Northeast Utilities System

107 Selden Street, Berlin, CT 06037

Northeast Utilities Service Company
P.O. Box 270
Hartford, CT 06141-0270
(860) 665-5000
www.nu.com

July 2, 2008

Mr. Daniel Caruso
Chairman
Connecticut Siting Council
10 Franklin Square
New Britain, CT 06051

Re: Docket No. F-08 - Connecticut Siting Council Review of 2008 Forecasts of Electric Loads and Resources

Dear Mr. Caruso:

This letter provides the response to requests for the information listed below.

<u>Response to CEAB-01 Interrogatories dated 06/18/2008</u>
CEAB-001, 002, 003, 004, 005, 006, 007, 008, 009, 010, 011, 012*, 013, 014, 015

Very truly yours,

Christopher R. Bernard
Manager
Regulatory Policy - Transmission
NUSCO
As Agent for CL&P

cc: Service List

* Due to the bulk nature of this material, copies are being provided to the CSC and DPUC only.

Witness: Robin E. Lewis
Request from: Connecticut Energy Advisory Board

Question:
Please provide a detailed description of the methodology by which the energy and peak load forecasts contained in your initial filing in this proceeding were prepared.

Response:

Several regression models are used to develop CL&P's forecast of monthly sales, reflecting local economic and demographic conditions. Economic and demographic forecasts for the state of Connecticut are based on a model developed by Moody's Economy.com in September 2007 for the state of Connecticut and the United States. The sales forecast is developed by class by various end uses that affect energy consumption and incorporates assumptions to reflect customers' response to price changes, conservation programs, distributed generation and other known changes. Sales forecasts provide input to the hourly load, output and peak load forecasts. The output forecast is equal to the sum of the class sales forecasts plus losses. The peak forecast is based on a regression model that uses sales as a driver. These models are all described in more detail below.

Sales Forecasts

The residential and commercial models are each comprised of a customer model to forecast customer counts, a statistically adjusted end-use model ("SAE") to forecast use per customer, and an elasticity model which provides price and economic elasticities that are used in the SAE.

Step 1: Residential and Commercial Customer Models

The residential customer forecast was estimated using historical data from January 1999 to August 2007 with residential customer counts as a function of housing stock and a 12 month lagged dependent variable. The commercial customer forecast is based on nonmanufacturing employment and was estimated using historical data from January 2002 through August 2007.

Step 2: Residential and Commercial Elasticity Models

The residential elasticity model was estimated using historical data from January 2003 to August 2007. The commercial elasticity model was estimated using historical data from January 2000 to August 2007. The functional forms of these models are:

$$\mathbf{ResUsePerDay}_m = f(HDD\_RD_m, CDD\_RD_m, Price_m, Income_m,)$$
$$\mathbf{ComUsePerDay}_m = f(HDD\_RD_m, CDD\_RD_m, Price_m, GSP_m,)$$

where:
m = Month
HDD_RD_m = Heating degree days per reading day per month
CDD_RD_m = Cooling degree days per reading day per month
$Price_m$ = 12 month moving average real typical bill per month
$Income_m$ = Monthly real average personal income per household
GSP_m = Monthly real gross state product for the service producing sector

The coefficients of the price terms are used to calculate point elasticities for each month, depending on the relationship of the actual or projected price to the mean price. Thus a higher forecasted price would give a higher price elasticity. The equation for the point elasticities is:

$$\mathbf{PriceElas}_m = CoefPrice * Price_m / MeanPred_m$$

where:
m = Month
CoefPrice = Coefficient on the price term in the elasticity model
$Price_m$ = 12 month moving average real typical bill per month
$MeanPred_m$ = Predicted value calculated from $Price_m$ and the mean value of all other independent variables

The range of point elasticities derived from the residential equation is -.099 to -.185 and the commercial equation is -.082 to -.137. The mean income and GSP elasticities are used throughout the estimation and forecast period because generally, average income and GSP change gradually from one period to the next with little variation in the point elasticities. The average elasiticities used were .276 for income and .272 for GSP.

Step 3: Residential and Commercial SAE Models

The SAE model uses regional end-use data from the U.S. Department of Energy's Energy Information Administration to develop independent variables that are used in traditional econometric models.

The SAE modeling framework begins by defining energy use ($Use_{y,m}$) in year (y) and month (m) as the sum of energy used by heating equipment ($Heat_{y,m}$), cooling equipment ($Cool_{y,m}$) and other equipment ($Other_{y,m}$). Formally,

$$\mathbf{Use_{y,m} = Heat_{y,m} + Cool_{y,m} + Other_{y,m}}$$

Although monthly sales for individual customers is available from billing data, the end-use components of those sales are generally not readily available. Substituting the estimates defined above for the unknown actual end-use usage gives the following econometric equation:

$$\mathbf{Use_{y,m} = b_1 \times XHeat_{y,m} + b_2 \times XCool_{y,m} + b_3 \times XOther_{y,m}}$$

Here, $XHeat_{y,m}$, $XCool_{y,m}$ and $XOther_{y,m}$ are explanatory variables constructed from end-use information, dwelling, weather, economic and price data and the income and price elasticities derived from Step 2. The equations used to construct these X-variables maintain an end-use structure as the X-variables are the estimated usage levels for each of the major end uses. The estimated model can then be thought of as a statistically adjusted end-use model, where the estimated slopes are the adjustment factors which scale the regional data to the Company's sales.

For the residential and commercial classes, trend sales equal the number of customers times use per customer derived from steps 1 and 3.

Step 4: Industrial, Streetlighting and Railroad Sales Forecasts

The industrial, streetlighting and railroad sales forecasts are based on traditional econometric models because SAE models and the required data are not available for these classes. The functional forms for these models are:

$\mathbf{IndSales}_m = f(CDD_m , RD_m , Price_m , Employment_m)$
$\mathbf{StlUse}_m = f(MonBinary_m , Time_m)$
$\mathbf{RRSales}_m = f(Time_m)$

where:
CDD_m = Cooling degree days per month
RD_m = Reading days per month
$Price_m$ = 12 month moving average real typical bill per month
Employment = Manufacturing employment
$StlUse_m$ = Streetlighting use per residential customer
MonBinary = Monthly binary variables
LagDependent = Lagged dependent variable

Industrial and railroad trend sales are derived directly from the econometric models. Streetlighting trend sales are equal to the model-produced use per residential customer from Step 4 times the number of residential customers from Step 1.

Step 5: Adjustments to Forecast

The final step in developing the Reference case forecast is to make adjustments to the Trend forecast to account for Conservation and Load Management losses, Distributed Generation losses, Large Commercial and Industrial gains or losses, and a final adjustment to convert billed sales into calendar sales. The end result is the Reference forecast.

Peak Load Forecast

The Reference peak load forecast is primarily used for allocating costs and it is not used for system planning purposes. The forecasted peaks are derived from an econometric model where monthly peaks are a function of weather, Reference forecast sales per reading day, and weather trends which capture increasing air conditioning load. Since the C&LM and economic development assumptions are already included in Reference sales, which the peak demand forecast is a function of, no explicit adjustments are made to the peak model-produced results. The functional form for this models is:

$$\mathbf{Peak}_m = f(\text{SalesPerRD}_m, \text{HDD}_m, \text{CDD}_m, \text{YestCDD}_m, \text{HDDTrend}_m\ \text{CDDTrend}_{m,}\ \text{THITrend}_{m,})$$

where:
Peak_m = Monthly peak load
SalesPerRD_m = Total retail sales per reading day per month
HDD_m = Heating degree days on day of monthly peak
CDD_m = Cooling degree days on day of monthly peak
YestCDDd_m = Cooling degree days on the day before the monthly peak day
HDDTrend_m = Heating degree days on day of monthly peak interacted with time
CDDTrend_m = Cooling degree days on day of monthly peak interacted with time
THITrend_m = Temperature Humidity Index on day of monthly peak interacted with time
Time = Year + month/12
THI = 0.4 * (dry bulb temperature + wet bulb temperature) + 15)

The Reference or 50/50 peak forecast assumes normal weather throughout the year, with normal peak-producing weather episodes in each season. The forecasted mean daily temperature for the summer peak day is 83° Fahrenheit ("°F") and is based on the average peak-day temperatures from 1977-2006.

Witness: Robin E. Lewis
Request from: Connecticut Energy Advisory Board

Question:
Please provide your Normal weather and economic activity ("50/50") 2008-2017 forecast without Conservation and Load Management impacts from continued funding or implementation of programs in the period 2008-2017 and no reductions from anticipated distributed generation from the Department of Public Utility Control's DG Grant Program for:

(a) total systems energy requirements; and
(b) summer peaks.

Response:
Page 2 of 2 shows the forecast without DG and CL&M impacts. Note, as described in response to Q-CEAB-01, explicit reductions to peaks are not made for DG and C&LM. Sales, which do include explicit reductions for DG and C&LM, is used as a driver of the peak regression model. Therefore the effect of the reductions is implicitly reflected in the peak forecast.

Year	Reference Sales Forecast	DG Sales Reductions	C&LM Sales Reductions	Sales without DG and C&LM Reductions	Forecasted Output without DG and C&LM Reductions (includes losses)
	GWh	GWh	GWh	GWh	GWh
2008	23,812	188	65	24,064	25,438
2009	23,853	253	258	24,365	25,755
2010	24,004	266	452	24,722	26,133
2011	24,061	272	645	24,978	26,404
2012	24,190	273	839	25,302	26,746
2013	24,164	272	1,032	25,469	26,923
2014	24,200	272	1,226	25,698	27,165
2015	24,234	272	1,419	25,926	27,406
2016	24,400	273	1,543	26,216	27,712
2017	24,464	272	1,667	26,403	27,911

Year	Reference Peak Forecast	Estimated DG Peak Impacts	Estimated C&LM Peak Impacts	Forecasted Peak without DG and C&LM Reductions
	MW	MW	MW	MW
2008	5,345	40	11	5,396
2009	5,384	43	48	5,475
2010	5,479	44	89	5,612
2011	5,557	45	128	5,730
2012	5,626	45	169	5,840
2013	5,714	45	209	5,968
2014	5,782	45	244	6,071
2015	5,905	45	266	6,216
2016	5,955	45	293	6,293
2017	6,026	45	320	6,391

Note: The C&LM peak impacts are the same as the C&LM shown in Table 3-2 of the 2008 FLR. Although the GWh savings in the tables are slightly different from those used in the filed energy forecast, the associated peak savings are a reasonable approximation of those implicitly included in the reference peak forecast.

The Connecticut Light and Power Company
Docket No. F-08

Data Request CEAB-01
Dated: 06/18/2008
Q-CEAB-003

Witness: Joseph R. Swift
Request from: Connecticut Energy Advisory Board

Question:
Please provide the number of MW and customers in your service territory that are currently enrolled in ISO-NE Demand Response Programs.

Response:
CL&P has directly enrolled 442 customers with ISO-NE representing 192 MW of enrolled load in ISO-NE's 30 Minute Demand Response program. Additionally, third party vendors under contract with CL&P through 12/31/2008 as authorized under Docket 05-07-14PH01, DPUC Investigation of Measures to Reduce Federally Mandated Congestion Charges, (i.e., Demand Direct and EnerNOC) have provided documentation to CL&P confirming enrollment of 581 customers representing 166 MW of enrolled load in ISO-NE's 30 Minute Demand Response program.

The Connecticut Light and Power Company
Docket No. F-08

Data Request CEAB-01
Dated: 06/18/2008
Q-CEAB-004

Witness: Joseph R. Swift
Request from: Connecticut Energy Advisory Board

Question:
Please provide the number of MW and customers in your service territory that:

(a) cleared in FCA1 as a real-time demand response or profiled response customer; or
(b) cleared in FCA1 as an other demand resource (ODR) customer.

Response:
The table below summarizes both the existing and new CL&P resources that cleared in FCA1. Note: These customers listed below were enrolled by CL&P. We have no knowledge on what third party vendors may have enrolled and ultimately cleared the FCA.

CL&P MWs which Cleared in FCA1

	MWs*			Customers
Demand Response	**Existing**	**Bid New****	**Total**	**Existing**
Demand Response using Load Curtailment	89.7	14.0	103.7	79
Demand Response using Emergency Generation	56.6	18.0	74.6	132
Sub-total Demand Response	146.3	32.0	178.3	211
Energy Efficiency	31.84	80.9	112.7	N/A
Distributed Generation	0.271	13.8	14.1	3
Total MWs cleared in FCA1	178.379	126.7	305.1	

*Excludes Line Losses and ISO-NE Reserve Margin
**Quantity of New Customers in place for FCA1 is yet to be determined.

Witness: Robin E. Lewis
Request from: Connecticut Energy Advisory Board

Question:
Please describe and show the calculations underlying the load factor forecasts found in CL&P's Table 2-1, UT's Exhibit 1, and CMEEC's Table I.

Response:
Please see response to Q-CEAB-006.

The Connecticut Light and Power Company
Docket No. F-08

Witness: Robin E. Lewis
Request from: Connecticut Energy Advisory Board

Question:
Please indicate whether the load factor forecasts found in CL&P's Table 2-1, UI's Exhibit 1, and CMEEC's Table I are an input (along with energy requirements) to the peak forecasts or are an output of the summer peak forecasts.

Response:
The load factor shown in Table 2-1 is derived by the following equation using output of the load model and peak model results.

Load Factor = Output / (8760 Hours x Seasonal Peak).

The Connecticut Light and Power Company
Docket No. F-08

Data Request CEAB-01
Dated: 06/18/2008
Q-CEAB-007

Witness: Robert J. Russo
Request from: Connecticut Energy Advisory Board

Question:
Please indicate which of the transmission improvements described in your initial filings in this proceeding are to serve planned or anticipated generating facilities.

Response:
All of the transmission projects listed in Chapters 5 and 6 of the 2008 CL&P FLR are primarily related to transmission and distribution system reliability. The projects are not related to generation interconnection studies.

Section 5.5 includes a discussion of renewable resources in Northern New England and Canada and the need for transmission improvements to deliver that output to serve Southern New England loads.

The Connecticut Light and Power Company
Docket No. F-08

Data Request CEAB-01
Dated: 06/18/2008
Q-CEAB-008

Witness: Robert J. Russo
Request from: Connecticut Energy Advisory Board

Question:
Please provide a copy of your ten-year plan for infrastructure improvements in Connecticut.

Response:
The CL&P FLR Report dated March 3, 2008, contains a ten-year transmission plan forecast. Chapters 5 & 6 of the CL&P FLR Report contain a listing of proposed transmission projects over the ensuing forecast period of 2008 through 2017. These projects are at different stages in the planning process. Certain projects are well defined in scope and therefore have proposed in-service dates, while other projects are not and don't have proposed in-service dates at this time.

The Connecticut Light and Power Company
Docket No. F-08

Witness: Joseph R. Swift
Request from: Connecticut Energy Advisory Board

Question:
Please provide the forecast of conservation and load management (C&LM) impacts from "a ramp-up in spending consistent with the Act," as referenced on page 15 of your March 3, 2008 filing, or implementation of programs in the period 2008-2017 on:

(a) total system energy requirements; and
(b) summer peaks. Provide data in the following form: total C&LM, conservation impacts only, and load management impacts only.

Response:
Please refer to Tables D.4 and D.7 in the Integrated Resource Plan (Attachment I) completed by the electric distribution companies and submitted to the CEAB in January 2008.

Table D.4: DSM-Focus Level DSM MW Savings

		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
UI	EE	10	13	24	38	57	81	107	131	157	182	208	234
UI	DR	20	42	92	103	108	113	118	118	119	120	121	122
CL&P	EE	36	50	96	154	224	308	401	501	594	668	723	768
CL&P	DR	346	380	447	453	476	496	506	506	506	506	506	506
Total (UI and CL&P)		**410**	**484**	**658**	**748**	**865**	**998**	**1,131**	**1,257**	**1,376**	**1,476**	**1,558**	**1,630**

Table D.7: DSM-Focus Level DSM GWh Savings

		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
UI	EE	54	72	133	214	321	455	596	724	854	985	1,118	1,253
CL&P	EE	194	271	521	832	1,214	1,663	2,165	2,702	3,203	3,597	3,892	4,134
Total (UI and CL&P)		**248**	**344**	**654**	**1,046**	**1,536**	**2,117**	**2,761**	**3,426**	**4,057**	**4,582**	**5,010**	**5,387**

The Connecticut Light and Power Company
Docket No. F-08

Data Request CEAB-01
Dated: 06/18/2008
Q-CEAB-010

Witness: Robin E. Lewis
Request from: Connecticut Energy Advisory Board

Question:
Please provide the values for "associated losses" referenced on page 3 of your March 3, 2008 filing.

Response:
The table below shows the losses* included in the forecast of net electrical energy output requirements shown in Table 2-1 of the filing.

Year	GWh
2008	1,359
2009	1,362
2010	1,370
2011	1,373
2012	1,381
2013	1,379
2014	1,381
2015	1,383
2016	1,393
2017	1,396

* As quantified between the customer's meter and the PTF boundary. Losses on the PTF network are not included.

The Connecticut Light and Power Company
Docket No. F-08

Witness: Robin E. Lewis
Request from: Connecticut Energy Advisory Board

Question:
Please provide any calculations that were used to determine that "the primary difference between the ISO-NE and CL&P forecasts is the treatment of C&LM and DG" as noted on page 5 of your March 3, 2008 filing.

Response:
The note describing the differences between the ISO-NE and the CL&P forecasts was meant to be qualitative and not quantitative. Both forecasts are based on regressions using weather and economic drivers, so they are conceptually similar. However CL&P makes post-model adjustments to the sales forecast for DG and C&LM which ISO-NE does not. For more detail on CL&P's forecast methodology, please see the response to Q-CEAB-001.

The Connecticut Light and Power Company
Docket No. F-08

Witness: Robert J. Russo
Request from: Connecticut Energy Advisory Board

Question:
Please provide any supporting calculations or analyses for the statement, "Meeting RPS and the RGGI will require looking beyond New England for low-emissions, renewable resources," as noted on page 22 of your March 3, 2008 filing.

Response:
Please see the two attached presentations by Northeast Utilities for supporting information.

The first presentation, "Creating Benefits for New England Through Additional DC Transmission Connections", was presented to ISO-NE's Planning Advisory Committee at the "ISO-NE DC Day" on December 18, 2007. The second presentation, "Creating Benefits for New England: Putting the Pieces Together", was presented to the "Power from the North Roundtable" discussion held in Boston on February 29, 2008.

The information provided in these presentations support the CL&P statements in its FLR Report that the need to meet RPS and RGGI requirements will require looking beyond New England.

* Due to the bulk nature of this material, copies are being provided to the CSC and DPUC only.

The Connecticut Light and Power Company
Docket No. F-08

Data Request CEAB-01
Dated: 06/18/2008
Q-CEAB-013

Witness: David A. Errichetti
Request from: Connecticut Energy Advisory Board

Question:
Please indicate whether the 265 MW of "New Owned Peaking Generation" noted on page 6 of your March 3, 2008 filing was included in the "279 MW of new combustion turbines to meet the fast-start requirement" described in the Integrated Resource Plan submitted to the CEAB on January of 2008.

Response:
These 265 MWs were CL&P's proposal to meet the 279 MW of need identified in the January 2008 IRP filing. CL&P's proposal is not being developed because it was not selected by the Department of Public Utility Control in its Final Decision in Docket No. 08-01-01, DPUC Review of Peaking Generation Projects, dated June 25, 2008 which addressed this fast-start requirement.

Witness: Robin E. Lewis, Joseph R. Swift
Request from: Connecticut Energy Advisory Board

Question:
Please compare your assumptions for C&LM impacts in both your 50/50 and 90/10 cases, in terms of GWh and peak MW savings, to the reference and DSM-focus levels described in the electric distribution companies' Integrated Resource Plan submitted to the CEAB on January 2, 2008.

Response:
Page 2 of 2 shows the comparison of the forecasted C&LM impacts in the 2008 FLR to the reference and DSM-focus levels described in the IRP submitted to CEAB in January, 2008. Since the FLR DSM forecast starts in 2008 and the IRP forecast starts in 2007, only the savings incremental from 2008 are compared.

Please note, the C&LM impacts are the same in both the 50/50 and Extreme Weather cases.

Year	C&LM Sales Reductions FLR*	Reference C&LM Sales Reductions IRP	Difference FLR less IRP	Focus C&LM Sales Reductions IRP	Difference FLR less IRP
	GWh	GWh	GWh	GWh	GWh
2008	65	62	3	77	-12
2009	258	261	-3	327	-69
2010	452	484	-32	638	-186
2011	645	704	-59	1,020	-375
2012	839	929	-90	1,469	-630
2013	1,032	1,149	-117	1,971	-939
2014	1,226	1,337	-111	2,508	-1,282
2015	1,419	1,486	-67	3,009	-1,590
2016	1,543	1,630	-87	3,403	-1,860
2017	1,667	1,775	-108	3,698	-2,031

Year	C&LM Peak Reductions FLR	C&LM Peak Reductions IRP	Difference FLR less IRP	Focus C&LM Peak Reductions IRP	Difference FLR less IRP
	MW	MW	MW	MW	MW
2008	11	43	-32	48	-37
2009	48	141	-93	161	-113
2010	89	173	-84	225	-136
2011	128	214	-86	318	-190
2012	169	255	-86	422	-253
2013	209	295	-86	525	-316
2014	244	330	-86	625	-381
2015	266	357	-91	718	-452
2016	293	384	-91	792	-499
2017	320	411	-91	847	-527

*GWH shown are those used in Table 2.1.
Note: Since the values shown in the IRP start in 2007 and the values are cumulative,
the 2008 values shown on this table are derived by subtracting the 2007 reduction from all subsequent years.

Witness: David A. Ferrante
Request from: Connecticut Energy Advisory Board

Question:
Please provide the forecast of impacts resulting from distributed generation projects for which the Department of Public Utility Control has approved grants pursuant to the DG Grant Program in the period 2008-2017 on:

(a) total system energy requirements; and
(b) summer peaks . Please provide a list of the DG units and their anticipated in-service dates.

Response:
Please see the attached list of the DG units. The data is derived from information used to generate the forecast data developed in September 2007.

a. See page 2 of 3 for the estimated DG system energy requirement reductions.

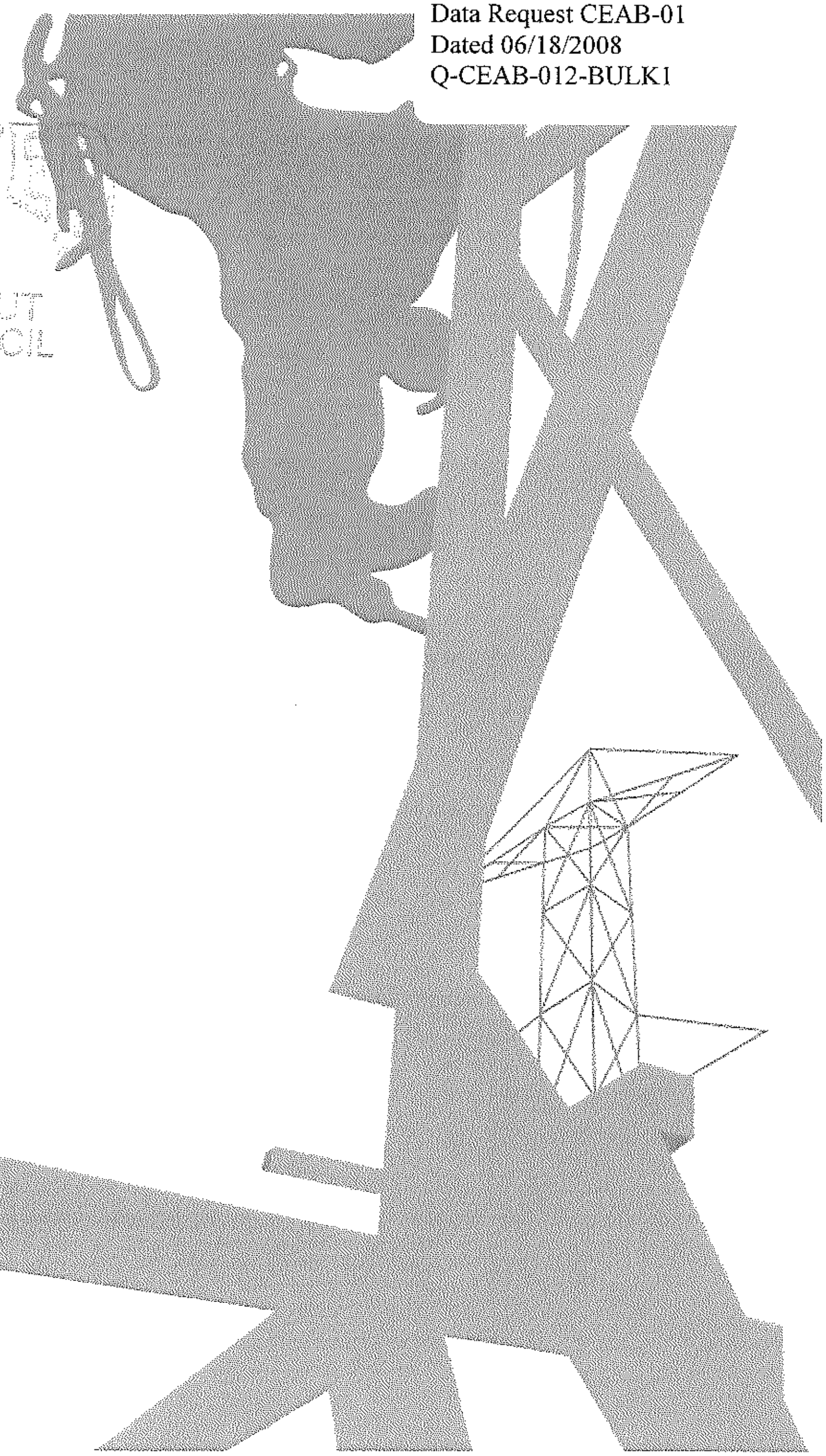
b. See page 2 of 3 for the estimated DG system summer peak reductions and page 3 of 3 for the list of the DG units and their estimated in-service dates.

Year	Estimated DG Sales Reductions	Estimated DG Peak Impacts
	GWh	MW
2008	254	40
2009	333	41
2010	341	42
2011	347	43
2012	348	43
2013	347	43
2014	347	43
2015	347	43
2016	348	43
2017	347	43

Note: DG sales reductions and peak impacts are calculated on a probability basis per customer.

Customer Number	Company Name	Docket No	DPUC Status	Estimated In-service Date
1	Duncaster Inc (1)	06-08-11	Final	Apr-07
2	Bradley Home- cogen	06-07-03	Final	May-07
3	Saint Mary Home	07-01-10	Final	Jun-07
4	SHEFFIELD LABORATORIES (1)	06-08-17	Final	Jul-07
5	SHEFFIELD LABORATORIES (2)	06-08-17	Final	Jul-07
6	Plainville Electric Products Co. (PEPCO)	06-04-06	Final	Sep-07
7	Smithfield Gardens (SHA Corp)	06-07-09	Final	Sep-07
8	PRATT & WHITNEY (UTC) (3)	07-02-30	Final	Oct-07
9	Duncaster Inc (2)	07-05-30	Final	Nov-07
10	Elim Park Baptist Home Inc.	07-03-04	Final	Nov-07
11	PRATT & WHITNEY (UTC) (1)	06-07-16	Final	Nov-07
12	East Hartford Public Schools	06-10-12	Final	Dec-07
13	INTERNATIONAL SKATING CENTER OF CONN LLC	06-09-15	Final	Dec-07
14	SOUTHINGTON CARE CENTER	07-05-29	Final	Dec-07
15	MERIDEN HOUSING AUTHORITY- WILLOW-T2	07-05-14	Final	Jan-08
16	MERIDEN HOUSING AUTHORITY- WILLOW-T1	07-05-14	Final	Jan-08
17	Norwalk High School (City of Norwalk)	06-07-22	Final	Feb-08
18	The Instititutes for Pharmaceutical Discovery(IPD)	06-06-10	Final	Feb-08
19	MASHANTUCKET PEQUOT TRIBAL CENTER	07-06-12	Final	Feb-08
20	Flanagan Industries (1)	07-03-10	Final	Mar-08
21	Flanagan Industries (2)	07-03-13	Final	Mar-08
22	Component Technologies, Inc	07-06-71	Final	Mar-08
23	Cellu-Tissue	06-04-12	Final	Apr-08
24	Kimberly Clark	06-10-19	Final	Apr-08
25	FRITO LAY INC 117383505	06-05-11	Final	May-08
26	Taylor and Fenn (1)	06-12-19	Final	Jul-08
27	WESLEYAN UNIVERSITY	06-12-23	Final	Jul-08
28	Rand Whitney (2)	07-03-03	Final	Sep-08
29	NU WAY TOBACCO 117386103	07-06-75	Final	Nov-08
30	Norcap Landfill/Manchester Methane	06-11-09	Final	Dec-08
31	EnvironmentalTechnologies,LLC/VeoliaWater North America	07-04-29	Final	Dec-08
32	CT Department of Transportation Aviation and Ports	07-06-64	Final	Dec-08
33	Branford High	06-10-29	Final	Jan-09
34	HAMILTON SUNDSTRAND 121763214	07-04-17	Final	Mar-09
35	US Coast Guard (1) USCGA	07-05-40	Final	Sep-09
36	Hartford Steam Company	07-05-39	Final	May-10
37	Mashantucket MPTN/Foxwoods	07-06-08	Final	Aug-10

CL&P Docket No. F-08
Data Request CEAB-01
Dated 06/18/2008
Q-CEAB-012-BULK1



Creating Benefits for New England:
Putting the Pieces Together

Power from the North Roundtable

February 29, 2008

Jim Robb

Northeast Utilities

Northeast
Utilities System

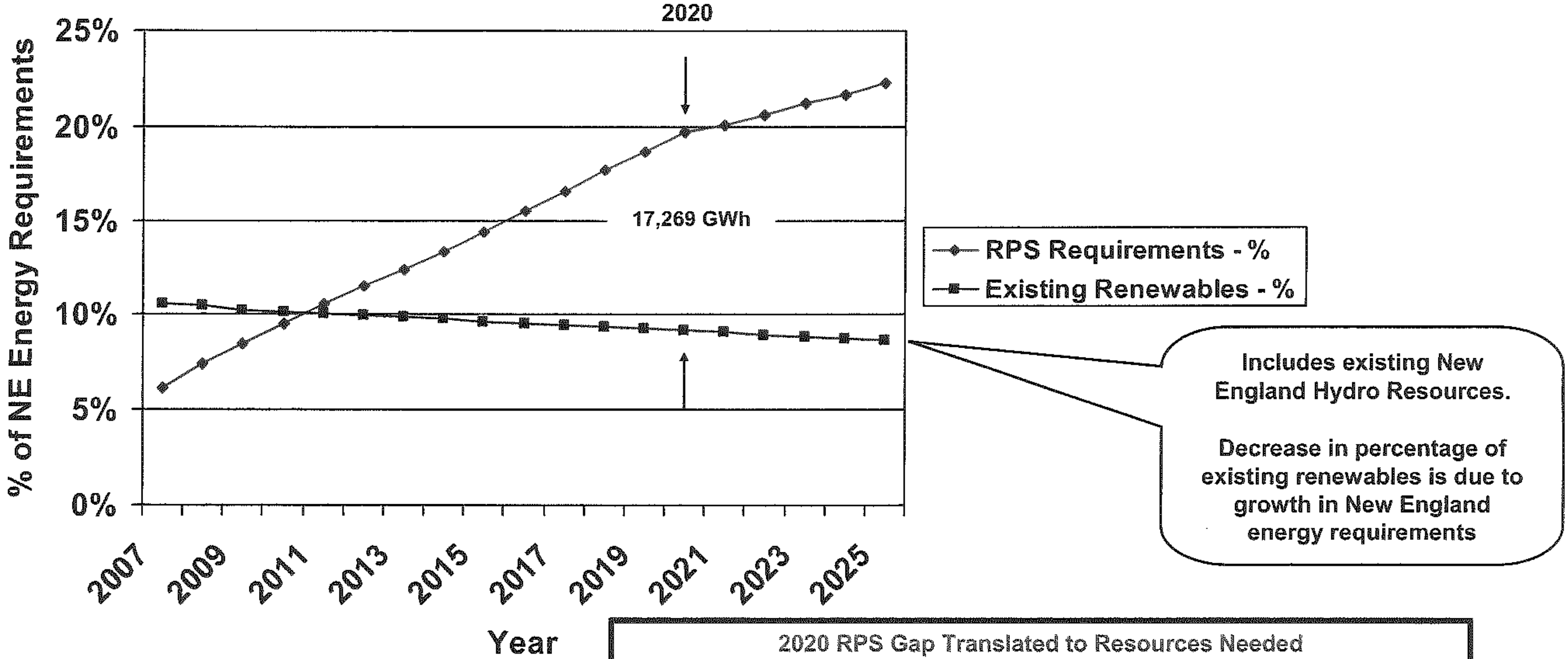
Energy / Growth / Leadership

New England Faces a Number of Significant Energy-Related Challenges

- Resource adequacy
- Energy needs
- Grid reliability
- Fuel diversity and system operability
- Price of electricity
- Environmental Requirements

New England's 1st Environmental Challenge: Renewable Portfolio Standards (RPS)

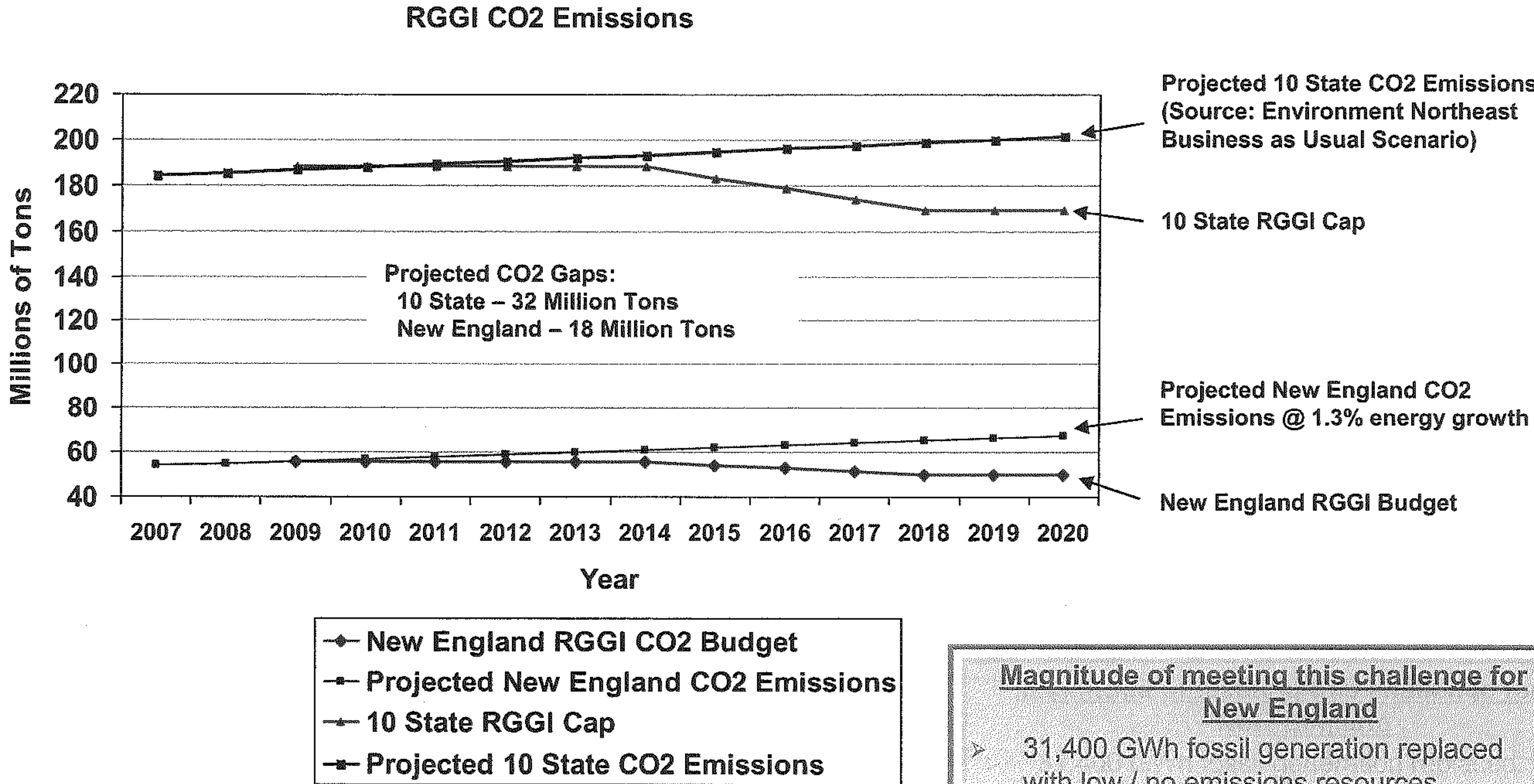
- Beyond 2010, a growing gap in meeting New England RPS is projected (could reach 17,000 GWh by 2020)



2020 RPS Gap Translated to Resources Needed				
Technology	Size	Number Required	Total MW Required	Assumed Capacity Factor
Biomass	50 MW plants	49	2,500	80%
Wind	3 MW Turbines	2,200	6,600	30%
Solar	2kW panels	8.2 million	16,400	12%

Northeast Utilities System

New England's 2nd Environmental Challenge: Regional Greenhouse Gas Initiative (RGGI) Requirements



Magnitude of meeting this challenge for New England

- 31,400 GWh fossil generation replaced with low / no emissions resources
- Equivalent to 4,500 MW of baseload generation (80% capacity factor)

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A Business As Usual Approach Will Not Result in an Acceptable Outcome

- ISO-NE's Scenario Analysis showed that the gas-fired scenario would not reach the RPS and RGGI goals and results in high prices and continued heavy reliance on natural gas
- The environmental targets themselves are deterministic and may be inconsistent with a market approach to determining generation supply and dispatch
- Significant changes required include:
  - Aggressive energy efficiency programs
  - Generation Mix
  - Generation Dispatch
  - Addition of new, low-emissions resources

A Portfolio of Energy Resources Will Be Required

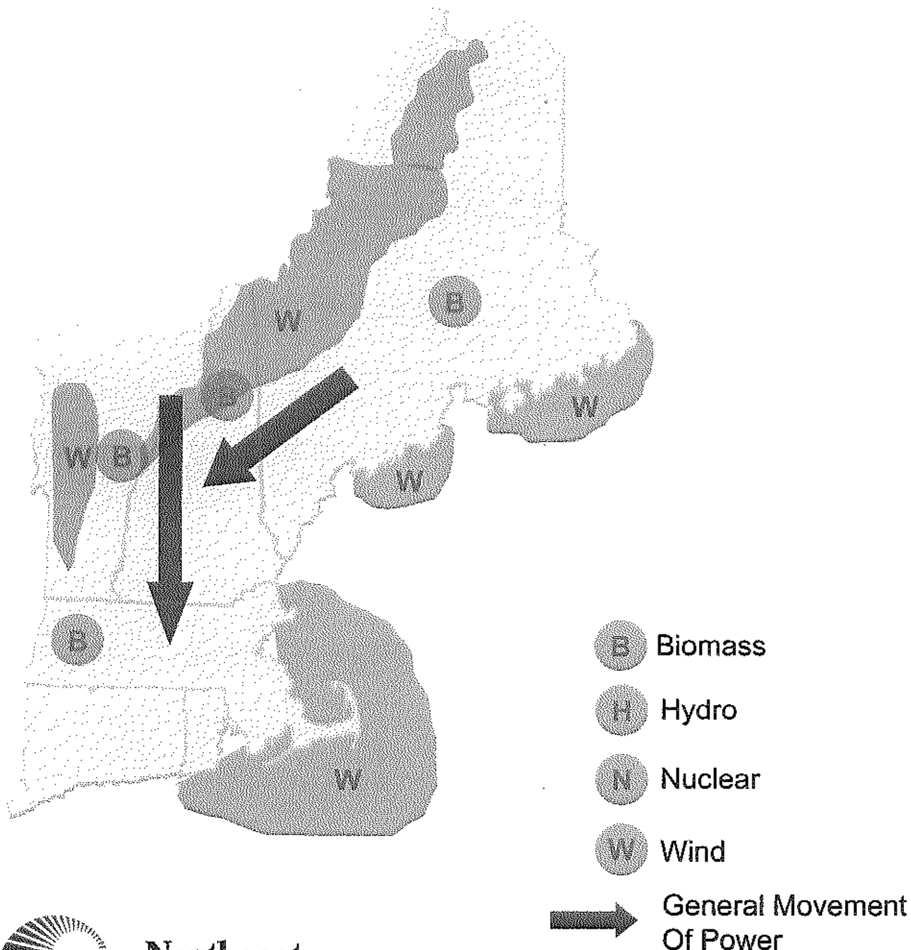
- Key elements of a portfolio approach
  - Energy efficiency and demand response
  - Efficient new generation and renewable resources within New England
  - Carbon emissions policies and programs
  - Low carbon emissions resources from Canada
  - New transmission connections within New England and to Canada

Finding the Right New England and Canadian Solutions Will Require Solving Many Issues

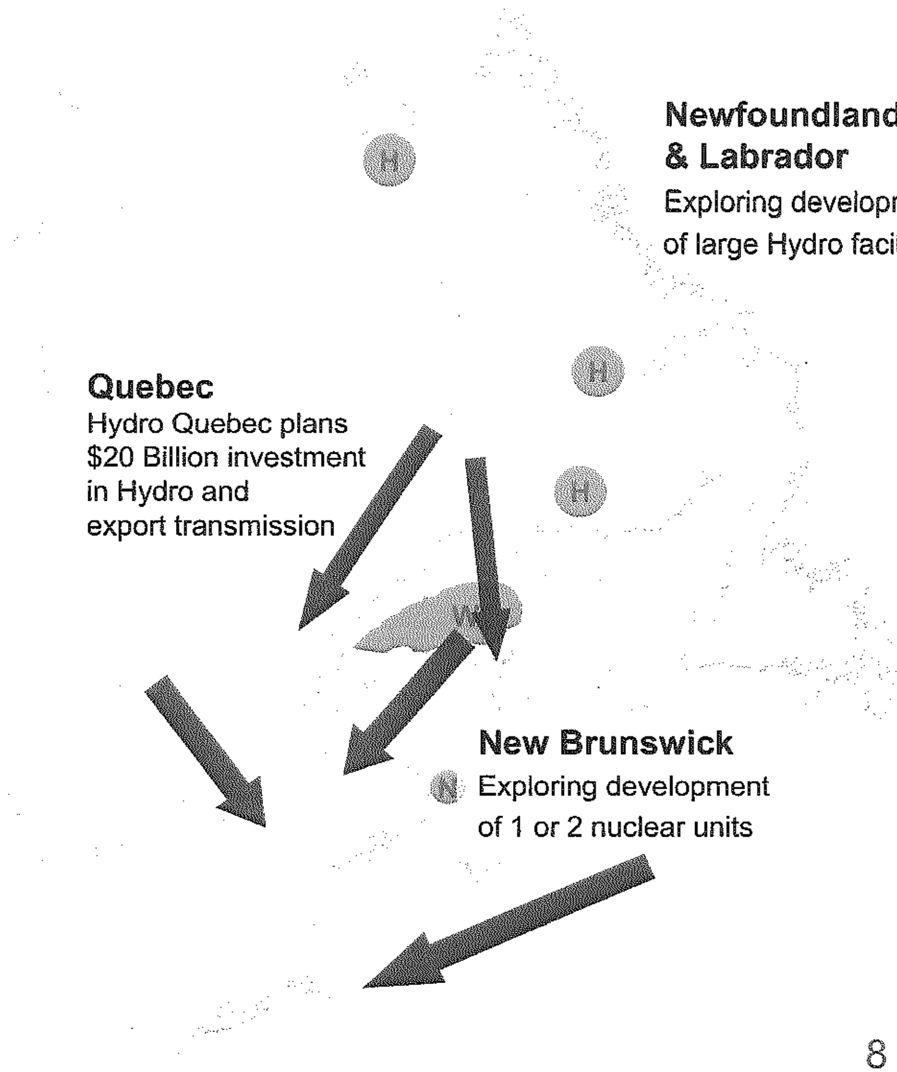
- What are the optimal solutions and how do we reach consensus?
- How do we create a transmission pricing protocol to enable new renewable development in remote areas of New England?
- What arrangements with Canadian suppliers will result in economic value?
- How will the costs of new transmission be recovered?
- How will environmental and diversity benefits be valued?
- What regulatory and legislative changes will need to be implemented?
- And others issues, as we move forward.

Northern New England and Eastern Canada Will Become Valuable Sources to Meet New England's Needs

New England's Most Attractive Renewable Energy Locations



Eastern Canadian Development

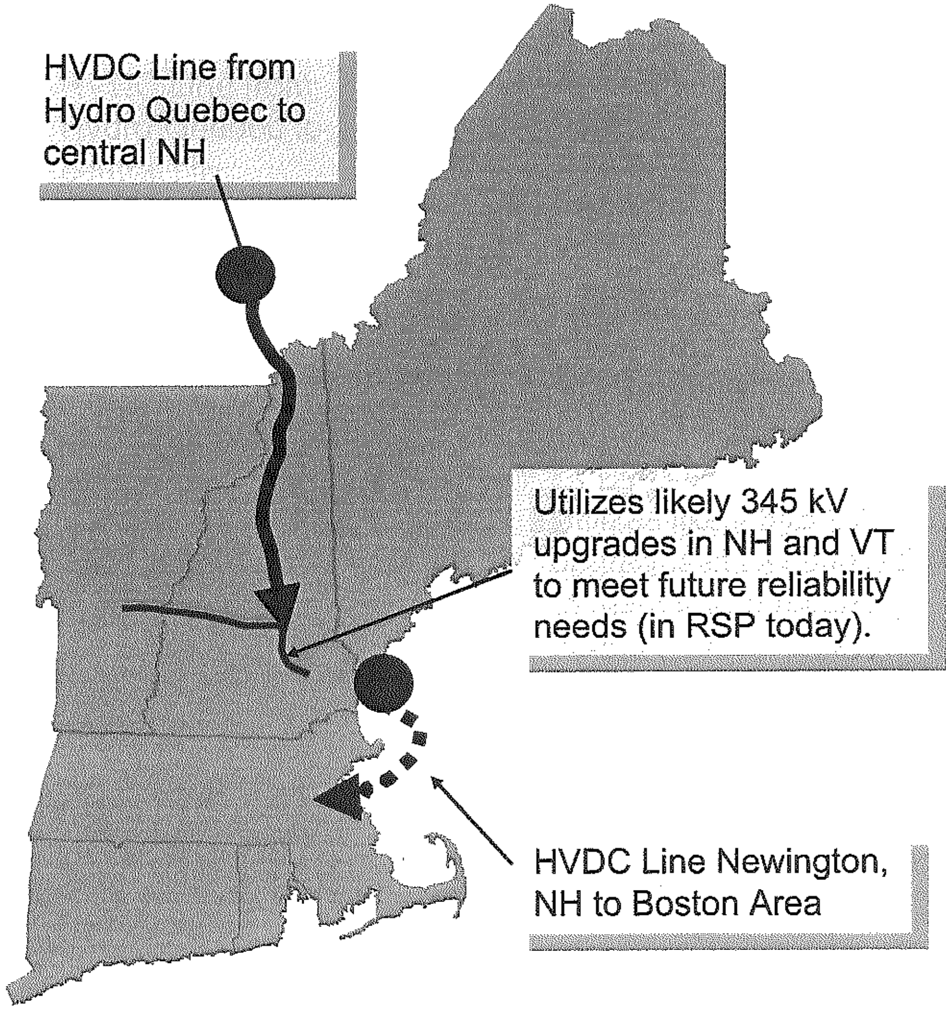


Newfoundland & Labrador
Exploring development of large Hydro facilities

Quebec
Hydro Quebec plans $20 Billion investment in Hydro and export transmission

New Brunswick
Exploring development of 1 or 2 nuclear units

A Set of Complementary Projects with Tangible Benefits for New England



Benefits

- A solution with real benefits for the region
  - Economic value
  - CO_2 reduction
  - Renewable resource additions
  - Fuel diversity
- HVDC tie line with Hydro Quebec allows for large import capability into New England
- Optimizes use of existing and planned bulk power grid -- connects the DC tie line from Hydro Quebec at a good location on the New England AC system
- Provides a new, strong and separate reliability path from HQ
- Addition of north-south DC connection allows for enhanced power flows to southern New England load centers

Thoughts on a Going Forward Process

- One project like this may not be enough -- may need multiple new lines to Canada
- Build upon ISO-NE Scenario Analysis key themes and results
- How do these kind of projects fit with "Market Efficiency Upgrades?"
  - Determination of need
  - Valuation of benefits
  - Planning process support for DC projects?
- We believe a collaborative process will work best
  - New England's rich history of cooperative bulk power system planning
  - Pooling our collective capabilities will result in a better solution
  - NU has begun a regional dialogue with transmission owners and other stakeholders

CL&P Docket No. F-08
Data Request CEAB-01
Dated 06/18/2008
Q-CEAB-012-BULK2

Creating Benefits for New England Through Additional DC Transmission Connections

ISO-NE DC Day

December 18, 2007

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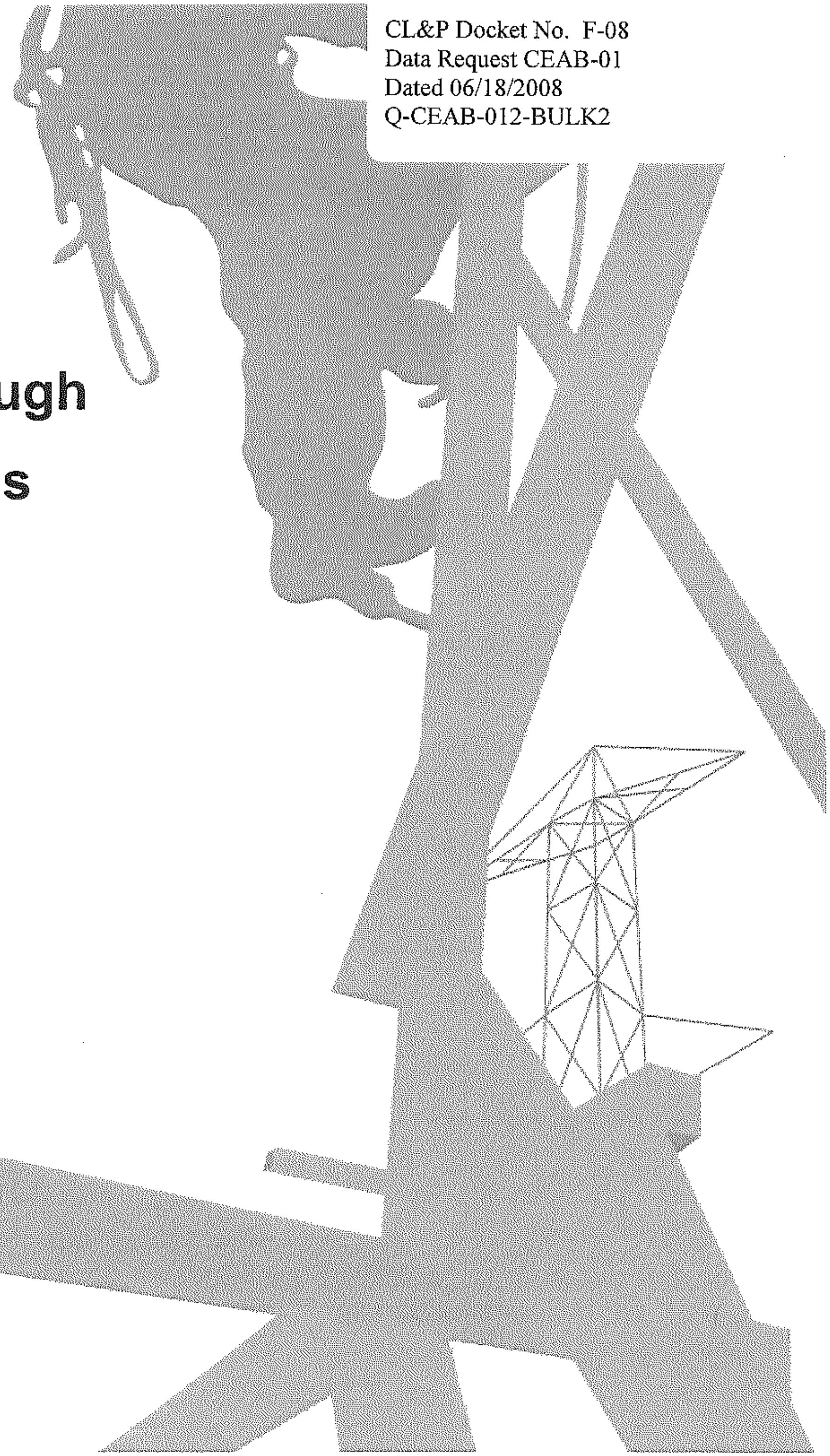

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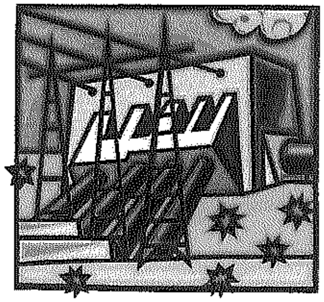
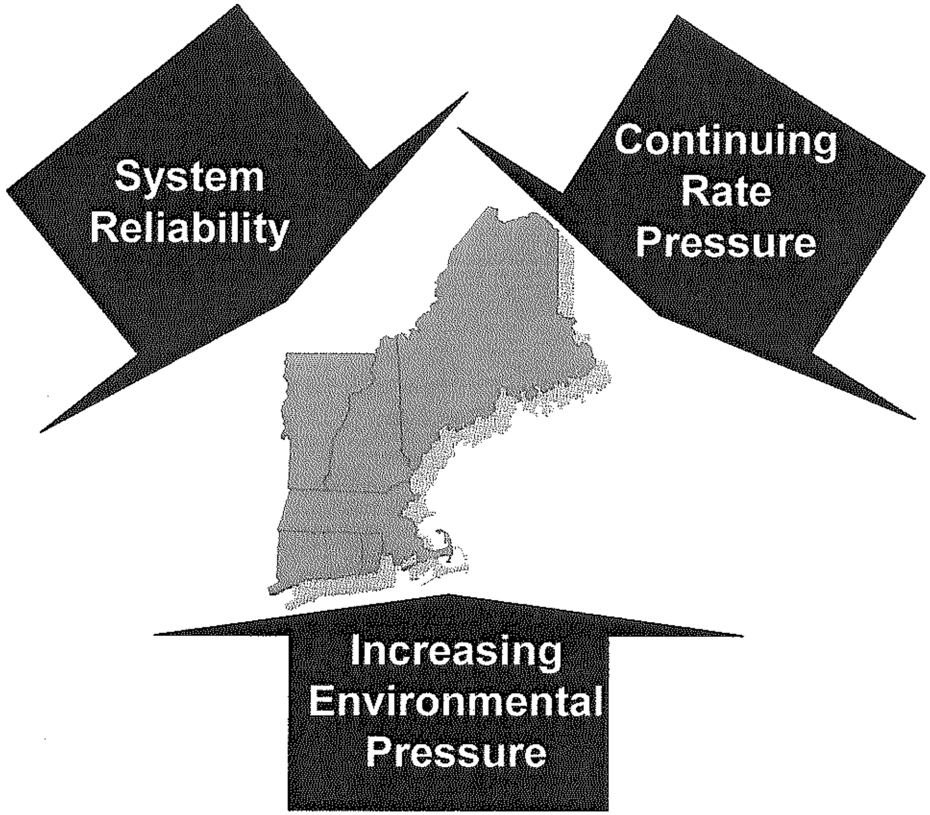
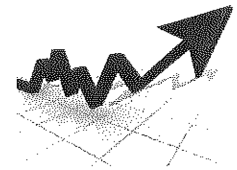
Energy / Growth / Leadership

New England is at Significant Cross Roads

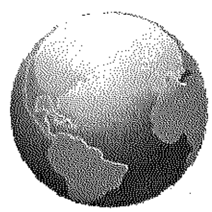


- Resource Adequacy
- Fuel Diversity
- Grid Reliability
- System Operability





- Record high electric prices
- Significant infrastructure investment on horizon
- Regulator and customer frustration



- Growing consensus on climate change with policy action
  - Federal GHG legislation likely in next 2 years
  - RGGI already here in Northeast
- Renewable Portfolio Standards
- Aggressive demand side / energy efficiency aspirations

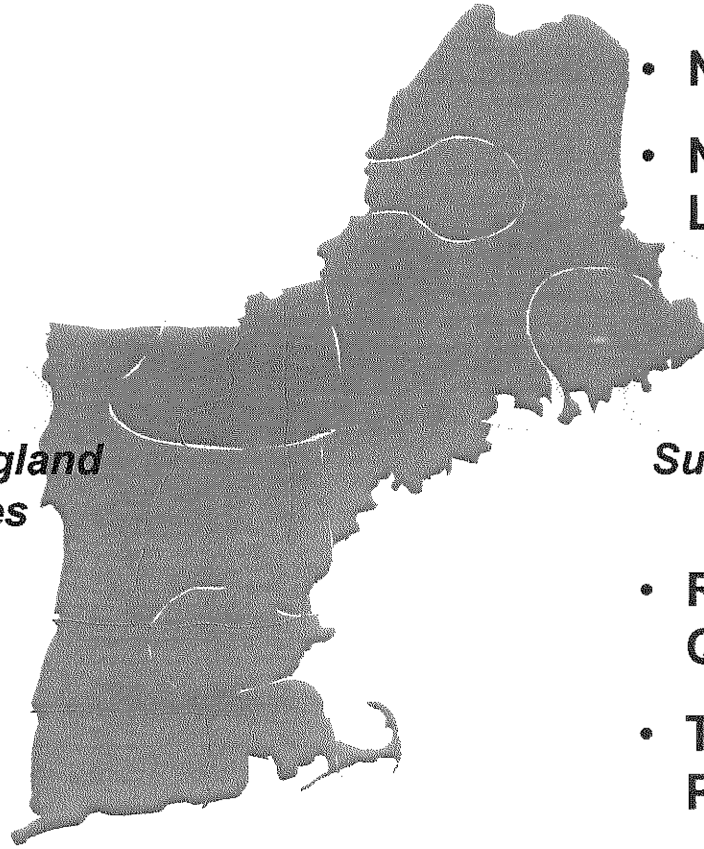
The Four Pieces of the Puzzle

New Energy Efficiency and Demand Response Models

- Funding
- Programs
- New Business Models

Economic Low Emissions Imports

- Quebec
- New Brunswick
- Newfoundland & Labrador



Development of New England Renewable Resources

- Wind
- Biomass
- Northern New England

Supportive Regulatory & Legislative Policy

- Renewable Qualifications
- Transmission Pricing
- Carbon Policies
- Contract Options

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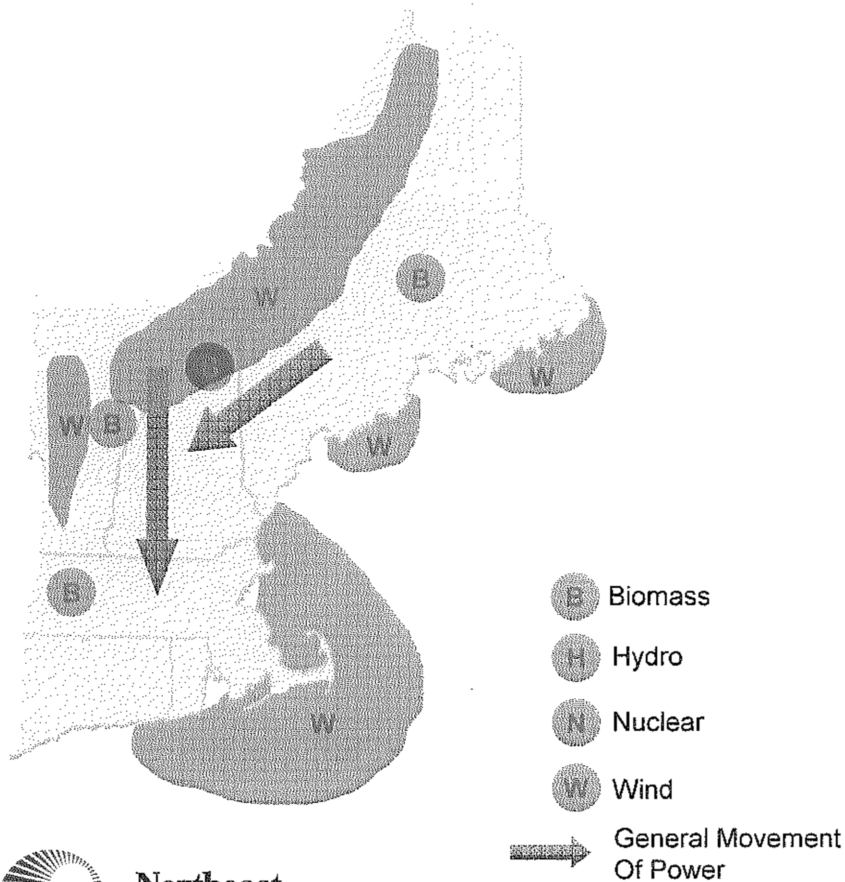
Northern New England and Eastern Canada Will Become Valuable Sources to Meet New England's Needs

New England's Most Attractive Renewable Energy Locations



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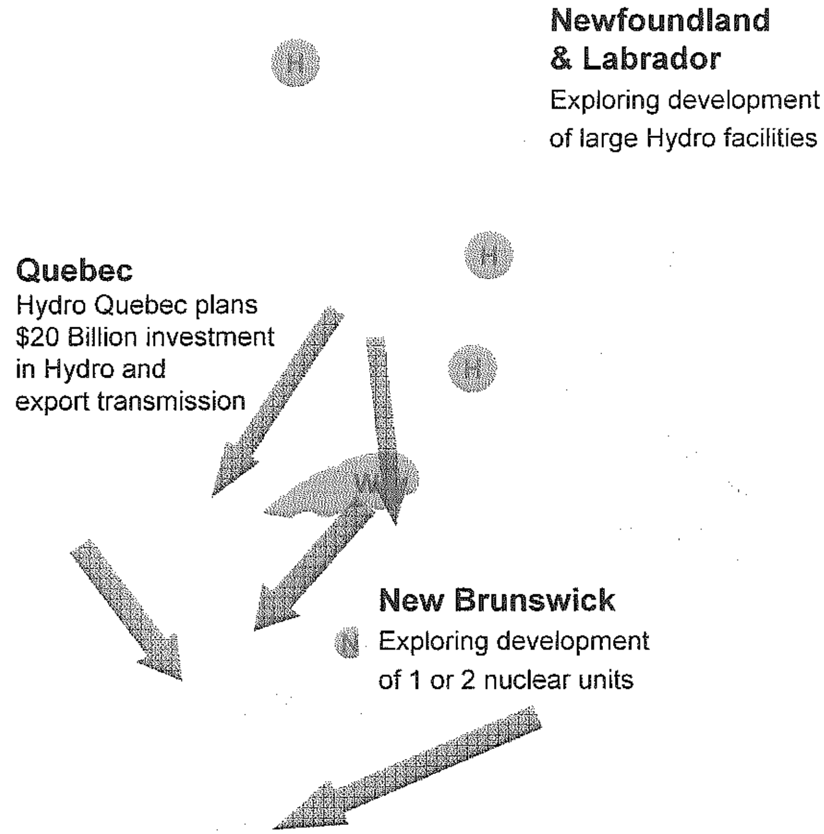

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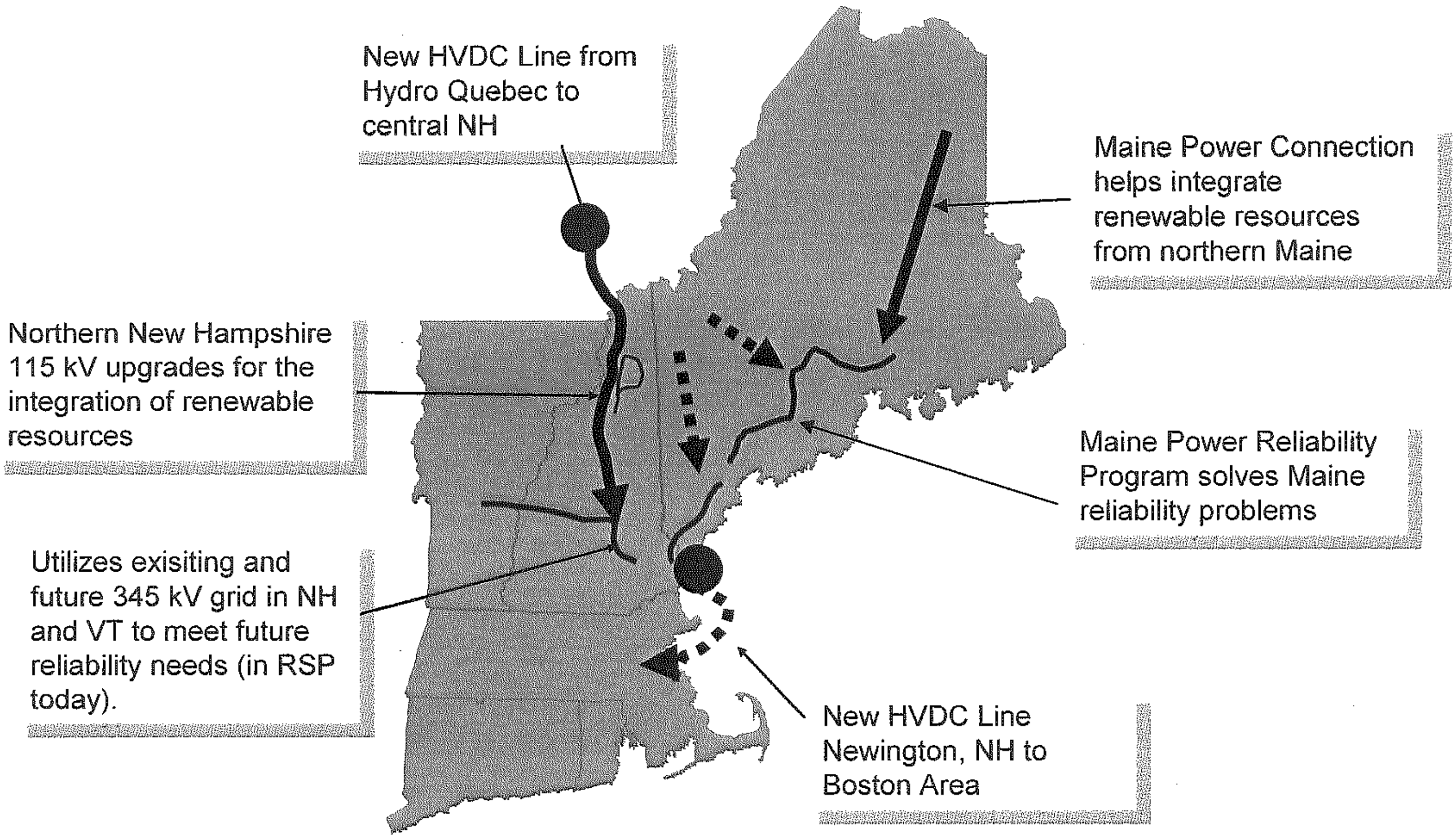
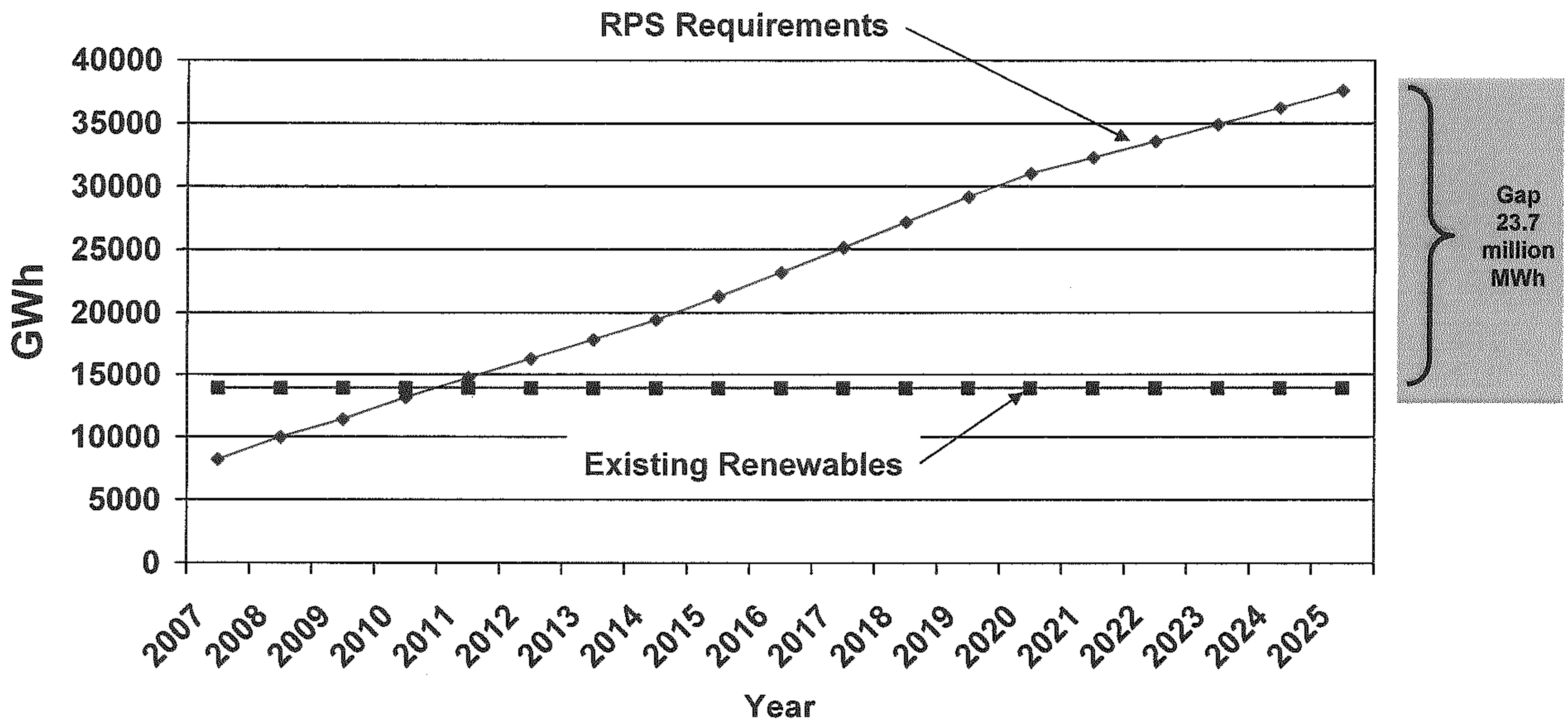
Transmission Enablers for the Integration of Renewable and Low Emissions Generation Resources



Components of a Portfolio

Component	Description	Contribution
DSM and Energy Efficiency	$5.2 B of investment through 2025 ($1.1 B more than current levels)	Reduces energy growth rate from 1.3% to 0.9% 12.8 million MWh reduction by 2025
New Renewable resources in New England	100 MW Biomass (NH – 80% capacity factor) 300 MW Wind (NH – 30% capacity factor) 1,300 MW Wind (ME – 30% capacity factor) 500 MW Wind (Queue – 30% capacity factor)	6.2 million MWh
New Tie Line with Hydro Quebec	1,500 MW (80% capacity factor)	10.5 million MWh

A Portfolio Approach for Renewable Portfolio Standards (RPS)



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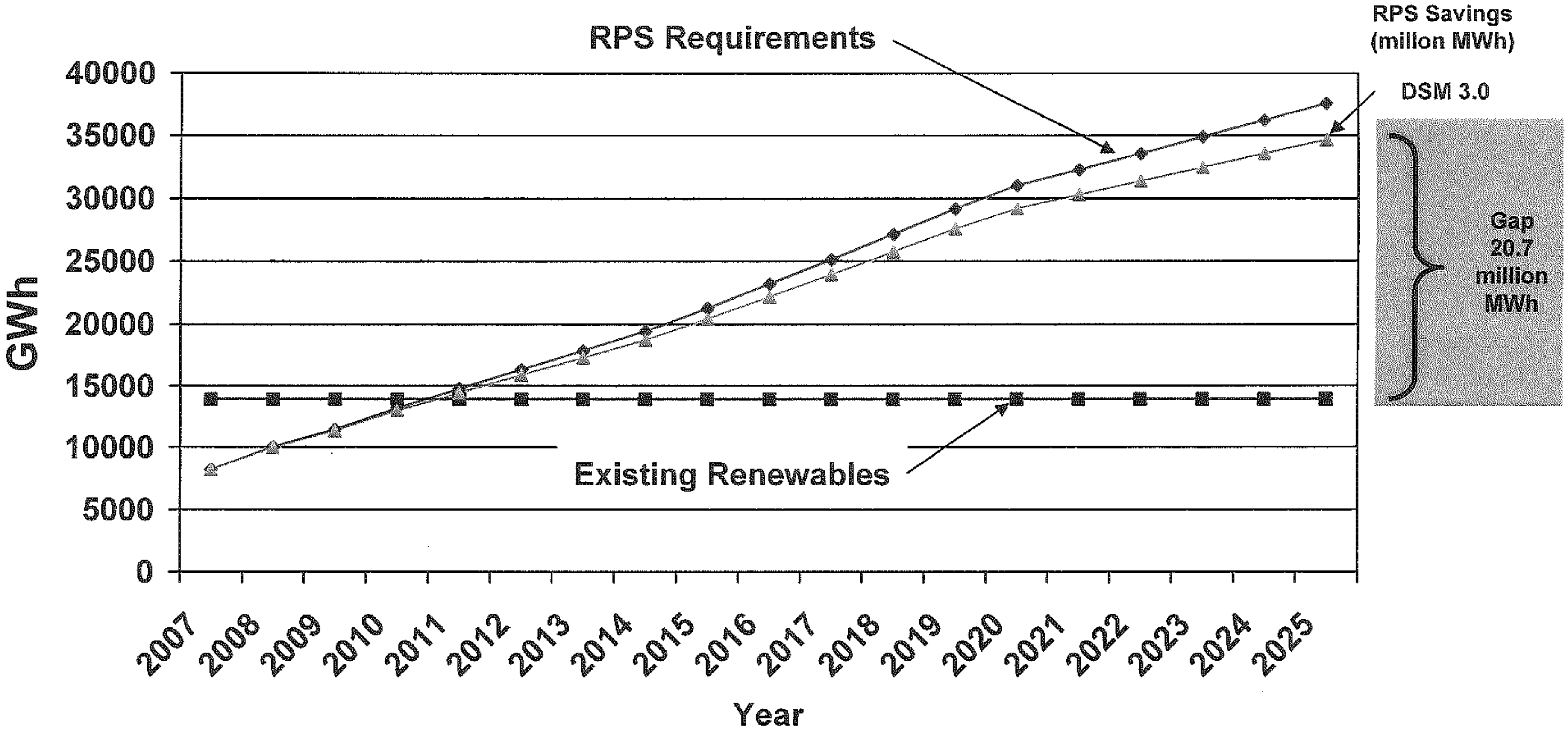

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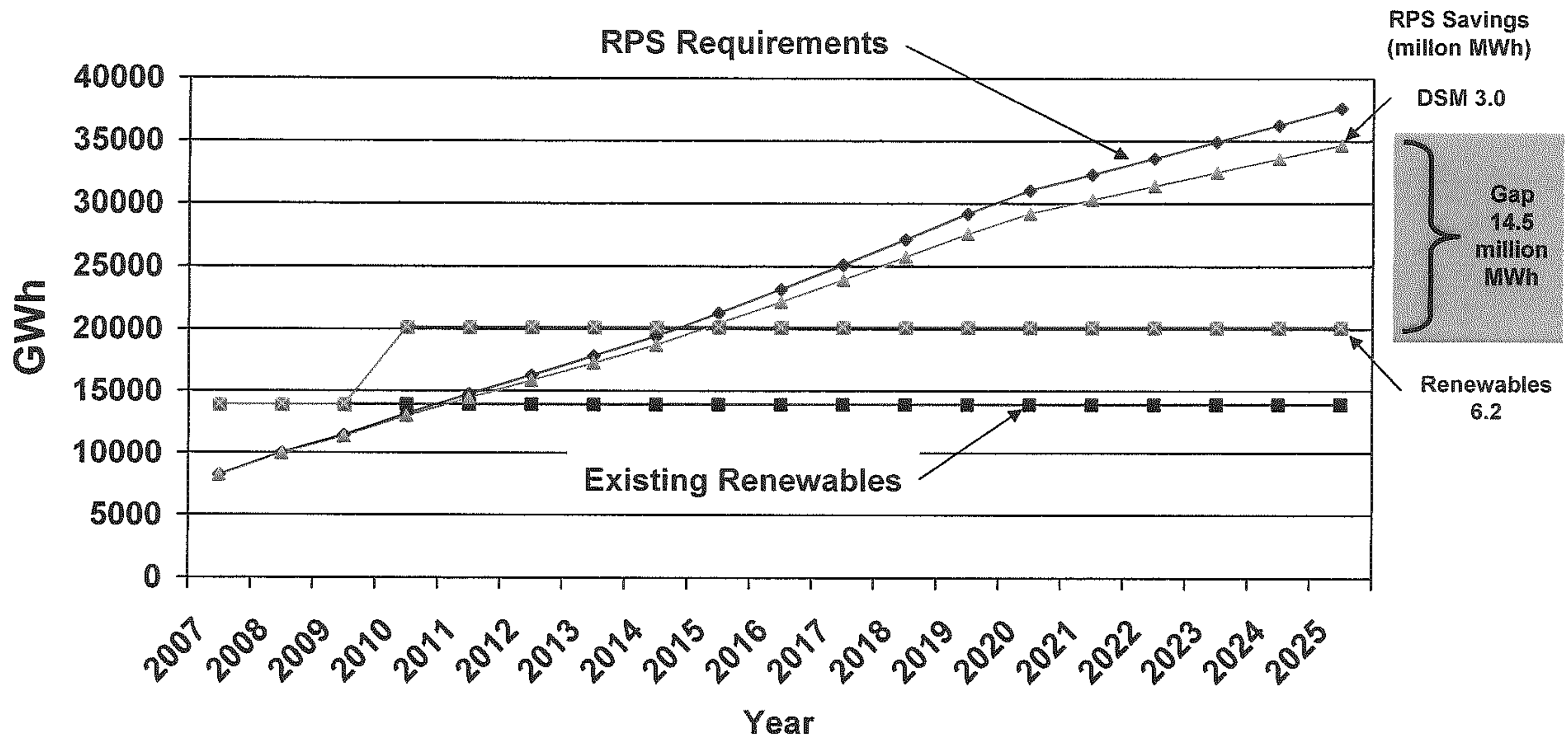

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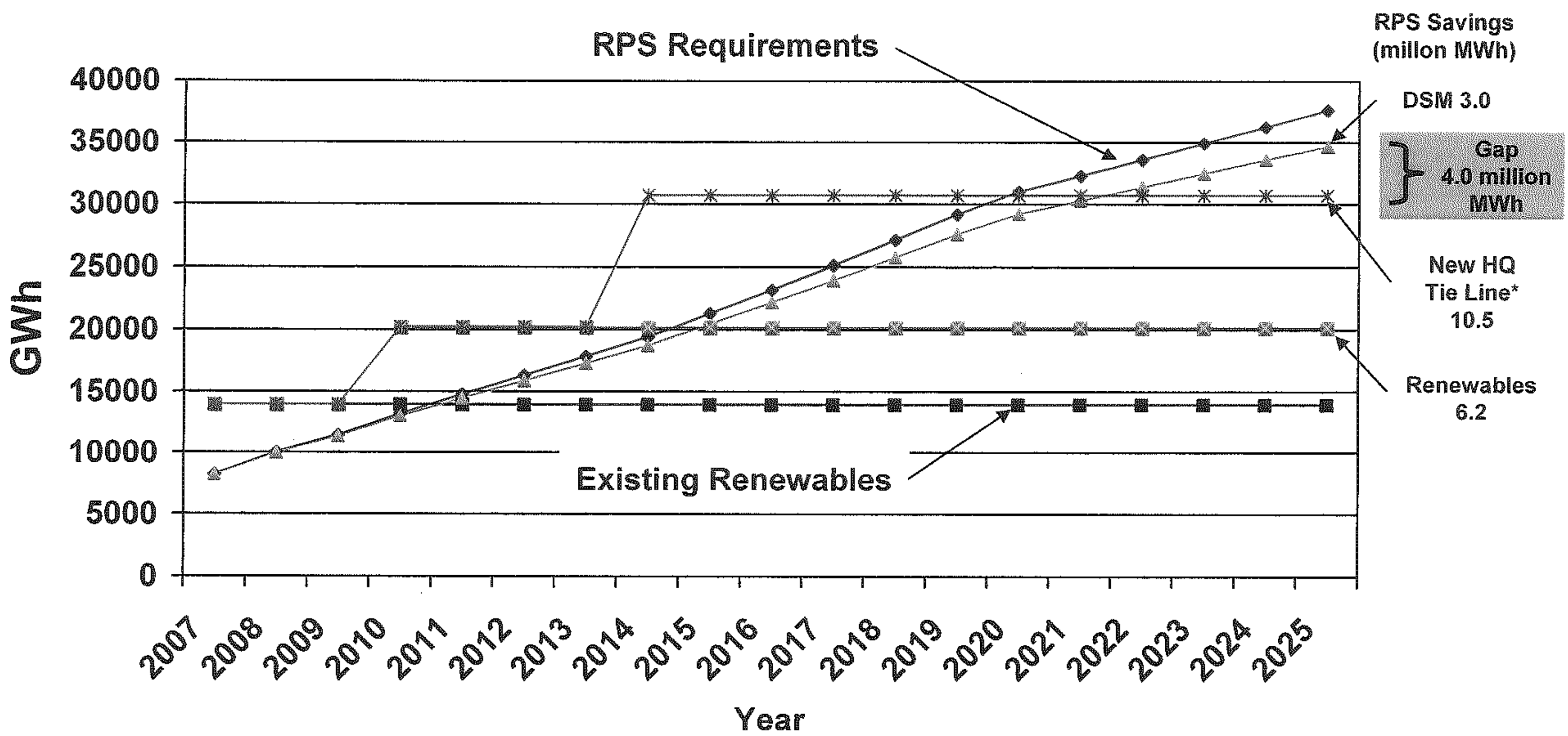

* Assumes large hydro from Canada qualifies as a renewable resource.

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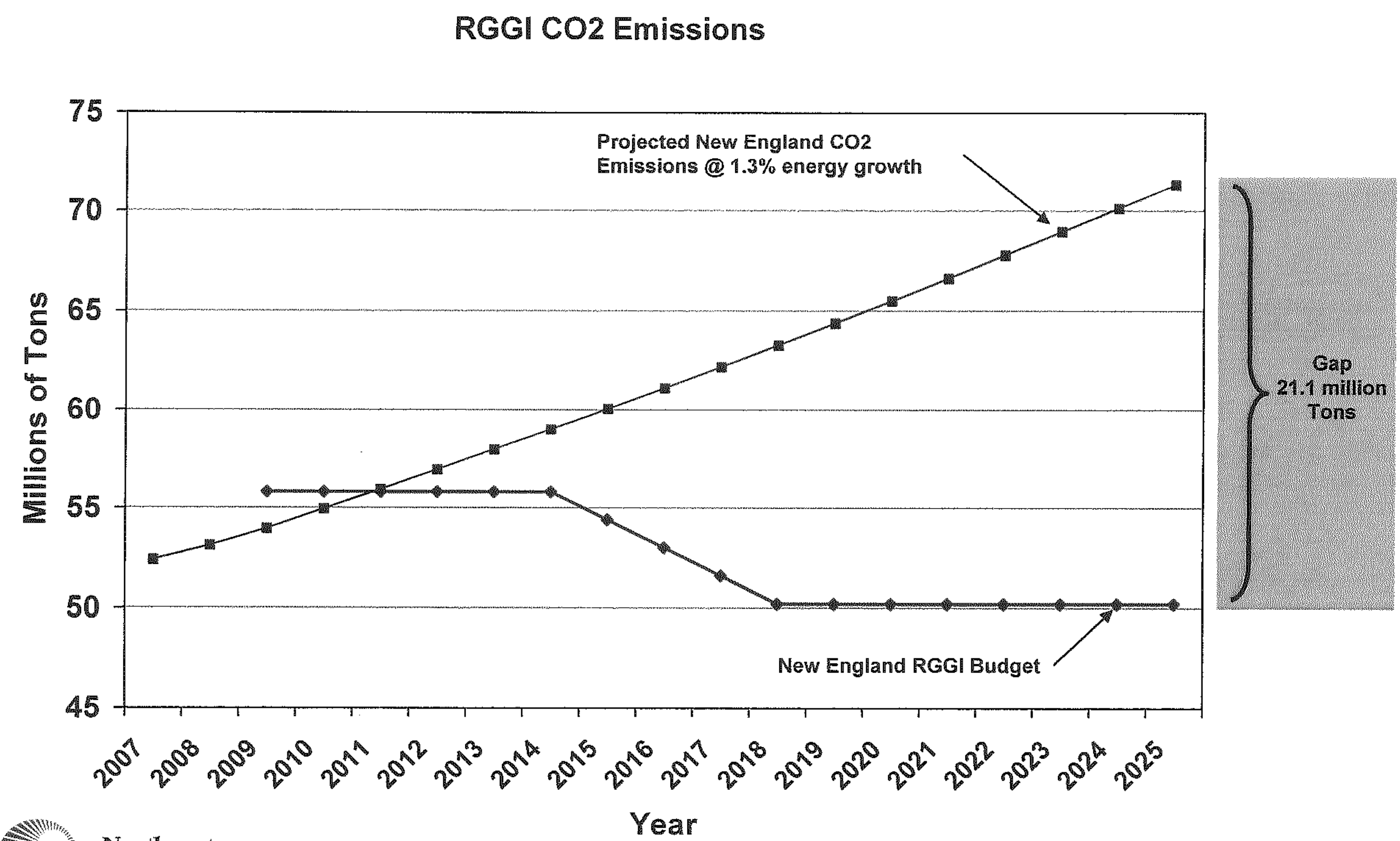
A Portfolio Approach for Regional Greenhouse Gas Initiative (RGGI) Requirements



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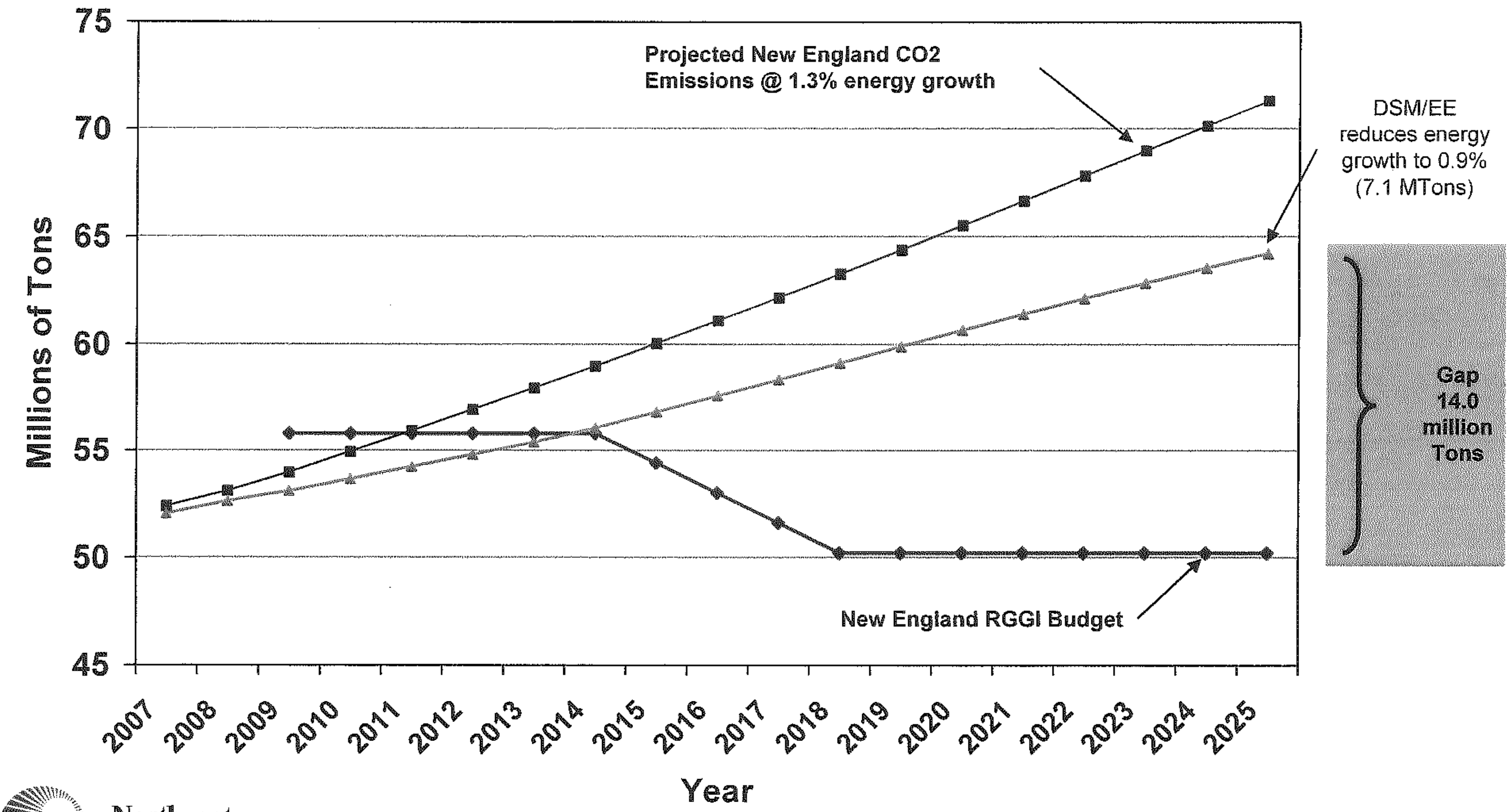
A Portfolio Approach for Regional Greenhouse Gas Initiative (RGGI) Requirements

RGGI CO2 Emissions



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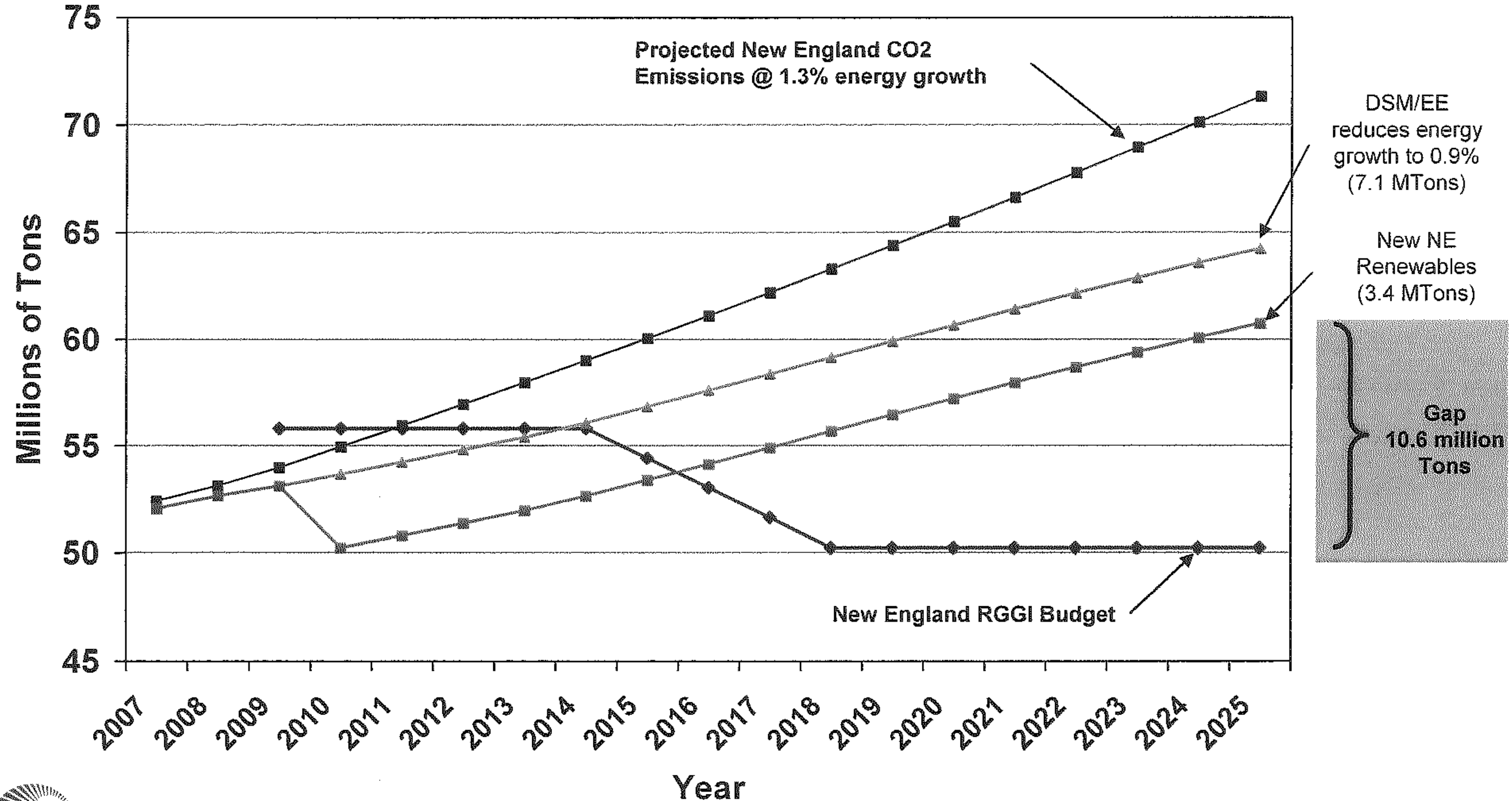
RGGI CO2 Emissions



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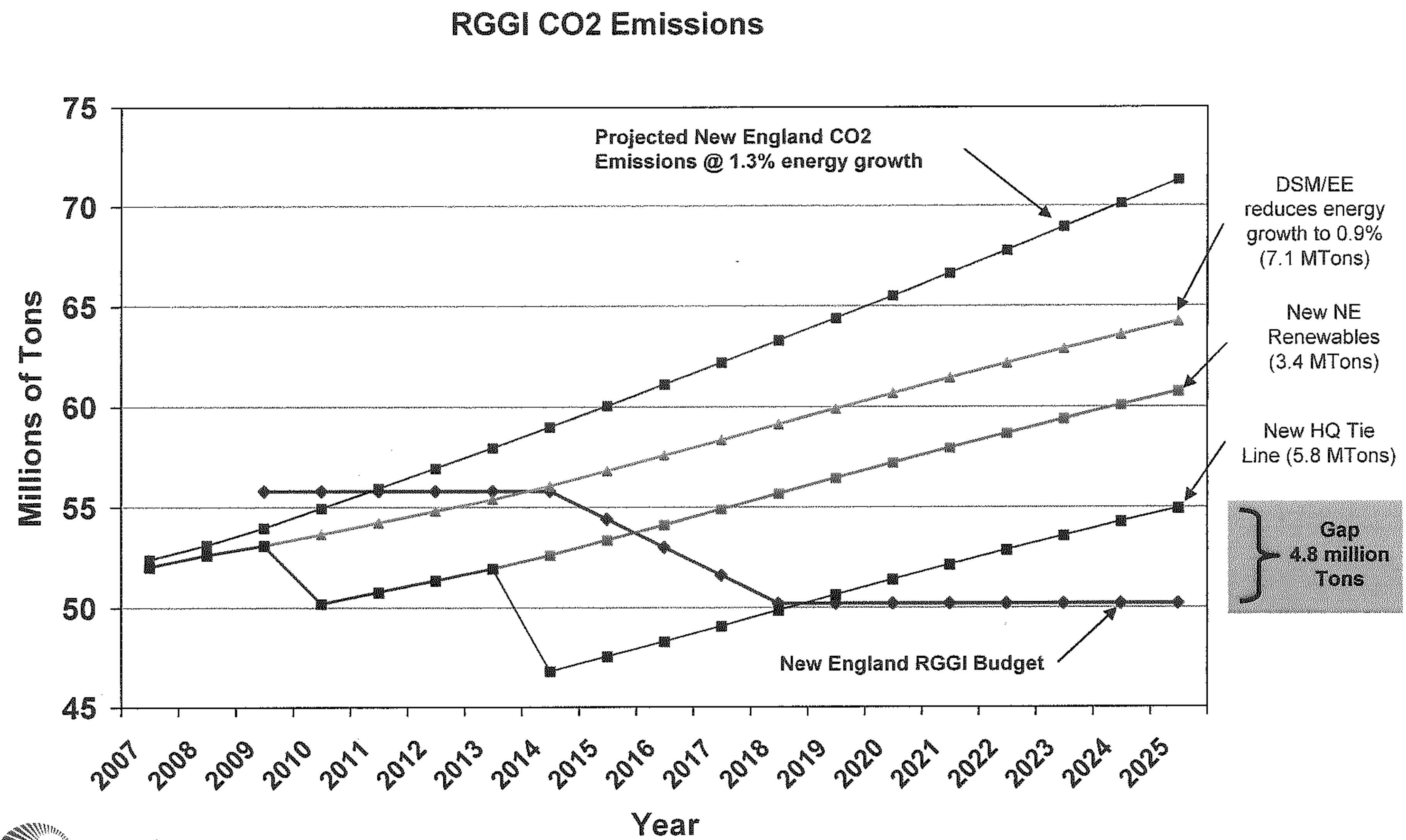

The Power of a Portfolio Approach

- Less risk – utilizes a mix of resources
- Transmission additions to enable remote resources to reach New England load centers
- Tangible benefits for customers
  - Economic
  - CO_2 Reduction
  - Renewable Resources
  - Fuel Diversity and System Operability

Despite seemingly aggressive targets, a portfolio of solutions pursued aggressively could succeed at addressing reliability issues, economic concerns, and environmental priorities