



Monthly Regional Network Load Cost Report January 2011

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Market Analysis and Settlements
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Contents

Contents	2
Figures.....	3
Tables	3
Section 1 Introduction	4
Section 2 Summary of Regional Network Load (RNL) Costs, January 2011.....	8
Section 3 New England Average RNL Costs	10
Section 4 Infrastructure Costs	12
Section 5 Reliability Costs.....	14
5.1 Units Retained for Reliability in the Forward Capacity Market	14
5.2 Reliability Costs by Type, Last 13 Months.....	14
5.3 Terminated Reliability Cost Types	16
5.4 Reliability Costs by Reliability Region, Last 13 Months.....	16
5.5 Voltage Support Costs, Last 13 Months	17
5.6 High-Voltage Control Costs by Reliability Region, Last 13 Months	19
Section 6 Administrative Service Costs.....	21
Section 7 Regional Network Load, Last 13 Months.....	23
7.1 Average Regional Network Load by Month, Last 13 Months	23
7.2 Monthly Regional Network Load by Reliability Region, Last 13 Months	25
7.3 Monthly Regional Network Load by Local Regional Network, Last 13 Months	26
7.4 Monthly Regional Network Load by State, Last 13 Months	27
Section 8 Average RNL Costs by State	28
Document History	29

Figures

Figure 3-1. New England-level RNL costs by major category, 13 months.	10
Figure 4-1: Infrastructure costs by type, 13 months.	13
Figure 5-1: Reliability costs by type, 13 months.	15
Figure 5-2: Average combined costs for reliability services by reliability region, 13 months.	17
Figure 5-3: Voltage support costs, 13 months.	18
Figure 5-4: High-voltage control costs by reliability region, 13 months.	19
Figure 6-1: Administrative costs by type, 13 months.	21
Figure 7-1: Average monthly regional network load, 13 months.	24
Figure 7-2: Monthly network load by reliability region, 13 months.	25
Figure 7-3: Monthly network load by local network, 13 months.	26

Tables

Table 1-1 Local Network to Reliability Region Mapping	6
Table 2-1 Summary of New England Average RNL Costs, Current Month	9
Table 3-1 New England-level RNL Costs by Major Category, 13 Months (\$/MW-Month).....	11
Table 4-1 Infrastructure Costs by Type, 13 Months (\$/MW-Month)	13
Table 5-1 Reliability Costs by Type, 13 Months (\$/MW-Month)	15
Table 5-2 Effective Start and End Dates for Certain Regional Network Load Cost Components	16
Table 5-3 Fixed Capacity, Variable, and Total Voltage Support Costs, 13 Months (\$/MW-Month).....	18
Table 5-4 Voltage Control, Voltage Support, and Total VAR Costs, 13 Months (\$/MW-Month)	19
Table 6-1 Administrative Costs by Type, 13 Months (\$/MW-Month)	22
Table 7-1 Average RNL aggregated by State and in Total, 13 Months (MW-Month).....	27
Table 8-1 Average RNL Costs by State and in Total, 13 Months (\$/MW-Month)	28

Section 1

Introduction

Created in 1997, ISO New England Inc. (ISO) is the not-for-profit regional transmission organization (RTO) responsible for the day-to-day reliable operation of the electric power generation and transmission system within the New England area, oversight and administration of the region's wholesale electricity markets and regional transmission service, and management of a comprehensive regional power system planning process.

The ISO operates under the *ISO New England Transmission, Markets, and Services Tariff* (the tariff), approved by the Federal Energy Regulatory Commission (FERC).¹ The tariff contains the detailed rules governing the provision of wholesale electric energy, capacity, transmission, reliability, and ancillary and other services, including the allocation of costs and billing for these services. The totality of these costs to load may be termed "total wholesale load costs." The larger portion of these costs, which include energy, capacity, and ancillary market charges are estimated and analyzed in \$/megawatt-hour (MWh) of electric load and reported elsewhere on the ISO web site.²

The smaller portion of "total wholesale load costs," reported here, are associated with providing *regional network service* (RNS) and other services to transmission customers that collectively provide for the use of transmission facilities, reliability, and certain administrative services.³ The *Open Access Transmission Tariff* (OATT) (Section II of the ISO tariff) governs the allocation of these costs, which are billed according to a transmission customer's *regional network load* (RNL).⁴ The RNL is the customer's hourly load at the time of the peak load of its local transmission network. The aggregate of these costs generally is referred to as "OATT costs" or "RNL costs," which are charged and reported by \$/MW-month.⁵

In response to requests from various New England stakeholders to increase transparency and facilitate their understanding of all the costs of serving load in New England, particularly those associated with transmission, the ISO has already published the [Historical Regional Network Load Cost Report](#) (Historical NLCR), which provided a comprehensive study of RNL costs for 2005 to 2009.⁶ The Historical NLCR provides a deeper background and discussion on the majority of concepts discussed in this report, and we recommend the reader reference the historical report for additional information.

¹ The *ISO New England Transmission, Markets, and Services Tariff* (2009), includes the *Open Access Transmission Tariff* (OATT) (Section II) and the *Self-Funding Tariff* (SFT) (Section IV). The OATT provides the terms and conditions for nondiscriminatory, open-access transmission services over the New England transmission system and comparable, nondiscriminatory treatment of all transmission owners (TOs), transmission providers, and transmission customers taking transmission services under the OATT. The SFT, Schedule 1, provides the terms and conditions for cost recovery associated with the scheduling, dispatch, and control service using RNL as an allocator, and the SFT Schedules 2 and 3 provide for cost recovery of other aspects of ISO operations allocated through non-RNL mechanisms. These documents are available at <http://www.iso-ne.com/regulatory/tariff/index.html> and http://www.iso-ne.com/regulatory/tariff/sect_2/index.html.

² These costs are reported in the *Wholesale Load Cost Report*, available at http://www.iso-ne.com/markets/mkt_anlys_rpts/whlse_load/index.html.

³ Total wholesale load costs include those reported here as well as those reported in the Monthly Wholesale Load Cost Report.

⁴ The OATT defines *network load* as a network customer's hourly load coincident with the aggregate load of all network customers served in each local network in the hour in which the respective local network's aggregate load is at its maximum for the month (i.e., the monthly peak).

⁵ To convert \$/MW-month to \$/kW-month, divide \$/MW-month by 1,000.

⁶ The *2005-2009 Historical Network Load Cost Report* provides the historical basis for this *monthly* report and is available at http://www.iso-ne.com/markets/mkt_anlys_rpts/regnl_ntwrk_cost/index.html.

RNL costs are categorized as follows, according to provisions in the OATT.⁷

- **Infrastructure** cost category—recovers the following costs associated with the use of pool transmission facilities (PTFs):⁸
 - Pre-1997 transmission infrastructure costs
 - Post-1996 transmission infrastructure costs
- **Reliability** cost category—recovers the costs associated with maintaining the following power system reliability services:
 - Reliability Agreements⁹
 - Resources retained for reliability (RFR) in the Forward Capacity Market (FCM)
 - Voltage support¹⁰
 - High-voltage control
 - System restoration¹¹
 - Load-response program
 - Demand-Response Reliability Pilot (DRRP) availability
 - DRRP OP 4 electric energy¹²
- **Administrative** cost category —recovers the costs associated with the administration of power system reliability and consists of the following:
 - PTO dispatch and control¹³
 - ISO dispatch and control
 - New England States Committee on Electricity (NESCOE) budget¹⁴

⁷ The full definitions and processes associated with the listed terms and concepts are included in the tariff and the ISO’s operating procedures, available at http://www.iso-ne.com/regulatory/tariff/sect_1/index.html and http://www.iso-ne.com/rules_proceeds/operating/index.html.

⁸ *PTFs* are certain transmission lines (69 kilovolts [kV] or greater), associated equipment, and facilities over which ISO New England has operational control. These facilities are owned and maintained by a group of approximately 17 participating transmission owners. PTFs do not include those lines and facilities that serve local load only or are generator leads (i.e., radial transmission from a generator bus to the nearest point on the PTF). The ISO reviews the status of transmission lines and related facilities at least once per year. A current listing of PTFs is available at http://www.iso-ne.com/trans/planning/ptf_cat/index.html. See the ISO tariff, Section II. H. II. 49 for a more detailed description of PTFs.

⁹ *Reliability Agreements*, previously referred to as “Reliability-Must-Run” Agreements, were contractual arrangements established with generators deemed necessary to ensure that the units needed for reliability were available when needed to support the transmission system. These agreements, which were subject to FERC approval, provided eligible generators with monthly fixed-cost payments for maintaining the capacity that provided the reliability services. As a result of the start of the Forward Capacity Market (FCM) on June 1, 2010, Reliability Agreements have expired, and any further need to retain units in the region for reliability is addressed under FCM market rules. Refer to the ISO’s 2009 *Annual Markets Report* (AMR09) for additional information on the FCM; http://www.iso-ne.com/markets/mkt_anlys_rpts/annl_mkt_rpts/index.html. Reliability costs reported here include only those for reliability services governed under the OATT.

¹⁰ Voltage control is when reactive power is used to maintain transmission voltages for meeting the operating requirements of the New England transmission system.

¹¹ System restoration (“black-start”) services enable the ISO to designate specific generators to start without an outside electrical supply following the partial or full shutdown of the transmission system.

¹² *OP 4* is ISO Operating Procedure No. 4, *Action during a Capacity Deficiency* (OP 4); http://www.iso-ne.com/rules_proceeds/operating/isone/op4/index.html.

¹³ *PTOs* are participant companies that own or support the PTFs in the New England Balancing Authority Area and are eligible to submit revenue requirements to recover their costs. Of the more than 30 PTOs that supported a portion of the PTFs during 2005 to 2009, approximately 17 both owned and operated facilities in the local networks. An even smaller group of the currently eight PTOs are recognized as having local network RNS rates, as discussed throughout the report. A *balancing authority area* is a group of generation, transmission, and loads within the metered boundaries of the entity (balancing authority) that maintains the load-resource balance within the area. Balancing authority areas were formerly referred to as control areas. Further information is available in the NERC glossary; http://www.nerc.com/docs/standards/rs/Glossary_12Feb08.pdf.

This *Monthly Regional Network Load Cost Report* (Monthly NLCR) summarizes RNL costs over the most recent thirteen months. This report is produced on a one-month lag to account for the many OATT settlement processes that lag behind other, non-OATT settlement processes by one month. For illustrative purposes, this report provides summaries of the RNL costs at several levels, including the balancing authority area (or pool), reliability region, state, and local network levels.¹⁵

The New England Balancing Authority Area is divided into eight reliability regions that have local networks with RNS rates. Table 1-1 lists these regions and the eight local networks and participating transmission owners operating in each one that had local RNS rates during the past few years.

**Table 1-1
Local Network to Reliability Region Mapping**

Reliability Region	Local Network/Participating Transmission Owner ^(a)
Connecticut (CT)	Northeast Utilities Service Company (NU) United Illuminating (UI)
Maine (ME)	Bangor Hydro Electric (BHE) Central Maine Power (CMP) NU
New Hampshire (NH)	New England Power (NEP) ^(b) NU
Northeastern Massachusetts (NEMA)	Boston Edison (BE), which merged into NSTAR ^(c) NEP
Rhode Island (RI)	NEP
Southeastern Massachusetts (SEMA)	BE, which merged into NSTAR in February 2007 Commonwealth Electric (CES), which merged into NSTAR ^(c) NEP
Vermont (VT)	Vermont Electric Power/VT Transco LLC (VELCO/VT Transco)
Western/Central Massachusetts (WCMA)	Fitchburg Gas and Electric Light (FGE) NEP NU

(a) Several of the local networks reside in more than one reliability region/state jurisdiction.

¹⁴ NESCOE is the FERC-approved regional-state committee for advising the ISO on the development of the Regional System Plan. The ISO serves as the vehicle for recovering funds from transmission customers to cover NESCOE's budgeted operating expenses. More information is available at www.nescoe.com.

¹⁵ *Reliability regions* are regions of the New England Balancing Authority Area that reflect the operational characteristics of the transmission system and therefore form the basis for allocating costs of certain wholesale market products and services. For example, costs for high-voltage control are allocated to RNL customers who benefit from that particular ancillary service within their specific reliability region. A *local network* is a portion of the PTF owned or operated by a PTO and serving RNL and "through or out service." This report removes the effect of through-or-out transactions on costs. "Through-or-out service," is the delivery of electricity over the PTFs through or from New England to another balancing authority area. This report does not provide summaries of the costs associated with the provision of Schedule 21-Local Service; Schedule 18, *Merchant Transmission Facility (MTF) Service*, or Schedule 21, *Other Transmission Facilities (OTF) Service*, under the OATT.

- (b) The NEP local network includes the National Grid USA companies that are included in the New England Balancing Authority Area.
- (c) The NSTAR local network was newly established in March 2007 to recognize the merger of Boston Edison Company, Cambridge Electric Light Company, Canal Electric Company, and Commonwealth Electric Company into the NSTAR Electric Company. The BE and CES local networks were separate and distinct local networks from February 2005 through February 2007.

New England state level summarizations are shown in Section 8 of the report. Each New England state is comprised of its respective reliability region of the same name, except for the state of Massachusetts (MA), which is comprised of the NEMA, SEMA, and WCMA reliability regions.

Each PTO with a local network RNS rate is responsible for determining the peak RNL value on its local network in a given month and for identifying the share of RNL to be assigned to each of the network load assets in its local network. The [*Historical Regional Network Load Cost Report*](#) contains additional information about the local networks with local network RNS rates in New England.

Section 2

Summary of Regional Network Load (RNL) Costs, January 2011

This section summarizes data on RNL and RNL costs for January 2011:

- **New England RNL**— Pool-aggregate RNL during January was 20,760 MW-month, reflecting an increase of 2.0% from the prior month and an increase of 5.4% from January of the prior year.
- **New England Average RNL Costs**
 - January RNL costs were approximately 11.3% of total wholesale load costs.¹⁶
 - In January, the average RNL cost for New England was \$5,991/MW-month, an increase of \$30/MW-month, or 0.5%, from December 2010 values, and an increase of 4.5% from the prior year.
- **New England Average RNL Costs by Major Category**—Average RNL costs varied across all RNL cost categories:
 - **Infrastructure** costs, for which underlying rates change on June 1 of each year, averaged \$5,402/MW-month during January. This cost represented no change from December values, and an increase of 8.1% from the prior year. Infrastructure costs were approximately **90%** of overall RNL costs.
 - Post-96 infrastructure costs averaged \$4,130/MW-month, representing no change from December and an increase of 8.6% from the prior year.
 - Pre-96 infrastructure costs averaged \$1,272/MW-month, representing no change from December and an increase of 6.8% from the prior year.
 - **Reliability** costs averaged \$320/MW-month in January, reflecting an increase of \$46/MW-month, or 16.8%, from December values and a decrease of 31.5% from the prior year. Reliability costs were approximately **5%** of overall RNL costs.
 - Load Response Program fell by \$5/MW-month from the prior month.
 - Reliability Agreement costs totaled \$0 and were \$310/MW-month lower than this month last year. Reliability Agreements were terminated effective June 1, 2010.
 - Voltage support (regional) costs averaged \$178.53/MW-Month, an increase of \$52/MW-month from the prior month. High-voltage control costs were \$0/MW-month.
 - **Administrative** costs averaged \$269/MW-month in January, a decrease of \$15/MW-month, or 5.4%, from December values, and a decrease of 1.5% from the prior year.¹⁷ Administrative costs were approximately **4%** of overall RNL costs.

¹⁶ Total wholesale load costs include those reported here as well as those reported in the [Monthly Wholesale Load Cost Report](#).

¹⁷ See Section 6 for discussion of factors that affect year-over-year changes in administrative component costs.

- **Reliability Region Average RNL Costs**— RNL costs in the CT load zone averaged \$6,031/MW-month, approximately \$54/MW-month higher than other load zones, due to FCM RFR costs in that particular load zone.

Table 2-1 provides a summary of New England average RNL costs for the current month for each cost component discussed in this report.

**Table 2-1
Summary of New England Average RNL Costs, Current Month**

Month	Major Cost Category	Cost Concept	Cost Rate (\$/MW-Mo.)	vs Prior Month (\$/MW-Mo.)	vs Prior Month (%)	
Jan-11	Infrastructure	Post-96 Infrastructure	\$4,130.46	\$0.00		
		Pre-97 Infrastructure	\$1,271.78	\$0.00		
		Infrastructure subtotal	\$5,402.24	\$0.00	0.00%	
	Reliability	DRRP Availability	\$0.00	\$0.00		
		DRRP OP-4 Energy	\$0.00	\$0.00		
		FCM RFR	\$13.62	(\$0.27)		
		High Voltage Control	\$0.00	\$0.00		
		Load Response Program	\$84.50	(\$4.70)		
		Reliability Agreements	\$0.00	\$0.00		
		System Restoration	\$42.92	(\$1.08)		
		Voltage Support	\$178.53	\$51.97		
			Reliability subtotal	\$319.57	\$45.93	16.79%
	Administrative	ISO Dispatch & Control	\$126.83	(\$14.04)		
		NESCOE Budget	\$4.13	(\$1.41)		
		PTO Dispatch & Control	\$137.90	\$0.00		
		Administrative subtotal	\$268.86	(\$15.45)	-5.43%	
		Total RNL or OATT Costs	\$5,990.66	\$30.48	0.51%	

Comments:

The month-over-month increase in voltage support costs in January 2011 reflect increased unit commitments for voltage support, particularly in the WCMA reliability region resulting from higher daily system loads relative to the prior month.

Section 3 New England Average RNL Costs

Figure 3-1 and Table 3-1 display New England-wide average RNL costs by major category over the past 13 months.

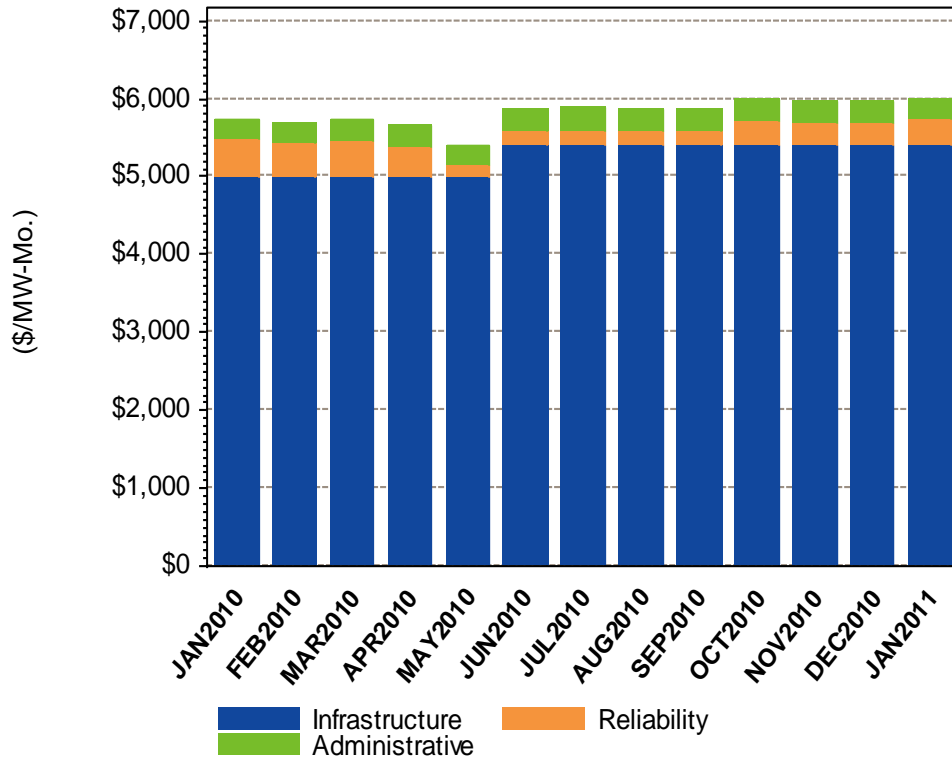


Figure 3-1. New England-level RNL costs by major category, 13 months.

**Table 3-1
New England-level RNL Costs by Major Category, 13 Months (\$/MW-Month)**

Month	Infrastructure	Reliability	Administrative	Total
Jan-10	\$4,996	\$466	\$273	\$5,735
Feb-10	\$4,996	\$420	\$273	\$5,688
Mar-10	\$4,996	\$465	\$273	\$5,734
Apr-10	\$4,996	\$385	\$273	\$5,653
May-10	\$4,996	\$139	\$273	\$5,408
Jun-10	\$5,402	\$165	\$284	\$5,851
Jul-10	\$5,402	\$187	\$284	\$5,873
Aug-10	\$5,402	\$173	\$284	\$5,859
Sep-10	\$5,402	\$174	\$284	\$5,861
Oct-10	\$5,402	\$298	\$284	\$5,985
Nov-10	\$5,402	\$270	\$284	\$5,956
Dec-10	\$5,402	\$274	\$284	\$5,960
Jan-11	\$5,402	\$320	\$269	\$5,991

Section 4

Infrastructure Costs

The infrastructure category of RNL costs reflects the rates charged through the tariff for the transmission owners' recovery of their infrastructure investments in the PTFs that provide regional transmission service to transmission customers. These investments serve to maintain or expand the PTFs, maintain or improve reliability, and improve the economic performance of the entire New England transmission system. Transmission rates, which are first developed by the PTOs, are currently based on PTF revenue requirements of the prior and current years, as well as the previous year's average of all monthly network load peaks for each local network.¹⁸

As part of industry restructuring, and in response to FERC directives to provide a "nonpancaked," or a single transmission rate, NEPOOL undertook an 11-year transition period from 1997 to March 2008 that revised the rate structure. The result was the convergence of individual local network rates that recovered costs associated with the PTFs (and, therefore, the overall pool transmission rate) into a single rate.¹⁹ Reflecting the transition process, the RNS rate, which is regulated by and filed with the FERC, includes the following two components:

- **Pre-1997 transmission infrastructure costs (Schedule 9 Pre-'97 RNS):**²⁰ This component is associated with PTFs and PTF upgrades placed in service or made before 1997. The pre-1997 values shown throughout the report reflect the FERC-filed rate for each local network. Pre-1997 values are also shown for each reliability region (i.e., at the pool level) for illustration purposes, as applicable. From 1997 to March 2008, each local network had a different rate.
- **Post-1996 transmission infrastructure costs (Schedule 9 Post-'96 RNS):** This component is associated with PTFs and PTF upgrades placed in service or made after 1996. The value shown in the report for each year reflects the FERC-filed rate, which has been homogenous across all local networks since 1997.

The RNS rate, which includes the pre-'97 and post-'96 components, is determined annually and is effective June 1 through May 31 of the following year.

PTOs typically make a multiple-year forecast of PTF additions (investments), PTO revenue requirements, and RNS rates.²¹ Such forecasts are meant to be indicative, are subject to change, and are not included here.

The [Historical Regional Network Load Cost Report](#) on the ISO web site provides a more detailed description of each of these components and how RNS rates are developed.

¹⁸ See both Section 2.2 and the Appendix of the [Historical Regional Network Load Cost Report](#).

¹⁹ See FERC Order 888 regarding FERC directives to provide nonpancaked rates; <http://www.ferc.gov/legal/maj-ord-reg/land-docs/order888.asp>.

²⁰ Schedule 9 of the ISO OATT is available at http://www.iso-ne.com/regulatory/tariff/sect_2/oatt/index.html.

²¹ PTOs publically post this information at the ISO's Transmission Committee web site; http://www.iso-ne.com/committees/comm_wkgrps/trans_comm/tariff_comm/index.html.

Figure 4-1 and Table 4-1 show the average monthly infrastructure costs for both the pre-'97 and post-'96 components for the last 13 months.

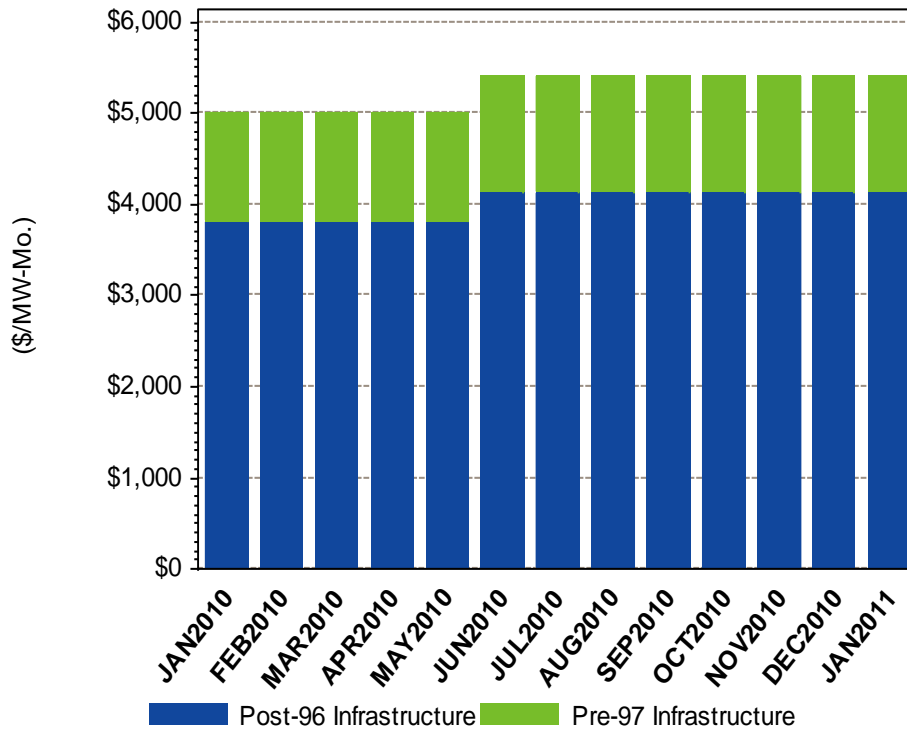


Figure 4-1: Infrastructure costs by type, 13 months.

Table 4-1
Infrastructure Costs by Type, 13 Months (\$/MW-Month)

Month	Post-96 Infrastructure	Pre-97 Infrastructure	Total
Jan-10	\$3,805	\$1,191	\$4,996
Feb-10	\$3,805	\$1,191	\$4,996
Mar-10	\$3,805	\$1,191	\$4,996
Apr-10	\$3,805	\$1,191	\$4,996
May-10	\$3,805	\$1,191	\$4,996
Jun-10	\$4,130	\$1,272	\$5,402
Jul-10	\$4,130	\$1,272	\$5,402
Aug-10	\$4,130	\$1,272	\$5,402
Sep-10	\$4,130	\$1,272	\$5,402
Oct-10	\$4,130	\$1,272	\$5,402
Nov-10	\$4,130	\$1,272	\$5,402
Dec-10	\$4,130	\$1,272	\$5,402
Jan-11	\$4,130	\$1,272	\$5,402

Section 5

Reliability Costs

Reliability services charged through the tariff serve to recover the costs of certain reliability programs and services administered through the OATT.²² The costs (and rates) in this category are developed by taking total payments for the provided service or program and dividing them by the appropriate value of RNL during the month. The components addressed in this section were listed in the text and footnotes of Section 1 of this report. The [Historical Regional Network Load Cost](#) report provides further background on most of these components and the calculation of their costs.

5.1 Units Retained for Reliability in the Forward Capacity Market

The Forward Capacity Market (FCM), implemented in June 2010, is an auction-based approach to meeting New England's forecasted capacity requirements for a future year. Resources that clear in the Forward Capacity Auction (FCA) acquire a capacity supply obligation (CSO) and receive payment based on their CSO and the forward-capacity payment rate. Resources that place auction bids to "delist" from the marketplace and have their bid rejected for reliability reasons are considered "retained for reliability" (RFR).²³ These RFR resources receive additional reliability credits based on their CSO retained for reliability and the difference between their delist bid price or cost-of-service rate, as approved by FERC, and the FCA clearing price. These reliability credits are allocated to RNL in the reliability region where the resource is located.

In this report, FCM reliability credits in each reliability region were divided by reliability region RNL to derive a \$/MW-month rate. For illustration and comparison purposes, a systemwide rate also was derived by dividing aggregated FCM reliability credits by aggregated RNL for the entire system.

More information on this subject is available on the ISO web site within the [Understanding Your Bill](#) area or in Section III.13.2.5.2.5.1 of [Market Rule 1](#).²⁴

5.2 Reliability Costs by Type, Last 13 Months

Both Figure 5-1 and Table 5-1 show reliability costs by type for the last 13 months. Projects improving the New England electric transmission system that were completed over the past few years have mitigated or eliminated the need for certain reliability programs and services. As a result, reductions in reliability costs have often been evident from year to year.

The benefits of an improved, more efficient transmission system extend beyond the reduced reliability costs reported here. Other benefits include lower transmission congestion costs (reflected in wholesale market prices for electric energy), costs of redispatching the system for providing reserves, and costs paid to less economic generators that provided local-area second-contingency protection to respect system

²² Not all reliability service costs are recovered through the OATT.

²³ Existing capacity resources are required to participate in the FCA and are automatically entered into the capacity auction. However, these resources may indicate a desire to be removed from the FCA by submitting a delist bid before the existing-capacity qualification deadline.

²⁴ Look for the "Forward Capacity Market (FCM) Reliability Credit (& Charge)" line items within the "Invoice and Remittance Advice Item Descriptions" found in the "Understanding Your Bill" portion of the ISO Web site.

reliability requirements.²⁵ Transmission investments should continue to play a role in mitigating these costs.

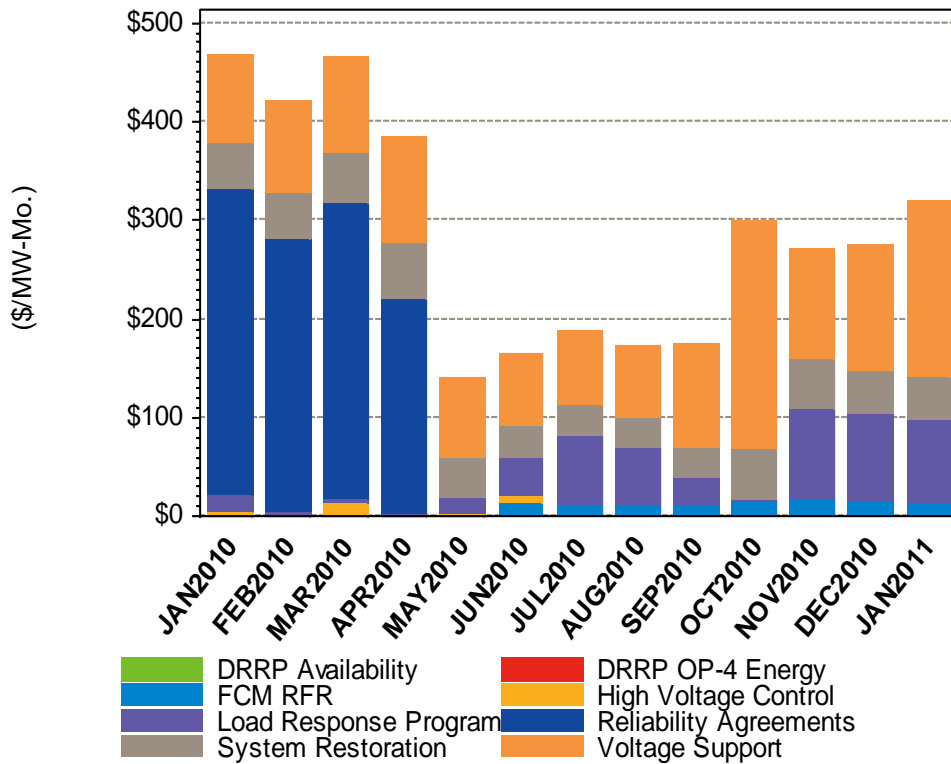


Figure 5-1: Reliability costs by type, 13 months.

Table 5-1
Reliability Costs by Type, 13 Months (\$/MW-Month)

Month	DRRP Availability	DRRP OP 4 Energy	FCM RFR	High Voltage Control	Load Resp. Program	Reliability Agreements	System Restoration	Voltage Support	Total
Jan-10	\$1.03	\$0.00	\$0.00	\$4.33	\$16.15	\$310.34	\$45.89	\$88.77	\$466.50
Feb-10	\$1.16	\$0.00	\$0.00	\$0.00	\$3.27	\$275.28	\$47.83	\$92.08	\$419.62
Mar-10	\$1.15	\$0.00	\$0.00	\$14.32	\$1.10	\$299.62	\$50.79	\$98.05	\$465.04
Apr-10	\$1.21	\$0.00	\$0.00	\$0.16	\$1.75	\$216.72	\$55.96	\$108.71	\$384.52
May-10	\$1.13	\$0.00	\$0.00	\$1.01	\$16.37	\$0.00	\$40.23	\$80.61	\$139.35
Jun-10	\$0.00	\$0.00	\$11.79	\$9.41	\$37.27	\$0.00	\$32.48	\$73.62	\$164.57
Jul-10	\$0.00	\$0.00	\$10.59	\$0.00	\$71.56	\$0.00	\$29.46	\$75.12	\$186.72
Aug-10	\$0.00	\$0.00	\$11.20	\$0.00	\$57.71	\$0.00	\$31.16	\$72.71	\$172.79

²⁵ 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 facility that has the largest impact is lost. See the ISO's AMR09 for further analysis of these costs over time; http://www.iso-ne.com/markets/mkt_anlys_rpts/annl_mkt_rpts/index.html.

Month	DRRP Availability	DRRP OP 4 Energy	FCM RFR	High Voltage Control	Load Resp. Program	Reliability Agreements	System Restoration	Voltage Support	Total
Sep-10	\$0.00	\$0.00	\$11.06	\$0.00	\$28.02	\$0.00	\$30.65	\$104.33	\$174.07
Oct-10	\$0.00	\$0.00	\$15.73	\$0.00	\$1.82	\$0.00	\$49.90	\$230.67	\$298.11
Nov-10	\$0.00	\$0.00	\$15.71	\$0.00	\$92.50	\$0.00	\$49.71	\$111.99	\$269.91
Dec-10	\$0.00	\$0.00	\$13.89	\$0.00	\$89.20	\$0.00	\$44.00	\$126.56	\$273.64
Jan-11	\$0.00	\$0.00	\$13.62	\$0.00	\$84.50	\$0.00	\$42.92	\$178.53	\$319.57

5.3 Terminated Reliability Cost Types

Table 5-2 shows the termination dates for certain reliability costs no longer in effect.

Table 5-2
Effective Start and End Dates for Certain Regional Network Load Cost Components

Cost Component Short Name	Effective Service Start Date	Effective Service End Date
Reliability Agreements ^(a)	Pre-2005	Jun-10
DRRP availability	Pre-2005	Jun-10
DRRP OP 4 electric energy	Pre-2005	Jun-10

(a) Starting in June 2010, coincident with the start of the FCM, Reliability Agreements expired, and any further need to retain units in the balancing authority area for reliability are addressed under the FCM market rules.

5.4 Reliability Costs by Reliability Region, Last 13 Months

Figure 5-2 shows the aggregated reliability costs of all types by reliability region for the last 13 months. The dramatic decline in costs in the Connecticut (CT) and Western/Central Massachusetts (WCMA) regions is associated with the planned expiration schedule of Reliability Agreements and is attributable to transmission system improvements. While these costs expired in June 2010, they remain subject to resettlement through the ISO's established data reconciliation process, also known as the 90-day resettlement. Price separation starting in June 2010 in the CT reliability region is attributable to the need to retain resources for reliability in that region for the first commitment period of the FCM.

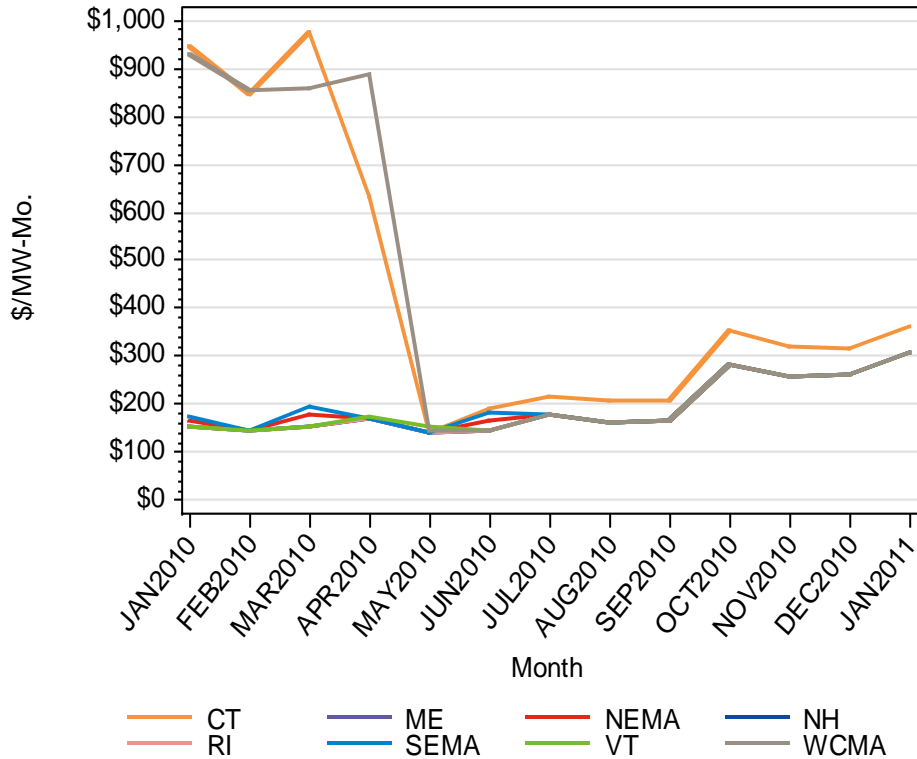


Figure 5-2: Average combined costs for reliability services by reliability region, 13 months.

5.5 Voltage Support Costs, Last 13 Months

Volt ampere reactive (VAR) is a measurement of reactive power used to maintain transmission voltages for meeting the operating requirements of the New England transmission system. Qualifying reactive resources that are compensated for providing VAR service may receive both fixed (capacity cost) payments and variable payments.

Before June 2008, the cost of resources committed to providing reactive power for either low-voltage support or regional high-voltage control was primarily borne by systemwide RNL. Starting in July 2008, the allocation for high-voltage control shifted from systemwide RNL to RNL within the specifically affected reliability region. The allocation for low-voltage-support costs remains at the systemwide level. The fixed payments paid to VAR resources are included in the allocation of low-voltage support to pool RNL.

Figure 5-3 shows voltage-support costs for the last 13 months. Table 5-3 shows the fixed capacity and variable components of voltage-support cost along with total voltage-support cost for the last 13 months. Variability in the fixed-cost portion is attributable to the monthly change in RNL used to allocate the costs. Elevated voltage support costs in October 2010 resulted from the commitment of a generator for five days during the month to address low voltage issues during a planned transmission outage.

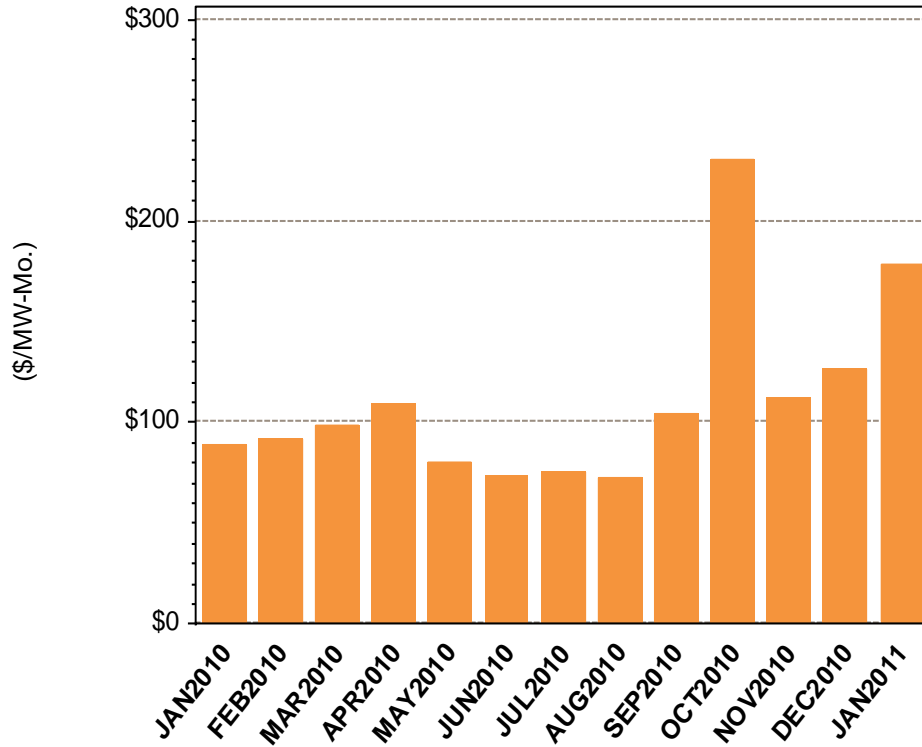


Figure 5-3: Voltage support costs, 13 months.

Table 5-3
Fixed Capacity, Variable, and Total Voltage Support Costs, 13 Months (\$/MW-Month)

Month	Fixed (Capacity Charge) Voltage Support Cost	Variable Voltage Support Cost	Total Low Voltage Support Cost
Jan-10	\$88.77	\$0.00	\$88.77
Feb-10	\$92.08	\$0.00	\$92.08
Mar-10	\$98.05	\$0.00	\$98.05
Apr-10	\$108.71	\$0.00	\$108.71
May-10	\$80.37	\$0.24	\$80.61
Jun-10	\$73.62	\$0.00	\$73.62
Jul-10	\$67.19	\$7.93	\$75.12
Aug-10	\$70.88	\$1.83	\$72.71
Sep-10	\$71.02	\$33.31	\$104.33
Oct-10	\$101.15	\$129.53	\$230.67
Nov-10	\$101.98	\$10.01	\$111.99
Dec-10	\$91.30	\$35.26	\$126.56
Jan-11	\$89.15	\$89.38	\$178.53

5.6 High-Voltage Control Costs by Reliability Region, Last 13 Months

In 2008, the tariff was changed to allocate the costs of high-voltage control to the reliability region and not regionwide. Figure 5-4 shows high-voltage control costs by reliability region for the last 13 months. Table 5-4 shows high-voltage control costs by reliability region, total voltage-support costs, and total voltage costs for the last 13 months.

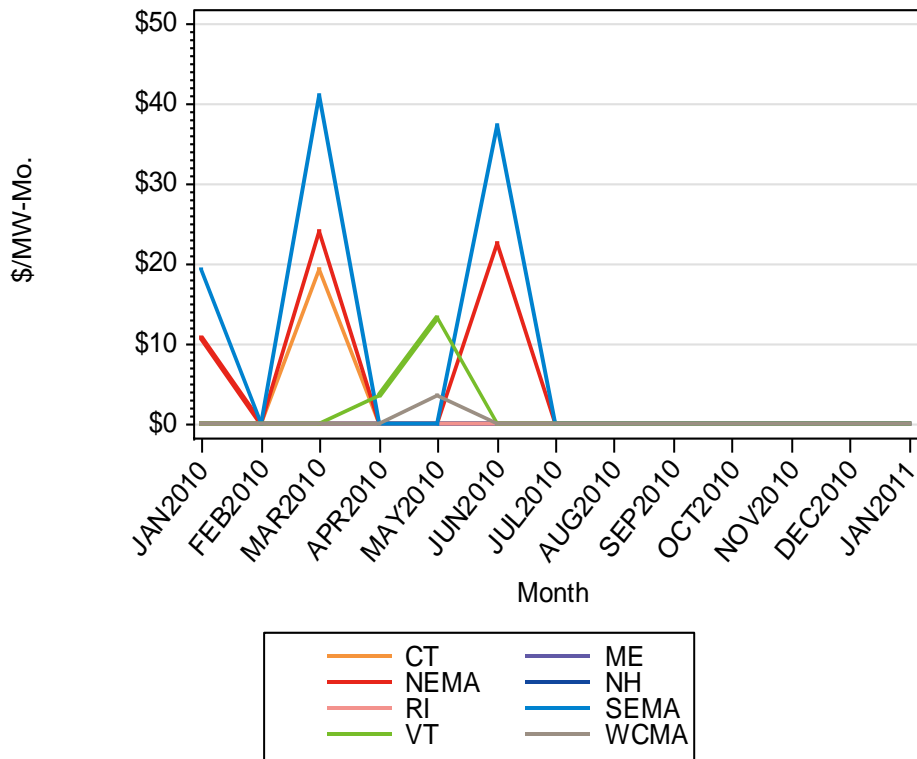


Figure 5-4: High-voltage control costs by reliability region, 13 months.

Table 5-4
Voltage Control, Voltage Support, and Total VAR Costs, 13 Months (\$/MW-Month)

Month	High Voltage Control								New England	Voltage Support	New England Total Voltage Cost
	ME	NH	VT	CT	RI	SEMA	WCMA	NEMA			
Jan-10	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$19.32	\$0.00	\$10.82	\$4.33	\$88.77	\$93.09
Feb-10	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$92.08	\$92.08
Mar-10	\$0.00	\$0.00	\$0.00	\$19.27	\$0.00	\$41.02	\$0.00	\$23.96	\$14.32	\$98.05	\$112.38
Apr-10	\$0.00	\$0.00	\$3.67	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.16	\$108.71	\$108.87
May-10	\$0.00	\$0.00	\$13.34	\$0.04	\$0.00	\$0.00	\$3.54	\$0.00	\$1.01	\$80.61	\$81.62
Jun-10	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$37.16	\$0.00	\$22.58	\$9.41	\$73.62	\$83.03
Jul-10	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$75.12	\$75.12

Month	High Voltage Control									Voltage Support	New England Total Voltage Cost
	ME	NH	VT	CT	RI	SEMA	WCMA	NEMA	New England		
Aug-10	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$72.71	\$72.71
Sep-10	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$104.33	\$104.33
Oct-10	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$230.67	\$230.67
Nov-10	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$111.99	\$111.99
Dec-10	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$126.56	\$126.56
Jan-11	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$178.53	\$178.53

Section 6 Administrative Service Costs

Administrative cost components reflect costs incurred by both the ISO and the PTOs for scheduling, system control, and dispatch service of the transmission system and to bill and collect for NESCOE's operating budget. Administrative costs are based on regulated, revenue requirements of the ISO, local control centers (LCCs) (operated by PTOs), and NESCOE. ISO dispatch and control costs reflect only Schedule 1 (and not Schedules 2 and 3) of the ISO Self-Funding Tariff.²⁶ Year-over-year volatility in individual administrative component costs may not be driven solely by changes in underlying revenue requirements, but may reflect true-ups (for over-collections or under-collections) of annual revenues and annual movements in underlying loads, both of which are influential in the rate determination process. The [Historical Regional Network Load Cost](#) report provides further background on each of these components and the calculation of their costs.²⁷

Figure 6-1 and Table 6-1 show administrative costs by type for the last 13 months.

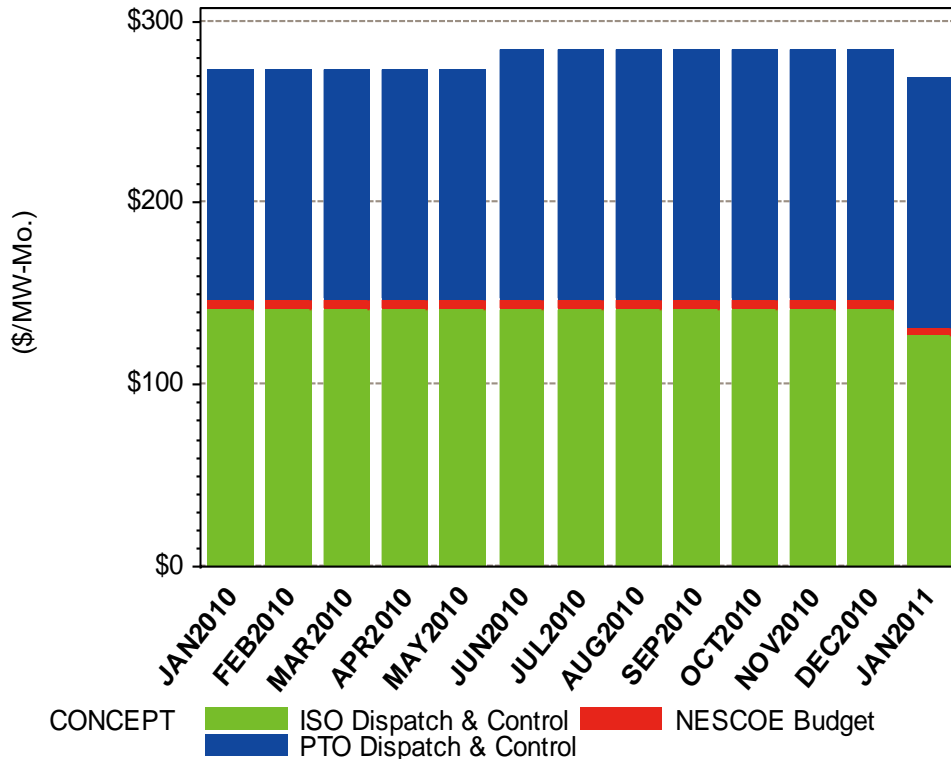


Figure 6-1: Administrative costs by type, 13 months.

²⁶ PTO dispatch and control costs stem from the OATT Schedule 1, Scheduling, Dispatch and Control Service, and are recovered through the OATT using RNL as an allocator. As the billing and collection agent for NESCOE, the ISO collects ISO Schedule 5 NESCOE payments and distributes them to NESCOE. Charges are based on the RNL for any transmission customer using RNS.

²⁷ The reader may also reference the annual ISO Administrative Budget filing, typically filed with the FERC in October of each year and searchable within the [ISO New England Filings](#) section of the ISO web site.

**Table 6-1
Administrative Costs by Type, 13 Months (\$/MW-Month)**

Month	ISO Dispatch Control	NESCOE Budget	PTO Dispatch Control	Total
Jan-10	\$140.87	\$5.54	\$126.49	\$272.90
Feb-10	\$140.87	\$5.54	\$126.49	\$272.90
Mar-10	\$140.87	\$5.54	\$126.49	\$272.90
Apr-10	\$140.87	\$5.54	\$126.49	\$272.90
May-10	\$140.87	\$5.54	\$126.49	\$272.90
Jun-10	\$140.87	\$5.54	\$137.90	\$284.31
Jul-10	\$140.87	\$5.54	\$137.90	\$284.31
Aug-10	\$140.87	\$5.54	\$137.90	\$284.31
Sep-10	\$140.87	\$5.54	\$137.90	\$284.31
Oct-10	\$140.87	\$5.54	\$137.90	\$284.31
Nov-10	\$140.87	\$5.54	\$137.90	\$284.31
Dec-10	\$140.87	\$5.54	\$137.90	\$284.31
Jan-11	\$126.83	\$4.13	\$137.90	\$268.86

Section 7

Regional Network Load, Last 13 Months

As defined in the OATT, a transmission customer's monthly RNL is based on monthly peak demand and determines the customer's use of RNS. A transmission customer's monthly RNL value (i.e., monthly network load) is the customer's hourly load at the time of the hourly peak load of the local transmission network to which the customer's load is connected.

Each PTO in New England that has a local network RNS rate calculates monthly RNL values, which it submits to the ISO. The ISO uses these values in the RNS-related settlement processes. Customers with RNL may or may not participate in the wholesale electric energy markets, depending on the way in which they do business in New England.

An *RNL customer* is a transmission customer that a PTO has identified as the billable entity for one or more of the RNL "assets" in its local network. These assets reflect one or more actual physical load facilities and are modeled in the ISO's RNS settlement process for calculating RNS settlements. The RNL cost components discussed in this report (and listed in Section 1) reflect the services for which these customers are charged for their assigned share of RNL. Among the eight local networks, approximately 80 RNL customers own approximately 130 network load assets. These assets are separate from the assets identified in other wholesale market settlements, such as for energy.

7.1 Average Regional Network Load by Month, Last 13 Months

Figure 7-1 shows average monthly regional network load by year for the entire New England Balancing Authority Area for the last 13 months.

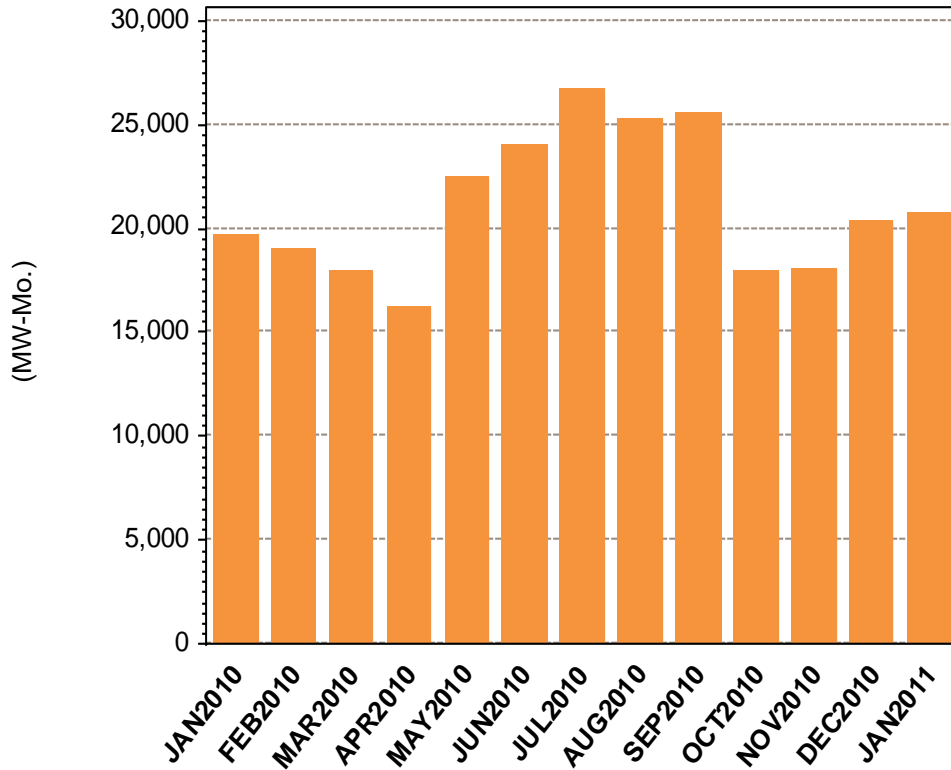


Figure 7-1: Average monthly regional network load, 13 months.

Since RNL reflects peak monthly demand usage, monthly aggregations of RNL appear more volatile during the highest demand months of the year, typically during the summer months, and within local networks or reliability regions serving a larger customer load base.

7.2 Monthly Regional Network Load by Reliability Region, Last 13 Months

Figure 7-2 shows monthly network load aggregated by reliability region for the last 13 months.

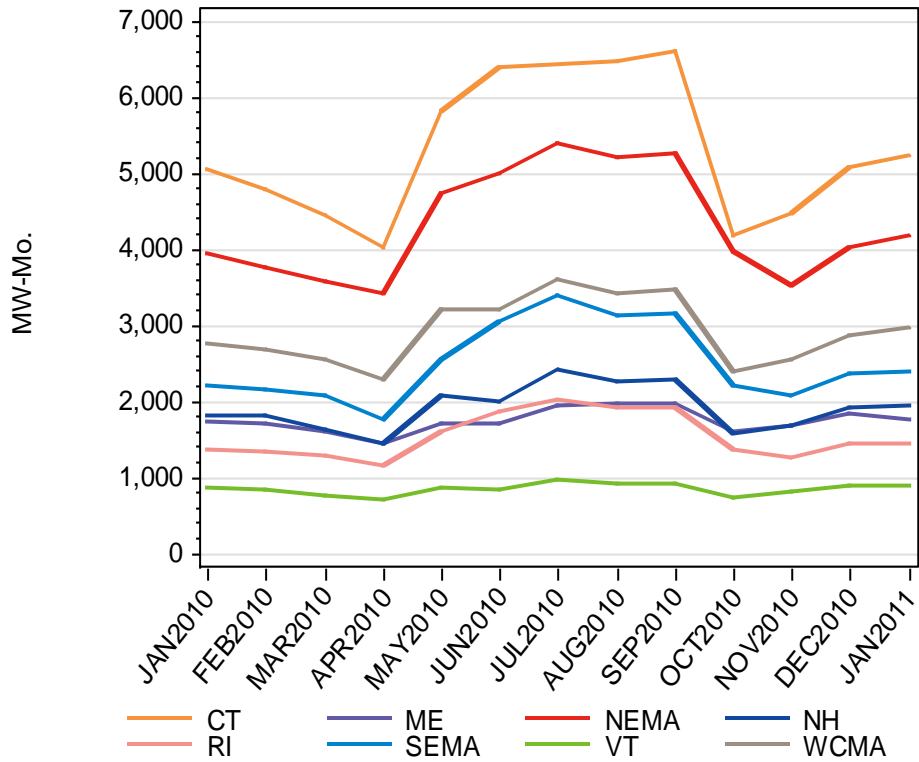


Figure 7-2: Monthly network load by reliability region, 13 months.

7.3 Monthly Regional Network Load by Local Regional Network, Last 13 Months

Figure 7-3 shows monthly network load by local network, as reported by PTOs for the last 13 months.

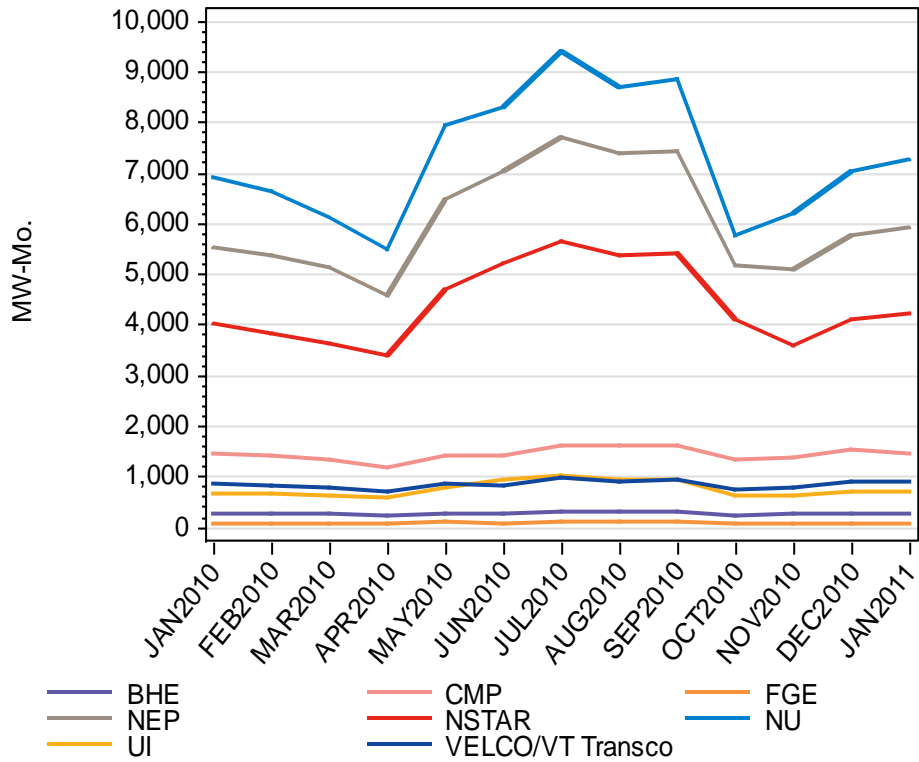


Figure 7-3: Monthly network load by local network, 13 months.

7.4 Monthly Regional Network Load by State, Last 13 Months

Table 7-1 shows monthly network load aggregated by state for the last 13 months.

Table 7-1
Average RNL aggregated by State and in Total, 13 Months (MW-Month)

Month	CT	MA	ME	NH	RI	VT	New England Total
Jan-10	5,030	8,899	1,725	1,809	1,367	862	19,692
Feb-10	4,772	8,581	1,695	1,793	1,328	833	19,003
Mar-10	4,442	8,170	1,598	1,633	1,279	763	17,885
Apr-10	4,027	7,438	1,434	1,442	1,140	697	16,177
May-10	5,811	10,450	1,708	2,065	1,601	847	22,482
Jun-10	6,377	11,237	1,687	1,993	1,860	826	23,980
Jul-10	7,026	12,341	1,947	2,406	2,004	972	26,697
Aug-10	6,464	11,747	1,957	2,255	1,905	904	25,232
Sep-10	6,585	11,875	1,969	2,283	1,919	920	25,551
Oct-10	4,162	8,540	1,607	1,575	1,364	725	17,973
Nov-10	4,467	8,121	1,674	1,685	1,261	792	18,000
Dec-10	5,058	9,242	1,833	1,911	1,424	891	20,359
Jan-11	5,228	9,523	1,748	1,947	1,437	877	20,760

Section 8

Average RNL Costs by State

This section shows state level summarizations. The correlation among states, reliability regions, and their underlying local area networks were mentioned in Section 1 of the report. The next table shows average RNL costs by New England state for the past 13 months.

Separation in RNL costs among the New England states may occur due to: high voltage control costs, FCM RFR costs, and prior to June 1, 2010, reliability agreement costs. Improvements to the transmission system have and should continue to minimize these costs over time.

Table 8-1
Average RNL Costs by State and in Total, 13 Months (\$/MW-Month)

Month	CT	MA	ME	NH	RI	VT	New England Average
Jan-10	\$6,211	\$5,670	\$5,420	\$5,420	\$5,420	\$5,420	\$5,735
Feb-10	\$6,112	\$5,634	\$5,413	\$5,413	\$5,413	\$5,413	\$5,688
Mar-10	\$6,243	\$5,659	\$5,420	\$5,420	\$5,420	\$5,420	\$5,734
Apr-10	\$5,899	\$5,657	\$5,436	\$5,436	\$5,436	\$5,440	\$5,653
May-10	\$5,407	\$5,408	\$5,407	\$5,407	\$5,407	\$5,420	\$5,408
Jun-10	\$5,874	\$5,850	\$5,830	\$5,830	\$5,830	\$5,830	\$5,851
Jul-10	\$5,903	\$5,863	\$5,863	\$5,863	\$5,863	\$5,863	\$5,873
Aug-10	\$5,892	\$5,848	\$5,848	\$5,848	\$5,848	\$5,848	\$5,859
Sep-10	\$5,892	\$5,850	\$5,850	\$5,850	\$5,850	\$5,850	\$5,861
Oct-10	\$6,037	\$5,969	\$5,969	\$5,969	\$5,969	\$5,969	\$5,985
Nov-10	\$6,004	\$5,941	\$5,941	\$5,941	\$5,941	\$5,941	\$5,956
Dec-10	\$6,002	\$5,946	\$5,946	\$5,946	\$5,946	\$5,946	\$5,960
Jan-11	\$6,031	\$5,977	\$5,977	\$5,977	\$5,977	\$5,977	\$5,991

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