP4) is a public notification that electric reserves can no longer be maintained using normal measures. Although full reserves are being maintained, utility personnel will begin to take further steps to continue to maintain these reserves.

- A Power Watch (Action 9 of OP4) is a notification that further steps to manage capacity could affect the public.
- A Power Warning (Action 15 of OP4) is a notification for public appeals when an immediate reduction in power usage is necessary to avert overload of the electrical system. Public appeals are made when other efforts (e.g., emergency purchases, voluntary curtailment, contracted curtailment and voltage reduction) have been unsuccessful in bringing supply and demand back into balance.

A follow-up notification is issued to the public once the Power Watch or Power Warning has been lifted. The ISO issues a notice that power supplies and operating reserves have returned to normal levels and that regular electricity usage can resume.

G. Overview of the New England Electricity Markets

1. Energy Markets

In the bulk power system, the transmission lines operate as a transportation system to deliver electric energy to load-serving entities who in turn deliver it to retail customers including commercial, industrial and residential customers. Throughout most of New England, load-serving entities are free to purchase electricity from a variety of competitive merchant generating and trading companies, and in several states in New England, individual retail customers can make similar choices among competitive energy suppliers. These market-based arrangements are intended to permit competition in electricity supply, and they replace earlier monopoly supply arrangements in which price levels were set by state or federal regulation, rather than by competition.

The reliable operation of the bulk power system must accomplish two goals. It must assure that the transportation system can handle the deliveries it is called on to make, while also accommodating the particular deliveries that market participants arrange among themselves. To accomplish these goals, the ISO schedules the use of the transmission system in concert with its operation of markets for electric energy and the provision of certain ancillary services, including reserves and ICAP. Each day, the ISO accepts supply offers and self-schedules for electricity supply delivery on the following day from generators and suppliers located both inside and outside of New England. Generators offer their electrical output in one or several increments (blocks) at specified prices for each hour of the day. Self-schedules specify generating unit output that the owner wishes to run regardless of price, either to serve its own load or to meet the terms and conditions of bilateral contracts with power purchasers. Buyers of electricity submit bids to purchase power in particular amounts either at specified prices or at any price available. Bids with no price limits often reflect bilateral contracts of the buyer that will determine the buyer's actual cost.

Based on the supply offers, bids and self-schedules, the ISO prepares a schedule for the operation of generating units during the next day that:

- honors all self-schedules (unless it would result in excess generation or result in transmission overloads as described in the last bullet);
- selects the balance of the merit-order generation needed to meet the bid-in load so as to minimize the "all-in cost" of electricity for the coming day, subject to the constraints and limitations listed in the next two bullet points;
- assures that enough reserves are available at all times and deliverable to all locations as described above; and
- assures that no portion of the transmission system will be overloaded beyond its normal transfer capability, even after the hypothetical occurrence of the loss of a generating unit or another transmission line (this is referred to as "first contingency" protection).

Due to the limitations of the transmission system, the constraints listed in the last two bullet points can result in generating units with higher supply offers being asked to operate out-of-merit order in locations with limited transmission capability. The price of electricity delivery may vary from location to location based on the various supply offers of generation needed to reliably serve load at a specific location.

2. Installed Capacity

To help assure the availability on any given day of sufficient generation and reserves, the ISO operates an ICAP market.[107] This market, which operates a month in advance, selects generating units with a collective output equal to the combination of the expected seasonal peak load plus the required level of reserves. Units that are selected and paid to be ICAP units are subject to certain requirements. The owners of ICAP units must obtain advance approval of schedules for any non-emergency outages (*i.e.*, maintenance outages) from the ISO, and the ISO can refuse or reschedule ICAP unit outages to assure sufficient capacity for reliability.[108]

In addition to the ISO coordinating their maintenance outages, the owners of ICAP resources are required to make their units available in the energy market. The owners of ICAP resources must submit supply offers or self-schedules that together with any permitted outage are equal to their rated capacity as an ICAP resource.[109] The ISO's Market Monitoring Department automatically evaluates all supply offers received to assure that ICAP units do not seek to avoid the supply offer requirement by submitting arbitrarily high supply offers, and it has the power to substitute a lower offer based on a generator's historic offer pattern to ensure compliance.[110]

3. Obligation to Run

Generating resources that submit supply offers or self-schedules may be scheduled to run as described above, regardless of whether or not they are ICAP resources. Once scheduled, a resource must adhere to ISO's dispatch instructions during the day it is scheduled, and must run

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[107] *See* Market Rule 1, § 8.

[108] *See* Market Rule 1, § 8.3.3.

[109] *See* Market Rule 1, § 8.3.7.

[110] Market Rule 1, Appendix A, § 2.3.4 (a). *See* discussion at Section III.

as scheduled unless it is permitted or required by ISO to change its schedule, or it experiences a forced outage.[111] A forced outage can only result from an emergency or other cause (such as fuel procurement difficulties) beyond the control of the unit operator. The market rules provide penalties for generators who fail to perform as dispatched where the failure is not due to a forced outage.[112]

4. <u>Economic Outages</u>

In addition to maintenance outages, generators can request advance permission to take an economic outage.[113] Requests must be submitted between one and seven days in advance. A generator is entitled to request such an outage when it does not believe it will be able to recover its costs of operation, including its opportunity costs, by running in the energy market. As an example, if the cost of natural gas to a gas-fired generator would require the generator to offer in excess of $1,000/MWh to recover its costs, the generator would request an economic outage because supply offers cannot exceed $1,000/MWh under the current market rules.[114]

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[111] *See* Market Rule 1, § 1.02(e), 1.10.4(a).

[112] *See* Market Rule 1, Appendix B, §§ 3.1.1, 3.1.2., 3.1.3.

[113] OP5, Part II, provides that an Economic Request is the request for a Maintenance Outage by a Participant for the removal of a Generator from service for purely economic reasons associated with market conditions. Such Participant requests shall be considered consistent with Market Rule 1, Section 1.10.4.a - ICAP Resources. Participant requests for such outages may include, but are not limited to, sale of gas available to the Participant as fuel for such Generator, reducing output temporarily to defer maintenance in response to unanticipated operating difficulties or refueling, or shutting down a Generator during a period when the Participant does not reasonably expect the Generator-specific NEPOOL market revenues to justify operation of the Generator in that period. Participants are expected to act in accordance with the applicable provisions of Market Rule 1, and NEPOOL Operating Procedures that provide for the coordination required to avoid actions of OP 4 or OP 7. These outage requests shall be coordinated through the Maintenance Outage Request process. These requests cannot be made more than seven (7) days in advance of such outage nor for duration in excess of seven (7) days. As part of the Economic Request, the Participant shall provide the time needed to restore the Generator to service, in the event of an actual or anticipated OP 4 implementation. The Participant, by requesting a Maintenance Outage for Economic reasons, is obligated, in the event that such a request is approved by the ISO, to make best efforts to restore the Generator to service as requested by the ISO in the event of an actual or anticipated OP 4 implementation.

[114] *See* Section III for further discussion.

The ISO may reject an economic outage if it will cause an actual or projected capacity deficiency, reserve violation or a transmission problem.[115] In addition, if a power system emergency arises after the approval of an economic outage, the ISO may request any such generator to return to service, and the generator is obligated to use its "best efforts" to do so.[116] However, if a generator has sold its gas for the day, it may be unable to purchase spot gas to enable it to return to service, and, if so, its inability to obtain fuel would change an economic outage into a forced outage.

As a result of the structure of the gas market,[117] gas-fired generators can face unusually complex decisions about the level of their supply offers and whether an economic offer can be made. It is not the intent of the market rules "to require a Participant to provide services from all or a portion of a Resource where the Resource-specific NEPOOL market revenues derived from the provision of such service do not justify the associated operating cost or opportunity cost (whether inter-temporal or in non-NEPOOL markets or both) of providing such service from such Resource."[118] Economic outages are intended as a measure to help manage such situations.

H. <u>Overview of the New England Natural Gas Markets</u>

1. <u>Regional Gas Supply</u>

New England's natural gas supply is produced in three principal supply regions of North America, the Gulf Coast, Western Canada and offshore Nova Scotia. Other potential sources of gas include producing fields in Appalachia, the U.S. Mid-continent and the Rocky Mountains.

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[115] Operating Procedure No. 5, Part III, § I.A.2.

[116] Operating Procedure No. 5, Part III, § II.A.4.

[117] *See* description in Sections I and III.

[118] Market Rule 1, Appendix B, § 3.2.6.

Gas is delivered from the producing fields by pipeline systems to New England, which is the end of the line for several major pipelines.[119] Natural gas is also imported to New England in the form of LNG through the Distrigas of Massachusetts terminal in Everett, Massachusetts. LNG delivered to Everett is primarily sourced from Trinidad. The LNG is re-gasified at Everett for distribution by pipeline or shipped as liquid by truck to satellite storage facilities operated by gas distribution companies to meet winter peak demand. The underground storage areas serving New England are located in depleted oil and gas fields or salt caverns in western Pennsylvania and New York, as well as the Dawn storage hub in southern Ontario. The geological formations in New England are not amenable to the economic operation of underground gas storage facilities. As a result, New England's natural gas usage is limited by its daily capacity to import gas by pipeline and to re-gasify LNG at Everett and the several dozen LDC satellite storage facilities located downstream of the pipeline citygates throughout New England.

Natural gas commodity is purchased from producers, usually for delivery into the interstate pipeline system in the producing region or from marketers who typically buy gas in the supply regions or at market hubs and resell the gas to end-users or LDCs in New England markets. LDCs provide either gas delivery to retail customers or local transportation services for end-user owned gas. Large retail purchasers such as manufacturing facilities, commercial buildings, and power plants can also purchase gas commodity directly from gas marketers or producers.

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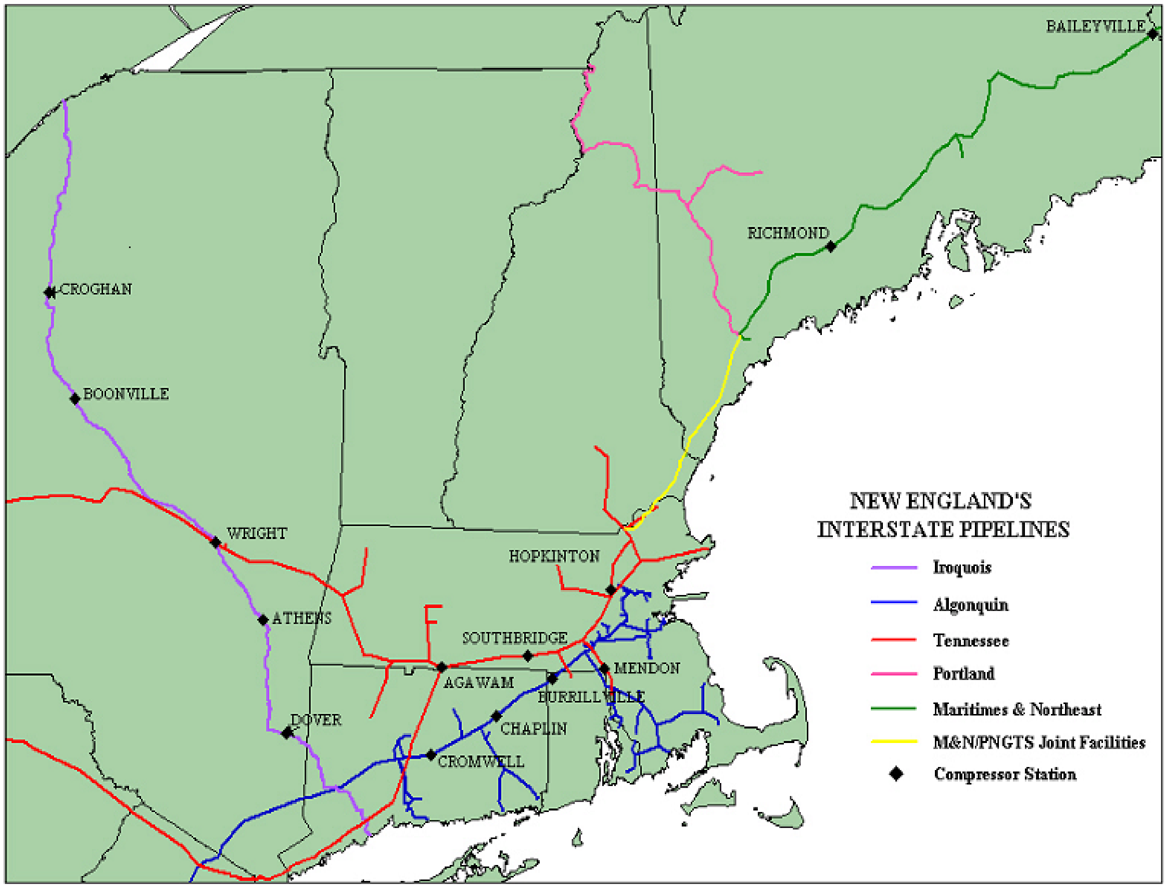
[119] Algonquin Gas Transmission Company (New Jersey to south-eastern Massachusetts), Granite State Gas Transmission, Inc. (Massachusetts to Portland, ME), Iroquois Gas Transmission System, L.P. (Ontario to New York and Connecticut), Maritimes & Northeast Pipeline, LLC (Nova Scotia to New England), Portland Natural Gas Transmission System (Southern Quebec through northern New Hampshire and southern Maine), and Tennessee Gas Pipeline Company (into Massachusetts and Connecticut from the Southwest).

Figure 31 - New England's Interstate Pipelines



2. Regional Interstate Gas Transportation

Transportation is generally purchased separately from the pipelines, although gas marketers may make advance purchases of transportation capacity and resell bundled commodity and transportation. Gas transportation must be scheduled through a system of advance nominations. Unlike the electric transmission system, which operates as a unified grid, gas flows are generally confined to a single pipeline, although New England's pipelines have a number of interconnects through which natural gas is delivered to downstream markets served by neighboring pipelines. Each pipeline has its own separate scheduling system for daily nominations and confirmations, which conform to NAESB guidelines. Each pipeline generally requests monthly and daily nominations to allow scheduling deliveries. Firm transportation shippers have priority over non-firm customers. The transportation capacity needs of non-firm customers are met after all of the firm customers requirements are satisfied.

Pipeline transportation services are sold on a firm basis and an interruptible basis. In addition, primary holders of firm transportation, predominantly LDCs, are permitted to release their firm transportation rights to other shippers who obtain the released capacity on a secondary firm basis. Shippers holding released capacity rights obtain these rights on an equivalent firm basis unless constraints arise, then the scheduling of secondary firm capacity is relegated to a priority lower than primary firm. Shippers holding released capacity only have secondary rights if they choose to move gas to locations other than those identified in the original contract. If they move gas to the same location as specified in the original capacity holder's contract they will be treated as a primary firm capacity holder. Thus, released capacity rights are often referred to as "quasi-firm" rights. Firm shippers pay monthly reservation charges that cover almost all of a pipeline's total cost-of-service. By releasing capacity rights, the primary firm shipper negotiates the price for the secondary shipper that may or may not equal the pipeline's full firm rate. Interruptible transportation is priced under value-of-service principles and may be available at a small fraction of the full firm rate.

3. Gas Contracting Practices

The natural gas commodity and transportation capacity markets are comprised of three segments: a long-term forward market, a short-term forward market and a daily market. The long-term market typically consists of contracts covering periods ranging from one year to as long as 10 or 15 years, although most long-term contracts generally fall in the one to five year range. The short-term market is focused on seasonal and monthly transactions and includes quantities and transportation released by long-term purchasers in the week or day ahead of delivery as their estimates of their own demand (or resales) become known. The daily market involves commodity quantities and transportation that are unused in the day-ahead scheduling process as well as daily purchases at regional market hubs. Prices in the long-term markets tend to reflect competitive supply conditions in the producing basins plus the cost of transportation. Prices in the short-term markets are more volatile. The greatest volatility is observed in the intra-day market. When there is excess intra-day capacity on pipelines, the intra-day price may be lower than long-term as long-term buyers seek to unload excess gas. Conversely, because gas utilities throughout New England retain the obligation to serve, when pipelines experience capacity constraints it can be impossible to arrange delivery of intra-day gas at any price.

Different types of natural gas users consume gas in differing patterns. Manufacturing processes typically have fairly steady demand. Heating and cooling uses vary with temperature in a fairly predictable manner. By contrast, generating plants in New England that do not have long-term contracts for the sale of their power only run if their supply offers are accepted on a day-by-day basis. Gas-fired generators are more expensive to operate in terms of total variable cost per MWh than nuclear, hydroelectric or coal-fired units. Very few gas-fired generators operate around the clock throughout the year. Most gas-fired generators, even the new fleet of combined cycle plants using state-of-the-art turbine technology, operate at part-load or are dispatched off-line during light load hours and on weekends. The total marginal cost of producing energy from gas-fired generators is generally about the same as oil-fired units, except during cold snaps when commodity gas prices are high on a BTU equivalent basis relative to oil generation plants. Oil-fired generators in New England no longer run in mid-range or baseload operating mode, however. Gas-fired electric generating plants are generally less likely to enter into firm gas supply arrangements than users with more stable usage patterns.[120]

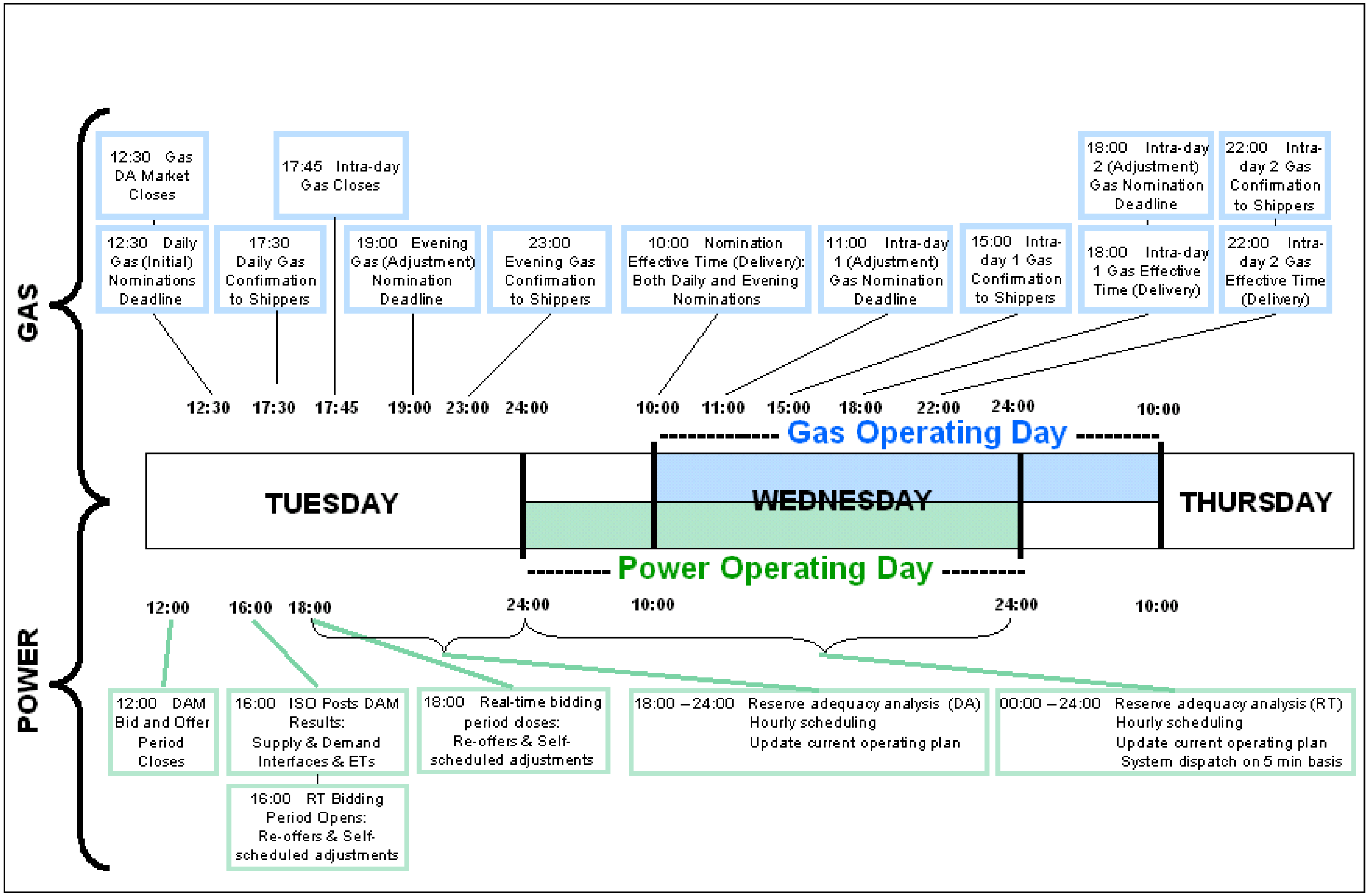
Pipeline reservation charges associated with firm transportation must be paid whether or not the shipper uses the contracted pipeline capacity. These charges represent a fixed cost disadvantage for merchant generators, which try to operate only when the spark spread is sufficient to allow natural gas to be burned to generate electricity on an economic basis. Merchant generators have significant incentives to hunt for transportation rights at the lowest price, avoiding demand charges as much as possible. Absent firm capacity rights, merchant generators use interruptible transportation, released capacity rights negotiated with firm transportation entitlement holders, such as LDCs, bundled gas supply and transportation purchased directly from a marketer, or a combination of these options.

4. <u>Interaction of Gas and Electric Contracting</u>

The timeline of decisions in the day-ahead and real-time gas and power markets illustrated in Figure 32 shows the limitations on the information that flows back and forth between these markets. These time lines compare the gas operational and trading day to the power market day, and included the various requirements and schedules for the physical transportation of the natural gas and the requirements and schedules for the power market.

[120] *See* Section III above.

Figure 32 - Gas and Power Markets Trading and Scheduling Timeline



Trading in the gas market typically takes one of two forms: bilateral trades, through trades on organized exchanges, or brokers or traders. The Intercontinental Exchange ("ICE") is an exchange through which gas destined for New England markets is traded. The product traded through ICE is firm gas. Beginning at 7:00 a.m. the trading market for day-ahead gas (gas for delivery beginning 10:00 a.m. on the next day) opens and the first available pricing is published. The price posted is the weighted average volume and number of trades for the day-ahead as of 7:00 a.m. As trading continues, the price of natural gas at various locations is continually updated. The largest amount of trading activity is typically recorded between the hours of 9:00 a.m. and 10:00 a.m. Although trades will continue, the cutoff for the day-ahead trading is set at 12:30 p.m. Trading continues beyond the day-ahead deadline, for the evening gas nomination deadline outside of the ICE trading platform. Generators anticipating gas requirements for the power day must make day-ahead commodity purchases no later than 12:30 p.m. day-ahead. Generators must also submit their daily transportation nomination to their respective shippers no later than 12:30 p.m. day-ahead in order for the gas system operators to determine the initial transportation needs of the pipeline. Day-ahead nominations and gas commodity purchases are effective for the gas-operating day that runs from 10:00 a.m. on the following day to 10:00 a.m. on the second following day.[121] Thus gas commodity purchases and transportation arrangements made in the day-ahead market are effective for portions of two different power days. Winter electricity demand typically exhibits both a morning and an evening peak (with evening typically somewhat higher) so that gas for the morning peak will generally be procured as a part of the previous gas-day nomination. With a majority of the typical gas trading activity completed by

[121] This corresponds to 9:00 a.m. to 9:00 a.m. following day (Central Standard Time).

10:00 a.m., the price of the gas commodity can reasonability be projected, with the actual closing price published by 12:30 p.m. It is not until 5:30 p.m. that initial gas transportation schedules for the day-ahead confirmation of shipping nominations are complete. Between 5:30 p.m. and 7:00 p.m., evening adjustments to the day-ahead transportation nominations can be made by the generators based on published day-ahead power schedules. When gas transportation is not constrained, such adjustments may be made on a fairly routine basis. However, when transportation is constrained, as it was during the Report Period, revised nominations may not be possible.

On the power market timeline, supply offers must be submitted by 12:00 noon day-ahead in order for the ISO to determine the day-ahead generator schedule to meet the day-ahead load. At 4:00 p.m. the ISO publishes the results of the day-ahead generator commitment schedule to meet load. Between 4:00 p.m. and 6:00 p.m., ISO accepts re-offers and self-schedule adjustments from generators. Between 6:00 p.m. and 12:00 midnight, the ISO performs a reserve adequacy analysis to determine what additional generators will be required for system reserves and capacity requirements to maintain real-time system reliability.

This comparison highlights that generators must make initial gas nominations before knowing day-ahead electricity schedules. Final nomination adjustments are required prior to the reliability commitment process. Thus any gas units selected during the resource adequacy assessment must buy intra-day gas, not day-ahead gas. While this works under normal conditions, it does not work well when pipelines are near their capacity limits.

It is also important to note that generator supply offers are fixed for the electricity operating day. This contrasts with the two different day-ahead gas prices applicable during this time period. Again, while this limited ability to reflect true underlying gas costs works acceptably well under normal conditions, it can be problematic when gas prices are highly volatile.

5. <u>Highlights of Prior New England Gas Studies</u>

The ISO previously assessed the capability of New England's natural gas infrastructure to serve the ever-increasing fuel requirements of the growing gas-fired generating fleet, especially during peak winter demand periods that would be coincident with the peak demand periods of New England's LDCs.

In January 2001, the ISO retained Levitan to develop hydraulic models of New England's natural gas infrastructure along with a supplementary report entitled *Steady-State Analysis of New England's Interstate Pipeline Delivery Capability, 2001-2005* ("Phase I Gas Study"). In December 2001, the ISO again retained Levitan to update the previously developed pipeline models by revising the input assumptions sets for both gas and electric sector topology and assessing the temporal aspects of gas flow dynamics under several postulated gas and electric side contingency scenarios. Based on this effort, Levitan produced a report entitled *Steady-State and Transient Analysis of New England's Interstate Pipeline Delivery Capability, 2001-2005* ("Phase II Gas Study").

In the Phase I study, Levitan found that absent facility expansions on the natural gas pipelines serving New England, the electric generation sector faced transportation shortfalls that would first materialize in the winter of 2003, and subsequently reveal insufficient interstate-intrastate gas pipeline deliverability to serve approximately 1,750 MW of gas-fired capacity. Expanding the analysis through 2005 revealed about 3,225 MW of generation at risk on the winter peak day.

The results and findings of the Phase II Gas Study are summarized as follows:

- Many of the proposed gas pipeline expansions and facilities improvements would not materially mitigate the size of the expected gas transportation shortfall to the electric generation sector during each winter peak day before 2005;
- On extremely cold winter days when there is insufficient operational flexibility for New England's pipelines to satisfy the coincident demands of both gas utilities and gas-fired generators, shortfalls would impact gas-fired merchant generators rather than New England's gas utilities, primarily because merchant generator gas transportation arrangements are not primarily "firm service" from the wellhead or storage centers to the burner-tip;
- Generation at risk at times of winter peak loads was expected to rise as high as 3,960 MW in winter 2002-03;
- New gas supplies that were expected from Atlantic Canada, to flow into the Algonquin and Tennessee systems, would create substantial operating flexibility and enable pipeline operators to respond more quickly to operating contingencies. However, recent disappointing exploration results from offshore Nova Scotia means that additional gas supplies, beyond current production levels, will not be available until 2010 or later;
- The response time available to the ISO-NE to schedule replacement generation in the event of the loss of a gas-fired generating plant or other postulated contingencies ranges from three to 48 hours; and
- Pipeline issuance of an OFO limiting variations in gas flow on New England's pipelines would have a minor incremental degradative effect on the availability of gas-fired generation, given that tight deliverability conditions on very cold days would already be expected to sharply limit the amount of gas-fired generation online.

In mid-2002, facing continued concerns about the sufficiency of the existing gas transmission pipeline infrastructure to meet the requirements of gas-fired generators, the ISO, IMO, PJM, NYISO, and NERC commissioned Levitan to conduct an independent analysis of the storage and delivery capability of the inter-provincial and interstate pipelines spanning the four bulk power market areas. In this study entitled, *Multi-Region Assessment of the Adequacy of the Northeast Natural Gas Infrastructure to Serve the Electric Power Generating Sector,* Executive Summary dated July 2003, the ISO once again updated its chronological modeling assumptions and its electric sector topology. Assuming an ideal amount of natural gas at New England's borders on a winter peak day, Levitan found that about 3,000 MW of gas-fired generation would be at-risk over the study period.[122] Had gas supply boundary assumptions been considered under more normal circumstances, the amount of gas-fired generation at-risk would have been materially higher.

In December 2003 FERC staff also published a report on New England natural gas infrastructure. FERC staff analyzed New England's pipeline and storage capacity to determine if there was sufficient deliverability to meet the increasing demand from gas-fired electric generation and other uses. The evaluation sought to determine whether New England could maintain electric service if the curtailment, as experienced during 2000, was fully absorbed by the generation sector. FERC Staff found that "adequate capacity exists to meet projected demand through 2005 and that proposed new construction of natural gas infrastructure would meet demand through 2010. [123]

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[122] Winter 2007-2008.

[123] Docket No. PL04-01-000, December 2003, p. 1.

VII. Appendix B - 1994 Severe Weather Event in PJM

On January 15, 2004, both the ISO and NYISO reached their all-time winter peak electric loads of 22,450 MW and 25,262 MW, respectively. The NYISO's previous record of 24,627 had just been set just the previous day.

In conditions of extreme cold, PJM faced similar generator unavailability in January 1994. A brief summary of the January 1994 events follows, most of which is drawn from testimony by Phillip G. Harris, President & CEO, PJM Interconnection, before the House Subcommittee on Energy and Power.[124]

Prior to January 1994, the historic PJM winter peak was 38,100 MW and the forecast peak demand for winter 1993-94 was 38,928 MW. During January, the peak load reached 41,350 MW (a 3,250 MW increase equating to a 8.5 percent percentage increase). At the worst point in January, 28 percent of PJM capacity was offline (compared with a usual 7-8 percent).

The 1994 sequence of events is as follows:

- January 7-8 - ice storm causing 900,000 to lose power
- January 13 - weather forecasts for upcoming week led PJM companies to ensure additional generation availability; PJM issues "Cold Weather Message" to member companies
- January 14 - PJM issues Cold Weather Alert (emergency procedure calling for more generation to be available)
- January 15 - bitter cold strikes, causing new all-time PJM winter peak
- January 15-17 - bitter cold continues
- January 18 - further drops in temperature; new all-time PJM winter peak requires utilization of all available PJM generation and imports from other regions; evening temperatures drop below forecast levels with high winds, creating increasing problems with generating

[124] The date of the House hearing was February 9, 1994.

resources (fuel delivery and unit difficulties) and depleting peaking unit fuel resources; PJM alerts member companies that further emergency procedures would be implemented in the morning of January 19 and that rotating customer blackouts might be required; oil barges got stuck on frozen rivers, coal piles froze and peaking units failed to start; PECO and PSE&G were surplus and sent power to other PJM members

- January 19 - system-wide 5 percent voltage reduction occurs at 6:45 a.m., and radio and TV load curtailment appeal was issued at 7:00 a.m. A rotating blackout of 500 MW (allocated among all PJM member companies) was implemented at 7:05 a.m. for 35 minutes; another rotating blackout of 1,500 MW was implemented at 9:22 a.m. for 3 hours and 45 minutes; PJM committees met in anticipation of the January 19 evening peak and decide that member companies should urgently request early closing of government and business facilities and reduce energy usage after closing, and appeal to residential customers to reduce overall electrical consumption. As a result of these measures, load was reduced to match available generating capacity

- January 20 - in light of continuing severity, PJM issued a press release at 7:30 a.m. relating the success of emergency operating procedures and requested that businesses remain closed or limit their hours of operation

- January 21 - record-setting weather conditions cease

- January 22 - review of prior period by PJM membership and system operator commences; analysis continues through February 9 (date of House hearing) and beyond; P. Harris forecasts (at House hearing) the need for months of detailed review to ascertain the cause and effects and to develop and refine any procedures that may be appropriate.

According to press accounts, the PJM review found that existing policies and procedures worked quite well, but recommended improved communication with government agencies and the media about the need for extraordinary conservation efforts, and improvements in predictions of near-term load forecasting and the ability of generating plants to perform during extreme conditions. A January 22, 1994 article in the Philadelphia Inquirer quotes a PJM spokesman as saying that rolling blackouts could have been avoided if PJM had alerted the member utilities earlier, while noting that imposing emergency measures can create unnecessary public anxiety if the emergency fails to occur. The article states that PJM asked utilities to cancel planned maintenance outages and speed the restart of some units already out for maintenance.

The chief differences between PJM's 1994 experience and the ISO's 2004 experience are: (1) gas commodity and pipeline availability did not appear to have been a predominant issue in PJM, nor was gas generation as significant a percentage of capacity as it currently is in New England; (2) bidding markets were not used in PJM at that time; (3) all generation was still owned largely by integrated utilities; (4) normally dependable weather forecasts consistently underestimated the temperature severity of the extreme conditions during the period; (5) PJM was forced to initiate rolling blackouts; and (6) PJM exceeded its prior winter peak by 8.5 percent, while ISO-NE exceeded its prior winter peak by 5.5 percent.

VIII. Appendix C - Gas Arbitrage and the Effect of Price Uncertainty

A. Gas Arbitrage

During the Report Period some generators sold firm gas back into the gas market rather than use it to generate electricity. This behavior is generally called arbitrage. If expected power prices are lower than the production costs of a unit burning firm gas, this presents an opportunity for that generator to sell gas back into the gas market for a profit greater than the expected profit in the electricity market. Generally, arbitrage improves market efficiency by allocating resources to those who value them most highly. Gas sold by generators in New England might be sold to other, more efficient generators, or sold to local gas companies seeking alternate sources of supply required for residential or commercial consumption, or to industrial end-users. All of these examples are desirable, with higher prices acting as the incentive to find such trades. If gas, for example, is more highly valued for home heating than for electric production, sale of the gas to a local gas distribution company allows that company to resell to customers who are undertaking a more highly valued activity.[125] The long-term purchase price is a sunk cost for purposes of the analysis. The electricity market responds by substituting electricity from other, cheaper resources. In the case of electricity, fuel arbitrage (selling fuel if it is priced higher than electricity) is accepted practice, codified in the market rules of most independent system

[125] Whether such a sale earns a profit or reduces a loss depends on the cost of the gas to the generator under its long-term contract. The profit or loss is irrelevant to the arbitrage. It makes sense to sell if the price is higher in the gas market no matter whether the result is a profit or a loss.

operators.[126] Whether or not a generator has sold its output has little bearing on this decision, as a generator could also fulfill its obligations by purchasing from the spot electricity market.

Arbitrage decisions may reflect risk differentials as well as price differentials. The following example illustrates that price uncertainty in the electricity market can influence the decision to sell gas even when prices seem comparable in the gas and electricity markets. Suppose that a generator with a heat rate of 10 MMBtu/MWh and a one-hour run time is seeking to formulate a supply offer. It estimates that power prices will be $300/MWh with two-thirds probability, and $900/MWh with one-third probability. The generator owns 1 MMBtu of firm gas, and the price at which this generator can sell its gas back to the gas market is $50/MMBtu. The gas price is known with certainty because the gas market clears in advance of the electricity market. What is the best economic decision that this generator can make? The following diagram illustrates this choice:

[126] *See* Market Rule 1, Appendix B, § 3.2.1 – "Certain Economic Decisions Excused" and NEPOOL Operating Procedure No.5: Generation Maintenance and Outage Scheduling, http://www.iso-ne.com/smd/operating_procedures/OP5_SMD_FIN.doc. Discussions with other market monitors confirm that it is accepted practice elsewhere, with ICAP deratings and lost power market revenues being the penalties. Arbitrage provisions are explicit in the rules of the California ISO (Section 2.4.3 of the market monitoring rules), Midwest ISO (Section 2.4.c of the market mitigation measures), and NYISO (Section 2.4 (2) of the market mitigation rules). They do not appear to be explicit in PJM.

Figure 33 - Expected Outcomes and Choices for a Gas-Fired Unit

Decision	Revenue (Electricity Equivalent)		Expected Revenue	
Sell Electricity	$900/MWh	p=1/3	Expected:	$500/MWh
	$300/MWh	p=2/3	Uncertainty:	$283/MWh
Sell Gas	$500/MWh	p=1	Expected:	$500/MWh
			Uncertainty:	$0/MWh

If the generator sells gas now, it effectively locks in a value of $500/MWh for each MWh that it could produce. If, instead, the generator decides to produce electricity and sells it in the power market, the expected price would be $500/MWh, the same as selling firm gas. However, there is uncertainty about the actual amount netted by selling power. Here uncertainty is measured by the standard deviation of the price distribution, which can be computed given the probabilities and the possible levels of prices.[127] Even under this scenario in which the generator expects high power prices with a relatively high probability, it is economically rational for the generator to sell gas because the expected value is the same with no risk. During the Report Period, expected on-peak electricity prices were often well below an efficient generator's break-even point, excluding any consideration of risk.

The main points of this example are:

- A generator evaluates firm profit from selling gas vs. the uncertain profit earned in power markets.

[127] The actual computation uses the definition of the standard deviation as the square root of the variance. The variance is calculated as the second moment of LMP probability distribution minus the square of the mean LMP.

- The generator is faced with increased riskiness of profits if it decides to forgo the sale of gas and face the uncertain real time price of power.
- Other penalties from gas over-pull during OFO conditions increase risk.

Arbitrage allocates resources more efficiently and is appropriate market behavior. Even generators that do not sell available gas may appropriately reflect the foregone revenue opportunity in their supply offers. The foregone revenues from the sale of gas are a cost (known to economists as an opportunity cost) of a decision to generate electricity. Opportunity costs are included in the calculation of submitted offers just like any other costs, and help to ensure that the electricity price reflects the true value of the resources used in the production of electricity. This also explains why the day-ahead/intra-day prices of gas are used throughout this report without reference to any long-term gas contracts. A rational owner of long-term gas will reflect any opportunity costs in its supply offers to reflect the mark-to-market value of natural gas in the regional marketplace.

B. Calculating the Supply Offer Price for a Gas-Fired Unit

As a result of the timing and arbitrage issues discussed above, a generator must consider the following costs and risks in determining an offer day-ahead:

- **The cost of gas**

Depending on the participant's expectations and contract position, this can be calculated in one of two ways:

  - The cost to purchase day-ahead gas if the generator expects to be dispatched.
  - The estimated cost of purchasing gas in the intra-day market, including uncertainty in the price and availability of intra-day gas.

- **Non-selection risk**

If a generator elects to buy or hold gas in the day-ahead market and is not scheduled to run by the ISO, it must attempt to sell its gas intra-day to avoid a loss on the purchase price of the gas. The value of an intra-day sale can only be estimated and in a period of high volatility, is highly uncertain. If intra-day transportation restrictions prevent timely resale, the loss may be comparable to the value of the original gas purchase. These risks are heightened by the price levels during the Report Period, when gas for a single operating day for a single generator could cost millions of dollars.

- **Risk of forced outage**

During the weather conditions experienced in the Report Period, the risk of a forced outage is substantially increased. The unit experiencing a forced outage must seek to resell any purchased gas (day-ahead or intra-day) on a very short-term basis. Intra-day nomination procedures may prevent sales entirely and, in any event, the generator will experience the same type of gas price-risk as that associated with not being scheduled.

- **Risk of being scheduled**

If a generator does not purchase (or hold) gas day-ahead and is selected to run, it must obtain gas in the intra-day market or be deemed to have taken a forced outage. The generator is obligated to purchase gas at the intra-day market price which, depending on demand and delivery conditions, may spike well above normal levels. The forced outage reduces its eligibility for payments in the ICAP market.

- **Risk of scheduling for reliability**

A generator that is not scheduled day-ahead (and as a result may have resold gas intra-day even if it bought or held gas day-ahead) may be called during the RAA process for reliability reasons and if so, experiences the same risk as a unit scheduled day-ahead that has not bought gas. In addition, units receiving forward reserve payments must be available to run in real-time if called, or they pay penalties in the reserve markets if they are unable to do so. Forward reserve resources must acquire and hold sufficient fuel supplies and transportation to allow them to perform.

- **Risk of imbalance changes**

During times when gas pipelines experience capacity constraints they may impose Ratable Takes and OFOs as described above. The pipeline's OFO daily or hourly tolerance is a percentage established by the pipeline. Both Tennessee and Algonquin impose a 2 percent daily tolerance on shippers, although some Algonquin customers can take 6 percent hourly, the sum of hourly takes cannot exceed 2 percent daily. Shippers are obligated to take their daily gas supply within these tariff-defined percentages. When ratable take provisions are triggered, most shippers are limited to about 1/24th of the MDQ each hour. Failure to stay in conformance with the daily or hourly flow limitations results in the shipper incurring expensive penalties for unauthorized contract over-pulls. While these measures are in effect, the pipeline typically charges a penalty ranging from $15/MMBtu (low intra-state pipeline penalties) to the sum of $15/MMBtu plus the applicable regional gas price. LDCs in New England charge as much as five times the spot regional gas price plus applicable interstate pipeline penalties. Since nearly all gas-fired generators do not operate at full or partial load flat out all day, significant cycling is inevitable for the majority of gas-fired generators on-line during extreme cold. A generator must assess the risk of incurring "pancaking" (successively accumulating) penalties in attempting to follow the ISO's dispatch instructions.

- **Risk of Ratable Takes**

When a ratable-take limitation is in effect, generators must consume nominated gas quantities in equal increments over a 24-hour period. In addition to the penalties discussed above, this has the effect of spreading a generator's daily gas nomination over a 24-hour period, however, a generator may have only expected to consume that gas in a few hours. This limited hourly fuel consumption may not be adequate to support generation at the generator's economic minimum thus essentially forcing the unit out of service. For the generator to run, it must purchase and nominate for each hour of the day sufficient quantities so that it can meet its maximum expected dispatch. These additional purchases may increase submitted offers/prices.

- **Risk of Being Curtailed**

Gas tariffs permit pipelines to cut off gas to customers that exceed their authorized withdrawal rates. Such a cutoff or restriction may result in an immediate forced shutdown of the generating unit, which could damage the unit. This could result in costly repairs as well as lost future profits during the time the unit is shut down or reduced.

As the discussion illustrates, gas-fired units must consider many factors beyond the day-ahead gas price when a making a supply offer. While day-ahead gas prices may be an appropriate indicator of costs during normal conditions, under extreme conditions many other factors become relevant. These factors, while difficult to quantify for all units, can significantly increase the expected costs for gas-fired units.

C. Conclusions

During the Report Period, generators faced not only increased gas prices but also a more complicated purchase environment and compliance than under normal conditions. Prices were more volatile and markets less liquid. Numerous gas-side penalties that are not applicable or material under normal circumstances were present. The gas prices in the day-ahead gas market did not necessarily communicate the same information about intra-day gas prices as under normal conditions. Incompatibilities between the gas and electric market timelines became difficult to accommodate. Given the trade-off between the certain high profits from selling gas back into the gas market and the uncertainties and diminished opportunities for profits in the electricity market, indicated by day-ahead power prices, the economic choice in these market conditions typically would be to sell available firm gas rather than to generate electricity. During the Report Period, gas units may have faced circumstances in which they could reasonably expect that no profitable supply offer would be accepted in the electricity market.

IX. Appendix D - Demand Response

Detailed information about Demand Response during Hour Ending 6 p.m. during the Report Period is presented below. Hour Ending 6 p.m. is the last hour for which a Demand Response event can be called on any given day. On January 14 and on January 16 system peak loads were reached during Hour Ending 6 p.m. The first table for each day shows the number and percentage of assets that had reductions in Hour Ending 6 p.m. for during the Report Period, as compared to the total number of program participants. The second table for each day shows the amount and percentage of MWs reduced on those days in comparison to the total contracted MWs of the assets that responded.

Table 44 - Demand Response, January 14 Hour Ending 6 p.m.

Zones	ME	NH	VT	CT	RI	SEMA	WCMA	NEMA	Grand Total
Total Ready To Respond Assets	1	1	13	44	14	76	82	105	336
# of Responding Assets	0	1	8	20	5	44	39	56	173
Asset Response Percent	0%	100%	62%	45%	36%	58%	48%	53%	51%

Zones	ME	NH	VT	CT	RI	SEMA	WCMA	NEMA	Grand Total
MWh of Interruption	0	0.063	1.658	5.289	0.121	2.89	2.023	13.419	25.463
Contract MW of Assets Responding	0	0.15	5.402	10.700	0.500	4.700	4.100	23.200	48.752
Response Percent	0%	42%	31%	49%	24%	61%	49%	58%	52%

Table 45 - Demand Response, January 15 Hour Ending 6 p.m.

Zones	ME	NH	VT	CT	RI	SEMA	WCMA	NEMA	Grand Total
Total Ready To Respond Assets	1	1	13	44	14	76	82	105	336
# of Responding Assets	0	1	9	20	8	47	44	65	194
Asset Response Percent	0%	100%	69%	45%	57%	62%	54%	62%	58%

Zones	ME	NH	VT	CT	RI	SEMA	WCMA	NEMA	Grand Total
MWh of Interruption	0	0.012	2.307	5.788	0.36	4.122	3.089	20.565	36.243
Contract MW of Assets Responding	0	0.15	5.547	11.050	0.800	5.000	4.600	27.250	54.397
Response Percent	0%	8%	42%	52%	45%	82%	67%	75%	67%

Table 46 - Demand Response, January 16 Hour Ending 6 p.m.

Zones	ME	NH	VT	CT	RI	SEMA	WCMA	NEMA	Grand Total
Total Ready To Respond Assets	1	1	13	44	14	76	82	105	336
# of Responding Assets	0	1	11	27	9	59	63	77	247
Asset Response Percent	0%	100%	85%	61%	64%	78%	77%	73%	74%

Zones	ME	NH	VT	CT	RI	SEMA	WCMA	NEMA	Grand Total
MWh of Interruption	0	0.024	3.377	6.27	0.386	6.373	4.654	20.295	41.379
Contract MW of Assets Responding	0	0.15	6.797	12.850	1.100	6.200	7.400	29.700	64.197
Response Percent	0%	16%	50%	49%	35%	103%	63%	68%	64%

X. Appendix E - Detailed Timeline of Gas Events, January 7 –17, 2004

1/7/2004 1:47 PM	Texas Eastern issues capacity constraint for January 8 • No due-shipper gas available on Texas Eastern
1/7/2004 3:40 PM	Algonquin issues capacity constraint for January 8 • No due-shipper gas available on Algonquin • No incremental nominations through Stony Point, NY • Shippers and point operators required to remain in balance daily
1/7/2004 5:50 PM	Tennessee issues notice of on-going capacity constraints (remaining in effect through the Report Period) • Flow restrictions at Station 321 (Uniondale, PA), Station 245 (West Winfield, NY), and Station 47 (Producing region)
1/8/2004 7:08 AM	Algonquin restricts interruptible transportation • Incremental nominations through Stony Point, NY under interruptible transport rate schedule, AIT-2 will not be accepted
1/8/2004 1:55 PM	Texas Eastern issues capacity constraint for January 9 • No due-shipper gas available on Texas Eastern
1/8/2004 4:07 PM	Algonquin issues capacity constraint for January 9 • No due-shipper gas available on Algonquin • Shippers and point operators required to remain in balance daily
1/9/2004 10:00 AM	Yankee Gas OFO for all firm and interruptible pool operators goes into effect • Firm pool operator under-deliveries limited to no more than 2%, over-deliveries limited to no more than 20% • Interruptible pool operators under-deliveries limited to no more than 2% of daily usage, with a penalty charge of $3.00/ccf
1/9/2004 2:49 PM	Algonquin issues capacity constraint for January 10 • No due-shipper gas available on Algonquin • Shippers and point operators required to remain in balance daily
1/9/2004 3:05 PM	Texas Eastern issues capacity constraint for January 10 • All shippers and point operators required to stay in balance daily • No incremental interruptible transport nominations in Market Zone 3 (NY/PA) • No due-shipper gas available on Texas Eastern
1/9/2004 3:28 PM	Algonquin issues capacity constraint for January 11 • No due-shipper gas available on Algonquin • Shippers and point operators required to remain in balance daily
1/9/2004 3:31 PM	Algonquin releases a limited amount of due-shipper gas
1/9/2004 4:00 PM	Texas Eastern revises capacity constraint for January 9 to include: • No incremental interruptible transport nominations in Market Zone 3 (NY/PA)
1/10/2004	Vermont Gas Systems issues press release announcing natural gas “Supply Watch” due in part to a reported TransCanada compressor station failure
1/10/2004 2:53 PM	Texas Eastern issues capacity constraint for January 11 • No incremental interruptible transport (IT-1) nominations for delivery in Market Zone 3 (NY/PA) • No due-shipper gas available on Texas Eastern • Shippers and point operators required to remain in balance daily

1/12/2004 3:56 PM	Algonquin issues capacity constraint for January 13 • No due-shipper gas available anywhere on the Algonquin • No incremental nominations flowing through Stony Point, NY • Shippers and point operators required to remain in balance daily
1/12/2004 4:59 PM	Algonquin revises capacity constraint for January 13 to include • All interruptible transport nominations flowing through Stony Point, NY are restricted • All interruptible transport and a portion of secondary transport were cut for nominations flowing through Cromwell, CT compressor station, along with all Cromwell-pathed incremental nominations • Shippers and point operators required to remain in balance daily
1/12/2004 6:29 PM	Texas Eastern issues capacity constraint for January 13 • No incremental nominations for Market Zone 3 (NY/PA) deliveries • No due-shipper gas available on Texas Eastern • Shippers and point operators required to remain in balance daily
1/13/2004 11:00 AM	Transco critical notice goes into effect • No due-shipper gas available on Transco • Imbalance at pooling points limited to ±1% during evening cycles
1/13/2004 3:28 PM	Algonquin issues capacity constraint for January 14 • No due-shipper gas available anywhere on Algonquin • Shippers and point operators required to remain in balance daily
1/13/2004 3:52 PM	Texas Eastern issues capacity constraint for January 14 • Interruptible transport deliveries in Market Zone 3 (NY/PA) restricted to zero • No due-shipper gas available on Texas Eastern except in producing zones • Shippers and point operators required to remain in balance daily
1/14/2004 6:56 AM	Algonquin revises capacity constraint for January 14 to include: • No incremental nominations flowing through Hanover, NJ or Stony Point, NY
1/14/2004 9:23 AM	Algonquin issues 2% Critical Notice (OFO) • Shippers and point operators must limit the daily discrepancy between scheduled deliveries and actual deliveries to 2% or less • Any unauthorized quantities to be charged a $15/dth penalty
1/14/2004 12:20 PM	Algonquin revises capacity constraint for January 14 to include: • Interconnection with HubLine operating at capacity, therefore no incremental nominations sourced from this point will be accepted
1/14/2004 3:48 PM	NGA issues press release requesting voluntary natural gas conservation in Eastern and Central Massachusetts, New Hampshire and Rhode Island through January 16
1/14/2004 4:13 PM	Texas Eastern issues capacity constraint for January 15 • Interruptible transport deliveries in Market Zone 3 (NY/PA) restricted to zero • No due-shipper gas available on Texas Eastern except in producing zones • No excess storage withdrawals allowed • Shippers and point operators required to remain in balance daily

1/14/2004 4:33 PM	Algonquin issues capacity constraint for January 15 • No due-shipper gas available on Algonquin • No incremental nominations sourcing gas from the M&N interconnect at Beverly, MA • 2% critical notice (OFO) remains in effect • Shippers and point operators required to remain in balance daily
1/14/2004 10:00 PM	Tennessee OFO goes into effect for Zones 5 & 6 (Northeast region) • Daily discrepancies between scheduled deliveries and actual flows required to not exceed the greater of 500 dths or 2% of scheduled quantities, a penalty of $15.00 plus the applicable Regional Daily Spot Price per dekatherm will be assessed on overtakes
1/15/2004 10:28 AM	Algonquin revises capacity constraint for January 15 to include: • No incremental nominations for supply sourced from Tennessee Gas Mendon, MA interconnect
1/15/2004 1:15 PM	Algonquin revises capacity constraint for January 15 to include: • No incremental nominations flowing through Hanover, NJ compressor
1/15/2004 2:12 PM	Texas Eastern issues capacity constraint for January 16 • Interruptible transport deliveries in Market Zone 3 (NY/PA) restricted to zero • No due-shipper gas available on Texas Eastern except in producing zones • No excess storage withdrawals allowed
1/15/2004 3:21 PM	Algonquin issues capacity constraint for January 16 • No incremental nominations flowing through Stony Point, except under interruptible rate AIT-2 • No incremental nominations sourced from M&N/AGT interconnect at Beverly, MA • 2% critical notice (OFO) remains in effect • No due-shipper gas available on Algonquin • Shippers and point operators required to remain in balance daily
1/15/2004 6:30 PM	ISO-NE holds conference call with gas industry representatives
1/16/2004 10:30 AM	ISO-NE holds conference call with gas industry representatives
1/16/2004 2:42 PM	Algonquin issues capacity constraint for January 17 • No incremental nominations flowing through Cromwell, except under interruptible rate AIT-2 • No incremental nominations sourced from M&N/AGT interconnect at Beverly, MA • 2% critical notice (OFO) remains in effect • No due-shipper gas available anywhere on Algonquin • Shippers and point operators required to remain in balance daily
1/16/2004 3:16 PM	Texas Eastern issues capacity constraint for January 17 • Limited due-shipper gas available, except in Zone M3, due-shipper gas in upstream zones cannot be used to supply M3 markets
1/17/2004 9:55 AM	Tennessee posts critical notice lifting OFO for Zones 5 & 6 (Northeast region), effective 1/16/2004 10:00 AM
1/17/2004 10:00 AM	Yankee Gas OFO lifted

1/17/2004 12:34 PM	Algonquin issues capacity constraint for January 18 • No incremental nominations flowing through Cromwell, except under interruptible rate AIT-2 • No incremental nominations sourced from M&N/AGT interconnect at Beverly, MA • Limited due-shipper gas available on Algonquin
1/17/2004 1:07 PM	Algonquin lifts 2% critical notice, noting that there is no due-shipper gas available for January 17
1/17/2004 7:00 PM	PNGTS lifts critical flow notice limiting daily flows to 105% of confirmed scheduled deliveries