National Grid

Fuel Adjustment Factor
Tariff Filing

June 30, 2008

Submitted to:
Rhode Island Public Utilities Commission
R.I.P.U.C. Docket No. ____

Submitted by:

nationalgrid

Thomas R. Teehan
Senior Counsel

June 30, 2008

VIA HAND DELIVERY & ELECTRONIC MAIL

Luly E. Massaro, Commission Clerk
Rhode Island Public Utilities Commission
89 Jefferson Boulevard
Warwick, RI 02888

Dear Ms. Massaro:

Enclosed for filing with the Commission are one original and 9 copies of a proposed Fuel Adjustment Factor Tariff ("FAF"). The FAF is being proposed for conditional application to two Wholesale Standard Offer Supply Agreements ("WSOSAs") the Company has with Constellation Energy Commodities Group ("Constellation").[1] The proposed FAF is provided as Attachment 1 to this filing. Copies of the two WSOSAs to which the FAF would apply are provided as Attachments 2 and 3.

The Company respectfully requests approval of this FAF, effective on a conditional basis, as of August 1, 2008. If approved by the Commission, the FAF would set forth a mechanism from which the Company may calculate fuel adjustment factor payments (if triggered) to Constellation, on a conditional basis. In months where fuel adjustment factor payments are triggered under the FAF, the Company would make payments to Constellation, with a reservation of rights that will be explained below. The payment amounts would be accounted for in the Company's standard offer reconciliation account for recovery from customers, subject to refund.

At this time, the Company is not requesting a change to the Standard Offer rate as a result of this filing. Rather, any payments would be included in the Standard Offer reconciliation and taken into account when a new Standard Offer rate is set for January 1, 2009 at the time the Company makes its annual year end rate filing, subject to refund.

Background Regarding Dispute

The Company is currently involved in a dispute with Constellation as to whether fuel adjustment factor payments are owed to Constellation for the period after 2004. A copy of Constellation's complaint filed against the Company is provided as Attachment 4 to this filing.

The WSOSAs have pricing provisions that include a fixed price for each year of the term. In addition, the pricing provisions refer to a fuel adjustment factor. Specifically, the agreements define the fuel adjustment factor in Article 5 as follows:

[1] There are no other agreements to which this FAF would apply.

> "Fuel Adjustment Factor is a cents per kilowatt-hour adder based on incremental revenues collected, if any, attributed to the operation of the retail Fuel Adjustment mechanism in the Companies' Standard Offer Service tariffs."

The same pricing provision also provides:

> "The retail Fuel Adjustment, and the resulting Fuel Adjustment Factor to be paid to Supplier, will be made subject to regulatory approval and only to the extent that the Companies are allowed to collect such revenues from their retail customers taking Standard Offer Service."

In May of 1998, the Commission approved Standard Offer Service tariffs for application to the then EUA companies. Copies of those tariffs are included in Attachment 5 to this filing. The 1998 tariffs, which were approved and on file with the Commission months before Constellation entered into the WSOSAs in December of 1998, contained fuel adjustment factor triggers that began in 2000 and ended after 2004.

Over the term of the agreements, Constellation invoiced for fuel adjustment factor payments and the Company made fuel adjustment factor payments for the period from 2000 through 2004. After 2004, however, Constellation stopped invoicing the Company for any fuel adjustment factor payments and did not invoice for any fuel adjustment factor payments for over three years thereafter. Over the same period, Constellation never claimed an entitlement to fuel adjustment factor payments and never claimed that the Company had any obligation to make another FAF Tariff filing with the Commission for application after 2004. Constellation maintained this silence knowing that TransCanada sued the Company claiming entitlement to a fuel adjustment factor in other power purchase agreements. It was not until April 14, 2008, when the complaint was filed, that Constellation first asserted a right to FAF payments. For all these reasons, and others, the Company is disputing Constellation's belated claim for fuel adjustment factor payments.

Constellation cites in its complaint a decision of the U.S. District Court for the District of Massachusetts in the TransCanada case. A copy of that decision is included as Attachment 6 to this filing. In that decision, the court determined that the Company had an obligation to file an FAF Tariff with the Commission with respect to TransCanada for the period after 2004, the approval of which would govern the amount of fuel adjustment factor payments that would be payable to the supplier.

While the Company strongly believes that the circumstances with TransCanada are substantially different than the circumstances with Constellation, the Company has determined that it is in the best interest of customers to make this conditional filing of an FAF Tariff that would apply prospectively from August 1, 2008 through December 31, 2009, on a provisional basis, without prejudice to the Company's litigation position and with a rate impact that will be subject to refund. In the meantime, the Company will continue to defend against Constellation's claims. When payments, if triggered, are made to Constellation, the Company will reserve its rights to dispute Constellation's entitlement to those payments in the pending litigation. To the extent the Company is successful and, as a result, any fuel adjustment factor payments made are returned to the Company, the Company would refund such amounts to customers. If, however, the court were to find that the Company has an obligation to file an FAF with the Commission, the Company believes this conditional filing would fulfill that obligation and create a just and reasonable FAF that does not over-compensate the supplier.

Explanation of the FAF

The FAF proposed for implementation on August 1, 2008, while very similar to the FAF mechanism that had been approved by the Commission and in effect at the time Constellation executed the WSOSAs in late 1998, is different in some respects to reflect current market conditions. The mechanism in 1998 was tied to both the market price of natural gas and the market price of oil. While prior to 1998 the wholesale prices for electricity were affected by both oil and gas prices, such is not the case today. In contrast, over ten years later, the wholesale energy market price for electricity is primarily determined by natural gas prices. An excerpt from a report by the New England ISO indicating this effect is provided as Attachment 7.[2] For that reason, the new FAF being proposed by the Company is tied only to natural gas prices, to more appropriately reflect actual market conditions.

The new proposed fuel triggers included in the FAF are based on natural gas prices as of the last three NYMEX trading days of April 2008 (April 24, 25 and 28, 2008) for the contract month of May 2008. The Company has chosen the April market reference point because Constellation did not give notice of its position that post-2004 fuel adjustment factor payments were allegedly owed until April 14, 2008. Accordingly, until April 14, 2008, Constellation performed under the WSOSAs without complaint and managed its portfolio without any fuel adjustment factor payments since January 1, 2005. Thus, the FAF being proposed by the Company provides a prospective benefit to the supplier to the extent natural gas prices escalate above this April 2008 market reference point.

Estimated Impact of FAF

Based on the NYMEX indices as of June 23, 24 and 25, 2008, the Company estimates that fuel payments from August 2008 through the end of the terms of the WSOSAs would be approximately $13.0 million, if the proposed FAF were to be approved. A schedule reflecting the estimated monthly payments is included as Attachment 8. As the attachment shows, payments are triggered to the extent natural gas

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[2] A complete copy of this report is available on the ISO-NE website at www.iso-ne.com, or from the Company, upon request.

prices exceed the May market reference point. Of course, this schedule is only an estimate. Actual payments would be determined by actual market prices reflected in the indices for natural gas on the applicable dates.

Nature of this Request for Approval

With this filing, the Company is not asking the Commission to make a determination whether the WSOSAs actually require fuel adjustment factor payments to be made after 2004. That is a matter that must be left to the court. Rather, the Company is asking the Commission to assume, only for purposes of this conditional filing, that a fuel adjustment mechanism needs to be established prospectively that provides reasonable compensation to the supplier in light of escalating natural gas prices that affect the market price of electricity. The Company believes the proposed FAF in this filing accomplishes that goal.

Request for August 1 Effective Date, Even if More Time is Needed

Given the litigation and apparent position taken by Constellation, the Company believes it important to have an FAF approved as soon as possible. However, the Company recognizes the importance of this matter and would fully understand if the Commission desires to establish a schedule that spans more than thirty days to reach a final decision. As such, to the extent the Commission believes it needs more time than thirty days to receive pre-filed testimony, conduct discovery, and hold hearings on this proposal, the Company respectfully requests the proposed FAF be allowed to take effect as of August 1, 2008, subject to prospective change later, based on the final outcome of the proceeding. This will allow the Company to commence payments, if any are triggered during the interim, without delay.

A copy of this filing is being provided to Constellation to give the supplier an opportunity to participate in the proceeding.

Sincerely,

Thomas R. Teehan

Enclosures

cc: Paul Roberti, Esq.
Leo Wold, Esq.
Steve Scialabba, Division
David O. Dardis, Constellation

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Attachment 1

Attachment 1

Fuel Adjustment Factor Tariff

The Narragansett Electric Company
Fuel Adjustment Factor Tariff

The provisions of this tariff are applicable exclusively to two Wholesale Standard Offer Supply Agreements ("WSOSAs") between Narragansett Electric Company and Constellation Energy Commodities Group ("Constellation"). These WSOSAs were originally made and entered into on 21st December, 1998 between Eastern Edison Company, a Massachusetts Corporation; Blackstone Valley Electric Company, a Rhode island Corporation; and Newport Electric Corporation, a Rhode Island Corporation, on the one hand, and Constellation Power Source, Inc, a Delaware Corporation, on the other hand.

The wholesale price paid to Constellation for supplying Standard Offer Service pursuant to the two WSOSAs shall be adjusted from time to time in accordance with the provision of a Fuel Index Adjustment as described below:

The Stipulated Price that is in effect for a given billing month is multiplied by a "Fuel Index Adjustment" that is set equal to 1.0 and thus has no impact on the rate paid unless the "Fuel Index" for the billing month exceeds the "Trigger Point" then in effect, where:

The Stipulated Price is the following predetermined, flat rate, for energy consumed at the customer meter point:

Calendar Year	Price per Kilowatt hour
2008	6.7 cents
2009	7.1 cents

Constellation will be paid the difference between the Stipulated Price as adjusted in accordance with this Fuel Index Adjustment Provision and the Stipulated Price for each kilowatt-hour it provides in the applicable month.

Fuel Index is the average of the daily settlement prices for the last three days that the NYMEX Contract (as defined below) for the month of delivery trades as reported in "The Wall Street Journal," expressed in dollars per MMBtu. NYMEX Contract shall mean the New York Mercantile Exchange Natural Gas Futures Contract as approved by the Commodity Futures Trading Commission for the purchase and sale of natural gas at Henry Hub;

If the index referred to above should become obsolete or no longer suitable, NECO shall file an alternate index with the RIPUC.

Trigger Point, expressed in dollars per MMBtu, shall be $11.011, which represents the NYMEX gas fuel index for the contract month of May 2008.

The Narragansett Electric Company
Fuel Adjustment Factor Tariff

In the event that the Trigger Point is exceeded, the Fuel Index Adjustment value for the billing month is determined based according to the following formula:

$$\text{Fuel Index Adjustment} = \frac{\text{Fuel Index /MMBtu}}{\text{Trigger Point/MMBtu}}$$

Where:

Fuel Index and Trigger Point are as defined above

For example, if at a point during calendar year 2008, the Fuel Index is $11.50, the Trigger Point of $11.01 would be exceeded. In this case, the Fuel Index Adjustment value would be:

$$\frac{\$11.50/\text{MMBtu}}{\$11.01/\text{MMBtu}} = 1.0445$$

The Stipulated Price is increased by this Fuel Index Adjustment factor for the billing month, becoming 6.998 cents/kWh (6.7 cents x 1.0445).

In subsequent months the same comparisons are made and, if applicable, a Fuel Index Adjustment determined.

Effective Date: August 1, 2008

Attachment 2

Attachment 3

Attachment 3

Wholesale Standard Offer Supply Agreement (2)

Attachment 4

Constellation Complaint for Declaratory Relief and Damages

UNITED STATES DISTRICT COURT
DISTRICT OF MASSACHUSETTS
(Central Division)

CONSTELLATION ENERGY COMMODITIES GROUP, INC. Plaintiff, v. THE NARRAGANSETT ELECTRIC COMPANY Defendant.	C.A. No. 08-40068 FDS

COMPLAINT
FOR DECLARATORY RELIEF AND DAMAGES

Plaintiff Constellation Energy Commodities Group, Inc. ("Constellation") as and for its complaint against The Narragansett Electric Company ("NEC") alleges as follows:

INTRODUCTION

1. This is an action for declaratory relief and breach of contract with regard to two wholesale power purchase agreements entitled Wholesale Standard Offer Service Agreements (collectively, the "WSOSAs") between NEC and Constellation, which were originally executed in 1998. Under the WSOSAs, Constellation agreed to supply wholesale electric power to NEC for NEC's retail customers in exchange for which NEC agreed to pay Constellation a fixed price where "Price = Standard Offer Wholesale Price + Fuel Adjustment Factor." The Fuel Adjustment Factor is an adjustment made to account for increases in the price of the fuel used to generate electricity. NEC breached these two contracts by purposely not seeking the Fuel Adjustment Factor in its rate filings with the Rhode Island Public Utilities Commission

("RIPUC"). Through this manipulation, NEC tried to lower the price it would have to pay Constellation.

2. The issue before the Court is NEC's breach of its obligation under the WSOSAs with respect to the Fuel Adjustment Factor. The WSOSAs between NEC and Constellation are identical with respect to the Fuel Adjustment Factor in all material respects to the wholesale standard offer service agreement between NEC and TransCanada, in C.A. No. 05-40076-FDS, pending before this Court.

PARTIES

3. Plaintiff Constellation is a corporation duly organized and existing under the laws of the State of Delaware with its principal place of business at 111 Market Place, Suite 500, Baltimore, Maryland, and the successor by name change to Constellation Power Source, Inc.

4. NEC is a corporation organized and existing under the laws of the State of Rhode Island with its principal place of business at 280 Melrose Street, Providence, Rhode Island. NEC is a retail electric distribution company engaged in the transmission and distribution of electricity to retail end-use customers in Rhode Island. NEC's predecessors include the retail electric distribution companies in Rhode Island formerly known as Blackstone Valley Electric Company ("Blackstone") and Newport Electric Company ("Newport"), which merged into NEC in 2000. NEC and its predecessors Blackstone and Newport have, at all relevant times and for all relevant purposes, acted through, and been managed and operated by, representatives at affiliated service companies (National Grid USA Service Company ("National Grid") and EUA Service Corporation) based in Northborough and Bridgewater, Massachusetts, respectively.

JURISDICTION AND VENUE

5. This Court has jurisdiction under 28 U.S.C. § 1332, as the amount in controversy exceeds $75,000. Venue is proper in this Court under 28 U.S.C. § 1391 because a substantial part of the events or omissions giving rise to the claim occurred in Massachusetts in that the WSOSAs were negotiated, signed, and subsequently administered in Massachusetts.

FACTS

Industry Background: The URA

6. In 1996, Rhode Island enacted legislation titled Utility Restructuring Act (the "URA") that restructured the regulatory structure governing public utilities serving customers in Rhode Island. The general objectives of the URA were to deregulate electric power supply and to develop a competitive retail market for electricity in Rhode Island. During the same period, Massachusetts was undergoing a similar electricity deregulation process.

7. The URA required that electric distribution companies in Rhode Island divest ownership of their electricity generation facilities, and offer "Retail Access" to Rhode Island retail customers. R.I.G.L. § 39-1-27.3 (1997) (which legislation has since been amended and revised). Retail Access required that each retail electric distribution company allow its customers to purchase electricity from non-affiliated retail suppliers. Retail Access also required each retail distribution company transport that purchased electricity over the retail distribution company's own lines from the alternative supplier to the customer.

8. The URA also required that, during the transition to Retail Access, the retail distribution companies provide a standard power supply ("Standard Offer Service") at regulated prices to Rhode Island retail customers through 2009. R.I.G.L. § 39-1-27.3(d) (1997). The purpose of Standard Offer Service was to provide a stable, competitively priced source of

electricity for those Rhode Island retail customers who had not yet obtained an alternative electricity supplier during the transition to a competitive Retail Access market.

9. Under the URA, the Standard Offer Service was to be priced to account for several factors reasonably beyond the control of power suppliers, including "extraordinary fuel costs." R.I.G.L. § 39-1-27.3(d) (1997). The URA required that retail distribution companies file tariffs with the RIPUC to implement Standard Offer Service through 2009, for the benefit of wholesale and retail customers and their suppliers. R.I.G.L. § 39-1-27(a) (1997). Thus, the protection offered by the Fuel Adjustment Factor was an important consideration for Constellation's agreement to enter into long term (12-year) electric supply contracts as the parties understood that fuel prices could significantly and unpredictably increase over the life of the WSOSAs.

Implementation of the URA

10. At the time of enactment of the URA, Blackstone and Newport were retail electric distribution companies in Rhode Island and wholly-owned subsidiaries of Eastern Utilities Associates ("EUA"), a Massachusetts-based public utility holding company. EUA also owned a retail electric company in Massachusetts, Eastern Edison Company ("Eastern" and, collectively with Blackstone and Newport, the "EUA Companies").

11. At the time of enactment of the URA and its Massachusetts counterpart, the EUA Companies, purchased their electricity, which they then supplied to their retail customers, from an affiliated wholesale electricity supplier in Massachusetts, Montaup Electric Company ("Montaup"). To comply with the URA (and the Massachusetts state law counterpart), the Companies were required to terminate their wholesale supply contracts with Montaup, and allow

their retail customers to have Retail Access to alternative suppliers. Montaup also was required to divest its generation facilities.

12. On October 17, 1997, in order to implement the URA, Blackstone, Newport, and Montaup entered into a Stipulation and Agreement with the RIPUC, as well as the Rhode Island Division of Public Utilities and Carriers ("Division") (hereinafter, the "RI Settlement Agreement"). The Federal Energy Regulatory Commission ("FERC") approved the RI Settlement Agreement. The same entities entered into a similar Stipulation and Agreement, executed in Massachusetts and approved by FERC (the "MA Settlement Agreement" and, collectively with the RI Settlement Agreement, the "Settlement Agreements").

13. In order to ensure a steady supply of Standard Offer Service, the RI Settlement Agreement required that Montaup provide Blackstone and Newport with a guaranteed "Backstop" supply of Standard Offer Service through 2009. Blackstone and Newport were in turn required to seek alternative wholesale suppliers for Standard Offer Service during that term, and were to release Montaup from its Backstop obligation to the extent Blackstone and Newport were able to obtain replacement contracts. In order to ensure a Standard Offer Service to Rhode Island retail customers through 2009, Montaup's Backstop obligation required that it provide Standard Offer Service to Blackstone and Newport through 2009, to the extent that those companies did not obtain alternative wholesale Standard Offer Service supply contracts.

14. The RI Settlement Agreement required Montaup and its successors to provide Standard Offer Service to Blackstone and Newport in exchange for a stipulated set of base prices rising over time, subject to a "fuel index" to account for future extraordinary fuel costs, through 2009. That fuel index is the crux of this litigation. The purpose of the fuel index, as envisioned by the URA and Settlement Agreements, was to protect wholesale Standard Offer Service

suppliers against the risk of future extraordinary increases in fuel costs, so that suppliers would agree to the desired long-term Standard Offer Service supply contracts for the benefit of Rhode Island retail customers.

Constellation's WSOS Agreements

15. On or about December 21, 1998, Constellation and Montaup entered into an agreement whereby Constellation purchased certain wholesale power purchase agreements from Montaup. The Settlement Agreements required that Constellation assume a percentage share of Montaup's Backstop obligation to provide Standard Offer Service to Blackstone, Newport, and Eastern.

16. Constellation and the EUA Companies entered into the two WSOSAs on or about December 21, 1998. Each of the WSOSAs state at Article 14 that "[t]he interpretation and performance of this Agreement shall be in accordance with and shall be controlled by the laws of the Commonwealth of Massachusetts, without regard to Massachusetts conflict of law principles." In those WSOSAs, Constellation agreed to provide wholesale Standard Offer Service to Blackstone and Newport through December 31, 2009 (the term of the Standard Offer Service in Rhode Island) and to Eastern through February 28, 2005. (*See* WSOSAs, § 3 & App. A.) Upon information and belief, the EUA Companies negotiated, signed, and subsequently administered the WSOSAs in and from their offices in Massachusetts.

17. Under the WSOSAs, the Settlement Agreements and the URA, Constellation was to receive a price for delivering Standard Offer Service consisting of the stipulated set of base prices rising over time (the "Standard Offer Wholesale Price"), plus a fuel index (the "Fuel Adjustment Factor") to account for future extraordinary fuel costs. Under the WSOSAs, the Fuel

Adjustment Factor is calculated based upon the tariffs that the URA and Settlement Agreements require Blackstone and Newport to file. Specifically, Article Five of the WSOSAs provides that:

> For each kilowatt-hour of Delivered Energy that Supplier [Constellation] provides in each month . . ., the Companies shall pay Supplier the applicable Price for the month in cents per kilowatt-hour calculated as follows:
>
> Price = Standard Offer Wholesale Price + Fuel Adjustment Factor
>
> Where: Standard Offer Wholesale Price in cents per kilowatt hour is as defined in Article 1 and shown in Appendix A, and
>
> Fuel Adjustment Factor is a cents per kilowatt-hour adder based on the incremental revenues collected, if any, attributed to the operation of the Retail Standard Offer Fuel Index ("Fuel Index") mechanism in the Companies' Standard Offer Service tariffs .... The Fuel Index, and the resulting Fuel Adjustment Factor to be paid to Supplier, will be made subject to regulatory approval and only to the extent that the Companies are allowed to collect such revenues from their retail customers taking Standard Offer Service.

18. The WSOSAs thus imposed upon Blackstone and Newport (and in turn upon NEC as their successor) the duty and good faith obligation to make the required Standard Offer Service Tariff filings with the RIPUC, and to use reasonable efforts to obtain regulatory approval for a Fuel Adjustment Factor by Blackstone and Newport to Constellation over the 2009 term of the WSOSAs.

19. The WSOSAs also provided Constellation with termination rights and damages rights, in the event that NEC failed to perform any of their obligations under the WSOSAs. Specifically, the WSOSAs provide that, upon an uncured default by any of the Companies (now, NEC), Constellation has the right to recover direct damages resulting from the default; to pursue all other remedies and damages provided for by law; and to terminate the WSOSAs upon sixty (60) days notice. (WSOSAs § 8.) Finally, the WSOSAs provide that Constellation is entitled to recover interest on any improperly withheld payments. (*Id.* § 6.)

20. NEC and Constellation are litigants before the United States District Court for the District of Rhode Island in a dispute concerning the change in law or market rules provisions of the WSOSAs (and two subsequent wholesale power purchase agreements between the parties), Civil Action C.A. No. 06-404S. The action in Rhode Island district court concerns a separate and distinct provision of the parties' contracts in the two 1998 WSOSAs, plus the parties' 2001 and 2002 agreements, and the factual and legal issues before that court do not relate to the issues asserted in this Complaint. The Rhode Island action concerns whether Constellation has the right under the change in law or market rules provisions of the party's contracts to an amendment in those contracts following regulatory changes mandated by FERC, and the issues in that dispute are subject to mandatory arbitration provisions in the parties' 2001 and 2002 agreements. In this case, there is no mandatory arbitration clause applicable to the dispute, and there is no Fuel Adjustment Factor dispute under the parties' 2001 and 2002 agreements.

The NEC Merger

21. From the signing of the WSOSAs in April 1998 through early 2000, Blackstone and Newport filed the required Standard Offer Service Tariffs with the RIPUC on a periodic basis. Blackstone, Newport and Eastern thereby obtained approval of the Standard Offer Wholesale Prices and a Fuel Adjustment Factor for 1999 and 2000, as required by the WSOSAs. Upon information and belief, Blackstone, Newport and Eastern's representatives planned and prepared the Tariff filings in EUA's offices in Massachusetts.

22. In 2000, Blackstone and Newport merged into NEC. At the same time, Eastern merged into Massachusetts Electric Company ("Mass. Electric").

23. NEC and Mass. Electric were at the time (and still are, upon information and belief), wholly-owned subsidiaries of National Grid, a Massachusetts-based public utility holding

company. Upon information and believe, at all relevant times National Grid exercised dominion and control over NEC with respect to the allegations herein from National Grid's offices in Massachusetts. Through the comprehensive merger, each of the EUA Companies' former retail distribution companies in Rhode Island and Massachusetts (Blackstone, Newport, and Eastern),[1] merged into the corresponding Rhode Island and Massachusetts retail distribution companies of National Grid, consisting of NEC and Mass. Electric.

24. By way of the Rhode Island portion of the merger, NEC became the retail electric distribution company both for the previous retail customers of Blackstone and Newport in Rhode Island (hereinafter the former "EUA Zone"), as well as its own previous retail customers in its former area (hereinafter the old "Narragansett Zone"). That distinction was for the benefit of NEC and its affiliates and was not intended to, and did not have the effect of, modifying any rights with regard to the Fuel Adjustment Factor that Constellation enjoyed under the WSOSAs.

25. The RIPUC approved the NEC merger in March 2000. At the request of NEC, the RIPUC cancelled the Blackstone and Newport Standard Offer Service Tariffs and ruled that NEC could continue to obtain payment for Standard Offer Service in both its new EUA Zone and in its old Narragansett Zone through NEC's own and future Standard Offer Service Tariffs and related filings.[2]

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[1] Eastern Edison Company merged into an affiliate of NEC and the portion of the WSOSAs concerning Eastern Edison ended in 2005.

[2] NEC, like Blackstone and Newport, had entered into its own Settlement Agreement with the RIPUC in 1997, which also required Retail Access and divestiture of generation assets. NEC's Settlement Agreement required NEC to provide Standard Offer Service at the same set of stipulated prices and fuel adjustment triggers as in Blackstone's and Newport's RI Settlement Agreement. Like Blackstone and Newport, NEC also subsequently entered into Standard Offer Service supply contracts with a number of wholesale Standard Offer Service suppliers. NEC was required, like Blackstone and Newport, to file tariffs under the URA to implement the Standard Offer Service for the benefit of its customers and suppliers.

NEC's Breach and Wrongful Conduct

26. In April 2000, NEC notified Constellation of the merger and asserted that NEC would succeed to and assume the obligations of Blackstone and Newport under the WSOSAs. That notice assured Constellation that the obligations of the parties "are not affected by the merger and assignments." NEC's notice further stated that NEC would continue to make Fuel Adjustment Factor payments to Constellation "after 1999," according to the mechanism previously established in the RI Settlement Agreement and in the Blackstone and Newport Standard Offer Service Tariffs.

27. It was to NEC's benefit not to pay a Fuel Adjustment Factor, particularly in times of rising fuel prices, in order to reduce its overall expenses and costs, among other reasons. Fuel prices began rising at the time of NEC's merger, which price increases triggered the Fuel Adjustment Factors in NEC's and Blackstone's and Newport's wholesale Standard Offer Service supply contracts.

28. From 2000 and through the end of 2004, NEC continued to pay Constellation for Standard Offer Service as required under the WSOSAs, including both the base Wholesale Standard Offer Price and a Fuel Adjustment Factor. Fuel prices continued to rise, however, and Fuel Adjustment Factor payments to Constellation and other wholesale Standard Offer Service suppliers became a regular, material component of the price NEC paid to its suppliers for Wholesale Standard Offer Services.

29. In May 2003, upon information and belief, NEC's Massachusetts representatives began to assert before the RIPUC (based on filings planned and prepared in Massachusetts) that its suppliers in the former EUA Zone should not be paid a Fuel Adjustment Factor after 2004.

30. In December 2004, NEC filed with the RIPUC its proposed Standard Offer Service Tariffs and rates for 2005. NEC specified that no Fuel Adjustment Factor should be

granted to Constellation (or any other EUA Zone suppliers) in 2005. As a result of that filing, and NEC's arguments, the RIPUC approved Standard Offer Service Tariffs and rates for 2005 that provide no allocation for a Fuel Adjustment Factor for Constellation. At the same time, NEC continued to request and to obtain approval for a Fuel Adjustment Factor in 2005 for its suppliers in the old Narragansett Zone. NEC also paid another supplier in the EUA Zone (TransCanada) a Fuel Adjustment Factor subject to NEC's contention that no liability was owed.

31. NEC's breaches of its obligations under the WSOSAs to file Standard Offer Service rates that include a fuel adjustment mechanism and, if allowed, to pay that higher fuel-adjusted price to Constellation, have deprived Constellation of its contractual rights to payment of a Fuel Adjustment Factor under the WSOSAs.

32. Constellation never waived any of its rights with regard to the Fuel Adjustment Factor, and NEC's breaches have caused and are continuing to cause Constellation substantial and ongoing damages.

33. On March 26, 2008, Judge F. Dennis Saylor IV issued a Memorandum and Order on Cross Motions for Summary Judgment ("TransCanada Order") in 05-40076-FDS, a case TransCanada filed in this district, against NEC, and involving identical issues in all material respects with regard to the Fuel Adjustment Factor. The TransCanada Order addressed the same provision of the WSOSAs between Constellation and NEC:

> The [TransCanada v. Narragansett] dispute essentially involves whether a wholesale contract for electric power between the parties required Narragansett (1) to include a fuel adjustment mechanism in its retail rate filings with the PUC for the period 2005 to 2009, permitting it to collect higher revenues if fuel costs went up, and thus (2) to pay a higher fuel-adjusted price to TransCanada.

TransCanada Order at 1. The court held that it did, and explained that

> [T]here is no indication anywhere in the contract that [NEC's] obligations as to the Fuel Adjustment Factor expire in 2004. The

> contract is an unambiguous, integrated agreement, negotiated and executed by sophisticated corporate entities. If the parties intended that [NEC's] obligations were to change in 2004, it would have been simple enough to say so. The parties elected not to. Accordingly, [NEC's] obligations … remain in place until December 31, 2009.

Id. at 15.

Count I
(Declaratory Relief)

34. Constellation repeats and incorporates by reference paragraphs 1 through 33 above.

35. An actual controversy exists as to whether NEC breached the WSOSAs with respect to NEC's duty owed to Constellation under the WSOSAs to (a) file for or make a reasonable effort to obtain regulatory approval of a Fuel Adjustment Factor, and (b) to pay a Fuel Adjustment Factor to Constellation as required under the WSOSAs. A further actual controversy exists regarding whether Constellation has the right to terminate the WSOSAs, including under Articles 5 and/or 8, for NEC's failure to abide by its duties with respect to the Fuel Adjustment Factor.

36. Constellation requests a declaratory judgment that NEC breached the terms of the WSOSAs; that NEC failed to cure the breach (to the extent cure was applicable); that Constellation had and has the unconditional right, in addition to the right to recover damages and interest, to terminate the WSOSAs because of such breaches; and that Constellation's is entitled to damages for NEC's breaches.

Count II
(Breach of Contract)

37. Constellation repeats and incorporates by reference paragraphs 1 through 36 above.

38. NEC has breached the WSOSAs through the acts described above, including (a) its failure to file for or make a reasonable effort to obtain regulatory approval of a Fuel Adjustment Factor after 2004; and (b) its failure to pay a Fuel Adjustment Factor to Constellation as required under the WSOSAs.

39. Because of these breaches, Constellation has suffered and will continue to suffer monetary damages. Constellation was and is entitled to terminate the WSOSAs, and to an award of its damages and interest in such amount as to be proven at trial.

Count III
(Breach of the Implied Covenant of Good Faith and Fair Dealing)

40. Constellation repeats and incorporates by reference paragraphs 1 through 39 above.

41. The WSOSAs contain an implied covenant of good faith and fair dealing.

42. NEC has breached the covenant of good faith and fair dealing implied in the WSOSAs through its conduct described above, including but not limited to its various contractual breaches of the WSOSAs, its behavior before the RIPUC regarding the WSOSAs Fuel Adjustment Factor, and its expropriation to its own benefit of Constellation's rights under the WSOSAs.

43. As a result of these breaches, Constellation has suffered and will continue to suffer substantial monetary damages. Constellation was and is entitled to terminate the WSOSAs, and to an award of damages and interest.

WHEREFORE, Constellation requests the following relief against NEC:

1. Judgment in its favor on all counts.

2. A declaratory judgment that NEC has breached the terms of the WSOSAs and the implied covenant of good faith and fair dealing; that NEC has failed to cure its breach; and that Constellation has the unconditional right, in addition to the right to recover damages and interest, to terminate the WSOSAs immediately.

3. An award of specific performance and/or damages, including interest, in an amount to bc determined at trial.

4. An award of costs and such further relief as this Court deems just and proper.

Respectfully submitted,

CONSTELLATION ENERGY COMMODITIES GROUP, INC.

By its attorneys,

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Attachment 5

Attachment 5

Blackstone Valley Electric Company/Newport Electric Corporation Standard Offer Service Tariffs

R.I.P.U.C. NO. 1173
CANCELS NO. 1172

BLACKSTONE VALLEY ELECTRIC COMPANY
STANDARD OFFER SERVICE

AVAILABILITY:

This Rate Schedule for Standard Offer Service is available to all Customers taking electric service from the Company before January 1, 1998, to all new Customers taking retail delivery electric service on and after January 1, 1998, and to Customers who were taking generation service from a Nonregulated Power Producer before January 1, 1998, who provided the Company with a written notice on or before December 26, 1997, of their intent to terminate generation service from their Nonregulated Power Producer and who were transferred to Interim Generation Service on January 1, 1998. Said Customers shall have the right to relocate to a different service location within the Company's service area and continue to receive service under this Rate Schedule.

APPLICABILITY:

Electricity supplied under this Rate Schedule shall be used solely by the Customer on the Customer's own premises for all purposes.

CHARACTER OF SERVICE:

Electric service supplied hereunder shall be single or three phase, alternating current, at a nominal frequency of sixty hertz, and at a locally available primary or secondary distribution voltage.

RATE:

The Rate for each Rate Class shall consist of the following charges:

Residential Retail Delivery Service Rate R-1

Energy Charge:	$0.03051	per kWh

Residential SSI Retail Delivery Service Rate R-2

Energy Charge:	$0.03051	per kWh

Residential Space Heating Retail Delivery Service Rate R-3

Energy Charge:	$0.03158	per kWh

Large Residential Retail Delivery Service Rate R-4

Energy Charge		
Peak Hours:	$0.15384	per kWh
Off-Peak Hours:	$0.00570	per kWh

Date Filed, July 17, 1998
per Order No. 15640 dated
July 10, 1998 in Docket No. 2716.

Date Effective, June 1, 1998
for consumption on and after
June 1, 1998.

Small Secondary Voltage General Retail Delivery Service Rate G-1

Energy Charge:	$0.03589	per kWh

Medium Secondary Voltage General Retail Delivery Service Rate G-2

Non Time-of-Use Billing Option (Rate Code G-2):

Demand Charge:	$5.81	per kW
Energy Charge:	$0.01403	per kWh

The Billing Demand in kilowatts for each month will be the lower of the maximum metered demand in any fifteen-minute period during the month or the monthly energy consumption divided by 150.

Time-of-Use Billing Option (Rate Code T-2):

Demand Charge:	$6.11	per kW
Energy Charge		
Peak Hours:	$0.02978	per kWh
Off-Peak Hours:	$0.00877	per kWh

The Billing Demand in kilowatts for each month will be the higher of the maximum metered demand in any fifteen-minute period during Peak Hours in the month or 10 kilowatts.

Medium Primary Voltage General Retail Delivery Service Rate G-5

Non Time-of-Use Billing Option (Rate Code G-5):

Demand Charge:	$5.29	per kW
Energy Charge:	$0.01610	per kWh

The Billing Demand in kilowatts for each month will be the maximum metered demand in any fifteen minute period during the month.

Time-of-Use Billing Option (Rate Code T-5):

Demand Charge:	$5.48	per kW
Energy Charge		
Peak Hours:	$0.03241	per kWh
Off-Peak Hours:	$0.01054	per kWh

The Billing Demand in kilowatts for each month will be the higher of the maximum metered demand in any fifteen-minute period during Peak Hours in the month or 10 kilowatts.

Large Secondary Voltage General Retail Delivery Service Rate T-4

Demand Charge:	$5.88	per kW
Energy Charge		
Peak Hours:	$0.03919	per kWh
Off-Peak Hours:	$0.01027	per kWh

The Billing Demand in kilowatts for each month will be the higher of the maximum metered demand in any fifteen-minute period during Peak Hours in the month or 100 kilowatts.

Large Primary Voltage General Retail Delivery Service Rate T-6

Demand Charge:	$5.37	per kW
Energy Charge		
Peak Hours:	$0.03914	per kWh
Off-Peak Hours:	$0.01239	per kWh

The Billing Demand in kilowatts for each month will be the higher of the maximum metered demand in any fifteen-minute period during Peak Hours in the month or 100 kilowatts.

Large Secondary Voltage Auxiliary
General Retail Delivery Service Rate A-4

Demand Charge:	$3.70	per kW
Energy Charge		
Peak Hours:	$0.03919	per kWh
Off-Peak Hours:	$0.01027	per kWh

The Supplementary Standard Offer Demand Charge shall be the Supplementary Demand times the Demand Charge.

The Backup Usage Demand in kilowatts is the Average Daily Demand in excess of the Supplementary Demand, where the Average Daily Demand is the sum of the daily maximum metered 15 minute average loads recorded during Peak Hours within the Backup Billing Period divided by the number of days in the Backup Billing Period. The Backup Usage Demand Charge shall be the Backup Usage Demand times the Demand Charge times the ratio of the number of Backup Billing Period Days to the number of Billing Period Peak Days. No Backup Usage Demand Charge shall be incurred for planned outages due to Maintenance.

The Billing Demand Charge shall be the sum of the Supplementary Standard Offer Demand Charge and the Backup Usage Demand Charge.

The terms Supplementary Demand, Backup Billing Period, and Billing Period shall be as defined in Large Secondary Voltage Auxiliary General Retail Delivery Service Rate A-4.

The Company agrees to furnish Maintenance Power to the customer at times convenient to the Company. The Contract will specify the customer's expected Maintenance Power requirements, expected frequency and duration of Maintenance Power periods, and the expected calendar schedule of Maintenance Power periods. Said Maintenance Power requirements, frequency, duration, and schedule must be determined by the Company to be reasonable given the design specifications and operating characteristics of the customer's Facility, and such other information the Company considers pertinent to the determination of the appropriate Maintenance Power requirements, frequency, duration, and schedule for the customer. The customer shall make all requests for Maintenance Power in writing at least thirty (30) days prior to a planned outage of the Facility, and the Company will consent to such requests in writing, which consent shall not be unreasonably withheld.

Large Primary Voltage Auxiliary
General Retail Delivery Service Rate A-6

Demand Charge:	$3.37	per kW
Energy Charge		
Peak Hours:	$0.03914	per kWh
Off-Peak Hours:	$0.01239	per kWh

The Supplementary Standard Offer Demand Charge shall be the Supplementary Demand times the Demand Charge.

The Backup Usage Demand in kilowatts is the Average Daily Demand in excess of the Supplementary Demand, where the Average Daily Demand is the sum of the daily maximum metered 15 minute average loads recorded during Peak Hours within the Backup Billing Period divided by the number of days in the Backup Billing Period. The Backup Usage Demand Charge shall be the Backup Usage Demand times the Demand Charge times the ratio of the number of Backup Billing Period Days to the number of Billing Period Peak Days. No Backup Usage Demand Charge shall be incurred for planned outages due to Maintenance.

The Billing Demand Charge shall be the sum of the Supplementary Standard Offer Demand Charge and the Backup Usage Demand Charge.

The terms Supplementary Demand, Backup Billing Period, and Billing Period shall be as defined in Large Primary Voltage Auxiliary General Retail Delivery Service Rate A-6.

The Company agrees to furnish Maintenance Power to the customer at times convenient to the Company. The Contract will specify the customer's expected Maintenance Power requirements, expected frequency and duration of Maintenance Power periods, and the expected calendar schedule of Maintenance Power periods. Said Maintenance Power requirements, frequency, duration, and schedule must be determined by the Company to be reasonable given the design specifications and operating characteristics of the customer's Facility, and such other information the Company considers pertinent to the determination of the appropriate Maintenance Power requirements, frequency, duration, and schedule for the customer. The customer shall make all requests for Maintenance Power in writing at least thirty (30) days prior to a planned outage of the Facility, and the Company will consent to such requests in writing, which consent shall not be unreasonably withheld.

General Space Heating Retail Delivery Service Rate H-1

Energy Charge:	$0.03308	per kWh

General Heating Retail Delivery Service Rate H-2

Energy Charge:	$0.03339	per kWh

Controlled Water Heating Retail Delivery Service Rate W-1

Energy Charge:	$0.03509	per kWh

Lighting Retail Delivery Service Rate S-1

Energy Charge:	$0.03408	per kWh

Time-Of-Use Time Periods for Rates R-4, G-2, T-4, G-5, T-6, A-4, & A-6

Peak Hours

Monday through Friday excluding holidays defined below

April through September,	11:00 a.m. to 4:00 p.m.
October through March,	8:00 a.m. to 12:00 noon, and 4:00 p.m. to 7:00 p.m.

Off-Peak Hours

All other hours.

Holidays are defined as:

New Year's Day	Columbus Day
President's Day	Veteran's Day
Memorial Day	Thanksgiving Day
Independence Day	Christmas Day
Labor Day	

Power Factor Adjustment for Rates G-2, T-4, G-5, and T-6:

Customers who have established a Billing Demand of 100 kilowatts or more in the current or preceding eleven months will receive a Power

Factor Adjustment (PFA) to their Demand Charge based on the following method, except that the Demand Charge shall not be less than 95% nor more than 110% of the Demand Charge before adjustment:

PFA = ((0.80 / Power Factor) - 1) x (Unadjusted Demand Charge / 3)

The foregoing Rates shall be adjusted from time to time in accordance with provisions of the Standard Offer Fuel Index and the Standard Offer Cost Adjustment described below:

STANDARD OFFER FUEL INDEX:

The Standard Offer Charge in effect for a billing month is multiplied by a Fuel Adjustment that is set equal to 1.0 unless the Market Gas Price plus Market Oil Price for the billing month exceeds the Fuel Trigger Point then in effect, where:

Market Gas Price is the average of the values of Gas Index for the most recent six months through and including the billing month, where:

Gas Index is the average of the daily settlement prices for the last three days that the NYMEX Contract (as defined below) for the month of delivery trades as reported in the Wall Street Journal, expressed in dollars per MMBTU. NYMEX Contract shall mean the New York Mercantile Exchange Natural Gas Futures Contract as approved by the Commodity Futures Trading Commission for the purchase and sale of natural gas at Henry Hub;

Market Oil Price is the average of the values of Oil Index for the most recent six months through and including the billing month, where:

Oil Index is the average for the month of the daily low quotations for cargo delivery of 1.0% sulfur No. 6 residual fuel oil into New York harbor, as reported in Platt's Oilgram U.S. Marketscan in dollars per barrel and converted to dollars per MMBTU by dividing by 6.3; and if the indices referred to above should become obsolete or no longer suitable, the distribution company shall file alternate indices with the Department.

Fuel Trigger Point is the following amounts, expressed in dollars per MMBTU, applicable for all months in the specified calendar year:

Year	Fuel Trigger Point
2000	$5.35 per MMBTU
2001	$5.35 per MMBTU
2002	$6.09 per MMBTU
2003	$7.01 per MMBTU

2004	$7.74 per MMBTU

In the event that the Fuel Trigger Point is exceeded, the Fuel Adjustment value for the billing month is determined based according to the following formula:

$$\text{Fuel Adjustment} = \frac{(\text{Market Gas Price}+\$0.60/\text{MMBTU})+(\text{Market Oil Price}+\$0.04/\text{MMBTU})}{\text{Fuel Trigger Point} + \$0.60 + \$0.04/\text{MMBTU}}$$

Where Market Gas Price, Market Oil Price and Fuel Trigger Point are as defined above. The values of $0.60 and $0.04/MMBTU represent for gas and oil respectively, estimated basis differentials or market costs of transportation from the point where the index is calculated to a proxy power plant in the New England market.

Incremental revenues received by the Company from the application of the Fuel Adjustment shall be fully allocated to Standard Offer Suppliers in proportion to the Standard Offer energy provided by a Supplier to the Company in the applicable billing month.

STANDARD OFFER COST ADJUSTMENT:

The following Standard Offer Cost Adjustment shall reflect the difference between the cost of Standard Offer Service paid by the Company to wholesale suppliers thereof and the revenues billed by the Company to Customers taking Standard Offer Service under this Rate Schedule. As used herein "Standard Offer Service costs" shall be those costs incurred by the Company in providing Standard Offer Service under this Rate Schedule including wholesale rate discounts arising from the competitive procurement process and any or all other costs determined by the Public Utilities Commission to be includable therewith, excluding all costs recoverable through the Standard Offer Fuel Index provision.

By March 1 of each year, the Company shall determine the amount of any over- or under-collection for the prior calendar year and make a filing with the Commission. The Company will propose at that time a rate recovery/refund methodology to recover or refund the balance, as appropriate, over the twelve-month period commencing April 1. The Commission may order the Company to collect or refund the balance over any reasonable time period from (i) all customers, (ii) only Standard Offer customers, or (iii) through any other reasonable method.

At the conclusion of the Standard Offer Service period on December 31, 2009, the Company will apply to the Public Utilities Commission for approval of a temporary per kilowatthour surcharge or credit factor to be applied to the distribution component of the Retail Delivery Rates for such a duration as necessary to provide for full recovery or return of any outstanding balance of Standard Offer Service costs or revenues that exists.

BILLING:

The Billing Amount for electric service supplied under this Rate Schedule shall consist of the sum, as applicable, of the Demand Charge and the Energy Charges as adjusted by the Standard Offer Fuel Index and Rhode Island Gross Receipts Tax.

TERM OF CONTRACT:

The Term of Contract for Standard Offer Service shall be for a period beginning on the date service is first taken and ending on the earlier of December 31, 2009, or the date the Customer terminates service. The Customer may terminate service on five (5) days notice. The Customer shall be ineligible to receive Standard Offer Service thereafter. The foregoing provision shall not apply to Customers who receive service under any of the Company's residential Retail Delivery Service Rates or under Small General Retail Delivery Service Rate G-1. Said Customers may elect to take electric power service from another Supplier during the period beginning June 1, 1998, and ending May 31, 1999, and elect to return to Standard Offer Service within one hundred twenty (120) days of commencing service from that Supplier.

TERMS AND CONDITIONS:

The Company's Terms and Conditions for Electric Service and Terms and Conditions for Electric Power Suppliers in effect from time to time, where not inconsistent with the specific provisions hereof, are a part of this Rate Schedule.

R.I.P.U.C. NO. 1398
CANCELS NO. 1397

NEWPORT ELECTRIC CORPORATION
STANDARD OFFER SERVICE

AVAILABILITY:

This Rate Schedule for Standard Offer Service is available to all Customers taking electric service from the Company before January 1, 1998, to all new Customers taking retail delivery electric service on and after January 1, 1998, and to Customers who were taking generation service from a Nonregulated Power Producer before January 1, 1998, who provided the Company with a written notice on or before December 26, 1997, of their intent to terminate generation service from their Nonregulated Power Producer and who were transferred to Interim Generation Service on January 1, 1998. Said Customers shall have the right to relocate to a different service location within the Company's service area and continue to receive service under this Rate Schedule.

APPLICABILITY:

Electricity supplied under this Rate Schedule shall be used solely by the Customer on the Customer's own premises for all purposes.

CHARACTER OF SERVICE:

Electric service supplied hereunder shall be single or three phase, alternating current, at a nominal frequency of sixty hertz, and at a locally available primary or secondary distribution voltage.

RATE:

The Rate for each Rate Class shall consist of the following charges:

Residential Retail Delivery Service Rate R-1

Energy Charge:	$0.03341	per kWh

Residential SSI Retail Delivery Service Rate R-2

Energy Charge:	$0.03341	per kWh

Large Residential Retail Delivery Service Rate R-4

Energy Charge		
Peak Hours:	$0.15396	per kWh
Off-Peak Hours:	$0.00667	per kWh

Small Secondary Voltage General Retail Delivery Service Rate G-1

Energy Charge:	$0.03357	per kWh

Date Filed, July 17, 1998
per Order No. 15640 dated
July 10, 1998 in Docket No. 2716.

Date Effective, June 1, 1998
for consumption on and after
June 1, 1998.

Medium Secondary Voltage General Retail Delivery Service Rate G-2

Non Time-of-Use Billing Option (Rate Code G-2):

Demand Charge:	$6.10	per kW
Energy Charge:	$0.01534	per kWh

The Billing Demand in kilowatts for each month will be the lower of the maximum metered demand in any fifteen-minute period during the month or the monthly energy consumption divided by 150.

Time-of-Use Billing Option (Rate Code T-2):

Demand Charge:	$6.59	per kW
Energy Charge		
Peak Hours:	$0.06416	per kWh
Off-Peak Hours:	$0.00096	per kWh

The Billing Demand in kilowatts for each month will be the higher of the maximum metered demand in any fifteen-minute period during Peak Hours in the month or 15 kilowatts.

Medium Primary Voltage General Retail Delivery Service Rate G-5

Non Time-of-Use Billing Option (Rate Code G-5):

Demand Charge:	$6.92	per kW
Energy Charge:	$0.01436	per kWh

The Billing Demand in kilowatts for each month will be the lower of the maximum metered demand in any fifteen-minute period during the month or the monthly energy consumption divided by 150.

Time-of-Use Billing Option (Rate Code T-5):

Demand Charge:	$7.24	per kW
Energy Charge		
Peak Hours:	$0.06222	per kWh
Off-Peak Hours:	$0.00228	per kWh

The Billing Demand in kilowatts for each month will be the higher of the maximum metered demand in any fifteen-minute period during Peak Hours in the month or 15 kilowatts.

Large Secondary Voltage General Retail Delivery Service Rate T-4

Demand Charge:	$8.04	per kW
Energy Charge		
Peak Hours:	$0.05990	per kWh
Off-Peak Hours:	$0.00096	per kWh

The Billing Demand in kilowatts for each month will be the higher of the maximum metered demand in any fifteen-minute period during Peak Hours in the month or 100 kilowatts.

Large Primary Voltage General Retail Delivery Service Rate T-6

Demand Charge:	$7.27	per kW
Energy Charge		
Peak Hours:	$0.06060	per kWh
Off-Peak Hours:	$0.00241	per kWh

The Billing Demand in kilowatts for each month will be the higher of the maximum metered demand in any fifteen-minute period during Peak Hours in the month or 100 kilowatts.

Transmission Voltage General Retail Delivery Service Rate C-1

Demand Charge:	$5.99	per kW
Energy Charge		
Peak Hours:	$0.01882	per kWh
Off-Peak Hours:	$0.01555	per kWh

I. Billing Period

The Billing Period consists of the days between consecutive meter readings. Service under this Rate is rendered on a full calendar day basis. The first day of any billing period is included in its entirety and the last day of any billing period is excluded in its entirety.

II. Backup Billing Period

The Backup Billing Period consists of the Peak Days within a Billing Period during which Backup Service is rendered. Backup Service is rendered when any part of a forced outage occurs during Peak Hours and electric service is actually taken.

III. Maintenance Billing Period

The Maintenance Billing Period consists of the Peak Days within a Billing Period during which Maintenance Service is rendered. Maintenance Service is rendered when any part of a planned outage occurs during Peak Hours and electric service is actually taken.

IV. Standard Offer Billing Demand

A. Requirements Service

The Standard Offer Billing Demand in kilowatts for each month is the maximum metered fifteen-minute demand during Peak Hours within the Billing Period.

B. Partial Requirements Service

The Supplementary Demand in kilowatts is the maximum metered fifteen-minute demand recorded during Peak Hours within the Billing Period excluding Backup and Maintenance Billing Periods.

The Backup Demand in kilowatts is the maximum metered fifteen-minute demand recorded during Peak Hours within the Backup Billing Period in excess of the Supplementary Demand.

The Standard Offer Demand in kilowatts for each month shall be the sum of:

1. The Supplementary Demand, and

2. The Backup Demand times the ratio of the number of Backup Billing Period Days to the number of Billing Period Peak Days.

V. Billing Demand Charge

The Billing Demand Charge shall be the Standard Offer Billing Demand times the Demand Rate.

The terms Requirement Service, Partial Requirements Service, Supplementary Service, and Backup Service shall be as defined in Transmission Voltage General Retail Delivery Service Rate C-1.

Large Secondary Voltage Auxiliary
General Retail Delivery Service Rate A-4

Demand Charge:	$4.88	per kW
Energy Charge		
Peak Hours:	$0.05990	per kWh
Off-Peak Hours:	$0.00096	per kWh

The Supplementary Standard Offer Demand Charge shall be the Supplementary Demand times the Demand Charge.

The Backup Usage Demand in kilowatts is the Average Daily Demand in excess of the Supplementary Demand, where the Average Daily Demand is the sum of the daily maximum metered 15 minute average loads recorded during Peak Hours within the Backup Billing Period divided by the number of days in the Backup Billing Period. The Backup Usage Demand Charge shall be the Backup Usage Demand times the Demand Charge times the ratio of the number of Backup Billing Period Days to the number of Billing Period Peak Days. No Backup Usage Demand Charge shall be incurred for planned outages due to Maintenance.

The Billing Demand Charge shall be the sum of the Supplementary Standard Offer Demand Charge and the Backup Usage Demand Charge.

The terms Supplementary Demand, Backup Billing Period, and Billing Period shall be as defined in Large Secondary Voltage Auxiliary General Retail Delivery Service Rate A-4.

The Company agrees to furnish Maintenance Power to the customer at times convenient to the Company. The Contract will specify the customer's expected Maintenance Power requirements, expected frequency and duration of Maintenance Power periods, and the expected calendar schedule of Maintenance Power periods. Said Maintenance Power requirements, frequency, duration, and schedule must be determined by the Company to be reasonable given the design specifications and operating characteristics of the customer's Facility, and such other information the Company considers pertinent to the determination of the appropriate Maintenance Power requirements, frequency, duration, and schedule for the customer. The customer shall make all requests for Maintenance Power in writing at least thirty (30) days prior to a planned outage of the Facility, and the Company will consent to such requests in writing, which consent shall not be unreasonably withheld.

Large Primary Voltage Auxiliary
General Retail Delivery Service Rate A-6

Demand Charge:	$4.40	per kW
Energy Charge		
Peak Hours:	$0.06060	per kWh
Off-Peak Hours:	$0.00241	per kWh

The Supplementary Standard Offer Demand Charge shall be the Supplementary Demand times the Demand Charge.

The Backup Usage Demand in kilowatts is the Average Daily Demand in excess of the Supplementary Demand, where the Average Daily Demand is the sum of the daily maximum metered 15 minute average loads recorded during Peak Hours within the Backup Billing Period divided by the number of days in the Backup Billing Period. The Backup Usage Demand Charge shall be the Backup Usage Demand times the Demand Charge times the ratio of the number of Backup Billing Period Days to the number of Billing Period Peak Days. No Backup Usage Demand Charge shall be incurred for planned outages due to Maintenance.

The Billing Demand Charge shall be the sum of the Supplementary Standard Offer Demand Charge and the Backup Usage Demand Charge.

The terms Supplementary Demand, Backup Billing Period, and Billing Period shall be as defined in Large Primary Voltage Auxiliary General Retail Delivery Service Rate A-6.

The Company agrees to furnish Maintenance Power to the customer at times convenient to the Company. The Contract will specify the customer's expected Maintenance Power requirements, expected frequency and duration of Maintenance Power periods, and the expected calendar schedule of Maintenance Power periods. Said Maintenance Power requirements, frequency, duration, and schedule must be determined by the Company to be reasonable given the design specifications and operating characteristics of the customer's Facility, and such other information the Company considers pertinent to the determination of the appropriate Maintenance Power requirements, frequency, duration, and schedule for the customer. The customer shall make all requests for Maintenance Power in writing at least thirty (30) days prior to a planned outage of the Facility, and the Company will consent to such requests in writing, which consent shall not be unreasonably withheld.

General Space Heating Retail Delivery Service Rate H-1

Energy Charge:	$0.03209	per kWh

General Heating Retail Delivery Service Rate H-2

Energy Charge:	$0.03241	per kWh

Controlled Water Heating Retail Delivery Service Rate W-1

Energy Charge:	$0.03433	per kWh

Lighting Retail Delivery Service Rate S-1

Energy Charge:	$0.03341	per kWh

Time-Of-Use Time Periods for Rates R-4, G-2, T-4, G-5, T-6, A-4, & A-6

Peak Hours
Monday through Friday excluding holidays defined below
May through September, 10:00 a.m. to 4:00 p.m.
October through April, 9:00 a.m. to 12:00 noon, and
5:00 p.m. to 8:00 p.m.

Off-Peak Hours
All other hours.

Holidays are defined as:

New Year's Day	Columbus Day
President's Day	Veteran's Day
Memorial Day	Thanksgiving Day
Independence Day	Christmas Day
Labor Day	

The foregoing Rates shall be adjusted from time to time in accordance with provisions of the Standard Offer Fuel Index and the Standard Offer Cost Adjustment described below:

STANDARD OFFER FUEL INDEX:

The Standard Offer Charge in effect for a billing month is multiplied by a Fuel Adjustment that is set equal to 1.0 unless the Market Gas Price plus Market Oil Price for the billing month exceeds the Fuel Trigger Point then in effect, where:

Market Gas Price is the average of the values of Gas Index for the most recent six months through and including the billing month, where:

Gas Index is the average of the daily settlement prices for the last three days that the NYMEX Contract (as defined below) for the month of delivery trades as reported in the Wall Street Journal, expressed in dollars per MMBTU. NYMEX Contract shall mean the New York Mercantile Exchange Natural Gas Futures Contract as approved by the Commodity Futures Trading Commission for the purchase and sale of natural gas at Henry Hub;

Market Oil Price is the average of the values of Oil Index for the most recent six months through and including the billing month, where:

Oil Index is the average for the month of the daily low quotations for cargo delivery of 1.0% sulfur No. 6 residual fuel oil into New York harbor, as reported in Platt’s Oilgram U.S. Marketscan in dollars per barrel and converted to dollars per MMBTU by dividing by 6.3; and if the indices referred to above should become obsolete or no longer suitable, the distribution company shall file alternate indices with the Department.

Fuel Trigger Point is the following amounts, expressed in dollars per MMBTU, applicable for all months in the specified calendar year:

Year	Fuel Trigger Point
2000	$5.35 per MMBTU
2001	$5.35 per MMBTU
2002	$6.09 per MMBTU
2003	$7.01 per MMBTU
2004	$7.74 per MMBTU

In the event that the Fuel Trigger Point is exceeded, the Fuel Adjustment value for the billing month is determined based according to the following formula:

$$\text{Fuel Adjustment} = \frac{(\text{Market Gas Price}+\$0.60/\text{MMBTU})+(\text{Market Oil Price}+\$0.04/\text{MMBTU})}{\text{Fuel Trigger Point} + \$0.60 + \$0.04/\text{MMBTU}}$$

Where Market Gas Price, Market Oil Price and Fuel Trigger Point are as defined above. The values of $0.60 and $0.04/MMBTU represent for gas and oil respectively, estimated basis differentials or market costs of transportation from the point where the index is calculated to a proxy power plant in the New England market.

Incremental revenues received by the Company from the application of the Fuel Adjustment shall be fully allocated to Standard Offer Suppliers in proportion to the Standard Offer energy provided by a Supplier to the Company in the applicable billing month.

STANDARD OFFER COST ADJUSTMENT:

The following Standard Offer Cost Adjustment shall reflect the difference between the cost of Standard Offer Service paid by the Company to wholesale suppliers thereof and the revenues billed by the Company to Customers taking Standard Offer Service under this Rate Schedule. As used herein "Standard Offer Service costs" shall be those costs incurred by the Company in providing Standard Offer Service under this Rate Schedule including wholesale rate discounts arising from the competitive procurement process and any or all other costs determined by the Public Utilities Commission to be includable therewith, excluding all costs recoverable through the Standard Offer Fuel Index provision.

By March 1 of each year, the Company shall determine the amount of any over- or under-collection for the prior calendar year and make a filing with the Commission. The Company will propose at that time a rate recovery/refund methodology to recover or refund the balance, as appropriate, over the twelve-month period commencing April 1. The Commission may order the Company to collect or refund the balance over any reasonable time period from (i) all customers, (ii) only Standard Offer customers, or (iii) through any other reasonable method.

At the conclusion of the Standard Offer Service period on December 31, 2009, the Company will apply to the Public Utilities Commission for approval of a temporary per kilowatthour surcharge or credit factor to be applied to the distribution component of the Retail Delivery Rates for such a duration as necessary to provide for full recovery or return of any outstanding balance of Standard Offer Service costs or revenues that exists.

BILLING:

The Billing Amount for electric service supplied under this Rate Schedule shall consist of the sum, as applicable, of the Demand Charge and the Energy Charges as adjusted by the Standard Offer Fuel Index and Rhode Island Gross Receipts Tax.

TERM OF CONTRACT:

The Term of Contract for Standard Offer Service shall be for a period beginning on the date service is first taken and ending on the earlier of December 31, 2009, or the date the Customer terminates service. The Customer may terminate service on five (5) days notice. The Customer shall be ineligible to receive Standard Offer Service thereafter. The foregoing provision shall not apply to Customers who receive service under any of the Company’s residential Retail Delivery Service Rates or under Small General Retail Delivery Service Rate G-1. Said Customers may elect to take electric power service from another Supplier during the period beginning June 1, 1998, and ending May 31, 1999, and elect to return to Standard Offer Service within one hundred twenty (120) days of commencing service from that Supplier.

TERMS AND CONDITIONS:

The Company’s Terms and Conditions for Electric Service and Terms and Conditions for Electric Power Suppliers in effect from time to time, where not inconsistent with the specific provisions hereof, are a part of this Rate Schedule.

Attachment 6

Attachment 6

United States District Court – District of Massachusetts
Memorandum and Order on Cross Motions for Summary Judgment

UNITED STATES DISTRICT COURT
DISTRICT OF MASSACHUSETTS

TRANSCANADA POWER MARKETING LTD., **Plaintiff,** **v.** **NARRAGANSETT ELECTRIC COMPANY,** **Defendant.**	)	**Civil Action No. 05-40076-FDS**

MEMORANDUM AND ORDER
ON CROSS MOTIONS FOR SUMMARY JUDGMENT

SAYLOR, J.

This is an action by plaintiff TransCanada Power Marketing Ltd., a wholesale electricity supplier, against Narragansett Electric Company, a retail electric distribution company. Narragansett is a regulated utility that is required to obtain approval from the Rhode Island Public Utilities Commission ("RIPUC") for the retail rates that it charges to consumers. The dispute essentially involves whether a wholesale contract for electric power between the parties required Narranganset (1) to include a fuel adjustment mechanism in its retail rate filings with the RIPUC for the period 2005 to 2009, permitting it to collect higher revenues if fuel costs went up, and thus (2) to pay a higher fuel-adjusted price to TransCanada. Jurisdiction is based on diversity of citizenship.

In substance, this is a declaratory judgment action, as Narragansett has been paying all disputed amounts to TransCanada pending resolution of this matter. The complaint asserts claims for breach of contract (Count 1), contractual indemnification (Count 2), breach of the implied covenant of good faith and fair dealing (Count 3), rescission or reformation of contract (Count 4), declaratory relief (Count 5), and unfair and deceptive acts and practices in violation of Mass. Gen. Laws ch. 93A § 11 (Count 6). Narragansett has filed a counterclaim, asserting claims for breach of contract (Count 1), declaratory relief (Count 2), and breach of the implied covenant of good faith and fair dealing (Count 3).

TransCanada has moved for summary judgment as to Counts 1, 3, and 5 (or, in the alternative, as to Count 4) of the complaint, and as to all three counts of the counterclaim. Narranganset has cross-moved for summary judgment as to Count 2 of the complaint. For the following reasons, summary judgment will be granted in part in favor of TransCanada as to the claims for declaratory relief, granted in favor of Narragansett as to the claim for contractual indemnification, and otherwise denied.

I. Statement of Facts

The following facts are undisputed unless otherwise noted.

A. The URA and Restructuring of the Electric Industry in Rhode Island and Massachusetts

Prior to 1996, electric utility companies in New England were generally vertically integrated monopolies—that is, one utility company controlled (through its affiliate subsidiaries) the generation, transmission, and distribution functions for a given area. Before 1996, essentially only two electric utilities operated in Rhode Island: Eastern Utilities Association ("EUA") and the New England Electric System ("NEES"). EUA's power generation affiliate was Montaup Electric Company, and its retail distribution affiliates were Blackstone Valley Electric Company and Newport Electric Company in Rhode Island and Eastern Edison Company in Massachusetts. NEES's power generation affiliate was New England Power Company ("NEP"), and its retail distribution affiliates were Narragansett Electric Company in Rhode Island and Massachusetts Electric Company in Massachusetts.[1]

The power generation companies (Montaup and NEP) were regulated by the Federal Energy Regulatory Commission ("FERC"). The distribution companies (in Rhode Island, Blackstone, Newport, and Narragansett) were regulated by state public utility commissions (in Rhode Island, the RIPUC).

As regulated entities, the distribution companies are not free to charge their retail customers whatever the market might bear. Instead, they are required make filings with the utility commissions to obtain approval of the rates they intend to charge. In simple terms, the utilities file tariffs, or schedules listing the rates they intend to charge, with the commissions, which may approve, modify, or reject the rates after a hearing. *See* R.I. Gen. Laws § 39-3-10.

The cost of fuel—such as oil and natural gas—is a significant component of the cost of generating power. Before 1996, the retail distribution companies paid their power generation affiliates pursuant to contracts for their fuel costs. In turn, the Rhode Island distribution companies filed retail tariffs with the RIPUC that included fuel-adjustment mechanisms that permitted the companies to charge consumers a higher rate if fuel costs rose beyond certain points.

In 1996, Rhode Island enacted the Utility Restructuring Act (the "URA"), and

[1] NEES supplied power to approximately three-quarters of Rhode Island, and EUA supplied it to most of the remaining quarter.

Massachusetts enacted a similar counterpart. The URA was intended to restructure the utility market in an effort to create a competitive market for power supply and ultimately to provide lower prices to consumers. The URA (and its Massachusetts counterpart) also mandated a transition supply of electricity to consumers called Standard Offer Service ("SOS"). Standard Offer Service was intended to be a guaranteed power supply to consumers who did not elect, or had not yet elected, to obtain their supply from a competitive marketer.

The URA required the retail distribution companies to provide SOS power to retail customers through 2009 and to arrange with wholesale power suppliers to provide the necessary power. R.I. Gen. Laws § 39-1-27.3(d). The URA established a pricing scheme for SOS that allowed the retail distribution companies to charge customers up to a price cap to be determined by a formula. The price cap was determined by (1) a rising stipulated annual price, adjusted upwards for (2) ". . . factors reasonably beyond the control of the electric distribution company and its former wholesale power supplier including but not limited to changes in federal, state or local taxes or extraordinary fuel costs . . . ." *Id.*

In 1997, in order to comply with the URA, the utility holding companies (NEES and EUA) negotiated "Settlement Agreements" with state and federal authorities. Among other things, the Settlement Agreements described public bid processes that the retail distribution companies would use initially to solicit wholesale suppliers for their SOS needs.[2]

B. <u>The WSOSA</u>

[2] In order to ensure a steady supply of power for SOS customers, the Settlement Agreements required the generation companies to provide a guaranteed "backstop" supply of power to the retail distribution companies through 2009 in the event that the latter were unable to obtain such a supply in the wholesale market. Thus, the EUA Settlement Agreement required Montaup to provide a guaranteed supply to Blackstone and Newport. In addition, the EUA Settlement Agreement required Montaup to assign to any purchaser of its generation assets a proportional share of its "backstop" obligation.

In November 1997, EUA and TransCanada began to negotiate an agreement under which TransCanada would purchase certain Montaup power generation assets. As a part of that process, TransCanada and EUA also negotiated a wholesale power supply contract. Eventually, on April 7, 1998, TransCanada and EUA's retail distribution affiliates (Blackstone and Newport) entered into a Wholesale Standard Offer Service Agreement ("WSOSA").[3] Under the WSOSA, TransCanada agreed to supply power to Blackstone and Newport for distribution to their customers for a certain number of years.

The price to be paid to TransCanada for the power supplied under the WSOSA had two components: a "Standard Offer Wholesale Price" and a "Fuel Adjustment Factor." Thus, Article 5 of the WSOSA states as follows:

> For each kilowatt-hour of Delivered Energy that Supplier Provides in each month, . . . the Companies shall pay Supplier the applicable Price for the month in cents per kilowatt-hour calculated as follows:
> Price= Standard Offer Wholesale Price
> + Fuel Adjustment Factor
>
> Where: . . . Fuel Adjustment Factor is a cents per kilowatt-hour adder based on the incremental revenues collected, if any, attributed to the retail Rate Fuel mechanism in the Companies' Standard Offer Service tariffs. The incremental revenues attributed to the retail Fuel Adjustment will be fully allocated to Suppliers in proportion to the Standard Offer Service energy provided by each Supplier for the applicable billing month through the Fuel Adjustment Factor. The retail Fuel Adjustment, and the resulting Fuel Adjustment Factor to be paid to Supplier, will be made subject to regulatory approval and only to the extent that the Companies are allowed to collect such revenues from their retail customers taking Standard Offer Service.

[3] EUA's Massachusetts retail distribution affiliate, Eastern Edison, was also a party to the agreement.

No further mention of the Fuel Adjustment Factor is made in the WSOSA.[4]

As noted, Narragansett contends that any obligation it may have had to file Standard Offer Service rates with a fuel adjustment mechanism, and thus to pay a higher fuel-adjusted price to TransCanada, expired in 2004. The WSOSA states that the "term of this agreement shall begin on the Commencement Date of Service and end at 12:00 midnight on December 31, 2009, unless terminated sooner . . . ." The only specific mention of the year 2004 in the WSOSA is set forth in Appendix A, where (1) Standard Offer Wholesale Prices are listed for every year from 1999-2009, including 2004, and (2) a footnote states that "Standard Offer Service for Eastern Edison [i.e., in Massachusetts] terminates at 12:00 midnight on December 31, 2004."

The WSOSA contains an integration clause. *See* Art. 19(d) ("This Agreement shall constitute the entire understanding between the Parties and shall supersede all prior correspondence and understandings pertaining to the subject matter of this Agreement").

C. <u>The Narragansett Merger</u>

In March 2000, Blackstone and Newport were merged into Narragansett. As a result, Narragansett assumed the obligations of Blackstone and Newport under the WSOSA.

In April 2000, Narragansett's power supply manager informed TransCanada via letter of the merger. The letter stated that

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[4] Article 8(3) of the WSOSA, also at issue in this case, states:

> In the event that the Standard Offer Service or the Terms and Conditions for Suppliers are terminated, amended or replaced by any governmental or regulatory agency having jurisdiction over the provision of Standard Offer Service in a manner which materially increases costs or obligations to provide Standard Offer Service, the Companies shall promptly reimburse Supplier for any such costs or increased obligations or otherwise provide relief reasonably acceptably to supplier to or indemnify the Supplier from such changes . . . .

Id.

> [Narragansett] will assume the obligations of the former EUA subsidiaries pursuant to Article 11 of the [WSOSA]. . . . The obligations of the parties or their successors and the terms of the [WSOSA] are not affected by the merger and assignments. The following actions will be taken in order to continue to facilitate the administration of the [WSOSA]. These actions are not intended and in no way constitute nor should be deemed to constitute a modification of the terms of the [WSOSA].

It went on to state:

> **2. Application of the Fuel Adjustment Factor**. Article 5 of the [WSOSA] entitles [TransCanada] to receive additional monies based on revenues collected from retail customers pursuant to Fuel Adjustment mechanisms [contained] in . . . Blackstone's and Newport's Standard Offer Service tariffs. . . . Narragansett will continue to make such Fuel Adjustment payments, if applicable, according to Attachment 2. Attachment 2 replaces the retail fuel adjustment mechanisms contained in the EUA Companies' respective Standard Offer Service tariffs. Said payments will be made by . . . Narragansett in the month immediately following service.

Attachment 2 was a "standard offer fuel adjustment provision" sheet that listed fuel trigger points and fuel adjustment values for the years 2000-2004. Attachment 2 did not set forth a fuel adjustment provision for the years 2005-2009.

D. <u>Activities of TransCanada and Narragansett between 2000 and 2004</u>

It is undisputed that Blackstone and Newport, and their successor Narragansett, filed tariffs with the RIPUC that included a fuel adjustment mechanism in their Standard Offer Service rates for the years 1999 to 2004. It is also undisputed that the companies received higher revenues from retail customers as a result, and that during those years they paid a higher fuel-adjusted price to TransCanada pursuant to the "Fuel Adjustment Factor" component of the contract pricing formula.

As noted, this dispute concerns whether Narragansett was required to do the same from 2005 to 2009. Narragansett contends that it has consistently taken the position, before the

RIPUC and elsewhere, that the Fuel Adjustment Factor component of the price expired in 2004.[5] TransCanada contends that Narragansett initially took the position that the Fuel Adjustment Factor was in operation through 2009, and that it subsequently changed its position. TransCanada also contends that Narragansett witnesses, in public proceedings before the RIPUC, made false statements about what TransCanada had been told. As a result, TransCanada contends that from 2000 to 2005, Narragansett engaged in "improper and misleading conduct" as to its interpretation of the contract.

E. <u>Activities of TransCanada and Narragansett from 2005 to Present</u>

Narragansett did not request a fuel adjustment mechanism in the Standard Offer Service tariff that it filed with RIPUC for January 2005, and the retail rates as approved did not contain such a mechanism. The payment to TransCanada in February 2005 therefore included only the Standard Offer Wholesale Price, without additional payments based on the Fuel Adjustment Factor.

TransCanada objected in writing on March 1, 2005, stating that it was providing "notice of default under Article 7(1)(b) of the [WSOSA], based upon [Narragansett's] failure to comply with Article V of the [WSOSA]."[6] The letter stated that Narragansett had thirty days to cure or

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[5] Narragansett contends that during the post-merger integration period, its employees reviewed past tariff filings and concluded that the Fuel Adjustment Factor obligation terminated in 2004. Narragansett also contends that EUA representatives advised it that the FAF was payable only until 2004 and was not applicable in subsequent years of the contract.

[6] Article 7(1)(b) provides as follows:

> (1) Unless excused . . . each of the following events shall be deemed to be an Event of Default hereunder:
>
> . . .
>
> (b) Failure of the Companies, in a material respect, to comply with, observe, or

rectify the default.

In order to forestall a disruption in power supply to its customers, Narragansett agreed on March 31, 2005, to pay under protest all amounts to which TransCanada claimed it was entitled, subject to refund if it prevails in this litigation. Narranganset's protest payments have since been included in the approved rates charged by Narragansett to consumers, again subject to refund. TransCanada commenced this action in May 2005.[7]

II. Analysis

Summary judgment is appropriate when "the pleadings, depositions, answers to interrogatories, and admissions on file, together with the affidavits, if any, show that there is no genuine issue of material fact and that the moving party is entitled to a judgment as a matter of law." Fed. R. Civ. P. 56(c). A genuine issue is "one that must be decided at trial because the evidence, viewed in the light most flattering to the nonmovant . . . would permit a rational fact finder to resolve the issue in favor of either party." *Medina-Munoz v. R.J. Reynolds Tobacco Co.*, 896 F.2d 5, 8 (1st Cir. 1990).

In substance, TransCanada contends that the WSOSA unambiguously requires Narragansett to file Standard Offer Service rates that include a fuel adjustment mechanism, and, if approved, to pay a higher fuel-adjusted price to TransCanada, and to do so through 2009. In

> perform any covenant, warranty or obligation under this Agreement, and such failure is not cured or rectified within thirty (30) days after notice thereof from the Supplier.

[7] Article 12 of the WSOSA contains dispute resolution provisions applicable to "all disputes between the Companies and Supplier resulting from or arising out of performance under this Agreement," other than certain disputes arising out of an Event of Default. The dispute resolution section, in substance, requires mandatory settlement discussions and provides that any dispute that cannot be resolved "may" be submitted to arbitration. Neither party has argued that Article 12 has been violated, or that the present dispute is subject to mandatory arbitration.

support (and opposition) to the motions for summary judgment, the parties have submitted thousands of pages of depositions, declarations, regulatory filings, and internal corporate documents. The text of the contract itself, however, disposes of most of the issues in this dispute.

A. <u>General Principles of Contract Interpretation</u>

Under Massachusetts law, interpretation of a contract is ordinarily a question of law for the court. *Edmonds v. United States*, 642 F.2d 877, 881 (1st Cir. 1981); *accord Fairfield 274-278 Clarendon Trust v. Dwek*, 970 F.2d 990, 993 (1st Cir. 1992).[8] Where the wording of the contract is unambiguous, it must be enforced according to its terms. *Id.* A triable issue of fact exists only if the contract is ambiguous. Evidence of prior or contemporaneous oral agreements cannot be considered to vary or modify the terms of an unambiguous, integrated contract. *Fairfield*, 970 F.2d at 993, *citing New England Financial Resources v. Coulouras*, 30 Mass. App. Ct. 140, 145 (1991).

B. <u>The Language of the Contract</u>

1. <u>Narragansett's Obligation to File Retail Rates Generally</u>

Article 5 of the WSOSA describes the price to be paid by Narragansett to TransCanada for wholesale power. That price has two components: a "Standard Offer Wholesale Price" and a "Fuel Adjustment Factor." The Fuel Adjustment Factor is defined as "a cents per kilowatt-hour adder based on the incremental revenues collected, if any, attributed to the retail Rate Fuel mechanism in the Companies' Standard Offer Service tariffs." The WSOSA further states that

[8] The WSOSA states that "the interpretation and performance" of the agreement is governed by Massachusetts law. (WSOSA Art. 13).

"The retail Fuel Adjustment, and the resulting Fuel Adjustment Factor to be paid to Supplier, will be made subject to regulatory approval and only to the extent that the Companies are allowed to collect such revenues from their retail customers taking Standard Offer Service." It is thus clear that Narragansett has the obligation to pay some portion of any higher revenues received through a retail rate fuel adjustment mechanism. Before turning to the issue of the duration of Narragansett's obligation—that is, whether that obligation existed after 2004—it is useful to consider whether Narragansett is obliged to file *any* such retail rates with the RIPUC.

The WSOSA, somewhat surprisingly, contains no express term requiring Narragansett to file retail rates containing a fuel-adjustment component. Indeed, it contains no express term requiring Narragansett to file retail rates at all. Normally, such an omission might create an ambiguity, permitting the Court to consider parol evidence to ascertain the parties' intentions. Here, however, it is clear that there is only one possible reasonable interpretation, and there is thus no ambiguity that must be resolved.

First, Narragansett's obligation to file retail rates is necessarily implicit in the contract. As a regulated utility, Narragansett essentially has one principal source of revenue: the payments that it receives from its retail customers. If it did not make filings seeking approval of retail rates, it could not stay in business, much less pay TransCanada its contractual obligations for wholesale power. Put simply, the contract would make no sense if Narragansett simply had the option to file retail rates. It is thus implicit in the contract that Narragansett will make the necessary filings with the RIPUC to charge retail rates to its customers.

Second, it is well-established that when a contractual payment depends on one party's application for government approval, that party has an obligation to make the necessary applications in a reasonable effort to obtain the required approval. *See, e.g.*, *Sechrest v. Safiol*, 383 Mass. 568, 569-72 n.4 (1981) (where a party's obligation to purchase real estate was conditioned upon "obtaining from the proper public authorities all permits and other approvals reasonably necessary," "[n]ecessarily implied in the provision is an obligation to use reasonable efforts to obtain town approval"); *Stabile v. McCarthy*, 336 Mass. 399, 402-04 (1957) (where a party had an option to cancel a contract for purchase of real estate "in the event that he shall have been unable to obtain the approval of the [town planning board]," he was required to use reasonable efforts to obtain board approval).[9]

Third, if Narragansett elected for some reason not to file retail rates with the RIPUC, that would almost certainly have violated the implied covenant of good faith and fair dealing. The covenant provides that "neither party shall do anything that will have the effect of destroying or injuring the rights of the other party to receive the fruits of the contract." *Speakman v. Allmerica Financial Life Ins.*, 367 F. Supp. 2d 122 (D. Mass. 2005); *Anthony's Pier Four, Inc. v. HBC Associates*, 411 Mass. 451, 471 (1991). "[T]he purpose of the covenant is to guarantee that the parties remain faithful to the intended and agreed expectations of the parties in their performance." *Uno Restaurants*, 441 Mass. 376, 385 (2004). If Narragansett for some reason deliberately failed to file tariffs with retail rates sufficient to fulfill its obligations to TransCanada, it would have obviously destroyed the right of TransCanada to receive the fruits of the contract. *See Seaward Constr. Co. v. City of Rochester*, 118 N.H. 128, 383 A.2d 707 (1978) (where payment by city to a contractor was dependent on receipt of HUD funds from the federal

[9] It is unclear whether the obligation derives from the implied covenant of good faith and fair dealing or whether it exists as a separate doctrine of Massachusetts contract law. The difference, if any, is not material here.

government, "the city was under an obligation under the implied covenant of good faith and fair dealing to make a good-faith effort to obtain funds from HUD to pay the [contractor].").

The next question is whether—again putting to one side the issue of the duration of its contractual obligations—Narragansett's implied obligation to file retail rates included an obligation to file retail rates containing a fuel-adjustment component. Put another way, if Narragansett had an implied obligation to file retail rates as to the "Standard Offer Wholesale Price" component of the contract price, did it also have an implied obligation to file retail rates as to the "Fuel Adjustment Factor" component?

There is nothing in the contract to suggest that Narragansett's implied obligation to file rates as to one price component should be any different than its implied obligation to file rates as to the other. Both are treated essentially the same under Article 5; accordingly, if Narragansett had an implied obligation to file as to one, it necessarily had the same obligation to file as to the other.

The fact that the WSOSA uses the phrase "if any" to modify the phrase "incremental revenues collected" does not require a different result. The phrase "if any" is directed to the various contingencies upon which any additional revenues would depend, including the fact that the fuel adjustment mechanism (and thus the "Fuel Adjustment Factor") is triggered only under certain circumstances. Significantly, the phrase "if any" is placed after "incremental revenues collected," not "retail Rate Fuel mechanism," suggesting that the parties expected such a mechanism to be present in all the Standard Offer Service retail rates. Similarly, the fact that the "retail Fuel Adjustment, and the resulting Fuel Adjustment Factor to be paid to Supplier," was made "subject to regulatory approval" and "only to the extent" that Narragansett is "allowed to collect such revenues from [its] retail customers," in no way suggests that the filing of retail rates with a fuel-adjustment mechanism was entirely optional.

Finally, although the parol evidence is not necessary to resolve the issue, clearly Narragansett and its predecessors acted at all times as if the contract created an obligation to seek retail rates with a fuel adjustment mechanism between 1999 and 2004. During that period, Narragansett filed tariffs containing such rates, and it paid a higher price to TransCanada, calculating that price according to the Fuel Adjustment Factor set forth in the contract. Indeed, Narragansett seems to concede that between 1999 and 2004 it was obligated to file rates with a fuel-adjustment mechanism, and to make higher fuel-adjusted payments as a result.

Accordingly, Narragansett was obligated, at a minimum, to file tariffs with the RIPUC that included a fuel-adjustment mechanism, and to pay a price under the WSOSA that included the Fuel Adjustment Factor component, through December 31, 2004. The question then becomes whether Narragansett's obligation ended in 2004, or whether it extends through the end of 2009. Put another way, if the contract imposed that obligation for the first five years, is there any reason to conclude that it did not do so for the last five years?

2. <u>The Duration of the FAF Obligation</u>

Article 2 of the WSOSA states that the contract expires on December 31, 2009, unless terminated sooner because of a party's default. As noted, Article 5 sets forth two components of the contract price: the Standard Offer Wholesale Price plus a Fuel Adjustment Factor. Nothing in Article 5 states or suggests that the duration of one price component is shorter or longer than the other. Nothing in any other article of the contract states or suggests anything to the contrary. The obvious conclusion is that the contract imposes the same obligations on Narragansett, at least as to its service in Rhode Island, in 2005-2009 as it did in 1999-2004.

That conclusion is strongly underscored by Appendix A, which states that "Standard Offer Service for Eastern Edison [i.e., in Massachusetts] terminates at 12:00 midnight on December 31, 2004." Again, no such temporal limitation appears in Article 5, or indeed anywhere else in the contract. The parties obviously know how to draft language terminating a contractual obligation in 2004 when they intended such a result.[10]

Put simply, there is *no* indication *anywhere* in the contract that Narragansett's obligations as to the Fuel Adjustment Factor expire in 2004. The contract is an unambiguous, integrated agreement, negotiated and executed by sophisticated corporate entities. If the parties intended that Narragansett's obligations were to change in 2004, it would have been simple enough to say so. The parties elected not to. Accordingly, those obligations—like all of Narragansett's obligations under the contract, other than Standard Offer Service for Eastern Edison—remain in place until December 31, 2009.[11]

This Court's determination that the WSOSA is unambiguous renders most of the evidentiary record irrelevant. Narragansett argues vigorously that (1) EUA's settlement agreement with Rhode Island, and the November 1997 tariff filing with RIPUC, described SOS

[10] Narragansett notes that the EUA settlement agreement (to which TransCanada was not a party) contemplated standard offer pricing to retail customers through 2009, but a fuel adjustment mechanism only through 2004. The settlement agreement, however, neither expressly requires nor prohibits a fuel adjustment mechanism between 2005 and 2009. More importantly, even if the settlement agreement is taken as a contemporaneous expression of EUA's intentions when negotiating the WSOSA, it cannot be considered to vary or contradict the terms of an unambiguous and integrated contract.

[11] Narragansett further contends that Article 5 is ambiguous because it does not specify the mechanism or the "trigger points" to be used in calculating and applying the FAF. Even if true—and the Court expresses no opinion on the subject—any such ambiguity is not relevant to the issue whether the contractual obligation expires in 2004 or 2009.

through 2009 but a FAF only through 2004; (2) various EUA representatives intended that the FAF would continue only through 2004; and (3) EUA consistently understood that the FAF would expire in 2004. TransCanada argues vigorously to the contrary that EUA and Narragansett took inconsistent and misleading positions throughout the relevant period.

These disputes are irrelevant. Again, the contract is integrated and unambiguous. The intentions and understandings of the parties prior to or at the time of the execution of the contract may not be considered to vary its terms. *See Hallmark Institute of Photography, Inc. v. Collegebound Network, LLC*, 518 F. Supp. 2d 328, 331 (D. Mass. 2007); *ITT Corp v. LTX Corp.*, 926 F.2d 1258, 1261-1262 (1st Cir. 1991).

C. Whether the Contract Was Subsequently Modified

Evidence of the actions of the parties after execution of the contract may, however, be relevant to show a modification, whether written or oral, of an integrated agreement. *John Beaudette, Inc. v. Sentry Ins.*, 94 F. Supp. 2d 77, 139 (D. Mass. 1999) (citing *Cambridgeport Sav. Bk. v. Boersner*, 413 Mass. 432, 439 (1992)). Mutual agreement on modification may "be inferred from the conduct of the parties and from the attendant circumstances." *Cambridgeport*, 413 Mass. at 439 (*citing First Pa. Mortgage Trust v. Dorchester Sav. Bank*, 395 Mass. 614, 625 (1985)).

There is considerable disagreement between the parties as to whether Narragansett made known its interpretation of the contract, and whether TransCanada had "notice" of that interpretation of the contract, during the period between 2000 and 2004. Narragansett does not, however, allege that TransCanada ever *assented* to that interpretation, either orally or through a written instrument, nor has it alleged that any subsequent modification was supported by valid consideration. *See John Beaudette*, 94 F. Supp. 2d at 139. Indeed, Narragansett does not even assert a theory of subsequent modification, contending instead that the original contract provided a 2004 expiration date for the FAF. *See Cambridgeport*, 413 Mass. at 440 (finding it "significant" in rejecting the theory of subsequent modification that defendants did not assert a subsequent agreement had been negotiated). Accordingly, any evidence concerning any party's understandings, intentions, or positions after execution of the contract do not create a genuine issue of material fact as to its terms.

In short, the contract unambiguously requires Narragansett to file Rhode Island Standard Offer Service tariffs with a fuel-adjustment mechanism through the full term of the contract, and to make higher payments to TransCanada as a result. Accordingly, TransCanada's notice on March 1, 2005, that it expected Fuel Adjustment Factor payments through 2009, and its subsequent position that it would exercise its contractual right to terminate the contract if FAF payments were not received, were entirely consistent with the terms of the contract.

D. <u>Whether Narragansett Breached the Contract</u>

The conclusion that Narragansett's interpretation of the contract is erroneous does not compel the conclusion that Narragansett is in material breach. The essential elements of a contract claim are "(1) an agreement, express or implied, in writing or oral, (2) for a valid consideration, (3) performance or its equivalent by the plaintiff *and breach by the defendant*, and (4) damage to the plaintiff." *Mass. Cash Register, Inc. v. Comtrex Systems Corp.*, 901 F. Supp. 404, 415 (D. Mass. 1995) (emphasis added).

As noted, Narragansett has made payment of the disputed amounts under protest. Article 7 of the WSOSA provides that an "Event of Default" occurs when there is a "[f]ailure of

[Narragansett], in a material respect, to comply with, observe, or perform any covenant, warranty or obligation under this Agreement, *and* such failure is not cured or rectified within thirty days (30) days after notice thereof from Supplier." (emphasis added).[12]

It is undisputed that TransCanada first gave notice to Narragansett of the alleged default on March 1, 2005. That notice specifically referred to the thirty-day cure or rectification requirement of the WSOSA. The first "protest payment" made to TransCanada was made on March 31, 2005. That payment was within the contract's thirty-day period for cure or rectification of alleged default. These payments have continued to the present day, and TransCanada has not alleged any deficiency as to their amount or timeliness.

In short, TransCanada has received every payment, and every other material benefit, that it contends that it is entitled to by contract. Accordingly, Narragansett has not breached the WSOSA.

E. <u>Whether Either Party Breached the Implied Covenant of Good Faith and Fair Dealing</u>

Both parties have asserted claims for breach of the implied covenant of good faith and fair dealing implicit in every contract. A party may breach the implied covenant without breaching any express term of the contract. *Speakman*, 367 F. Supp. 2d at 132 (citing *Fortune v. National Cash Register Co.*, 373 Mass 96, 101, 105 (1977)). The essential inquiry is whether "the challenged conduct conformed to the parties' reasonable understanding of performance obligations, as reflected in the overall spirit of the bargain, not whether the defendant abided by

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[12] The contract also provides that if Narragansett commits any "Event of Default," TransCanada may unconditionally terminate the contract upon sixty days written notice. TransCanada never obtained the contractual right to provide sixty-day notice of termination.

the letter of the contract in the course of performance." *Speakman*, 367 F. Supp. 2d at 132 (citing *Larson v. Larson*, 37 Mass. App. Ct. 106, 110 (1994)).

1. <u>Whether TransCanada Breached the Implied Covenant</u>

Narragansett contends that TransCanada violated the implied covenant because it (1) "failed to object" to Narragansett's stated intention to not pay a FAF after 2004, (2) did not notify Narragansett that it expected to receive FAF payments from 2005-2009 until March 2005, and (3) [threatened] to terminate the WSOSA "as a pretext to avoid a contract that had become economically disadvantageous."

It is apparently undisputed that TransCanada did not object, formally or informally, to Narragansett's interpretation of the contract until March 2005.[13] Even if the Court credits Narragansett's contention that TransCanada had "notice" of its interpretation at some point between 2000 and 2004, none of TransCanada's subsequent acts or omissions rise to the level of a breach of the implied covenant of good faith and fair dealing.

The implied covenant does not apply when a party "has exercised an express contractual power in good faith." *Speakman*, 367 F. Supp. 2d at 132. Furthermore, the covenant may not be invoked to create rights and duties not contemplated by the provisions of the contract or the contractual relationship. *Uno Restaurants*, 441 Mass. at 385.

Here, the contract contains no explicit or implicit requirement that TransCanada "object" every time Narragansett expresses an opinion about the contract with which it disagrees. Furthermore, the March 2005 notice to Narragansett was expressly permitted under the

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[13] TransCanada disputes, however, whether it was notified prior to March 2005of Narragansett's interpretation.

contract—the contract provides that TransCanada was to give notice after the occurrence of an event of default, so that Narragansett would have an opportunity to cure or rectify. TransCanada's statement that it would exercise its unconditional contract termination right if FAF payments were not resumed was similarly proper and did not violate the implied covenant.

2. Whether Narragansett Breached the Implied Covenant

TransCanada, for its part, contends that defendant has breached the implied covenant of good faith and fair dealing through a variety of misleading actions and representations. Its argument, however, is essentially an alternative argument: "[t]o the extent EUA (or Narragansett) maintained discretion under the Agreement as to whether to file a fuel adjustment in its Standard Offer Service tariffs through 2009, it was obligated to exercise that discretion consistent with the expectations of the contracting parties." (Pl. Mem. at 23). Because the Court has ruled that the contract in fact required Narragansett to make such a filing, TransCanada's claim for breach of the implied covenant is essentially moot.

F. Indemnification

Narranganset has moved for summary judgment in its favor as to Count 2 of the complaint. Count 2 alleges that Narranganset will be contractually obligated to indemnify TransCanada in the event of action by a "government or regulatory agency . . . which materially increases [TransCanada's] *costs or obligations* to provide Standard Offer Service" to Narranganset. TransCanada contends that Narranganset's failure to file rates with a fuel-adjustment mechanism after 2004 (and thus, the failure of Narranganset to remit FAF payments to TransCanada) materially increases its "costs and obligations" under the WSOSA. TransCanada further contends that its "obligations" to provide Standard Offer Service increase in the absence of a FAF, as it "is then obliged to cover on its own its higher supply costs due to extraordinary fuel costs."

The crux of TransCanada's argument is that because its *profits* may decrease, or because its *revenue* may decrease, it will suffer increased costs or obligations. An increase in "costs and obligations" is obviously not the same as a decrease in "profits" or "revenue." To conflate costs and obligations with reduced revenues or profit would run counter to elementary bookkeeping and accounting concepts. Furthermore, and in any event, TransCanada's fuel costs are determined by market forces, not by the action of any "government or regulatory agency." Accordingly, summary judgment will be granted in favor of Narragansett as to Count 2 of the complaint.

G. <u>Rescission or Reformation</u>

TransCanada alternatively seeks rescission or reformation of the contract on grounds of unilateral mistake. Because the WSOSA unambiguously requires Narragansett to make FAF payments through 2009, no rescission or reformation of the contract is necessary. Accordingly, the motion for summary judgment by TransCanada as to Count 4 will be denied.

H. <u>Declaratory Relief</u>

TransCanada requests declaratory judgment stating that (1) Narragansett breached the terms of the WSOSA, (2) Narragansett failed to cure that breach, (3) TransCanada had the unconditional right to terminate the WSOSA upon the breach, and (4) TransCanada is entitled to damages. Narragansett requests declaratory judgment stating that TransCanada had no right to terminate the WSOSA. The Court has determined that although the WSOSA unambiguously requires the filing of fuel-adjusted rates and payment of the FAF through 2009, Narragansett never actually breached the contract and TransCanada therefore never had the right to terminate.

The Court may declare the rights and other legal relations of parties seeking declaratory judgment "whether or not further relief is or could be sought." 28 U.S.C. § 2201. The Court will grant summary judgment in part to TransCanada as to both declaratory judgment claims, but in a form to be determined consistent with this opinion, and not as to the specific declaratory relief sought.

III. <u>Conclusion</u>

For the foregoing reasons,

1. the motion of plaintiff TransCanada Power Marketing Ltd. for summary judgment is
   a. DENIED as to Counts 1 (breach of contract), 3 (breach of the implied covenant of good faith and fair dealing), and 4 (rescission or reformation of contract) of the complaint;
   b. GRANTED in part as to Count 5 (declaratory relief) of the complaint;
   c. GRANTED as to Counts 1 (breach of contract) and 3 (breach of the implied covenant of good faith and fair dealing) of the counterclaim; and
   d. GRANTED in part as to Count 2 (declaratory relief) of the counterclaim; and
2. the motion of defendant Narragansett Electric Company for summary judgment as to Count 2 (contractual indemnification) of the complaint is GRANTED.

So Ordered.

/s/ F. Dennis Saylor
F. Dennis Saylor IV
United States District Judge

Dated: March 26, 2008

Attachment 7

The Narragansett Electric Company
d/b/a/ National Grid
R.I.P.U.C. Docket No. ____

Attachment 7

2007 ISO-NE Energy Markets Report

2007 Annual Markets Report

June 6, 2008

Preface

The Internal Market Monitoring Unit (INTMMU) of ISO New England (ISO) annually publishes an Annual Market Report that assesses the state of competition in the wholesale electricity markets operated by the ISO. The *2007 Annual Markets Report* covers the ISO's most recent operating year, January 1 to December 31, 2007, including 2008 results associated with some key developments in 2007. The report addresses the development, operation, and performance of the wholesale electricity markets administered by the ISO and presents an assessment of each market based on market data, performance criteria, and independent studies.

This report fulfills the requirement of Market Rule 1, Section 11.3, Appendix A, *Market Monitoring, Reporting, and Market Power Mitigation*:

> The INTMMU will present an annual review of the operations of the New England markets, which will include an evaluation of the procedures for the determination of energy, reserve and regulation clearing prices, NCPC [Net Commitment-Period Compensation] costs, and the performance of the Forward Capacity Market and FTR [Financial Transmission Rights] auctions. The review will include a public forum to discuss the performance of the New England markets, the state of competition, and the ISO's priorities for the coming year. [1]

The INTMMU submits this report simultaneously to the ISO and United States Federal Energy Regulatory Commission (FERC) per FERC order:

> The Commission has the statutory responsibility to ensure that public utilities selling in competitive bulk power markets do not engage in market power abuse and also to ensure that markets within the Commission's jurisdiction are free of design flaws and market power abuse. To that end, the Commission will expect to receive the reports and analyses of an RTO's [Regional Transmission Organization's] market monitor at the same time they are submitted to the RTO.[2]

The Independent Market Monitoring Unit (IMMU) also publishes an annual assessment of the ISO New England electricity markets. The IMMU is external to the ISO and reports directly to the board of directors. This IMMU's report assesses the design and operation of the markets and the competitive conduct of the market participants.

[1] FERC. Electric Tariff No. 3, Section III, Market Rule 1, *Standard Market Design, Appendix A: Market Monitoring, Reporting and Market Power Mitigation*, III.A.11—Reporting (effective July 1, 2005).

[2] PJM Interconnection, L.L.C. et al., *Order Provisionally Granting RTO Status*, Docket No. RT01-2-000, 96 FERC ¶ 61, 061 (July 12, 2001).

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Section 1
Summary of the
2007 Annual Markets Report

Created in 1997, ISO New England (ISO) is the not-for-profit corporation responsible for three main functions:

- Day-to-day operation of New England's bulk power generation and transmission system
- Oversight and administration of the region's wholesale electricity markets
- Management of a comprehensive regional bulk power system planning process

Since February 1, 2005, the ISO has operated as a Regional Transmission Organization (RTO), assuming broader authority over the daily operation of the region's transmission system and possessing greater independence to manage the region's bulk electric power system and competitive wholesale electricity markets. The ISO operates the Day-Ahead and Real-Time Energy Markets, the Forward Capacity Market (FCM), the Regulation Market, the reserve markets, and the annual and monthly auctions of Financial Transmission Rights (FTRs). Figure 1-1 shows key facts about New England's power system and electricity markets.

- 6.5 million households and businesses; population 14 million
- Over 8,000 miles of high-voltage transmission lines
- 13 interconnections to electricity systems in New York and Canada
- More than 32,000 megawatts (MW) of total supply (includes 1,693 MW of demand-resource capacity)
- All-time peak demand of 28,130 MW, set on August 2, 2006
- More than 300 participants in the marketplace (those who generate, buy, sell, transport, and use wholesale electricity)
- $10 billion annual total energy market value (2007)
- More than $1.0 billion in transmission investment made for reliability since 2002; another $4.0 to $7.0 billion planned over the next 10 years
- Approximately $1.0 to $2.0 billion of economic transmission investment to enable renewable resources under study
- Five major 345-kilovolt projects already in various stages of construction and operation

Figure 1-1: Key facts about New England's bulk electric power system and wholesale electricity markets.

This report highlights the state of New England's wholesale electricity markets, presents specific 2007 results, discusses ongoing efforts to improve market performance, and recommends ways to address additional issues facing the region.

Sections 2 to 5 assess the energy, capacity, reserve, and regulation markets. Section 6 assesses reliability costs. The Financial Transmission Rights market and its outcomes are covered in Section 7, and Section 8 evaluates the ISO's demand resources and programs.[3] Sections 9 and 10 highlight market oversight and analysis activities and internal ISO market operations assessments.

Appendices A through C provide supplemental materials. Appendix A provides electricity market statistics at the zonal and monthly levels and additional details of the all-in wholesale electricity cost metric. Appendix B includes offer curves for the Forward Reserve Market. Appendix C provides supplemental cost components of the ISO's *Self-Funding Tariff* and the *Open Access Transmission Tariff* (OATT) and additional data on transmission congestion revenues.[4]

1.1 Key Developments of 2007

The New England wholesale electricity markets continued to perform competitively in 2007, responding to changing supply and demand conditions while supporting reliable grid operations. Several particularly noteworthy developments in 2007 are as follows:

- The Forward Capacity Market, successfully introduced in 2007/2008, improved investment incentives for electric energy supply and demand resources.
- Transmission investment improved the ability to import power into the Norwalk/Stamford area (the southwestern corner of Connecticut) and Boston.
- The region experienced several disruptions to natural gas delivery during 2007 and early 2008 that affected electricity reliability and pricing. The region remains vulnerable to disruptions in the gas infrastructure.

1.1.1 Capacity Investment

By providing long-term investment incentives for supply and demand resources, the Forward Capacity Market complements the existing short-term markets, thus completing the basic structure of the New England wholesale markets. For the FCM, the ISO projects the capacity needs of the power system approximately three years in advance, which allows time for new resources to be built. Through an annual Forward Capacity Auction (FCA), enough qualified resources are purchased to satisfy the region's future needs. The critical task of qualifying resources and potential new projects for participation in the first FCA was completed during 2007. The first auction, covering resources for the 2010/2011 capability year (for June 2010 delivery), concluded successfully on February 6, 2008.[5] As part of the Settlement Agreement approving the FCM, capacity transition payments also were

[3] In the New England Control Area, *demand resources* are installed measures (i.e., products, equipment, systems, services, practices, and strategies) that result in additional and verifiable reductions in end-use demand on the electricity network during specific performance hours. In electricity markets, demand-resource programs allow participants to modify their electric energy consumption in exchange for payments based on wholesale market prices.

[4] The ISO operates under several FERC tariffs, including the *ISO New England Transmission, Markets, and Services Tariff* (Transmission Tariff) (2005), a part of which is the *Open Access Transmission Tariff* (OATT), and the *Self-Funding Tariff*. These documents are available online at http://www.iso-ne.com/regulatory/tariff/index.html.

[5] A capability year is a one-year period beginning June 1 of one year and ending May 31 of the following year.

approved for all installed capacity (ICAP). The payments began in December 2006 and will continue until May 2010.[6]

1.1.2 Transmission Investment

Increased transmission capacity helps power move more freely throughout the system, thereby improving competition and reducing the overall cost of the generation needed to meet the bulk power system's total loads. In 2007, major progress was made on projects to strengthen the transmission system. In Connecticut, Phase 1 of the Southwest Connecticut (SWCT) 345-kilovolt (kV) Reliability Project was completed, expanding transmission in the Norwalk/Stamford area. The completion of Phase 1 improved reliability and helped equalize the energy price in Norwalk/Stamford with that in the rest of Connecticut and at the Hub.[7] Phase 2 is scheduled to be completed no later than December 2009 and will improve flow between SWCT and the rest of Connecticut. Transmission improvements in the Boston area, which increased the Boston import limit from 3,600 megawatts (MW) to a range of 4,500 MW to 4,800 MW, also helped improve regional reliability.

Transmission improvements also reduce the need for cost-of-service Reliability Agreement contracts with individual generators in certain load pockets, which are more expensive than competitive resources outside those load pockets.[8,9] These payments to individual generators in load pockets cannot be hedged and are not subject to competition.

1.1.3 Natural Gas Infrastructure

In 2007, New England electricity markets demonstrated their vulnerability to disruptions in the natural gas infrastructure. Natural-gas-fueled resources, including dual-fueled units, generated 42% of New England's electricity in 2007. On December 1, 2007, two major generators in Maine were lost because of a mechanical failure at the Sable Island production fields (offshore Nova Scotia). The losses led to a suspension of gas delivery and caused approximately 1,200 MW of generator reductions in Maine. The supply reductions, in combination with higher-than-forecast loads, led to the implementation of ISO Operating Procedure 4 (OP 4), *Action during a Capacity Deficiency*.[10]

As a result of the event of December 1–2, the gas pipeline companies significantly improved communications with the ISO. Although six similar events occurred afterward—between December 2007 and March 2008—none required the implementation of OP 4. In five of these six events, timely communication allowed the ISO to commit additional oil units to prevent a capacity deficiency. In the sixth event, no ISO action was necessary.

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[6] *Order Accepting in Part and Modifying in Part Standard Market Design Filing and Dismissing Compliance Filing* (hereafter cited as SMD Order), FERC Docket Nos. ER02-2330-000 and EL00-62-039 (September 20, 2002), p. 37. For background information, see *Explanatory Statement in Support of Settlement Agreement of the Settling Parties and Request for Expedited Consideration and Settlement Agreement Resolving All Issues*, FERC Docket Nos. ER03-563-000, -030, -055 (filed March 6, 2006; as amended March 7, 2006).

[7] The Hub is a collection of locations for which the ISO calculates and publishes prices. The Hub price is intended to represent an uncongested price for electric energy.

[8] Long-term contracts providing for reliability are known as Reliability Agreements; short-term payments for single-day commitments of out-of-merit generators are called daily reliability payments.

[9] *Load pockets* are areas of the system in which the transmission capability is not adequate to import energy from other parts of the system and demand is met by relying on local generation (e.g., Southwest Connecticut and the Boston area).

[10] ISO New England's Operating Procedure 4 is available online at http://www.iso-ne.com/rules_proceds/operating/isone/op4/index.html.

1.2 Key Market Results

New England's wholesale markets have entered a new phase with the introduction of the Forward Capacity Market. In 2007, capacity costs were a larger component of total wholesale electric energy costs than in previous years in both absolute and relative terms. Figure 1-2 shows the all-in cost metric for wholesale electric energy that load-serving entities (LSEs) with real-time load obligation paid in 2005 through 2007.

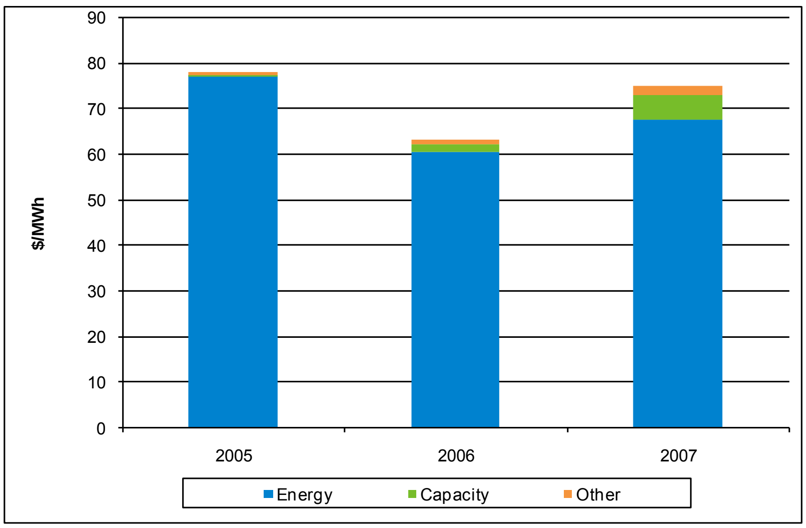

Figure 1-2: All-in wholesale electric energy cost metric for 2005 to 2007.

The all-in cost for serving load in New England fell in 2006 but rose in 2007 primarily as a result of higher energy costs and the introduction of capacity transition payments. Before the capacity market Settlement Agreement and the beginning of the FCM transition payments, capacity prices were determined by a deficient capacity market with low but highly volatile prices that did not provide appropriate allocative signals. In 2006, capacity could be bought in the ICAP supply auction at an average price of $0.205/kW-month. The transition payment specified by the Settlement Agreement was fixed at $3.05/kW-month during 2007. This was offset by a reduction of $214 million in net Reliability Agreement payments. Table 1-1 shows the detailed breakdown of the wholesale load cost metric for 2006, 2007, and the year-to-year change. The 2007 energy cost rose from $60.63/MWh in 2006 to $67.59/MWh in 2007, an 11% increase. The cost of capacity rose from an average of $1.62/MWh to $5.38/MWh, and the category "Other" increased from $0.93/MWh to 2.11/MWh. The energy and capacity components account for 90% of the total change in the all-in cost.

Table 1-1
Change in All-In Wholesale Electric Energy Cost Components, 2006 to 2007, $/MWh

Component	2006	2007	Change
Energy	60.63	67.59	6.97
Capacity	1.62	5.38	3.76
Other	0.92	2.11	1.19
Total	**63.17**	**75.08**	**11.92**

The electric energy portion of the all-in costs was driven by rising fuel costs and higher consumption of electricity during 2007. In 2007, natural gas resources set price in New England 74% of the time. Figure 1-3 illustrates the close relationship between natural gas prices and electricity prices. The figure demonstrates several issues. First, electric energy costs are tightly linked to the price of natural gas. As natural gas prices rise, electricity prices also rise. Second, oil prices have been growing faster than natural gas prices. Thus, when oil-fueled units are needed to meet summer peak loads, electricity prices are higher than the cost of a natural-gas-fired generator. This caused the summer 2007 gap between electricity prices and natural gas costs shown in Figure 1-3. Overall, the tight link between the marginal fuel and electricity prices is consistent with a competitive market in which prices are determined by marginal costs.

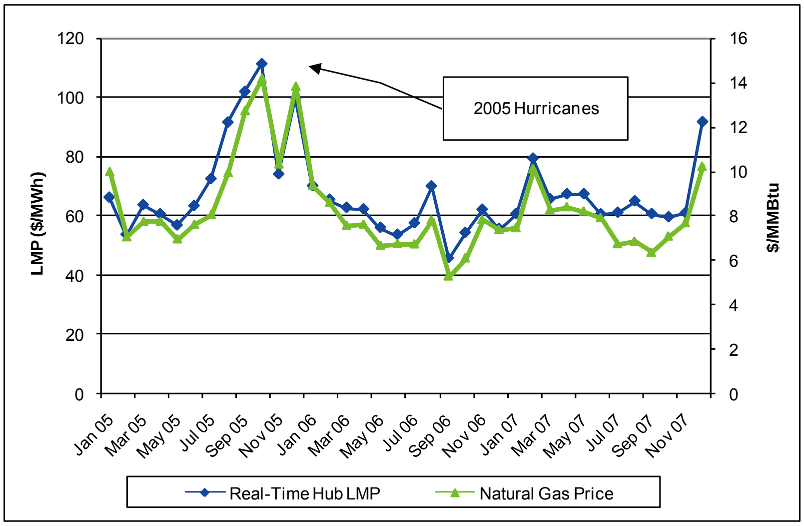

Figure 1-3: Electricity prices and natural gas prices.

Net revenues for New England resources improved significantly in 2007. This is a result of higher electric energy prices and the introduction of the $3.05/kW-month capacity transition payments. FERC has developed standard metrics to measure net revenues for a representative combined-cycle generator and a representative combustion turbine, both gas fired. The net revenue of the representative combined-cycle generator in 2007 increased 51% from the 2006 estimate to

$13.10/kW-month. For the representative combustion turbine, the estimated net revenue increased 96% between 2006 and 2007 to $7.80/kW-month. If transition payments were excluded from both years, the net revenues still would have increased 16% and 20%, respectively, for combined-cycle and combustion turbine generators.

The increase in net revenues from higher capacity payments was consistent with the design objectives of the FCM. The remaining increase in net revenues compared with 2006 levels, after accounting for higher capacity costs, is within the range of variability expected from the underlying supply and demand conditions. It is too soon to evaluate the impact of these changes in short-term revenues on long-term investment decisions, such as generation project developments or retirements.

1.3 Market-by-Market Highlights

This section presents the main 2007 results for each of New England's wholesale markets for electric energy, capacity, reserves, regulation, and financial transmission rights. Out-of-market compensation for reliability also is summarized.

1.3.1 Electric Energy Markets

The factors that most affected the electric energy markets in 2007 included the increased cost of fuel, reduced transmission constraints, and a lower peak demand yet higher total yearly electric energy consumption.

1.3.1.1 2007 Fuel Prices

The primary input to electricity production is fuel, and fuel prices increased in 2007. The price for liquid fuels, such as diesel and No. 6 oil, increased more rapidly than natural gas prices. Both these patterns—the general increase in fuel prices and the increasing disparity between the prices for liquids and natural gas—continue trends from the past few years. This is illustrated in Figure 1-4.

Figure 1-4: Growth in fuel prices relative to year 2000 prices.

The ISO historically has calculated a "fuel-adjusted" electricity price using a simple, limited methodology. The analysis uses the year 2000 as a base and normalizes the locational marginal price (LMP) of the marginal unit in each five-minute interval to fuel prices in 2000. This methodology assumes that the same marginal units would be dispatched in both the base year of 2000 and the current year being evaluated. While this methodology has been informative, it can become less accurate as electricity demand, generation capacity, relative fuel prices, and the mix of resources change. For example, the recent divergence of relative fuel prices, as illustrated in Figure 1-4, is the type of change that would lead to different units being dispatched at the margin and, more importantly, potentially different fuels firing the marginal unit. The ISO intends to improve the estimation of fuel-adjusted prices in future years to account for all factors more appropriately.

Electric energy prices appear to be normal when adjusted for fuel prices. The fuel-adjusted price of electric energy in 2007 of $45.15/MWh was $2.51/MWh higher than in 2006. In comparison, the average fuel-adjusted price from 2000 to 2006 was $45.01/MWh. Actual unadjusted average electric energy prices rose from $62.74/MWh in 2006 to $69.57/MWh in 2007. This increase was paralleled by an 8.8% increase in natural gas prices and a 16.2% increase in the price of 1% sulfur No. 6 oil.

The increase in the fuel-adjusted price is within the range of the estimation uncertainty. Additionally, the size and direction of the change are consistent with the effect of increased energy demand in 2007. The ISO estimated the effect of increased demand by applying the increased demand to representative supply curves. Average hourly energy demand increased by 279 MW, yielding estimates ranging from a low of $1.29/MWh to $4.96/MWh. The observed increase in the fuel-adjusted energy price of $2.51 (5.8%) falls well within this range. Therefore, changes in the market price are consistent with the shifts in the underlying demand and supply conditions. More details of this analysis are provided in Section 2.4.2.

1.3.1.2 Transmission Improvements

Transmission improvements reduced congestion in the Norwalk/Stamford area of Southwest Connecticut. The maps in Figure 1-5 show average annual real-time nodal prices for 2006 and 2007. The maps show that the chronic congestion into the Norwalk/Stamford area eased from 2006 to 2007, indicated by the lack of the red coloring in the 2007 map compared with the concentrated red corner in the 2006 map. The map also reflects that prices over all New England generally were higher in 2007 (indicated by the predominance of the yellow-green color in the 2007 map compared with the more blue-green color in the 2006 map). As mentioned, this was largely due to higher fuel prices in 2007 than in the previous year.

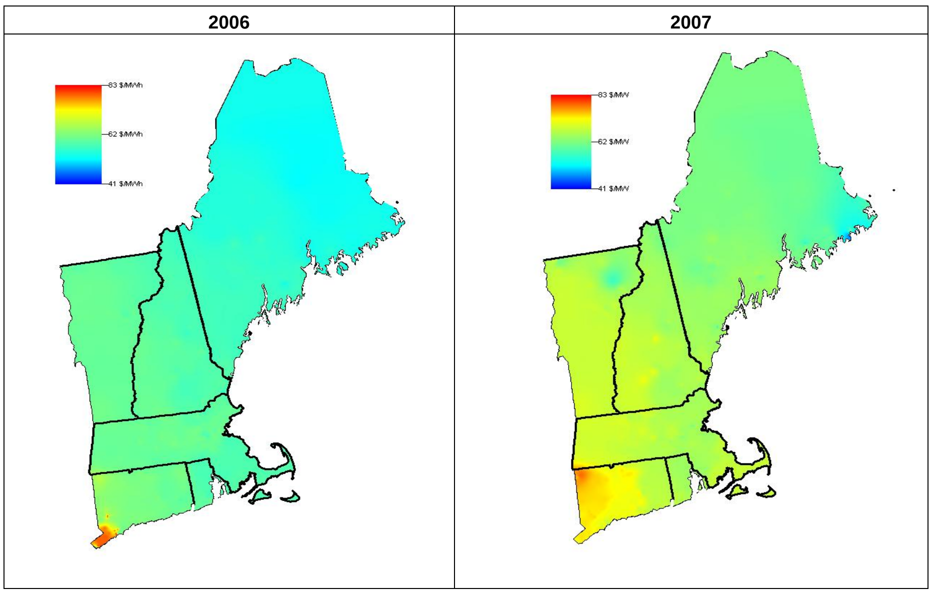

Figure 1-5: Average real-time nodal prices, 2006 and 2007, $/MWh.

Average nodal prices in the Norwalk/Stamford area of Connecticut also were reduced by the elimination of the Peaking-Unit Safe-Harbor (PUSH) threshold in June 2007. FERC established the PUSH threshold to give generators in designated congestion areas (Connecticut and Northeast Massachusetts and Boston [NEMA/Boston]) an opportunity to recover capital costs. PUSH allowed units with low capacity factors to offer into the market at prices above marginal cost.[11] FERC terminated the PUSH threshold with the advent of the FCM and transition payments.

1.3.1.3 2007 Demand

Demand in 2007 was marked by two significant features: a lower peak than in 2006 and a higher yearly total consumption. The record peak demand of 2006 was attributable to extraordinary weather. The 2007 peak demand of 26,134 MW occurred with temperatures more consistent with long-term averages.[12]

The long-run trend of a decreasing weather-normalized load factor continued, although the actual (unadjusted) load factor increased.[13] When normalizing for weather, peak hourly demand rose faster than average demand from 2006 to 2007, resulting in a lower load factor. The actual, unadjusted load

[11] Under PUSH, affected units could offer into the market at prices above marginal cost, which if accepted, sometimes raised the Connecticut price above levels elsewhere in the region. See Section 6 for more information about PUSH thresholds.

[12] The system peak for 2006 was driven by a period of unusually hot and humid weather in late July and early August. Other than these periods, temperatures in 2006 were somewhat mild relative to long-term averages, which when also accounting for retail price increases, resulted in a decrease in average load for the year.

[13] The *load factor* is the ratio of the average hourly demand during a year to the peak hourly demand. *Weather-normalized* results are those that would have been observed if weather were the same as the long-term average.

factor increased between 2006 and 2007. This is because the actual peak load decreased while the average load increased between 2006 and 2007.

The net energy for load (NEL) supplied to the system in 2007 increased 1.9% from the 2006 level.[14] Figure 1-6 shows yearly total NEL for 1980 through 2007. After a decrease in NEL from 2005 to 2006, aggregate energy consumption increased in 2007 following historical patterns. The decline in energy use in 2006, both actual and weather normalized, was a response to the large increases in natural gas and electricity prices.[15]

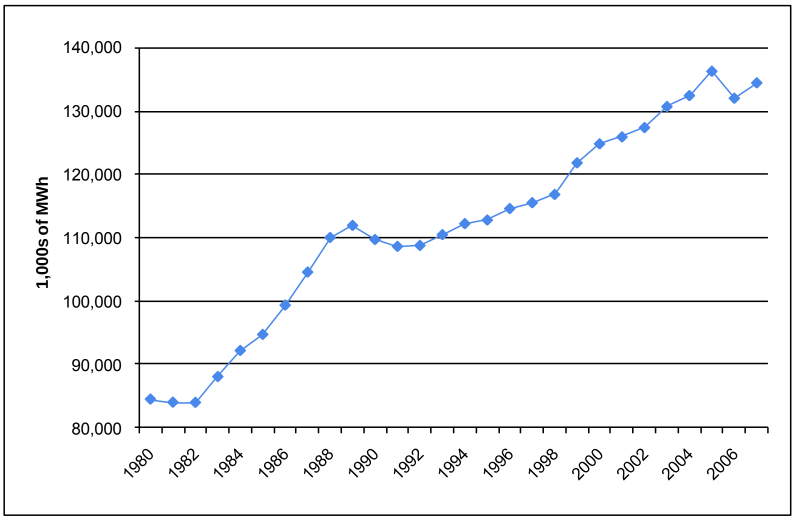

Figure 1-6: New England actual net energy for load, 1980 to 2007.

1.3.1.4 Competition Analysis

The ISO uses three primary metrics to assess competition in the energy markets:

- The *Herfindahl-Hirschman Index* (HHI). This is a measure of market concentration based on generating capacity. An HHI below 1,000 indicates a low concentration of market power.
- A price mark-up model, or *competitive benchmark price* model, which models and compares prices based on competitive offers with prices based on actual offers. The difference also is used to estimate an index called the *Quantity-Weighted Lerner Index.* See Section 9.4.4 for more details.
- The *Residual Supply Index* (RSI). This index measures the hourly percentage of load in megawatt-hours (MWh) that can be met without the largest supplier. Such suppliers are termed "pivotal" and can affect market prices.

[14] *Net energy for load* is calculated as total generation (not including the generation used to support pumping at pumped-storage hydro generators), plus net imports.

[15] The decline of energy use in 2006 is discussed in the ISO's *2006 Annual Market Report* (AMR06) (June 11, 2007), available online at http://www.iso-ne.com/markets/mkt_anlys_rpts/annl_mkt_rpts/index.html.

On the basis of these three metrics, the 2007 analyses, like the 2006 analyses, confirm that the wholesale electricity markets in New England continue to be competitive. However, the level of competition was significantly reduced in some typically constrained areas. The HHI in 2007 for New England markets as a whole was 670, relatively unchanged since 2004 and well below the benchmark set by the U.S. Department of Justice (DOJ) for raising market power concerns.[16] But the HHI calculated for individual load zones indicated highly or moderately concentrated markets.[17] The ISO's mitigation thresholds for constrained areas are designed to alleviate market power in instances where transmission constraints expose the market to conditions of high market concentration. The Quantity-Weighted Lerner Index of 2%, in the absence of congestion, is in line with competitive conditions and past results in New England. The Residual Supply Index shows that in only 1.3% of total hours during 2007 were there pivotal suppliers.

1.3.1.5 Energy Market Conclusions

The electric energy markets in the New England region continued to work competitively in 2007. These markets have adjusted effectively to rising fuel prices and higher electric energy consumption. The introduction of new transmission successfully improved reliability in the Norwalk/Stamford area and, combined with the elimination of the PUSH treatment, reduced LMPs in that area. Further transmission upgrades scheduled for Southwest Connecticut and the rest of Connecticut should provide similar benefits. The competitive analyses further confirm that the electric energy markets continued to function competitively in 2007.

1.3.2 Reliability Costs

At times, resources that are needed for reliability but cannot recover their costs through the energy and ancillary services markets require out-of-market compensation. These resources receive either daily reliability payments (i.e., "uplift") or payments through cost-of-service Reliability Agreements.[18] Daily reliability payments compensate resources needed during particular hours for first-contingency and second-contingency protection, voltage reliability, or out-of-merit operation of special-constraint resources.[19] Reliability Agreements compensate eligible resources with monthly fixed-cost payments for maintaining capacity that provides reliability services and for ensuring that these resources will continue to be available. These contractual arrangements are subject to approval by FERC.

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[16] U.S. Department of Justice and the Federal Trade Commission, *Horizontal Merger Guidelines*, issued April 2, 1992, and revised April 8, 1997. Available online at http://www.usdoj.gov/atr/public/guidelines/hmg.pdf.

[17] New England is divided into the following load zones: Maine, New Hampshire, Vermont, Rhode Island, Connecticut (CT), Western/Central Massachusetts (WCMA), Northeast Massachusetts and Boston (NEMA), and Southeast Massachusetts (SEMA). Refer to Section 2.1 for a more detailed definition of load zones. The New England Control Area also is divided into subareas and reserve zones, explained more fully in Section 2.3.6 and Section 4.1, respectively.

[18] Daily reliability payment is another term for Net Commitment-Period Compensation (NCPC) credit, which is paid to resources for providing operating or replacement reserves in either the Day-Ahead or Real-Time Energy Markets. The accounting for the provision of these services is performed daily and considers a resource's total offer amount for generation, including start-up fees and no-load fees, compared with its total electric energy market value during the day. If the total value is less than the offer amount, the difference is credited to the market participant. For more information, see Market Rule 1, Section III, Appendix F, *Net Commitment-Period Compensation Accounting* (2005), available online at http://www.iso-ne.com/regulatory/tariff/sect_3/.

[19] A *contingency* is the sudden loss of a generation or transmission resource. A *first contingency* (N-1) is when the first power element (facility) of a system is lost, which has the largest impact on system reliability. A *second contingency* (N-1-1) is the loss of the facility that would have the largest impact on the system after the first facility is lost. A *special-constraint resource* is committed at the request of a transmission owner or distribution utility. Throughout this document, the term *distribution payments* is used as a synonym for payments made to special-constraint resources.

1.3.2.1 Daily Reliability Payments

Figure 1-7 shows total daily reliability payments by month for 2006 and 2007. January and February 2007 payments were lower than in 2006, while payments sharply increased in March 2007. The March 2007 rise was at least partly the result of the increasing price of No. 6 oil. Reliability resources burning No. 6 oil became increasingly expensive as a result. Overall, total daily reliability payments increased by only 6% between 2006 and 2007, despite the marked rise in March 2007.

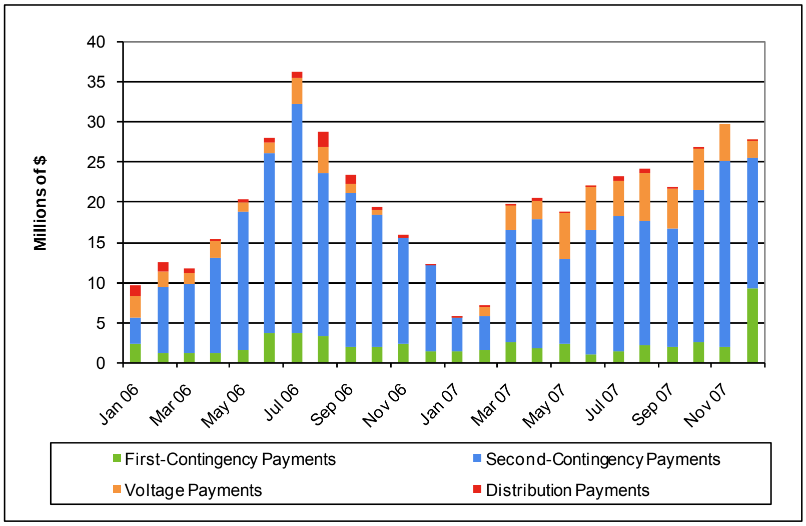

Figure 1-7: Daily reliability payments by month, January 2006 to December 2007.

In response to the introduction of capacity transition payments and FCM, the ISO conducted a deeper analysis of 2007 daily reliability payments. This analysis confirmed that during 2007, more than 50% of daily reliability payments were made to two resources. Other years show a similar pattern of concentration. These two resources did not trigger daily reliability payment mitigation thresholds during 2007. Thus, despite the existing mitigation thresholds for daily reliability payments, a few resources have been able to garner net revenues from out-of-market daily reliability payments in the absence of competition of approximately $3/kW-month. This suggests that the mitigation thresholds for daily reliability payments need to be reexamined. See Section 9.3.3 for further details.

1.3.2.2 Reliability Agreements

Compared with 2006, the amount of capacity operating under a Reliability Agreement declined by 2,640 MW in 2007. Net Reliability Agreement payments declined 59%, from $348 million in 2006 to $143 million in 2007, which represents significant progress for New England. The drop was the result of transmission improvements, especially into NEMA; economic signals provided by the recently revised Forward Reserve Market; and the recently implemented FCM transition payments. While transmission infrastructure improvements have reduced the need for Reliability Agreements, market reforms have improved market incentives, making market-based rates more attractive to resources.

1.3.3 Forward Capacity Market

The year 2007 marked the first full year of transition to the Forward Capacity Market. Three primary FCM results occurred during 2007 and early 2008:

- Capacity market transition payments of $3.05/kW-month were made to all ICAP resources in accordance with the FCM Settlement Agreement.
- The ISO evaluated over 13,000 MW of new capacity projects submitted in the qualification stage for the first Forward Capacity Auction.
- The first FCA was successfully completed in February 2008 with competitive offers from 6,102 MW. A total of approximately 1,813 MW of new resources was selected.

The $3.05/kW-month transition payments have motivated a large increase in participation in ISO demand-resource programs, as discussed in more detail in Section 3.5.

Nearly 74% of the 13,000 MW of new capacity projects submitted during the first FCA qualification process consisted of demand resources, contributing nearly 20% of the total new capacity selected in the first auction. The FCM introduced the possibility of composite offers, which allow summer-only demand resources to make joint offers with winter-only capability from other resources. For the first qualification process for the first FCA, 1,224 MW of composite offers were submitted.

Qualified new capacity participating in the first FCA totaled 6,102 MW. Approximately 18% of the capacity competing in the auction was surplus above New England’s total requirement of 32,305 MW. The auction selected approximately 1,813 MW of new supply and demand resources. Of the new resources chosen, 1,188 MW represent new demand-resource projects, and 626 MW represent new supply projects. The auction closed at the administrative floor price of $4.50/kW-month (see Section 3.7). This capacity will be in service by June 2010.

Although the capacity obligation period has not yet started and many steps remain to achieve full implementation of the FCM, the successful implementation of the Forward Capacity Auction represents a significant achievement for the ISO. One goal of the FCM was to ensure adequate competition from new resources in the capacity market by holding the auction well in advance of the delivery or obligation period. The evidence to date supports the conclusion that the market succeeded in this regard. The market rules still need to be conformed to FCM-related changes to complete the FCM implementation. A second goal of the FCM was to incorporate demand resources in the capacity markets. The level of demand-resource participation, including composite offers that allow for seasonal resource participation, show that the market has been successful in attracting demand resources.

1.3.4 Reserve Markets

The ISO compensates resources for providing operating reserves through two means: the locational Forward Reserve Market (FRM) and locational real-time reserve pricing. The locational Forward Reserve Market was designed to induce long-term investment in reserve capability. The FRM auctions are held twice per year for a service period beginning one month after the auction. Locational real-time reserve pricing, in contrast, was designed to complement the short-term electric energy markets. Locational real-time reserve pricing is co-optimized with energy and transmission use every five minutes.

1.3.4.1 Locational Forward Reserves

The year 2007 marks the first full year of operation for these markets in their current form, which procures forward reserves and pays real-time reserve prices for individual reserve zones.[20] Before October 2006, the Forward Reserve Market was not locational, and real-time reserve pricing did not exist in New England when locational markets and Standard Market Design (SMD) were introduced in 2003.

A primary goal of the FRM is to encourage the retention of and in some areas an increase in the level of resources capable of providing reserves. Overall participation in the FRM auctions has increased. The total supply offered into the winter 2007 auction was 390 MW, or 14% greater than for the winter 2006 auction. The supply increases were concentrated in NEMA/Boston and Connecticut. NEMA/Boston offers increased by 39%. Connecticut offers (combined with Southwest Connecticut offers) increased by 44%. The participation results are encouraging for these markets. However, evaluating the market results still is premature.

The FRM design uses several fixed parameters that determine reserve requirements and threshold prices. The threshold price is intended to preselect resources with capacity factors less than 2.5% (i.e., resources designed to provide reserve). Market results indicate that the threshold price often is lower than the LMP. This allows forward-reserve resources to be dispatched for electric energy rather than being used for reserve. This outcome is inconsistent with the market design objectives, and the threshold-price methodology should be reviewed. In the forward-reserve auction, the quantity of reserves required for the Rest-of-System (ROS) reserve zone is based on several parameters, one of which is the expected reliability of resources, which is based on an estimate of the number of failures of fossil-fueled fast-start units. However, hydro resources that historically have had higher-than-average reliability records often clear the auction in the ROS reserve zone. Because of these market results, the parameters used to set the ROS reserve-zone requirement also should be reviewed.

1.3.4.2 Real-Time Reserve Pricing

In real time, resources are dispatched in a least-cost manner to meet simultaneously the system's requirements for electric energy and reserve, while respecting transmission-security constraints. Reserve prices are calculated using the electric energy offer prices and reserve-constraint penalty factors (RCPFs) when applicable—there are no real-time reserve offers.[21]

Real-time reserve prices are expected to be zero most of the time because sufficient reserve usually is available based on normal economic dispatch; therefore, no additional costs are incurred to provide reserves. Nonzero reserve prices occur when resources are redispatched to meet reserve requirements. Real-time reserve pricing results match the expected pattern of relatively infrequent positive prices. In 452 hours during 2007, positive reserve-clearing prices occurred in at least one reserve zone.

[20] *Reserve zones* are geographic areas that have specific reserve requirements necessary for reliable operations of the system. The ISO has four reserve zones: NEMA/Boston, Connecticut (CT), Southwest Connecticut (SWCT), and the rest of the system (Rest-of-System; ROS). The New England Control Area also is divided into subareas and load zones, explained more fully in Section 2.3.6 and Section 2.1, respectively.

[21] *Reserve-constraint penalty factors* are the rates, in $/MWh, that are used within the real-time dispatch and pricing algorithm to reflect the value of operating-reserve shortages. RCPFs are more fully defined in Market Rule 1, Section III.2.7, available online at http://www.iso-ne.com/regulatory/tariff/sect_3/.

1.3.4.3 Performance Capping

In conjunction with the revised reserve markets, the ISO implemented additional performance monitoring and auditing for resources with off-line reserve capability. Beginning in January 2007, failure to perform, either during normal operations or during audits, resulted in a cap being placed on the megawatt value of reserve credit allowed to the nonperforming resource. Off-line 30-minute reserve capability fell from a systemwide average of 4,621 MW in December 2006 to an average of 3,907 MW in December 2007. Off-line 10-minute reserve capability fell from a systemwide average of 3,262 MW in December 2006 to an average of 2,139 MW in December 2007. The performance auditing and capping program has improved the measurement of reserve capability. This ensures that resources are paid for reserve only to the extent of their true capability. Better measurement also improves reliability by giving system operators more accurate knowledge of the reserve margins.

1.3.4.4 Reserve Market Conclusions

The Forward Reserve Market cleared megawatts of reserve obligation in reserve zones that typically have been short. While some reserve zones continue to be short, the quantity of offers has increased in response to market clearing. Real-time reserve pricing has performed effectively to create additional reserve through redispatch and to compensate reserve providers for their opportunity costs of backing down resources.

The ISO should reevaluate and fine-tune the parameters used to determine reserve requirements and threshold prices. The ISO has begun to evaluate the values for one of these parameters, the reserve-constraint penalty factor. Performance capping is working well and has improved both reliability and market performance through more accurate measurement.

1.3.5 Regulation Market

Regulation is the capability of specially equipped generators to increase or decrease their generation output every four seconds in response to signals they receive from the ISO to control slight changes on the system. This capability is necessary to balance supply levels with the second-to-second variations in demand and to assist in maintaining the frequency of the bulk power system. The Regulation Market is the mechanism for selecting and paying generation needed to manage this system balancing.

On October 1, 2005, the ISO implemented modifications to the Regulation Market.[22] The market changes included adding a service payment and improving the calculation of opportunity costs. In January 2007, the ISO implemented further changes. Specifically, the 2007 changes improved the selection of regulation resources to meet the market design objective of minimizing costs.

The regulation provided by the market allowed the ISO to exceed the North American Electric Reliability Corporation's (NERC's) primary regulation metric, *Control Performance Standard 2*, which is NERC's primary measure for evaluating control performance.[23] On the market side, total costs fell from $78.1 million in 2006 to $43.8 million in 2007.

[22] See the ISO's 2003 through 2005 *Annual Markets Reports* for a detailed description of the SMD Regulation Market, available online in the ISO archive at http://www.iso-ne.com/markets/mkt_anlys_rpts/annl_mkt_rpts/index.html.

[23] NERC's mission is to ensure the reliability of the bulk electric system in North America. For more information on NERC's Control Performance Standard 2, see the NERC Web site at http://www.nerc.com/~filez/rs.html.

In 2007, the Regulation Market performed well both in terms of reliability and market efficiency. The 44% drop in market costs provides early but reassuring evidence that the reforms were effective in improving market performance.

1.3.6 Financial Transmission Rights Market

A Financial Transmission Right is a financial instrument that entitles the holder to a stream of revenues (or obligates them to a stream of costs). This stream of revenues or costs is based on the difference between the day-ahead congestion component of the locational marginal price at each of the nodes that defines the FTR. The market performance of Financial Transmission Rights can be evaluated from two functional perspectives—as a cost hedge for transmission congestion or as a financial arbitrage instrument.

An appropriate metric for FTR market competitiveness as an arbitrage instrument is the path profitability of FTRs. This is defined as the difference between the cost of acquiring the FTR (i.e., the auction cost) and the revenue generated or the costs obligated by the FTR. In a competitive market, the expected profits of a risk-neutral participant holding an FTR as an arbitrage instrument should approach zero. As in 2006, the FTR auction revenue ($123 million) was close to the day-ahead congestion revenue ($130 million) in 2007. Moreover, the average monthly profits for FTRs were 5 cents/MWh for on-peak FTRs and 1 cent/MWh for off-peak FTRs. These results are in accordance with a competitive market for FTRs used as arbitrage instruments.

The performance metric of an FTR as a hedge against congestion costs is whether the FTR provides the congestion cost certainty the buyer is expecting, defined by full funding in the year-end FTR settlements. In the monthly FTR settlements, funds are collected from the day-ahead and real-time congestion revenues and paid to FTR holders on the basis of their FTR amount and direction. The monthly process is followed by a year-end "true up" with any available remaining funds. Full funding is measured by comparing the amount paid through the monthly and year-end FTR settlement with the actual day-ahead congestion paid in the energy market settlement. For example, if an FTR holder received $50 for the year, but had an energy transaction matching the FTR size and direction that required payment of $100 in day-ahead congestion, the FTR holder would have received 50% of the hedge. Any single month could have a shortfall or surplus. The Congestion Revenue Balancing Fund (CRBF) accrued positive amounts during four months in 2007.[24] The four months of surpluses were not enough to make up the shortfalls in the remaining eight months. The FTRs did not provide a full hedge of day-ahead congestion costs. Of the $191.8 million owed to FTR holders, $182.0 million, or 95%, was distributed after the year-end settlement.

Monthly shortfalls and surpluses arise from differences in outage assumptions or transfer limits between the different markets associated with the FTR settlement process. Such differences can be caused by unexpected transmission outages, generation outages, or unexpected load patterns. The ISO forecasts the cumulative effect of the outages and other changes so that the amount of FTRs awarded will be as accurate as possible and shortfalls and surpluses both will be minimized.

[24] The *Congestion Revenue Balancing Fund* is a mechanism for tracking congestion revenues, FTR payments, and monthly surpluses and shortfalls. Year-end surpluses in the CRBF are allocated to FTR holders that received less than 100% of the amount they were owed based on their monthly FTR allocation amounts during the year.

Beginning in December 2007, the PJM Interconnection encountered several FTR payment defaults.[25] Such default risks fundamentally create a moral hazard because every FTR represents a potential financial obligation that the holder can avoid through default when the loss of collateral is less costly than payment of its FTR obligation. The default leaves other participants to bear the consequence of the defaulting holder's untenable FTR positions. FTRs expose their holders to the risk of almost unlimited losses regardless of whether the path cleared the auction as a prevailing or *counterflow* FTR.[26] This risk further increases as the term of the FTR lengthens because of the probability that congestion patterns will change. The risk of default, however, is minimized when an FTR is used as part of a strategy to hedge congestion costs by pairing the FTR with an energy transaction settled in the Day-Ahead Energy Market.

The ISO is working with NEPOOL participants through an FTR credit working group, organized under the NEPOOL Budget and Finance Committee, to develop changes necessary to minimize exposure to payment defaults resulting from FTR market participation. The discussions will focus on improving the financial-assurance policy to better manage the ISO's FTR risk exposure and may include market design revisions.

The FTR market performed competitively during 2007 on the basis of the arbitrage performance metric of path profitability. However, at the end of 2007, FTRs were not fully funded, which limited the effectiveness of the FTR hedge. The ISO has taken two actions that should lessen any shortfalls in the future. First, the ISO has proposed changes to Operating Procedure 3 (OP 3), *Transmission Outage Scheduling*, to enhance the coordination between FTR scheduling and outage coordination.[27] Second, the ISO has begun developing advanced applications for interface-limit calculations that will promote more consistent application of interface limits across FTRs and the Day-Ahead and Real-Time Energy Markets and will thus improve the effectiveness of the FTR hedge.

1.3.7 Demand Resources

Participants' modification of electric energy consumption through demand response and other types of demand resources may provide relief from capacity and reserve constraints in the wholesale electricity markets, or they may promote more economically efficient uses of electrical energy. Along with adequate supply and a robust transmission infrastructure, demand resources are important aspects of a well-functioning wholesale market that improve market efficiency. The ISO operates three types of demand-response programs: those activated by price, those activated for reliability, and those that reduce on-peak consumption.

The price-response programs are made up of a Day-Ahead Load-Response Program (DALRP) and the Real-Time Price-Response Program. Three reliability programs, which are activated as needed during a capacity deficiency, include a 30-minute notice program, a two-hour notice program, and a two-hour notice profiled-response program. The measured on-peak reduction demand-response programs were introduced as part of the FCM and are intended to reduce planning capacity needs. These FCM program resources, termed *other demand resources* (ODRs), credit energy efficiency,

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[25] PJM Interconnection LLC is the RTO for all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, and the District of Columbia.

[26] With a counterflow FTR, the participant acquires power-flow capacity against the prevailing direction of power flows, represented by other participants' offers in the auction (see Section 7.1).

[27] ISO New England's Operating Procedure 3 is available online at http://www.iso-ne.com/rules_proceds/operating/isone/op3/index.html.

load management, and distributed generation with capacity on the basis of their on-peak contributions.[28] The past three years have seen a large increase in demand response and ODRs, as shown in Figure 1-8.

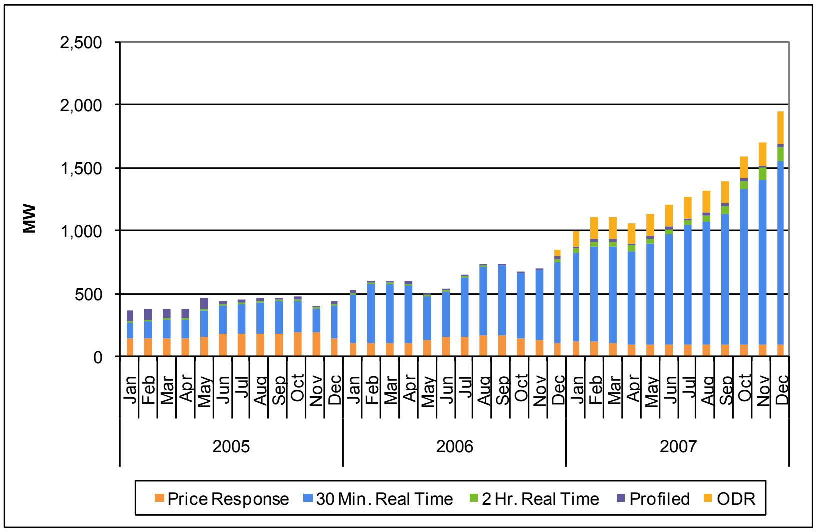

Figure 1-8: **Monthly megawatts enrolled in ISO demand-resource programs, 2005 to 2007.**

Overall enrollment in demand-response programs increased approximately 162% during 2007, from an annual monthly average of 646 MW in 2006 to 1,693 MW in 2007. The total increase between January 2005 and December 2007 has been 360%. Most of these increases have been in the Real-Time 30-Minute Demand-Response Program. The very sizable increase in these programs is most likely a result of the implementation of the Forward Capacity Market and its capacity transition payments. This assessment is supported by the fact that all the increases in demand-resource participation have been in the reliability programs and in the ODR categories, both of which are eligible for FCM transition payments. Audits of the 30-minute and two-hour demand-response programs on August 15, 2007, and of the real-time price-response and profiled demand-response programs on August 17, 2007, showed that participants reduced energy usage from the bulk power system by 2,143 MWh.[29] This was 77% of the enrolled amount, which is similar to historical response rates from audits and actual event activations. The now-implemented FCM rules have revised the incentive structure for demand-response participants. The rule revisions are expected to improve the estimates for load-interruption capability and the performance of demand-response resources.

[28] Distributed generation is a resource that is located behind the end-use customer's billing meter, which reduces the amount of electric energy and capacity that would have been drawn from the electricity network. The nameplate capacity for distributed generation must not exceed 5 MW or the most recent annual customer peak demand, whichever is greater.

[29] Market Rule 1 requires the ISO to conduct a demand-response program audit for any zone that was not part of an OP 4 event before August 15, 2007. The rule requires the audits (when necessary) to occur between August 15 and August 31.

The ISO identified a design flaw in the DALRP that resulted in inappropriate customer baseline calculations, and it filed market-rule revisions in February 2008. More details are included in Section 8.4.1.

The Real-Time Price-Response Program was called on 229 days, an unexpectedly high frequency. This program is designed to trigger interruptions when the real-time price is expected to be above $100/MWh. In 79% of the interruptions, the actual real-time price fell below the $100/MWh trigger. The ISO will review the Real-Time Price-Response Program in 2008. As the region gains experience with expanded demand resources, changes and improvements can be expected. These should be viewed as part of the necessary learning process that comes with the type of growth New England has achieved in the availability of demand resources.

1.4 Conclusions and Recommendations

The ISO-operated markets provide participants and policymakers transparent wholesale market price signals that guide long-term investment in generation and transmission infrastructure. To support this, continued market development is required to complete the Forward Capacity Market design and FCM-conforming changes to energy and ancillary services markets and to integrate demand resources into market operations.

This Annual Markets Report has assessed the market results for 2007. The energy prices have closely tracked fuel costs and changes in demand, evidence of a competitive market. More detailed analyses support the conclusion that the wholesale electricity markets in New England continued to perform competitively during 2007. Market power monitoring and mitigation continue to be needed, particularly in constrained areas. While the market structure is complete, possibilities still exist for efficiency improvement through incremental changes in market elements.

The report draws a number of conclusions and makes a number of recommendations for evaluating and making incremental improvements to the market design rules or specific market design parameters. These are grouped into four areas: reserve market parameters, FTR market issues, demand-response program improvements, and the thresholds used in Net Commitment-Period Compensation (NCPC) mitigation.

- Reserve Markets—The parameters used to calculate the quantity of reserves purchased for the Rest-of-System reserve zone in the Forward Reserve Market, the mechanism for calculating the FRM threshold price, and the level of reserve-constraint penalty factors used in real-time reserve pricing should be evaluated.
- FTR Markets—In the FTR markets, participant defaults in PJM have refocused the ISO's ongoing efforts to evaluate the financial-assurance rules. The ISO also is evaluating possible improvements to the procedures for scheduling outages and the methods used to calculate interface limits used in FTR auctions and the Day-Ahead and Real-Time Energy Markets. These efforts will promote the consistency of transfer limits and improve the effectiveness of FTRs as a hedge of day-ahead congestion costs.
- Demand Resources—The ISO identified a market design flaw in the customer baselines used in the Day-Ahead Load-Response Program. The ISO has filed revisions to the market rule to fix the design flaw. The Real-Time Price-Response Program was called more often than expected, and in 79% of those interruptions, prices were lower than the intended $100/MWh activation price. The ISO also is evaluating possible changes to the Real-Time Price-Response Program.

- Daily Reliability Payments—NCPC is intended to ensure that resources will not incur losses by following out-of-merit scheduling instructions. Analysis confirms that a few resource owners have earned NCPC payments above the amount required to prevent losses. The ISO is recommending an evaluation of the NCPC mitigation thresholds.

Table 1-2 provides a summary of selected market results detailed in the individual sections of this report.

Table 1-2
2007 Results Summary

Section	Topic	Data Summary
Section 2—Electric Energy Markets		
2.2	**Peak demand and electric energy consumption**	Annual actual electric energy consumption increased from 132,078,000 MWh in 2006 to 134,525,000 MWh in 2007, or 1.9%. Weather-normalized electric energy consumption increased by a smaller percentage (0.9%). The actual peak demand in 2007 of 26,134 MW was 7% lower than the historical high of 28,130 MW set during the summer of 2006. The weather-normalized system peak increased by 1.9%. The continued growth of weather-normalized peaks at a rate greater than weather-normalized total consumption results in a continued decline in the weather-normalized load factor. In contrast to the weather-normalized load factor, the actual load factor for 2007 increased as a result of the higher actual energy consumption and lower actual peak demand.
2.3.1	**System capacity growth**	Total system capacity grew slightly during 2007. Summer system capacity in 2007 was 32,918 MW compared with 31,193 MW in 2006. Of the 1,725 MW of increased system capacity, the majority (1,681 MW) was from higher capacity net of firm purchases and sales, and 44 MW was summer claimed capability.
2.3.5	**Imports and exports**	New England remained a net importer of power during 2007. The volume of systemwide net imports has remained relatively constant year to year. New England was a net importer from Canada and a net exporter to New York. The volumes imported from Canada and exported to New York have increased. During 2007, net imports from other control areas served about 4.5% of NEL.
2.4	**Wholesale electricity price levels and fuel costs**	The average real-time electricity price at the Hub in 2007, weighted by system load, was $69.57/MWh, an increase of 11% from an average of $62.74/MWh in 2006. The increase in prices is attributable to higher fuel prices and higher average demand for electricity. The fuel-adjusted electric energy price was $45.15/MWh, a 5.8% increase from the 2006 level. The average fuel-adjusted price for 2000 to 2006 was $45.01/MWh.
2.4.3	**Day-ahead and real-time prices**	During 2007, the yearly average day-ahead price was 1.8% higher than the average real-time price. In 2006, the difference was 2.0%. Each load zone except Connecticut also demonstrated modest price premiums in the Day-Ahead Energy Market over the Real-Time Energy Market. In Connecticut, average real-time prices were 4 cents higher than average day-ahead prices.

Section	Topic	Data Summary
2.4.6	**Zonal price separation**	Price separation among load zones was less pronounced in 2007 than in 2006, although Connecticut LMPs continued to be higher than those in other zones. LMPs were lowest in Maine. Overall for the year, the average difference between the LMPs for Connecticut and Maine was $7.35/MWh in the Day-Ahead Energy Market and $8.10/MWh in the Real-Time Energy Market. Day-ahead and real-time LMPs in the NEMA/Boston zone were lower than in most other load zones in 2007; the exceptions were Maine and Rhode Island.
2.5	**Critical power system events**	Higher-than-expected demand for electricity that was sometimes combined with supply disturbances required the ISO to declare OP 4 actions during 2007. Systemwide, OP 4 was declared on February 10, August 2, and September 8. On December 1, OP 4 was declared first for Maine and then systemwide because of a disturbance in the natural gas supply infrastructure. Some OP 4 actions continued in Maine on December 2, 2007. Throughout each of these events, the ISO maintained system reliability, and no forced load reductions were needed.
Section 3—Forward Capacity Market		
3.2	**Capacity requirement**	The auction met the Installed Capacity Requirement (ICR) of 32,305 MW for the 2010/2011 capability year by selecting approximately 1,813 MW of new supply and demand resources along with 30,492 MW of capacity from existing resources. Of the new resources chosen, 1,188 MW represent new demand-resource projects, and 626 MW represent new supply projects. The auction closed at the administrative floor price of $4.50/kW-month, with 2,047 MW of surplus capacity.
3.5	**Transition payments**	FCM transition payments replaced the Installed Capacity Market in December 2006 and will continue until the 2010/2011 capability year when the FCM payments based on the auction results will begin. During 2007, FCM transition payments to qualifying capacity resources totaled $1.3 billion.
3.7	**First Forward Capacity Auction**	The Forward Capacity Auction was completed in February 2008. A total of 32,392 MW of existing capacity qualified for the auction along with 6,937 MW of new capacity projects. Almost 36% of the qualified new capacity projects was from demand-resource projects.
Section 4—Reserve Markets		
4.2.1	**Forward Reserve Market auctions**	Two forward-reserve auctions for locational forward-reserve products were conducted in 2007: in April 2007, for summer 2007; and in August 2007, for the winter 2007/2008 period.[(a)] For the summer 2007 auction, 10-minute nonsynchronized reserves (TMNSR) cleared at $10,800/MW-month, while the price for 30-minute operating reserves (TMOR) was $3,550/MW-month in the Rest-of-System reserve zone. In the winter 2007/2008 auction, TMNSR cleared at $9,050/MW-month, while no TMOR cleared in the ROS reserve zone. Offered quantities were short of requirements in the SWCT and CT reserve zones in both auctions. Consequently, the clearing prices in these areas were set to the offer cap of $14,000/MW-month. In the summer 2007 auction, offered quantities in the NEMA reserve zone were short of requirements, which caused the clearing price to be set to $14,000/MW-month. The requirements in NEMA were met in the winter 2007/2008 auction, which resulted in a clearing price there of $8,500/MW-month for TMOR and $14,000/MW-month for TMNSR.

Section	Topic	Data Summary
4.3	**Real-time reserve pricing**	Positive reserve-clearing prices occurred in at least one reserve zone in 452 hours during 2007. Positive reserve-clearing prices occurred most frequently in the SWCT reserve zone, where prices for local 10-minute spinning reserves (TMSR) were positive in 5.1% of the hours. In the Rest-of-System reserve zone, TMSR prices were positive in 3.3% of the hours.
4.6	**Forward Reserve Market operations**	Net forward-reserve credits were about $163.8 million in 2007. Failure-to-reserve and failure-to-activate penalties for the year totaled $6.4 million.
Section 5—Regulation Market		
5	**Regulation Market**	Total Regulation Market costs fell from $78.1 million in 2006 to $43.8 million in 2007. The markets continued to provide sufficient amounts of regulation, and the New England Control Area fully complied with NERC reliability requirements for regulation.
Section 6—Reliability Costs and Peaking-Unit Safe-Harbor Bidding		
6.1	**Daily reliability commitments and payments**	The cost of payments to maintain daily reliability increased 6% from $232 million in 2006 to $247 million in 2007. The increase is the result of higher fuel prices and higher voltage payments to resources in the NEMA load zone. Second-contingency payments, the largest category, decreased 6% systemwide.
6.2	**Reliability Agreements**	Capacity under Reliability Agreements decreased dramatically between 2006 and 2007, dropping from 5,843 MW in 2006, or 19% of total system capacity, to 3,203 MW in 2007, 10% of systemwide capacity. At the end of 2007, no generating resource in NEMA had a Reliability Agreement, a decrease from 62% of NEMA capacity having agreements at the end of 2006.
Section 7—Financial Transmission Rights		
7	**Financial Transmission Rights**	FTRs were offered to the marketplace in 12 ISO-administered monthly auctions and one annual auction for 2007. Participation in the auctions was strong, and market participants purchased FTRs that generally were consistent with expected patterns of congestion. Net auction revenues from the annual and 12 monthly auctions totaled about $122 million.
Section 8—Demand Resources		
8	**Demand resources**	In 2006, with the advent of the Forward Capacity Market transition payments, the ISO introduced a category of demand resources called *other demand resources*, which qualify as capacity resources. ODRs consistently reduce on-peak demand. With FCM transition payments as incentives for increased enrollment, the level of participation by demand resources increased approximately 162% in 2007, from an annual monthly average of 646 MW in 2006 to 1,693 MW in 2007.
8.4	**Demand-response interruptions**	The ISO identified flaws in the Day-Ahead Load-Response Program and has filed revisions to resolve the problems. Other refinements in existing programs may be desirable.

Section	Topic	Data Summary
Section 9—Oversight and Analysis		
9.2	**Market power mitigation**	During 2007, the ISO exercised its market-mitigation authority 16 times as part of its responsibility to monitor the market and ensure efficient and competitive market results. Thirteen mitigation events were for economic withholding in the Real-Time Energy Market, and the remaining three mitigation events were for economic withholding as part of the evaluation of Net Commitment-Period Compensation (see Section 9.3). Mitigation was imposed when the participants did not adequately explain a supply offer that exceeded conduct and market-impact thresholds. As a result of the mitigation, a supply offer intended to represent the unit's marginal costs was substituted for the generating resource's offer.

(a) Ten-minute nonsynchronized reserve (TMNSR) is off-line operating reserve generation that can be electrically synchronized to the system and reach rated capability within 10 minutes in response to a contingency. Ten-minute spinning reserve (TMSR) is on-line reserve electrically synchronized to the system and at rated capability that can respond to a contingency within 10 minutes. Thirty-minute operating reserve (TMOR) is on-line or off-line operating reserve generation that can increase output within 30 minutes or be electrically synchronized to the system and reach rated capability within 30 minutes in response to a contingency.

Section 2
The Electric Energy Markets

The electricity markets operated by the ISO include a Day-Ahead Energy Market and a Real-Time Energy Market, each producing a separate but related financial settlement. This arrangement is known as a *multi-settlement system*. The Day-Ahead Energy Market produces financially binding schedules for the production and consumption of electricity one day before the operating day. However, supply or demand for the operating day can change for a variety of reasons, including generator reoffers of capacity into the market, real-time hourly self-schedules (i.e., operating at a determined output level regardless of price), self-curtailments, transmission or generation outages, and unexpected real-time system conditions. The Real-Time Energy Market balances differences between the day-ahead scheduled amounts of electricity and the actual real-time load requirements. Participants either pay or are paid the real-time locational marginal price for the amount of load or generation in megawatt-hours that deviates from their day-ahead committed schedules. Locational marginal pricing is a way to efficiently capture the impacts on electric energy prices caused by locational variations in supply, demand, and transmission limitations at every location on the system.

This section contains information about the Day-Ahead and Real-Time Energy Markets. Information on the factors that drive the price of electric energy, market results for 2007, and an analysis of the data are included for each market.

2.1 Underlying Drivers of Electric Energy Market Prices

The ISO calculates and publishes day-ahead and real-time LMPs at five types of locations, called *pricing locations*. These include the external interface proxy nodes, load nodes, individual generator-unit nodes, load zones, and a trading hub (Hub). New England is divided into the following load zones: Maine, New Hampshire, Vermont, Rhode Island, Connecticut, Western/Central Massachusetts (WCMA), Northeast Massachusetts and Boston (NEMA), and Southeast Massachusetts (SEMA). The Hub, which contains a specific set of predefined nodes, is used to establish a reference price for electric energy trading and hedging. The Hub also is a location used in the FTR markets (see Section 7).

The market-clearing process calculates and publishes LMPs at these locations based on supply offers, virtual bids, and day-ahead demand bids in the Day-Ahead Energy Market and on supply offers and real-time load in the Real-Time Energy Market. A generator is paid the price at its node, whereas participants serving demand pay the price at the load zone. This is a load-weighted average price of the zone's load-node prices. (Refer to Section 2.1.2 for more information about how the market price is determined.)

LMPs differ among locations as a result of the marginal costs of congestion and losses. *Congestion* is caused by transmission constraints that limit the flow of otherwise economic power. Congestion costs arise because of the need to dispatch individual generators to provide more or less energy to respect transmission constraints. The marginal cost of losses is a result of physical losses that arise as electricity travels through the transmission lines. Physical losses are caused by resistance in the transmission system and are inherent in the existing transmission infrastructure. As with the marginal cost of congestion, the marginal cost of losses has an impact on the dispatch level of generators to minimize total system costs.

If the system were entirely unconstrained and had no losses, all LMPs would be the same, reflecting only the cost of serving the next increment (in megawatts) of load. This incremental megawatt of load would be served by the generator with the lowest cost, and energy from that generator would be able to flow to any node over the transmission system.

The key factors that influence the LMPs are supply and demand. Supply is influenced in turn by fuel prices and the frequency and location of transmission constraints. The following subsections elaborate on each of these factors.

2.1.1 Supply and Demand

In the Day-Ahead Energy Market, market participants may bid *fixed demand* (i.e., they will buy at any price) and *price-sensitive demand* (i.e., they will buy up to a certain price) at their load zone. They also may offer virtual supply and bid virtual demand (see Section 2.2) at the Hub, load zones, the external interface pricing nodes, or individual generator or load nodes. Appendix A.1 provides a monthly breakdown of energy market volumes by numerous categories. Generating units offer their output at the pricing node specific to their location. The intersection of the supply and demand curves as offered and bid, along with transmission constraints and other system conditions, determines the Day-Ahead Energy Market price at each node. The processing of the Day-Ahead Energy Market results in binding financial schedules and commitment orders to generators. In the Day-Ahead Energy Market, participants have incentives to submit supply offers that reflect their units' marginal costs of production, which are largely driven by fuel costs. Supply offers also incorporate the units' operating characteristics. Separate start-up and no-load offers are submitted as well. Demand bids reflect participants' load-serving requirements and accompanying uncertainty, tolerance for risk, and expectations about congestion.

After the Day-Ahead Energy Market clears, the supply at each location can be affected in two ways. First, generators that were not committed in the Day-Ahead Energy Market can request to self-schedule their units for real-time operation. Alternatively, units that were committed can incur a forced outage or request to be decommitted. Second, as part of its Reserve Adequacy Analyses (RAA) (see Section 6.1), the ISO may be required to commit additional generating resources to support local-area reliability or to provide contingency coverage.[30] Finally, all generators have the flexibility to change their incremental energy-supply offers during the reoffer period.[31]

In the Real-Time Energy Market, the ISO dispatches generators to meet the actual demand on the system and to maintain the required operating-reserve capacity. Higher or lower demand than that scheduled day ahead, actual generator availability, and system operating conditions all can affect the level of generator dispatch and therefore the real-time LMPs. In the Real-Time Energy Market, the ISO balances supply and demand, while ensuring that reserves are sufficient and transmission line loadings are safe. Unexpected increases in demand, generating-unit outages, and transmission line outages all can cause the ISO to call on additional generating resources to preserve the balance between supply and demand.

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[30] A *contingency* is the sudden loss of a generation or transmission resource. A *first contingency* (N-1) is when the first power element (facility) of a system is lost, which has the largest impact on system reliability. A *second contingency* (N-1-1) is the loss of the facility that would have the largest impact on the system after the first facility is lost.

[31] The reoffer period is normally the time spanning 4:00 p.m. and 6:00 p.m. on the day before the operating day during which a market participant may submit revised supply offers or revised demand bids associated with dispatchable asset-related demand.

2.1.2 Fuel Prices

Fuel prices alone account for a large portion of year-to-year electricity prices. For most electricity generators, the cost of fuel is the largest production cost variable, and as fuel costs increase, the prices at which generators submit offers in the marketplace increase correspondingly.

Over the past five years in New England, new generating capacity has been almost entirely fired by natural gas. Generating units burning natural gas or fuel oil, or capable of burning both natural gas and oil, constitute approximately 62% of electric generating capacity in the region. During most hours, a generator burning one of these two fuels is a marginal unit, which results in New England electricity prices being highly sensitive to changes in the price of fuel oil and natural gas. On average, both oil and gas prices increased in 2007. The average annual price of fuel oil increased 17% from 2006, while the average annual price of natural gas increased 9%. In particular, No. 6 fuel oil has become more expensive than natural gas, which changes the dispatch order of some generation resources.

2.1.3 Transmission Constraints

In the Day-Ahead Energy Market, RAA, and Real-Time Energy Market, generating units are committed to ensure that the levels of cleared, anticipated, and actual demand can be served reliably. The commitment takes into account transmission system limits, the need for reserves, and the need to provide contingency coverage. High demand relative to economic supply in a given area may result in binding transmission constraints, which then would require the selection of more expensive generation and would lead to higher LMPs in that area. In contrast, export-constrained areas will experience lower LMPs relative to unconstrained areas.

2.2 Electric Energy Demand in 2007

Average loads and system peak demand in 2007 both were consistent with long-term trends. Temperatures also were consistent with long-term trends, and there were no periods of unusually high temperatures combined with high humidity, which drive peak loads. This is in contrast to 2006 when the average load levels in New England were lower than expected, but there were a few unusually high load days that were driven by high temperatures combined with high humidity. The net energy for load (NEL) supplied to the system in 2007 was 134,525,000 MWh, an increase of 1.9% from the 2006 level.[32] Historically, increases and decreases in demand have correlated with changes in economic activity, electricity prices, weather conditions, and consumer preferences (e.g., an increased use of centralized air conditioning and greater use of home electronics). Employment grew by 1% and real income by 3.2% in 2007. Changes in retail electricity prices and weather were modest.

Figure 2-1 shows annual NEL for 1980 through 2007. After a decrease in NEL from 2005 to 2006, aggregate energy consumption increased in 2007. This increase followed historical patterns resulting from weather, economic and real income growth, and a smaller increase in retail electricity prices (3.4% from 2006 to 2007, compared with a 21% rise from 2005 to 2006).

[32] *Net energy for load* is calculated as total generation (not including the generation used to support pumping at pumped-storage hydro generators), plus net imports.

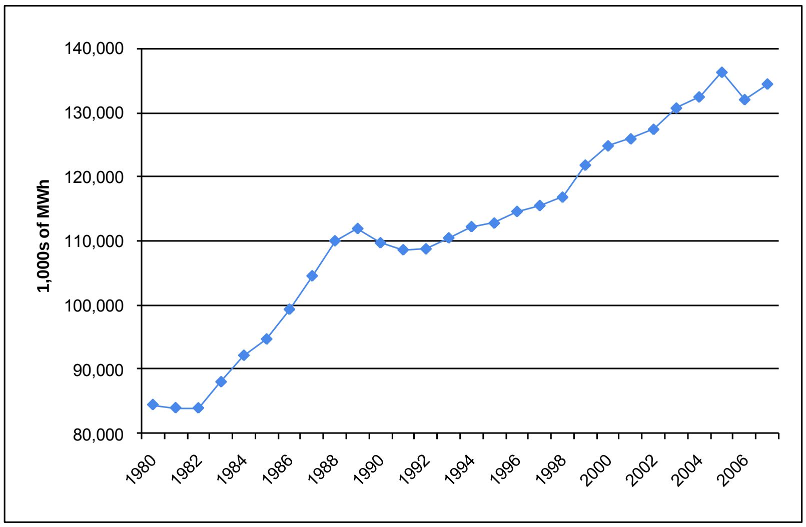

Figure 2-1: New England actual net energy for load, 1980 to 2007.

Since NEL is influenced significantly by weather, the ISO also calculates weather-normalized NEL (i.e., the NEL that would have been observed if weather were normal). This calculation indicates that after weather normalization, annual consumption rose 0.9% from 2006 to 2007.[33] Table 2-1 shows the annual and peak electric energy statistics for 2006 and 2007.

Table 2-1
Annual and Peak Electric Energy Statistics, 2006 and 2007

	2006	2007	Change	% Change
Annual NEL (MWh)	132,078,000	134,525,000	2,447,000	1.9
Normalized NEL (MWh)	132,480,000	133,720,000	1,240,000	0.9
Recorded peak demand (MW)	28,130	26,143	–1,987	–7.1
Normalized peak demand (MW)	26,940	27,460	520	1.9

As illustrated in Figure 2-2, New England monthly temperatures in 2007 were consistent with long-term averages. February was slightly colder than normal, while September and October were slightly warmer than normal.[34]

[33] The ISO uses statistically derived factors to adjust energy consumption levels to reflect the deviation of actual weather from 20-year average or "normal" levels. In the weather-normalization calculation, consumption is adjusted downward when temperatures are more severe than normal and upward when temperatures are milder than normal. Data for summer months also account for the effect of humidity on consumption levels.

[34] Weather information is available at http://www.weather.gov/climate/index.php?wfo=box. Normalized climate values cover the period from 1971 to 2000.

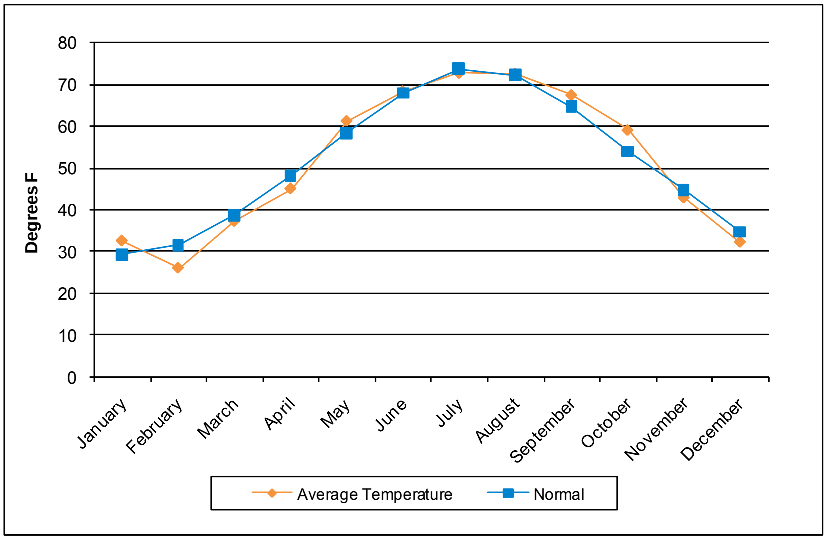

Figure 2-2: Average temperatures for 2007 compared with normal values.

Loads exceeded 25,000 MW in only 17 hours in 2007. The 2007 system-peak hourly demand of 26,143 MW occurred on August 3. The temperature at the time of this peak was 91°F. By comparison, demand exceeded 25,000 MW in 55 hours in 2006 and 28 hours in 2005. The ISO calculates a weather-normalized peak demand for the summer and winter seasons. After weather normalization, the 2007 summer seasonal peak increased 1.9% over the 2006 weather-normalized peak.

Figure 2-3 and Figure 2-4 show the actual system electrical load for New England over the past five years as load-duration curves, ordering load levels from highest to lowest. The duration curve for each year shows the percentage of time the hourly load was at or above the load levels shown on the vertical axis. Figure 2-4, which includes only the highest 5% of hours, shows that 2007 had much lower peak loads than 2005 and 2006.

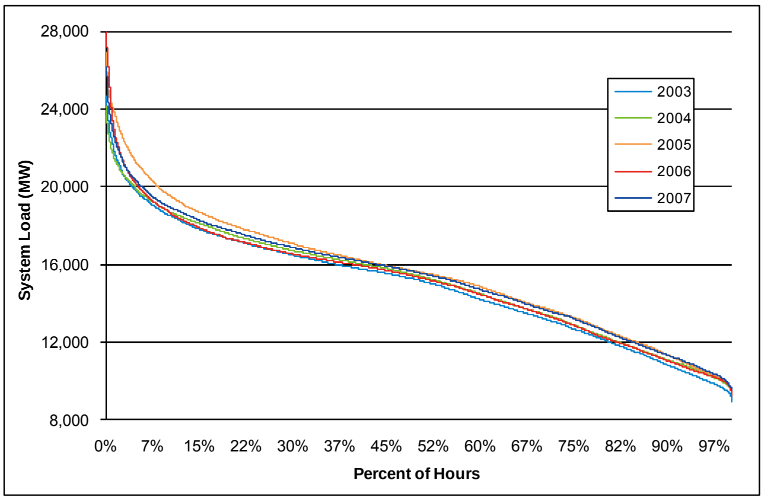

Figure 2-3: New England hourly load-duration curves, 2003 to 2007.

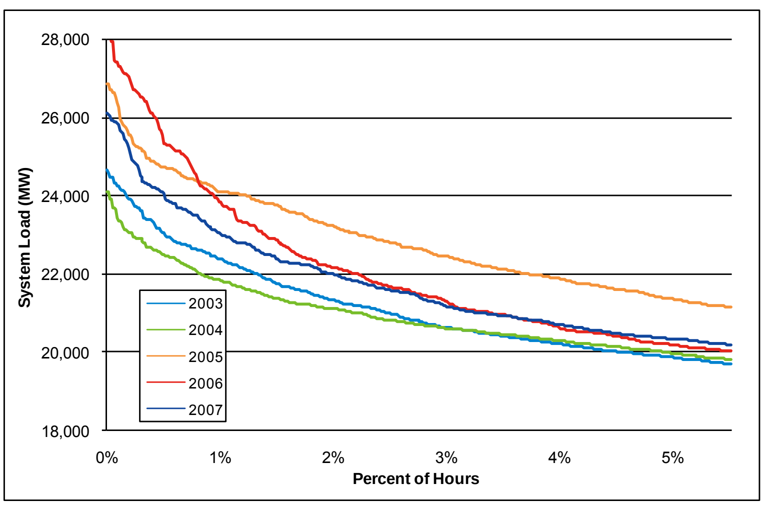

Figure 2-4: New England hourly load-duration curves, top 5% of hours, 2003 to 2007.

2.2.1 2007 Load Factor

Figure 2-5 shows historical load factors for New England expressed as a percentage for both weather-normalized and actual load levels. New England is a summer-peaking region in which hot weather and the resultant use of air conditioners drives peak consumption. Because summer peak demand has grown disproportionately compared with average demand, load factors have been declining. Over the past few decades, weather-normalized load factors (i.e., the ratio of the average hourly demand during a year to the peak hourly demand, both adjusted to normal weather conditions) have fallen significantly, dropping from 65% in 1980 to 56% in 2007. In addition to air-conditioning saturation, conversion from individual room air conditioning to central air conditioning and an increase in the size of the homes being cooled have been primary factors contributing to the long-run decline in the summer-peak load factor. From 2006 to 2007, actual demand increased, while the summer peak decreased, resulting in an increase in the actual load factor. However, weather- normalized peak hourly demand rose faster than average demand, resulting in a lower weather-normalized load factor. Because peak electricity consumption is projected to grow faster than average consumption, load factors likely will continue to decline in the future.

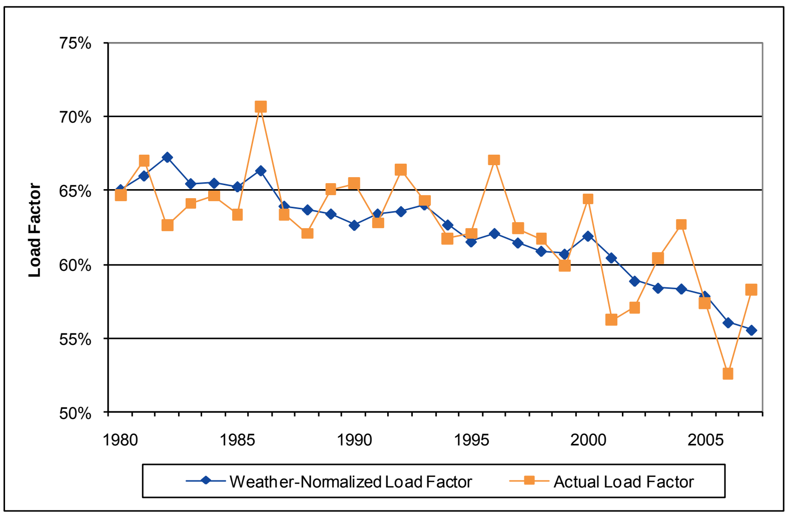

Figure 2-5: New England summer-peak load factors, 1980 to 2007.

The higher electricity consumption in the summer leads to higher wholesale electricity prices and increasing amounts of investment in generation and transmission to meet the peak demand for only a small number of hours per year. Additional demand-response and other demand resources would decrease peak loads, which would result in higher load factors.[35]

2.2.2 Day-Ahead Demand and Virtual Trading Trends

Two types of demand bids can be submitted in the Day-Ahead Energy Market: demand bids at the zonal level, and decremental bids that can be submitted at any pricing node on the system. Decremental bids are referred to as *virtual demand*. Demand bids may be submitted only by entities that have real-time load obligations (RTLOs) (i.e., they are serving load). Demand bids can be fixed or price sensitive and are made only at the zonal level. Virtual demand can be price sensitive only and submitted by any participant that satisfies the financial-assurance requirements detailed in the market rules.

[35] *Demand response* in wholesale electricity markets occurs when market participants modify their consumption of electric energy, such as shifting their consumption to off-peak periods. The ISO operates several demand-response programs, as discussed in Section 8. The Forward Capacity Market added two new programs, allowing energy efficiency and distributed generation to compete in the capacity market as suppliers.

Both types of bids can be used to hedge the difference between day-ahead and real-time prices. Because load is priced at the zone and demand bids are only zonal, the demand bids are well suited to hedge the price of RTLOs. Virtual demand bids can be used to arbitrage differences between day-ahead and real-time prices at a node. They also may hedge a particular load, such as a factory that has elected to receive the nodal LMP.

Virtual trading enables market participants that are not generator owners or load-serving entities to participate in the Day-Ahead Energy Market by establishing virtual (or financial) positions. It also allows more participation in the day-ahead price-setting process, allows participants to manage risk in a multi-settlement environment, and enables arbitrage that promotes price convergence between the Day-Ahead and Real-Time Energy Markets.

Virtual supply offers that clear in the Day-Ahead Energy Market create a financial obligation for the participant to purchase electric energy at the same location during the Real-Time Energy Market. Cleared virtual demand bids create a financial obligation for the participant to sell at the same location in the Real-Time Energy Market. That is, a virtual supply offer in the Day-Ahead Energy Market is "filled" by a purchase in the Real-Time Energy Market, and a virtual demand bid in the Day-Ahead Energy Market is sold in the Real-Time Energy Market. The financial outcome for a particular participant is determined by the difference between the day-ahead and real-time LMPs at the location at which the participant's offer or bid clears, plus all applicable transaction costs, including daily reliability cost. Figure 2-6 shows average hourly quantities of fixed and price-sensitive day-ahead demand and virtual demand and supply for 2007.

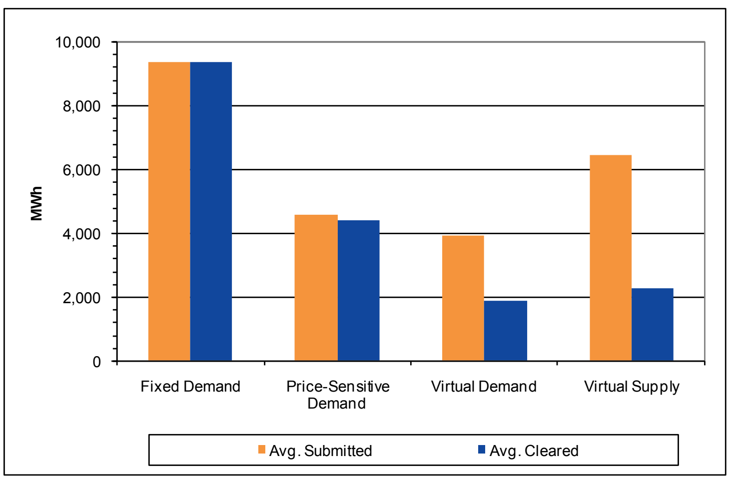

Figure 2-6: Average hourly submitted and cleared demand, virtual demand, and virtual supply, Day-Ahead Energy Market, 2007.

During 2007, 60% of cleared demand bids were fixed bids, insensitive to price, while 28% of the bids were price sensitive. The remaining 12% of cleared day-ahead demand was composed of cleared virtual demand bids representing day-ahead locational purchases of electric energy. Figure 2-7 shows the total monthly submitted and cleared virtual demand from January 2006 through December 2007. The figure shows that the volumes of both submitted and cleared virtual demand increased in 2007 compared with 2006.

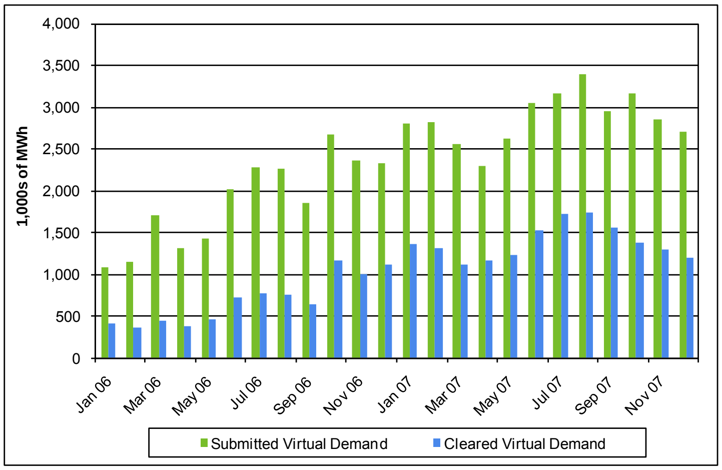

Figure 2-7: Monthly total submitted and cleared virtual demand, January 2006 to December 2007.

Figure 2-8 shows the monthly submitted and cleared virtual supply from January 2006 through December 2007. Similar to the trend in virtual demand, the volume of submitted and cleared virtual supply offers increased. Much of the increase in virtual electric energy (MWh) offered to the day-ahead market, however, was the result of a few participants that increased their virtual trading activity by large percentages to arbitrage the price. This increase in virtual transaction offers indicates a more mature market.

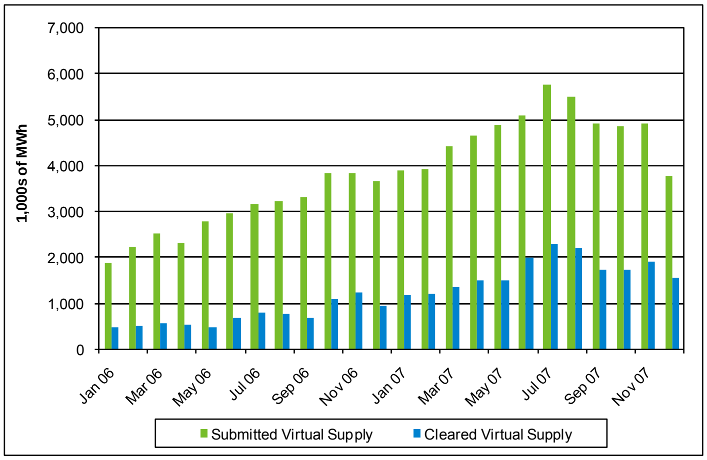

Figure 2-8: Monthly total submitted and cleared virtual supply, January 2006 to December 2007.

2.3 Electric Energy Supply in 2007

This section discusses elements of electric energy supply in 2007, including generation capacity, fuel types, self-scheduling, imports and exports, reserve margins, virtual supply, and changes related to the reoffer period.

2.3.1 System Capacity

The total 2007 summer seasonal claimed capability (SCC-S) grew by 44 MW, from 30,835 MW in 2006 to 30,879 MW in 2007.[36] Total summer peak capability, including firm capacity imports and exports (referred to as capacity net of purchase and sales), grew from 31,193 MW in 2006 to 32,918 MW in 2007. These values represent actual conditions as of the summer peaks. The 2007 SCC-S value does not include the 75 MW Pierce generating station that was put in commercial service in the fourth quarter of 2007. By comparison, no new generation resources were added to the system in 2006, while 92 MW of new generation were added in 2005; 656 MW were added in 2004; 2,949 MW were added in 2003; and 2,786 MW were added in 2002.[37]

New England has adequate installed capacity to meet its regional capacity needs through 2009.[38] The ISO is optimistic that adequate demand and supply resources will be purchased and installed in time to meet the projected capacity needs and the resource adequacy requirements for 2010 and beyond. As part of the system planning process, the ISO maintains a Generator Interconnection Queue, which tracks the resources that have requested interconnection studies.[39] As of January 4, 2008, about one month before the first Forward Capacity Auction, 97 projects totaling 13,066 MW, an increase of 24% from January 2006, were listed in the queue.[40] (See Section 3 for more information on the FCA.)

Figure 2-9 shows summer capacity (MW) by year and by fuel type for the past five years. Capacity levels have changed little during this period.[41] In 2007, dual-fueled generators capable of burning either oil or natural gas made up 24% of installed capacity, while natural-gas-fired generators made up 26% of installed capacity. Many dual-fueled generators capable of burning either oil or natural gas operate primarily on natural gas. In most cases, environmental restrictions on emissions from burning oil limit the total number of hours per year a generator can operate on oil.

[36] *Claimed capability* is a measure of capacity. *System capacity* includes capability available to New England adjusted for transfers of capacity between control areas through net purchase and sales. See the ISO's *2008–2016 Forecast Report of Capacity, Energy, Loads, and Transmission (CELT)* (2007).

[37] No new generating infrastructure was added to the system in 2006; however, some resources came from "behind the meter," resulting in additional SCC-S.

[38] See the ISO's *2007 Regional System Plan* (RSP07). (October 18, 2007). Available online at http://www.iso-ne.com/trans/rsp/2007/rsp07_final_101907_public_version.pdf or by contacting ISO Customer Service at 413-540-4220.

[39] Additional information on the projects in the Generation Interconnection Queue is available online at the "New or Modified Interconnections" section of the ISO Web site, http://www.iso-ne.com/genrtion_resrcs/nwgen_inter/index.html.

[40] Presentation by the ISO's chief operating officer at the NEPOOL Participants Committee meeting. (January 4, 2008). Available online at http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/prtcpnts/mtrls/2008/jan42008/npc_jan2008.pdf.

[41] Detailed information about generating capacity is available in the ISO's forecast reports of capacity, energy, loads, and transmission. See http://www.iso-ne.com/trans/celt/report/index.html.

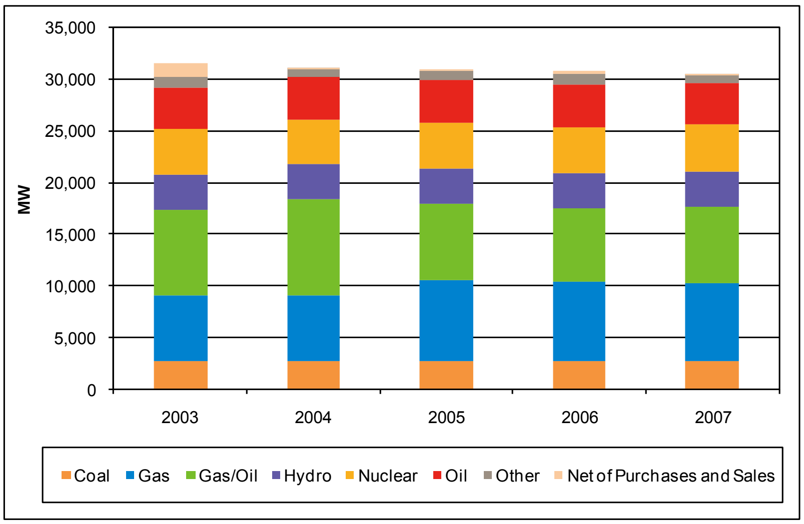

Figure 2-9: System summer capacity by generator type.

Note: Capacity values are for August, summarized from the ISO's forecast reports on capacity, energy, loads, and transmission (CELT Reports), which are available online at http://www.iso-ne.com/trans/celt/report/index.html.

Figure 2-10 compares zonal demand and generation for generators within each load zone. Generators within the Rhode Island, New Hampshire, and SEMA load zones produced more power than was used within these zones, while the Vermont, Maine, NEMA, WCMA, and Connecticut load zones all had demand that was greater than the power generated within these zones.

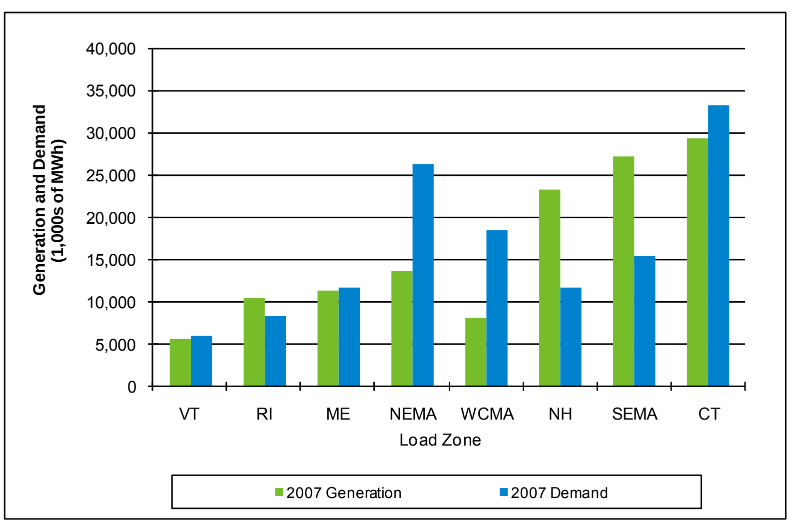

Figure 2-10: Annual generation and electric energy demand by load zone.

2.3.2 Generation by Fuel Type

Figure 2-11 shows actual generation by fuel type as a percentage of total generation for 2003 through 2007. The figure shows the fuels used to generate electric power, which differ from the capacity fuel mix shown in Figure 2-9 and the marginal unit by fuel type shown later in Figure 2-18 (see Section 2.4.2). The percentage of total generation produced by gas-fired and gas- and oil-fired plants in New England was 42% in 2007. Nationwide, about 21% of electric energy is produced by power plants fueled by natural gas.[42]

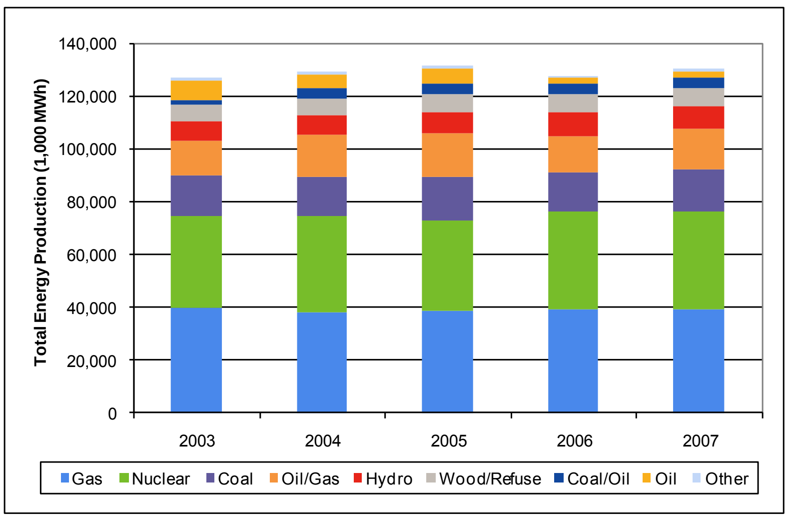

Figure 2-11: New England generation by fuel.

Note: "Other" includes jet fuel, diesel, composite, small renewables, and other small generation.

As discussed in Section 2.2, NEL increased by 1.9% from 2006 to 2007. Overall, 2007 generation increased 2.1%, from 128,046,000 MWh in 2006 to 130,720,000 MWh in 2007. Net imports from other control areas declined, accounting for the difference between changes in NEL and generation. During 2007, net imports from other control areas totaled 6,117,000 MWh, or about 4.5% of NEL.

2.3.3 Renewable Portfolio Standards in New England

Five of the six New England states (all but Vermont) have Renewable Portfolio Standards (RPSs) to encourage the development of renewable resources in the region. New Hampshire is the most recent state to establish a standard and is in the process of promulgating RPS regulations, which will go into effect sometime in 2008. Several states have other related requirements for the growth of renewable resources and energy efficiency. Vermont and Maine have newly established renewable requirements outside the RPS structure. Connecticut has new growth requirements for energy-efficiency programs, and Massachusetts recently announced energy-efficiency goals.

The Renewable Portfolio Standards in the New England states require a certain percentage of the electric energy produced or purchased by utilities to be from designated types of renewable resources

[42] EIA 2008. *Short-Term Energy Output.* Available online at http://www.eia.doe.gov/steo. (Accessed January 29, 2008).

over the next five years or more. This percentage typically increases annually up to a specified level. General types of resources the states qualify as renewable include small hydro, solar, wind, biomass, landfill gas, ocean thermal, and, in some states, fuel cells. [43] Some specific types unique to each state's RPS exist as well. The RPSs are intended to stimulate the development of new renewable resources and achieve a more diverse and "clean" generation portfolio.

To meet their renewable energy requirements, suppliers may buy Renewable Energy Certificates (RECs) created at renewable facilities within the New England region.[44] Alternatively, they may own and operate such resources to create RECs. Suppliers that do not meet their state's RPS requirements with generation are required to make Alternative Compliance Payments (ACPs) to cover the gap. These funds are to be used to invest in renewable projects within the state. These standards do not apply to municipal utilities.

Maine, Connecticut, and Massachusetts implemented RPSs before other states in the region. Rhode Island implemented its RPS in 2007, and Vermont, which passed a state law in 2005, is implementing its regulations for renewables. A number of other northeastern states, including New York, New Jersey, and Pennsylvania, also have implemented RPSs.

The specific percentages of electric energy that suppliers must obtain from renewable sources vary by state and year, as do the types of resources that qualify as renewable. The RPS requirements in 2007 were 5% for Connecticut suppliers, 2.5% for Massachusetts suppliers, 30% for suppliers in Maine. Rhode Island's RPS requirements started in 2007 at 3%. Vermont's requirement covers just incremental growth from 2005 to 2015. By 2015, the RPS requirements will increase to 14% in Connecticut, 10% in Massachusetts, and 10% in Rhode Island. The requirement in Maine will remain at 30%.

In 2007, renewable resources in New England generated about 10% of the region's total electricity. These resources included wind, refuse, landfill gas, biomass, and hydroelectric generators, excluding hydro generators that use pumping facilities to store the water source. The ISO's *2007 Regional System Plan* (RSP07) indicates that the New England renewable projects in the ISO Generator Interconnection Queue will not provide sufficient energy to meet the aggregate RPS energy requirements set for New England for 2016.[45] Unless many smaller projects are installed and operating by 2016, or renewable projects outside New England are certified for meeting the New England states' RPSs, the suppliers could fail to meet their RPS requirements. RSP07 contains additional information on Renewable Portfolio Standards.

2.3.4 Self-Scheduled Generation

Figure 2-12 shows the monthly percentage of total real-time generation that was self-scheduled for 2005 to 2007. Self-scheduling is of interest because self-scheduled generators are willing to operate at any price and are not eligible to set clearing prices. Participants may choose to self-schedule the output of their generators for a variety of reasons. For example, those with day-ahead generation

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[43] Pumped hydro is not counted as a renewable resource because the energy for pumping comes mostly from fossil-fueled (i.e., nonrenewable) generating plants.

[44] A *Renewable Energy Certificate* represents the environmental attributes of one megawatt-hour of electricity from a certified renewable generation source for a specific state's RPS. Providers of renewable energy are credited with RECs, which are sold or traded separately from the electric energy commodity.

[45] RSP07 is available online at http://www.iso-ne.com/trans/rsp/2007/rsp07_final_101907_public_version.pdf or by contacting ISO Customer Service at 413-540-4220.

obligations may self-schedule in real time to ensure that they meet their day-ahead obligations. Participants with bilateral contracts to provide energy, or fuel contracts that require them to take fuel, also may self-schedule. In addition, participants may self-schedule resources to prevent the units from being cycled off overnight and then started up again the next day. At times, self-scheduling contributes to Minimum-Generation Emergencies.[46] In 2007, self-scheduled generation averaged between 59% and 73% of total real-time generation, broadly consistent with past trends.

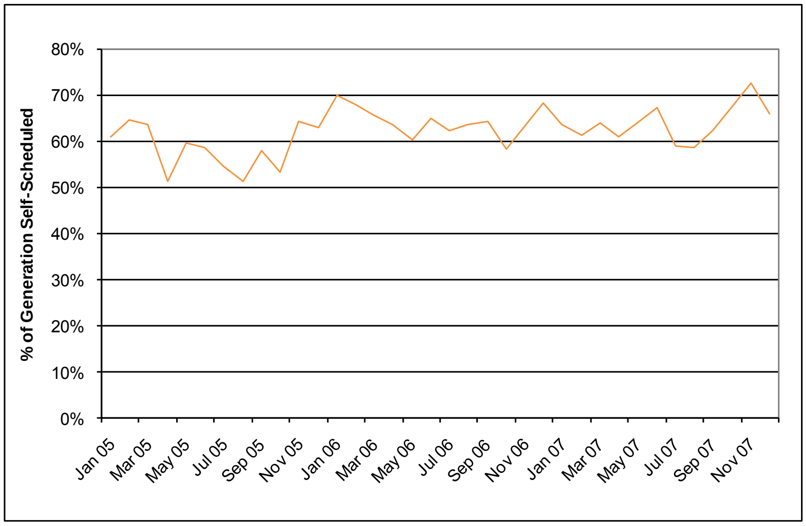

Figure 2-12: Self-scheduled generation as a percentage of total generation for 2005 to 2007.

Table 2-2 shows by generator fuel type the percentage of generation that was self-scheduled during 2007. Nuclear-fueled generators self-scheduled 100% of their generation, while coal/oil, oil, and jet fuel generators self-scheduled less than 20% of their generation. The percentage of generation self-scheduled is highest in off-peak hours and lowest in on-peak hours. This pattern suggests that participants may use self-scheduling as a tool to prevent generating units from being cycled on and off.

[46] A *Minimum-Generation Emergency* is a type of emergency declared by the ISO for which it anticipates requesting one or more generating resources to operate at or below its economic minimum limit so that it can manage, alleviate, or end the emergency.

Table 2-2
Percentage of Self-Scheduled Generation by Generator Fuel Type, 2007

Generator Type	% of Generation
Oil	10
Coal/Oil	15
Jet Fuel	19
Gas	40
Oil/Gas	45
Coal	67
Wood/Refuse	77
Hydro	82
Diesel Oil	94
Nuclear	100

2.3.5 Imports and Exports

During 2007, New England remained an overall net importer of power; its net imports from Canada exceeded the net exports to New York. Net interchange with neighboring regions amounted to 6,113,000 MWh for the year, about in line with net interchange in 2006. In 2007, both net imports from Canada and net exports to New York increased. Figure 2-13 shows net interregional power flows for 2003 through 2007, and Figure 2-14 shows imports and exports by interface for 2007.

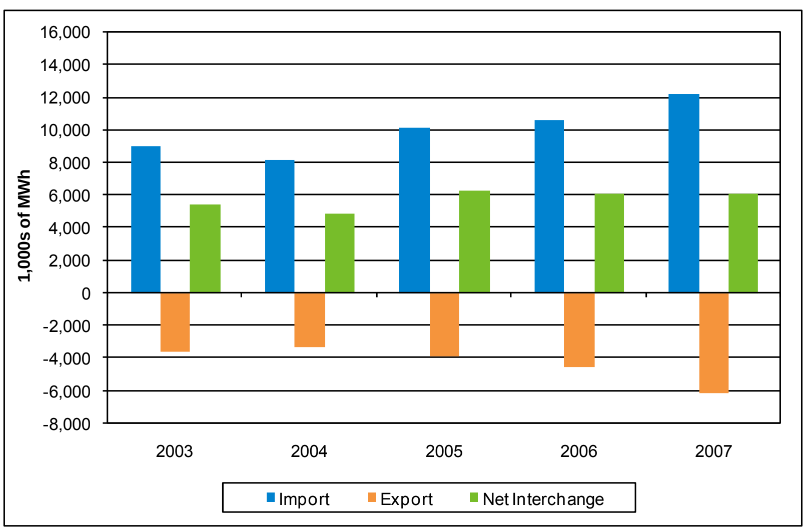

Figure 2-13: New England annual imports, exports, and net interchange, all interfaces.

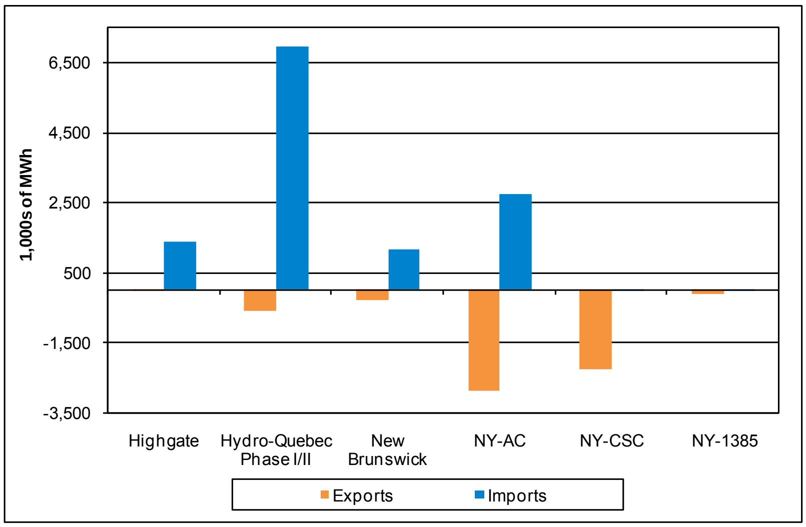

Figure 2-14: New England imports and exports by interface, 2007.

Note: The New York-AC interface is the collection of AC tie lines connected through Connecticut, Massachusetts, and Vermont. The NY-CSC interface is the Cross-Sound Cable.

Participant energy trading between New England and eastern and northern New York (i.e., on the NY-AC interface) exhibits bidirectional patterns (imports and exports), while trading over the CSC always is an export to Long Island associated with a long-term contract. Most of the power transfers between New York and New England are the result of contracts, in particular long-term contracts for exports over the CSC.

In June 2007, the ISO implemented the 1385 cable external node (Northport–Norwalk Harbor), establishing an external node unique to the 1385 cable. This node allows market participants to request electric energy schedules for delivery to New England specifically over this facility and for the specific pricing of that energy. With the creation of this external node, the region has three NY–NE interfaces (Cross-Sound Cable, 1385 cable, NY Northern AC). Although the new pricing and scheduling node was implemented in June, the cable went out of service in early August so that it could be replaced, and it did not return to service during 2007.

2.3.6 Operable Capacity Margins

The *operable capacity margin* is the sum of generating capacity and net imports minus the sum of load and reserve requirements. The capacity margin includes generation that may have been unavailable because of start-up time requirements, subarea export constraints, or a combination of both.[47]

[47] To conduct resource planning reliability studies within New England, the region is modeled as 13 subareas and three neighboring control areas. These areas include northeastern Maine (BHE); western and central Maine/Saco Valley, New Hampshire (ME); southeastern Maine (SME); northern, eastern, and central New Hampshire/eastern Vermont and southwestern Maine (NH); Vermont/southwestern New Hampshire (VT); Greater Boston, including the North Shore

In summer 2007, the operable capacity margin was higher than in previous years. Figure 2-15 shows operable capacity margins for the peak-demand hour of each month for 2005 to 2007. As usual, margins were lower during the summer months than in other months, which is consistent with summer-peak demand. The unseasonably high margins in July and August 2007 were due to monthly peak demand levels that were lower than usual.

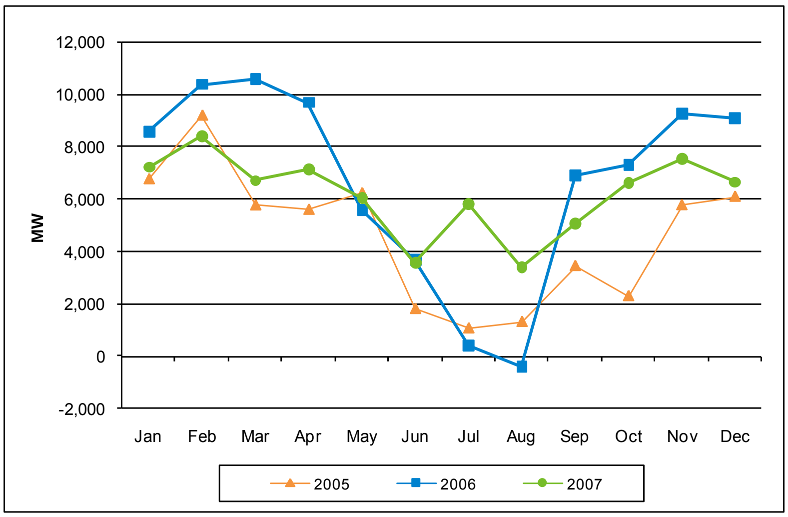

Figure 2-15: Monthly peak-hour operable capacity margins for 2005 through 2007.

2.4 Electric Energy Prices in 2007

This section provides information about wholesale electricity prices in New England, including the impact of fuel costs on prices, price separation between load zones, and capacity deficiencies that resulted in price spikes.

2.4.1 Annual Real-Time Electric Energy Prices

Figure 2-16 and Figure 2-17 show the real-time system electricity price for New England over the past five years as duration curves with prices ordered from highest to lowest. The system price is the load-weighted Real-Time Energy Market LMP. For each year, the duration curve shows the percentage of time the system price was at or above the price levels shown on the vertical axis.

(BOSTON); central Massachusetts/northeastern Massachusetts (CMA/NEMA); western Massachusetts (WMA); southeastern Massachusetts/Newport, Rhode Island (SEMA); Rhode Island bordering Massachusetts (RI); Southwest Connecticut (SWCT); Norwalk/Stamford (NOR); and Connecticut (CT). Greater Connecticut includes the CT, SWCT, and NOR subareas. Greater Southwest Connecticut consists of the SWCT and NOR subareas. The three neighboring control areas are New York, Hydro-Québec, and the Canadian Maritimes. The New England Control Area also is divided into load zones and reserve zones, explained more fully in Section 2.1 and Section 4.1, respectively.

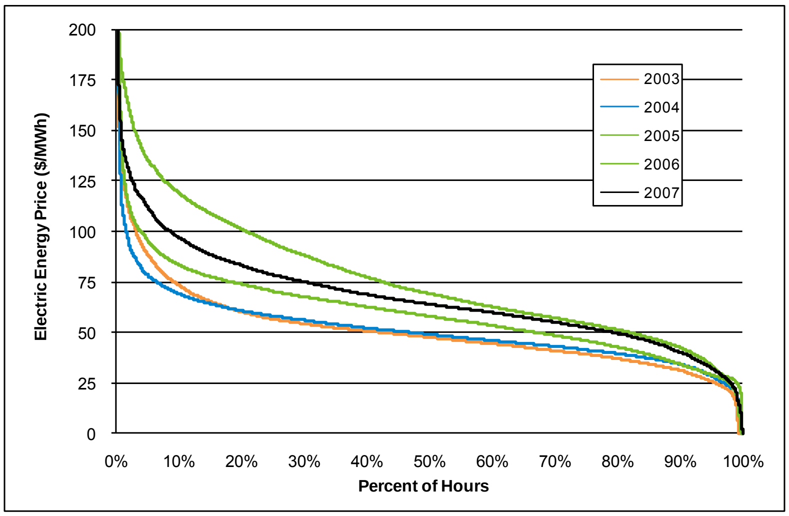

Figure 2-16: System real-time price-duration curves, prices less than $200/MWh, 2003 to 2007.

Note: System price is the single energy-clearing price (ECP) for the Interim Market period ending February 28, 2003, and load-weighted Real-Time Energy Market LMPs for March 2003 to December 2006.

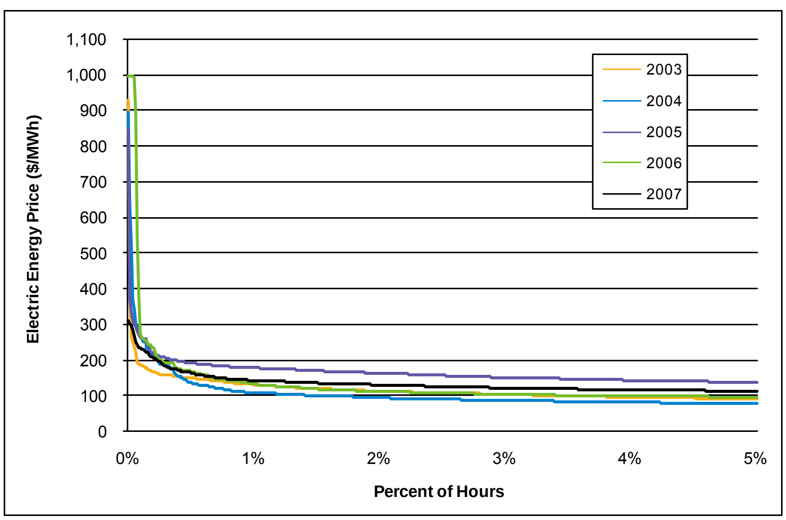

Figure 2-17: System real-time price-duration curves, prices in most expensive 5% of hours, 2003 to 2007.

Note: System price is the single ECP for the Interim Market period ending February 28, 2003,and load-weighted Real-Time Energy Market LMPs for March 2003 to September 2007.

The figures show that typical prices during 2007 were higher than prices during 2006 but lower than those in 2005. The increase from 2006 primarily was due to increased fuel prices (as discussed in the next section). The peak prices shown in Figure 2-17 were lower than in both 2006 and 2005. This is consistent with the higher operable capacity during summer peak periods discussed in Section 2.3.6. Appendix A.2 includes LMP summary statistics for on- and off-peak hours and the monthly average day-ahead and real-time LMPs by zone.

2.4.2 Electricity Prices and Fuel Costs

Electric energy prices were slightly higher in 2007 than in 2006 primarily due to a rise in fuel prices. Other factors that affected the price of electric energy in 2007 include a higher use of electric energy (net energy for load), fewer Minimum-Generation Emergency hours when prices are set to zero, and the institution of co-optimization of reserves with electric energy. Gas-fired generation continues to be the marginal resource most of the time. In 2007, gas-fired resources were marginal 72% of the time, similar to 2006 when gas was marginal 73% of the time.

This similarity, however, masks a deeper change in fuel costs. During 2007, liquid fuel prices (No. 2 oil, jet kerosene, No. 6 oil) increased more than natural gas prices, building on a trend observed in 2006 of a widening gap between the cost of natural gas and liquid fuels. This change in relative prices affects generator dispatch by shifting liquid-fueled generators to a later point in the dispatch stack and substituting natural gas resources that otherwise would have been out of merit. The result is a steeper dispatch curve—a dispatch stack that rises in cost sooner. In this new environment, natural gas combined-cycle resources are providing a lower-cost alternative to liquid-fueled resources.

2.4.2.1 Marginal Units

Because the price of electricity changes as the price of the marginal fuel changes, analyzing marginal units by fuel type helps explain this electricity price factor. In all circumstances, the system has one marginal unit that is classified as the *unconstrained* marginal unit. In a locational marginal pricing market, however, more than one resource sets price when transmission constraints are present. For example, during high load levels, the interface between Connecticut and the rest of the New England power system could become constrained, and local generation would need to be *dispatched up* to meet load. In this instance, the local unit dispatched up would be considered *constrained up for transmission* because, absent the limit on the interface, it would otherwise be off or dispatched at a lower level. For some transmission-constraint conditions, the ISO lowers the output of a marginal unit, which then is classified as *constrained down for transmission*.

Figure 2-18 shows the percentage of total marginal minutes that each input fuel was marginal during 2007. If there are two marginal units during a single five-minute interval, the analysis counts 10 marginal minutes. Using this methodology, the sum of marginal minutes across all input fuels will equal 100%.

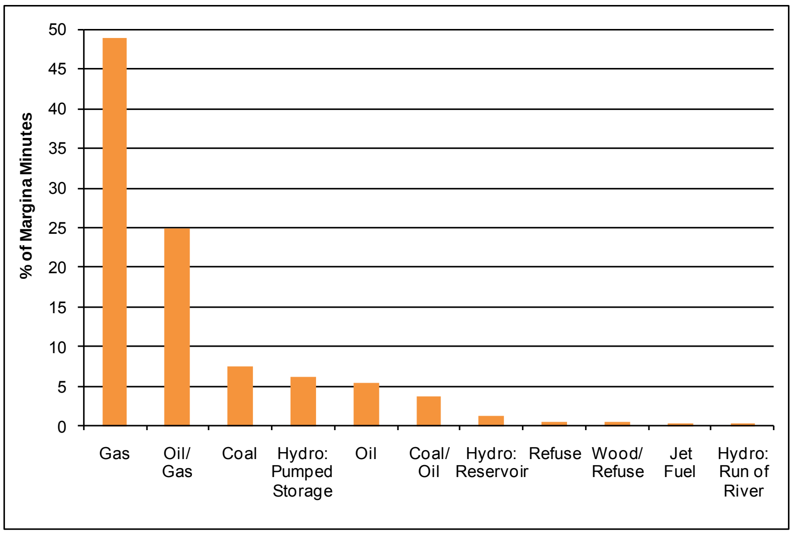

Figure 2-18: Percentage of pricing intervals by marginal fuel type in real time, 2007.

Note: The figure includes each marginal unit; during periods when the system has more than one marginal unit at the same time, the marginal minutes are distributed equally across the marginal units' fuel types. Diesel-fueled units were marginal during the year for less than 1/10 of a percent of the total marginal minutes. This fuel source is not included in the figure.

Figure 2-18 shows that a unit burning natural gas was marginal during 49% of all the marginal minutes. Units capable of burning both gas and oil, most of which burn gas as their primary fuel, accounted for 25% of all marginal minutes. These results show the extent to which New England electricity prices depend on the offers of units capable of burning natural gas. The data presented in Figure 2-18 demonstrate that almost 80% of all minutes marginal are from natural-gas-fired or oil-fired units. This dependence on gas and oil to generate electricity contributes to the year-to-year volatility of the region's electricity price.

2.4.2.2 Relative Fuel Prices

The marginal fuel types have remained relatively constant between 2006 and 2007. However, the relative fuel prices changed significantly because of the rise in petroleum prices. In the last week of 2006, the average cost of imported crude oil was $54/barrel. This rose to $85.52/barrel in the last week of 2007.[48] Geopolitical concerns and uncertainty in financial markets have contributed to rising oil prices over most of the year.[49] The decline of the dollar against most other currencies has contributed to the rise in prices because most U.S. oil is imported.

Table 2-3 shows indices for average annual prices of several fuels for each of the last eight years, with each fuel indexed to its value in 2000. Generators that burn natural gas and No. 6 oil set price a majority of the time in New England, as shown in Figure 2-18. Natural gas prices were 8.8% higher

[48] Weekly crude prices are available at http://www.eia.doe.gov/.

[49] Energy Information Administration. *Residential Natural Gas Prices What Consumer Should Know*. DOE/EIA-X046 (Washington, D.C.: U.S. DOE; 2007). Available online at http://www.eia.doe.gov/neic/brochure/oil_gas/rngp/index.html.

in 2007 than in 2006. No. 6 oil (1%) increased 16.2%. The higher natural gas and oil prices were the primary cause of the higher overall electricity prices shown in Figure 2-16.

Table 2-3
Fuel Price Index, Year 2000 Basis

Fuel	2000	2001	2002	2003	2004	2005	2006	2007
Natural gas	1	0.88	0.75	1.3	1.37	1.97	1.48	1.61
No. 2 oil	1	0.84	0.8	0.99	1.32	1.95	2.15	2.43
No. 6 oil (1%)	1	0.83	0.9	1.09	1.12	1.66	1.85	2.15
High-sulfur coal	1	1.72	1.11	1.32	2.22	2.38	2.02	1.83
Low-sulfur coal	1	1.76	1.15	1.35	2.35	2.49	2.22	1.91
Jet fuel	1	0.82	0.78	0.95	1.31	1.87	2.14	2.37
Kerosene	1	0.82	0.77	0.95	1.31	1.89	2.15	2.38
Diesel	1	0.84	0.8	0.98	1.33	1.97	2.27	2.50

During recent years, petroleum prices have grown faster than natural gas prices. Figure 2-19 shows the relative prices for No. 2 and No. 6 oils and natural gas normalized to year 2000 prices. The spike in gas prices in 2005 is attributed to the supply interruptions of hurricanes Katrina and Rita.

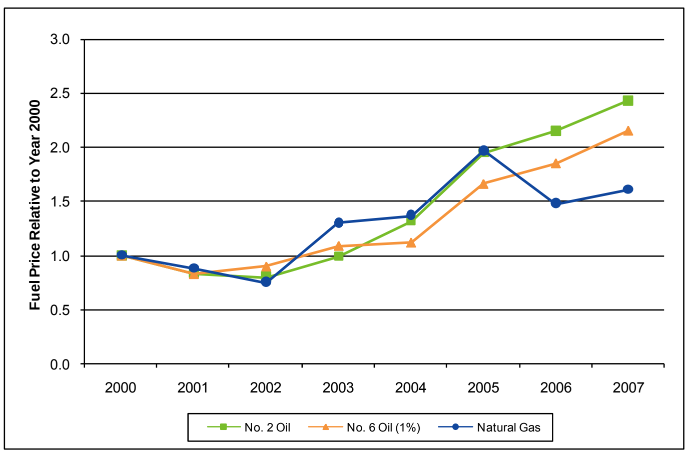

Figure 2-19: Growth in fuel prices relative to year 2000 prices.

Figure 2-20 shows the daily average real-time system price plotted against the daily average variable production cost of hypothetical power plants burning either natural gas or No. 6 oil.[50] The gas resource marginal costs are based on a combined-cycle gas resource with a heat rate of 7,500 British

[50] Averages are not weighted.

thermal units (Btu) per kilowatt-hour (kWh), while the oil resource production costs are based on a heat rate of 10,500 Btu/kWh.[51] The day-ahead spot prices for fuel are used to calculate each unit's variable costs. Unexpected system conditions, such as an unplanned generator or transmission line outage, or unexpected high demand levels may cause electricity price spikes unrelated to fuel prices.

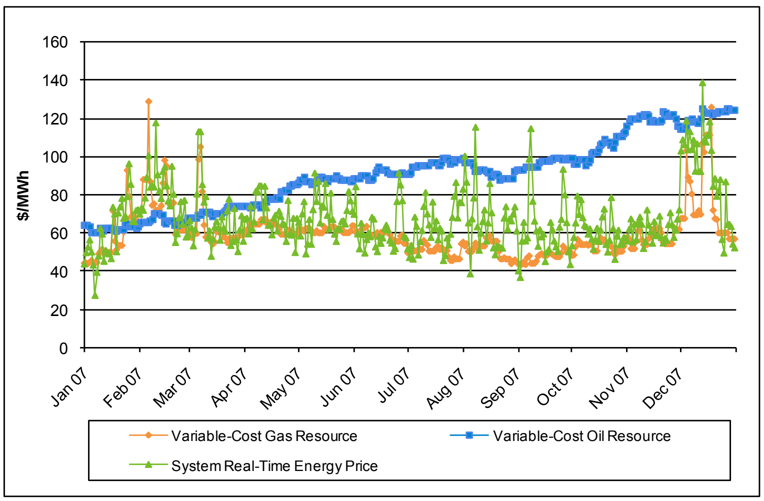

Figure 2-20: Daily average real-time system price of electricity compared with variable production costs.

During many days in January and February 2007, the hypothetical No. 6 oil unit shown in Figure 2-20 would have had costs less than the real-time system price and less than the gas unit's costs. However, the costs of No. 6 oil rose almost continuously during the year, and the No. 6 oil unit would have been more often out of merit relative to the system price as the year progressed.

The change in the merit status of No. 6 oil units relative to natural gas units affected the underlying supply curve. Before the increase in the cost of No. 6 oil, some oil units offered at the same level as some efficient combined-cycle natural gas units. As the cost of oil increased by more than the cost of natural gas did, some No. 6 oil units have been displaced by less efficient (i.e., higher heat rate) natural gas units.

Figure 2-21 illustrates the effect of the increased prices of No. 6 oil and other liquid fuels on the marginal cost supply curve while holding the natural gas price constant. The supply curve is limited to fossil fuel resources; it excludes nuclear, hydro, and other nonfossil fuels. The higher of the two curves represents the 2007 supply curve using average 2007 fuel prices. The lower of the two curves uses the same heat rates and megawatt blocks as the 2007 supply curve but uses fuel costs that have normalized 2004 prices to the 2007 price of natural gas. To normalize the 2004 fuel prices, the 2004 price of each fossil fuel was multiplied by the ratio defined by the 2007 average natural gas price divided by the 2004 average natural gas price.

[51] A generator's *heat rate*, traditionally reported in Btu/kWh, is the rate at which it converts fuel (Btu) to electricity (kWh) and is a measure of the thermal efficiency of the conversion process.

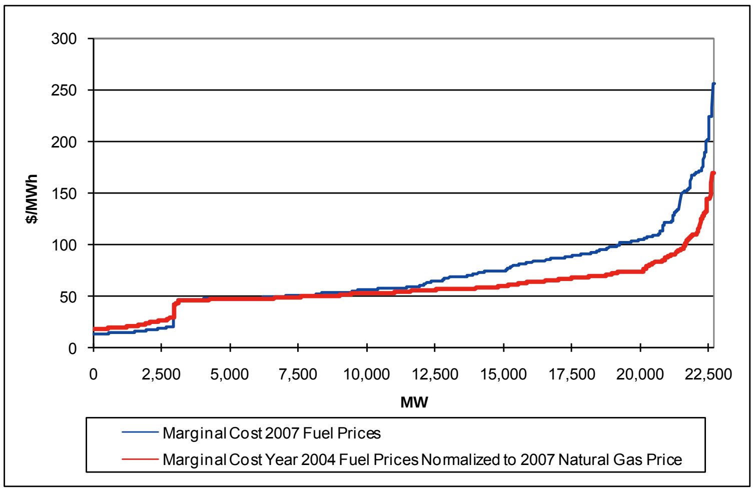

Figure 2-21: Effect of increased fuel prices of No. 6 oil and other liquid fuels on marginal cost supply curve while holding natural gas prices constant.
Note: Fuel costs are annual averages. The 2004 fuel costs are normalized to 2007 gas prices.

Figure 2-22 illustrates the change in the relative merit order of No. 6 oil resources offering at marginal cost. The data here are from the same supply curves illustrated in Figure 2-21, but Figure 2-22 presents only those blocks associated with No. 6 oil. The No. 6 oil resources are uniformly higher in the stack than they would be if the price of No. 6 oil had risen at the same rate as the price of natural gas. The marginal cost of a combined-cycle gas resource operating at a heat rate of 7,500 Btu/kWh is included as a benchmark.

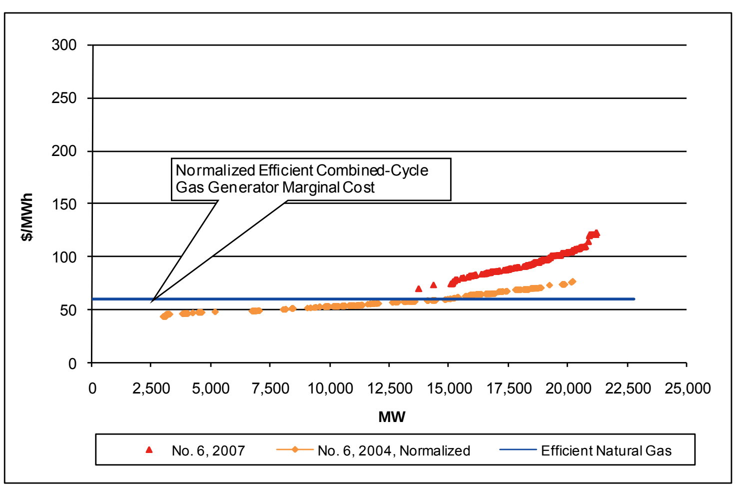

Figure 2-22: No. 6 oil generator marginal costs using 2007 actual and 2004 normalized fuel prices.

Figure 2-22 confirms that No. 6 oil resources competed with natural gas resources much less often in 2007 than in 2004. The dispatch order and supply curves have changed as a result of the relative price changes.

2.4.2.3 Fuel-Adjusted Electric Energy Price

The ISO historically has calculated a "fuel-adjusted" electricity price using a simple methodology, recognizing its limitations. The analysis uses the year 2000 as a base and normalizes the price of the marginal unit in each five-minute interval for the change in the unit's fuel price compared with fuel prices in 2000. This marginal unit methodology assumes that the marginal units are similar in all years. In contrast, the analysis surrounding Figure 2-20 through Figure 2-22 shows that marginal units have changed significantly.

Fuel-adjusted electric energy prices for the Interim Markets period of January 2000 through February 2003 were derived by adjusting each five-minute real-time marginal price (RTMP) by a monthly index of spot-market prices for the fuel used by the generator setting the RTMP. Fuel-adjusted electric energy prices for the Standard Market Design (SMD) period of March 2003 through December 2007 were derived by adjusting the five-minute Hub real-time LMPs by a monthly index of spot-market prices for the fuel used by the marginal generator. This generator was not constrained up or down for transmission in the Unit Dispatch System (UDS) case that formed the basis for the LMP.

Five-minute prices set by hydro plants in 2007 were adjusted by a monthly index of average electric energy prices to reflect changes in opportunity costs. Nuclear, wood, composite, refuse, and other fuels for which reliable prices were not available were not adjusted. These unadjusted prices should not significantly affect the results because units using these fuels were marginal less than 1% of the time during the seven-year analysis period. The adjusted five-minute electric energy prices were then averaged to the hourly level and weighted by hourly load before calculating the yearly averages.

Table 2-4 and Figure 2-23 show yearly average actual and fuel-adjusted real-time electric energy prices for New England. These averages are load weighted. Actual average real-time electric energy prices in 2007 were higher than in 2006 but lower than in 2005. After adjusting for the price of fuels used to generate electricity, the average electric energy price in 2007 was similar to prices in the previous years.

Table 2-4
Actual and Fuel-Adjusted Average Real-Time Electric Energy Prices, $/MWh

	2000	2001	2002	2003	2004	2005	2006	2007
Load-weighted actual electric energy price (ECP during Interim Markets; Hub LMP during SMD)	45.95	43.03	37.52	53.40	54.44	79.96	62.74	69.57
Load-weighted electric energy price normalized to 2000 fuel-price levels	45.95	48.60	46.65	43.51	43.33	44.99	42.64	45.15

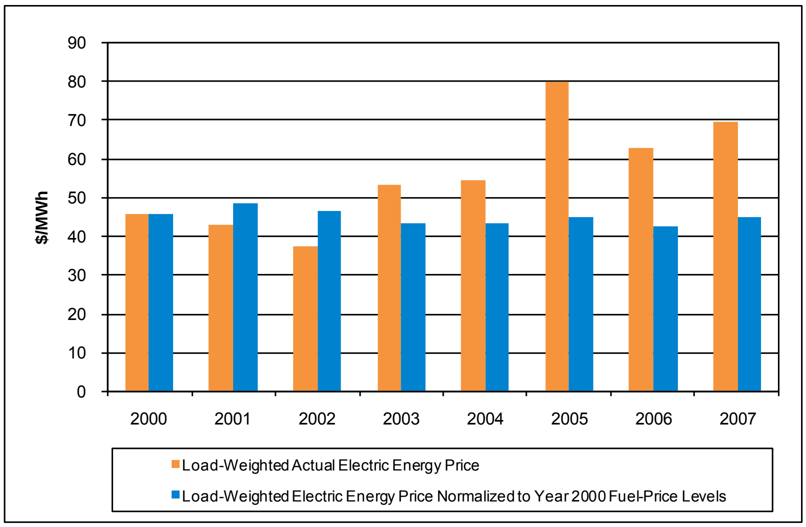

Figure 2-23: Actual and fuel-adjusted average real-time electric energy prices, 2000 to 2007.

The variation among fuel-adjusted yearly average prices was less than among average unadjusted prices. Adjusted prices in 2001 and 2002, years with lower overall natural gas prices than 2000, were higher than actual prices, while energy prices in 2003 to 2007, when gas prices were higher, were lower after adjustment.

Electric energy prices appear to be normal when adjusted for fuel prices. The fuel-adjusted price of electric energy in 2007 of $45.15/MWh was $2.51/MWh higher than in 2006. In comparison, the average fuel-adjusted price from 2000 to 2006 was $45.01/MWh. Actual unadjusted average electric energy prices rose from $62.74/MWh in 2006 to $69.57/MWh in 2007. This increase was paralleled by an 8.8% increase in natural gas prices and a 16.2% increase in the price of 1% sulfur No. 6 oil.

The size and direction of the change is consistent with the effect of increased energy demand in 2007. The ISO estimated the effect of increased demand by applying the increased demand to representative supply curves. Average hourly energy demand increased by 279 MW, yielding estimates ranging from $1.29/MWh to $4.96/MWh. The observed increase in the fuel-adjusted energy price of $2.51/MWh (5.8%) falls well within this range. Therefore, market price changes are consistent with the shifts in the underlying demand and supply conditions.

2.4.3 LMPs and Nodal Prices for 2007

Table 2-5 shows the 2007 average LMP values for the Hub and the eight load zones in New England. On average, day-ahead prices exhibited a slight premium over their real-time counterparts. During 2007, average prices were similar across the Hub and New England load zones, with the exception of Maine and Connecticut. Average LMPs in Maine were several dollars lower than in other areas, as a result of negative marginal loss and congestion components costs on Maine LMPs, while average LMPs in Connecticut were higher than in other areas. Average day-ahead LMP differences between Maine and Connecticut were $7.35/MWh. During high-demand periods, Connecticut frequently is import constrained, which results in congestion and higher prices. On average, electric energy prices in the day-ahead market should approximate their real-time counterparts. However, the slightly higher day-ahead LMPs noted in Table 2-5 are consistent with a premium that reflects the price risk of the real-time market. Load is willing to pay a little more to avoid the potentially high prices that occur more frequently in real time, and generators will want a premium to assume the risk of nonperformance in the real-time market.

Table 2-5
Average LMP Statistics by Zone for 2007, All Hours, $/MWh

Location/Load Zone	Average LMP	
	Day Ahead	Real Time
Internal Hub	67.97	66.72
Maine	64.35	63.65
New Hampshire	66.83	65.99
Vermont	69.35	68.11
Connecticut	71.70	71.75
Rhode Island	66.16	65.05
SEMA	67.95	66.19
WCMA	68.55	67.49
NEMA	66.63	65.6

In general, prices in the Real-Time Energy Market are more variable than prices in the Day-Ahead Energy Market as a result of unexpected events, such as generator and transmission contingencies or variations in the actual demand compared with the demand forecast. Table 2-6 shows the greater spread in difference between minimum and maximum day-ahead and real-time prices for the Hub and each load zone in 2007. For all pricing locations shown, the minimum real-time price is lower than the minimum day-ahead price, and the maximum real-time price is greater than the maximum day-ahead price. In 2007, maximum hourly prices never reached $1,000/MWh in the Day-Ahead Energy Market or the Real-Time Energy Market.

Table 2-6
Minimum and Maximum Annual Average LMPs, 2007

Location/ Load Zone	Minimum LMP		Maximum LMP	
	Day Ahead	Real Time	Day Ahead	Real Time
Internal Hub	25.18	0.00	207.35	297.92
Maine	21.47	0.00	194.99	817.08
New Hampshire	24.62	0.00	188.47	497.85
Vermont	24.94	0.00	195.82	300.39
Connecticut	24.73	0.00	205.40	631.65
Rhode Island	24.85	0.00	206.04	294.40
SEMA	24.98	0.00	208.45	295.71
WCMA	25.16	0.00	206.96	300.10
NEMA	24.69	0.00	209.08	331.76

Most of the largest differences between day-ahead and real-time prices occurred during ISO Operating Procedure 4, *Actions during a Capacity Deficiency* (OP 4) events.[52] The largest difference between day-ahead and real-time prices occurred on February 10, in hour ending (HE) 10 (10:00 a.m.).[53] OP 4 was in effect at the time, and the day-ahead price was $99.31/MWh, while the real-time price was $297.92/MWh, a difference of $198.61/MWh. The high maximum price for the Maine load zone occurred when a transmission line was out of service at the same time a generator experienced an unexpected outage.

On the maps in Figure 2-24, the average annual nodal LMPs are shown as color gradations from blue, representing $51/MWh or less, to red, representing prices of $77/MWh and higher.[54] Western Connecticut and Southeast Massachusetts had the highest average day-ahead prices, while Maine had the lowest prices. Day-ahead and real-time LMPs in northwestern Connecticut are higher than in most other areas because of a persistent loss component associated with one of the NY-AC interface tie lines.

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[52] ISO OP 4 establishes procedures and guides for actions during capacity deficiencies. Actions 1–5 and 7–10 are implemented to maintain operating-reserve requirements. Action 6 allows for the depletion of 30-minute reserve, while Action 11 involves arranging to purchase emergency capacity. Actions 12 and 13 call for implementing various levels of voltage reductions.

[53] LMPs are based on *hour endings*, which denote the preceding hourly time period. For example, "hour ending 1" is the time period of 12:01 a.m. to 12:59 a.m.

[54] The extreme minimum and maximum values of nodal LMPs are not included in the scale to provide more resolution in price difference of the figures. The actual maximum average annual LMP for the day-ahead market was $77.55/MWh, and the true minimum was $47.80/MWh. The actual maximum for the real-time market was $78.57/MWh, and the actual minimum was $41.81 $/MWh.

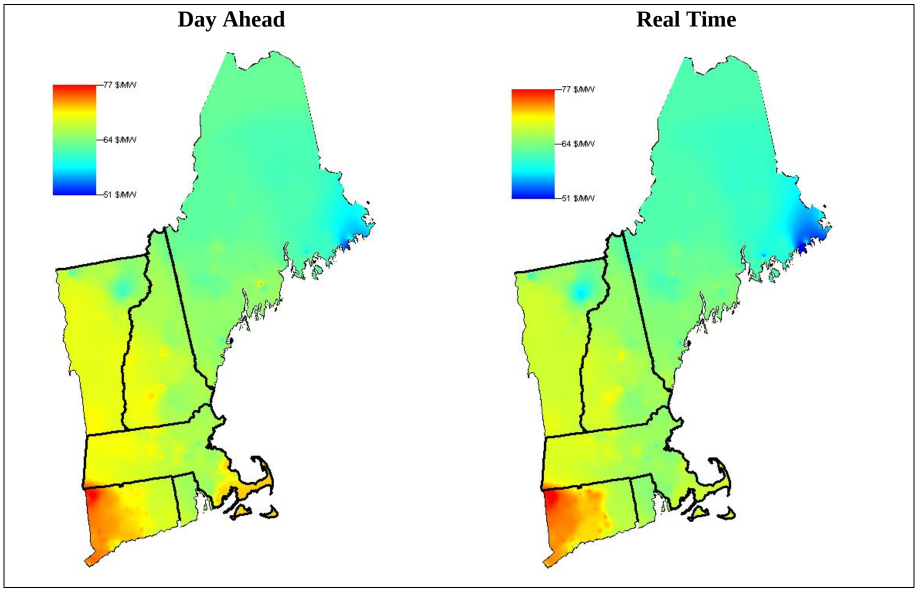

Figure 2-24: Average nodal prices, 2007, $/MWh.

2.4.4 Wholesale Prices in Other Northeastern Pools

Comparing price levels across interconnected power pools provides a context for evaluating price levels in New England. Figure 2-25 compares the 2006 average system prices with the 2007 prices for the three northeastern ISOs—ISO New England, the New York ISO (NYISO), and PJM Interconnection. The average prices for 2007 were moderately higher in all three pools (PJM real-time prices excepted). ISO New England and NYISO average prices are calculated hourly system prices based on locational prices and locational loads, while PJM prices are published hourly system prices.[55] New York had the highest average prices, while PJM had the lowest.

[55] Yearly average system prices are not load weighted. See PJM's Web site at http://www.pjm.com and NYISO's Web site at http://www.nyiso.com.

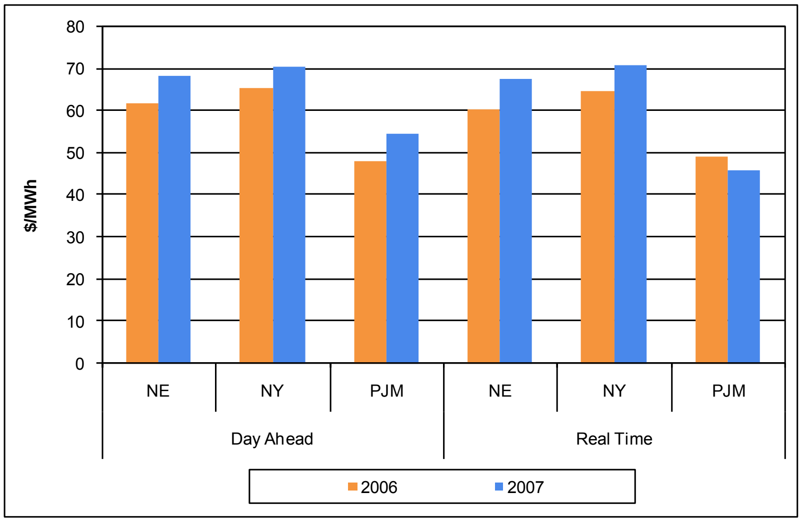

Figure 2-25: Average system prices, 2006 and 2007, ISO New England, NYISO, and PJM.

The variation in average prices among the power pools is affected by a variety of factors, such as transmission congestion, daily and seasonal demand patterns, load concentration in congested areas, and differences in the generator fuel mix. Significant coal and nuclear capacity in the PJM Control Area is a key driver of its lower average system price.[56] Appendix A.3 shows the yearly average system prices for on- and off-peak periods for ISO New England, NYISO, and PJM.

2.4.5 Comparison with Bilateral Prices

In addition to buying and selling electricity through the ISO-administered markets, participants trade electric energy bilaterally through a variety of avenues. These include the Intercontinental Exchange (ICE), an electronic marketplace for energy trading. This section presents comparisons between ISO energy market prices and ICE prices. Convergence of bilateral trading prices with wholesale market prices is an indicator of efficient markets.

Figure 2-26 shows day-ahead Hub LMPs and ICE day-ahead trade prices. The price trends generally are similar. The average difference between ISO and ICE prices for the days that power was traded is $0.41/MWh.[57]

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[56] PJM Interconnection. *Capacity by Fuel Type* (December 31, 2006). Available online at http://www.pjm.com/services/system-performance/downloads/capacity-by-fuel-type-2006.pdf.

[57] This number is the simple average of the difference between ISO and ICE prices. It indicates that, on average, ICE day-ahead trade prices were higher than ISO day-ahead LMPs.

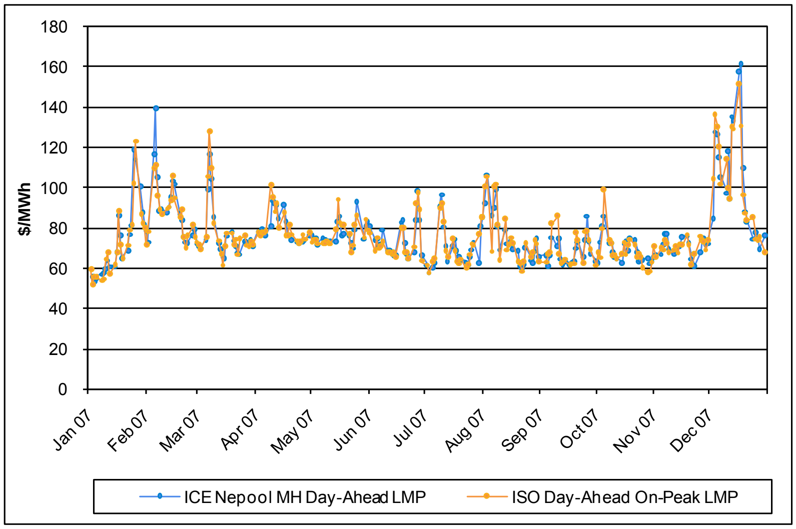

Figure 2-26: Comparison of ISO day-ahead Hub LMPs with ICE day-ahead New England trade prices.

Figure 2-27 compares the monthly average for day-ahead LMPs with the average of the last bid and last offer for each monthly delivery period traded for ICE. Prices were similar in most months but differed by $21.75/MWh in December because of the end-of-the-year spike in day-ahead ISO electricity prices, which was not fully accounted for in the ICE bilateral market.

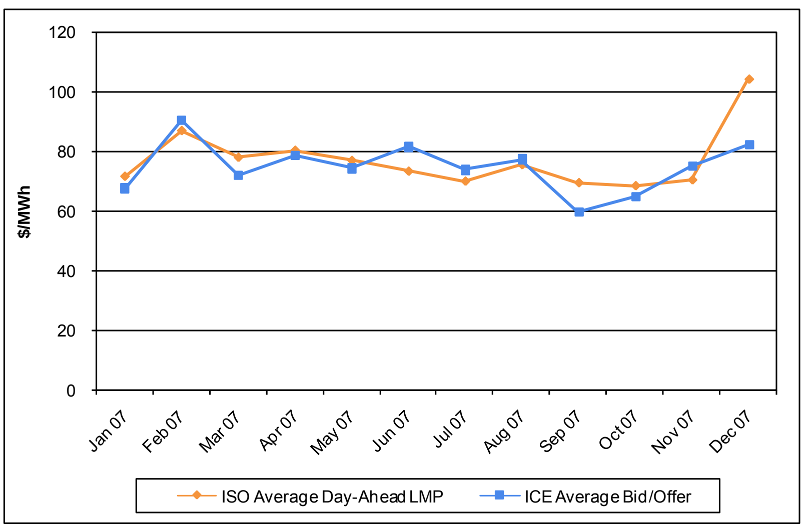

Figure 2-27: Monthly delivery—last ICE bilateral trade compared with day-ahead ISO LMPs.

2.4.6 Price Separation—Congestion and Losses

In addition to energy production costs, LMPs reflect the marginal costs of congestion and losses. The inclusion of these costs in the electric energy price and the resulting price separation between locations are key elements of efficient pricing.

Figure 2-28 shows the average hourly differences between the LMP in each zone and the LMP at the Hub in the Day-Ahead and Real-Time Energy Markets for 2007. The results for day-ahead and real-time LMPs are similar. The average LMPs for the Maine, New Hampshire, Rhode Island, SEMA, and NEMA load zones are less than the Hub LMP, and the LMPs for the Connecticut, Vermont, and WCMA load zones are greater than the Hub LMP. Differences in LMPs among the load zones are due to the joint impact of congestion and losses in the Day-Ahead and Real-Time Energy Markets. The direction and relative relationships are similar in the Day-Ahead and Real-Time Energy Markets, which indicates that the Day-Ahead Energy Market is functioning well.

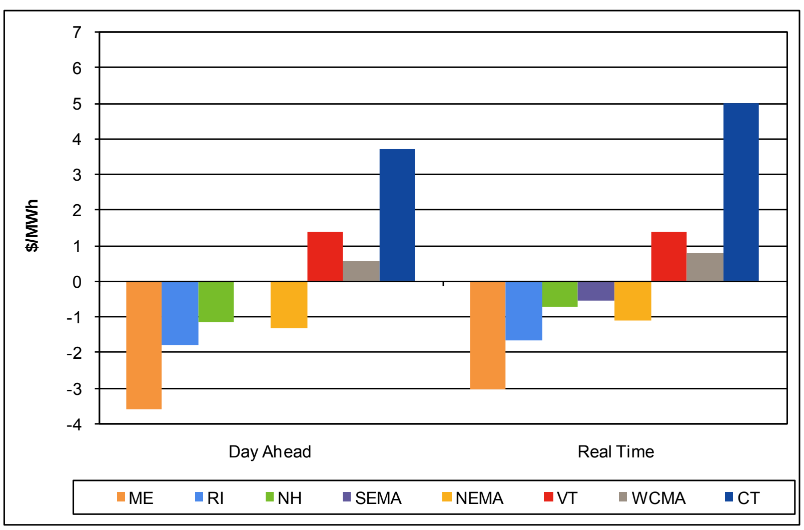

Figure 2-28: Average hourly zonal LMP differences from the Hub, 2007.

In 2007, the day-ahead price separation between Connecticut and other load zones was less pronounced than in 2006. On average in 2007, day-ahead prices in Connecticut were $3.73 higher than at the Hub, compared with $6.34/MWh higher in 2006. Real-time CT prices were higher by about the same amount as in 2006, at $5.03/MWh higher.

Total system congestion revenues from both the Day-Ahead and Real-Time Energy Markets are collected in the Congestion Revenue Fund and are used to pay FTR holders. Congestion revenues from the day-ahead market are strictly positive. Congestion revenues from the real-time market can be positive or negative. The possibility of negative congestion revenues arises because the real-time market is settled on deviations from the day-ahead market, and the deviations can be positive or negative. Deviations do not exist in the day-ahead market. Section 7 discusses the Congestion Revenue Fund in more detail.

Figure 2-29 shows total congestion revenue by quarter from the second quarter of 2003. Total congestion costs were lower in 2007 compared with 2006, dropping from $192 million to $112 million. During 2007, day-ahead congestion revenue was lower than the 2006 level, and negative real-time congestion revenue was more negative than in previous years. Both day-ahead and real-time congestion revenue combined to result in lower net congestion revenue.

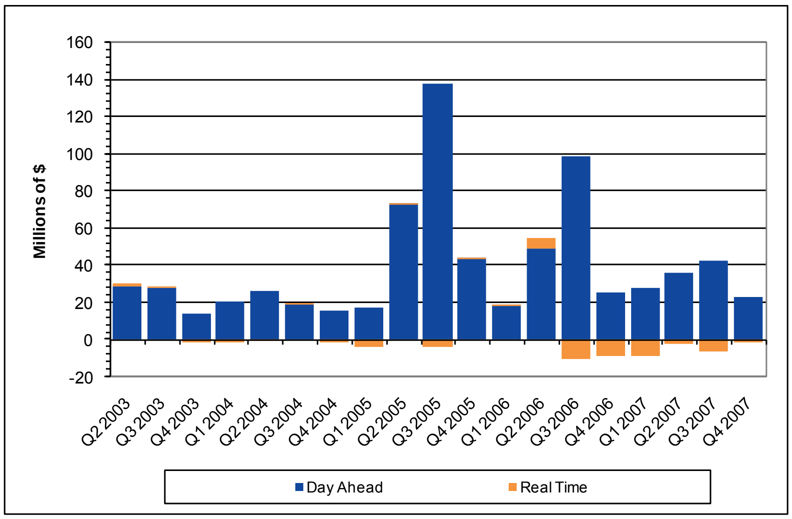

Figure 2-29: Total congestion revenue by quarter.

Table 2-7 and Table 2-8 show the 2007 averages of the congestion component, the marginal loss component, and the sum of the two components for the Hub and each load zone for the Day-Ahead and Real-Time Energy Markets, respectively. These values indicate the relative impact of congestion and marginal losses among the load zones. The proportions of the electric energy, congestion, and loss components of the LMPs are calculated in relation to a distributed reference bus. The distributed reference bus formula incorporates seasonal variations in locational load; it is not a physical interconnection to the system. Because the distributed reference bus varies over time, comparing trends in the differences between LMPs over time is more useful than comparing trends in the values of the congestion and marginal loss components. The reference bus calculation will affect the variation in each component but will not have an impact on the nodal prices.

Table 2-7
Average Day-Ahead Congestion Component, Loss Component, and Combined, $/MWh

Location/ Load Zone	Congestion Component	Marginal Loss Component	Congestion Component Plus Marginal Loss Component
Hub	–0.52	0.29	–0.23
Connecticut	2.04	1.45	3.49
Maine	–1.72	–2.14	–3.86
NEMA	–1.00	–0.57	–1.57
New Hampshire	–1.01	–0.37	–1.37
Rhode Island	–1.27	–0.77	–2.04
SEMA	0.36	–0.61	–0.25
Vermont	0.05	1.09	1.14
WCMA	–0.35	0.70	0.35

Table 2-8
Average Real-Time Congestion Component, Loss Component, and Combined, $/MWh

Location/ Load Zone	Congestion Component	Marginal Loss Component	Congestion Component Plus Marginal Loss Component
Hub	–0.92	0.19	–0.72
Connecticut	2.84	1.47	4.31
Maine	–1.53	–2.26	–3.79
NEMA	–1.22	–0.62	–1.84
New Hampshire	–1.08	–0.37	–1.45
Rhode Island	–1.48	–0.91	–2.39
SEMA	–0.58	–0.67	–1.25
Vermont	–0.35	1.01	0.67
WCMA	–0.57	0.63	0.05

Because the relative values of the three LMP components depend on the definition of the distributed reference bus, the dollar value of the congestion component should not be used directly to measure the underlying actual cost of congestion in a location over time. The differences between the LMP congestion components serve as indicators of relative congestion costs. The Hub and most load zones (ME, NH, RI, WCMA) experienced negative congestion on average in both the Real-Time and Day-Ahead Energy Markets. This means that the typical Real-Time Energy Market clearing process resulted in constraints, such that an increase in demand could have been met at a lower cost in those locations than in the other load zones. Connecticut was the only load zone with positive average congestion both in day-ahead and real-time markets. This is consistent with historical experience showing that Connecticut is a transmission-constrained area. Between 2006 and 2007, however, NEMA average congestion became negative both in day-ahead and real-time markets. The recent investment in the transmission system into Boston, which has significantly lowered congestion prices in the NEMA load zone, can explain these results.

The marginal loss component of the LMP reflects the change in the cost of transmission losses for the entire system when one additional megawatt of power is injected at that location. System losses are related to transmission voltage and the distance between generation and load. An additional injection of electricity at a location, which is estimated to decrease system losses, results in a positive marginal loss component for that location and a higher LMP. Electricity at that location has additional value because it results in smaller losses. An additional injection at a location that is estimated to increase system losses results in a negative loss component for that location, lowering the LMP. Exporting zones generally have negative loss components, while importing zones generally have positive marginal loss components. An additional injection in an exporting zone increases losses, which increases the amount of power shipped long distances. Injections into an importing zone reduce losses, which lessens the need for power to travel long distances.

Day-ahead and real-time loss components were positive in the Connecticut, Vermont, and WCMA load zones and at the Hub. They were negative in the NEMA, Rhode Island, SEMA, New Hampshire, and Maine load zones. Although the NEMA and Rhode Island importing zones had small negative losses, Maine, an exporting zone, had the most negative loss component, indicative of its long distance from the major load centers in New England. While Rhode Island and NEMA are importing zones, they are adjacent to the exporting zone of SEMA; therefore, power does not need to travel long distances to reach Rhode Island and NEMA.

Similar to congestion pricing, marginal loss pricing and accounting can result in a surplus collection of marginal loss revenue. These revenues are maintained in the Marginal Loss Revenue Fund. The revenues in the fund are allocated to load-serving entities according to each participant's monthly share of the real-time load obligation, net of bilateral trades. In 2007, a total of $93 million was returned to load-serving entities from the Marginal Loss Revenue Fund.

2.4.7 Effect of Transmission Improvements—Connecticut Subarea

The Southwest Connecticut 345 kV Transmission Project promises to improve New England transmission system reliability by allowing additional electric energy to be transferred into Southwest Connecticut to meet the regional load requirements. When the project is complete, the Southwest Connecticut import limit will increase from 2,350 MW to over 3,650 MW. Phase 1 of the project, which included transmission upgrades in the Norwalk–Plumtree area, was completed and placed in service in October 2006. Phase 2, which includes transmission upgrades in the greater Southwest Connecticut area, is 48% complete and is expected to be in service by December 2009.

The maps in Figure 2-30 show average annual real-time nodal prices for 2006 and 2007 as color gradations from blue, representing prices up to $41/MWh, to red, representing prices of $83/MWh and higher. The map shows that the chronic congestion into the southwest corner of Connecticut has been relieved.

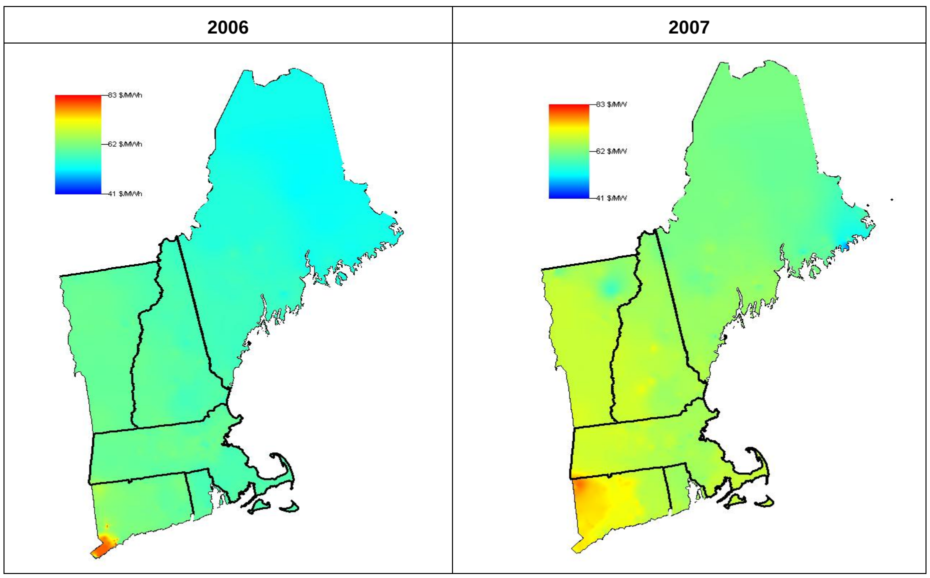

Figure 2-30: Average real-time nodal prices, 2006 and 2007, $/MWh.

Average nodal prices in Southwest Connecticut were affected by the elimination of the Peaking-Unit Safe-Harbor (PUSH) adder in June 2007 as well as the transmission improvements in October 2006 (see Section 6.3). Under PUSH, units with low capacity factors could offer higher prices into the market. If accepted and marginal, these offers set the price for Connecticut and raised the Connecticut price in the state above levels elsewhere in New England, which was a reflection of transmission congestion. Under the Reliability Agreements in effect since late June 2007, the same units can offer only their variable costs—the generators recover other costs through a side payment for the "annualized fixed-cost requirement." The same units still can set the marginal price for Connecticut but with no premium above marginal cost.

In addition to energy market costs, generation resources in Connecticut historically have been paid out-of-market costs associated with Reliability Agreement cost-of-service contracts and daily reliability commitments. Figure 2-31 shows the total out-of-market payments made to generators in the Connecticut load zone for daily reliability agreement payments and for second-contingency, voltage, and distribution support. Total payments to Connecticut generators outside the markets declined after the transmission improvements were put in place in October 2006. In 2007, Reliability Agreements for Devon, Wallingford, and Bridgeport Energy were terminated, while a Reliability Agreement for Norwalk Station was added. Both second-contingency daily reliability payments and net Reliability Agreement payments to resources in Connecticut decreased in 2007 compared with 2005 and 2006. (See Section 6.2 for information about daily reliability payments and Reliability Agreements.)

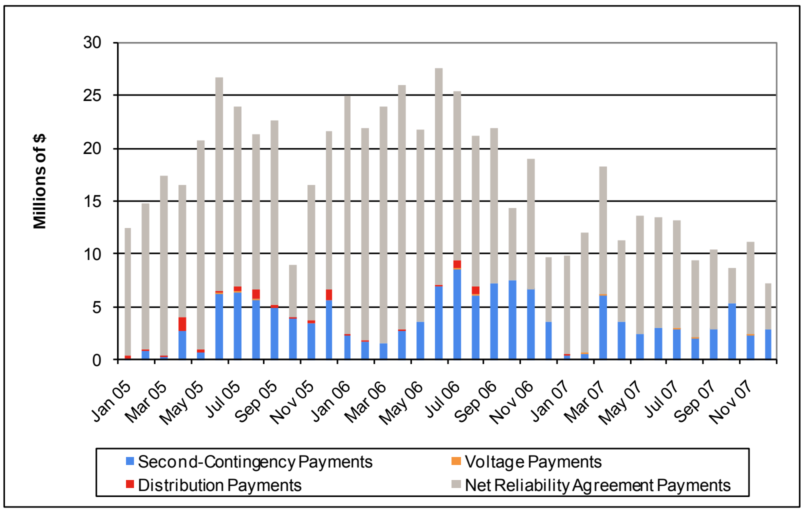

Figure 2-31: Total nonmarket payments to Connecticut generators.

2.4.8 Effect of Transmission Improvements—NEMA Boston Subarea

Transmission improvements were made in the Boston area in addition to those made in Connecticut. The NSTAR 345 kV Transmission Project improves New England reliability by increasing the Boston import limit from 3,600 MW to a range of 4,500 MW to 4,800 MW. Upgrades in the Merrimack Valley will increase system reliability for the North Shore area independent of the on-line status of Salem Harbor generation. Unlike Connecticut, the effect has not been so much on the NEMA LMP but on daily reliability payments and net Reliability Agreement fixed-cost payments. Figure 2-32 shows total daily reliability payments for second-contingency, voltage, and distribution support and total net fixed-costs payments for units with Reliability Agreements by month in the NEMA area for January 2005 to December 2007. Total annual payments declined by $85 million, but the voltage portion of the payments increased. This was driven by three changes. First, all Reliability Agreements and settlement payments to resources in NEMA were terminated as of June 2007. Second, second-contingency reliability payments decreased 31%, and third, daily reliability payments for voltage increased by approximately $40 million compared with 2006 payments. The voltage payments were similar to those in 2005 before Reliability Agreements were signed. Voltage payments increased as a result of the termination of the Reliability Agreements and their stipulated bidding.

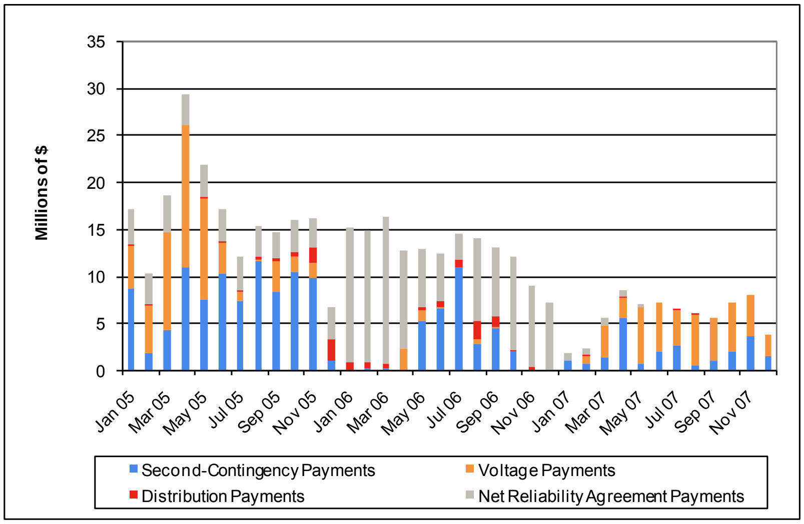

Figure 2-32: Total nonmarket payments to NEMA generators.

2.4.9 All-In Wholesale Electricity Market Cost Metric

The *all-in* wholesale electricity cost is the annual total for energy, daily reliability, capacity, and ancillary services.[58] Figure 2-33 shows the all-in wholesale electricity cost metric for New England over the past seven years ($/MWh) using a FERC-defined methodology.

[58] FERC uses this metric to compare the various regions in the country.

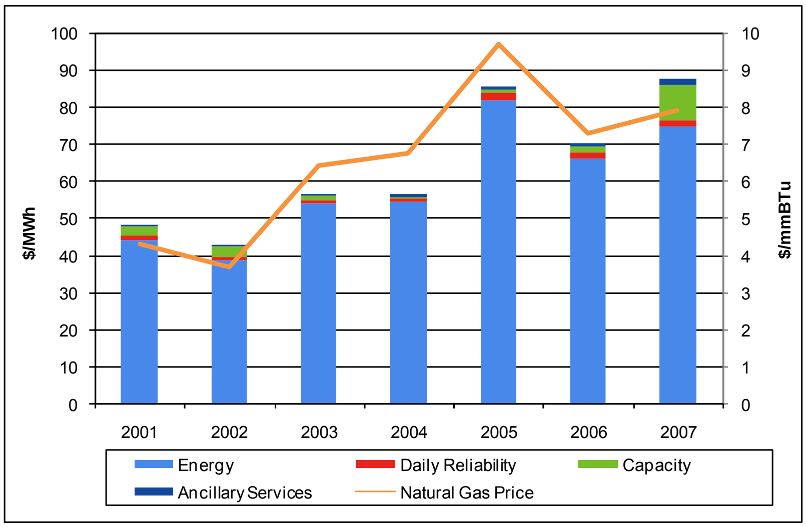

Figure 2-33: New England wholesale electricity market cost metric—electric energy, daily reliability, capacity, and ancillary services, $/MWh, and annual average natural gas prices, $/MMBtu, 2001 to 2007.

Note: Over time, the names and definitions of all-in cost components have changed. See Appendix A.4 for a description of these components for each period. Electric energy costs for the Interim Markets period = (ECP × system load). Electric energy costs for the SMD period = (real-time load obligation × real-time LMP).

Energy costs are by far the largest component of FERC's all-in wholesale cost metric, accounting for 85% of the total in 2007 down from 94% in 2006. Figure 2-33 also shows the annual average price of natural gas. The energy cost varies in a pattern consistent with the annual variations in natural gas prices, which can be attributed to New England's dependence on natural gas as a marginal input fuel. Beginning in December 2006, under the Forward Capacity Market Settlement Agreement, negotiated transition payments for capacity have been implemented.[59] With a full year of transition payments, total capacity costs rose, and as a percentage of the FERC all-in metric, capacity costs increased from 2% in 2006 to 11% in 2007.[60] Daily reliability costs and ancillary service costs combined for a total of 4% in both 2006 and 2007.

As shown in Figure 2-34, the ISO publishes a metric similar to FERC's metric presented in Figure 2-33. The ISO's market cost metric represents the average cost associated with serving real-time load obligation in the New England wholesale markets. It does not include costs that are allocated to network load, such as net payments for Reliability Agreements, ISO self-funding tariff charges, or OATT tariff charges (i.e., voltage and distribution daily reliability payments, which are allocated to transmission owners rather than participants responsible for real-time load obligation). Further, the

[59] *Order Accepting in Part and Modifying in Part Standard Market Design Filing and Dismissing Compliance Filing* (SMD Order). FERC Docket Nos. ER02-2330-000 and EL00-62-039 (September 20, 2002). p. 37. For background information, see *Explanatory Statement in Support of Settlement Agreement of the Settling Parties and Request for Expedited Consideration and Settlement Agreement Resolving All Issues,* FERC Docket Nos. ER03-563-000, -030, -055 (filed March 6, 2006; as amended March 7, 2006).

[60] The method of calculating capacity costs has changed a number of times over the period presented. See Appendix A.4.

method used to calculate components used in both metrics can differ. As an example, in the FERC metric, the energy component is calculated on the basis of real-time nodal prices, while in the wholesale load cost-report metric, the energy component is derived from real-time load-zone prices.

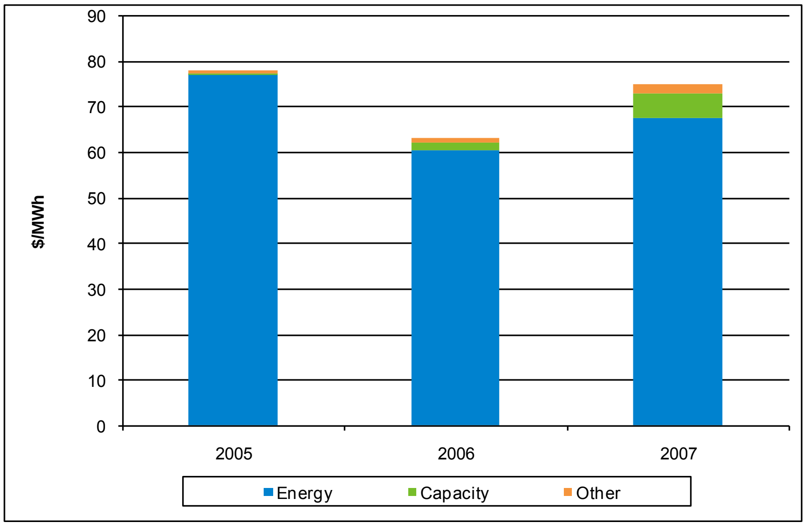

Figure 2-34: New England *Wholesale Load Cost Report* metric of all-in-costs, 2005 to 2007.

Note: The values presented are annual load-weighted averages of the monthly load zone based on data included in the ISO's *Wholesale Load Cost Reports*, which are available online at http://www.iso-ne.com/markets/mkt_anlys_rpts/whlse_load/index.html (accessed March 20, 2008).

2.5 Critical Power System Events

The high demand for electricity coincident with other events required the ISO to declare OP 4 on five days in 2007. The ISO also issued Master/Local Control Center Procedure No. 2, *Abnormal Conditions Alert* (M/LCC 2), on several occasions. The M/LCC 2 procedure alerts power system operations, maintenance, construction, and test personnel, as well as market participants, when the power system is facing a critical event or when such conditions are anticipated.[61] In 2007, the market worked as expected under these stressed conditions. This section briefly discusses the events of the days in 2007 when OP 4 actions were activated. Figure 2-35 through Figure 2-38 show real-time system conditions during OP 4 events.

2.5.1 February 10, 2007, OP 4 Systemwide

On Saturday, February 10, 2007, from 9:40 a.m. until 11:00 a.m., the ISO implemented Actions 1 and 6 of Operating Procedure 4 systemwide in New England. The actions resulted from a combination of higher-than-expected loads, lower-than-expected transfers into New England, and slightly higher-than-anticipated forced generator outages and reductions. Morning temperatures running under

[61] M/LLC 2 considers abnormal conditions to exist when the reliability of the New England Control Area is degraded. These conditions relate to forecasts of operating-reserve shortages, low transmission voltages or reactive reserves, the inability to provide some types of first-contingency protection, solar magnetic disturbances, and credible threats to the security of the power system. Additional information is available at http://www.iso-ne.com/rules_proceds/operating/mast_satllte/.

forecast by 5°F in Boston and 8°F in Hartford resulted in morning loads running 450 MW over projections. Transfers into New England were about 650 MW less than what cleared in the day-ahead market. Figure 2-35 illustrates the net capacity conditions on February 10, 2007.

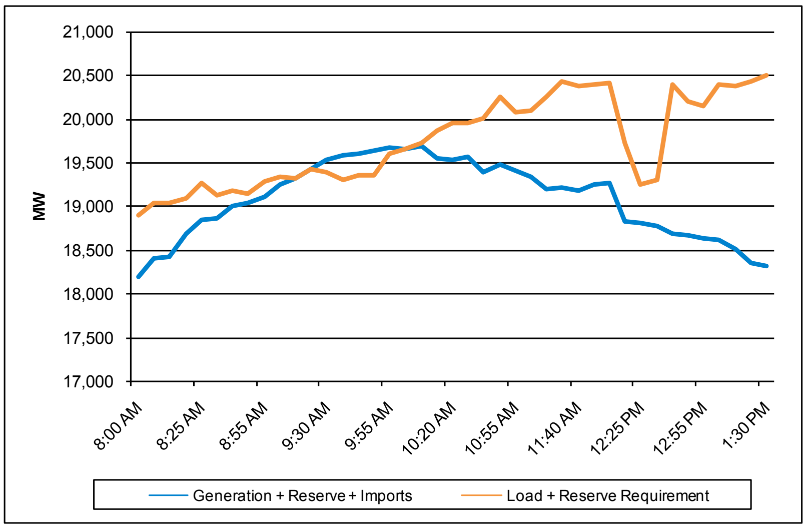

Figure 2-35: Supply and capacity required for energy and reserves, February 10, 2007, MW.

2.5.2 August 2, 2007, OP 4 Systemwide

On Thursday, August 2, 2007, OP 4 was implemented systemwide in New England as a result of higher-than-expected heat and humidity. Temperatures over the eastern portion of New England ran 6°F above forecast, and dew points throughout New England averaged 4°F above forecast. The peak-hour demand was 25,978 MW, 1,178 MW above the forecast of 24,800 MW. The ISO implemented M/LCC Procedure 2 at 2:30 p.m. At 3:30 p.m., New England went deficient in 30-minute operating reserves and implemented OP 4 Actions 1 and 6 systemwide. These OP 4 actions were cancelled at 6:00 p.m. M/LCC 2 was cancelled at 8:30 p.m. Figure 2-36 illustrates the net capacity conditions on August 2, 2007.

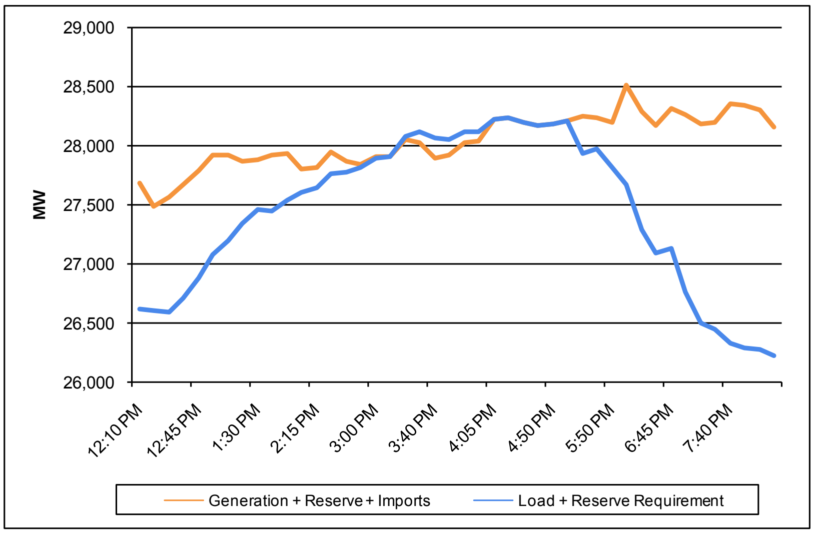

Figure 2-36: Supply and capacity required for energy and reserves, August 2, 2007, MW.

2.5.3 September 8, 2007, OP 4 Systemwide

On Saturday, September 8, 2007, OP 4 was implemented systemwide in New England as a result of higher-than-expected heat and humidity. Temperatures throughout New England ran 6°F above forecast, and dew points throughout the area averaged 2°F above forecast. The peak-hour demand was 21,876 MW for 2:00 p.m., 1,526 MW above the forecast of 20,350 MW. The ISO did not experience a 30-minute operating-reserve deficiency until 4:00 p.m., when an additional 500 MW of external sales were delivered. The ISO implemented M/LCC 2 at 12:00 noon. At 4:00 p.m., the ISO implemented OP 4 Actions 1 and 6 systemwide. M/LCC 2 and OP 4 Actions 1 and 6 were cancelled at 9:00 p.m. Figure 2-37 illustrates the net capacity conditions on September 8, 2007.

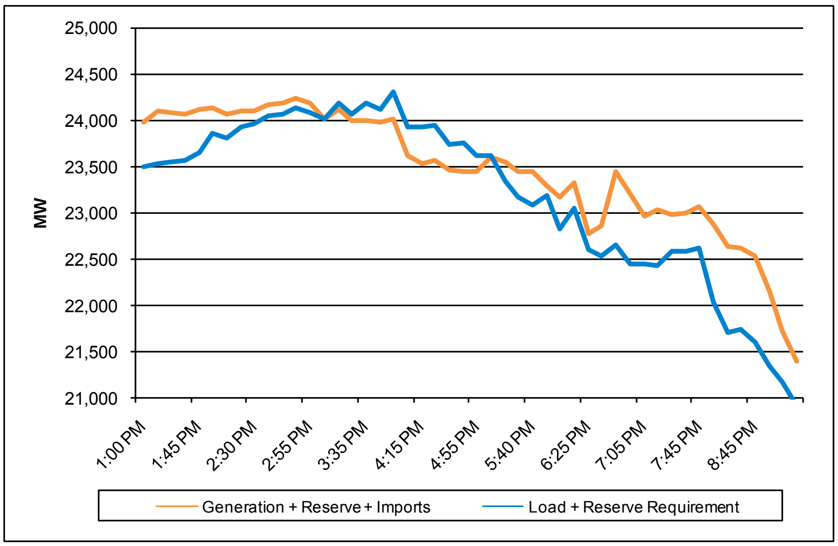

Figure 2-37: Supply and capacity required for energy and reserves, September 8, 2007, MW.

2.5.4 December 1, 2007, OP 4 Systemwide and in Maine

On Friday, November 30, 2007, the dehydration unit that separates natural gas from liquids at the Sable Island production fields, which are offshore of Nova Scotia, experienced a mechanical failure. After the failure occurred, the natural gas supply feeding the Maritimes and Northeast (M&N) pipeline was suspended. As a consequence of this event, two major natural-gas-fired generators located in Maine lost their fuel supply on Saturday, December 1, and subsequently ramped off line and out of service before the evening peak. This loss resulted in a reduction of approximately 1,000 MW of generation. In addition to the Sable Island event, two gas compressors located at Trans Canada's Lachenaie compressor station on the Trans Quebec and Maritimes pipeline (TQM) also failed on December 2.

The Sable Island dehydration unit was back in service on December 4. The M&N pipeline was fully repacked by the end of the week. The Lachenaie compressors subsequently were repaired by December 11.

2.5.4.1 Local Implementation within Maine

On Saturday, December 1, 2007, the ISO implemented OP 4 locally within the Maine area as a result of gas supply issues. M/LCC 2 was implemented in Maine at 5:00 p.m. At 6:00 p.m., OP 4 Actions 1–12 were implemented for Maine. Actions 2–12 were cancelled at 9:45 p.m. for Maine. M/LCC 2, and OP 4 Action 1 remained in effect on December 1.

2.5.4.2 Systemwide Implementation

On Saturday, December 1, 2007, the ISO implemented OP 4 systemwide in New England as a result of a combination of higher-than-forecast loads and higher-than-expected external sales and generator outages. Loads in New England ran approximately 800 MW over forecast on peak, external transactions were approximately 500 MW higher than expected, and generator outages and reductions were approximately 1,300 MW over expectations. The ISO implemented OP 4 Actions 1 and 6 systemwide at 5:45 p.m. OP 4 Actions 1 and 6 were cancelled at 8:45 p.m. Figure 2-38 illustrates the net capacity conditions on December 1, 2007.

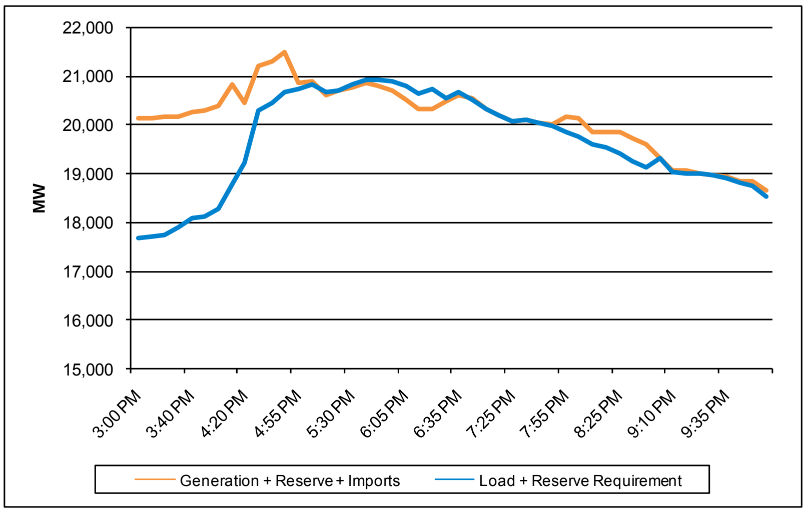

Figure 2-38: Supply and capacity required for energy and reserves, December 1, 2007, MW.

2.5.5 December 2, 2007, OP 4 in Maine

Ongoing fuel-related capacity deficiencies within the state of Maine led the ISO to remain in M/LCC 2 and OP 4 Action 1 within Maine on Sunday, December 2, 2007. At 11:00 a.m., the loss of approximately 620 MW of on-line capacity within Maine resulted in the implementation of OP 4 Actions 2–11 for Maine only. At 2:15 p.m., Action 11 was canceled, and all remaining OP 4 actions were canceled at 10:00 p.m.

2.6 Electric Energy Markets Conclusions

During 2007, electricity energy and demand levels continued to follow long-term trends. One of those trends is the continued decline of the weather-normalized load factor. Over time, this decreasing load factor will require additional generation capacity or demand response, assuming demand continues to increase.

Fuel prices continued to increase in 2007, driving energy prices higher. A notable difference during the last two years has been the increasing disparity between the price for liquid fuels and the price for natural gas. A comparison of various fuels shows that liquid fuels, such as diesel and No. 6 oil, have become increasingly more expensive than natural gas in terms of $/MMBtus. Past Annual Markets Reports have pointed out the dependence of New England on natural gas and the fact that natural gas units set the marginal price most often.[62] Recent trends, however, have increasingly pushed natural gas units toward a baseload role and generators using No. 6 oil out of this role.

Transmission investments in the Boston and Norwalk/Stamford areas have allowed more imports of electric energy into these traditional load pockets; thus, fewer Reliability Agreements are needed and daily second-contingency protection is needed less often. The results are lower congestion in Norwalk/Stamford and lower reliability payments in both areas.

[62] The Annual Markets Report archive is available online at http://www.iso-ne.com/markets/mkt_anlys_rpts/annl_mkt_rpts/index.html.

Attachment 8

Attachment 8

Estimated Payments to Constellation Pursuant to Fuel Adjustment Factor Tariff

The Narragansett Electric Company d/b/a National Grid

Estimated Payments to Constellation Pursuant to Proposed Fuel Adjustment Factor Tariff

	Gas Index (a)	Adjustment Value (b)	Stipulated Price (c)	per kWh Adjustment (d)	Constellation Estimated Load (e)	Estimated Payment (f)
Aug-08	$13.10467	1.19014	6.70000	$1.274	88,174,005	$1,123,301
Sep-08	$13.15733	1.19493	6.70000	$1.306	82,871,046	$1,082,301
Oct-08	$13.24333	1.20274	6.70000	$1.358	71,554,716	$971,953
Nov-08	$13.49933	1.22599	6.70000	$1.514	71,307,438	$1,079,671
Dec-08	$13.85600	1.25838	6.70000	$1.731	78,267,991	$1,354,923
Jan-09	$14.05167	1.27615	7.10000	$1.961	82,556,589	$1,618,647
Feb-09	$13.98933	1.27049	7.10000	$1.920	76,656,753	$1,472,161
Mar-09	$13.72467	1.24645	7.10000	$1.750	76,834,968	$1,344,457
Apr-09	$11.54300	1.04832	7.10000	$0.343	72,393,827	$248,339
May-09	$11.37300	1.03288	7.10000	$0.233	68,795,196	$160,583
Jun-09	$11.44400	1.03932	7.10000	$0.279	73,445,132	$205,061
Jul-09	$11.53600	1.04768	7.10000	$0.339	83,211,006	$281,690
Aug-09	$11.59667	1.05319	7.10000	$0.378	84,922,529	$320,704
Sep-09	$11.61600	1.05495	7.10000	$0.390	82,814,228	$323,066
Oct-09	$11.69033	1.06170	7.10000	$0.438	75,158,395	$329,224
Nov-09	$11.94700	1.08501	7.10000	$0.604	70,144,133	$423,349
Dec-09	$12.30033	1.11710	7.10000	$0.831	79,984,369	$664,970
						$13,004,401

(a) May: Averge of natural gas prices for May 2008 as reported on April 24, 25 and 28, 2008. All other months: average of current month's natural gas prices as reported on June 23, 24 and 25, 2008
(b) If column (a) > 11.011(Trigger), (column (a) ÷ 11.01), otherwise 0.
(c) Per contract
(d) column (c) x (column (b) - 1)
(e) based on Constellation estimated share of forecasted Standard Offer load.
(f) column (d) x column (e)