Avoided Energy Supply Costs in New England:

2009 Report

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AUTHORS

Rick Hornby, Paul Chernick, Dr. Carl V. Swanson, Dr. David E. White, Ian Goodman, Bob Grace, Bruce Biewald, Chris James, Ben Warfield, Jason Gifford, and Max Chang

PREPARED FOR

Avoided-Energy-Supply-Component (AESC) Study Group

Synapse Energy Economics, Inc.
22 Pearl Street
Cambridge, MA 02139
www.synapse-energy.com
617.661.3248

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Chapter 1: Executive Summary

This 2009 Avoided-Energy-Supply-Component (AESC) report provides projections of marginal energy supply costs which will be avoided due to reductions in the use of electricity, natural gas, and other fuels resulting from energy efficiency programs offered to customers throughout New England. All reductions in use referred to in the report are measured at the customer meter unless noted otherwise.

These projections were developed to support decisions during 2009 and 2010 regarding the design, evaluation and approval of energy efficiency programs to be implemented in 2010 and 2011 respectively. These projections should not be regarded as proxies for the market prices of any commodity. For example, these projections do not attempt to forecast short-term variations in natural or electric energy prices due to volatility in those markets. Instead the purpose of these projections is to provide an estimate of these avoided costs in the long-term.

The 2009 AESC Study updates the 2007 AESC Study to reflect current market conditions and cost projections. The report provides detailed projections of avoided costs by year for an initial fifteen year period, 2010 through 2024, and extrapolated values for another fifteen years from 2025 through 2039.

All values are reported in 2009$ unless noted otherwise. For ease of reporting and comparison many results are expressed as a levelized value over 15 years. These levelized results are calculated at discount rate of 2.22% solely for illustrative purposes.

1.1. Background to Report

The 2009 AESC Study was sponsored by a group of electric utilities, gas utilities and other efficiency program administrators (collectively, “program administrators” or PAs). The sponsors, along with non-utility parties and their consultants, formed a 2009 AESC Study Group to oversee the design and execution of the report. The 2009 AESC sponsors include Berkshire Gas Company, Cape Light Compact, National Grid USA, New England Gas Company, NSTAR Electric & Gas Company, New Hampshire Electric Co-op, Bay State Gas, Northeast Utilities (Connecticut Light and Power, Western Massachusetts Electric Company, Public Service Company of New Hampshire, and Yankee Gas), Unitil (Fitchburg Gas and Electric Light Company, Unitil Energy Systems, Inc, and Northern Utilities), United Illuminating, Southern Connecticut Gas and Connecticut Natural Gas, the State of Maine, and the State of Vermont. The non-utility parties represented in the Study Group were Connecticut Energy

Conservation Management Board, Massachusetts Department of Public Utilities, Massachusetts Department of Energy Resources, Massachusetts Attorney General, Massachusetts Energy Efficiency Advisory Council, Massachusetts Low-Income Energy Affordability Network (LEAN) and other Non-Utility Parties, New Hampshire Public Utilities Commission, and Rhode Island Division of Public Utilities and Carriers.

The 2009 AESC Study Group specified the scope of work, selected the Synapse Energy Economics (Synapse) project team, and monitored progress of the study. The Synapse project team presented its analyses and projections to the 2009 AESC Study Group in nine substantive tasks. The draft deliverable for each task was reviewed in a conference call. The relationship between the chapters in this report and the task deliverables is as follows:

- Chapter 2. Wholesale Markets for Electric Energy, Capacity and Renewable energy—Task 3;
- Chapter 3. Wholesale Market for Natural Gas—Task 4;
- Chapter 4. Avoided Costs of Natural Gas—Task 6;
- Chapter 5. Avoided Costs of Crude Oil and Related Fuels—Tasks 5 and 9;
- Chapter 6. Avoided costs of Electricity—Task 7;
- Chapter 7. Sensitivity of Wholesale Electric Energy Prices to Changes in Key Inputs—Task 8;
- Chapter 8. Instructions for Applying avoided electricity Costs—Task 10.

The report was prepared by a project team assembled and led by Synapse. Dr. David White and Ben Warfield of Synapse were responsible for projecting wholesale electric energy prices. Paul Chernick of Resource Insight led the analysis of wholesale capacity costs and DRIPE. Bob Grace and Jason Gifford of Sustainable Energy Advantage (SEA) provide estimates of renewable energy credit demand, supply and price. Ian Goodman and Brigid Rowan of The Goodman Group prepared an analysis of the economic development impacts of Massachusetts efficiency programs with input from Dr. William Steinhurst. Dr. Carl Swanson of the Swanson Energy Group led the analysis of avoided natural gas costs and Rick Hornby developed projections of other fuels. Chris James, Max Chang and Bruce Biewald of Synapse developed externality values for air emissions avoided due to reductions in electricity and fuel use. Rick Hornby served as project manager with support from Max Chang. Adam Auster of Resource Insight provided editorial support.

1.2. Avoided Costs of Electricity to Retail Customers

An electric energy efficiency program that enables a retail customer to reduce his or her annual electricity use has a number of key energy cost benefits. The benefits from those reductions include some or all of the following avoided costs:

- Avoided electric energy costs due to a reduction in the annual quantity of electric energy that has to be generated, including renewable energy to comply with the applicable Renewable Portfolio Standard (RPS);[1]
- Avoided electric capacity costs due to a reduction in the annual quantity of electric capacity and/or demand reduction that ISO-NE requires load serving entities (LSEs) to acquire from the Forward Capacity Market (FCM) to ensure an adequate quantity of generation during hours of peak demand;
- Avoided electric energy costs due to a reduction in the price of electric energy that is generated to serve remaining load, because that remaining load will be met at prices set by more efficient generating units. This reduction is referred to as energy Demand Reduction Induced Price Effect, or energy DRIPE;
- Avoided electric capacity costs due to a reduction in the price of electric capacity that is acquired to serve remaining load, because that remaining load will be met at prices set by less expensive capacity resources. This reduction is referred to as capacity DRIPE;
- Avoided environmental externalities due to a reduction in the quantity of electric energy that has to be generated. An environmental externality is the value of an environmental impact associated with the use of a product or service, such as electricity, that is not reflected in price of that product. AESC 2009 uses the externality value of carbon dioxide emissions as a proxy for these externalities.
- Avoided costs of local transmission and distribution (T&D) infrastructure due to a reduction in the timing and/or size of new projects that have to be built resulting from the reduction in electric energy that has to be delivered.

AESC 2009 provides estimates of each category of avoided costs except for avoided T&D, which is utility specific and beyond the scope of the study. These costs are provided by geographic area and then by year and costing period within the year.

[1]Electric energy is measured in kilowatt hours (kWh) or megawatt hours MWh; electricity capacity is measured in kilowatts (kW) or megawatts (MW).

Avoided electric energy costs are the largest of these benefits. The relative magnitude of each component for the summer peak costing period is illustrated in Exhibit 1-1 for an efficiency measure with a 55% load factor implemented in the Northeast Massachusetts zone (NEMA).

Exhibit 1-1:Avoided Electricity Costs for NEMA Zone, AESC 2009 vs. AESC 2007
(Summer Peak 15-year levelized results, 2009 dollars)

Component	**AESC 2007** (cents/kWh)	**AESC 2009** (cents/kWh)	**Difference relative to AESC 2007** *(cents/kWh)*	*%*
Avoided Energy Costs	10.5	9.6	−0.9	−9%
Avoided Capacity Costs[a]	2.3	0.4	−1.9	−84%
DRIPE				
Energy[b]	1.7	4.3	2.6	156%
Capacity[c]	0.4	0.3	0.1	-21%
CO_2 Externality	3.2	2.9	−0.3	−10%
TOTAL	18.1	17.5	-0.7	-4%

a) Avoiding costs from purchasing from the Forward Capacity Market
b) Values are for total DRIPE (Intrastate and Rest of Pool)
c) Assuming a 55% load factor.

The 2009 AESC projections of avoided energy plus avoided capacity cost are approximately 20% to 25% lower than those from the 2007 AESC while the projection of total avoided costs is approximately 10% to 15% lower. The factors driving those differentials are discussed below.

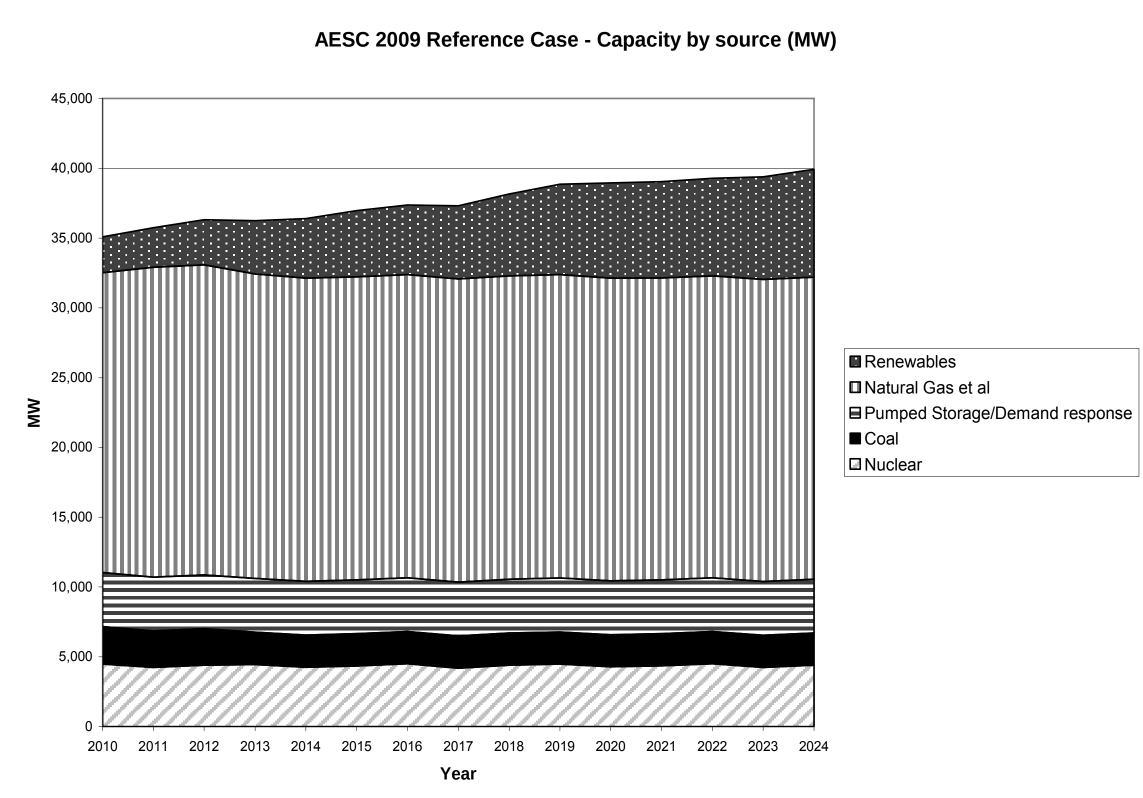
1.2.1. Avoided electric energy costs

Avoided electric energy costs are an estimate of the value of a reduction in annual electric energy use by retail customers. The major inputs to this calculation are avoided wholesale electric energy market prices, avoided costs of Renewable Energy Certificates (RECs) and a wholesale risk premium of 9 percent.

The avoided wholesale electric energy market prices are estimates for a hypothetical future, “Reference Case”, in which no new energy efficiency is implemented from 2010 onward. The major drivers of the prices in this Reference Case are the forecasts of load, natural gas prices, carbon emission regulation compliance costs and renewable energy quantities required to comply with the Renewable Portfolio Standard of each state. (The carbon emission compliance costs assume limits imposed under the Regional Gas Greenhouse Initiative or

RGGI through 2012 and federal cap and trade regulations thereafter.[2]) The only significant quantity of new capacity added under the Reference Case is from renewable resources. See Exhibit 1-2.

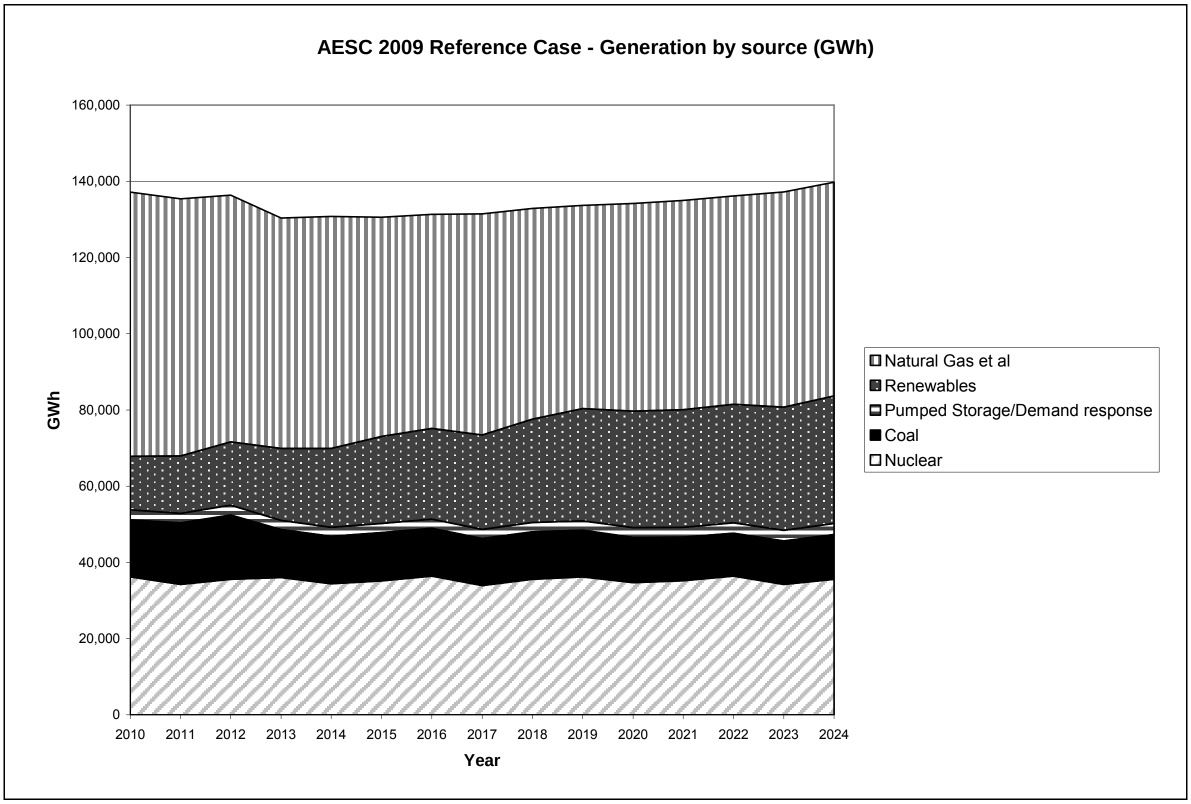
Exhibit 1-2: AESC Reference Case, Capacity by Source (MW)



Natural gas is the dominant source of generation under the Reference Case, but its dominance is reduced over time by generation from renewable resources. Forecasts of annual generation from natural gas and from renewables are depicted in Exhibit 1-3.

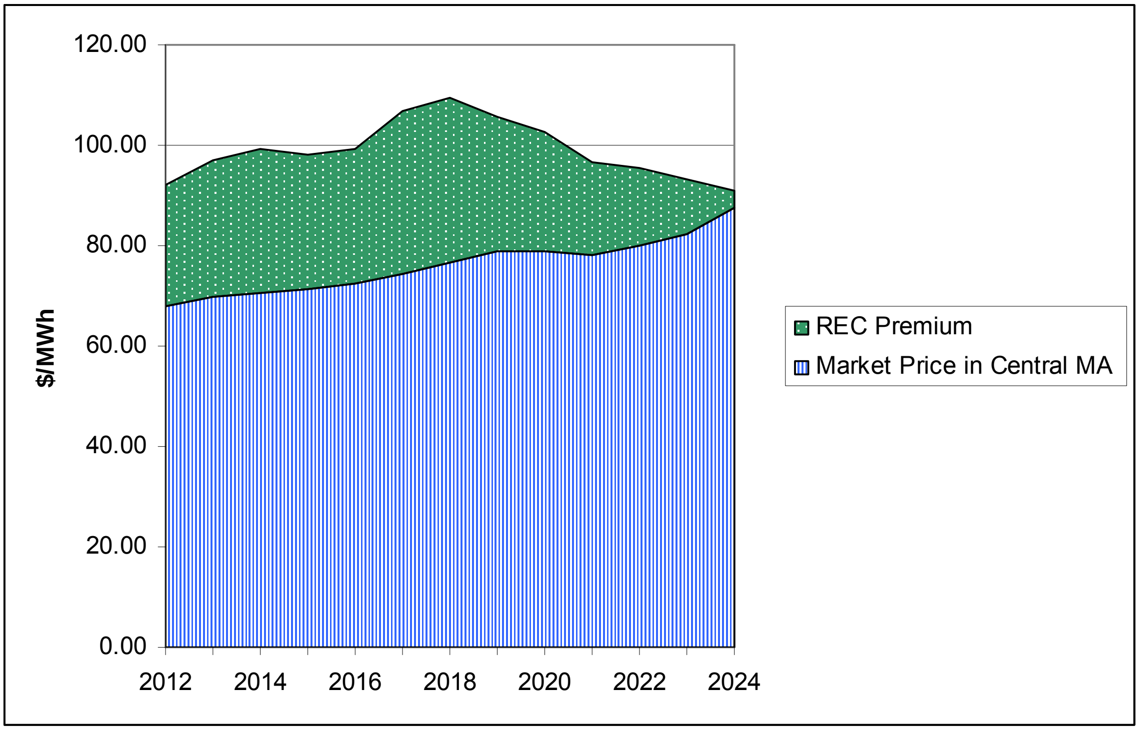
[2] The exception is Rhode Island, whose avoided electricity costs assume carbon regulation according to RGGI for the entire study period.

Exhibit 1-3: Reference Case, Generation by Source (GWh)



The avoided costs of RECs are a function of two factors. One is the forecast quantity of renewable energy that load serving entities (LSEs) will have to acquire in order to comply with the relevant Renewable Portfolio Standard. The second is the forecast premium over wholesale electric energy market prices that LSE will have to pay to acquire that renewable energy. The forecast REC premium is based upon an estimate of the cost of new entry of Class I renewables from 2012 onward and the forecast annual wholesale electric energy price. See Exhibit 1-4.

Exhibit 1-4: Forecast Wholesale Electric Energy Prices and REC premiums



The 15 year levelized projections of avoided electric energy costs for the 2009 and 2007 AESC studies are shown in Exhibit 1-5.

Exhibit 1-5: 15 Year Levelized Avoided Electric Energy Costs—AESC 2009 vs. AESC 2007 (2009 dollars)

	AESC 2009	Winter Peak Energy $/kWh	Winter Off-Peak Energy $/kWh	Summer Peak Energy $/kWh	Summer Off-Peak Energy $/kWh
1	Maine (ME)	0.083	0.070	0.086	0.069
2	Vermont (VT)	0.091	0.076	0.095	0.073
3	New Hampshire (NH)	0.087	0.073	0.091	0.070
4	Connecticut (statewide)	0.095	0.079	0.099	0.076
5	Massachusetts (statewide)	0.092	0.076	0.095	0.072
6	Rhode Island (RI)	0.082	0.067	0.084	0.063
7	SEMA	0.091	0.076	0.094	0.072
8	Central & Western Massachusetts (WCMA)	0.091	0.076	0.095	0.073
9	NEMA	0.092	0.076	0.096	0.072
10	Rest of Massachusetts (non-NEMA)	0.091	0.076	0.094	0.072
11	Norwalk / Stamford (NS)	0.096	0.080	0.100	0.076
12	Southwest Connecticut (SWCT) including Norwalk/Stamford	0.096	0.080	0.100	0.076
13	Southwest Connecticut (SWCT) excluding Norwalk/Stamford	0.096	0.080	0.100	0.076
14	Rest of Connecticut (non-SWCT)	0.094	0.078	0.098	0.075

	AESC 2007	$/kWh	$/kWh	$/kWh	$/kWh
1	Maine (ME)	0.088	0.065	0.090	0.063
2	Vermont (VT)	0.100	0.073	0.105	0.072
3	New Hampshire (NH)	0.094	0.069	0.097	0.067
4	Connecticut (statewide)	0.102	0.074	0.109	0.073
5	Massachusetts (statewide)	0.098	0.072	0.104	0.071
6	Rhode Island (RI)	0.097	0.071	0.102	0.069
7	SEMA	0.093	0.068	0.098	0.066
8	Central & Western Massachusetts (WCMA)	0.098	0.073	0.103	0.071
9	Boston (NEMA)	0.099	0.072	0.105	0.071
10	Rest of Massachusetts (non-NEMA)	0.097	0.072	0.103	0.070
11	Norwalk / Stamford (NS)	0.103	0.075	0.116	0.074
12	Southwest Connecticut (SWCT) including Norwalk/Stamford	0.103	0.075	0.110	0.073
13	Southwest Connecticut (SWCT) excluding Norwalk/Stamford	0.098	0.072	0.102	0.070
14	Rest of Connecticut (non-SWCT)	0.101	0.074	0.108	0.072

	Change from AESC 2007	$/kWh	$/kWh	$/kWh	$/kWh
1	Maine (ME)	(0.005)	0.006	(0.004)	0.006
2	Vermont (VT)	(0.009)	0.003	(0.010)	0.001
3	New Hampshire (NH)	(0.007)	0.003	(0.007)	0.003
4	Connecticut (statewide)	(0.007)	0.005	(0.011)	0.003
5	Massachusetts (statewide)	(0.006)	0.004	(0.009)	0.002
6	Rhode Island (RI)	(0.015)	(0.004)	(0.018)	(0.005)
7	SEMA	(0.002)	0.008	(0.004)	0.006
8	Central & Western Massachusetts (WCMA)	(0.007)	0.003	(0.009)	0.002
9	Boston (NEMA)	(0.007)	0.004	(0.010)	0.001
10	Rest of Massachusetts (non-NEMA)	(0.006)	0.004	(0.008)	0.002
11	Norwalk / Stamford (NS)	(0.007)	0.004	(0.016)	0.003
12	Southwest Connecticut (SWCT) including Norwalk/Stamford	(0.007)	0.005	(0.010)	0.003
13	Southwest Connecticut (SWCT) excluding Norwalk/Stamford	(0.002)	0.008	(0.002)	0.006
14	Rest of Connecticut (non-SWCT)	(0.007)	0.004	(0.010)	0.003

	% Change from AESC 2007	%	%	%	%
1	Maine (ME)	-6%	8%	-4%	10%
2	Vermont (VT)	-9%	3%	-9%	2%
3	New Hampshire (NH)	-7%	5%	-7%	4%
4	Connecticut (statewide)	-7%	7%	-10%	4%
5	Massachusetts (statewide)	-7%	6%	-9%	2%
6	Rhode Island (RI)	-15%	-6%	-18%	-8%
7	SEMA	-2%	11%	-4%	8%
8	Central & Western Massachusetts (WCMA)	-7%	4%	-8%	2%
9	Boston (NEMA)	-7%	5%	-9%	2%
10	Rest of Massachusetts (non-NEMA)	-6%	6%	-8%	3%
11	Norwalk / Stamford (NS)	-7%	6%	-14%	4%
12	Southwest Connecticut (SWCT) including Norwalk/Stamford	-7%	6%	-9%	4%
13	Southwest Connecticut (SWCT) excluding Norwalk/Stamford	-2%	10%	-2%	9%
14	Rest of Connecticut (non-SWCT)	-7%	6%	-9%	4%

On an annual average basis the 15 year levelized 2009 AESC avoided energy costs are within approximately 3% of those from AESC 2007. However, on a state-wide basis the avoided energy costs during winter peaks and summer peaks are 6% to 18% lower. The lower avoided energy costs during peak periods are due to lower projections of peak load and greater quantities of generation from renewable resources in peak periods. As a result of those two factors the prices during peak periods in the AESC 2009 Reference Case are set by somewhat more efficient gas units, i.e., those with lower heat rates, than in the AESC 2007 Reference Case which in turn results in lower market prices in those peak periods.

1.2.2. Avoided Capacity Costs

Avoided electric capacity costs are an estimate of the value of a reduction in energy use by retail customers during hours of system peak demand. The major inputs to this calculation are avoided wholesale electric capacity costs, an ISO-NE adjustment of 8% for transmission losses, and the wholesale risk premium of 9%.[3]

Again, the avoided wholesale electric capacity market prices are estimates for a hypothetical future in which no new energy efficiency is implemented from 2010 onward. The major drivers of avoided capacity costs are load, quantity of existing capacity, retirements and capacity from resources added to comply with RPS requirements.

The 15-year levelized projections of avoided capacity costs from purchasing from the Forward Capacity Market (FCM) from the 2009 and 2007 AESC studies are shown in Exhibit 1-6.

Exhibit 1-6: 15 Year Levelized Avoided Electric Capacity Costs—AESC 2009 vs. AESC 2007

	Annual Market Capacity Value 2009$/kW-yr		
Zone	**AESC 2007**	**AESC 2009**	**Change**
Maine (ME)	106.9	17.81	-83%
Vermont (VT)	108.1	17.11	-84%
New Hampshire (NH)	106.9	17.81	-83%
Connecticut (statewide)	106.9	17.81	-83%
Massachusetts (statewide)	106.9	17.81	-83%
Rhode Island (RI)	106.9	17.81	-83%
SEMA	106.9	17.81	-83%
Central & Western Massachusetts (WCMA)	106.9	17.81	-83%
NEMA	106.9	17.81	-83%
Rest of Massachusetts (non-NEMA)	106.9	17.81	-83%
Norwalk / Stamford (NS)	106.9	17.81	-83%
Southwest Connecticut (SWCT) including Norwalk/Stamford	106.9	17.81	-83%
Southwest Connecticut (SWCT) excluding Norwalk/Stamford	106.9	17.81	-83%
Rest of Connecticut (non-SWCT)	106.9	17.81	-83%

[3] Vermont Public Service Board requires a wholesale risk premium of 11.1%.

The AESC 2009 projected values of avoided capacity costs are approximately 83 percent lower than those from AESC 2007 on a 15 year levelized basis. The lower projected values reflect our analyses of the empirical information on the actual operation and results of the FCM available from FCAs 1 and 2, the quantity of existing capacity available to bid relative to the quantity required and the projected quantity of renewable resource capacity expected over the study period. There is considerable uncertainty regarding prices for power years from June 2013 onward, and hence in the avoided capacity costs for those power years.

The amount of wholesale electric capacity costs that kW reductions from an energy efficiency measure will avoid will vary according to the approach followed by a Program Administrator (PA). An efficiency measure can avoid capacity costs in a given year indirectly if the responsible PA bids its kW reduction into the Forward Capacity Auction (FCA) for that power year and the FCA for subsequent power years. The revenues from each FCA for each power year offset the capacity costs for that power year. However, this bid must be submitted when each FCA is held, which is approximately three years in advance of the applicable power year. Alternatively an efficiency measure can avoid capacity costs directly by reducing the quantity of capacity that has to be bought from the FCM. However there may be a four year lag between the first year in which the reduction causes a lower actual peak demand, i.e., the power year in which the energy efficiency measure is installed, and the year in which ISO-NE translates that reduction into a reduction in the quantity of capacity that has to be purchased from the FCM. The time lag results from the fact that ISO-NE sets the quantity of capacity a LSE must acquire from the FCM up to three years in advance of the actual power year.

The actual strategy that a particular PA follows will likely fall somewhere between bidding the entire reduction from its efficiency measures into the FCM and bidding none of the reductions. An illustration of an approach that consists of bidding 50% of the 100 kW reduction from a five year program into the relevant FCAs is presented in Exhibit 1-7.

Exhibit 1-7: Value of Illustrative Alternative Approaches to Avoiding Capacity Costs via Efficiency Measure Reductions in Peak Demand for NEMA Zone

Hypothetical measure assumptions—Installation in 2010, peak reduction of 100 kw, 5 year measure life						
	Values per ISO-NE NICR and FCA			**PA bids 50 kw into FCA 1 (held in 2008) and into FCAs 2 through 5**		
	FCA #	**Sell into FCA**	**Reduced Purchase from FCA**	**Reduction Bid into FCA**	**Impact of Reduction on NICR set for power year**	**Value of Reduction in Peak demand**
Units		$ per kw-yr	$ per kw-yr	kw	kw	
Year		a	B	c	d	e = (a * c) + (b* d)
2010	1	$65.84	$67.71	50	0	$3,292
2011	2	$50.58	$52.02	50	0	$2,529
2012	3	$35.74	$42.03	50	0	$1,787
2013	4	$16.85	$19.85	50	0	$842
2014	5	$16.85	$19.86	50	50	$1,835
Net Present Value @ 2.2%						**$9,734**

1.2.3. *Demand-Reduction-Induced Price Effects ("DRIPE")*

The Demand-Reduction-Induced Price Effect (DRIPE) is the reduction in prices in the wholesale energy and capacity markets, relative to those forecast in the Reference Case, resulting from the reduction in need for energy and/or capacity due to efficiency and/or demand response programs. Thus DRIPE is a measure of the value of efficiency in terms of the reductions in wholesale prices seen by all retail customers in a given period, whereas avoided electric energy costs and capacity costs measure the value of efficiency in terms of the reductions in the quantity of energy used by retail customers in a given period.

In order to estimate DRIPE one begins by estimating the impact a reduction in load will have upon the market price and then estimates the pace at which suppliers participating in that market will respond by taking a different set of actions than they would have taken in the Reference Case. The responses taken by suppliers will eventually offset, or dissipate, the DRIPE impact.

DRIPE impacts are small when expressed as percentage impacts on the market prices of energy and capacity. However, DRIPE impacts are significant when expressed in absolute dollar terms, since very small impacts on market prices, when applied to all energy and capacity being purchased in the market, translate into large absolute dollar amounts. Moreover, consideration of DRIPE impacts can also increase the cost-effectiveness of DSM programs on the order of 15% to 20%, because the estimated absolute dollar benefits of DRIPE are being attributed to a relatively small quantity of reductions in energy and/or capacity.

DRIPE will have an impact on market prices within the zone where the reduction occurs, referred to as intrastate impacts, as well as throughout the rest of the New England market, referred to as rest of pool. Thus DRIPE impacts can be expressed as intrastate only or total (intrastate + rest of pool) according to the perspective of the analyst.

AESC 2007 presents 15-year levelized energy and capacity DRIPE estimates by zone in Exhibit 1-8. The values reported are total DRIPE, except for Massachusetts and Connecticut. The statewide and zone values for those two states are intrastate only. We recommend that program administrators include DRIPE values in their analyses of demand side management (DSM), unless specifically prohibited from doing so by state or local law or regulation.

Exhibit 1-8: AESC 2009 and 2007 15 Year Levelized Energy and Capacity DRIPE for Installations in 2010 by Zone

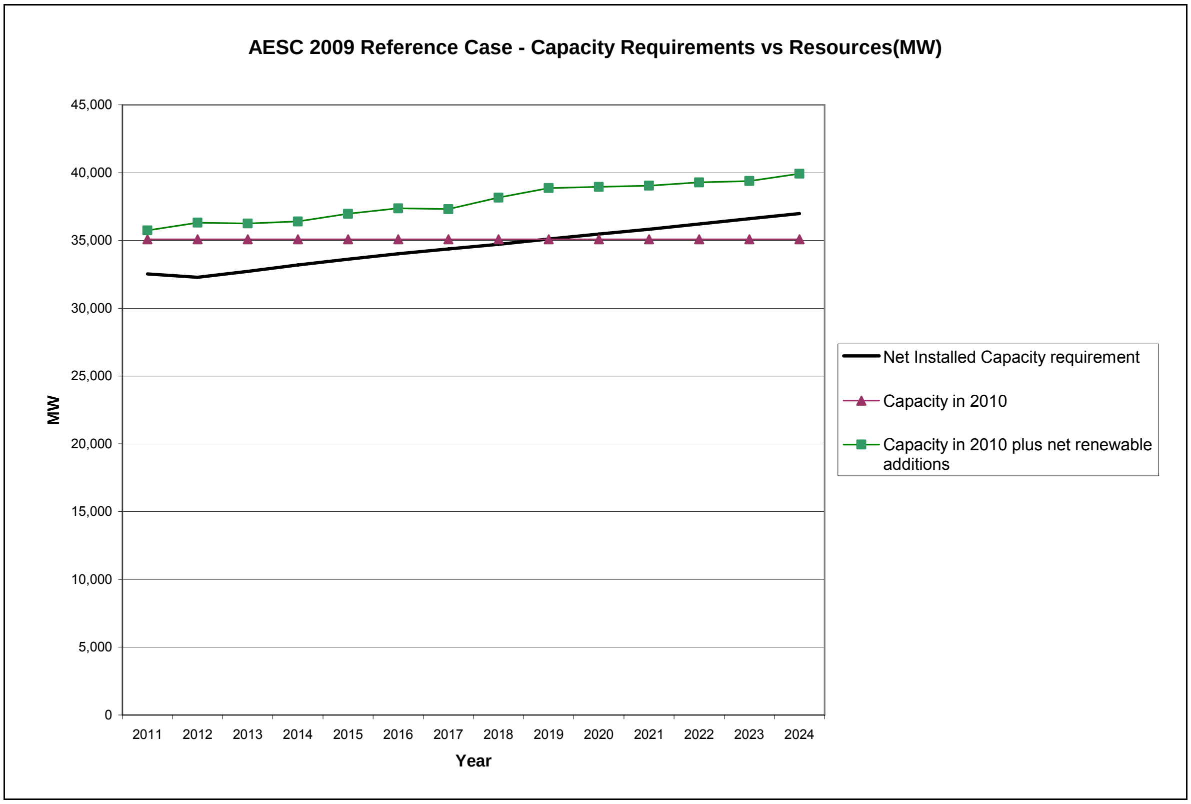
	Energy DRIPE				Capacity DRIPE
	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	
Zone	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr
Maine (ME)	$0.029	$0.019	$0.032	$0.020	$2.79
Vermont (VT)	0.028	0.018	0.031	0.019	0.91
New Hampshire (NH)	0.029	0.020	0.033	0.019	1.51
Connecticut (statewide)	0.019	0.012	0.020	0.009	8.30
Massachusetts (statewide)	0.025	0.019	0.027	0.014	15.84
Rhode Island (RI)	0.034	0.024	0.032	0.021	2.56
SEMA	0.025	0.019	0.027	0.014	15.84
Central & Western Massachusetts (WCMA)	0.025	0.019	0.027	0.014	15.84
NEMA	0.025	0.019	0.027	0.014	15.84
Rest of Massachusetts (non-NEMA)	0.025	0.019	0.027	0.014	15.84
Norwalk / Stamford (NS)	0.019	0.012	0.020	0.009	8.30
Southwest Connecticut (SWCT) including Norwalk/Stamford	0.019	0.012	0.020	0.009	8.30
Southwest Connecticut (SWCT) excluding Norwalk/Stamford	0.019	0.012	0.020	0.009	8.30
Rest of Conneticut	0.019	0.012	0.020	0.009	8.30
AESC 2007					
Maine (ME)	$0.008	$0.007	$0.014	$0.006	$23.76
Vermont (VT)	0.008	0.006	0.015	0.005	23.76
New Hampshire (NH)	0.008	0.007	0.015	0.006	23.76
Connecticut (statewide)	0.010	0.008	0.023	0.011	25.63
Massachusetts (statewide)	0.010	0.008	0.019	0.007	25.63
Rhode Island (RI)	0.009	0.007	0.016	0.007	25.63
SEMA	0.011	0.009	0.020	0.008	25.63
Central & Western Massachusetts (WCMA)	0.009	0.007	0.002	0.006	25.63
Boston (NEMA)	0.008	0.007	0.017	0.007	23.76
Rest of Massachusetts (non-NEMA)	0.010	0.008	0.019	0.007	25.63
Norwalk / Stamford (NS)	0.010	0.008	0.023	0.011	25.63
Southwest Connecticut (SWCT) including Norwalk/Stamford	0.009	0.008	0.020	0.010	23.76
Southwest Connecticut (SWCT) excluding Norwalk/Stamford	0.010	0.008	0.023	0.011	25.63
Rest of Connecticut (non-SWCT)	0.010	0.008	0.023	0.011	25.63

On a 15-year levelized basis the 2009 AESC estimates of capacity DRIPE are lower than those from AESC 2007. This reduction is primarily due to the absence of any price impacts in the 2010, 2011 and 2013 power years since FCAs 1–3 clear at the floor price. In contrast, the 2009 AESC estimates of total energy DRIPE are approximately double those from 2007. These higher estimates are attributable to differences in the assumptions regarding the phase-in and the phase-out of energy DRIPE effects between AESC 2009 and AESC 2007.

The AESC 2009 results reflect an immediate phase-in energy DRIPE effects. This phase-in assumes that wholesale energy prices reflect anticipated load reductions from efficiency programs and thus the impacts of those reductions on wholesale prices are fully reflected in the prices charged to retail customers. In contrast, AESC 2007 assumed that retail prices would gradually reflect energy DRIPE effects over a few years according to the mix of contracts under which retail customers were acquiring their electricity supply.

Second, the AESC 2009 results reflect a longer phase-out or dissipation of energy DRIPE effects up to 14 years versus the 5 years assumed in AESC 2007. The longer projected dissipation of energy DRIPE is based upon an analysis of the various factors that tend to offset the reduction in energy prices. Those factors include demand elasticity, renewable resource additions, existing generator deactivations (and reactivations) and incremental improvements, and the timing of municipally-owned generation additions. This anticipated longer duration of energy DRIPE is consistent with the results of our Reference Case, which indicate a significant excess of capacity relative to Net Installed Capacity requirements through 2024 due to additions of renewable resources to comply with RPS requirements. That excess is shown in Exhibit 1-9.

Exhibit 1-9: Capacity Requirements vs. Resources (Reference Case)



Although there remains uncertainty regarding the projections of energy DRIPE and capacity DRIPE, the Study Group believes that these projection incorporate and reflect the most recent and available information..

1.2.4. Carbon-Dioxide Externalities

Externalities are impacts from the production of a good or service that are neither reflected in the price of that good or service nor considered in the decision to provide that good or service. There are many externalities associated with the production of electricity, including the adverse impacts of emissions of SO_2, mercury, particulates, NO_x and CO_2. However, the magnitude of most of those externalities has been reduced over time, as regulations limiting emission levels have forced suppliers and buyers to consider at least a portion of their adverse impacts in their production and use decisions. In other words, a portion of the costs of the adverse impact of most of these externalities has already been "internalized" in the price of electricity.

AESC 2009 identifies the impacts of carbon dioxide as the dominant externality associated with marginal electricity generation in New England over the study period for two main reasons. First, policy makers are just starting to develop and implement regulations that will "internalize" the costs associated with the impacts of carbon dioxide from electricity production and other energy uses. The Regional Greenhouse Gas Initiative and anticipated future federal CO_2 regulations will internalize a portion of the "greenhouse gas externality," but AESC 2009 projects that the externality value of CO_2 will still be high even with those regulations. Second, New England avoided electric energy costs over the study period are likely to be dominated by natural gas-fired generation, which has minimal emissions of SO_2, mercury, particulates and NO_X, but substantial emissions of CO_2.

The AESC 2009 estimate of $80/ton is higher than the AESC 2007 estimate of $60/ton. While based on the same approach as AESC 2007, i.e., the cost of limiting CO_2 emissions to a "sustainability target" level, the higher estimate reflects the most recent literature on the cost of achieving this level. Efficiency measures can lead to reductions in the absolute quantity of CO_2 emissions primarily by demonstrating that existing caps can be met at less cost than anticipated and thus justifying new, tighter caps.

AESC 2007 estimates of 15-year levelized CO_2 additional environmental costs by zone are presented in Exhibit 1-10 below.[4] As with DRIPE, we recommend that program administrators include CO_2 additional environmental costs in their analyses of DSM, unless specifically prohibited from doing so by state or local law or regulation.

[4] Values for Rhode Island incorporate RGGI only scenario.

Exhibit 1-10: Fifteen-Year Levelized CO_2 Avoided Externality Costs by Zone ($/kWh)[5]

AESC 2009	Winter Peak Energy $/kWh	Winter Off-Peak Energy $/kWh	Summer Peak Energy $/kWh	Summer Off-Peak Energy $/kWh
Maine (ME)	0.029	0.030	0.029	0.031
Vermont (VT)	0.029	0.030	0.029	0.031
New Hampshire (NH)	0.029	0.030	0.029	0.031
Connecticut (statewide)	0.029	0.030	0.029	0.031
Massachusetts (statewide)	0.029	0.030	0.029	0.031
Rhode Island (RI)	0.039	0.039	0.038	0.041
SEMA	0.029	0.030	0.029	0.031
Central & Western Massachusetts (WCMA)	0.029	0.030	0.029	0.031
NEMA	0.029	0.030	0.029	0.031
Rest of Massachusetts (non-NEMA)	0.029	0.030	0.029	0.031
Norwalk / Stamford (NS)	0.029	0.030	0.029	0.031
Southwest Connecticut (SWCT) including Norwalk/Stamford	0.029	0.030	0.029	0.031
Southwest Connecticut (SWCT) excluding Norwalk/Stamford	0.029	0.030	0.029	0.031
Rest of Connecticut (non-SWCT)	0.029	0.030	0.029	0.031

The 2009 AESC estimates of CO_2 externalities per kWh are approximately 10% lower than those from those of AESC 2007 on a 15-year levelized basis. These lower values are primarily due to the fact that the gas units on the margin in the AESC 2009 Reference Case are more efficient than those in the AESC 2007 Reference Case, and therefore emit less CO_2 for every kWh they generate. Also the CO_2 emission prices are slightly higher so that the externality differences are less.

1.3. Avoided Costs of Natural Gas to Retail Customers

Gas efficiency programs, like electric energy efficiency programs, have a number of key energy cost benefits. The benefits from those reductions include some or all of the following avoided costs:

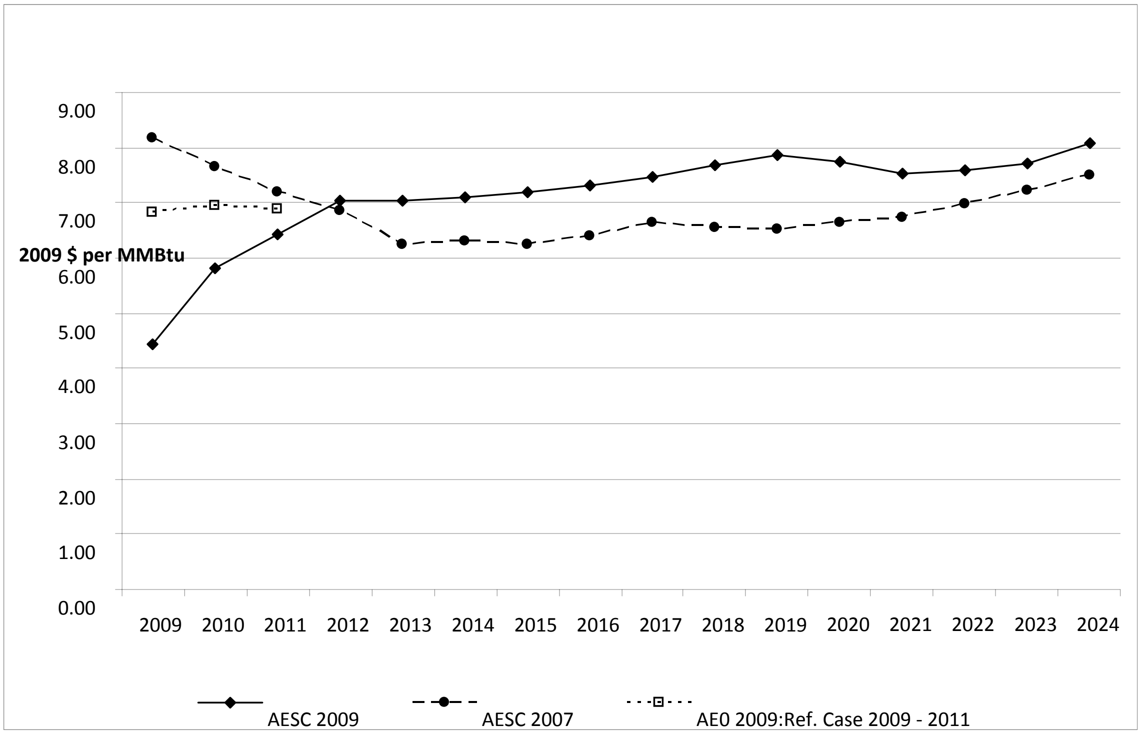
- Avoided gas supply costs due to a reduction in the annual quantity of gas that has to be produced, transported by pipeline and possibly stored;
- Avoided costs of local transmission and distribution (T&D) infrastructure due to a reduction in the timing and/or size of new projects that have to be built resulting from the reduction in electric energy that has to be delivered; and
- Avoided environmental externalities due to a reduction in the quantity of gas that is burned.

The largest component of avoided gas supply costs is the cost of producing gas. AESC 2009 uses the price of gas at the Henry Hub in Louisiana as a proxy for that cost. The forecast is based upon the New York Mercantile Exchange ("NYMEX")

[5] One megawatt-hour = 1 MWh = 1,000 kilowatt-hours = 1,000 kwh

gas futures prices for the Henry Hub for the years 2009 to 2011 and the Energy Information Administration ("EIA") Reference Case forecast from Annual Energy Outlook ("AEO") 2009 for the years 2012 through 2024. The forecast is presented in Exhibit 1-11.

Exhibit 1-11: Comparison of Henry Hub Gas Price Forecasts



AESC 2009 provides forecasts of Henry Hub prices under base, high and low cases. Actual daily and monthly Henry Hub prices are volatile and will vary from day-to-day and month-to-month around the expected average prices forecast in each of those three cases. AESC 2009 does not attempt to forecast the actual prices that would result from that volatility because it is forecasting prices used to evaluate avoided costs in the long-term. Our analyses indicate that the levelized price of gas over the long-term would not be materially different if one estimated increases from an occasional one to three day price spike during a cold snap or even the type of several month gas price increases following Hurricane Katrina in the fall of 2005.

AESC 2009 provides estimates of each category of avoided costs for three regions. These are Connecticut and Rhode Island ("southern New England"), Massachusetts, Maine and New Hampshire ("central and northern New England") and Vermont. For each region the estimates are presented by year and major end-use. These estimates of avoided gas costs reflect all fixed and variable costs that would be avoided due to a reduction in gas use. Unlike the electric industry, which has an FCM separate from the energy market, there is no separate avoided gas capacity cost beyond, or additional to, the estimated avoided gas supply costs.

The 2009 AESC projections of avoided natural gas costs to retail customers over the next fifteen years range from $10.00 to $12.00 per dekatherm (DT)[6] (2009$) depending on the end-use and location as shown in Exhibit 1-12.

[6] 1 dekatherm (DT) = 10 Therms = one-million British Thermal Units (Btu) = 1 mmBtu

Exhibit 1-12: Comparison of Levelized Avoided Costs of Gas Delivered to Retail Customers by End Use: AESC 2005 and AESC 2007 (2007$/Dekatherm)

Summary of Levelized Avoided Cost Of Gas Delivered To Retail Customers AESC 2009 versus AESC 2007

(2009$/Dekatherm)

	RESIDENTIAL				COMMERCIAL & INDUSTRIAL			ALL RETAIL
	Non Heating	Hot Water	Heating	All	Non Heating	Heating	All	
AESC 2007 end-use period (a)		annual	5-month	6-month	Annual	5-month	6-month	5-month
Southern New England								
AESC 2009	11.42	11.42	14.52	13.52	9.88	11.83	11.21	12.26
AESC 2007		11.62	12.84	12.48	9.50	10.72	10.36	11.65
2007 to 2009 change		-1.71%	13.09%	8.33%	4.04%	10.36%	8.25%	5.25%
Northern & Central New England								
AESC 2009	10.87	10.87	13.54	12.68	10.02	12.05	11.40	12.03
AESC 2007		11.32	12.35	12.04	10.19	11.23	10.92	11.74
2007 to 2009 change		-3.95%	9.62%	5.28%	-1.65%	7.31%	4.40%	2.44%
Vermont								
AESC 2009	9.75	9.75	12.51	11.62	8.05	9.53	9.07	10.00
AESC 2007		10.43	11.67	11.31	8.34	9.58	9.21	10.37
2007 to 2009 change		-6.52%	7.22%	2.82%	-3.48%	-0.48%	-1.56%	-3.53%

(a) In AESC 2007 the end-use profiles was defined as a certain number of months in the winter period; e.g. 5-months is Nov.—March.

(b) Factor to convert 2007$ to 2009 $ 1.0420

Note: AESC 2007 levelized costs for 16 years, 2007—2022 at a discount rate of 2.2165%.

AESC 2009 levelized costs for 15 years 2010—2024 at a discount rate of 2.22%.

Other than residential hot water use, AESC 2009 is projecting somewhat higher avoided costs for each end use than AESC 2007 did. The higher avoided costs for those end-uses are due to higher distribution costs in general and a higher allocation of avoided distribution costs to heating loads based upon a more detailed analysis of the shape of each end-use load.

1.4. Economic-Development Impact of Massachusetts Energy-Efficiency Programs

In addition to energy cost benefits, energy-efficiency programs have economic-development benefits. These benefits include direct and indirect jobs supported by direct spending on energy efficiency plus the jobs supported by retail customers spending their energy cost savings.

The Massachusetts members of the Study Group sponsored an analysis of the economic development impact of the 2010-2012 Massachusetts Joint Statewide Three-Year Electric and Gas Efficiency Plans. The key results of the analysis are summarized in Exhibit 1-13.

Exhibit 1-13: Economic Development Impacts of Massachusetts Electric and Gas Energy Efficiency (EE) (Net Impact Multipliers per $1 million)

	Electric EE Net Impact	**Gas EE Net Impact**
MULTIPLIERS (per $1 million, 2009 $)		
Employment (job-years)	22.9	19.1
Earnings	$1,126,900	$885,200
Value-Added	$1,478,300	$891,500

The exhibit indicates that the Net Employment Impact of electric energy efficiency programs is 22.9 job-years per $1 million. In terms of other economic activity, electric energy efficiency expenditures of $1 million yield Earnings of $1,126,900 and Value-Added of $1,478,300. On the gas side, the Net Employment Impact of gas energy efficiency is 19.1 job-years per $1 million. In terms of other economic activity, gas energy efficiency expenditures of $1 million yield Earnings of $885,200 and Value-Added of $891,500.

Exhibit 1-14 provides the results on a physical unit basis (Electric EE Net Impact per lifetime GWh and Gas EE Net Impact per million lifetime therms). The economic development impacts of a given amount of EE can be calculated on the basis of: (a) expenditures or (b) physical units. The impacts as calculated on the basis of (a) or (b) are not additive.[7]

Exhibit 1-14 Economic Development Impacts of Massachusetts Electric and Gas Energy Efficiency (EE) (Net Impact Multipliers per GWh and million therms)

	Electric EE Net Impact (per lifetime GWh)	**Gas EE Net Impact (per lifetime million therms)**
MULTIPLIERS		
Employment (job-years)	1.09	7.8
Earnings (2009 $)	$53,300[a]	$362,800[b]
Value-Added (2009 $)	$69,900[a]	$365,300[b]

[a] Expressed per lifetime kWh, the Electric EE Net Impact Multipliers would be $0.053 for Earnings and $0.070 for Value-Added (multiplier per kWh = multiplier per GWh/1,000,000).
[b] Expressed per lifetime dekatherm, the Gas EE Net Impact Multipliers would be $3.63 for Earnings and $3.65 for Value-Added (multiplier per dekatherm = multiplier per million therms/100,000).

The exhibit indicates that the Net Employment Impact of electric energy efficiency programs is 22.9 job-years per $1 million. In terms of other economic activity, electric energy efficiency expenditures of $1 million yield Earnings of $1,126,900 and Value-Added of $1,478,300. On the gas side, the Net Employment Impact of gas energy efficiency is 19.1 job-years per $1 million. In terms of other economic activity, gas energy efficiency expenditures of $1 million yield Earnings of $885,200 and Value-Added of $891,500. Exhibit 1-14 summarizes the economic impact results based on physical units.

Investment in electric and gas energy efficiency leads to a shift in economic activity from environmentally stressful, low multiplier supply to more environmentally benign, high multiplier efficiency measures, as well as a large amount of respending. Cost-effective energy efficiency reduces the cost of living and operating businesses and thus promotes economic development in Massachusetts. It increases the efficiency of the overall economy and makes the state a more attractive place for residents and businesses. Moreover, given the current economic downturn and the potential for continued high unemployment rates (particularly in construction) over the next several years, energy efficiency represents an excellent and very timely opportunity for Massachusetts.

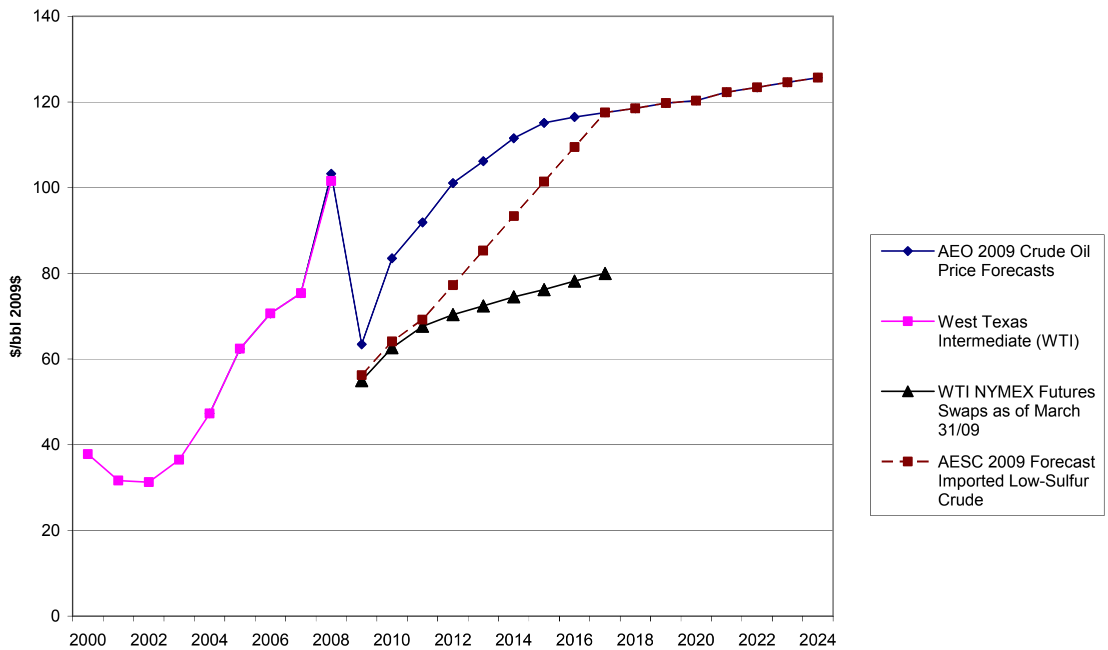
[7] These values should not be added to avoided costs.

1.5. Avoided Costs of Other Fuels

Some electric and gas efficiency programs enable retail customers to reduce their use of energy sources other than electricity or natural gas. The benefits from reducing the use of other fuels include avoided fuel supply costs and avoided environmental externalities.

The major driver of these avoided fuel costs are forecast crude oil costs. Given the significant uncertainty regarding the future price of crude oil, the AESC 2009 forecast of crude oil prices is based upon NYMEX futures through 2011, an interpolation of NYMEX futures and the EIA AEO 2009 Reference Case forecast through 2017 and the AEO 2009 Reference Case forecast thereafter. The AESC 2009 and AESC 2007 forecasts are presented in Exhibit 1-15.

Exhibit 1-15: Low-Sulfur Crude Actual and Forecast (2009 dollars per bbl)



The AESC 2009 forecasts of avoided costs of fuels by sector and region are summarized in Exhibit 1-16.

Exhibit 1-16: Comparison of Levelized Avoided Costs of Other Retail Fuels

	No. 2 Distillate	No. 2 Distillate	No. 6 Residual Fuel (low sulfur)	Propane	Kerosene	BioFuel (B5 Blend)	BioFuel (B20 Blend)	Wood
Sector	**Res**	**Com**	**Com**	**Res**	**Res & Com**	**Res**	**Res**	**Res**
AESC 2009 Levelized Values (2009$/MMBtu)								
2010-2024	22.83	21.68	17.52	$34.02	22.17	22.83	22.83	8.22
AESC 2007 Levelized Values (2009$/MMBtu)								
2010-2024	15.31	13.50	9.15	30.99	15.92	15.31	15.31	5.48
Percent Difference from AESC 2007								
2010-2024	49.1%	60.6%	91.6%	9.8%	39.2%	49.1%	49.1%	49.9%

Notes
Res Residential Sector
Com Commercial Sector
AESC 2007 values from Exhibit 4-6 New England Average Price Forecast of Other Fuel Prices by Sector (AESC 2007)

The AESC 2009 avoided costs for these fuel prices are generally higher than those from AESC 2007 primarily due to a higher forecast of underlying crude oil prices. On a 15 year levelized basis the AESC 2009 values are higher by 10% to 6 0% depending on the fuel and sector. The wood values are for cordwood. Values for wood pellets would be approximately twice as high according to the limited data on wood pellet prices.

Chapter 2: Methodology and Assumptions Underlying Projections of Avoided Electricity Supply Costs

2.1. Background

The goal of the AESC study is to project the electricity supply costs that would be avoided by reductions in retail energy and/or demand. These avoided electricity supply costs incorporate: avoided electric-energy-market prices, avoided capacity-market prices, avoidable costs not internalized in those market prices, and demand reduction induced price effects (DRIPE).

We use Market Analytics, under license from Ventyx (formerly Global Energy Decisions), to simulate the operation of the wholesale electric-energy market. Our own spreadsheet model simulates future Forward Capacity Auctions in the forward capacity market.

Section 2.5 describes the methodology and assumptions we use to develop a forecast of the components of avoided electricity supply costs that are not internalized in the wholesale market prices for energy and capacity.

In Chapter 6, we provide a set of avoided electricity supply costs for the New England region as a whole as well as for each of 14 component zones in each year of the planning horizon (2009–2039). Each set of avoided electricity supply costs comprises avoided energy costs by year for the four energy costing periods: Summer Peak, Summer Off-Peak, Winter Peak, Winter Off-Peak.

2.2. Wholesale Market Prices for Electric Energy and Capacity–Common Methodologies and Assumptions

2.2.1. Structure of Wholesale Markets

The ISO-New England (ISO-NE) market is part of the Northeast Power Coordinating Council and includes the six states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont.[8] ISO-New England is the regional transmission organization for the New England power market. It coordinates several markets for electric-power products including energy, capacity, and operating reserves markets (Regulation Up and Down, spinning reserves, ten-minute non-spinning reserves, and thirty-minute non-spinning reserves).

[8] Parts of northeastern Maine are not included in ISO-New England.

2.2.1.1. Wholesale Energy Markets

The wholesale energy markets are managed by ISO-NE. There are two primary markets: (1) the Day-Ahead Market where the majority of the transactions occur and 2) the Real-Time Market where the remaining energy supplies and demands are balanced. These two markets represent the bulk of the electricity transactions and their prices on average are very close to each other, although there is greater volatility in the real-time market.

The following material from the 2007 Annual Market report provides more details about how these markets operate.

According to ISO-New England (2007, 23–24):

> 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.
>
> 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. 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.

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.

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.

2.2.1.2. Wholesale Capacity Market

The Federal Energy Regulatory Commission (FERC) has approved a new framework, the Forward Capacity Market (FCM), which will go into effect in June 2010. The power year for the FCM, also referred to as an FCM year, is from June through May. Thus, for a calendar year the unit cost of capacity in the FCM, expressed as dollars per kW-year, will be the average of January through May from one power year and June through December of the following power year.

The transition period from the current installed wholesale capacity market to the forward capacity market is December 2006 through May 2010. ISO-NE has set the installed-capacity prices to be paid to suppliers for each power year during that transition. The prices for the remaining portion of the transition period covered by AESC 2009 are $4.10/kW-month for June 2009 through May 2010. Reductions in energy use from new energy efficiency initiated during this transition period would have no effect on the total capacity costs incurred by New England load since all resources are paid the settlement price during this period.

Under the FCM, ISO-NE will acquire sufficient capacity to satisfy the installed capacity requirement (ICR) it has set for a given power-year through a forward-capacity auction (FCA) for that power-year.[9] The price for capacity in that power year will be based upon the results of the FCA for that year. The FCA for each power-year will be conducted roughly three years in advance of the start of that year. ISO-NE has held two FCAs to date, FCA 1 for the June 2010 power year and FCA 2 for that of June 2011.

Under the FCM, ISO-NE set a ceiling price and a floor price for each of the first three FCAs.[10] For FCA 1 and FCA 2 the floors were $4.50/kW-month (60% of $7.50, the estimated cost of new entry) and $3.60/kW-month respectively. For FCA 3 the floor is $2.95/kW-month. At this point in time there is no provision for ISO-NE to set floors or ceilings for future FCAs although there have been discussions within ISO-NE on that issue.

Suppliers of capacity whose bids are accepted in the FCA will be paid an amount equal to the quantity of capacity they bid multiplied by the final auction price. In each month of the capacity year, this amount will be reduced by *peak energy rent,* (PER), an estimate by ISO-NE (2006, 9) of the annual energy profits that a

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[9]Some of the ICR (1,400 MW in the first FCA, 911 MW in the second FCA) was met by installed capacity credits from the Phase I/II interconnection, which are allocated to the transmission owners with entitlements in the line. The Hydro Quebec Interconnect Certificates are priced at the market-clearing price, and the actual auction acquired the remaining ICR, called the net ICR.

[10]If, in a given FCA, more capacity clears at the floor price than is required to satisfy the ICR, each cleared resource must accept downward proration of either the quantity of capacity that it bid or the final auction price. For example, if the capacity clearing at the market is roughly 6% above the net ICR (as in FCA 1), each resource must choose between being paid 94% of the floor price (about $4.23 in FCA 1) for all its bid capacity, or the floor price for 94% of its bid capacity. In FCA 2, the excess remaining at the floor price was 4,914 MW and resources will be paid $3.60 for about 87% of their bid capacity or $3.12 for 100% of their capacity.

generator with a heat rate of 22,000 Btu/kWh would earn[11]. These suppliers will also be subject to penalties for any failure to perform.

Load (customers) will pay costs equal to the quantity of capacity it is required to support in the power-year times the auction price for that power-year. (These costs will be reduced by the PER as well as by credits for any supplier performance penalties.) The quantity of capacity that a particular load is required to hold in the power-year is set by ISO-NE and is called the Capacity Load Obligation (ISO-NE Market Rule 1 §III.13.7.3). This obligation is based on the estimated contribution of that load to the ISO annual peak in the preceding power year. Thus, the total cost of capacity to a load for a given power year, i.e., required kW of capacity multiplied by FCA price in dollars per kW, is set in advance of that power-year and, once set, is essentially fixed or unavoidable regardless of the load's actual peak demand.

An energy efficiency program that produces a reduction in peak demand has the ability to avoid all, or a portion, of these wholesale capacity costs. The capacity-cost amount that a particular reduction in peak demand will avoid in a given year will depend upon the approach that the program administrator responsible for that energy efficiency program takes towards bidding all, or some, of that reduction into the applicable FCAs.

A program administrator (PA) can choose an approach that ranges between bidding 100% of the anticipated demand reduction from the program into the relevant FCAs to not bidding any reduction into any FCA.

- A PA that wishes to bid 100% of the anticipated demand reduction from the program into the relevant FCA has to do so when that FCA is conducted, which can be up to three years in advance of the program implementation year. For example, a PA responsible for an efficiency program that will be implemented starting January 2010 would have had to have bid 100% of the forecast reduction in demand from that program into FCA 1, which was held in 2008. Since a bid is a firm financial commitment, there is an associated financial risk if the PA is unable to actually deliver the full reduction for whatever reason. The value of this approach is the compensation paid by ISO-NE, i.e. the quantity of peak reduction each year times the FCA price for the corresponding year.
- If a PA does not bid any of the anticipated demand reduction into any FCA, the program can still avoid some capacity costs if it has a measure life longer

[11] Our analyses do not adjust for PER as it appears to be minimal based on a review of estimates for 2007 through 2009.

than three years. Under this approach, a PA responsible for an efficiency program starting January 2010 simply implements that program.

Exhibit 2-1 below illustrates the various approaches that a Program Administrator could choose for avoiding wholesale capacity costs via a hypothetical energy efficiency measure that is implemented in 2010 and produces a 100 kw reduction for a five year period, 2010 to 2014. In this example, the PA considers three approaches.

The first approach is to bid 100% of the projected reduction, 100 kw, into each of the relevant FCAs, i.e. FCAs 1–5. Under this approach the reduction avoids capacity costs equal to its revenues from the FCM each year, i.e., l to 100 kW times the FCA price in each of the 5 years, 2010 through 2014. However the PA would have had to bid that 100-kw reduction, which is scheduled to start in 2010, into three FCAs held prior to 2010. These are FCA 1 and FCA 2, both of which were held in 2008, and FCA 3 which will be held in October 2009.

The second approach is to bid none of the projected reductions into any FCA. Under this approach the reduction avoids capacity costs equal to the value of the reduction in installed capacity it causes in 2014. That value is 100 kW increased by the reserve margin in 2014 and multiplied by the FCA price in 2014. The avoided capacity cost is limited to the impact in 2014 because ISO-NE sets the Installed Capacity Requirement (ICR) to be acquired in each power year three years in advance of that year. Thus, in this approach, ISO-NE would first see the 100 kW reduction as a lower actual peak load in 2010. However, 2014 is the earliest power year for which ISO-NE could reflect the actual reduction in 2010 because, by July 2011 ISO-NE will have forecast peak load for 2014, set the ICR for 2014 and run FCA for 2014.

The third approach is to bid 50% of the projected reduction, 50 kw, into each of the relevant FCAs.

Exhibit 2-1: Illustration of Alternative Approaches to Capturing Value from Reductions in Peak Demands

Hypothetical measure installed in 2010, reduces peak by 100 kw for 5 years									
ISO-NE sets NICR and Conducts FCA			Example 1—PA bids 100% of expected demand reduction into each corresponding FCA		Example 2—PA bids zero expected demand reduction into each corresponding FCA		Example 3—PA bids 50% of expected demand reduction into each corresponding FCA	
FCA #	Calendar year	FCA for power year Starting	Reduction Bid into FCA	Impact of Reduction on NICR set for power year	Reduction Bid into FCA	Impact of Reduction on NICR set for power year	Reduction Bid into FCA	Impact of Reduction on NICR set for power year
			kw	kw	kw	kw	kw	kw
1	2008	6/1/2010	100		0		50	
2		6/1/2011	100		0		50	
3	2009	6/1/2012	100		0		50	
4	2010	6/1/2013	100	0	0	0	50	0
5	2011	6/1/2014	100	0	0	0	50	0
	2012			0		0		0
	2013			0		0		0
	2014			0		**100**		**50**

2.2.2. Loads and Resources

2.2.2.1. Load Forecast

In order to forecast electric energy and capacity prices that would occur in the absence of new DSM programs, the project team developed a forecast of peak demand and energy requirements in the absence of new DSM programs. [12]

[12]The purpose of the overall the study is to develop avoided costs for program administrators to use in their economic evaluations of measures for inclusion in DSM program budgets for calendar years 2010 and beyond. The program administrators will submit those proposed budgets in regulatory filings from mid-2009 onward. If the program budgets are approved, the measures would be installed after January 1, 2010, causing savings from that point onward.

Our proposed load forecast for 2010 through to 2018 is the same as that in ISO-NE CELT (2009a), as discussed below. Beyond 2018, we extrapolate our estimates using the long-term (2009–2018) Compound Annual Growth Rate reflected in that report..

Analysis of ISO-New England's Forecast

We based our load forecast on a review of ISO-NE's (2009) forecast of peak demand and energy requirements through 2018. The ISO uses econometric models to forecast energy and peak demand.[13]

The ISO forecasts annual energy for New England as a whole and for each individual state. ISO-NE (2009a) is based on previous-year usage along with real electricity price, real personal income, and heating and cooling degree days (ISO-NE 2009b). The ISO developed the model and its coefficients by analyzing the historical relationships between energy requirements and those independent variables over the period 1984 through 2008. Therefore, the forecast implicitly assumes some level of reductions from efficiency programs because the programs in effect during the historical period would have influenced the actual level of energy use and be reflected in the derived model coefficients, most likely for the personal income and electricity price variables. However, it is difficult to estimate the size of the effect of prior DSM on the energy forecast. One way to calculate those effects would be to explicitly include the DSM energy savings and recalculate the model coefficients. This would be a fairly significant task to undertake and is beyond the scope of this project. Such work would probably best done by ISO-NE.

For the peak-load forecast, the ISO develops peak-load models for each calendar month, for New England as a whole and each state, using daily historical data for 2000 through 2008. The models are based on the annual energy load, a temperature humidity index and several dummy variables for weekends and holidays. The historical peak loads are explicitly reduced by the other demand resources (ODRs) based on DSM programs that qualified for transition payments.[14] Thus the peak-load forecasts based on these models represent loads after the effects of ODRs. As Ehrlich (2009, 24) explains, ISO-NE's (2009a) peak-load forecast is produced using this model with the addition of 350 MW of ODR for all the years (2009–2017) to represent what the peaks would be without the

[13]Further information about the CELT (Capacity, Energy, Loads and Transmission) forecasting process can be found at ISO-NE's web page, http://www.iso-ne.com/trans/celt/fsct_detail/index.html as of June 15, 2009.

[14]ISO-NE (2009a) indicates that the ODR resources, on average, provided 385 MW during 2008.

existing ODR reductions. The 350 MW of ODR corresponds to 1.24% of the forecasted 2010 peak load.

We use ISO-NE's (2009a) peak-load forecast. This is consistent with the purpose of the avoided-cost calculations, to represent costs in the absence of energy-efficiency effects. We also use ISO-NE's (2009a) energy forecast since it is public and fully documented, and since adjusting it upward for embedded DSM effects would be a major task beyond the scope of this project, and since the revised energy load is unlikely to have a material impact on energy prices. We test that potential impact in our scenario analyses described in more detail in Chapter 7.

For modeling of the capacity market, we use ISO-NE's (2009a) published forecast of load, and include the ODRs as resources.

AESC 2009 Forecast

Beyond 2018, we extrapolate using the long-term compound annual growth rate (CAGR) reflected in the CELT 2009 forecast. For context, ISO-NE's (2009a) long-term annual average rate of summer peak growth for the ISO-NE control area is 1.17%.

The following two exhibits show ISO-NE's (2009a) projections of summer peak load and annual net energy consumption for ISO-NE relative to historical levels.

Exhibit 2-2: ISO-NE Peak Summer Load

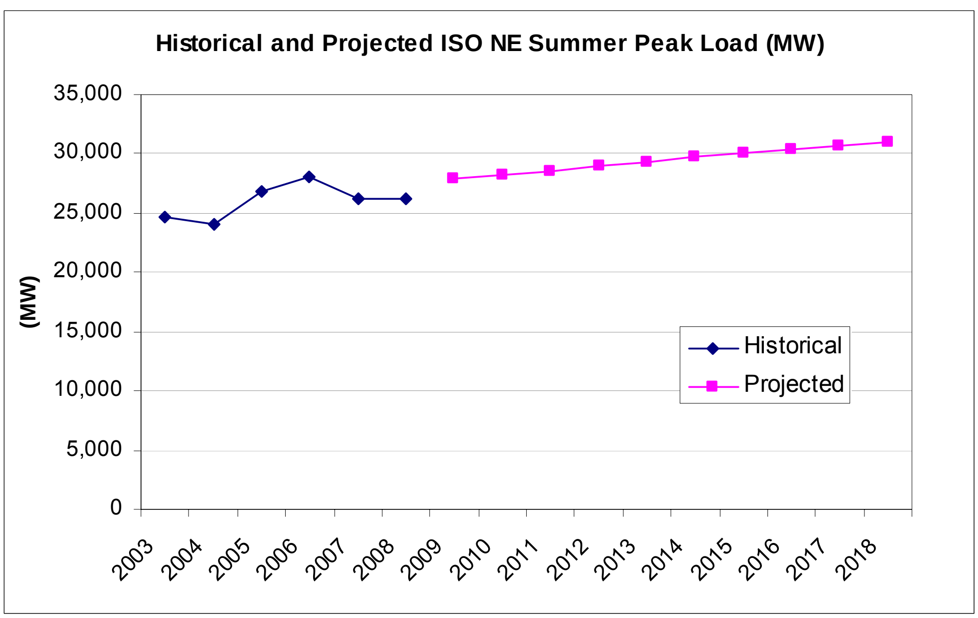
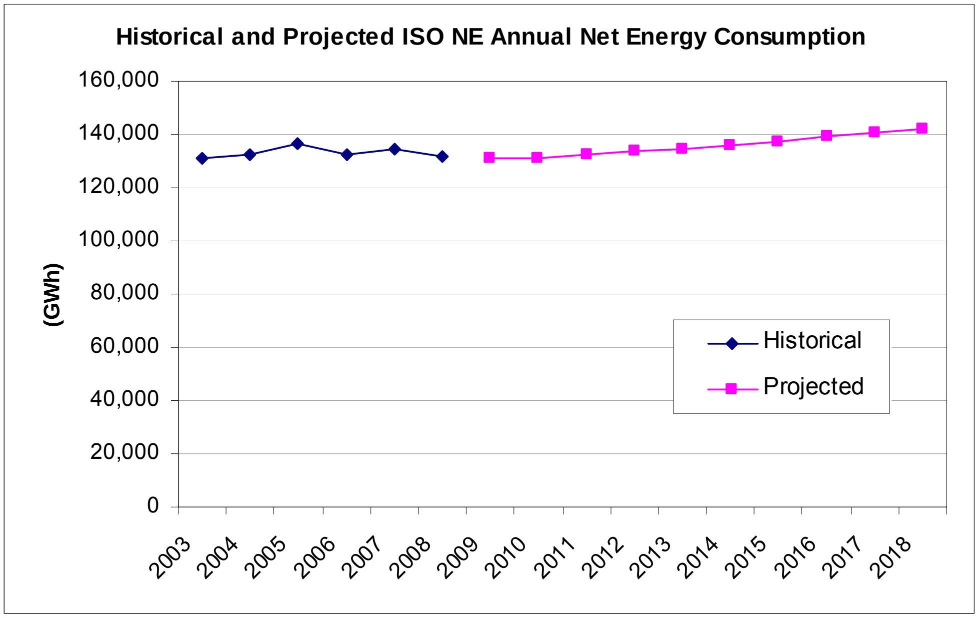


Exhibit 2-3: ISO-NE Net Annual Consumption



Specific information regarding the load forecast used in this study is provided in Section 2.3.2.2 below on pages 2-25–2-27.

2.2.2.2. Transmission

The interface limits used in the simulations reflect the existing system, ongoing transmission upgrades including those discussed in the ISO-NE Regional System Plan, and the reference Market Analytics database. We also consider any congestion identified during our modeling.

The detailed transmission assumptions are closely related to the modeling topology and are presented in below in Section 2.3.2.3 (pages 2-27–2-28).

2.2.2.3. Retirements

In most situations, a plant that has been operating through the last decade or so of restructured markets would almost certainly continue to operate as long as market and regulatory conditions were to remain unchanged. The exceptions would arise from any of the following circumstances:

- Construction of new generation at the site of existing generation, requiring retirement due to lack of space, transmission capacity or emissions offsets.
- Failure of major components in old and marginally cost-effective units. In these situations, restoring the plant to service may not be cost-effective.
- The expiration of nuclear, hydro or other licenses for plants that cannot economically meet requirements for license extension.

Since restructuring of the New England electric-utility industry, several units have retired in connection with construction of new generation, such as Mystic 4–6 and the Edgar jets. No pending generation additions will require similar retirements, even those at existing plant sites, such as Middletown, New Haven, and Devon. When new generic units are added, some existing units on those sites may retire; we assume that the additions will offset the retirements with little effect on market prices.

Component failure is inherently unpredictable. Our assumptions about the retirement of older capacity reflect anticipated effects of equipment failure.

We describe the relicensing of New England nuclear units in Section 2.3.2.5 below, specifically on pages 2-33–2-34.

Relicensing of hydroelectric plants has resulted in reduced capacity or retirement of a few small units; we do not anticipate any significant effects on hydro capacity in the future.

The effects of changing conditions—environmental and economic—are discussed in Section 2.3.2.4 below.

2.2.2.4. Resource Additions

New generation resources will be needed in addition to the existing mix of generating capacity in order to satisfy renewable portfolio standards, meet future load growth, and respond to retirements. Since Market Analytics is not a capacity expansion model, these additions have been input manually. Our assumptions regarding new additions are presented below.

Additions to Meet Renewable Portfolio Standards

Each New England state has adopted some form of renewable portfolio standard or renewable energy standard, referred to here generically as RPS. The major requirements by state are presented in tabular form in Appendix C

All but Vermont currently require the use and retirement of NEPOOL Generation Information System certificates, commonly referred to as Renewable Energy Certificates (RECs) to demonstrate compliance.[15] The quantity of *new* or *incremental* renewables that will be added each year during the study period will be driven by these requirements, primarily requirements for "Class I"

[15] Currently, Vermont's requirement will allow RECs to be sold off elsewhere (presumably for compliance in other states), therefore not leading to incremental renewable-energy additions beyond what would be predicted in the presence of other states' requirements. (However, it has been argued that the Vermont requirements will support financing and therefore lead to more renewables being built, and therefore less reliance on Alternative Compliance Payments). We assume that by 2012, Vermont's standard will be altered to require retirement of RECs, and which increase the total RPS additions we project.

(Connecticut, Massachusetts, New Hampshire, Maine) or “new” (Rhode Island) renewables RPS tiers, plus the ‘Class II’ (solar) tier in New Hampshire (collectively referred to herein as “New Renewables RPS Tiers”). In the near future, Massachusetts will be subdividing its Class I requirement to create a behind-the-meter tier which would include, at a minimum, solar.

The gross demand for new renewable generation resources is derived by multiplying the load of obligated entities (those retail load-serving entities subject to RPS requirements, often excluding public power) by the applicable annual RPS percentage target for New Renewables RPS Tiers.

The net demand for incremental renewable generation within New England is derived by subtracting from the gross demand: (a) existing eligible generation already operating (including biomass co-firing in existing facilities); and (b) the current level of RPS imports.

Over time, the net demand to be met by resources within ISO-NE will be further reduced by an estimate of additional RPS-eligible imports over existing tie lines, phased in towards a maximum level of usage (consistent with competing uses of the lines and appropriate capacity factors of imported resources) at a rate consistent with the recent historical rate of increase in RPS-eligible imports over a ten-year period.

Renewable resources eligible to satisfy those state requirements have considerable overlap, but vary by state. We assume that in the long run for most years in the study period those resources eligible in one or a few states only are insufficient to completely fulfill the demand of the states in which they are eligible. In effect, at the margin every state in New England is competing to satisfy its requirements for new renewables, other than the solar tiers, from the same group of eligible supply resources.[16]

In the near term (2009 and 2010), we assume that the aggregate net RPS demand for New Renewables RPS Tiers will be met by a mix of renewable resource generation consistent with: (1) RPS-eligible resources in the New England, administered systems and Maine Public Service interconnection queues, and (2) other expected RPS-eligible generation in the development pipeline not appearing in the queue (such as distributed wind, solar and fuel cell projects).[17] This generation is derated to reflect the likelihood that not all generation proposed will ultimately be built, and may not be built on the timetable reflected in the queue.

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[16]Massachusetts, and possibly Rhode Island, may be exceptions, if long-term in-state contracting requirements end up resulting in higher compliance costs relative to the rest of the region.

[17]In this analysis “near-term” becomes “long-term” in the 2010 to 2014 time frame.

This information is grouped by load area as an input to the Market Analysis model.[18]

For the longer term (generally after 2012), we estimate the quantity and types of renewables that will be developed using a supply-curve approach based on resource potential studies. In this approach, potentially available resources are sorted from least to greatest REC premium required to attract financing. This approach identifies the incremental resources required to meet net incremental demand in each year through 2020.

The one exception to this methodology is solar PV. We assume that resource is developed in proportion to various state policies intended to promote solar, including solar RPS tiers and other factors.

In this work we assume full compliance with established RPS targets. Entities subject to RPS targets comply primarily through the acquisition and retirement of RECs. Failing that, an obligated entity can comply through payment of an Alternative Compliance Payment (ACP), which allows a shortfall in RECs below the requirement to be made up through a per-MWh payment.[19] ACP levels have been set at prices above that minimum level expected to be necessary to allow plants to be financed and built to generate RECs. Because of the presence of the ACP as a valid form of compliance, actual non-compliance with RPS requirements will be extremely rare: if the market is short on supply, there is a valid alternative route to comply. Given these options we expect load-serving entities to comply, particularly since regulators have the authority to impose penalties or ultimately withdraw the right to participate in the markets.

Planned Additions and Uprates

The non-renewable generation resources used as inputs to our simulations are drawn from the capacities in ISO-NE (2009a). Exhibit 2-9 below (page 2-33) lists the specific generation additions we assume beyond that. These are primarily the

[18]Currently, Vermont's requirement will allow RECs to be sold off elsewhere (presumably for compliance in other states), therefore not leading to incremental renewable energy additions beyond what would be predicted in the presence of other states' requirements (although it has been argued that the Vermont requirements will support financing and therefore lead to more renewables being built, and therefore less reliance on Alternative Compliance Payments). We assume that by 2012, Vermont's standard will be altered to require retirement of RECs, and thereby add to the total RPS additions projected.

[19]In Massachusetts, Rhode Island, New Hampshire, and Maine, the Class-I or new-renewables tiers utilize an ACP mechanism set at a common level, corresponding to nearly \$61/MWh in 2009, and increasing with inflation. In Connecticut, the penalty for non-compliance is set at \$55/MWh. While it called a penalty rather than ACP in Connecticut, its effect is similar and it is often referred to as an ACP, which has become the generic term of art in the industry.

new units that are under contract to the Connecticut utilities and those under construction for municipal utilities, and include the generators that cleared in FCA 1 and/or FCA 2.

Demand-Response Resources

Demand Response (DR) resources participate in the FCA. For simulation purposes we start with the quantities of DR that cleared in FCA 2 and project quantities for future FCAs. DR resources, when dispatched, affect energy prices primarily in peak hours.

Generic Non-Renewable Additions

New generic non-renewable resources will be added to meet any residual installed capacity requirements after adding planned and RPS additions. We will develop our assumptions regarding the quantity, type, and timing of these generic additions in coordination with our simulation of the FCM because revenues from FCA prices help support those investments.

Based on the mix of resources in the interconnection queue, and the constraints on construction of new coal or nuclear units in New England in the foreseeable future, we assume generic additions comprising gas-oil-fired 300-MW combined-cycle units and 100-MW combustion turbines. These additions will be dispersed throughout New England based on zonal need and historical zonal capacity surplus-deficit patterns.

2.2.3. Environmental Regulations

Market Analytics has the ability to model, and apply unit compliance costs to, multiple emissions. For AESC 2009, we model emissions of SO_2, NO_x, CO_2, and mercury. The model includes the costs associated with each of these emissions when calculating bid prices and making commitment and dispatch decisions.

Our assumptions regarding the unit-compliance costs for each emission, except mercury, reflected, or internalized, in our projected market prices for energy are presented in Exhibit 2-4. These assumptions are based upon forward market prices in the near term and projections from those and other futures prices in the long-term. [20] For mercury, we assume no trading, and hence no allowance price.

[20]NOx and SO_2 allowance prices have fallen considerably since the previous AESC report in 2007. The NOx prices in AESC 2007 ranged from $1000 to $1800 per ton, whereas for 2009 they start at $1500 and fall to $284. The SO_2 price range in AESC 2007 was $434 to $750 per ton whereas for this analysis the values start at $60.8 and fall to $4.83 per ton. CO_2 prices are approximately 20% higher in this study than they were in 2007.

Exhibit 2-4 Emission Allowance Prices per Short Ton (Nominal, 2007, and 2009 Dollars)

	NO_2		SO_2		CO_2		RGGI Scenario CO_2	
	Nominal	2009	Nominal	2009	Nominal	2009	Nominal	2009
2009	$2,075	$2,075	$61	$61	$3.85	$3.85	$3.85	$3.85
2010	$1,550	$1,520	$34.90	$34.22	$3.99	$3.91	$3.99	$3.91
2011	$785	$755	$33.90	$32.58	$4.18	$4.02	$4.18	$4.02
2012	$494	$466	$32.40	$30.53	$4.25	$4.00	$4.25	$4.00
2013	$623	$576	$31.50	$29.10	$15.00	$15.63	$4.34	$4.00
2014	$311	$282	$27.50	$24.91	$17.30	$18.03	$4.42	$4.00
2015	$317	$282	$18.10	$16.07	$19.50	$20.32	$4.51	$4.00
2016	$326	$284	$8.40	$7.31	$21.80	$22.72	$4.60	$4.00
2017	$333	$284	$7.80	$6.66	$24.00	$25.01	$4.69	$4.00
2018	$339	$284	$7.20	$6.02	$26.30	$27.41	$4.79	$4.00
2019	$346	$284	$6.60	$5.41	$28.50	$29.70	$4.88	$4.00
2020	$353	$284	$6.00	$4.83	$30.80	$32.10	$4.98	$4.00

Pricing data based on March 31 2009 prices from Chicago Climate Futures Exchange

CO_2 allowance estimates from 2013 onwards are based on 2008 Synapse estimates expressed in 2007 dollars

Sulfur Dioxide and Oxides of Nitrogen Regulations

On March 10 2005, EPA issued its final Clean Air Interstate Rule (CAIR), applicable to 28 Eastern states and the District of Columbia. CAIR applied to individual generating units larger than 25 MW. CAIR was designed to reduce SO_x emissions by 70% and NO_x emissions by 61%, as compared to 2003 levels. Provisions for NO_x and SO_x were to be applied separately. NO_x emissions were expected to decrease by about 53% in 2009 and were expected to achieve a 61% reduction by 2015. SO_x emissions were expected to decrease by 45% in 2010, by 57% in 2015, and by 73% by 2019 or 2020.

On July 11, 2008, the US District Court of Appeals (DC Circuit) vacated the Clean Air Interstate Rule.[21] On September 24, 2008, EPA filed a petition for rehearing, or in the alternative, a remand of the rule back to EPA, to the Court. On December 23, 2008, the Court remanded CAIR rule back to EPA, and let the rule stand in place as written, but ordered EPA to correct the flaws the Court identified in its July 11th decision. The identified flaws pertain to EPA's treatment of emissions that occur in one state, but which have adverse air quality impacts in another state

[21] *State of North Carolina v. EPA,* U.S. App. D.C.,US Environmental Protection Agency; US District Court of Appeals, No. 05-1244 (Argued March 25, 2008)., decided July 11, 2008. *http://www.epa.gov/cair/pdfs/05-1244-1127017.pdf*

downwind. The Court found that EPA did not adequately treat or explain the treatment of these impacts.

Uncertainty over the initial Court's decision, and the December decision to remand back to EPA, has caused SO_x and NO_x allowance prices to tumble. When EPA responds to the Court's decisions, future allowance prices may rise above the currently historically low levels. However, regulation of CO_2 emissions from the power sector as part of Congressional efforts to establish a national cap and trade program is likely, and the value of CO_2 allowances will have a significantly greater impact on electricity prices than the allowance prices for SO_x and NO_x. A cap and trade system for CO_2 will tend to drive down SO_x and NO_x allowance prices. Since a CO_2 cap and trade program will apply to the same sources as the SO_x and NO_x programs. In fact, the Waxman/Markey bill, appears to apply to smaller generating sources than the current SO_x and NO_x programs.[22] Reductions of CO_2 at these generators will also result in reductions of SO_x, $NO_{x,}$ and mercury. We believe that emissions market brokers have built expectations of a national cap-and-trade system for CO_2 into their SO_x and NO_x price forecasts for the years after 2013.

A national cap-and-trade program for CO_2 will probably be effective in 2012 or 2013. The influence on price of CO_2 regulation will be much greater than that of NO_x regulation and will depress future NO_x allowance prices. We assume that allowance prices for NO_x beyond 2014 and for sulfur-dioxide-allowance price for years beyond 2020 each increase at the general rate of inflation.

Regulation of CO_2

We assume that CO_2 allowance prices will be based upon the regional greenhouse gas initiative (RGGI) framework through 2012 and a new Federal regulatory framework in following years and a special case that is RGGI only.

On December 20, 2005, seven Northeastern states signed a memorandum of understanding that established a mandatory cap on utility sector emissions. Three additional states have since joined RGGI, and the ten state program became effective on January 1 2009.[23] RGGI caps utility-sector emissions at a 2000–2004 baseline from 2009 through 2014, and then requires the cap to decline 2.5% each year to achieve a total reduction of ten percent from the initial baseline by December 31 2018. RGGI applies to individual generating units larger than 25 MW, the same as CAIR. The December 2005 memorandum of understanding

[22] H.R. 2454, "American Clean Energy and Security Act of 2009."

[23] The original seven are: Connecticut, Delaware, Maine, New Jersey, New Hampshire, New York, and Vermont. The three additional states are Maryland, Massachusetts, and Rhode Island.

provides for a mid-course review during 2012, during which the program will be completely evaluated. The RGGI states anticipate that if an equivalent or more-stringent national program has been enacted or effective by 2012, RGGI will transition into the national program. Three auctions of RGGI allowances have been completed as of March 2009. (An allowance equals one short ton of carbon dioxide.) RGGI allowances are also traded in secondary markets or futures markets.

The pace and stringency of proposals for a national cap-and-trade program have increased since 2007. Passage of national greenhouse-gas (GHG) requirements is also a priority of the Obama Administration. In the United States House of Representatives, Chairman Waxman and Chairman Markey have been guiding the American Clean Energy and Security Act of 2009 (ACES Act) that would (if passed and enacted) comprehensively address climate change issues within the United States. The specific carbon regulations that will ultimately be established are uncertain since the ACES Act is still under negotiation within the House of Representatives and has not received input from the United States Senate.

A major provision of the current version of the ACES Act is the creation of a nationwide carbon dioxide emission allowance trading program for electricity generators among other emitters of GHG starting in 2012. Combined with other sectors, the Act would cover 85% of GHG emissions in the United States. Estimates of the initial allowance price range from $13 to $17 per short ton in 2009$ for 2015.[24] In comparison, as noted below, AESC 2009 uses an initial Federal allowance price of $15.63 per short ton (2009$) starting in 2013.

AESC 2009 assumes RGGI allowances as reported in Exhibit 2-4 based upon the following auction and trading results.

- 2009—a range from $3.50 to 3.85 per allowance, as reported from the March 2009 RGGI auction results (www.rggi.org) and secondary-allowance-market information from the Chicago Climate Exchange (www.ccfe.com).
- 2010—$3.99 per allowance based on secondary-allowance-market information from the Chicago Climate Exchange.
- 2011—$4.18 per allowance based on secondary-allowance-market information from the Chicago Climate Exchange.
- 2012—$4.25 per allowance based on secondary allowance market information from the Chicago Climate Exchange.

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[24]Values originally reported as 2005 dollars per metric ton and expressed here as 2009 dollars per short ton from slide 3 of "EPA Analysis of the American Clean Energy and Security Act of 2009 H.R. 2454 in the 111th Congress." dated June 30, 2009

After 2012, we use prices estimated by Schlissel et al. (2008) for a reference case, in which a national cap-and-trade program for GHG is enacted. From 2024 onward, we assume allowance prices in the reference case will rise at the rate of inflation.

As requested, we have also estimated CO_2 allowance prices for a special case that assumes no new Federal regulatory framework and thus continuation of RGGI indefinitely (RGGI only). We do not believe this case is likely. After 2013, under the RGGI-only scenario we assume that RGGI prices will remain relatively stable due to electricity imports. Thus, we assume allowance prices after 2012 in that RGGI only case will rise at the rate of inflation.

Mercury Regulation

On February 8, 2008, the U.S. District Court, DC Circuit, issued a judgment that vacated the EPA's proposed Clean Air Mercury Rule (CAMR).[25] The basis of the court's decision was that mercury was listed as a hazardous air pollutant under Section 112 of the Clean Air Act (CAA), and therefore subject to Best Available Control Technology (BACT). The proposed CAMR would have effectively moved mercury to under Section 111 of the CAA in order to implement a cap-and-trade program, and therefore not subject to BACT. On February 6, 2009, the Department of Justice on behalf of the EPA requested the US Supreme Court to dismiss the EPA's request to appeal the DC Circuit of Appeals decision, thus leaving mercury subject to Section 112 of the Clean Air Act.[26] As a result, it appears unlikely that mercury allowances will be traded.

EIA (2009a) modeled adoption of mercury regulation by state.[27] For New England, the EIA assumed mercury reduction would take place and that plants would incorporate BACT by 2015.[28] We assume mercury emission reductions consistent with EIA (2009a). This is reflected in the tables of reported marginal mercury emissions. With respect to the avoided costs we do not anticipate that mercury control costs will matter, because they are low per kWh generated, and because mercury-emitting power plants are on the margin a very small portion of the time in New England.

[25] *State of New Jersey et al. v. EPA,* 517 F.3d 574 (D.C. Cir. 2008)[25] http://pacer.cadc.uscourts.gov/docs/common/opinions/200802/05-1097a.pdf

[26] Petition for a Writ of Certiorari of United States Environmental Protection Agency, *New Jersey v. EPA,* 517 F.3d 574 (No. 08-512)[26] http://www.epa.gov/air/mercuryrule/pdfs/certpetition_withdrawal.pdf

[27] Conversation and correspondence with Laura Martin of the EIA on March 30 2009

[28] Conversation and correspondence with Laura Martin of the EIA on March 30 2009. The authors understand that none of the scenarios modeled by EIA (2009a) include CAMR.

2.2.4. Results of Forward Capacity Auctions and Regional Greenhouse Gas Initiative Auctions

Results of Forward Capacity Auction

According to Powers (2006), suppliers of capacity whose bids are accepted in the FCA will be receive revenues equal to (1) the quantity of capacity they provide times (2) the auction price minus (3) penalties for any failure to perform and minus (4) an estimate of the energy profits (called *peak energy rent,* or PER) that would be earned by a generator with a 22,000 Btu/kWh. The PER that the hypothetical peaking unit would earn in each hour will be multiplied by the ratio of load in that hour to the peak load for the power year. It is not clear how large the credits to load for the failure to perform are likely to be. The PER is likely to be small.

The first forward-capacity auction, for June 2010 through May 2011, ended at the predetermined floor price of $4.50/kW-month, with 2,047 MW of excess capacity. FCA 2, for June 2011 through May 2012, with a floor price of $3.60/kW-month closed with 4,914 MW of excess at that price.[29]

As noted earlier, revenues from FCAs will influence decisions regarding continued operation of existing generating units and investments in new generating units.

Results of Regional Greenhouse-Gas-Initiative Auctions

Three RGGI auctions have been held as of March 2009. The March 18 2009 auction cleared at $3.51 for vintage 2009 allowances and $3.05 for vintage 2012 allowances. Previous auctions were held in December and September 2008 with allowances clearing at $3.38 and $3.07, respectively. New England states use revenues from RGGI auctions to fund state energy efficiency and renewable energy programs. This is discussed more fully as described above.

2.2.5. Model Calibration

Since a key objective of this study is the calculation of avoided electric energy costs, we took steps to ensure that the model is forecasting energy market prices accurately. The calibration approach we use is to compare the prices forecast by the model to electric energy future prices at the ISO-NE hub over the five years for which they are publicly traded on NYMEX. The ability to make this

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[29]This excess does not count 427 MW of capacity in Maine in excess of the transfer capacity to the rest of the pool, or 159 MW of emergency generation beyond the 600 MW that the ISO counts towards capacity. Up to 427 MW of Maine retirements or growth in Maine requirements would not reduce the capacity excess, nor would withdrawal of up to 159 MW of emergency generation. When the FCA closes with excess capacity the payments are prorated downward in proportion to the excess.

comparison is complicated by the SOW requirement for the model to forecast prices assuming no continuation of energy-efficiency activities, i.e. no “new” reductions. The complication is that the electric-energy future prices will reflect the expectations of buyers and sellers in the actual market, who are likely assuming continuation if not escalation of existing efficiency programs.

Consequently, we model the current market situation with some energy efficiency resources, especially those that have cleared in the forward capacity auctions. We then make appropriate model adjustments (e.g. bidding strategies, etc.) to reasonably match the electric-energy-future prices at the ISO-NE hub over the five years (2009–2014) for which they are publicly traded on NYMEX.

After confirming that the model is accurately forecasting market prices, we re-ran it without those added demand-side resources, forecasting electric-energy prices in the absence of any new efficiency. We added generic thermal resources as needed to maintain reasonable reserve margins.

2.3. Wholesale Electric Energy Market Simulation Model and Inputs

2.3.1. The Energy-Market-Simulation Model

Market Analytics is a zonal locational marginal-price-forecasting model that simulates the operation of the energy and operating reserves markets. It produces forecasts of prices for each product. The model does not simulate the forward capacity market and, therefore, does not require assumptions regarding the capital costs of new generation capacity, and the interconnection costs associated with such capacity. However, the model does entail assumptions about the quantity and type of existing and new capacity over the study horizon, as does our model of the FCM. Our assumptions regarding new capacity additions are below.

Market Analytics will take as inputs the monthly regional fuel-price forecasts to be discussed later (including the regional natural-gas forecast and regional forecasts for petroleum products, coal, and fuel wood). Other inputs as discussed in the sections below will be incorporated in order to produce an avoided-electric-energy-cost forecast by state.

2.3.1.1. Zonal Locational Marginal Price-Forecasting Model

The following section provides a high-level overview of the Market Analytics data-management and production-simulation-model functionality. Market Analytics uses the PROSYM simulation engine to produce optimized unit commitment and dispatch options. The model is a security-constrained chronological dispatch model that produces detailed and accurate results for hourly electricity prices and market operations.

The basic geographic unit in PROSYM is a sub region of a control area, called a transmission area. Transmission areas are defined in practice by actual transmission constraints within a control area. That is, power flows from one area to another in a control area are governed by the operational characteristics of the actual transmission lines involved. New England, for example, comprises twelve transmission areas, including Southwest Connecticut. The service territories of the New England distribution utilities are mapped onto the transmission areas, and hourly load data is entered into PROSYM by distribution utility area. PROSYM can also simulate operation in any number of control areas. Groups of contiguous control areas were modeled in order to capture all regional impacts of the dynamics under scrutiny.

PROSYM uses highly detailed information on generating units. Data on specific units in the Market Analytics database are based on data drawn from various sources including the U.S. Energy Information Administration, U.S. Environmental Protection Agency, North American Electric Reliability Corporation, Federal Energy Regulatory Commission (FERC), and ISO-New England databases as well as various trade press announcements and Ventyx's own professional assessment. Total existing capacity in the Market Analytics database was compared with that of ISO-NE (2009a) and found to be reasonably consistent, although we made a few adjustments to reflect retirements as detailed below.

For larger units, emission rates and operating characteristics are based on unit-specific data reported to EPA and EIA rather than on data based on unit type. Operating costs for each unit are based on plant-level operating costs reported to FERC and assessment of unit type and age. For smaller units (e.g., combustion turbines), most input data are based on unit type. All generating units in PROSYM operate at different heat rates (efficiencies) at different loading levels. This distinction is especially important in the case of combined-cycle units, which often operate in a simple-cycle mode at low loadings. PROSYM determines the fuel a unit burns by placing each generating unit into a "fuel group." PROSYM does not limit the number of fuel groups used, and creating new fuel groups to simulate a few unusual units is a simple matter. In New England, for example, it is especially important to model the operation of dual-fueled units as accurately as possible.

Based upon hourly loads, PROSYM determines generating unit commitment and operation by transmission zone based upon economic bid-based dispatch, subject to system operating procedures and constraints. PROSYM operates using hourly load data and simulates unit dispatch in chronological order. In other words, 8,760 distinct hourly load levels are used for each transmission area for each study year. The model begins on January 1st and dispatches generating units to meet load in each hour of the year. Using this chronological approach, PROSYM takes into account time-sensitive dynamics such as transmission constraints and operating characteristics of specific generating units. For example, one power plant might not be available at a given time due to its minimum down time (i.e., the period it must remain off line once it is taken off). Another unit might not be available to a given transmission area because of transmission constraints created by current operating conditions. These are dynamics that system operators wrestle with daily, and they often cause generating units to be dispatched out of merit order. Few other electric system models simulate dispatch in this kind of detail.

The model's fundamental assumption of behavior in competitive energy markets is that generators will bid their marginal cost of producing electric energy into the energy market. The model calculates this marginal cost from the unit's opportunity cost of fuel[30] or the spot price of gas at the location closest to the plant, variable operating and maintenance costs, and opportunity cost of tradable permits for air emissions.

PROSYM does not make capacity-expansion decisions internally. Instead, the user specifies capacity additions, a practice that increases transparency and allows the system-expansion plans to be specified to reflect non-market considerations. As discussed in more detail, PROSYM also models randomly occurring forced outages of generating units probabilistically rather than as deterministic capacity de-rating, thereby producing more accurate estimates of avoided costs, particular for peak-load periods. PROSYM models generating units with a much higher level of detail including inputs for unit specific ramp rates, minimum up/down times, and multiple capacity blocks, all of which are critical for accurately modeling hourly prices. This modeling capability enabled production of locational prices by costing period in a consistent manner at the desired level of detail.

PROSYM simulates the effects of forced (i.e., random) outages probabilistically, using one of several Monte Carlo simulation modes. These simulation modes initiate forced outage events (full or partial) based on unit-specific outage probabilities and a Monte Carlo–type random number draw. Many other models simulate the effect of forced outages by "de-rating" the capacity of all generators within the system. That is, the capacities of all units are reduced at all times to simulate the outage of several units at any given time. While such de-rating

[30]A number of generators have the ability to utilize a secondary fuel type. Units that are allowed to burn gas or fuel oil are allowed to burn oil during the winter months (December, January, and February) and burn natural gas during the rest of the year. Fuel switching only occurs if oil is the less expensive option for these plants.

usually results in a reasonable estimate of the amount of annual generation from baseload plants, the result for intermediate and peaking units can be inaccurate, especially over short periods.

PROSYM calculates emissions of NO_x, SO_2, CO_2 and mercury based on unit-specific emission rates. Emissions of other pollutants (e.g., particulates and air toxics) are calculated from emissions factors applied to fuel groups.

2.3.2. Values for Input Assumptions to Electric-Energy-Price Model

The input assumptions to the Market Analytics locational-price-forecasting model include market rules and topology, hourly load profiles, forecasted annual peak demand and total energy, thermal-unit characteristics, conventional hydro and pumped storage unit characteristics, fuel prices, renewable unit characteristics, transmission system paths and upgrades, generation retirements, additions and uprates, outages, environmental regulations, and demand-response resources.

2.3.2.1. Market Rules and Topology

The major assumptions are described below as inputs to the model.

Marginal-Cost Bidding

In deregulated markets generation units are assumed to bid marginal cost (opportunity cost of fuel plus variable operating and maintenance costs (VOM) plus opportunity cost of tradable permits). It is reasonable to assume that the real markets are not perfectly competitive and thus the model prices based on marginal costs tend to underestimate the prices in the real markets. To represent that effect we investigated bid adders to represent more realistic market behavior. The energy-price outputs are benchmarked against futures prices.

Installed Capacity

Installed-capacity requirements for the resource-addition model include reserve requirements established by ISO-NE on an annual basis. Current estimates of the reserve-margin and installed-capacity requirement (with and without the Hydro Quebec (HQ) installed capacity credits) are listed in Appendix C. Installed capacity for the energy model in each model year will be consistent with the values assumed in the FCA analysis, although the values will not be the same, due to imports and exports.

Ancillary Services

Market Analytics allows users to define generating units based on their ability to participate in various ancillary services markets including Regulation, Spinning Reserves, and Non-Spinning Reserves. The database includes specifications for these abilities based on unit type. Market Analytics generates prices for these markets in conjunction with the energy market. The spinning reserves market affects energy prices since units that spin cannot produce electricity under normal conditions. The energy prices are higher when reserves markets are modeled. Reserves requirements for New England are applied to the model.

Electric Model Topology

Market Analytics represents load and generation areas at various levels of aggregation. Assets within the model, including physical or contractual resources such as generators, transmission links, loads, and transactions, are mapped to physical locations which are then mapped to transmission areas. Multiple transmission areas are linked by transmission paths to create control areas. For this study, New England is represented by 13 transmission areas that are based on the 13 load areas as defined by ISO-New England for the 2008 Regional System Plan. Neighboring regions that are modeled in this study are New York, Quebec, and the Maritime Provinces.[31] Areas outside of New England are represented with a high level of zonal aggregation to minimize model run time. The load and generation areas to be modeled are presented in Exhibit 2-5 below.

[31] The Maritimes zone includes Maine Public Service (MPS) and Eastern Maine Electric Cooperative (EMEC) which are not part of ISO-New England and, therefore, are not included in any of the New England pricing zones used in this study. MPS and EMEC are not modeled as part of the Maine pricing zone and were modeled as part of the New Brunswick transmission area.

Exhibit 2-5 Load Areas Used to Model New England

	Load-Area Descriptor	Description
New England	BHE	Northeastern Maine
	ME-CMP	Western and Central Maine & Saco Valley
	SME	Southeastern Maine
	NH	Northern, Eastern, and Central New Hampshire, Eastern Vermont and Southwestern Maine
	VT	Vermont & Southwestern New Hampshire
	Boston	Greater Boston, including the North Shore
	CMA/NEMA	Central Massachusetts & Northeastern Massachusetts (Corresponds closely to the ISO-NE Hub)
	WMA	Western Massachusetts
	SEMA	Southeastern Massachusetts
	RI	Rhode Island
	CT	Northern and Eastern Connecticut
	CT-SW	Southwestern Connecticut
	CT-NOR	Norwalk/Stamford Connecticut
New York	NY	NY-ISO control area
Quebec	HQ	Hydro Quebec control
Maritimes	M	Maritimes control area

The model explicitly models neighboring control areas that have direct connections to the New England grid, including New York ISO, the Maritimes region (New Brunswick, Nova Scotia, and Prince Edwards Island), and Hydro Quebec. These external markets are modeled in the same manner and simultaneously with New England. The Market Analytics database is used as the primary data source for external regions. New capacity is added to meet RPS requirements and generic gas capacity is added based on the same methodology that is used in New England.

The electricity prices so modeled for the above load areas are appropriately mapped and weighted into the pricing zones as used by ISO-NE.

2.3.2.2. Load Forecast

ISO-New England changed its long-run load forecasting methodology to reflect the fact that DSM resources may participate in the Forward Capacity Market. See also the earlier discussion of the ISO-NE methodology in Section 2.2.2.1.

Historical profiles for each utility were developed by Ventyx Decisions based on a set of annual historical load shapes. Hourly load profiles based on historical profiles were calculated for each load serving entity. Loads were then mapped to transmission areas based on location ratios.

Hourly load data for future years were scaled based on forecasted annual peak demand and total energy. Forecasted annual peak demand and total energy were derived from ISO-New England (2009a). The load forecasts for each area in the Market Analytics model were derived from the ISO-NE's (2009a) load forecasts for 2009–2018. For 2019–2024, we assume load in each area grows at the Compound Annual Growth Rate of the 2009–2018 period.[32]

The area ISO-NE load forecasts are used to get the transmission area loads required for the Market Analytics modeling. This is a one-for-one process with the exception that southeastern Massachusetts (SEMA) & Rhode Island are combined.

Exhibit 2-6 Summer Peak Forecast by Model Load Area

Zone	**2009** (MW)	**2018** (MW)	**2009–18 CAGR**	**2024** (MW)
BHE	325	350	0.83%	368
ME	1,165	1,305	1.27%	1,408
SME	585	665	1.43%	724
NH	2,020	2,330	1.60%	2,563
VT	1,265	1,400	1.13%	1,498
BOST	5,690	6,260	1.07%	6,671
CMA/NEMA	1,820	2,145	1.84%	2,393
WMA	2,095	2,345	1.26%	2,528
SEMA	2,945	3,270	1.17%	3,506
RI	2,540	2,865	1.35%	3,104
CT	3,575	3,805	0.70%	3,966
SWCT	2,445	2,735	1.25%	2,947
NOR	1,395	1,480	0.66%	1,540
ISO-NE	27,875	30,960	1.17%	33,204

2019–2024 values are developed by growing 2018 values at the 2009–2018 CAGR.

[32]ISO-NE's (2009a) forecast used in this study has a significantly lower growth rate than that in ISO-NE (2007), which was used in AESC 2007. ISO-NE's (2007) forecast had a summer peak CAGR of 1.72%, whereas the peak growth rate for current CELT is 1.17%, a reduction of about one third.

Exhibit 2-7 Energy Forecast by Model Load Area

Zone	2009 (GWh)	2018 (GWh)	2009-2018 CAGR	2024 (GWh)
BHE	1,880	2,010	0.75%	2,102
ME	6,685	7,175	0.79%	7,521
SME	3,175	3,415	0.81%	3,585
NH	9,705	10,845	1.24%	11,678
VT	7,130	7,720	0.89%	8,140
BOST	26,440	28,580	0.87%	30,102
CMA/NEMA	8,445	9,535	1.36%	10,339
WMA	10,350	11,300	0.98%	11,981
SEMA	13,495	14,670	0.93%	15,510
RI	11,535	12,630	1.01%	13,417
CT	15,825	16,365	0.37%	16,735
SWCT	10,835	11,835	0.99%	12,552
NOR	5,820	6,040	0.41%	6,191
ISO-NE	131,320	142,120	0.88%	149,809

2019–2024 values are developed by growing 2018 values at the 2009–2018 CAGR.

2.3.2.3. Transmission Upgrades

Transmission-path assumptions were developed by Ventyx based on the transmission paths represented in ISO-NE (2008b). The transmission system within Market Analytics is represented by links between transmission areas. These links represent aggregated actual physical transmission paths between locations. Each link is specified by the following variables:

- "From" location
- "To" location
- Transmission capability in each direction
- Line losses in each direction
- Wheeling charges

Appendix C shows the transmission capabilities of each path between New England zones and between New England and external areas as indicated in the Market Analytics database, reconciled to the interface limits reported by Mezzanotte (2009). The Ventyx and ISO documents assume the addition of all four projects of the New England East-West Solutions transmission program. Most of the additional transfer capability into Connecticut (and on the East-West and SE Massachusetts–Rhode Island export interfaces as well) results from two projects—the Interstate Project and the Cross-Connecticut Project. These were justified primarily by the objective of meeting Connecticut's load with combined generation and transmission outages at times of extraordinary (once in ten year) high-load conditions, even if more than 1,200 MW of Connecticut generation is retired. Since the original analyses, Connecticut has contracted for over 1,500 MW of additional capacity and load forecasts have fallen, resulting in little if any shortfall in the Connecticut transmission-security analysis.[33] We have thus assumed that the Western Massachusetts–Connecticut transfer capacity increases 200 MW in 2014, rather than the 1,900 MW increase assumed by Ventyx in 2013, or the 1,100 MW of increased Connecticut import capacity the ISO estimated for 2014.

2.3.2.4. Generating Unit Retirements

A number of environmental regulations may affect older New England fossil generation, including limits on:

- NOx emissions,
- SO_2 emissions,
- mercury emissions,
- fine particulate emissions,
- use of surface water for cooling in once-through cooling systems.

To the extent that emissions can be offset with allowance purchases (as for carbon, and to some extent NOx and SO_2), the costs of the allowances are included in economic dispatch and in the next section. This section deals with unit- or plant-specific requirements, in addition to tradable regional or national emission limits.

Environmentally-Driven Retirements of Coal Plants

Only eight coal plants (consisting of 15 units) are operating in New England. Our understanding of the environmental regulatory status of those plants is as follows:

- Thames A and B (CT) is a fluidized-bed plant built in the late 1980s, with relatively low emissions. We expect this plant to operate throughout the modeling period.
- Bridgeport 3 (CT) has relatively low emission rates that do not appear to be under great pressure from environmental regulators. The owner, PSEG, recently installed a baghouse to control particulate and mercury emissions, according to PSEG's Mike Jennings (2008).[34]

[33] The ISO is revisiting the need analyses for the NEEWS components.

[34] "Bridgeport Harbor: reliable, affordable—now cleaner—electricity" PSEG Outlook, July 2008, p. 1.

- Brayton 1–3 (Massachusetts) appears committed to making the improvements necessary to meet all pending emission and water-use requirements and stay in operation. The same is true for the Brayton 4 oil unit.
- Somerset 6 (Massachusetts) has agreed to shut down by October 2010 unless it repowers. Somerset has not cleared in the first two FCAs, and has submitted a high bid for the third FCA, essentially ensuring that it will not clear. NRG has proposed an innovative plasma boiler for repowering Somerset, and to burn a combination of coal, wood, and construction waste, and the Massachusetts DEP has accepted that proposal, but it is not clear when or if NRG will determine that market prices (for energy, RECs and capacity) are sufficient to cover the costs of the new boiler. We treat Somerset 6 as retired in January 2011.[35] It just cleared in the first auction, but not the second, and has submitted a prohibitively high bid in the third, so we will treat it as retired in June 2011.
- Salem 1–3 (Massachusetts) and the Salem 4 oil plant have submitted a high bid for the third FCA, essentially ensuring that they will not clear This may be part of a stratagem for getting a higher-priced reliability contract from the ISO (as Norwalk Harbor did in FCA 1), or a legitimate plan to mothball or retire the plant. We plan to treat it as the latter, and treat all four units as being retired in June 2012.
- Mt. Tom (Massachusetts) is adding a $55 million scrubber in 2009, reducing forward-going costs and implying that the owner is planning on continuing to operate the unit.
- Merrimack 1 and 2 (New Hampshire) are installing a scrubber and other expensive controls. We expect that the plant will continue to operate.
- Schiller 4 and 6 (New Hampshire) are small and old, but we have not identified any particular factor that would lead to their shutdown.

Environmentally Driven Retirements of Oil- and Oil-and-Gas-Fired Steam Plants

We have less complete information on the old steam plants fired by oil and/or gas. None of these plants are likely to be able to support the cost of major emissions controls, so we do not have the evidence of owner commitment to continuing operation (as we do for Brayton, Bridgeport 3, Mt. Tom, and Merrimack).

[35] We model additions and retirements as occurring January 1.

The likely fate of Salem 4 and Brayton 4 are described above, in connection with the coal plants of which they are part. The information we have been able to assemble about other major plants is summarized below:

- Wyman 1–4 (Maine) run on higher-sulfur (2.2% sulfur by weight) and hence less expensive fuel than other oil plants in New England (generally 0.5%, or 0.3% in Connecticut), and hence operate more often, even though they are in Maine, the zone with the lowest market energy prices. Other than a requirement to switch to 0.5% sulfur oil in 2018, Wyman does not appear to face any environmental challenges.
- Newington (New Hampshire) burns both 1% sulfur oil and gas and does not appear to face any environmental challenges.
- Mystic 7 (Massachusetts) burns both oil and gas and does not appear to face any environmental challenges.
- West Springfield 3 (Massachusetts) burns both oil and gas and does not appear to face any environmental challenges.
- Canal 1 (Massachusetts) has installed selective catalytic reduction (SCR) and operates with very low NOx emissions, while Canal 2 has installed selective non-catalytic reduction (SNCR). Mirant has repeatedly proposed replacing Unit 2 with a gas-fired combined-cycle, suggesting some doubt in the unit’s long-term viability.
- Connecticut has particularly strict plant-specific SO_2 and NOx emissions criteria, which it may tighten in 2011 and further tighten in 2018. The Connecticut steam plants have all cleared in the forward capacity auctions through May 2012, so they appear to be committed to meeting the 2011 standards. The potential Connecticut standards for 2018 would require sulfur emissions that could not be meet with any existing residual fuel, so plants that cannot burn gas would need to switch to distillate fuel or a residual/distillate blend. We expect that a number of the Connecticut oil-fired steam plants, and to a less extent the dual-fuel plants, will be retired as part of the economic shutdowns.

Combustion Turbines

Approximately 10% of the capacity of old (pre-1980) New England combustion turbines retired in the decade from 1998 to 2008. Throughout this period, the generation market was largely restructured, although market rules have continued to change. We assume that about 1% of the old combustion turbines (roughly 10 MW, or a unit every year or two) will retire annually through the modeling period. For modeling purposes, we will assume that the oldest units are retired first, except that the Connecticut combustion turbines will remain on line longest, due to the higher forward reserve prices.

We will assume that the Somerset Jet will be retired in June 2011.

Economic Shutdown and Retirements

The economic viability of the oil- and gas-fired steam plants, most of which generate a relatively small amount of energy, is strongly influenced by capacity-market prices. The old combustion turbines operate even less, but receive revenues in the forward and real-time reserve markets. Starting in June 2013, the floor on the FCM price will end, and the capacity price in New England would fall dramatically if no existing resources delist (that is, withdraw from the auction either in advance or as the price falls).

We expect that a large amount of capacity now imported to New England from HQ, New York, and Ontario will withdraw as the price falls, and instead sell capacity into the markets in New York, PJM, and possibly Ontario. Some domestic New England capacity will probably also delist to sell capacity out of the region, but will continue to be available to serve energy loads in New England. These changes in capacity imports and exports will have no effect on our energy modeling.

The lower capacity prices will also probably cause the providers of some of the existing demand-response resources that the capacity revenues are not worth the cost and inconvenience of reducing load, resulting in their delisting. These resources have no effect on our energy modeling.

About 3,400 MW of resources would need to delist to maintain a capacity price of $2/kW-month in 2013, even without additional energy-efficiency savings. We assume for modeling purposes that at least some of the steam plants will shut down rather than operate with just $24/kW-year of capacity revenues. The changes in imports, exports and demand resources are not likely to achieve that level of delisting, requiring some delisting of steam units.

In general, we will model those delistings generically, shutting down units starting with the oldest and smallest (both age and size may be indicators of higher operating costs) and those with low recent capacity factors (indicating a lack of energy profits). We will consider the recent decline in oil prices compared to gas prices in assessing the likely operation of these units. Considering the challenges awaiting them in 2018, we will preferentially deactivate the oil-only high-emission units in Connecticut.

We will assume the delisting and retirement of Salem 4 in June 2012, consistent with its submitted bid for FCA 3. We will also assume the deactivation of Wyman units 1 and 2 as of June 2013. FPL Energy has filed with the ISO a “Request for

Determination of Need for System Reliability and Consideration of RMR Cost-of-Service Agreement for Wyman Units No. 1 and 2" (December 11, 2008). In that filing, FPL Energy says

> Units No. 1 and 2 are not expected to realize any energy revenues in the foreseeable future. Additionally, a bleak capacity revenue outlook makes it unlikely that the subject units will recover their full operations and maintenance costs, and capital expenditures. Since it is not economically feasible to maintain the units, FPL Energy is seriously contemplating retiring Units No. 1 and 2 in the near future.

Given Wyman's location, the existence of the larger Wyman 3 and 4, and the surplus of capacity for the foreseeable future, we expect that Wyman 1 and 2 will not be found to be needed for local reliability and will thus be deactivated once capacity prices fall in 2013.

There are several examples of power plants that have been deactivated (or even declared retired) and then restored to service when supply conditions changed. In the absence of additional energy-efficiency or renewables, the 2009 CELT forecast implies the FCM price could remain at $2/kW-month with the addition of about 400 MW of additional capacity each year from 2014 onward. After accounting for additional renewables, we will compute that capacity need each year and fill it with reactivation of steam plants deactivated in 2013, through 2018. After 2018, we will assume that any remaining deactivated steam units would be retired and new load growth will be met with generic CT and CC units.

Exhibit 2-8 below lists the specific retirements we will assume; other than Somerset 6, we assume the retirements occur on January 1. In addition, we will retire about 10 MW of old gas turbines annually after 2012, and deactivate or retire enough capacity to keep the FCM prices at reasonable levels.

Exhibit 2-8 Unit Retirements

Retirement Date	Unit Type	Station Name	Unit ID	Summer CELT Capacity (MW)
10/1/2010	ST	Somerset	6	108.5
1/1/2012	GT	Somerset	Jet 2	21.8
	GT	St Albans	1 and 2	2.2
1/1/2013	ST	Salem Harbor	1	83.9
			2	80.5
			3	149.9
			4	436.5
1/1/2014	ST	Wyman	1	52.7
			2	52.8

2.3.2.5. Generating Unit Additions

A detailed table in Appendix C provide specific information about the resource types that qualify for each state program and the future RPS requirements levels for each state.

As discussed in section B (iii)(e) Renewable Portfolio Standard Additions, specific renewable energy resources will be based in the near-term on generation in the interconnection queues and other sources in the near-term, and based on a supply curve analysis in the longer term.

The operating characteristics of renewable generation units will be reasonably consistent between the Market Analytics modeling inputs and the Sustainable Energy Advantage, LLC (SEA) analysis. Inputs into the model will be verified by SEA to ensure consistency.

Planned Additions & Uprates

The AESC 2009 forecast of non-renewable generator additions is based on capacity that has cleared in FCA 1 and FCA 2, filings with the Connecticut DPUC for projects under contract with the Connecticut utilities, and reports by municipal utilities (for the Watson and Swanton units).[36] New entry assumptions are shown in the exhibit below. These planned additions are highly likely to reach commercial operation. Further additions will be treated as generic units.

Exhibit 2-9 Planned Non-Renewable Additions (in Addition to ISO-NE 2009a)

	Unit Type	Fuel Type	Summer Net MW	State	Projected Commercial Operation Date
Thomas A. Watson Generating Station (Braintree Electric)	GT	NG, DFO	108	Mass.	4/15/2009
Waterbury Generating Facility	GT	NG	95.7	Conn.	7/1/2009
Swanton Gas Turbines	GT	NG, DFO	40	VT	6/1/2010
Millstone 3 uprate	ST	UR	80	Conn.	6/1/2010
Devon 15-18	GT	NG, DFO	196.8	Conn.	6/1/2010
Kleen Energy Project	CC	NG, DFO	619.8	Conn.	11/30/2010
New Haven	GT	NG, DFO	133	Conn.	6/1/2012
Middletown 12-13	GT	NG, DFO	196.8	Conn.	6/1/2010
Ansonia Generating	GT	NG	60	Conn.	6/1/2010

[36]The Watson and Waterbury facilities are included in the "Expected Summer Capacity" tabulation in Section 3.2 of the 2009 CELT, but not in the "Existing Capability" tabulation in Section 2.1. They are listed as additions here for clarity.

This tabulation does not include the fuel cell projects under contract in the Connecticut DPUC Project 150 process, since these are treated as renewable generation for Connecticut purposes.

Generic Additions

In order to reliably serve the forecasted load in the mid- to long-term portion of the forecast period, new generic additions will be added to the model. These, generic additions will be comprised of a 50/50 mix of capacity from gas/oil fired 300 MW combined-cycle and 100 MW combustion turbines. No coal or nuclear units will be added.

Generic additions will be added to meet the New England Installed Capacity Requirement in conjunction with our analysis of the forward capacity market. New resources will be dispersed geographically based on a combination of zonal need and historical zonal capacity surplus/deficit patterns. Maine's surplus of capacity, low energy prices and export constraints will tend to suppress development of new generic capacity in that zone. The locational markets for energy and forward reserves will tend to provide incentives to build new generation in import-constrained zones, principally Connecticut.

2.3.2.6. Generic Generating Unit Operating Characteristics

Thermal Units

Market Analytics represents generation units in detail, in order to accurately simulate their operational characteristics and therefore project realistic hourly dispatch and prices. These characteristics include:

- Unit type (steam-cycle, combined-cycle, simple-cycle, cogeneration, etc)
- Heat rate values and curve
- Seasonal capacity ratings (maximum and minimum)
- Variable operation and maintenance costs
- Forced and planned outage rates
- Minimum up and down times
- Quick start and spinning reserves capabilities
- Startup costs
- Ramp rates
- Emission rates (SO_2, NO_x, CO_2, and mercury)

The Ventyx Market Analytics data is based on a variety of reliable public sources such as EIA reports and FERC filings, although some sources are proprietary.

Specific details can be provided under appropriate confidentiality agreements. Note though that no such generic units were added for the AESC 2009 modeling.

Exhibit 2-10 Characteristics of Market Analytics Generic Unit Additions

	NG CC	NG GT
Typical Size (MW)	245	180
Heat Rate (Btu/kWh)	6,800	10,500
Variable O&M costs (2009 dollars per MWh)	$2.06	$3.66
Availability	90%	92%
NO_x (lb/mmBtu)	0.01	0.06
SO_2 (lb/mmBtu)	0	0
CO_2 (lb/mmBtu)	119	119

Fuel Prices

Prices for electric generation fuels were developed in Chapters 0 and 5. The results are summarized here in Appendix C.

Nuclear Units

There are four nuclear plants and five nuclear units in New England (Millstone 2 and 3, Pilgrim, Seabrook, and Vermont Yankee) with a combined summer capacity of 4,541 MW, representing approximately 15% of the total New England capacity.

Exhibit 2-11 New England Nuclear Unit Capacity and License Expirations

Unit	AESC Zone	Capacity (MW)[a]	License-Expiration Year[b]
Millstone 2	CT	877	2035
Millstone 3	CT	1,137	2045
Pilgrim	SEMA	677	2012
Seabrook	NH	1,245	2017
Vermont Yankee	VT	604	2012
[a]CELT 2009 Summer capability [b]U.S. Nuclear Regulatory Commission			

Of the five operating nuclear units in New England, Millstone 2 and 3 have been relicensed by the Nuclear Regulatory Commission (NRC) through 2035 and 2045, respectively. The NRC is currently reviewing 20-year license-extension applications for Pilgrim and Vermont Yankee, whose licenses expire in 2012, and anticipates that Seabrook (whose license expires in 2017) will file for relicensing in the second quarter of 2010. In the past nine years, the NRC has reviewed license extensions for 30 plants and not one of these applications was denied (Nuclear Energy Institute 2009). Based on this track record and the lack of evidence that suggests that the NRC would deny the license renewals for any of these plants, we assume that all of the nuclear plants in New England will receive NRC licenses to operate for another 20 years, through the entire modeling period.

Vermont Yankee must also receive an extension of its license from the State of Vermont; that application is currently in hearings before the Vermont Legislature and before the Vermont Public Service Board. Approval is not assured, and may be granted with conditions. Nonetheless, we assume that Vermont Yankee will be allowed to operate through the modeling period.

The licensed capacity of some nuclear units may be increased, as licenses are amended. We assume 2009 capacities, other than the 80 MW increase in Millstone, which has all necessary approvals and has cleared in FCA 1.

Conventional Hydro and Pumped Storage Unit Characteristics

The Market Analytics database will be used as the primary source all hydro unit information. Conventional reservoir and run-of-river hydro resources are considered a “fixed energy” station or contract in the model. Like thermal stations, these stations have a maximum and minimum generating capacity, but they also have a fixed amount of energy available within a specified time (i.e., a week or a month). Hydro stations operate generally on peak in a manner that levels the load shape served by other stations. Hydro stations are scheduled one at a time over the horizon of a week, subject to hourly constraints for minimum and maximum generation, and weekly constraints for ramp rates and total energy. Although the load shape they intend to level is the overall system load, a hydro station can be scheduled against the load of a specified transmission area or control area.

Pumped-storage type resources (with exchange contracts) have slightly different modeling requirements, typically involving a series of reservoirs used to release water for energy generation during peak load periods and pump water back uphill during off-peak times when energy demand and price is lower. The water (fuel) of pumped hydro generation is valued at the cost of pumping, allowing for net plant efficiency. Hourly reservoir levels are computed and a look-ahead is employed to prevent drawing the reservoir below the level where pumping space allows refilling to the desired level before the beginning of the next peak period.

2.3.2.7. Demand Resources

Demand resources will be included in the model consistent with the ISO-NE 2008 RSP and the FCA results. These resources will be modeled as generating units that act as load reduction resources that are committed only if all other available generating resources are operating at full capacity and load is about to be lost. These resources do not set the marginal clearing price.

2.3.2.8. Emission allowance costs

The proposed inputs for emission allowances costs are summarized in Exhibit 2-4, above.

2.4. Wholesale Electric Capacity Market Simulation Model and Inputs

2.4.1. Description of Forward Capacity Market Simulation Model

For power-years from June 2013 onward, we will estimate FCM auction prices using a spreadsheet model. The major input assumptions regarding the forecasts of peak load and available capacity in each power-year will be coordinated with, and consistent with, the corresponding input assumptions used in the Market Analytics energy market simulation model.

The major assumptions that will be used to simulate the future operation of the FCM are listed below*:*

The FCM remains as currently structured.

Installed capacity requirements (including the Hydro Quebec capacity credits), estimated from the peak loads in the 2009 CELT and the required reserve margins (ICR ÷ peak load–1) in the 2008 RSP. Both are extrapolated through the analysis period. Growth in Maine requirements can be met by some of the 427 MW of Maine capacity in excess of Maine's requirements and export capability. Since the required reserve margin rises steadily over time in the 2008 RSP, we will extend that trend.

Most resources continue to bid FCM capacity in a manner similar to their bidding in FCA 1 and FCA 2. Specifically, the capacity bid into the second FCA, which produced excess capacity of about 4,500 MW at the floor price of $3.60/kW-month, continues to bid. Most existing resources continue to bid in as a "price-taker," at or below the minimum FCM price. Units built by municipal utilities or under contract to the Connecticut utilities bid as price-takers.

Generators facing large costs for maintenance, equipment replacement or environmental compliance will submit bids high enough to cover their costs. If the FCM price falls below that level, the generators will not clear in the FCA and will be free to shut down.

Once the existing surplus no longer exists, due to retirements and load growth, FCM prices will be determined by the price of new peaking units under long-term contracts, net of a conservative estimate of energy profits and operating-reserve revenues. We assume that one or more states or utilities will intervene to ensure that new generation is built without waiting for the price becoming high enough to motivate merchant generators[37]. Capacity will be added preferentially in the areas with the lowest reserves and the highest market prices, gradually equalizing reserves across the region. Connecticut is most likely to have energy and LFRM prices higher than average, and Maine is the zone most likely to energy and possibly effective FCM prices below average.

Assumptions regarding FCM prices will be based upon the slope of the supply curve. We have detailed supply curves above \$3.60/kW-month from the published results of FCA 1 and FCA 2. Below \$3.60/kW-month we assume the average slope from the historical auctions.

We will use these assumptions to estimate FCM prices past 2012/13. We will start with the capacity that cleared in FCA 2, adding the capacity and subtracting the retirements described in Section 2.2.2.3 above. The resulting capacity for each year would be compared to the future ICR suggested by the ISO's RSP analyses. In both retirements and load growth, we would first net Maine changes against the Maine-specific surplus. We would extrapolate the FCM price from the remaining capacity surplus and the prices at various points in the second FCA at similar surplus levels, as described in Section 2.2.4 above.

2.4.2. Values for Input Assumptions to FCM Model

The underlying driver to the Forward Capacity Auctions is the Installed Capacity Requirement (ICR). The ICR is calculated by applying a percentage reserve requirement to the CELT peak load forecast. The owners of capacity entitlements on the Hydro Quebec Phase I/II interconnection (the New England utilities that pay for the HVDC transmission link) are price-takers, and the auction is actually for the remaining capacity need, the Net Installed Capacity Requirement (NICR). Holders of Hydro Quebec Interconnect Certificates (HQICC) receive the resulting auction price although they do not participate in the auction itself as shown in Appendix C.

[37]For example, in 2007 and 2008 Connecticut acquired over 1,300 MW of new generation through capacity contracts (Kleen and Waterbury), cost-of-service peaker contracts (Devon 11–14, Middletown 12 and 13, New Haven Harbor), and the Project 150 renewables and fuel cells. Similarly, the Connecticut municipals, Braintree Electric Light Department and the Vermont Public Power Supply Authority have over 200 MW of recent or near-term peaker additions. All those resources would be operating by 2012. The Massachusetts Municipal Wholesale Electric Company is planning to add a 280 MW combined-cycle unit at its Stony Brook plant.

2.5. External Costs Avoided

The calculation of avoided electricity costs incorporate some costs that that are not internalized, or reflected, in our projections of wholesale market prices for energy and capacity. We address the following components:

- Reliability-must-run (RMR) contracts;
- Wholesale risk premium; reflecting the risks and costs related to power procurement;
- Renewable Energy Credit (REC) purchases;
- Reserve margin multiplier;
- Transmission and distribution loss factors and avoided capacity
- Demand-reduction-induced price effects (DRIPE) in the wholesale energy and capacity markets; and
- Environmental externalities.

These avoided electricity-supply costs do not include several components of wholesale power costs that we consider to be largely or entirely unavoidable through Demand Side Management (DSM). These components include the locational forward reserve market, real-time operating reserves, automatic generation control (also called regulation), uplift, and the reliability contracts with particular generators.

The major changes in these topics from AESC 2007 are the inclusion of estimates for the region's many REC requirements and changes in the pattern of DRIPE due to changes in market expectations.

2.5.1. Reliability-Must-Run Contracts

In the past, ISO-NE granted special reliability-must-run (RMR) contracts to a set of power plants. The ISO determined that these plants needed to continue to operate in order to ensure reliability, typically because of their unique location, but that they would not be economically viable based solely upon the revenues from then-current market prices. The prices in the RMR contracts covered the plants' variable production costs (e.g., operations and maintenance) as well as their fixed costs (mostly capital).

Many of the RMR contracts have expired. The remainder will expire on June 1 2010 except for two Norwalk Harbor units which will be covered through June 1 2011. See Exhibit 2-12 below.

Exhibit 2-12: Plants with RMR Contracts Through 2010

	2009 CELT Summer Capability	Annualized Fixed Revenue Requirement	
	MW	Total	Per kW-Mo.
ConEd—W.Springfield 3	94.28	$7,050,000	$6.23
Berkshire Power	229.28	26,000,000	9.45
Pittsfield Gen. "Altresco"	141.04	13,000,000	7.68
ConEd—W.Springfield GT-1 GT-2	74.35	9,800,000	10.98
Sub-Total WCMA	538.94	$55,850,000	8.64
NRG—Middletown 2-4, 10(6)	770.12	49,611,273	5.37
NRG—Montville 5,6,10&11(6)	493.70	28,696,612	4.84
PSEG—New Haven Harbor	447.89	37,492,000	6.98
PSEG—Bridgeport Harbor 2	130.50	14,008,000	8.95
NRG—Norwalk Harbor 1 & 2	330.00	32,000,000	8.08
Sub-Total Connecticut	2,172.21	$161,807,885	6.21
Total New England RMR Agreements	2,711.15	$217,657,885	6.69

It is possible that if some or all of these plants seek to *delist,* or not bid, in future forward-capacity auctions, then ISO-NE may require them to stay on line under new RMR contracts. We expect that the prices under any such future RMRs would be close to prices from the FCA. However, there is considerable uncertainty regarding which, if any, plants will be needed and at what price.

Based on our analysis we made the following assumptions for calculating avoided electricity costs.

- the costs of the existing RMR contracts, expiring June 1 2010 and 2011 respectively, are not be avoidable;
- The costs of new RMR contracts, if any, are avoidable. For example, energy-efficiency programs may avoid the need for some RMR contracts through relief of transmission constraints.

2.5.2. Other Wholesale-Load-Cost Components

In addition to the locational marginal energy prices and capacity prices, the ISO-NE monthly "Wholesale Load Cost Report" includes the following cost components:

- First-Contingency Net Commitment Period Compensation (NCPC),
- Second-Contingency NCPC,

- Regulation (automatic generator control),
- Forward Reserves,
- Real-Time Reserves,
- Inadvertent Energy,
- Marginal Loss Revenue Fund,
- Auction Revenue Rights revenues,
- ISO Tariff Schedule 2 Expenses,
- ISO Tariff Schedule 3 Expenses,
- NEPOOL Expenses.

These cost components are described in more detail in the Wholesale Load Cost Reports, available from the ISO's web site, www.isone.com.

None of these components vary clearly enough with the level of load to warrant inclusion in the avoided-cost computation. More specifically:

- The NCPC costs are compensation to generators that are comply with ISO instructions to warm up their boilers, ramp up to operating levels, remain available for dispatch, possibly generate some energy, and then shut down without earning enough energy- or reserve-market revenue to cover their bid costs. Older boiler plants may take many hours to reach full load and have minimum run-times and shut-down periods, requiring plants to continue running at minimum levels overnight. Smaller loads would tend to reduce the need for bringing these plants into warm reserve, thus reducing NCPC costs. On the other hand, lower energy prices would tend to increase the net compensation due to these units when they were required, since they would earn less when they actually operated. Hence, while energy efficiency may affect NCPC costs, the direction and magnitude of the effects are not clear.
- Regulation costs are associated with units that follow variations in load and supply in the range of seconds to a few minutes. Reduced load due to efficiency is likely to result in reduced variation in load (in megawatts per minute), reducing regulation costs. On the other hand, some controls may increase regulation costs, if end-use equipment responds more quickly to changing ambient conditions. Overall, energy efficiency programs will probably reduce regulation costs, but we cannot estimate the magnitude of the effect.
- Forward and real-time reserve requirements should decrease slightly with energy efficiency, for two reasons. First, lower load will tend to leave more

available capacity on transmission lines, which will tend to reduce the need for local reserves. (This factor could be important in the Connecticut Locational Forward Reserve Market, as well as in other areas in the real-time market.) Second, a portion of real-time reserves are priced to recover forgone energy for units that remain in reserve; lower energy prices will tend to depress reserve prices. We expect that these effects would be small and difficult to measure.

- Inadvertent Energy exchanges with other system operators (NY ISO, Hydro Quebec, and New Brunswick) are small and probably not affected by energy efficiency.
- The Marginal Loss Revenue Fund returns to load the difference between marginal losses included in locational energy prices and the average losses actually experienced over the pool transmission facilities. That fund is—by definition—generated by inframarginal usage, and will not be affected by reduction of loads at the margin.
- Auction Revenue Right revenues are generated by the sale of Financial Transmission Rights (FTR), to return to load the value of transfers on the ISO transmission facilities. To the extent that efficiency programs reduce energy congestion, the value of these rights will tend to decrease.
- Expenses (ISO Tariff Schedules 2 and 3 and NEPOOL) are largely fixed for the pool as a whole, although a portion of the ISO tariffs are recovered on a per-MWh basis. Some of the ISO costs may decrease slightly as energy loads decline, if that leads to a reduction in the number of energy transactions, dispatch decisions, and other ISO actions required. Any such effect is likely to be small and slow of occur, and energy-efficiency programs add their own costs in load forecasting, resource-adequacy planning, and operation of the forward capacity market.

2.5.3. ***Wholesale Risk Premium***

The retail price of electricity supply from a full-requirements fixed-price contract over a given period of time is generally greater than the sum of the wholesale market prices for energy, capacity, and ancillary-service in effect during that supply period.

This premium over wholesale prices, or *wholesale risk premium,* is attributable to various costs that retail electricity suppliers incur in addition to the cost of acquiring wholesale energy, capacity, and ancillary-service at wholesale market prices. These additional costs include costs incurred to mitigate cost risks associated with uncertainty in charges that will be borne by the supplier but whose unit prices cannot be definitely determined or hedged in advance. These cost risks include costs of hourly energy balancing, transitional capacity, ancillary services, and uplift. Probably the larger component of the risk is the difference between projected and actual energy requirements under the contract, driven by unpredictable variations in weather, economic activity, and/or customer migration. For example, during hot summers and cold winters load-serving entities (LSEs) may need to procure additional energy at shortage prices while in mild weather they may have excess supply under contract that they need to "dump" into the wholesale market at a loss. The same pattern holds in economic boom and bust cycles. In addition, the suppliers of power for utility standard-service offers run risks related to migration of customer load from utility service to competitive supply (presumably at times of low market prices, leaving the supplier to sell surplus into a weak market at a loss) and from competitive supply to the utility service (at times of high market prices, forcing the supplier to purchase additional power in a high-cost market).

We make the following assumptions for calculating avoided electricity cost:

- We apply a wholesale risk premium to the avoided wholesale energy prices and avoided wholesale capacity prices.[38]
- Estimates of the appropriate adder range from less than 8% to around 10%, based on analyses of confidential supplier bids, primarily in Massachusetts, Connecticut, and Maryland, to which the project team or sponsors have been privy. Short-term procurements (for six months or a year into the future) may have smaller risk adders than longer-term procurements (upwards to about three years, which appears to be the limit of suppliers' willingness to offer fixed prices). Utilities that require suppliers to maintain higher credit levels will tend to see the resulting costs incorporated into the adders in supplier bids. Risk adders appear to be greater since the credit crunch in the fall of 2008 (which was also associated with increased uncertainty in prices and load levels), and may remain high for some time and then fall if credit and economic conditions return to levels more like 2007.

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[38]Capacity costs present a different risk profile than energy costs. With the advent of the Forward Capacity Market, suppliers will have a good estimate of the capacity price three years in advance and of the capacity requirement for any given set of customers about one year in advance. (Reconfiguration auctions may affect on the capacity charges, but the change in average costs is likely to be small.) On the other hand, since suppliers generally charge a dollars-per-MWh rate, and energy sales are subject to variation, the supplier retains some risk of under-recovery of capacity costs. There is no way to determine the extent to which an observed risk premium in bundled prices reflects adders on energy, capacity, ancillary services, RPSs, and other factors. Given the uncertainty and variability in the overall risk adder, we do not believe that differentiating between energy and capacity adders is warranted under this scope of work. We thus apply the retail adder uniformly to both energy and capacity values.

- In the absence of robust information on the retail adders implicit in the prices being bid for retail supply in New England we assume 9% as a default risk adder. The risk adder will be a separate input to the avoided-cost spreadsheet. Therefore, program administrators will be able to input whatever level of risk adder they feel best reflects their specific experience, circumstances, economic and financial conditions, or regulatory direction.
- The details of the risks and costs of serving load are somewhat different for Vermont, Public Service of New Hampshire (PSNH), and various municipal utilities, where vertically-integrated utilities procure power from owned resources and a variety of long- and short-term contracts. For Vermont, we will include the 11.1% risk adder mandated by the Vermont Public Service Board. For PSNH and the municipal utilities, program administrators should use a risk adder less than the 9% default.

2.5.4. Cost of Compliance with Renewable Portfolio Standards

Each New England state has adopted some form of renewable portfolio standard or renewable energy standard, referred to here generically as RPS; see Section 2.2.2.4. All states other than Vermont currently require LSEs to demonstrate compliance through the acquisition and retirement of NEPOOL Generation Information System certificates, commonly referred to as RECs. In this study, we assume LSEs will comply fully with established RPS targets each year. Some states have also implemented Alternative Portfolio Standards (such as the Massachusetts and Connecticut Class III standards), requiring that specific percentages of energy be provided by unconventional non-renewable resources. For ease of presentation, this discussion generally refers to all these requirements as RPS requirements, which must be met with RECs, even though some of the resources are not renewable.

Our estimate of avoided costs will include an estimate of the REC costs that reduction in load will enable an LSE to avoid. Reduction in load due to DSM will reduce the RPS requirement of the LSE and therefore reduce the cost they incur to comply with that requirements. That RPS compliance cost is equal to the price of renewable energy in excess of market prices, i.e., the REC price, multiplied by the portion of retail load that a supplier must meet from renewable energy under the RPS. In other words,

$$\text{Avoided RPS cost} = \text{REC price} \times \text{RPS percentage}$$

For example, in a year in which REC prices are at \$30/MWh (or 3¢/kWh) and the RPS percentage was 10%, the avoided RPS cost to a retail customer would be \$0.30 cents/kWh. We will calculate the RPS compliance costs that retail customers in each state avoid through reductions in their energy usage in each year for each major applicable RPS tier as follows:

$$(\text{REC Price}_n \times \text{RPS }\%_n)/(1-L)$$

where

n = the RPS tier

L = the load-weighted average loss rate from ISO wholesale load accounts to retail meters

We forecast annual REC prices for three major RPS tiers. These are new renewables (primarily Class I), all New Hampshire Class II solar, and all other renewables.

The major quantity of new renewables come from new-renewables RPS tiers. These are Class I in Massachusetts, Maine, Connecticut, and New Hampshire; the New RPS requirement in Rhode Island, and the Vermont RPS as assumed to be altered by 2012. For 2009 and 2010 we rely upon recent broker quotes. REC markets in New England suffer from a lack of depth, liquidity, and price visibility. Broker quotes for RECs represent the best visibility into the market's view of current spot prices. However, since REC markets are annual and actual transactions occur sporadically, the average annual price at which RECs transacted will not necessarily correspond to the average of broker quotes over time. Broker quotes for RECs may span several months with few changes and no actual transactions (being represented by offers to buy or sell), and at other times may represent a volume of actual transactions. As a result, care should be taken to filter such data for reasonableness. Exhibit 2-13 below provides the type of REC prices we will use to characterize the near-term REC market prices.[39] We may utilize a greater breadth and depth of data to estimate near-term REC prices for the purposes of this study.

[39]This table was developed from a representative sampling and averaging of quotes from a few REC brokers of either reported transactions consummated or bid-ask spreads in periods where transactions were not reported. Because some of the markets identified (MA Class II, NH Class III and IV) have just started trading, those numbers may not yet be representative.

Exhibit 2-13: Average REC and APS Prices 2008 and January–March 2009
(Dollars per MWh)

		2008	2009
Conn.	Class I	$23.44	$27.71
	Class II	$0.53	$1.18
	Class III	$19.18	N/A
Mass.	Class I	$26.76	$33.47
	Class II renewable	N/A	$1.75
	Class II waste-energy	*No public values available*	
	Class III	*No public values available*	
R.I.	New	$30.25	$34.50
	Existing	$1.00	$1.25
Maine	New	$30.25	$34.50
	Existing	$0.23	$0.24
N.H.	Class I	$35.50	$37.50
	Class III	$21.75	$22.00
	Class IV	$20.00	$26.00
Data from confidential REC brokers quotations compiled by Sustainable Energy Advantage, LLC			

Sustainable Energy Advantage, LLC (SEA) estimate REC prices for new renewables RPS Tiers in the longer-term (after 2012) based on their analysis of the cost of entry of new renewable energy resources. That analysis will utilize SEA's renewable energy supply curve model to determine the marginal (or market-clearing) resource in each year through 2020 based on the difference between a levelized cost for the marginal renewable resource and the resource's commodity market value based on our reference-case forecast of wholesale electric-energy-market prices.

We will forecast REC prices for the remaining two tiers as follows:

- For all New Hampshire Class II (solar) our estimate is the lesser of (1) the alternative compliance price and (2) the difference between a levelized cost of energy estimate for solar and our production-weighted reference-case forecast of wholesale electric-energy-market prices.
- For all other RPS tiers we will escalate recent broker-derived prices at inflation.

2.5.5. ***Reserve-Margin Multiplier***

The New England ISO acquires sufficient capacity to ensure reliability in each power-year. In the FCM, starting June 2010, the absolute cost of that capacity equals the required capacity, i.e. the ICR, times the FCA auction price. The percentage by which the ICR exceeds the projected system peak is the reserve margin. The ISO charges each LSE a pro-rata portion of those total capacity costs, based upon the actual contribution of the customers served by the LSE to the actual system summer peak.

Our estimate of avoided capacity costs reflects the ISO-NE capacity costs that load will avoid due to reduction in its peak demand from DSM. Roughly speaking, the avoided capacity cost will equal the reduction in peak load, grossed up by the reserve margin and multiplied by the FCA price. In other words

$$\text{avoided capacity cost (\$)} = \text{reduction in peak (kW)} \times (1+ \text{reserve margin}) \times \text{FCA price (\$/kW)}$$

The actual operation of the forward-capacity markets is a bit more complicated than this relationship. In capacity years 2010–11 and 2011–12, the ISO will pay program administrators the FCA price (prorated down in proportion to the oversupply in the auction at the floor price) for their average qualifying reductions during summer peak periods, plus the reserve margin; the LSEs serving the program participants will have lower allocation of capacity due to actual load reductions in the summer preceding the capacity year; and the total cost to regional load will benefit from reduction in ICR, to the extent that program load reductions are not bid into or selected in the FCA.

Starting in capacity year 2012–13, the ISO will pay program administrators the prorated FCA price only for their load reductions, without reserves. The reduction in reserves due to the higher reliability of energy-efficiency measures versus generation will reduce the ICR, benefiting the entire system load. LSEs serving the program participants will still have lower capacity allocations, and load reductions not receiving FCM credits will still reduce the total cost to the system load.

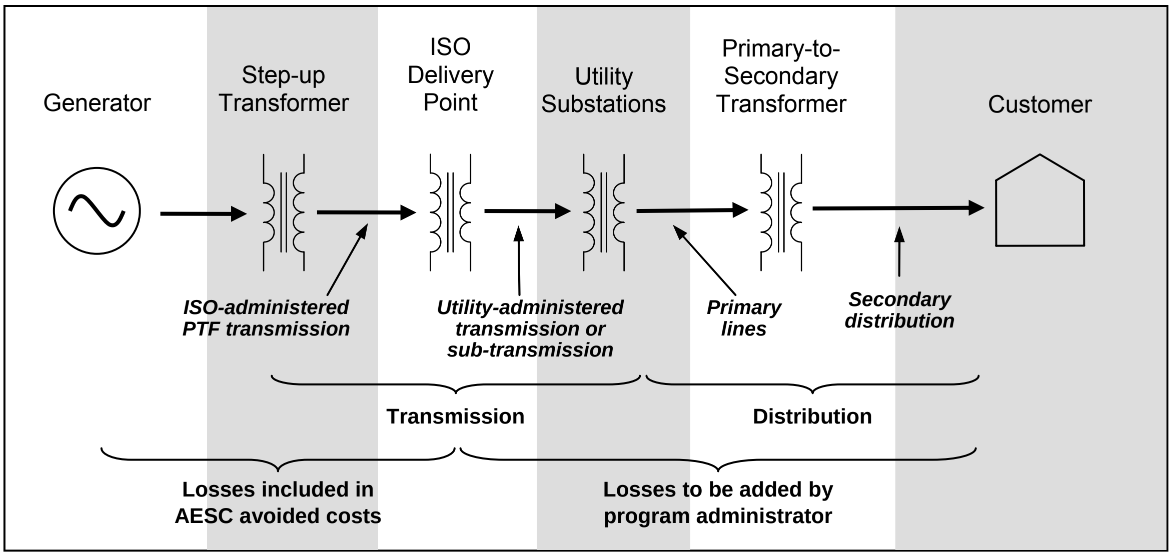
Through May 2013 participants may be rewarded twice for some load reductions: the program administrator can receive capacity credit for the load reduction cleared in the FCA, and the load-serving entity's capacity obligation is reduced by the load reduction. We understand that by September 1 2009 the ISO will file a recommendation with FERC regarding whether to eliminate this situation, by reconstituting load. This discussion has just started in the ISO committees, so the fate and form of reconstitution is not clear.

The assumptions regarding ISO-NE specified reserve margins that proposed for AESC 2009 are presented in Exhibit 6-3 (page 6-9).

2.5.6. *Transmission and Distribution Factors*

Exhibit 2-14 below is a simplified illustration of the structure of the electric system and the sources of the losses that occur between the generator and the ultimate retail customer.

Exhibit 2-14: Electric System Structure and Losses between Generator and Point of End Use



We develop estimates of wholesale avoided energy and capacity costs that reflect the losses on ISO-administered pool transmission facilities (PTF), i.e., between the generator and the delivery points at which the PTF system connects to local non-PTF transmission or to distribution substations. Our forecast of wholesale electric energy prices reflects an implicit estimate of PTF losses as simulated by the Market Analytics model. Our forecast of FCM capacity costs is adjusted for an explicit estimate of PTF losses. That estimate is developed by regressing system losses against real-time demand for the top 100 hours in the most-recent summer for which data is available since ISO-NE does not publish estimates of losses at system peak[40].

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40 Losses will be computed as the difference between ISO-reported values for System Load, which it defines as the sum of generation and net interchange, minus pumping load, and Non-PTF Demand, the term the ISO uses for load delivered into LDCs. (While PTF losses may vary by zones, we have not identified the data necessary to make such an estimate.)

The estimates of wholesale avoided energy and capacity costs do not reflect losses on the local distribution company, i.e. between the local non-PTF transmission or distribution facilities and the customer's meter. Those local-distribution-company (LDC) losses occur in the following locations:

- over the non-PTF transmission substations and lines to distribution substations;
- in the distribution substations;
- from the distribution substations to the line transformers on the primary feeders and laterals;[41]
- from the line transformers over the secondary lines and services to the customer meter;[42]
- from the customer meter to the end use.

This distinction is important because most DSM-program administrators measure the physical reduction in energy and demand resulting from their programs at the meter. In order to calculate certain categories or components of the avoided costs attributable to those reductions the program administrator will need to gross up those reductions at the meter by the losses on the LDC. For example, if the energy delivered to the utility at the PTF is "a," losses on the LDC are "b," and the energy delivered to the customer is "c,"

- losses as a fraction of deliveries to the LDC are b ÷ a
- losses as a fraction of deliveries to retail customers are b ÷ c.

The resulting *loss-adjustment ratio* required to gross-up the reduction in kilowatt or kilowatt-hour at the meter is $(1 + b/c)$. Program administrators will need to estimate the loss adjustment ratios for each of the specific LDCs on which they offer DSM programs.

See Chapter 6 for a summary of methods used by each utility to value transmission-and-distribution capacity.

[41]In some cases, this may involve multiple stages of transformers and distribution, as (for example) power is transformed from 115-kV transmission to 34-kV primary distribution and then to 14-kV primary distribution and then to 4-kV primary distribution, to which the line transformer is connected.

[42]Some customers receive their power from the utility at primary voltage. Since virtually all electricity is used at secondary voltages, these customers generally have line transformers on the customer side of the meter and secondary distribution within the customer facility.

2.5.7. Adjustment of Capacity Costs for Losses on ISO-Administered Pool Transmission Facilities

There is a loss of electricity between the generating unit and the ISO's delivery points, where power is delivered from the ISO-administered pool transmission facilities (PTF) to the distribution utility local transmission and distribution systems. Therefore, a 1 kilowatt load reduction at the ISO's delivery points, as a result of DSM on a given distribution network, reduces the quantity of electricity that a generator has to produce by 1 kilowatt plus the additional quantity it would have had to generate to compensate for losses.[43] The energy prices forecast by the Market Analytics model reflect these losses. However, the forecast of capacity costs from the FCM do not. Therefore, the forecast capacity costs should be adjusted for theses losses.

The ISO does not appear to publish estimates of the losses on the ISO-administered transmission system at system peak. We estimated the marginal peak losses on the PFT system for each summer 2006–2008 by regressing the system losses against real-time demand for the top 100 summer hours. We computed losses as the difference between ISO-reported values for System Load, which it defines as the sum of generation and net interchange, minus pumping load, and Non-PTF Demand, the term that the ISO uses for the load delivered into the networks of distribution utilities. While PTF losses probably vary among zones, marginal losses by zone could not be identified using the available data.

While there was a large scatter in the data (probably due to plant availability, import availability, and the changing geographical mix of load), there was a clear upward trend in losses with load as shown in Exhibit 2-15 below.

[43] Computations of avoided costs sometimes assume that only average, and not marginal, losses are relevant at the peak hour. The reasoning for that approach is that changes in peak load will lead to changes in transmission and distribution investment, keeping average percentage losses approximately equal. The AESC 2007 avoided costs do not include any avoided PTF investments, so marginal losses are relevant in this situation.

Exhibit 2-15: PTF Losses vs. Non-PTF Demand for the Top 100 Summer Hours, 2006

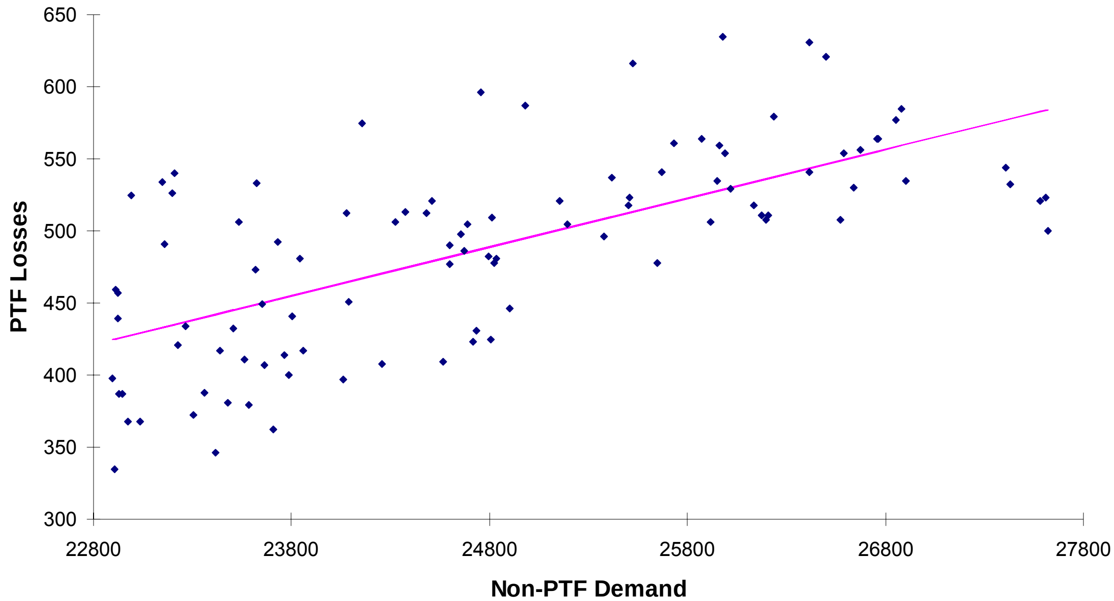
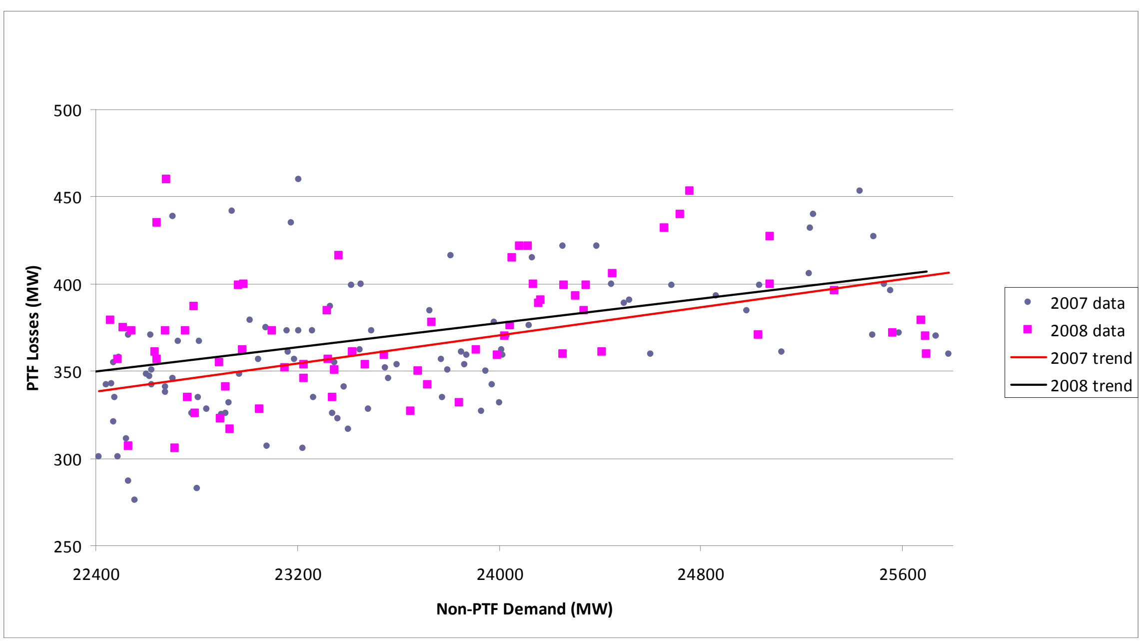


Exhibit 2-16: PTF Losses vs. Non-PTF Demand for the Top 100 Summer Hours, 2007 and 2008



The regression equations (with all variables in MW) were

2006: PTF Losses = 0.0338 × Non-PTF Demand–350.

2007: PTF Losses = 0.0201 × Non-PTF Demand–112

2008: PTF Losses = 0.0177 × Non-PTF Demand–57

The marginal demand loss coefficients were all highly significant, with t-statistics over 5.9.

It is not clear whether the downward shift over time of the data represent permanent changes in the transmission system, load and/or generation dispatch or temporary fluctuations in regional loads and/or dispatch due to weather patterns and the varying ratios of fuel prices.

AESC 2009 estimates the costs of avoiding capacity purchased from each FCA to be the FCA price adjusted by the estimated marginal demand loss factor of 1.9%. That factor is an average of the results for 2007 and 2008.

2.5.8. Demand Reduction Induced Price Effects–Methodology and Assumptions

We estimate the effect of reductions in energy demand and energy from DSM programs on wholesale market prices for energy and capacity.

2.5.8.1. Wholesale Energy Market Effects

We intend to estimate the magnitude of wholesale energy market DRIPE by year in two ways. First, we extract from the Market Analytics model consistent estimates of the market-price reductions resulting in small reductions in load. Second, we conduct a set of regressions of historical zonal hourly market prices against zonal and regional load, like that of AESC 2007.

After estimating the magnitude of energy DRIPE, we estimate its duration. We estimate the phase-out of energy DRIPE based upon the assumption that the effect of reductions from efficiency programs on energy market prices will not last indefinitely. Instead, over time, the market will respond to sustained lower loads, for example by retiring existing generating capacity.[44] While the shutdown of peaking units (gas turbines and older steam units) has little effect on market energy prices, the shutdown of coal plants or the delay in construction of new renewable or combined-cycle plants may have larger effects. We develop a phase-out of DRIPE effects consistent with the load-related retirements above in Section 2.2.2.

Finally, in order to develop the energy DRIPE to be used in avoided costs we phase in its impact based upon the portion of retail electricity power that reflects wholesale market prices at any point in time. This adjustment is required because the actual percentage of electricity supply being acquired at prices reflecting

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[44]Simple delisting of generators in the forward-capacity markets, such as to permit exports, does not directly change their operation in the energy markets.

current wholesale market prices varies among the states, among the utilities within some states, between municipal utilities and independently owned utilities (IOUs), and between customers on standard utility offer (standard service, default service, last-resort service, etc.) and those served by competitive suppliers. We also make adjustments for the quantity of energy supply effectively under contract to consumers at fixed prices including (1) pre-restructuring independent power producer (IPP) contracts, (2) Connecticut contracts with Kleen, the Project 150 capacity, and any long-term contracts acquired in respond to pending RFPs before the end of this project, (3) resources committed to the Vermont utilities and PSNH, which have not divested their generation, (4) Vermont Yankee contracts as well as standard-offer, and (5) competitive supply.

2.5.8.2. Wholesale Capacity Market Effects

We estimate the magnitude of wholesale-capacity-market DRIPE from May 2012 onward. Any post-2008 efficiency programs will not affect FCM prices prior to that time. As noted earlier, ISO-NE has set FCM prices in FCA 1 and FCA 2 through May 2012.

For the period after May 2013, we estimate capacity DRIPE using our estimates of capacity price in each FCA as a function of ISO requirements. From May 2012 onward we assume that ISO-NE will no longer set FCM floor prices. From that point onward, FCM prices will be determined by the prices at which generators choose to delist. (By delisting, generators in New England are able to sell into another market such as New York, or to shut down.) We use the model described in above in Section 2.4.

2.5.9. Carbon-Mitigation Value.

Our approach to quantifying the reduction in physical emissions due to energy efficiency will be as follows:

- Identify the marginal unit in each hour in each transmission area from our energy model;
- Draw the heat rates, fuel sources, and emission rates for NO_x, SO_x, CO_2, and mercury of those marginal units from the database of input assumptions used in our Market Analytics simulation;
- Calculate the physical environmental benefits from energy efficiency and demand reductions by calculating the emissions of each of those marginal units in terms of lbs/MWh and lbs/kW. We will multiply the quantity of fuel each marginal unit burned by the corresponding emission rate for each pollutant for that type of unit and fuel.

Our recommended dollar values to use for relevant avoided pollutant emissions are summarized in Exhibit 2-4. We distinguish between avoided values already embedded in the avoided energy and capacity-market costs and externalities.

For externalities, AESC 2007 identified CO_2 as the key significant non-internalized environmental cost for evaluation of energy-efficiency programs. Other air pollutants from generators (NO_x, SO_2, particulates, mercury) have been and are being significantly reduced through direct regulation, and NO_x and SO_2 are subject to cap-and-trade regulations that charge generators for their remaining emissions. Other environmental effects, such as water discharges, are not clearly related to energy usage.

Since 2007, regulation of non-CO_2 pollutants has become more stringent, so we continue to limit consideration of non-internalized environmental costs to CO_2 emissions.

AESC 2007 proposed a “sustainability-target” approach to monetize these cost associated with carbon-dioxide emissions based on a review of various approaches to monetize carbon-dioxide-emission societal costs or *mitigation value.*[45] We also support a “long-term marginal abatement cost” approach for expressing the aggregate value of CO_2 reductions in dollar terms. For this work we review studies published subsequent to July 2007 that address global CO_2 costs (damages and mitigation) and revise the AESC 2007 analysis to reflect the more-recent information as necessary and appropriate. In other words, the numbers may change relative to AESC 2007, but our general methodology is the same.

[45] *2007 AESC Report* dated August 10, 2007. page 7-12.

Chapter 3: Wholesale Natural Gas Prices

This Chapter provides a projection of wholesale natural gas prices, in constant 2009$, for the New England region and each state for the forecast horizon of 2009 through 2039. It also provides a forecast of natural gas prices for electric generation. The forecast of wholesale prices is an input to the forecast of sector specific natural gas prices presented in Chapter 4.

3.1. Overview of New England Gas Market

In order to place our forecast of wholesale natural gas prices for New England, and the method we used to develop this forecast, into context we begin with an overview of the demand for gas in New England, the physical supply of gas to the region and the "product" which is being purchased at wholesale commodity prices.

3.1.1. Demand for Wholesale Gas in New England

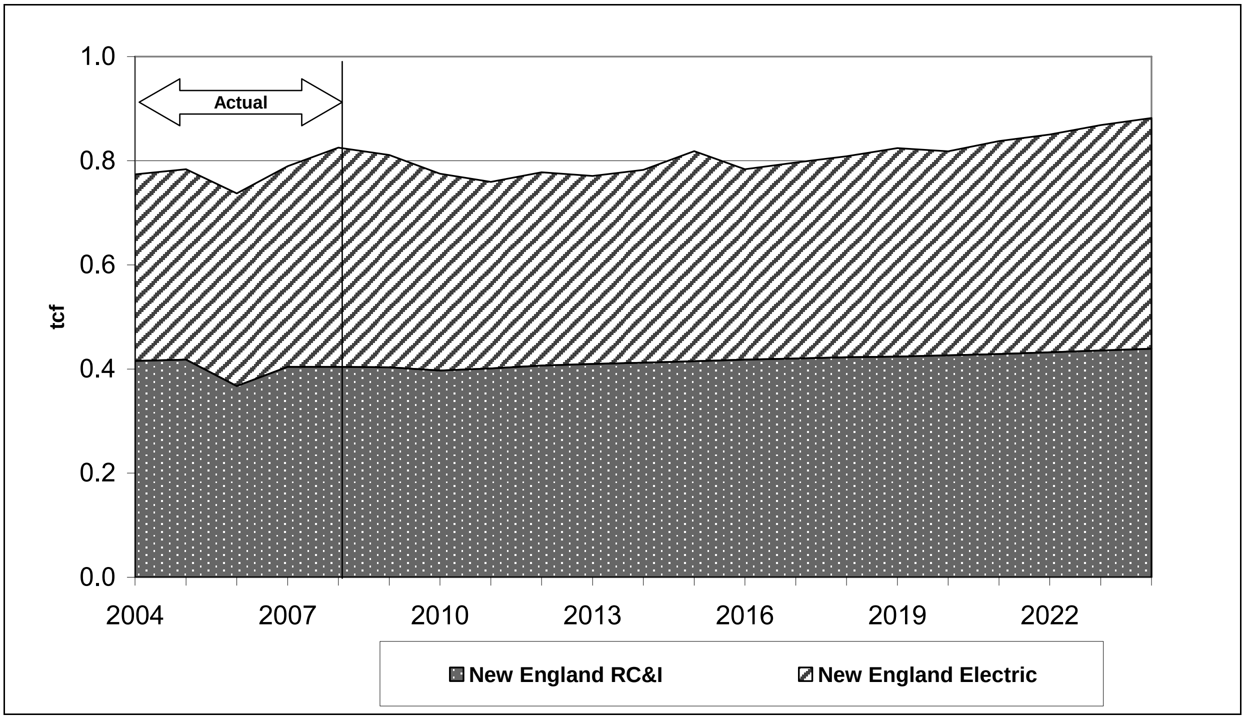
Natural gas accounts for approximately 23 percent of New England energy consumption, the same fraction of total energy consumption as for the United States as a whole. The market for wholesale gas in New England can be grouped into two distinct categories. The first is gas purchased for direct use by, or on behalf of, very large end-users in the electric-generation, industrial, commercial, and institutional sectors. The second category is gas purchased by local distribution companies (LDCs) for re-sale to retail customers in the residential, commercial, and industrial sector.

The annual quantity of gas purchased for direct use by very large end users, primarily for electric generation, has increased dramatically since the 1990s. That demand today accounts for roughly half of the annual gas consumption in New England. In its 2009 Reference Case, the EIA (2009a, 109–150) forecast annual gas use for electric generation to grow at about 0.3% per year between 2008 and 2024.

The annual quantity of gas purchased by LDCs for resale to residential, commercial and industrial customers has remained relatively stable since the 1990s. In the Reference Case, annual gas use in this category is forecast to grow at about 0.5% per year between 2008 and 2024.

Actual and projected levels of annual gas use in these two categories are presented in Exhibit 3-1 below. (The projections are drawn from the EIA's (2009a) Reference Case.)

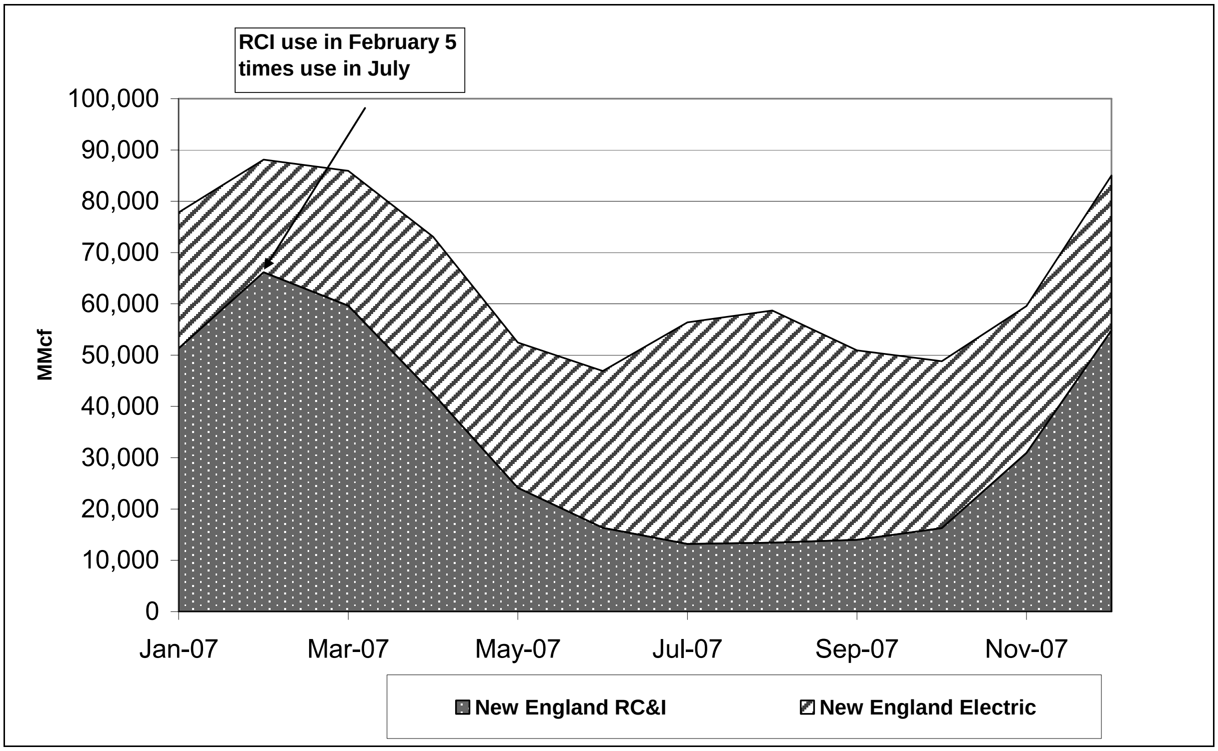
Exhibit 3-1: Annual Gas Use in New England (Tcf) Actual with EIA 2009 Projections



The demand for wholesale gas in New England in these two categories also varies substantially by season, and from month by month within each season.

The quantity of gas for direct use varies by month, with the greatest use occurring in summer months. In contrast, the greatest gas use by retail customers occurs in winter months since the dominant end-use is heating. As a result LDCs have a much greater seasonal *swing* in gas load during the course of a year. For example, an LDC's gas load in January or February can be five times its load in July or August. Because of these large swings in gas load, LDCs acquire a portion of their winter requirements during the summer, have it stored in underground facilities outside of New England, and withdraw it during the winter. In addition, LDCs use liquefied natural gas (LNG) and propane stored in New England to meet a portion of their peak requirements on the coldest days of the winter.

Exhibit 3-2: Monthly Gas Use in New England in 2007



The variation in gas use by month in New England in 2007 is illustrated in Exhibit 3-2.

3.1.2. Supply of Wholesale Gas in New England

The natural gas used in New England is acquired from producing regions elsewhere and delivered to the region via pipeline or by ship as LNG. Adequate delivery capacity from producing areas to New England is essential to the firm supply of natural gas to the region.

Most of the gas consumed in New England comes from the supply areas of Appalachia and the Southwest. Additional supplies of gas come from western Canada and from Nova Scotia. LNG is obtained from Trinidad and Tobago, Nigeria, Algeria, and other LNG exporting countries.

The physical system through which gas is delivered to New England, and within the region, excluding Vermont, currently comprises six interstate and intrastate pipelines and two LNG facilities.

Pipelines deliver gas directly to a number of electric generating units and very large customers, as well as indirectly through deliveries to LDCs who in turn distribute that gas to retail customers. Two pipelines deliver the majority of gas to New England, Tennessee Gas Pipeline and Algonquin Gas Pipeline. Tennessee delivers primarily into Massachusetts, New Hampshire and Maine while

Algonquin delivers primarily into Connecticut and Rhode Island. (Consistent with prior AESC reports this report refers to Massachusetts, New Hampshire and Maine as Northern and Central New England and to Connecticut and Rhode Island as Southern New England.) Also, the Maritimes & Northeast and Portland Natural Gas pipelines deliver into Maine, Massachusetts, and New Hampshire. Those pipelines ultimately deliver into the Tennessee Gas system at the interconnection in Dracut, Massachusetts and into Algonquin via the Hubline project from Beverly to Weymouth, Massachusetts. Iroquois delivers into Connecticut while Granite State Pipeline delivers gas in New Hampshire and Maine.

The two LNG facilities are Distrigas in Everett, Massachusetts and the Northeast Gateway facility offshore Cape Ann, Massachusetts. The Distrigas facility delivers gas into Algonquin, the National Grid (formerly KeySpan) system, the Mystic Electric Generating Station, and sends LNG by truck to LDC storage tanks throughout the region. The Northeast Gateway facility delivers gas into Algonquin.

The one LDC serving northern Vermont receives its gas from TransCanada Pipelines at Highgate Springs on the border with Canada.

A more extensive discussion of the New England gas industry and gas supply is published by the Northeast Gas Association (2009).

3.1.3. Prices for Purchases of Wholesale Commodity Supply in New England

The AESC 2009 forecast of commodity prices for wholesale supply in each New England state, and in the region in general, are for a monthly supply of gas expressed in dollars per million Btu. These are prices for one of the major "products" that is bought and sold in the wholesale market in New England, i.e., a one month supply of gas for delivery at one of the region's market hubs.[46] Another major product in the wholesale market is a one day supply of gas for delivery at a market hub. The prices for these monthly and daily products are published in various gas industry publications.

The first and largest component of the forecast price for this product is a forecast of the monthly commodity price at the Henry Hub, which is located in Louisiana and is the most liquid trading hub in North America, as described in more detail below. The second component is an estimate of the *basis differential* between the wholesale price of gas at the Henry Hub and the wholesale price of gas at the relevant market hub in New England

[46]The major market hubs in New England are Tennessee Gas Pipeline Zone 6, Algonquin Gas Pipeline City Gate, and Dracut.

Thus, the forecast of wholesale natural-gas prices in New England in each month are estimates of the market value of a spot supply of gas at that location in that month. As such the wholesale commodity price in a given month does not necessarily reflect the actual long-term fixed costs that a seller would incur to ensure firm delivery of gas to New England every month of the year over a long-term planning horizon.

This forecast will be a key input to the forecast of regional electric-energy-supply prices. Gas-fired plants base their daily bids into the wholesale electric energy market on the corresponding market value or opportunity cost of a one day supply of natural gas in New England for that day. Our forecast of wholesale gas prices by month is a reasonable proxy for those daily prices over time. On the other hand, the forecast on monthly wholesale prices in New England will not be a key input to the forecast of retail natural-gas prices for residential, commercial and industrial customers. As noted earlier, applicable retail customers acquire their supply from local distribution companies (LDCs) who, in turn, acquire little if any of their annual supply through purchases of spot gas at New England market hubs. Instead, LDCs purchase gas from major producing areas at prices tied to the Henry Hub price and assure firm delivery of that gas to their city-gate receipt points through long-term contracts for firm pipeline transportation service and underground storage service. [47] Some LDCs also acquire supply from local LNG facilities.

3.2. Forecast Henry Hub prices

3.2.1. Henry Hub as a Starting Point

The forecast of wholesale commodity prices of gas in New England begins with a forecast of the price of gas at the Henry Hub. These prices are the most relevant starting point for forecasting US gas supply costs for several reasons.

First, the Henry Hub is located in the U.S. Gulf Coast area, which is the dominant producing region of the United States; EIA (2009a) projects that production from the "Lower 48" will be the dominant source of physical gas supply to U.S. markets over the AESC 2009 study period. Production from the lower 48 states in 2007 was about 83% of US supply (see Exhibit 3-3). The remaining supply came from imports via pipeline, primarily from Canada, and by ship as LNG. EIA (2009a) projects U.S. production to increase to approximately 91% of total national supply by 2020 due primarily to forecast increased production from unconventional gas sources, i.e., shale gas, tight-sand gas and coal-bed methane. Of those three, EIA (2009a, 77) expects shale gas to be the most rapidly growing portion of U.S. gas supply. EIA (2009a, 78) projects a decline in pipeline imports from Canada, due to

[47] A city-gate is a point at which a pipeline delivers gas into the system of an LDC.

increases in Canadian consumption relative to Canadian supply and a doubling of imports of LNG.

Exhibit 3-3 Sources of US Natural-gas Supply 2005 and 2020 (Trillion cf)

Sources of Supply	2007 (Actual)	2020 (Reference Case forecast)
US Production	19.30	21.42
Imports via Pipeline	3.06	0.48
Imports via LNG	0.73	1.38
Total	23.15	23.34

Source: EIA (2009a, 135 (Table A13)).

Totals include other sources not detailed in the table, such as supplemental gas supplies, propane-air, and substitute natural gas.

Second, the market for wholesale natural gas is essentially a North American natural-gas market. The Henry Hub is the most liquid trading hub with the longest history of public trading NYMEX. The wholesale market prices of gas in various regions of the United States and Canada reflect Henry Hub prices with an adjustment for their location—generally referred to as a basis differential. A basis differential is the difference between the wholesale natural-gas price at a given market hub and the corresponding gas price at the Henry Hub.

Note that prices at the Henry Hub are different from and somewhat higher than the average U.S. wellhead price. For example EIA (2009a 109–150), in its Reference Case, forecasts that, on average for the period 2009 through 2030, the annual Henry Hub price will be $0.92/MMbtu more (in 2009 dollars) than the annual average U.S. wellhead natural-gas price. For AESC 2009 we assume the gap between the average national wellhead price and the Henry Hub price for new wells from unconventional production will be $1.00 per MMBtu.

3.2.2. Review of EIA 2009 Cases and Forecasts of Annual Henry Hub Prices

The first step in developing a forecast of annual Henry Hub natural-gas prices was to review the forecasts in EIA (2009a).[48] This is an appropriate starting point for several reasons. First, the inputs and algorithms are public, transparent and incorporate the long-term feedback mechanisms of energy prices upon supply, demand, and competition among fuels. Second, EIA (2009a) and prior EIA forecasts are standard and widely used.

[48][48]EIA (2009) prices are expressed in 2007 dollars. Except as noted, those prices are converted into 2009 dollars in this report using the indexes and conversion factors specified as major assumptions.

For AESC 2009 we rely on the EIA's 2009 Reference Case (EIA 2009a, 109–150). EIA considers its Reference Case to be the most likely or probable of 39 different forecast cases or scenarios. The various cases reflect different values for various key input assumptions (EIA 2009a, Appendix E, especially 203–205). The project team did examine the various other cases, particularly the "LW110" case which includes the greenhouse gas emissions policy proposed in the 110th Congress by Senators Lieberman and Warner. While we believe that national greenhouse-gas policy is likely to be enacted in the next few years, we do not recommend relying on the LW110 case for AESC 2009. Our recommendation is based upon the facts that the EIA describes this case as "illustrative," that it does not provide the underlying detailed annual data for the case, and that it reflects several assumptions we consider to be questionable.

In AESC 2007 we adjusted the EIA (2007) Reference Case forecast of Henry Hub prices based upon our examination of the EIA estimates of gas exploration-and-development costs underlying those forecasts. For AESC 2009, after preparing a similar examination, we conclude that the 2009 Reference Case forecast of Henry Hub gas prices appear reasonable. The key points of our analysis are summarized below.

First, EIA (2009a) projects less total energy consumption, almost 11% less by 2020. The lower projection of energy use between the two is due in part to somewhat slower economic growth in EIA (2009a), 2.5% per year from 2007 to 2030 versus 2.9% per year assumed in EIA (2007), and in part to assumed increases in efficiency of energy use. [49] Part of the greater efficiency of energy use is due to projected higher prices for fuels in the 2009 forecast compared to the 2007 forecast and part due to projected increases in government policies that promote energy efficiency (EIA 2009a, 5).

Second, the 2009 Reference Case assumes a modest effect to control carbon dioxide emissions, equivalent to $15 per metric ton fee for CO_2 emissions (EIA 2009a, 50) and increased incentives for renewable energy production. These assumptions, combined with less economic growth and more efficiency, result in a substantially reduced projected quantity of natural-gas use for electricity production in 2009 compared with 2007, (about 10% less—see Exhibit 3-4).

[49] Part of the slower U.S. economic growth reflects the current downturn.

Exhibit 3-4: Comparison of EIA Annual Energy Outlooks

	Actual 2007	Forecast for Year 2020 EIA (2007)	Changes '07 to '09	EIA (2009a)	EIA (2009b)
Supply of Natural Gas (Tcf/year)					
U.S. Dry Gas Production	$19.30	$20.79	3.0%	$21.42	$19.58
Net Imports of Natural Gas					
Pipeline	3.06	1.65	-71.0%	0.48	0.47
LNG	0.73	3.69	-62.5%	1.38	1.38
Total	23.15	26.21	-10.9%	23.34	21.50
Consumption of Natural Gas (Tcf/year)					
Total	23.05	26.26	-10.8%	23.43	21.53
In Electric Power Generation[a]	6.87	7.19	-9.0%	6.54	5.22
Total U.S. Energy Consumption (Quads/year)	101.9	118.2	-10.8%	105.4	104.7
Prices of Energy (2009 Dollars)					
Natural Gas at the Henry Hub $/MMBtu	7.25	6.28	23.3%	7.74	7.79
$/bbl	75.37	57.51	109.2%	120.30	121.69
Net Generation of Electricity by Fuel Type (Billion kWh)[b]					
Total	4,159	5,037	-8.3%	4,618	4,573
Nuclear Power	806	885	-2.7%	862	876
Coal	2,021	2,489	-13.4%	2,156	2,198
Natural Gas	892	1,059	-15.2%	898	714
Renewables, Including Hydro	352	492	25.5%	617	708
Macroeconomic Indicators					
Real Gross Domestic Product (Billions of 2000 Dollars)	11,524	17,077	-9.1%	15,524	15,398
Total Energy Intensity MMBtu per 2000 Dollar	8.84	6.92	-1.9%	6.79	6.80
GDP, chain-type, Price Index (2000 = 1.000)	1.198	1.495	3.5%	1.548	1.521
Employment, nonfarm (Millions)	137.2	154.6	-1.3%	152.6	150.9
AA Utility Bond Rate (Nominal)	5.94%	7.72%	-3.0%	7.49%	7.95%

Prices are 2009 dollars, except for macroeconomic indicators, which are as noted.

[a]Includes gas consumption in plants that sell to the public but not the end-use that generates heat and electricity.

[b]Includes generation in utilities, plants producing heat and power for sale, and end-use production of heat and power.

Third, the 2009 forecast of Henry Hub prices are based upon substantially different underlying assumptions than the corresponding 2007 forecast. The forecast Henry Hub natural-gas prices in 2009 are much higher than the price forecast in 2007 and also higher than the prices forecast in AESC 2007; see Exhibit 3-5. [50]

The EIA (2009a) forecasts are based on laws and regulations in effect as of November 2008 and upon economic projections provided in November 2008. Because of the enactment in February 2009 of the American Recovery and Reinvestment Act and the rapid change in the macroeconomic outlook since the fall of 2008, the EIA issued an Updated Annual Energy Outlook 2009 (EIA 2009b) in April 2009. This revision incorporates into the 2009 Reference Case the provisions of the new law, which include significant stimulants for investments in energy efficiency and renewable energy and a revised macroeconomic outlook, especially the deepness of the current recession.

Exhibit 3-4 contrasts the EIA (2009a) Reference Case with the revision. EIA (2009b) projects annual gas use to be approximately 20%, or 1.9 Tcf/year, less in 2020 relative to EIA (2009a). The projection of less natural gas use results from the EIA's (2009b) projections of greater energy efficiency and renewable energy displacing gas use for electricity generation, and to some extent for direct use. EIA (2009b) projects annual Henry Hub natural-gas prices in 2020 to be essentially the same as those projected in EIA (2009a). However, prior to 2020 EIA (2009 b) projects lower Henry Hub prices than in EIA (2009a), reflecting its lower projected demand for gas.

However, we believe that it is appropriate to continue to base the AESC 2009 Henry Hub gas prices forecast upon EIA (2009a), the original 2009 reference-case gas-price forecast rather than the revision for the following two reasons:

- The revised 2009 forecast includes the effect of significant efficiency measures. Yet EIA's (2009a) estimate of avoided gas costs is intended to provide a measure of the impact of these same efficiency measures. It seems that the proper avoided cost calculation should be based on price and cost estimates before the efficiency measures are implemented; otherwise the avoided cost is underestimated.
- The macroeconomic assumptions underlying the revised 2009 forecast are about the same as reported *Blue Chip Economic Indicators* (May 2009, 10). However, EIA (2009a) relied on the futures market to forecast gas prices for 2009 through 2011. As described below, those futures-market prices reflect recent facts and views on the current state and path of the U.S. economy.

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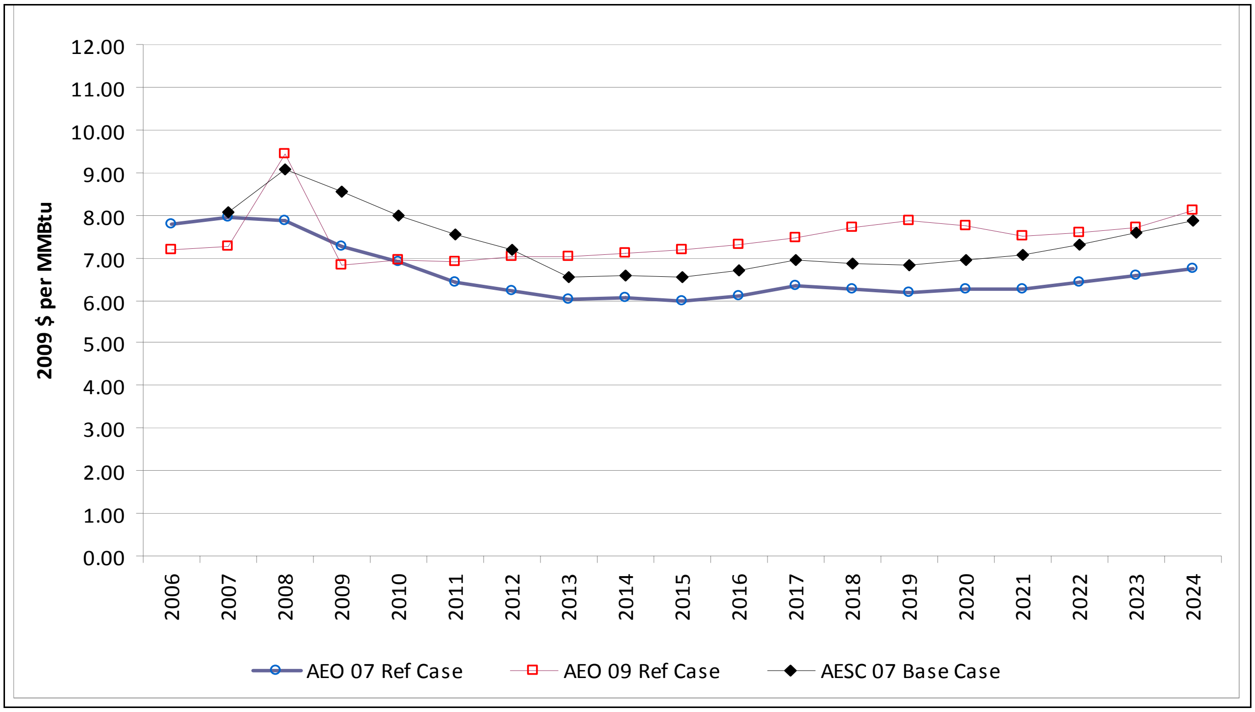
[50]The short decline beginning in 2020 reflects an assumption that natural gas will start arriving in the lower 48 from a new pipeline from Alaska (EIA 2009a, 78).

Consequently, we do not need to adjust further for the changed macroeconomic view from November 2008 to March 2009.

Exhibit 3-5: Comparison of Henry Hub Natural-Gas Prices



The projections by EIA (2009a) of greater U.S. gas production and less gas consumption, especially in electricity generation, compared with EIA (2007) ordinarily would lead one to expect lower gas prices in 2009 due to more supply and less demand. However, our analysis indicates that the higher prices forecast in the 2009 Reference Case are reasonable. These higher prices are primarily due to the 2009 projection of significant gas production from unconventional sources, i.e. tight sand gas and shale gas. While gas from tight sands is now, and is projected to remain the largest source of unconventional production, shale gas production is projected to grow most rapidly. The projected production prices in 2009 reflect the *full cycle* cost of producing gas from these unconventional resources, as discussed in detail below.

The full-cycle cost of gas, expressed in dollars per MMBtu, is an estimate of all the costs a company would incur to find and produce gas from this resource, over the life of the resource. These include all capital costs of finding, drilling, and well completion and capping; all production costs including overhead; all taxes on production, property, and income; all royalty payments; and the internal rate of return the company seeks in order to justify its investment. Thus, the full-cycle cost of gas is a good indicator of the long-run price of gas supply, since companies will only invest in shale gas if they expect to receive a price that will more than cover their full-cycle costs. Several analyses of the full-cycle costs of shale gas are summarized in Exhibit 3-7.

3.2.3. Projected Costs of Finding and Producing Natural Gas in North America, Particularly Shale Gas

The major change in the U.S. natural-gas industry since 2007 has been the change in outlook for production of natural gas from shale. Shale gas, considered a promising gas-supply source in 2007, is now viewed as a major source of gas supply to North America for many years into the future. This revised expectation is based upon the substantial growth in U.S. shale gas production during 2008. However, as EIA (2009a, 76) notes, production of shale gas requires "relatively high capital expenditures." There are also two ways that the EIA has increased its estimates of the costs of finding and producing gas from other sources relative to the EIA (2007) estimates that AESC 2007 criticized. These projected higher costs of finding and producing natural gas, especially shale gas, explain the higher prices projected for natural gas in EIA (2009a) depicted in Exhibit 3-5.

The following key changes since 2007 explain the higher gas prices in 2009.

- EIA (2009a) projects shale gas will account for a larger portion of U.S. supply, with more than double the estimated resources as 267 Tcf compared with 126 Tcf in EIA (2007).
- The starting point for natural-gas-finding and -production costs is revised to a more recent time and thus is costlier than in 2007.
- EIA (2009a) projects a slower pace of productivity improvement in drilling, expressed as annual reductions in drilling costs, than EIA (2007). This is shown in Exhibit 3-6, with drilling costs now expected to decline by 0.25% per year as compared to 0.89% per year in 2007.[51]

See Exhibit 3-6.

[51] In contrast, 2007 the Synapse team argued that the EIA (2007) forecast assumed technological progress in cost reduction and success in finding gas that dramatically exceeded the experience of the recent past (AESC 2007, 2-5). By assuming slower technological change, the AESC 2007 Henry Hub gas price forecast was greater than EIA's (2007) Reference Case forecast; see Exhibit 3-5.

Exhibit 3-6 Selected Assumptions in the EIA Annual Energy Outlook 2009 and 2007 Reference Cases

	EIA (2009a)	EIA (2007)
Real Gross Domestic Product Growth (Annual)	2.5%	2.9%
Inflation Rate CPI (Annual)	2.1%	2.0%
Natural Gas		
Technically Recoverable Gas Resources (Tcf)	1,747	1,341
Offshore	260	164
Unconventional Gas	645	478
Shale Gas	267	126
Technological Progress		
Drilling Costs (Annual)	0.25%	0.89%
Lease Equipment Costs (Annual)	0.40%	0.58%
Operating Costs (Annual)	0.20%	0.38%

The EIA (2009a) and other observers of the North American natural-gas markets expect shale gas to be the most rapidly growing source of gas supply in North America. They also expected shale to be a large gas resource. The 267 Tcf of resource anticipated by EIA (2009a) is small compared to the estimate of Chesapeake Energy Corporation's CEO, Aubrey McClendon (2009, 6), of 1,150 Tcf from just the four large U.S. shale plays: Barnett in Texas, Fayetteville in Arkansas, Haynesville in Louisiana, and Marcellus in New York, Pennsylvania and West Virginia.

Because those shale plays are known, large, and relatively expensive to develop, we expect they will be the marginal source of natural gas in North America and, thus, will tend to set the market price in the North American gas supply market. Therefore, estimates of the full-cycle cost of gas from these plays provide an important insight into the long-run average price of natural-gas supply in North America.

Exhibit 3-7 Full-Cycle Cost of Finding and Producing Natural Gas from U.S. Lower-48 Shales

	Full-Cycle Production Cost	Required Henry Hub Price
Full-Cost Accounting Impairment Prices ($/MMBtu)		
Devon Energy Corp.[a]	$4.68	$5.71[b]
Chesapeake Energy Corp.[c]		$5.71[b]
Estimated no-impairment price[d]		$6.85
Cost Analysis[f]		
INGAA/ICF ($/MMBtu)[g]		
2007 Shale Gas	$5.00	$6.00
2007 Tight Sands	$5.90	$6.90
CERA ($/Mcf)[h]		
2009	$4.63	$5.63
2018	$7.54	$8.54

[a]Devon Energy Corporation, 2008 SEC Form 10-K, 46.

[b]December 31 2008 actual price

[c]Chesapeake Energy Corporation, 2008 SEC Form 10-K, 24.

[d] About 20% of property cost was impaired, suggesting that the no impairment price is about 120% of $5.71 per MMBtu, or $6.85.

[f] Henry Hub price is estimated by adding $1.00 per MMBtu (or Mcf) to the wellhead price, which represents the costs of gathering and processing to bring pipeline-quality gas to a transmission pipeline and then transportation to the Henry Hub on average.

[g]Vidas and Hugman (2008).

[h]Cambridge Energy Research Associates study as quoted in Davis (2009, 18–19).

The first two estimates are from the 2008 SEC Form 10-Ks filed by Devon Energy and Chesapeake Energy respectively. They are two of the largest shale gas producers in the U.S. These two companies use full-cost accounting to capitalize their costs of finding, developing, and equipping their oil and gas properties, and are therefore required by the U.S. Securities and Exchange Commission every quarter to test whether or not their capitalization of these properties is too high. A ceiling value is established by computing at the end of each quarter a net present value of producing gas from the properties in the future including the costs of this production and taxes. This net present value is computed based on the gas price and various costs at the end of the quarter and using a 10% per year discount rate.[52] If the capitalized property exceeds the ceiling value, the company must write down the capitalized value to the ceiling amount.

[52]The SEC has recently implemented some changes in this ceiling test.

Both Devon and Chesapeake had multi-billion dollar write-downs at the end of 2008, when the Henry Hub price was $5.71 per MMBtu, as shown in Exhibit 3-7. Each company wrote off about 20% of its capitalized cost. This indicates that $5.71 per MMBtu at the Henry Hub was too low to provide a 10% per year internal rate of return (IRR), before income taxes, to these companies for the average cost of the producing gas properties. Using that information one can estimate the Henry Hub price at which the companies would not have had to write down 20% as $5.71/MMBtu multiplied by 120%, or $6.85/MMBtu. This is an estimate of the market price that would justify the average cost of the reserves with a before tax IRR of 10%. Moreover, a before-tax IRR of 10% is low for the oil-and-gas industry. For example EnCana, one of the larger North American gas producers, has a target IRR of 20% or more for its development program and looks to a risked IRR of 9%, presumably after tax, to set a *ceiling* on its supply cost (Eresman 2009, 6). This analysis suggests that a price above $7.00 per MMBtu (2009 dollars) in the long-term will be needed to attract continued major investments in finding and producing unconventional gas resources such as shale gas. This conclusion is supported by a statement made by Mr. Aubrey McClendon, the CEO of Chesapeake Energy Corporation, that a shale-gas producer in the U.S. cannot make money at a production price less than $7–8/MMbtu Davis (2009, 19).

The following other analyses of the full-cycle cost of new gas supplies and of unconventional gas supply support this conclusion.

- Vidas and Hugman (2008) calculated that the average full-cycle cost of shale gas in 2007 was $5.00 per MMBtu and of tight sand gas at $5.90 per MMBtu at the wellhead, to which $1.00 per MMBtu should be added to approximate a Henry Hub price. See Exhibit 3-7.
- Davis (2009, 18–19) reports that Cambridge Energy Research Associates recently issued a multi-client study in which it concluded that full-cycle unit costs of new gas supplies are at a weighted average of $4.63 per Mcf in 2009 which then increases as the economy rebounds from the current recession to $7.54 per Mcf in 2018. These costs presumably are computed at the wellhead. Thus the Henry Hub price would be about $1.00/Mcf more. In addition, since these are weighted average costs, the marginal cost for increased supply would be greater than the averages shown here.

Exhibit 3-7 shows a range of full-cycle gas costs and related Henry Hub prices primarily for shale gas, which EIA (2009a, 109–150) forecasts will be the marginal source of gas in the U.S. over the study period. The 2009 Reference Case forecasts Henry Hub natural-gas prices to be between $6.89 and $8.09 per MMBtu from 2010 to 2024 and then trend upwards thereafter. The data in Exhibit 3-7 are consistent with the 2009 Reference Case Henry Hub prices. Thus—and unlike our views of the projected Henry Hub gas prices in EIA's (2007) Reference Case—from the point of view of technological change and the prices for the marginal sources of natural gas, we find the 2009 Reference Case gas prices to be reasonable from a cost of the marginal gas source, shale gas, and technological progress prospective.

3.2.4. Forecast of Annual Natural-gas Prices at the Henry Hub

For the above stated reasons, we select the gas prices forecast in the 2009 Reference Case for AESC 2009 in the long-term. However, futures-market prices are a better forecast of Henry Hub natural-gas prices in the near term since they reflect current circumstances and near-term expectations better than the EIA's simulation model. For the longer-term the EIA simulation model better reflects the fundamental economics of energy including the inter-fuel competition and the feedbacks among supply, demand, price, and investments in energy-producing facilities and consumer choices.

Thus, our proposed AESC 2009 Henry Hub annual price forecast uses NYMEX gas futures prices for the Henry Hub for the years 2009 to 2011 and EIA's (2009a, 109-150) Reference Case forecast for the years 2012 through 2024.

The NYMEX futures prices are as of March 31 2009, expressed in 2009 dollars. This approach is consistent with the method used in AESC 2007. The NYMEX futures prices used are representative of NYMEX futures from various days in February, March, and April as indicated in Exhibit 3-8 below. That Exhibit compares the average annual price in 2010 through 2015 according to NYMEX futures on the various trading days.

Exhibit 3-8: Annual Average Henry Hub Prices per NYMEX Futures, various trading days

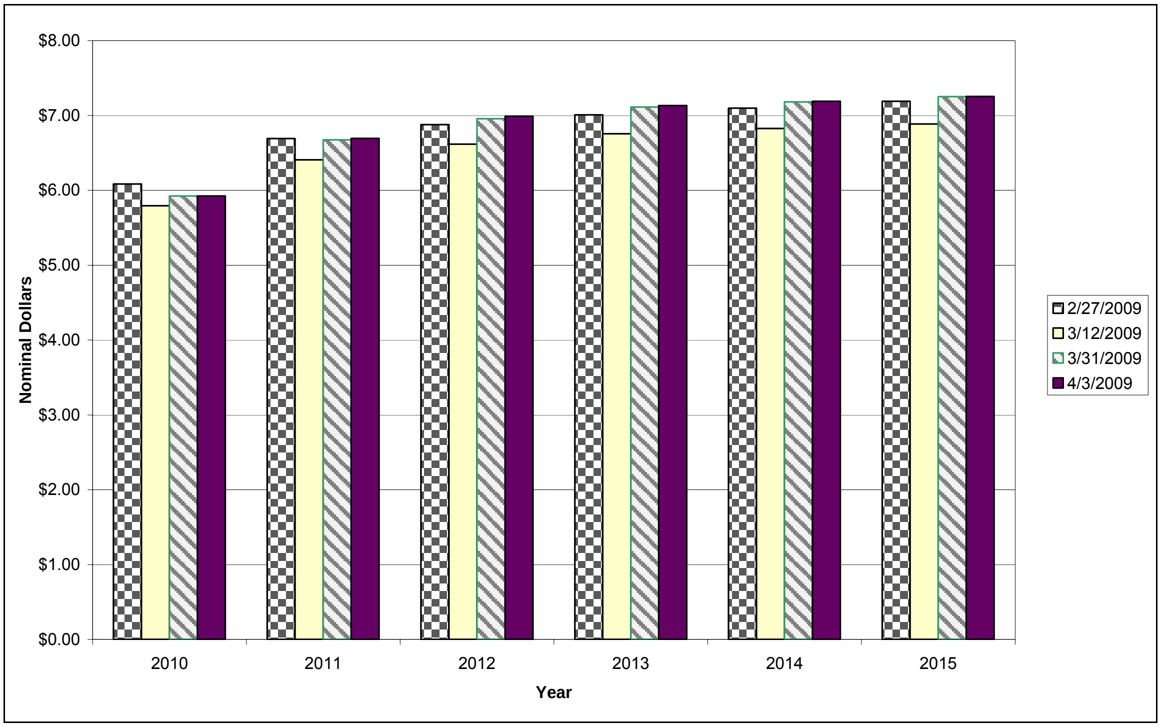
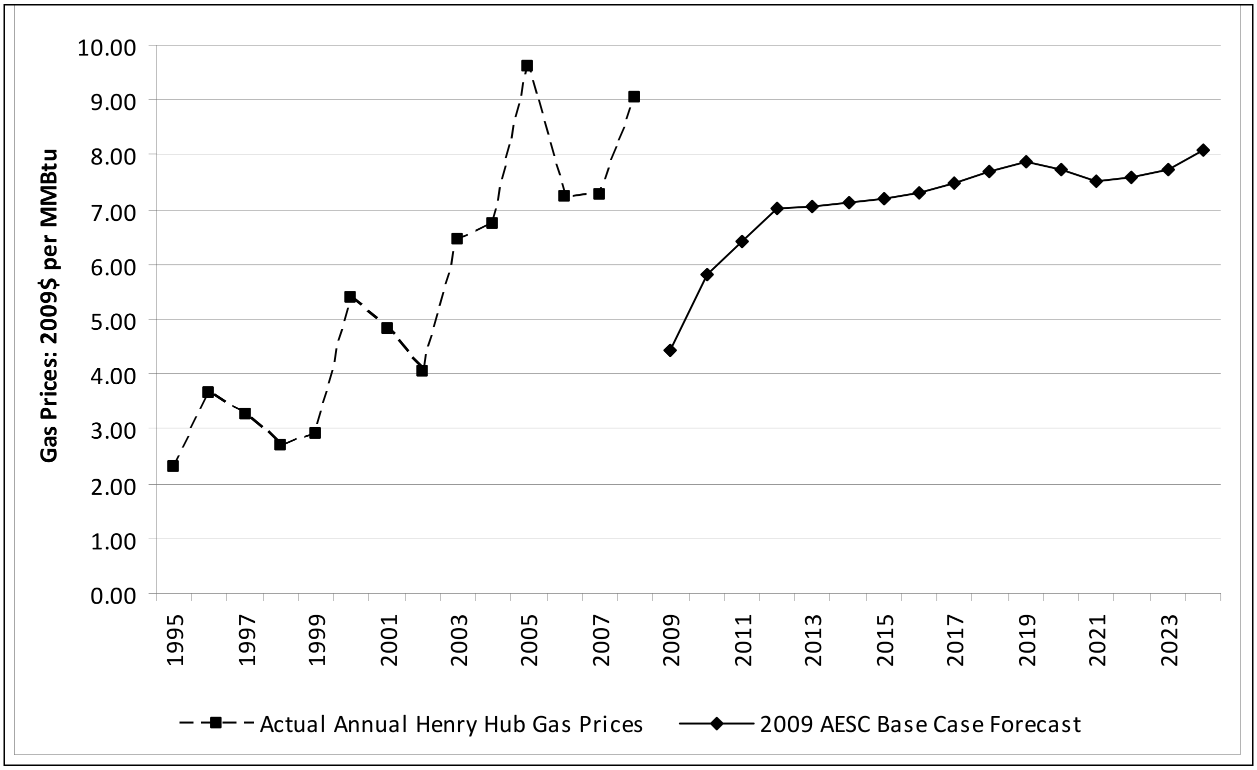


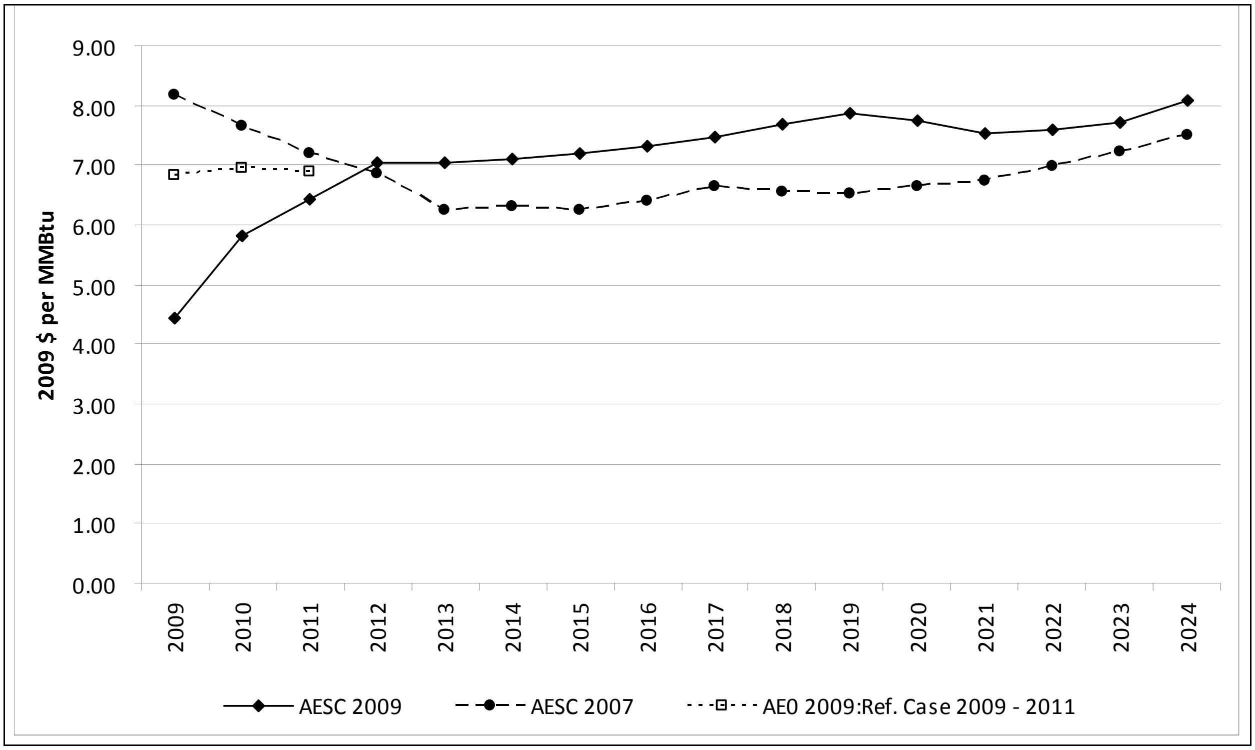
Exhibit 3-9 shows the actual Henry Hub average annual spot price from 1995 and the AESC 2009 forecast of Henry Hub gas prices to 2024. The forecast reflects the current depressed price of natural gas and rises to about $7.00 per MMBtu, in 2009 dollars, and then slowly rises until the year 2024. The small dip in the forecast price after 2019 reflects the expected beginning of arrivals of Alaska natural gas in the lower 48 states.

Exhibit 3-9: Actual and Forecast Annual Henry Hub Natural-Gas Prices (2009 Dollars per MMBtu)



The AESC 2009 price forecast is lower than the AESC 2007 forecast prior to 2012. This reflects the current sharp drop in gas prices currently and futures market prices through 2011. The AESC 2009 forecast is higher than the AESC 2007 forecast after 2012. The higher forecast in the long-term reflects the higher costs of finding and producing gas, particularly shale gas, assumed by the EIA (2009, 109–150) in its Reference Case forecast. See Exhibit 3-10.

Exhibit 3-10: Comparison of Henry Hub–Gas-Price Forecasts



3.2.5. Forecast of Annual Henry Hub Prices, High and Low Cases

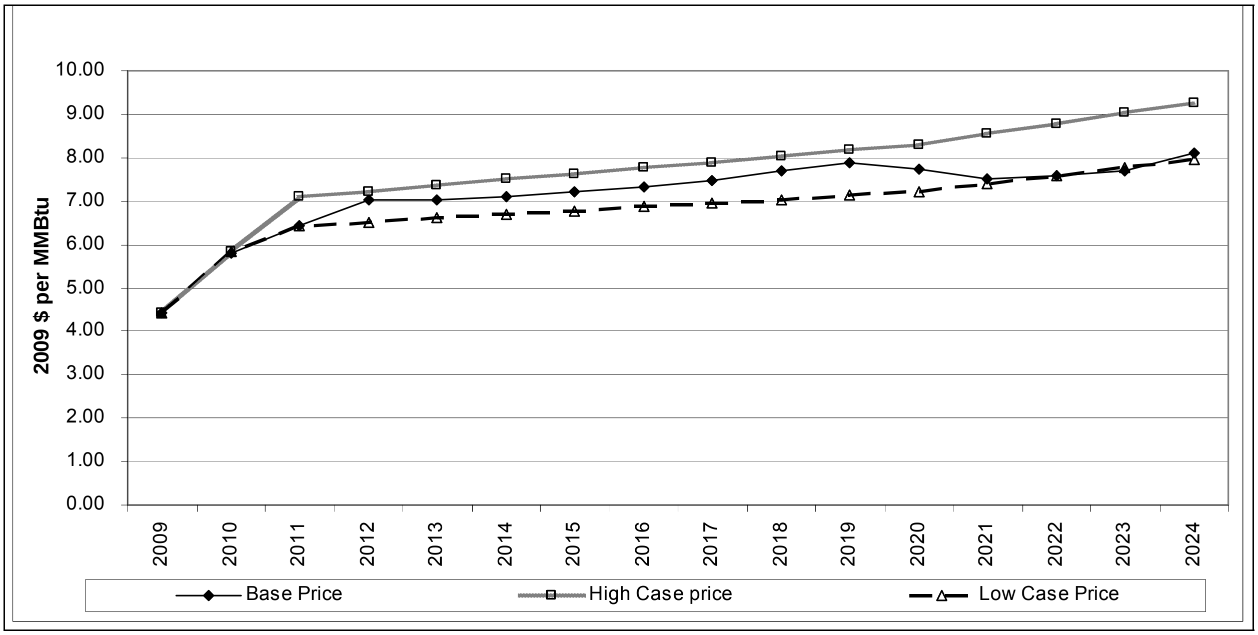
This section develops high and low gas-price cases recognizing the uncertainty associated with all forecasts, including the EIA's(2009a, 109–150) 2009 Reference Case gas-price forecast. Similar to the base price forecast, these forecasts were derived from various price cases presented in EIA(2009a). They are intended to represent the possible variation in expected annual average Henry Hub spot gas prices. They are not intended to address the issue of price volatility, which is discussed in the next section.

High Case

The EIA(2009a, 109–150), in its Reference Case gas forecast, makes the following assumptions: (1) there are ample unconventional gas resources in the U.S., (2) they are expensive to produce, and (3) the cheaper and more-accessible resources will be developed first with greater costs incurred, implying a higher gas price in the future as the less-accessible resources are developed. The EIA(2009a) develops 38 different forecasts in addition to its Reference Case. These represent different paths of technological advance in energy use and energy supply, high and a low world-oil-price cases, and cases for high and low economic-growth in the U.S., different costs in building electricity-generation facilities, and differences in regulations about oil and gas drilling and carbon control. Using these different cases we can develop estimates of higher or lower natural-gas price forecasts.

The EIA(2009a) case that provides the highest gas price assumes slow technological development in finding and producing oil and gas, which is the case we use for our high-price forecast. Exhibit 3-11 shows the AESC 2009 base case Henry Hub price forecast as well as our proposed high and low price forecasts. The high-price forecast is not much more than the base case forecast through 2020. The reason is that while slower technological advance in gas drilling and production will raise costs, and thus prices, technological development was already slower than in previous years in the EIA's (2009a, 109–150) Reference Case. These prices are somewhat, but not substantially, higher.

Exhibit 3-11: Forecast of Henry Hub Natural-Gas Prices, Base, High, and Low Cases



The high oil price case also raises the price of gas but by slightly less than the slow technology case. The Reference Case in EIA(2009a, 109–150) already assumes a high oil price, of $130 per barrel; the high-price case assumes a price of $200 per barrel (both in 2007 dollars). Given the assumption of large gas resources, the high price of oil does not have an overwhelming effect on the price of gas.

Low Case

The low price forecast is also shown in Exhibit 3-11. It is the case assuming low oil prices: $50 (again in 2007 dollars) per barrel for most of the forecast period. This is 60% less than the Reference Case. The effect on gas prices of the low oil price case is also modest. In part this is due to the fact that even with $50 crude oil, the price is $8.62 per MMBtu (2007 dollars), which does not provide strong competition to natural gas.

3.2.6. *Forecast of Base-Case Henry Hub Monthly Prices*

The forecast base-case monthly natural-gas prices at the Henry Hub are presented in Appendix D.

We developed monthly Henry Hub natural-gas prices as follows:

- January 2009 through April 2009 are actual prices;
- May 2009 through December 2011 are NYMEX futures prices as of March 31 2009 expressed in 2009 dollars;
- January 2012 through December 2024 are forecasts derived by applying monthly ratios to EIA's (2009a, 109–150) Reference Case forecast annual prices for those years.

The monthly Henry Hub–price ratios of each month's price to the annual average price is also shown in Appendix D. These average ratios were developed by analyzing the ratios between monthly NYMEX Henry Hub prices and annual prices over the period January 2009 through December 2014.

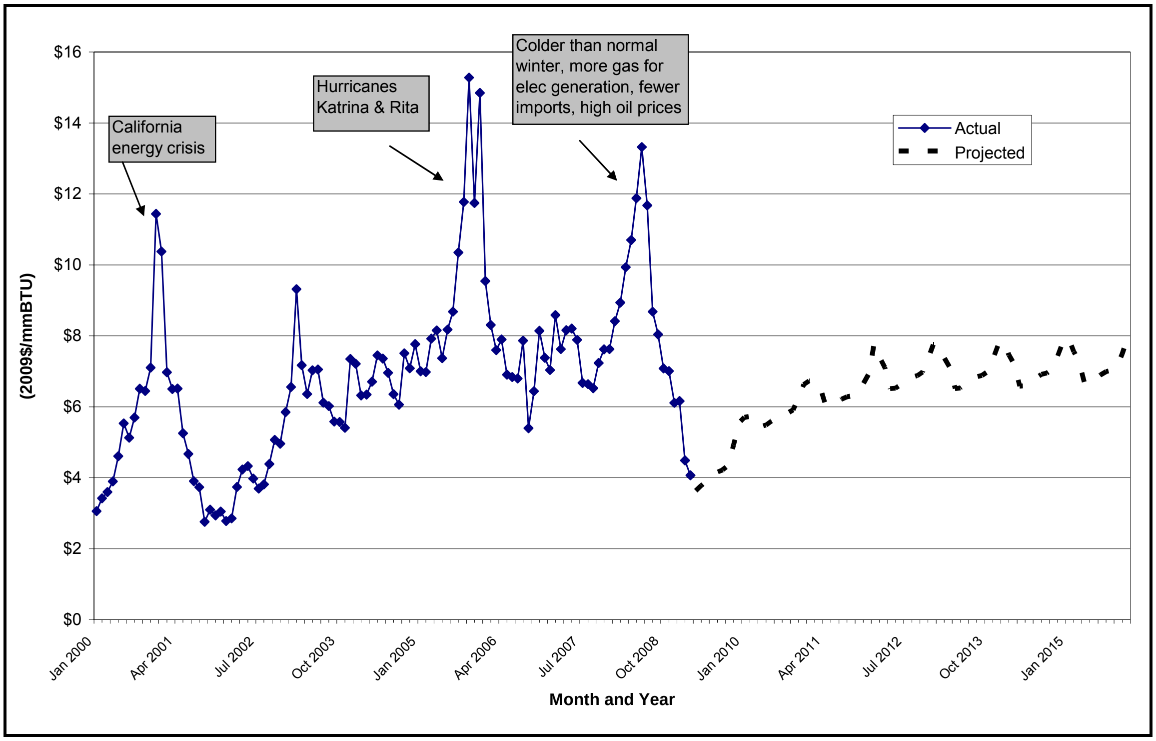
This approach is consistent with the method in AESC 2007.

3.3. Representation of Volatility in Henry Hub Prices

Volatility is a measure of the randomness of variations in prices over time as affected by short-term factors such as extreme temperatures, hurricanes, supply systems disruptions, etc. It is not a measure of the underlying trend in the price over the long-term. As a result we have not attempted to forecast the actual monthly gas prices that would result from volatility in the natural-gas market. Instead, our forecasts of Henry Hub prices under the base, high, and low cases provide projections of expected average natural-gas price in any year. Actual gas prices in any future month will vary around the expected annual average prices forecast in each of those three cases. Actual daily and monthly Henry Hub prices are volatile and will vary from day-to-day and month-to-month. We have not attempted to forecast the actual monthly prices that would result from that volatility in any month, primarily because we are forecasting prices used to evaluate avoided costs in the long term. Our analyses indicate that the levelized price of gas over the long term would not be materially different if one estimated increases from an occasional one-to-three-day price spike during a cold snap or even the type of several month gas price increases following Hurricane Katrina in the fall of 2005. For example, monthly Henry Hub prices were very volatile between 2000 and 2008, ranging from less than $4.00/MMbtu to over $14/MMbtu. See Exhibit 3-12. However, the levelized average annual cost over that period was $6.04/MMBtu. Moreover, if one excludes certain months with very high prices, such as the months affected by Hurricanes Katrina and Rita, or the spikes in early

2008, the levelized price over the entire nine year period remains very similar at approximately $5.90/MMBtu.

Exhibit 3-12: Monthly Henry Hub Prices, Historical (EIA) and Projected (2009 Dollars per MMBtu)



Pindyck (1999) argues that oil, coal, and natural-gas prices tend to move toward long-run total marginal cost. This behavior is consistent with the forecast of an average price but with the expectation that the actual price will vary around the average price in a random manner with an annual standard deviation of 11% to 14% even while tending to move to the average. However, Pindyck suggests that the movement of oil and gas prices to a long-run marginal cost is slow and can take up to a decade.[53]

Applying Pindyck's conclusions to the AESC 2009 base-price forecast, one should expect that the random movements in gas prices from month-to-month could send the actual gas price in any month above or below the expected annual average price shown in Exhibit 4-9 for several months or in some cases for more than a year. For example, in 2015 the annual base case price forecast is $7.19 per MMBtu (in 2009 dollars). A 12% random increase applied to that annual price would result in an annual price of *$8.05/MMBtu,* which is also greater than the

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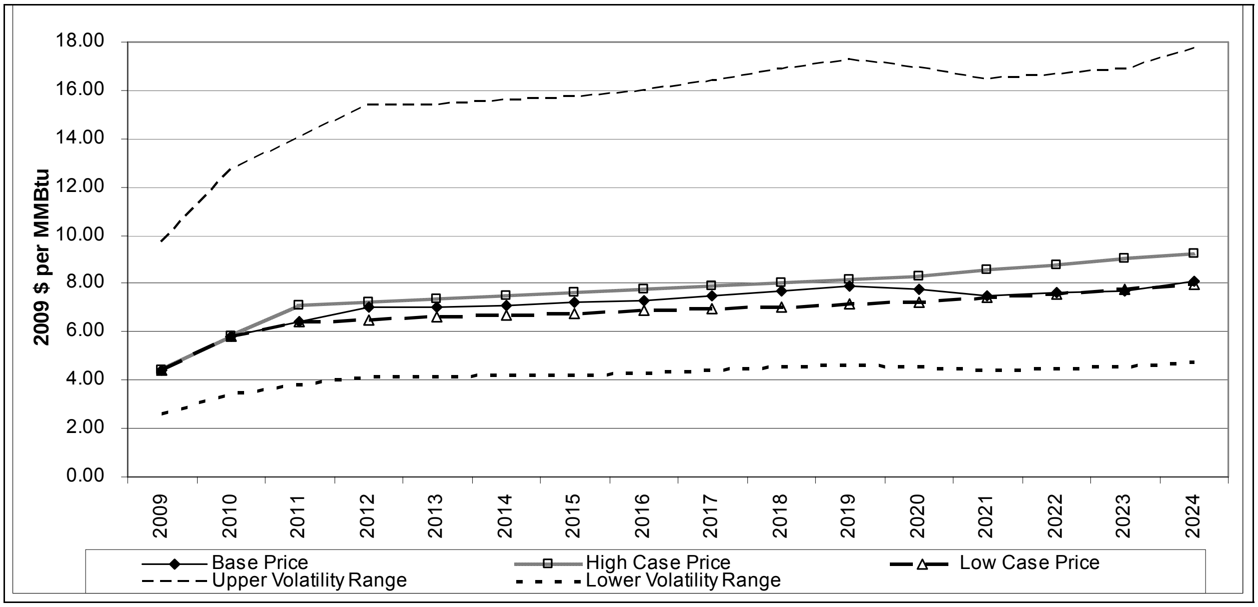
[53]Pindyck (6, 24–25) shows that the random variation is similar to a geometric Brownian motion with an annual standard deviation of 11 to 14 percent for natural gas, but with a slow movement back toward a mean, which is related to the long-run total marginal cost of the resource

$7.63/MMBtu forecast in the high case. Similarly, random movements could result in actual gas prices below the forecast price. Random movements could move prices in different directions from year to year, above and below the prices forecast for those years. This range of potential volatility in annual average prices is shown in Exhibit 3-13.

Exhibit 3-13: Range of Potential Volatility versus Forecast Annual Average Henry Hub Natural-Gas Prices

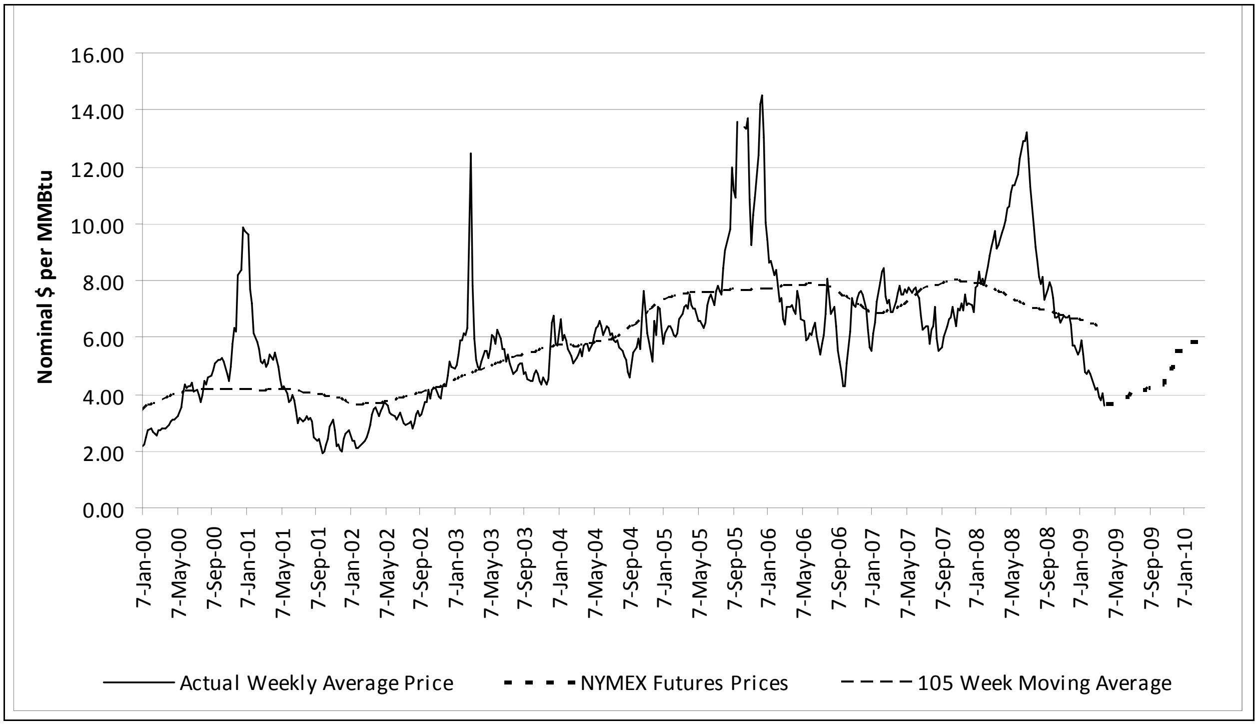


Source: *Natural Gas Intelligence,* "Weekly Gas Price Index."

The range of volatility in monthly and daily prices is even higher, given the variation in monthly prices. See Exhibit 3-14.

Exhibit 3-14 shows the weekly average of the daily spot price of natural gas at the Henry Hub from 2000 through March of 2009 and then monthly NYMEX gas futures prices through March 2010. These prices are in nominal dollars; they have not been adjusted for inflation because this discussion of volatility does not require prices in real terms.

Exhibit 3-14: Henry Hub Average Weekly Natural-Gas Prices, Actual and Futures, Jan 2000–March 2010



Price spikes are an example of price volatility. From time to time, the daily spot or even the monthly price of natural-gas spikes. In New England and in other gas consuming areas there have been daily price spikes during very cold weather. In addition, natural-gas prices have increased for longer periods. The recent example of Hurricane Katrina in 2005 is illustrative, as follows.

- On July 29 2005 the NYMEX gas futures contract for September 2005 delivery was priced at *$7.89* per MMBtu;
- On August 29 2005 Katrina hit the Gulf Coast;
- On December 13, 2005 the NYMEX January 2006 gas futures contract settlement price was *$15.38* per MMBtu;
- on March 1 2006, six months after Katrina struck the Gulf Coast, the April 2006 gas-futures contract was priced at *$6.73* per MMBtu;
- Subsequently 2006 experienced few hurricanes and on September 27 2006 the October 2006 gas futures contract closed at *$4.21* per MMBtu.

In this example a shock that removed 5 billion cubic feet per day of natural-gas supply produced a strong increase in prices. However, prices quickly reversed to more-typical levels and in less than a year gas futures price fell (temporarily) to a level less than one-third of the peak of December 2005. We expect such shocks and gas price volatility to continue periodically in the future. Nonetheless, the AESC 2009 base gas price forecast provides a reasonable estimate of average or expected Henry Hub gas prices for the purposes of this study.

We quantify Henry Hub–price volatility as follows. First we find a 105-week moving average of the weekly prices centered on the current week. This 105-week moving average is the average of the 52 previous weeks of prices, the price of the instant week, and the prices from the 52 weeks following. Then for each week we calculate the ratio of the current price to the 105 week average price. There have been four peak prices during this period of 2000 to March 2009 and the average ratio of the peak price to the 105-week moving average price as of that week is 2.19. Similarly, there were four downside bottoms in price and the average ratio of the four bottom prices is 0.59 of the 105-week moving average price. These results indicate that the actual average of daily prices in any week could range between 0.59 and 2.19 of the long-term average of Henry Hub daily prices. Exhibit 3-13 depicts this range. The range of price volatility is large, especially compared with the upper and lower range of forecast average prices.

3.4. Forecast of Wholesale Natural-Gas Prices in New England

The forecasts of wholesale monthly natural-gas prices for New England as a region, and for each state, are presented in Appendix D.

The forecast wholesale natural-gas commodity prices each month comprise the forecast monthly commodity price at the Henry Hub plus the forecast monthly basis differential for the relevant market hub(s) in New England. Our forecasts are based on Henry Hub prices plus the following components:

- *Massachusetts, New Hampshire and Maine*–Basis differential to Tennessee Gas Pipeline (TGP) Zone 6;
- *Connecticut and Rhode Island*–Basis differential to Algonquin Gas Transmission (AGT);
- New England region excluding Vermont–Average of basis differential to Tennessee Gas Pipeline (TGP) Zone 6 and to Algonquin Gas Transmission (AGT).

We do not forecast a wholesale natural-gas commodity price for Vermont because there is no liquid spot market for gas in that state.

3.4.1. Forecast by Market Hub and State

Like AESC 2007, we assumed that the market hubs on Tennessee Gas Pipeline (TGP) Zone 6 and Algonquin Gas Transmission (AGT) represented the majority of gas traded in wholesale markets in New England.

As in AESC 2007, we calculated historical average basis differential ratios for each of those two market hubs as a ratio of the monthly Henry Hub price and the monthly price reported at the hub. The ratios were calculated for each month over nine years, January 2000 through December 2008. The average monthly basis-differential ratios for TGP Zone 6 and AGT were then applied to the monthly forecast of Henry Hub natural-gas prices to develop monthly prices for TGP Zone 6 and AGT over the forecast period.

The AESC 2009 average monthly basis differentials are within 0.5% of the AESC 2007 ratios. See Exhibit 3-15 below.

Exhibit 3-15 Monthly Basis-Differential Ratios (to Henry Hub): 2009 vs. 2007

	AESC 2007			**AESC 2009**		
	Tenn. Zone 6 Dlvd Mo	*Algonquin CG Mo*	*Average of Tenn. 6 and Algonquin*	*Tenn. Zone 6 Dlvd Mo*	*Algonquin CG Mo*	*Average of Tenn. 6 and Algonquin*
Jan	1.27	1.37	1.32	1.27	1.37	1.32
Feb	1.28	1.33	1.31	1.36	1.41	1.39
Mar	1.13	1.14	1.14	1.13	1.14	1.14
Apr	1.09	1.09	1.09	1.08	1.09	1.09
May	1.08	1.09	1.09	1.08	1.09	1.09
Jun	1.08	1.09	1.09	1.08	1.09	1.09
Jul	1.08	1.10	1.09	1.09	1.10	1.09
Aug	1.08	1.08	1.08	1.08	1.09	1.08
Sep	1.07	1.07	1.07	1.07	1.07	1.07
Oct	1.08	1.09	1.09	1.08	1.09	1.08
Nov	1.11	1.12	1.12	1.11	1.12	1.11
Dec	1.18	1.20	1.19	1.18	1.21	1.19
Average	1.13	1.15	1.14	1.13	1.16	1.15

3.4.2. Forecast by Region

The forecast of regional monthly spot prices, with the exception of Vermont, was calculated as the average of the forecasts for prices of spot gas delivered to market hubs TGP Zone 6 and AGT.

The average of forecast gas prices for these two zones is appropriate for several reasons. An analysis of spot gas prices delivered to TGP Zone 6 and AGT between January 2000 and March 2009 shows no material difference between prices on the two pipelines in most months. This is not surprising. There is ample opportunity for price arbitrage between the two pipelines given the number of interconnections between the two and the number of participants buying and selling gas in the wholesale New England market every day. Were the price on these two pipelines to diverge by too much over a sustained time period, arbitrage would reduce the price difference. In addition, arbitration panels rely upon the average of these two price indices, TGP Zone 6 and AGT, to represent the market value of gas in New England for purposes of setting prices under gas supply contracts between gas producers and generating units.

The AESC 2009 forecasts of New England regional wholesale prices are shown in Exhibit 3-16

Exhibit 3-16: Forecast Annual Average Wholesale Gas Commodity Prices in New England (2009 Dollar per MMBtu)

	Henry Hub	Conn.	R.I.	Mass.	N.H.	Maine	New England (excluding Vt.)
2009	$4.44	$5.15	$5.15	$5.02	$5.02	$5.02	$5.11
2010	$5.81	$6.74	$6.74	$6.56	$6.56	$6.56	$6.68
2011	$6.42	$7.44	$7.44	$7.25	$7.25	$7.25	$7.38
2012	$7.04	$8.16	$8.16	$7.95	$7.95	$7.95	$8.09
2013	$7.04	$8.17	$8.17	$7.96	$7.96	$7.96	$8.10
2014	$7.11	$8.25	$8.25	$8.04	$8.04	$8.04	$8.18
2015	$7.19	$8.35	$8.35	$8.13	$8.13	$8.13	$8.27
2016	$7.31	$8.48	$8.48	$8.26	$8.26	$8.26	$8.41
2017	$7.48	$8.68	$8.68	$8.45	$8.45	$8.45	$8.60
2018	$7.69	$8.92	$8.92	$8.69	$8.69	$8.69	$8.84
2019	$7.88	$9.14	$9.14	$8.91	$8.91	$8.91	$9.06
2020	$7.74	$8.98	$8.98	$8.75	$8.75	$8.75	$8.90
2021	$7.52	$8.73	$8.73	$8.50	$8.50	$8.50	$8.65
2022	$7.60	$8.81	$8.81	$8.58	$8.58	$8.58	$8.73
2023	$7.71	$8.95	$8.95	$8.72	$8.72	$8.72	$8.87
2024	$8.09	$9.39	$9.39	$9.15	$9.15	$9.15	$9.31

Connecticut and Rhode Island per basis-differential ratios to Algonquin market hub. Massachusetts, Maine, and New Hampshire per basis differential ratio to Tennessee Zone 6 market hub. New England, excluding Vermont, is based on the average basis-differential coefficient to Algonquin and Tennessee Zone 6.

3.4.3. Impact of New Regional Supplies on Wholesale Prices in New England

Additional gas supply sources have commenced or are being developed since AESC 2007. Maritime and Northeast Pipeline has been expanded. The Excelerate Northeast Gateway LNG port is operational. GDF Suez’s Neptune LNG port is under construction off Gloucester, Massachusetts. The Canaport LNG terminal in New Brunswick is reported to be 95% complete. Encana is developing the Deep Panuke gas field off Nova Scotia. While these new supply sources probably will bring some new gas supply to New England, they may not result in a major reduction in regional prices for natural gas. Some of these new supply sources are operational, yet the basis differential for New England gas market has changed little and that was a very small increase (see Exhibit 3-15).

The LNG terminals are operating below capacity as LNG prices are higher in other parts of the world. This may well continue especially if the high oil prices forecast by EIA (2009) are realized because other markets often offer higher prices for LNG than does the U.S. gas market. Elsewhere gas imports are frequently priced relative to crude oil, but they are not in North America.

Second, if more supply does enter New England from Canada, the result is likely to be a displacement of gas that would otherwise have been delivered into the region from the Mid-Atlantic Region, a much larger market. The demand for natural gas in that market is correspondingly greater.

3.5. Forecast of Wholesale Demand Costs

Based on conversations with the gas-company representatives in the AESC 2009 Study Group the authors concluded that a reasonable representation of the avoided costs of pipeline transmission and storage to New England states are the currently effective rates on the major pipelines serving New England from the Southwest. These pipelines are Tennessee Gas Pipeline Company (TGP) and the combination of Texas Eastern Transmission and Algonquin Gas Transmission (AGT). This is the same representation of pipeline costs by AESC (2007, 2-25, Exhibit 2-16).

Assumptions for pipeline demand are in Chapter 5.

3.6. Forecast of Gas Prices for Electric Generation in New England

The price of natural gas for electric generation at any particular location can be represented as the wholesale Henry Hub price plus a basis differential representing the cost of delivering gas from the Henry Hub to that particular electric generating unit. The AESC 2009 forecast of prices of natural gas for electric generation in New England and New York thus comprises forecast monthly Henry Hub prices multiplied by a forecast differential. Because of the wide variation in natural-gas prices represented in the historical data we have normalized those relationships and presented the differentials as multipliers rather than adders. The forecast monthly Henry Hub prices are presented in Appendix D. This section describes our derivation of the forecast differentials, presented below in Exhibit 3-17.

Exhibit 3-17 : Monthly Natural-Gas Basis-Differential Ratios (to Henry Hub)

	New York	New England
Jan	1.249	1.280
Feb	1.134	1.141
Mar	1.146	1.114
Apr	1.088	1.048
May	1.081	1.046
Jun	1.093	1.046
Jul	1.126	1.072
Aug	1.107	1.066
Sep	1.130	1.073
Oct	1.052	1.017
Nov	1.132	1.059
Dec	1.144	1.136
Average	1.123	1.092

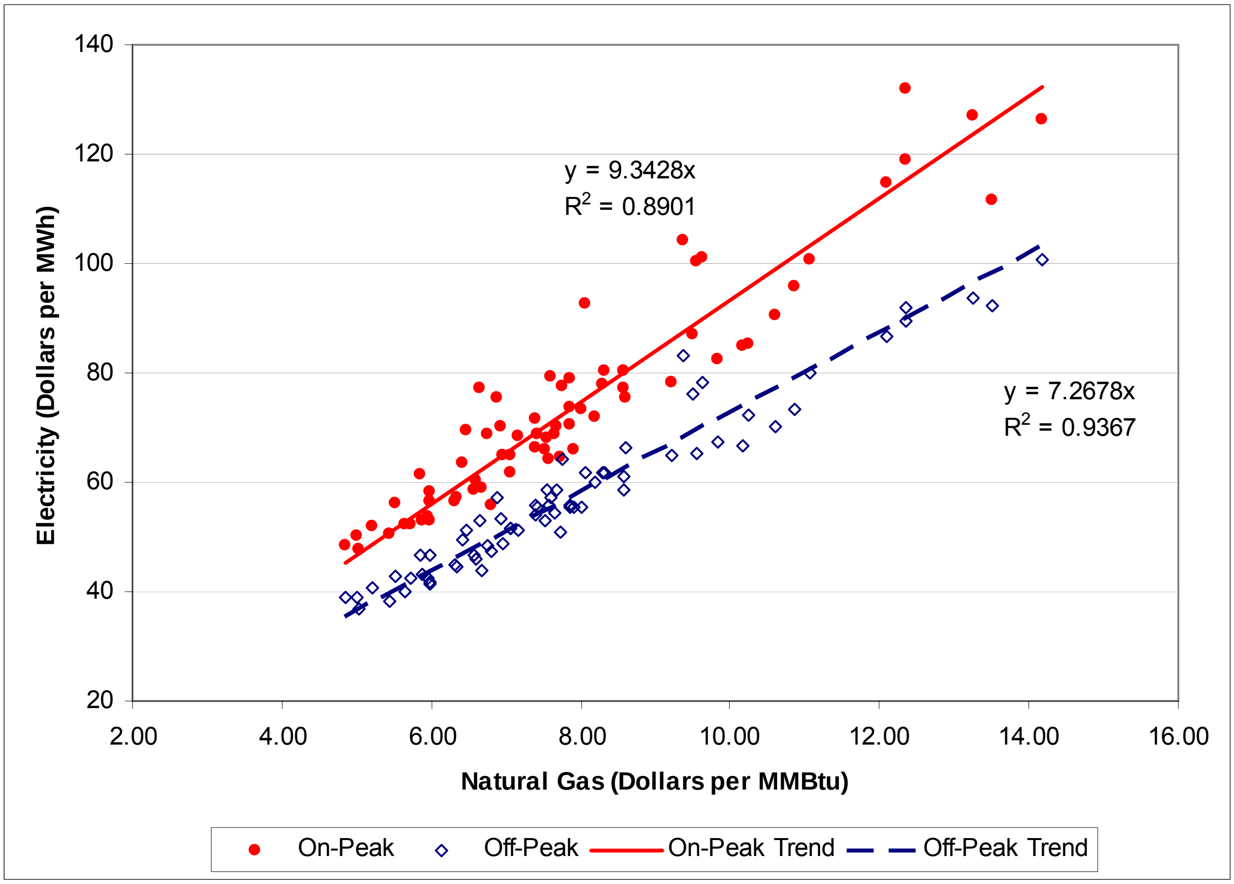
The forecast differentials are based on several analyses of monthly prices for natural gas and electricity over the period 2003–2008. There are two candidate sets of gas prices for which the gas differentials can be calculated. The first data set comprises monthly prices reported at New England market hubs and the corresponding monthly Henry Hub prices. We selected Algonquin as the relevant market hub for this analysis. The second data set comprises monthly natural-gas prices paid by electric generators as reported to the EIA (2009c, 96) and the corresponding monthly Henry Hub prices. The goal is to calculate historical monthly differentials from the data set that will provide the most-accurate forecast of monthly prices for natural gas to electric generating units.

The first step was to calculate and examine the monthly basis differentials from each data set. The EIA data produced an average differential of $0.54/mmBtu with a standard deviation of $0.61. For the Algonquin market point the average differential was $0.95/mmBtu with a standard deviation of $1.55. The Algonquin data also produced some very large differentials unrelated to season.

The next step was to test the correlation between historical market prices of electricity at the ISO-NE Hub and the New England prices in each data set. This analysis used monthly electricity prices from March 2003 through December 2008. The correlations between electricity prices and EIA natural-gas prices were 0.89 for the peak periods and 0.94 for the off-peak periods. The correlations between electricity prices and Algonquin prices showed a much wider scatter and poorer correlations of 0.46 and 0.56 respectively.

Exhibit 3-18 below presents a scatter plot of the monthly peak and off-period electricity prices versus the natural-gas prices as reported by EIA along with fitted trend lines. The coefficients on those lines represent average effective heat rates for the given periods.[54] For example the implied heat rate for the peak period is 9,343 Btu/kWh representing a mix of less-efficient plants than for the off-peak period.

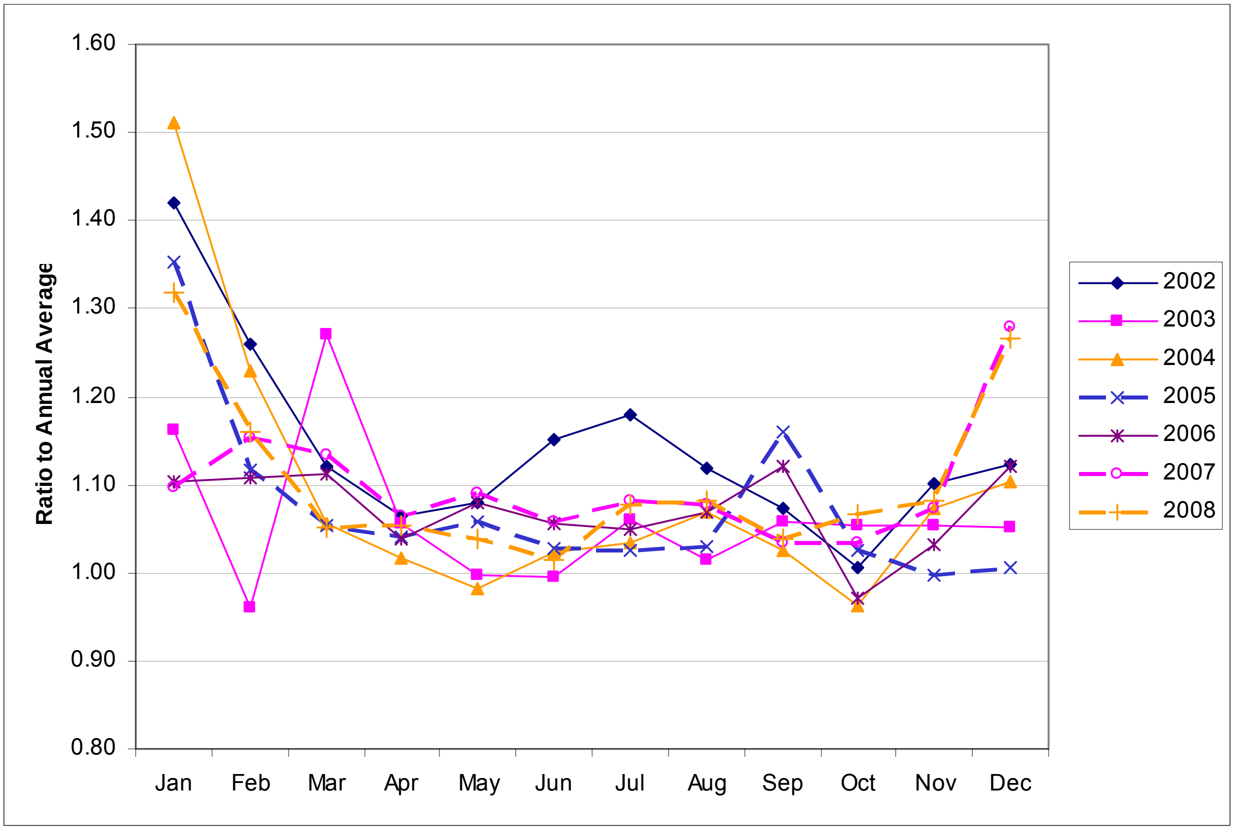
Exhibit 3-18: Monthly NE Electricity Prices vs. EIA Natural Gas Prices (2003–2008)



Based upon those analyses we developed the forecast monthly basis differentials presented in Exhibit 3-17 above. The forecast differential in each month is the average differential between the price reported to the EIA for that month and the monthly Henry Hub price over the seven-year period of 2002 to 2008. Exhibit 3-19 below shows those monthly ratios for New England. Although there are significant variations from one year to the next, there is also a consistent seasonal pattern reflecting much greater basis differentials for the winter heating season.

[54]Heat rate is a measure of the efficiency with which a generating unit converts fuel energy into electric energy. It is expressed in Btu of fuel burned per kWh of energy generated.

Exhibit 3-19: Ratio of Monthly Gas Prices Reported by New England Generating Units to Monthly Henry Hub Price



Chapter 4: Avoided Natural-Gas Costs

4.1. Introduction and Summary

The avoided cost of gas at a retail customer's meter comprise the following two major components:

- the avoided cost of gas delivered into the distribution systems of New England local distribution companies (LDCs)
- the avoided cost of delivering gas on those distribution systems.

These avoided costs vary primarily according to the shape of the gas load being avoided, with some additional variation by sector due to differences in distribution service costs by sector. We have calculated avoided costs by sector and load shape for three different regions—southern New England, northern and central New England, and Vermont—because of the differences in the cost of gas supply between those three areas.

Our projected values are presented in below in Exhibit 4-1, alongside the corresponding values from AESC 2007.

Exhibit 4-1 Summary Table

Summary of Levelized Avoided Cost Of Gas Delivered To Retail Customers AESC 2009 versus AESC 2007
(2009$/Dekatherm)

	RESIDENTIAL				COMMERCIAL & INDUSTRIAL			ALL RETAIL
	Non Heating	Hot Water	Heating	All	Non Heating	Heating	All	
AESC 2007 end-use period (a)		annual	5-month	6-month	annual	5-month	6-month	5-month
Southern New England								
AESC 2009	11.42	11.42	14.52	13.52	9.88	11.83	11.21	12.26
AESC 2007		11.62	12.84	12.48	9.50	10.72	10.36	11.65
2007 to 2009 change		-1.71%	13.09%	8.33%	4.04%	10.36%	8.25%	5.25%
Northern & Central New England								
AESC 2009	10.87	10.87	13.54	12.68	10.02	12.05	11.40	12.03
AESC 2007		11.32	12.35	12.04	10.19	11.23	10.92	11.74
2007 to 2009 change		-3.95%	9.62%	5.28%	-1.65%	7.31%	4.40%	2.44%
Vermont								
AESC 2009	9.75	9.75	12.51	11.62	8.05	9.53	9.07	10.00
AESC 2007		10.43	11.67	11.31	8.34	9.58	9.21	10.37
2007 to 2009 change		-6.52%	7.22%	2.82%	-3.48%	-0.48%	-1.56%	-3.53%

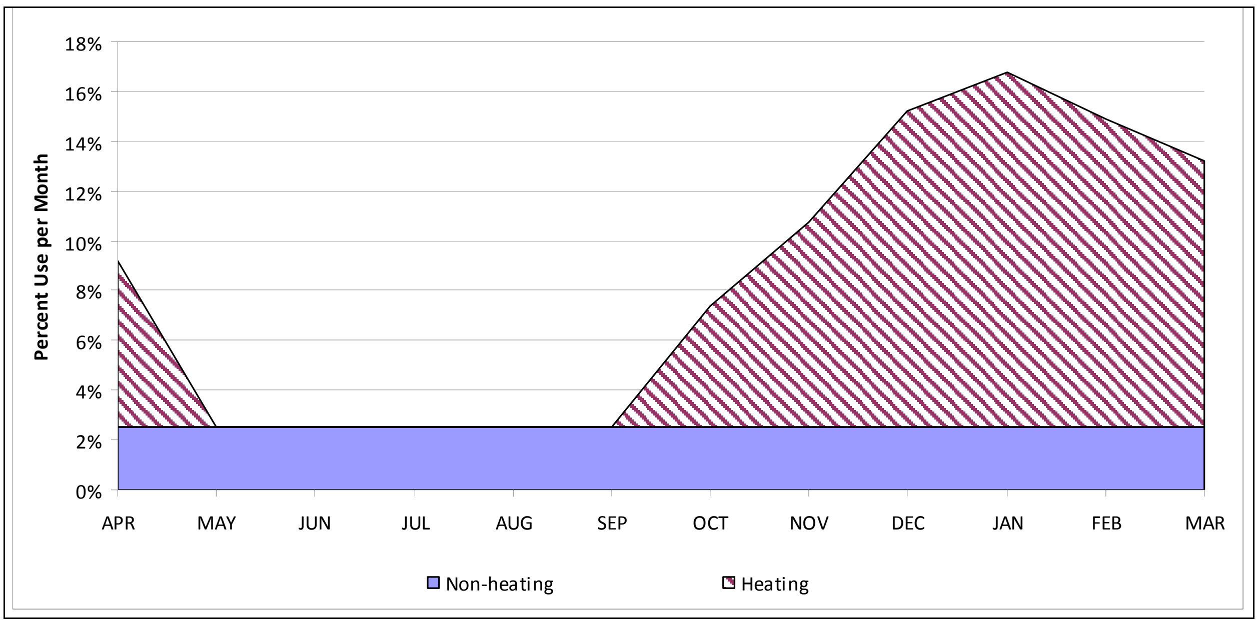
(a) In AESC 2007 the end-use profiles was defined as a certain number of months in the winter period; e.g. 5-months is Nov. - March.
(b) Factor to convert 2005$ to 2007 $ 1.0420
Note: AESC 2007 levelized costs for 16 years, 2007 - 2022 at a discount rate of 2.2165%.
AESC 2009 levelized costs for 15 years 2010 - 2024 at a discoiunt rate of 2.22%.

Other than residential hot water use, we project somewhat higher avoided costs for each end compared with those projected in AESC 2007. These higher avoided costs are due to increases in distribution costs in general and a larger allocation of avoided distribution costs to heating loads based on a more-detailed analysis of each end use.

4.2. Load Shape Is a Key Driver of Avoided Retail Gas Costs

The shape of the retail gas load being supplied has a major impact on the cost of that supply, and hence on the avoided cost of supply. The major end uses of gas by retail customers fall into two broad categories, heating and non-heating. Space-heating or winter temperature-sensitive end-uses represent the largest use in New England. As a result LDCs supply a load that has a significant swing from summer to winter and further temperature-driven variations by month throughout the winter. This variation in load by season, and month, by type of end-use are illustrated graphically in Exhibit 4-2.

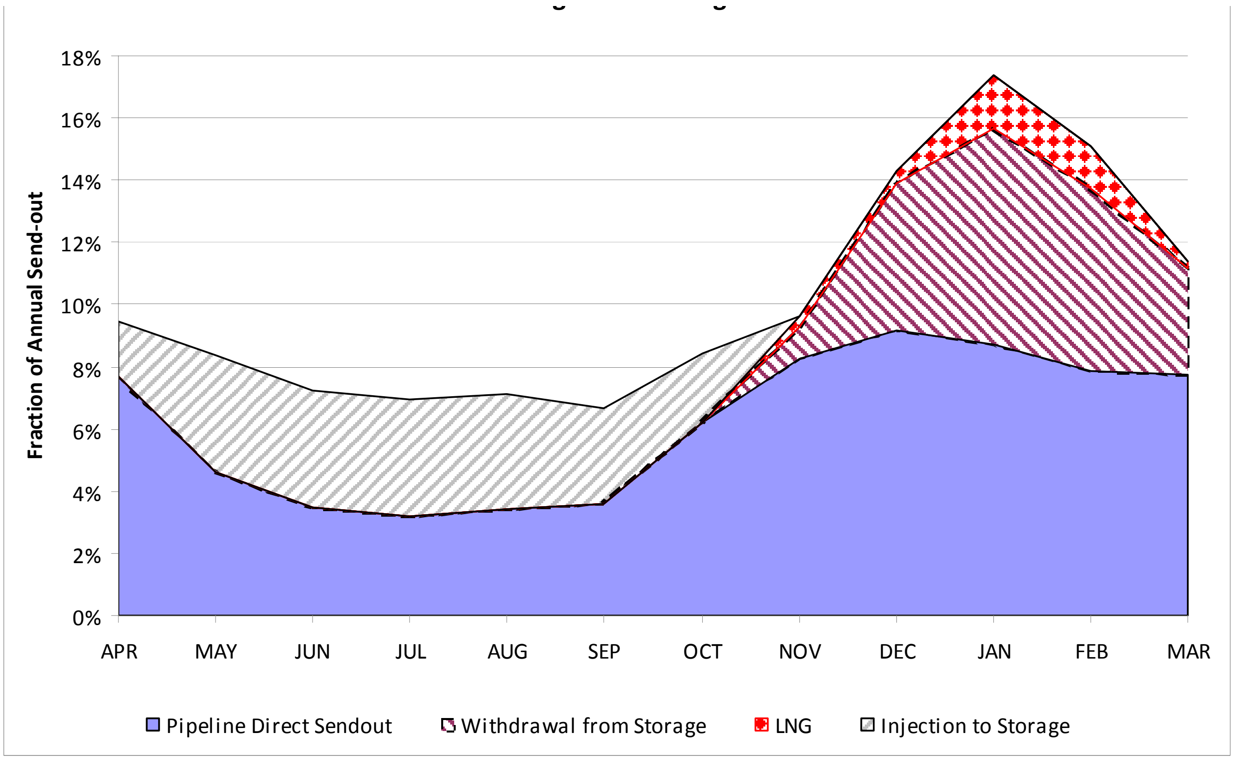
Exhibit 4-2: End-Use-Load Profile



Because of the size of the gas load during the winter (defined as November through March in the gas industry) relative to the summer, and because the variation in daily load during winter months due to variation in daily temperatures, LDCs develop a portfolio of supplies in order to provide reliable service at reasonable cost over time. These portfolios comprise three major categories of delivery and storage resources: long-haul pipeline transportation, underground storage, and LNG or propane facilities.[55] We calculate the avoided cost of gas delivered into the distribution system of a New England local distribution company from the avoided cost of each resource in each month and the relative quantity of each resource that an LDC uses in each month.

Local distribution companies use their long-haul pipeline transportation to supply load directly in each month of the year. In addition, in summer months LDCs use a portion of that pipeline transportation capacity to deliver gas from producing areas for injection into underground storage, and sometimes into LNG tanks.[56] In winter months LDCs meet customer load with gas delivered by pipeline directly from producing areas and from underground storage. LDCs use gas from LNG and propane facilities delivered directly into their distribution systems to meet daily peaking and seasonal requirements during the months of heaviest load, mostly December through February. See Exhibit 4-3.

Exhibit 4-3: Representative New England Gas LDC Sendout by Source



Because LDCs incur fixed costs to hold pipeline transportation capacity, in the form of *demand charges* multiplied by their capacity entitlements, and because

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55Local distribution companies acquire pipeline and storage services through contracts with pipeline companies whose terms and conditions are regulated by the Federal Energy Regulatory Commission.

56Local distribution companies may use some of their pipeline capacity to deliver gas in summer for injection into LNG tanks where there are liquefaction facilities on site.

they use long-haul pipeline transportation capacity to provide supply in three major ways, we had to determine how best to allocate those fixed costs among the three applications.[57] The three applications are direct supply in winter months, delivery of gas in summer months for injection to underground storage (and subsequent withdrawal in winter months) and direct supply in summer months. Our analysis of how LDCs use their long-haul capacity for each application is presented in detail below. That analysis indicates that in winter months LDCs use all of this capacity to provide direct supply while in summer months they use approximately 80% of this capacity. Of that 80% they use 47% to provide direct supply and 33% to deliver gas for injection into storage.

Based upon our analysis of LDC use of long-haul capacity, our projections of avoided costs are based upon the following allocations of the demand charges of long-haul pipelines:

- 100% of demand charges incurred in winter months are allocated to avoided costs in winter months;
- 20% of pipeline transportation demand charges incurred in summer months are allocated to avoided costs of winter months, corresponding to the approximately 20% of physical capacity not being used in the summer either to refill storage or provide direct supply;
- 33% of demand charges in summer months, i.e. the percentage associated with the quantity of long-haul capacity used to refill underground storage in summer, are allocated to the avoided costs of gas injected into storage. (All costs of gas injected into storage are allocated to avoided costs of winter months).

The remaining portion of demand charges in summer months associated with the quantity of long-haul capacity used to provide direct supply in summer are not allocated to avoided costs of summer months because our analysis indicates that LDCs cannot avoid those costs.

4.3. Avoided Cost of Gas to LDCs

This analysis estimates long-run avoided costs because efficiency improvement is a long-term effect that can allow an LDC to avoid both short-run variable costs and some long-term fixed costs. We calculate the avoided cost of gas delivered into the distribution system of a New England LDC in two steps. First, we calculate the avoided cost of supply from each major resource in each month.

[57] An LDC's fixed cost of capacity on a pipeline for a given month equals the pipeline's demand charge, expressed in dollars per month per dth/day of capacity, multiplied by the LDC's capacity entitlement or contract demand expressed in dth/day.

Then we calculate the weighted average cost in each month based upon the relative quantity of each resource the LDC uses in each month. We also calculate a marginal cost (avoided cost) for the peak day.

4.3.1. Summary Results

Our estimated levelized avoided costs are very similar to those of AESC 2007 because the methodology to develop avoided costs is the same in each and there is no dramatic change in key input assumptions (projection of Henry Hub prices and pipeline-service rates). Our estimate of avoided costs in February and March than those for other months largely because the data used to compute the prices in these months showed a lower monthly coefficient to the annual price relative to AESC 2007.[58] In addition, we forecasts lower gas prices at Henry Hub in the years 2009 to 2011 than AESC 2007 does, and also higher Henry Hub prices thereafter. However, the differences in these prices tend to be offset with the discounting and levelization over the fifteen-year period. See Exhibit 4-4.

Exhibit 4-4 Comparison of the Levelized Avoided Cost of Gas Delivered to LDC's by Month From AESC 2007 to AESC 2009

	Units		APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	Annual Average
SOUTHERN NEW ENGLAND: Gas Delivered via Texas Eastern and Algonquin Pipelines															
AESC 2007	2007$/DT	(a)	7.14	7.04	7.12	7.21	7.28	7.34	7.46	8.75	9.35	9.68	9.39	9.07	8.07
AESC 2007	2009$/DT	(b)	7.44	7.34	7.42	7.51	7.58	7.65	7.77	9.12	9.74	10.08	9.78	9.45	8.41
AESC 2009	2009$/DT	(c)	7.37	7.39	7.51	7.64	7.74	7.78	7.90	9.17	9.86	10.14	9.62	9.17	8.44
Percent Difference 2007 to 2009	2009$/DT		-0.9%	0.7%	1.2%	1.8%	2.0%	1.7%	1.6%	0.6%	1.2%	0.6%	-1.6%	-3.0%	0.4%
NORTHERN and CENTRAL NEW ENGLAND: Gas Delivered via Tennessee Gas Pipeline															
AESC 2007	2007$/DT	(a)	7.12	7.02	7.10	7.19	7.26	7.32	7.43	8.53	8.98	9.27	9.05	8.80	7.92
AESC 2007	2009$/DT	(b)	7.42	7.32	7.40	7.49	7.56	7.63	7.75	8.88	9.35	9.66	9.43	9.17	8.25
AESC 2009	2009$/DT	(c)	7.35	7.37	7.48	7.61	7.71	7.75	7.87	8.94	9.41	9.69	9.23	8.83	8.27
Percent Difference 2007 to 2009	2009$/DT		-1.0%	0.6%	1.1%	1.7%	2.0%	1.6%	1.6%	0.6%	0.6%	0.2%	-2.1%	-3.7%	0.3%
VERMONT GAS SYSTEMS: Gas delivered via TransCanada Pipeline															
AESC 2007	2007$/DT		6.20	6.11	6.18	6.25	6.31	6.37	6.47	7.73	8.21	8.86	8.57	8.19	7.12
AESC 2007	2009$/DT		6.46	6.37	6.44	6.51	6.58	6.64	6.74	8.06	8.55	9.23	8.93	8.53	7.42
AESC 2009	2009$/DT		6.32	6.16	6.35	6.46	6.55	6.58	6.68	8.34	8.74	9.20	8.84	8.44	7.39
Percent Difference 2007 to 2009	2009$/DT		-2.1%	-3.2%	-1.3%	-0.8%	-0.5%	-0.8%	-0.9%	3.6%	2.2%	-0.4%	-1.0%	-1.1%	-0.4%

(a) AESC 2007 levelized costs over the 16 years 2007 - 2022 with a discount rate of 2.2165 %.
(b) Factor to convert 2007$ to 2009$ 1.0420
(c) AESC 2009 levelized costs over the 15-year period 2010 - 2024 with a discount rate of 2.22%.

[58] Monthly coefficients are described in Chapter 3.

4.3.2. Representative New England Local Distribution Company and Resources

New England LDCs use three basic supply resources to meet the sendout requirements of their customers. These resources are (1) gas delivered directly from producing areas via long-haul pipelines, (2) gas withdrawn from underground storage facilities (most of which are located in Pennsylvania) and delivered by pipeline, and (3) gas stored as liquefied natural gas and/or propane in tanks located in the LDC service territories throughout New England.

This avoided-cost analysis used a representative New England LDC to determine the fraction of customer requirements met from each resource each month and the fraction of storage refill in each of the summer months, April through October. The characteristics of a representative New England LDC are shown in Exhibit 4-5 below, which presents the numerical data, and Exhibit 4-3, which is a graphical representation of the typical New England LDC used in this analysis. For Vermont, which has one LDC, Vermont Gas Systems, Inc. (VGS) the characteristics of VGS were used and are shown later in this report in Exhibit 4-15. Our analysis assumes that LDCs have optimized the mix of supply sources and thus a long-term efficiency improvement will enable them to avoid both the fixed and the variable costs associated with their mix of supply sources.[59]

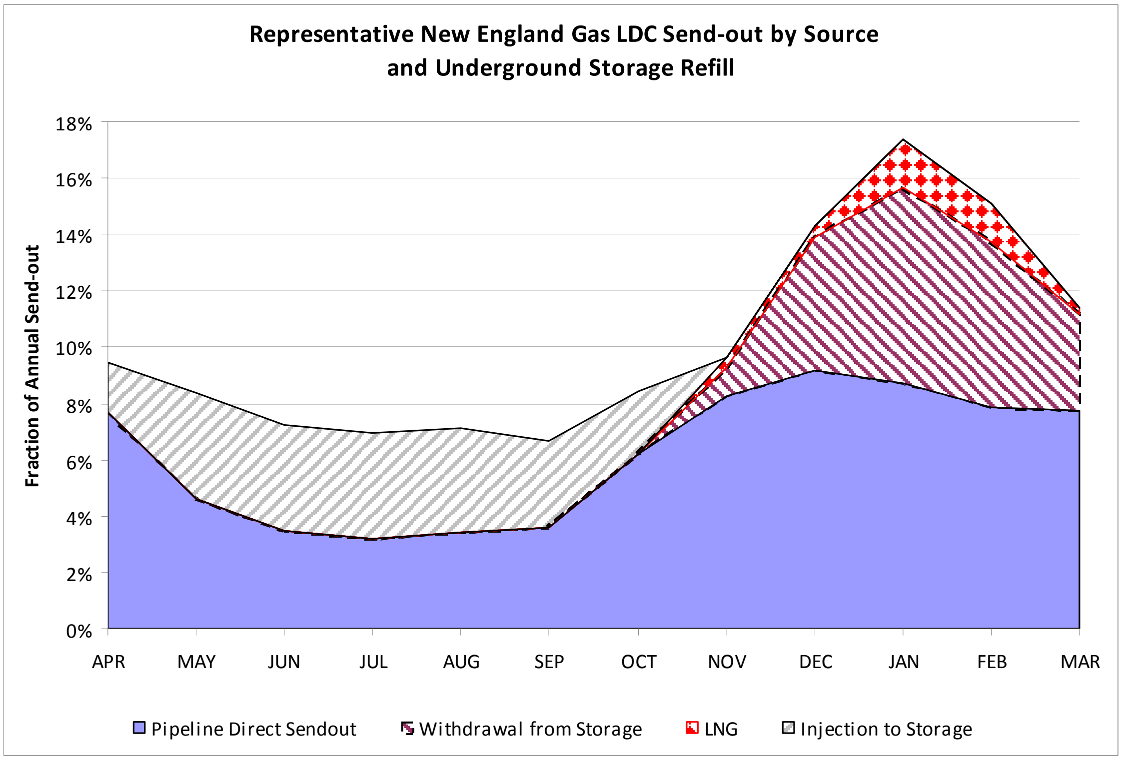
Exhibit 4-5 Representative New England LDC Monthly Characteristics of Send-out by Source, Peak-Month, and Storage Injection

	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR
Fractions of LDC Send-out by Source Each Month												
Pipeline Deliveries, Long-haul	100%	100%	100%	100%	100%	100%	100%	86%	64%	50%	52%	68%
Underground Storage	0%	0%	0%	0%	0%	0%	0%	11%	33%	40%	39%	30%
LNG and Propane Peaking Supply	0%	0%	0%	0%	0%	0%	0%	3%	3%	10%	9%	2%
Total	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Fraction of Annual Sendout each Month	8%	5%	4%	3%	3%	4%	6%	10%	14%	17%	15%	11%
Monthly Sendout as a Fraction of Peak Month	44%	26%	20%	18%	20%	21%	36%	55%	82%	100%	87%	66%
Fraction of Underground Storage Injection by Month	8%	17%	17%	17%	17%	14%	10%	0%	0%	0%	0%	0%

Sources:
Cost of Gas Adjustment filings from Department of Public Utilities for Yankee Gas Systems, Connecticut Natural Gas Company, Bay State Gas Co., NSTAR and KeySpan Energy.

[59]In a short-run marginal cost analysis only variable costs can be adjusted and thus the avoided cost is determined by the one supply source which has the highest variable cost.

Exhibit 4-6 : Representative New England Gas LDC Sendout by Source



The fractions portraying the representative New England LDC were essentially an average of data from Cost of Gas Adjustment filings for Yankee Gas Services Company, Connecticut Natural Gas Corporation, Bay State Gas Company, NStar Gas Company, and National Grid.

The LDC's weighted average avoided cost in each month is a function of the avoided cost of each resource and the relative quantity of *sendout* (retail load) met by each source each month.

4.3.3. Inputs to Avoided Costs by Resource

The cost of gas delivered to an LDC using pipeline transportation and storage facilities comprise the following four basic components:

- the unit cost of the gas commodity, which in this study is the forecast price at the Henry Hub in Louisiana;
- the demand charges for pipeline-transportation capacity, storage capacity and withdrawal capacity;
- the usage (volumetric) charges for transporting gas on a pipeline and for storage injections and withdrawals;
- the fraction (percentage) of volumes of gas received by a pipeline or storage facility that is retained by the facility for compressor fuel and losses. This

fuel and loss retention increases the cost of gas above the Henry Hub price because more volumes of gas must be purchased at the Henry Hub than is delivered to the LDC. In the analysis that follows, the fuel and loss retention is represented as the ratio of the volumes of gas purchased at the Henry Hub to the volumes of gas delivered to the LDC.

Local distribution companies generally own the LNG and/or propane tanks and accompanying liquefaction and vaporization facilities. The bulk of the New England peak gas supply comes from LNG facilities although in certain circumstances propane is the dominant peak gas source. The LDC pays for the construction, financing, operation and maintenance of the LNG facility as well as the cost of the gas that is loaded into the tank as LNG.

4.3.3.1. Commodity Costs

For this avoided-cost analysis we assume that the marginal cost of the gas commodity was the monthly price of gas at the Henry Hub. Like AESC 2007, we assumed that the marginal source of gas to New England LDCs from the Henry Hub is transportation and storage on either of the Tennessee Gas Pipeline (TGP), for LDCs in Northern and Central New England, or the route of Texas Eastern Transmission (TETCo) and Algonquin Gas Transmission (AGT), for LDCs in Southern New England.[60] While the two existing LNG receiving and re-gasification terminals, an additional one under construction in New England, and the nearly completed terminal in New Brunswick will likely be new gas suppliers to New England, it is not likely that they will establish the avoided cost of gas supply to New England. Rather, the price of gas from these new terminals will be set by the price of gas in New England supplied by TGP and TETCo-AGT.[61]

4.3.3.2. Pipeline Rates (Charges)

As described above, we assume that the marginal source of gas to New England LDCs is transportation and storage on either of TGP or the route of TETCo and AGT. The cost for transportation and underground storage is set by the rates charged by these pipelines and their fuel and loss retention percentages, which are shown in Exhibits 4-7 and 4-8,. We assume that these rates and retention percentages would persist for the forecast period, 2009–2024; AESC 2007 made

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[60]Northern and Central New England is Massachusetts, New Hampshire and Maine; Southern New England is Connecticut and Rhode Island.

[61]Unlike in the past, the Federal Energy Regulatory Commission has decided that LNG terminals will not need to offer open access services and will be able to sell LNG at market prices. In a similar fashion the Maritimes & Northeast pipeline expansion is contracted by Repsol YPF, which is the provider of the LNG to the Canaport LNG terminal in New Brunswick. Thus this LNG will also be sold at market prices in New England.

the same assumption. Exhibit 4-7 shows typical rates that New England LDCs pay on the TGP and TETCo AGP routes from the Henry Hub. These are the same rate schedules used in AESC 2007. For TGP the rates, in nominal dollars, and the fuel and loss retention percentages are the same as in AESC 2007. For TETCo the 2009 rates and fuel and loss retention are similar with small changes up and down. AGT's demand and usages charges are nearly identical in nominal dollars to the 2007 rates while the 2009 fuel and loss retention percentages are increased.

Exhibit 4-7 Pipeline Rates for Transportation and Storage

	Demand $/DT/month	Usage $/DT	Fuel & Loss (a) Winter %	Summer %
Texas Eastern Transmission, L.P. (b)				
Transportation: FT-1, WLA - M3			Dec - Mar	Apr - Nov
WLA-AAB	2.602			
ELA-AAB	2.152			
M1 - M3	10.813			
Total Demand	15.567			
WLA - M3 usage (c)		0.061	7.72	6.98
Storage & Transportation: SS-1				
Reservation,	5.537			
Space (d) ($/DT/year)	0.129		0.08	0.08
Injection		0.028	1.27	1.27
Withdrawal (c)		0.044	3.49	3.53
Algonquin Gas Transmission LLC (e)				
			Dec - Mar	Apr - Nov
Transportation: AFT-1 (FT-1,WS-1)	6.585			
Usage (c)		0.013	1.44	1.02
Tennessee Gas Pipeline Company				
			Nov - Mar	Apr - Oct
Transportation FT-A (f) (g) (c)				
Zone 1 (LA) to 6	15.15	0.150	7.82	6.67
Zone 1 (LA) to 4	10.77	0.101	5.90	5.06
Zone 4 to 6	5.89	0.083	2.17	1.92
Storage FS - Market Area (h)				
Reservation	1.15			
Space ($/DT/month)	0.0185			
Injection		0.010	1.49	1.49
Withdrawal		0.010		

Sources and Notes:

(a) Fuel and loss retention percentage is applied to volumes received.
(b) FT-1: Tariff Sheet Nos. 30 & 31 effective February 1, 2009 and Sheet Nos. 126 & 127 effective December 1, 2008.
SS-1: Tariff Sheet No. 52 effective February 1, 2009 and Sheet Nos. 126 & 127 effective December 1, 2008.
(c) ACA charge ($0.0017) in the Algonquin and Tennessee usage rates, but not in TETCO usage rates. Since ACA charge levied only once ina haul, the Algonquin charge is sufficient.
(d) SS-1 space charge as listed is paid at 1/12 rate per month. Fuel and loss is collected monthly.
(e) AFT-1: Tariff Sheet No. 22 effective October 1, 2008.
(f) FT-A: Tariff Sheet Nos. 23 effective July 1, 2008, Sheet No. 23A effective October 1, 2008 and
(g) Tennessee transportation fuel & loss retention percentages on Sheet No. 29 effective April 1, 2008
(h) FS: Sheet No. 27 effective July 1, 2008.

Exhibit 4-8 shows representative incremental rates for underground storage and the movement of the gas from the underground storage in Pennsylvania to New England in the case where an LDC wants to buy new capacity. This is used to compute peak-day avoided costs that an LDC could save if it did not need to commit to new peak-day capacity.

Exhibit 4-8 Representative Incremental Pipeline Rates for Transportation and Storage

	Demand $/DT/month	Usage $/DT		Fuel & Loss (a) Winter %	Summer %
Texas Eastern Transmission, L.P. (b)					
Transportation: FT-1, WLA - M3				Dec - Mar	Apr - Nov
WLA-AAB	2.602				
ELA-AAB	2.152				
M1 - M3	10.813				
Total Demand	**15.567**				
WLA - M3 usage (c)		0.061		7.72	6.98
FTS 8 (M3 - M3)	6.864	0.000		2.43	2.42
Dominion: USA Storage: (d)					
Reservation,	4.960				
Space (d) ($/DT/year)	0.083				
Injection		0.023		2.56	2.56
Withdrawal (c)		0.018		0.00	0.00
Dominion transporation (e)					
FT	4.358	0.025		2.85	2.85
Algonquin Gas Transmission LLC (f)					
Transportation: AFT-1 (ITP)	13.011				
Usage (c)		0.002		1.44	1.02
Tennessee Gas Pipeline Company					
				Nov - Mar	Apr - Oct
Transportation FT-A (g) (h) (c)					
Zone 1 (LA) to 4	10.770	0.101		5.90	5.06
Zone 5 to 6	4.930	0.078		2.09	1.86
Stuben Storage FS - Market Area (i)					
Reservation	4.364				
Space ($/DT/month)	0.042				
Injection		0.003		1.50	1.50
Withdrawal		0.003		0.60	0.60
Dominion Transportation (Stuben Storage) (j)					
X-78	2.282	0.003		0.00	0.00

Sources and Notes:

(a) Fuel and loss retention percentage is applied to volumes received.

(b) FT-1: Tariff Sheet Nos. 30 & 31 effective February 1, 2009 and Sheet Nos. 126 & 127 effective December 1, 2008.

SS-1: Tariff Sheet No. 52 effective February 1, 2009 and Sheet Nos. 126 & 127 effective December 1, 2008.
FTS-8: Tariff Sheet No. 59 effective Oct. 1, 2008 and for fuel retention Sheet Nos. 126 & 127 effective Dec. 1, 2008

(c) ACA charge ($0.0017) in the Algonquin and Tennessee usage rates, but not in TETCO usage rates.
Since ACA charge levied only once ina haul, the Algonquin charge is sufficient.

(d)
Dominion: USA Storage Sheet No. 41 effective April 9, 2009 and Sheet 35 (GSS) effective December 4, 2008.

(e) Dominion: FT Sheet No. 32 effective November 1, 2008.

(f) AFT-1 (ITP): Tariff Sheet No. 22 effective October 1, 2008. Fuel & loss retention Sheet No. 40 effective Nov 1, 08.

(g) FT-A: Tariff Sheet Nos. 23 effective July 1, 2008, Sheet No. 23A effective October 1, 2008 and

(h) Tennessee transportation fuel & loss retention percentages on Sheet No. 29 effective April 1, 2008

(i) Stuben Storage FS: Tariff Sheet No. 5 effective May 15, 2007.

(j) Dominion Stuben X-78: Tariff Sheet No 36A effective December 4, 2008.

4.3.3.3. Long-Haul Pipeline "Cash" Costs

Gas is delivered to the LDC each month by pipelines from producing areas, in this analysis assumed to be the Henry Hub.[62] "Cash cost" means the avoided cost of transportation arising from pipeline usage charges, which are paid for each dekatherm of gas transported, and the demand charges allocated to that month, which pay for the reservation of pipeline capacity whether used or not. The avoided commodity cost of gas purchased was the price of gas at the Henry Hub that month multiplied by the ratio of the Henry Hub volume purchased to one dekatherm of gas delivered to the LDC. Because of the retention of gas for fuel and loss in both transportation and storage, more than one dekatherm of gas must be purchased at the Henry Hub in order to deliver one dekatherm to the LDC.

This ratio of gas volumes purchased at the Henry Hub to one dekatherm of gas delivered to the LDC was established by the fuel and loss retention percentages of the various pipeline transportation and storage services used between the Henry Hub and the LDC. For example, assume that the gas is transported by two pipelines: A and B from the Henry Hub to the LDC. The fuel and loss percentage is 6% for A (Fa) and 4 percent for pipeline B (Fb). The fuel and loss amount taken by the pipeline is based on the volumes received by the pipeline (R) while the demand and usage charges are based on the volume of gas delivered by the pipeline (D). In order to compute the ratio of gas received to that delivered the following equations were used:

1. D = R–FR
2. D = R(1-F)
3. R/D = 1/(1-F)

For pipeline A; Ra/Da = 1/(1-.06) = 1.0638; or Ra = 1.0638 Da

For pipeline B; Rb/Db = 1/(1-.04) = 1.0417; or Rb = 1.0417 Db

Since Db is the amount delivered to the LDC, Ra/Db or the ratio of the amount to be purchased in the field to the amount delivered to the LDC is what needs to be computed.

Since: Rb = Da

Ra = 1.0638 Da = (1.0638)Rb = (1.0638)(1.0417)Db

Thus: Ra/Db = (1.0638)(1.0417) = 1.1082

[62] Rate schedules assumed for the long-haul transportation: TETCo, FT-1 from zone WLA to zone M3; AGT, AFT-1 (FT-1) and TGP, FT-A from Zone 1 to Zone 6.

Or: 1.1082 DT of natural gas must be purchased for each DT delivered.

4.3.4. Avoided Costs of Supply (Energy) by Resource by Month

The LDC's weighted average avoided cost in each month is a function of the avoided cost of each resource and the relative quantity of *sendout* provided by each source each month. Exhibit 6-6 provides illustrative avoided costs by gas source and pipeline route for gas delivered to New England LDCs in January and June. The relative quantities of sendout, and injections into storage, by month by resource for a typical New England LDC are shown in Exhibit 4-3. Our estimates of the avoided cost of each resource by month are described below.

Exhibit 4-9 Comparison of Avoided Costs of Delivering One Dekatherm of Gas to a New England LDC from Three Sources of Natural Gas and Peak Day

		Texas Eastern & Algonquin		Tennessee Gas Pipeline	
		January	June	January	June
Pipeline Long-haul to LDC	**units**				
Total Demand Cost of Gas Delivered to LDC	2009 $/DT	$0.99	$0.00	$0.67	$0.00
Total Usage Cash Cost of Gas delivered to LDC	2009 $/DT	$0.07	$0.07	$0.15	$0.15
Ratio of Gas Purchased at HH to Gas Delivered to LDC		1.099	1.086	1.085	1.071
Delivered From Underground Storage					
Total Demand Cost of Gas Delivered to LDC from UG Storage	2009 $/DT	$1.37		$1.16	
Total Cash cost for refill + Usage Cost of Gas delivered to LD(	2009 $/DT	$0.83		$0.80	
Ratio of Gas Purchased to Gas Delivered to LDC		1.145		1.093	
LNG Regasified into LDC System					
Total Demand Cost of Gas Delivered to LDC for LNG refill	2009 $/DT	$0.91		$0.62	
Total Usage Cash Cost of Gas delivered to LDC for LNG refill	2009 $/DT	$0.09		$0.19	
Ratio of Gas Purchased at HH to Regasified Gas at the LDC		1.349		1.331	
Peak Day in January From Underground Storage					
Typical Rates					
Pipeline Cash Demand Cost of Gas Delivered to LDC	2009 $/DT	$100.33		$84.79	
Pipeline Cash Commodity Cost of Gas Delivered to LDC	2009 $/DT	$0.83		$0.80	
Ratio of Gas Purchased at HH to Gas Delivered to LDC		1.145		1.093	
Incremental Rates					
Pipeline Cash Demand Cost of Gas Delivered to LDC	2009 $/DT				
Pipeline Cash Commodity Cost of Gas Delivered to LDC	2009 $/DT				
Ratio of Gas Purchased at HH to Gas Delivered to LDC					
Based on pipeline rates effective May 12, 2009					

4.3.4.1. Direct Long-Haul Pipeline Delivery

The analysis of a typical New England LDC send-out and storage refill shown in Exhibit 6-2 indicates that LDCs use 100% of their pipeline capacity to provide deliver supply in winter months. The use of the long-haul transportation capacity in the winter varies from about 85% in February and March to 100% in December. In summer months they use approximately 80% of this capacity. Like AESC 2007, this report allocates the winter-month pipeline-transportation-demand charges plus

20% of summer demand charges among the five winter months according to the quantity of capacity used each winter month. As a result, the avoided transportation demand cost varies among the five winter months with the month of heaviest use, December, receiving the largest allocation of demand charges.

Of that 80% of pipeline capacity LDCs use in the summer, they use 47% to deliver gas for injection into storage and 33% to provide direct supply.

- Like AESC 2007, we allocate the costs of demand and usage charges and the fuel and loss fraction for pipeline transportation from the Henry Hub to refill storage to the avoided cost of underground storage and LNG peaking services.
- Like AESC 2007, we assume that an LDC will not avoid any capacity cost due to a reduction in summer load, because it needs to hold the capacity entitlement in order to serve its winter load and because the market value of short-term, summer releases of pipeline capacity is close to zero. This low market value is reflected in the low basis differentials in the summer between the Henry Hub and either the ALG gas spot market or the TGP Z6 spot gas market. The basis differential for each market was enough to cover the usage charges and fuel, but there was little or no amount remaining to pay for demand charges. This means that an LDC would continue to pay the full demand charge in each summer month even if the gas requirements of customers were reduced due to energy efficiency in the summer; thus the LDC would not avoid the summer pipeline demand charges.

4.3.4.2. Underground Storage

Natural gas is delivered to the LDC from underground storage during the five winter months of November through March; see Exhibit 4-3 above. For both TETCo and TGP, the underground storage is located in Pennsylvania. The avoided cost of underground storage supply for one dekatherm in January is shown in Exhibit 4-9.

The avoided cost of underground storage included the cost of buying gas at the Henry Hub, pipeline demand and usage charges to bring gas to the storage facility in the summer, the cost of injection, the demand cost of storage capacity, the demand and variable costs of withdrawing gas from storage and the demand and variable costs of transporting gas to the LDC from underground storage.[63]

[63] Rate schedules used in the calculation for the TETCo-AGT route are: TETCo, FT-1 zone WLA to zone M3; storage on TETCo and transportation to AGT, SS-1; and transportation to the LDC on AGT, AFT-1 (WS-1). Rate schedules used in the Tennessee route are: TGP, FT-A zone 1 to zone 4; storage on TGP, FS–market area; and transportation to the LDC on TGP, FT-A zone 4 to zone 6.

The cost of gas injected into storage was the cost of buying gas at the Henry Hub, as adjusted for fuel and loss retention, plus the cost of transportation to underground storage including both demand and usage costs at 100% load factor. The cost of the gas injected into storage was less than the average cost of gas for a year, 95.6% of the annual cost, because gas is purchased for injection during the summer months when the price of gas is less than average.

Pipelines bill to LDCs the demand charges for the capacity LDCs hold for withdrawal of gas from storage and transportation to the LDC every month of the year. Therefore, in this study we allocated a full year of withdrawal and transportation-demand charges to the five winter months.[64] These annual demand charges were allocated among each of the five winter months according to the relative quantity of capacity the LDC used in each month. January is the peak send-out month from all gas sources and from underground storage; the other winter months, especially November and March, experience less send-out as shown in Exhibit 4-5. Thus, the demand cost of unused capacity of storage withdrawal and of transportation capacity from underground storage to the LDC in November and March was assigned to the sendout during December through February based on usage each month. Similarly, the unused capacity during December and February was assigned to the cost of withdrawing and transporting gas to the LDC in January.

4.3.4.3. Liquid Natural Gas and Peak Shaving

There are 46 liquefied-natural-gas (LNG) tanks in New England in addition to the Distrigas LNG import terminal. These tanks, and to a lesser extent propane, provide peak-shaving supply for LDCs. The costs avoided by peak shaving are based only on LNG in AESC 2009. These facilities have fixed and variable costs. The estimate of avoided costs was based on the variable costs only.

The major embedded or accounting costs of LNG send-out for peaking service are the fixed costs of building the tank, vaporization and liquefaction capacity, and the fixed costs of operation and maintenance. However, these fixed costs are likely to be unaffected by reductions in gas demand due to modest-sized efficiency improvement measures. These fixed costs are sunk costs. Moreover, LNG peaking facilities have strong economies of scale and thus are lumpy investments. They are likely to be sized to accommodate growth in gas send-out. In addition, the cost of changing the capacity of send-out is the cost of vaporization facilities, which is a

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[64]This is true of the storage and delivery service of TETCo in rate schedule SS-1 as well at withdrawal from storage and transportation to the LDC on TGP. However, AGT has a winter service, WS, firm transportation from the interconnection with TETCo to New England LDCs which has demand charges for only the five winter months. AESC 2007 reflects AGT's five months of demand charges in its allocation and calculation.

small portion of the total fixed costs of the LNG peaking facility. Thus, it was assumed that the avoided cost of LNG peaking facilities due to efficiency improvements should ignore these fixed costs.

The avoided costs of LNG peaking are the variable costs of the LNG; the cost of gas at the Henry Hub, costs of pipeline transport to bring gas to the LNG facility, including pipeline demand charges, and then the variable costs of liquefaction and re-gasification.[65] The variable costs of liquefaction and vaporization are principally the gas that is used in the liquefaction stage and the vaporization stage. It was assumed that fuel use is 17% for liquefaction and 3% for vaporization. This is the same cost methodology used in AESC 2007.

The estimated avoided cost of LNG peaking service varies by time and pipeline; see Exhibit 4-9.

4.3.5. Avoided Costs of Peak Day Supply

We calculate the avoided costs of gas delivered on a single peak day. There was some discussion among the members of the study group as to whether avoided peak day costs are needed to evaluate gas energy efficiency measures. Like AESC 2007 we calculate the avoided gas cost at the city gate by month. This monthly avoided gas cost includes both avoided fixed costs (cash pipeline demand charges) and variable costs (gas commodity costs, cash pipeline usage charges and adjustments for fuel and losses in pipeline transportation and storage of gas). These avoided costs are then used in the avoided cost of gas in end uses, which LDCs tell us are used to evaluate efficiency programs.

Nonetheless, some program administrators have raised questions regarding the calculation of avoided peak-day gas costs used in AESC 2009, and how to apply those costs when evaluating gas efficiency programs. One question relates to the apparent differences between avoided electric capacity costs and avoided gas peak-day costs. In electricity distribution, load-serving entities (LSEs) responsible for providing firm supply of electricity to retail customers acquire a sufficient total quantity of capacity to ensure reliable service using a mix of different types of resources. The New England electric industry has separate, explicit wholesale markets for electric capacity and for electric energy. ISO-NE requires load-serving entities to hold sufficient total capacity equal to their projected summer coincident peak plus an additional reserve equal to an explicit “reserve margin multiplier.”

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[65] Rate schedules used for the long-haul transportation of gas in the summer to be liquefied are the same as those cited for long-haul transportation: TETCo, FT-1 from zones WLA to zone M3; AGT, AFT-1 (FT-1) and TGP, FT-A from zone 1 to zone 6. LDC LNG tanks are also filled by hauling imported LNG from the Distrigas facility to the LNG tank by tanker truck. However, we assume that Distrigas will price this LNG at the LDC’s avoided cost of liquefaction.

The electric reserve margin multiplier reflects the additional quantity of capacity in order to ensure reliability. It is in the range of 15%: LSEs are required by ISO-NE to hold capacity equal to 1.15 times their projected peak demand under normal conditions. This is a uniformly applied regulatory requirement that allows a calculation of avoided cost when the peak requirement is reduced by efficiency programs: usually assuming a gas-fired combustion turbine is the proxy for the cost of the peaking resource.

But the electricity and gas industries are different. Gas can be and is stored in substantial quantities in various ways: LNG tanks, underground storage, and line pack. In contrast, electricity, as a practical matter, cannot be stored. Furthermore, the flow of electricity in the electricity grid is controlled largely by Kirchoff's laws, which at times of stress has led to large scale blackouts. In contrast, the flow of gas in the gas grid is controlled by compressors and valves that are themselves controlled by people who follow contracts, nominations, and, occasionally, emergency protocols. As a consequence the gas grid has not experienced the equivalent of widespread blackouts. These differences have led to some of the differences in regulation and operation between the gas and electricity industry.

Unlike the electricity industry, the New England gas industry LDCs buy gas largely in the wholesale markets of production areas of the U.S. Southwest, Appalachia, and Canada, and some perhaps in the New England wholesale market for gas energy. There is no New England market for gas capacity. Rather LDCs buy transmission and underground storage capacity from pipelines via bilateral contracts where the prices are generally set in a FERC regulated tariff. Moreover there is no equivalent to ISO-NE that imposes explicit uniform reliability requirements to LDCs in New England. Instead, it is our understanding that each LDC determines the total physical quantity of capacity it needs to hold to ensure reliable supply service under two sets of design conditions. The first set is a *design day*, a needle peak demand during 1–days of substantially colder-than-normal temperatures that occur only rarely. The second set is a *design winter,* the level of sendout in each month of a winter with colder-than-normal temperatures. LDCs must demonstrate to their state regulators that they hold sufficient capacity to ensure reliable service.

Local distribution companies acquire the capacity needed to meet design-day demands from a range of resources, according to their particular location and circumstances. For example Vermont Gas Systems relies on spot gas for peaking under an arrangement with its supply pipeline. Many New England LDCs use local LNG storage facilities to meet peak day requirements. One New York utility appears to rely upon a large, gas-fired cogeneration power plant to switch to No. 2 fuel oil and release gas to the LDC on a few peak days in a year. Thus, it is clear that there is no uniform generally applicable formula to use peak-day avoided costs for efficiency program evaluations.

It appears that the avoided costs presented in Exhibit 4-4 are comprehensive and generally applicable in New England. However, we provide an estimate of avoided peak-day costs for those LDCs who do wish to include an avoided peak-day cost in our exhibits. Other LDCs may wish to add an amount to account for a design-winter reserve margin, perhaps 10% greater than during a normal winter sendout, when computing their avoided cost. The avoided demand charges for each month of the winter will provide the number for such an addition to the avoided costs computed here.[66]

4.3.5.1. Peak-Day Avoided Cost

Liquid-natural-gas peaking facilities are generally used to meet the peak-day requirements of New England LDCs. The fixed costs were excluded from the estimate of the avoided costs for the LNG facilities. The resulting modest cost, which excludes fixed costs, does not properly capture the high avoided costs that are expected for peak day service.

Consequently, peak-day avoided costs are estimated based on the costs of underground storage. We assume that underground storage and transportation capacity to the LDC was needed to meet a one-day peak even though the demand charges are generally paid for twelve months.[67] Thus, in calculating the peak-day avoided cost, the demand charges for all twelve months were allocated to the one-day peak.

Two sets of demand charges were used to produce two estimates of peak-day avoided costs: (1) the typical rates that LDCs in New England pay, Exhibit 4-7 above, and (2) representative incremental rates that a New England LDC might pay for new underground storage capacity and new transportation capacity from that storage to the LDC in winter, Exhibit 4-8 above.[68]

The estimate of peak-day avoided costs is shown in Exhibit 4-9 for both the TETCo-ALG and the TGP routes and for typical and incremental rates. As can be

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[66] Two LDCs assured us that such costs are already accounted for in their calculations and that we should not change our methodology from that of AESC 2007.

[67] In the case of transportation of stored gas to New England on AGT, a winter service is used for which demand charges are paid for only the five-month winter period.

[68] The rates shown in Exhibit 4-8 are currently charged by the indicated utilities but these are representative of the rates for new underground storage and transportation capacity. They are not necessarily rates that any LDC could today obtain for new underground storage capacity and associated transportation, which may be even greater than shown in Exhibit 4-8.

seen greater incremental demand charges, especially when several pipelines are used for transportation, produce high peak-day avoided costs.

An alternative estimate of the avoided cost of natural gas on a peak-day to a New England LDC is the spot market price of natural gas in New England on a peak day. The largest peak-day sendout in New England since 2002 occurred on January 15, 2004 (Leahey 2008, 62). During that day the spot price of gas in ALG was $63.42 per dekatherm, and the spot price at TGP Zone 6 was $49.81 per dekatherm.

4.3.6. Total Avoided Costs by Month

In this step, the avoided costs of natural gas were determined by month in two of the three geographic areas: Northern and Central New England (Massachusetts, New Hampshire and Maine) and Southern New England (Connecticut and Rhode Island). The avoided cost forecast for Vermont is presented later within this chapter. The avoided cost of natural gas by month is calculated as the weighted average of the avoided cost of gas delivered to the LDC from each of the three sources: long-haul pipeline, underground storage, and LNG storage.

The weightings each month are shown in Exhibit 4-5 above under the “Fraction of Annual Sendout Each Month” section of the exhibit.[69]

Like AESC 2007, we assume that the avoided cost in Southern New England is the cost of gas delivered to LDCs by the Texas Eastern and Algonquin pipeline route. Similarly, we assume that the avoided cost of gas delivered to LDCs in Northern and Central New England was provided by Tennessee Gas Pipeline.

The avoided cost forecast by month for Southern New England, Northern and Central New England, and Vermont Gas Systems are detailed in Appendix D. Also shown in the appendix is the annual Henry Hub forecast price of natural gas. Other than for the peak-day, the commodity cost of gas based on the Henry Hub price was the largest component of the avoided cost.

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[69]The summer periods, April–October, and November and December all fall within a single calendar year; thus, the commodity cost of gas for those months is based on the Henry Hub price for that calendar year. However, the winter periods, November–March, span calendar years. The majority of gas delivered in the winter is from LNG and underground storage, which was purchased during the previous summer. Thus, we assume that the commodity cost of gas from underground storage and LNG is based on the Henry Hub price from the year in which the winter delivery period begins. However, we assume that the gas supplied directly from the long-haul pipeline delivery is purchased in the month of delivery and thus January–March costs are based on the Henry Hub price for the following year.

The levelized avoided cost is the cost for which the present value at the real riskless rate of return of 2.22 percent has the same present value as the estimated avoided costs for the years 2010 through 2024 at the same rate of return.

4.3.6.1. Comparison with the AESC 2007 Avoided-Cost Calculations for an LDC

Avoided costs by source in 2009 dollars are very similar to those in 2007 dollars in AESC 2007, see Exhibit 4-10.[70] Rates did not change much from 2007 to 2009 in nominal dollar terms. When comparing these costs by source in 2009 dollars the AESC 2007 costs are higher because the rates charged by TETCo, AGT, and TGP do not keep up with inflation. The major difference in the avoided costs will be due to changes in the cost of gas at Henry Hub.

Exhibit 4-10 Comparison of AESC 2007 and AESC 2009 Avoided Costs by Source

		AESC 2007	AESC 2007	AESC 2009
	units	2007$/DT	2009 $ per Dekatherm	
Pipeline Long-haul to LDC				
Total Demand Cost of Gas Delivered to LDC	$/DT	$0.98	$1.02	$0.99
Total Usage Cash Cost of Gas delivered to LDC	$/DT	$0.07	$0.08	$0.07
Ratio of Gas Purchased at HH to Gas Delivered to LDC		1.113	1.113	1.099
Delivered From Underground Storage				
Total Demand Cost of Gas Delivered to LDC from UG Storage	$/DT	$1.39	$1.45	$1.37
Total Cash cost for refill + Usage Cost of Gas delivered to LDC	$/DT	$0.83	$0.87	$0.83
Ratio of Gas Purchased to Gas Delivered to LDC		1.149	1.149	1.145
LNG Regasified into LDC System				
Total Demand Cost of Gas Delivered to LDC for LNG refill	$/DT	$0.90	$0.94	$0.91
Total Usage Cash Cost of Gas delivered to LDC for LNG refill	$/DT	$0.09	$0.09	$0.09
Ratio of Gas Purchased at HH to Regasified Gas at the LDC		1.349	1.349	1.349
Peak Day in January From Underground Storage				
Typical Rates				
Pipeline Cash Demand Cost of Gas Delivered to LDC	$/DT	$101.73	$106.00	$100.33
Pipeline Cash Commodity Cost of Gas Delivered to LDC	$/DT	$0.83	$0.87	$0.83
Ratio of Gas Purchased at HH to Gas Delivered to LDC		1.149	1.149	1.145

AESC 2009 based on pipeline rates effective May 12, 2009. AESC 2007 based on rates effetive April 2007

As can be seen the avoided costs by source are very similar when comparing the AESC 2007 costs in 2007 dollars and the AESC 2009 costs in 2009 dollars. This is true because the rates did not change much from 2007 to 2009 in nominal dollar terms. When comparing these costs by source in 2009 dollars the AESC 2007 costs are higher because the rates charged by TETCo, AGT and TGP do not keep up with inflation. The major difference in the avoided costs will be due to changes in the cost of gas at Henry Hub.

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70 This comparison is for the pipeline route of TETCo and AGT. However, the comparison of avoided-cost estimates along the TGP route would provide similar qualitative comparisons.

4.4. Avoided Gas Costs by End Use

End uses of natural gas at retail are distinguished by the type of end-use: heating or non-heating and all. The costs associated with these end-uses also vary by the type of customer, i.e., residential, commercial, and industrial.[71]

4.4.1. Load Shape by End Use

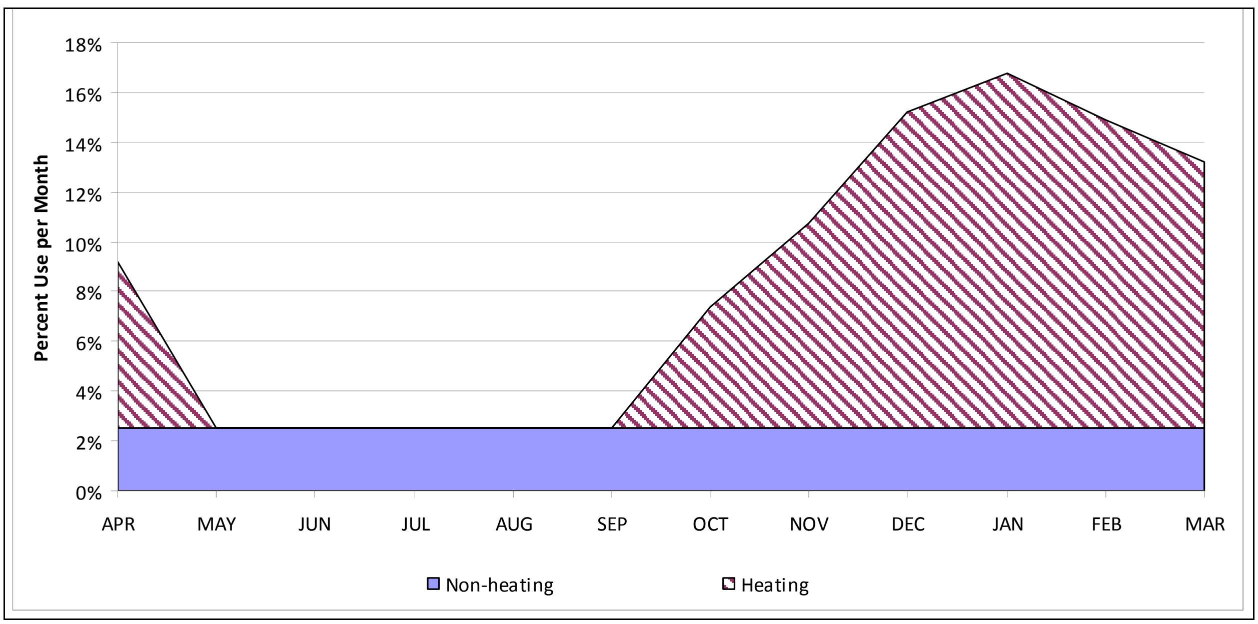
The different types of end-use have different profiles of gas use by month as shown in Exhibit 4-11 and Exhibit 4-12. Exhibit 4-11 shows the load profile of heating loads as percentages, which are graphed in Exhibit 4-12.

Exhibit 4-11 End-Use Load Profiles

		APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	ANNUAL
Non-Heating (base load)	(a)	8.33%	8.33%	8.33%	8.33%	8.33%	8.33%	8.33%	8.34%	8.34%	8.34%	8.34%	8.33%	100%
	30%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	
Heating Load	(b)	9.60%	0.00%	0.00%	0.00%	0.00%	0.00%	7.00%	11.80%	18.20%	20.40%	17.70%	15.30%	100%
	70%	6.7%	0.0%	0.0%	0.0%	0.0%	0.0%	4.9%	8.3%	12.7%	14.3%	12.4%	10.7%	
All Loads: Heating and Non-heating	(c)	9.22%	2.50%	2.50%	2.50%	2.50%	2.50%	7.40%	10.76%	15.24%	16.78%	14.89%	13.21%	100%

(a) Constant load all year; rounding altered in the winter months to maintain 100% use for the year.
(b) Based on Average Heating Degree Days for New England, excluding May thru September, for 60 years.
Source: NOAA, National Climatic Data Center, Historical Climatological Series 5-1, "Heating Degree Days, July 1931 - June 1992 Weighted by Population (1990 C
(c) Weighted average for each month at 70% heating load shape and 30% non-heating load shape.

Exhibit 4-12 End-Use Load Profiles Graphed



[71] The electric power sector is not addressed here.

The heating loads occur October through April with a peak in January. This load profile is derived from the heating degree days in New England averaged over a 61 year period.[72] The non-heating load is constant year round while all loads are represented as the weighted average between the heating and the non-heating load weighted 70% to heating and 30% to non-heating.

The avoided cost of the gas sent out by the LDCs by load type is the sum across all months of the avoided cost per dekatherm each month as detailed in Appendix D, multiplied by the percent used each month for each load type. The levelized avoided cost is the cost for which the present value at the real riskless rate of return of 2.22 percent has the same present value as the estimated avoided costs for the years 2010 through 2024 at the same rate of return. The resulting avoided cost each year for the different load types is shown in Appendix D.

4.4.2. Distribution Cost by Sector

The avoided cost for each end use sector by load type and the retail sector is the sum of the avoided cost of the gas sent out by the LDC and the avoidable distribution charges, called the avoidable LDC margin, applicable from the city gate to the burner tip.

Some LDCs in New England have estimated incremental costs, that is, the cost of distribution incurred as demand increases. The conclusion was that the incremental cost of distribution depends upon the load type and the customer sector. For heating loads approximately 70% of the embedded cost for each sector is incremental or avoidable. For non-heating loads approximately 40% of the embedded cost is avoidable. For all loads approximately 60% of the embedded cost is avoidable. As in AESC 2007, the embedded cost was measured as the difference between the city-gate price of gas in a state and the price charged each of the different retail customer types: residential, commercial, and industrial.[73] The embedded distribution cost for each of the two regions, Southern and Northern and Central, were the weighted average distribution costs among the relevant states where the weighting is the volumes of gas delivered to each sector in each state.

Exhibit 4-13 shows the estimated avoidable LDC margin costs, measured as 2009 dollars per dekatherm, by each of the end-use types and customer sectors for each region in New England.

[72] A heating degree day is defined as the positive difference between the average temperature, as determined by the average of the high and low daily temperatures, and 65 degrees F.

[73] The city-gate gas prices and the prices charged to each retail customer sector are reported by the Energy Information Administration for each state each year.

Exhibit 4-13 Avoidable LDC Margin

	Total LDC Retail Margin & CG Price	Avoidable LDC Margin		
Type of End Use		Heating	Non-heating	All
Avoidable Margin (percent) (b)		70.0%	40.0%	60.0%
Southern New England (c)				
Average City Gate Price	8.87			
Residential	7.44	5.21	2.98	4.46
Commercial	4.50	3.15	1.80	2.70
Industrial	2.09	1.46	0.84	1.25
Commercial & Industrial (e)	3.60	2.52	1.44	2.16
All Retail (f)	5.35	3.74	2.14	3.21
Northern & Central New England (d)				
Average City Gate Price	9.93			
Residential	6.51	4.56	2.60	3.91
Commercial	4.72	3.30	1.89	2.83
Industrial	3.94	2.76	1.58	2.37
Commercial & Industrial (e)	4.38	3.07	1.75	2.63
All Retail (f)	5.43	3.80	2.17	3.26
Vermont				
Average City Gate Price	7.63			
Residential	5.90	4.13	2.36	3.54
Commercial	3.10	2.17	1.24	1.86
Industrial	0.24	0.17	0.10	0.14
Commercial & Industrial (e)	1.64	1.15	0.66	0.98
All Retail (f)	3.20	2.24	1.28	1.92

Source: EIA Annual Energy Review 2007 or EIA website data sources.
(a) Average of Margins among states for 2003 - 2007 weighted by the delivered volumes in each state.
(b) Based on LDC marginal cost studies.
(c) Southern New England is Rhode Island and Connecticut
(d) Northern & Central New England is Massachusetts, New Hamshire and Maine.
(e) An average of the margins weighted by the commercial and industrial use delivered volumes.
(f) An average of residential, commercial and industrial margins weighted by associated volumes.

4.4.3. Avoided Costs by End-Use

Appendix D shows the total avoided costs for the retail end-uses categorized by the end-use type and customer sector for Southern New England. The avoided cost for each retail end-use type is the sum of the avoided cost of gas delivered to LDCs for the end-use type (heating, non-heating or all) plus the avoided LDC margin for the associated end-use type and customer sector as shown in the exhibit above.

Appendix D shows the total avoided cost for the various retail end-uses categorized by the end-use types and customer sector for Northern and Central New England.

4.4.4. Comparison of Avoided Retail Gas Costs with AESC 2007

Other than residential hot water use, the retail avoided cost is greater in AESC 2007 even in 2009 dollars; see Exhibit 4-14. The cause is not an increase in the avoided cost of gas at the city gate. Our estimated levelized avoided costs are very similar to those of AESC 2007 because the methodology to develop the avoided costs is the same in each and there was no dramatic change in key input assumptions (projection of Henry Hub prices and pipeline-service rates). Our estimate of avoided costs in February and March is larger than other months because the data used to compute the prices in these months showed a lower monthly coefficient to the annual price relative to AESC 2007. In addition, we forecast lower gas prices at the Henry Hub in the years 2009 to 2011 and higher prices thereafter than what was forecasted for AESC 2007. However, the differences in these prices tend to be offset with the discounting and levelization over a fifteen-year period as shown in Exhibit 4-4.

That exhibit shows that the levelized avoided cost of gas at the city gate that we estimate is slightly less than in AESC 2007. Rather the avoidable LDC margin has increased since 2007; see Exhibit 4-4. The avoidable margin has increased for two reasons: (1) the five-year average LDC margin has increased, and (2) the percentage of the LDC margin that is avoidable has increased for heating and for all loads.

Exhibit 4-14 Comparison of Avoided Cost with Those of AESC 2007

2009$/Dekatherm except where indicated as 2007$/DT

	RESIDENTIAL				COMMERCIAL & INDUSTRIAL			ALL RETAIL
	Non Heating	Hot Water	Heating	All	Non Heating	Heating	All	
AESC 2007 end-use period (a)		annual	5-month	6-month	annual	5-month	6-month	5-month
Southern New England								
AESC 2007 (2007$/DT)		11.15	12.32	11.97	9.12	10.29	9.94	11.18
AESC 2007 (b)		11.62	12.84	12.48	9.50	10.72	10.36	11.65
AESC 2009	11.42	11.42	14.52	13.52	9.88	11.83	11.21	12.26
2007 to 2009 change		-1.71%	13.09%	8.33%	4.04%	10.36%	8.25%	5.25%
Northern & Central New England								
AESC 2007 (2007$/DT)		10.87	11.86	11.56	9.78	10.78	10.48	11.27
AESC 2007 (b)		11.32	12.35	12.04	10.19	11.23	10.92	11.74
AESC 2009	10.87	10.87	13.54	12.68	10.02	12.05	11.40	12.03
2007 to 2009 change		-3.95%	9.62%	5.28%	-1.65%	7.31%	4.40%	2.44%
Vermont								
AESC 2007 (2007$/DT)		10.01	11.20	10.85	8.00	9.19	8.84	9.95
AESC 2007 (b)		10.43	11.67	11.31	8.34	9.58	9.21	10.37
AESC 2009	9.75	9.75	12.51	11.62	8.05	9.53	9.07	10.00
2007 to 2009 change		-6.52%	7.22%	2.82%	-3.48%	-0.48%	-1.56%	-3.53%

(a) In AESC 2007 the end-use profiles was defined as a certain number of months in the winter period; e.g. 5-months is Nov. - Mar

(a) Factor to convert 2005$ to 2007 $ 1.0420

Note: AESC 2007 levelized costs for 16 years, 2007 - 2022 at a discount rate of 2.2165%.
AESC 2009 levelized costs for 15 years 2010 - 2024 at a discoiunt rate of 2.22%.

In both cases the total LDC margin is estimated as the average of the most recent five years of data; 2001–2005 for AESC 2007 and 2003–2007 for AESC 2009. The total LDC margins, in nominal dollars, for all states but Vermont were greater in the years 2006 and 2007, which were added to the average for AESC 2009 than in the years 2001 and 2002 which are included in the 2007 analysis but excluded from the current one. Thus the current LDC margins are greater, except for Vermont, than in AESC 2007.

In addition, with a closer look at the underlying analysis of LDC marginal costs, it became apparent that heating loads had about 70% of the margin was avoidable and only about 40% was avoidable for non-heating loads. The result is an increase in the estimate of the avoidable margin for heating and all loads.

4.5. Avoided Gas Costs in Vermont

There is one LDC in Vermont, Vermont Gas Systems, Inc. (VGS). It receives its gas from TransCanada Pipeline at Highgate Springs, Vermont. The analysis of the avoided cost to the LDC in Vermont was performed similarly to that for the other two areas. Based on a purchased-gas-adjustment filing by VGS, the source of gas was determined for each month of the year by the fraction contribution each month to serve firm customers.[74] Next, the marginal cost of natural gas to VGS by source for each month the source is in operation was computed, and then volume weighted average avoided cost of gas received at the city gate was computed by month.

Each month, Vermont receives gas purchased in Alberta and transported by TransCanada Pipeline. During the winter months, November through March, Vermont also receives gas from underground storage and about 20% from purchases in spot markets. VGS has interruptible customers whom it serves using gas purchased in spot markets. During the winter, including April, when gas is needed to serve firm customers' peak loads, VGS interrupts its interruptible customers and delivers the spot gas thus released to its firm customers. Exhibit 4-15 shows the gas-supply characteristics of VGS for the as fractions while Exhibit 4-16 shows the gas supply by source each month and also storage refill.

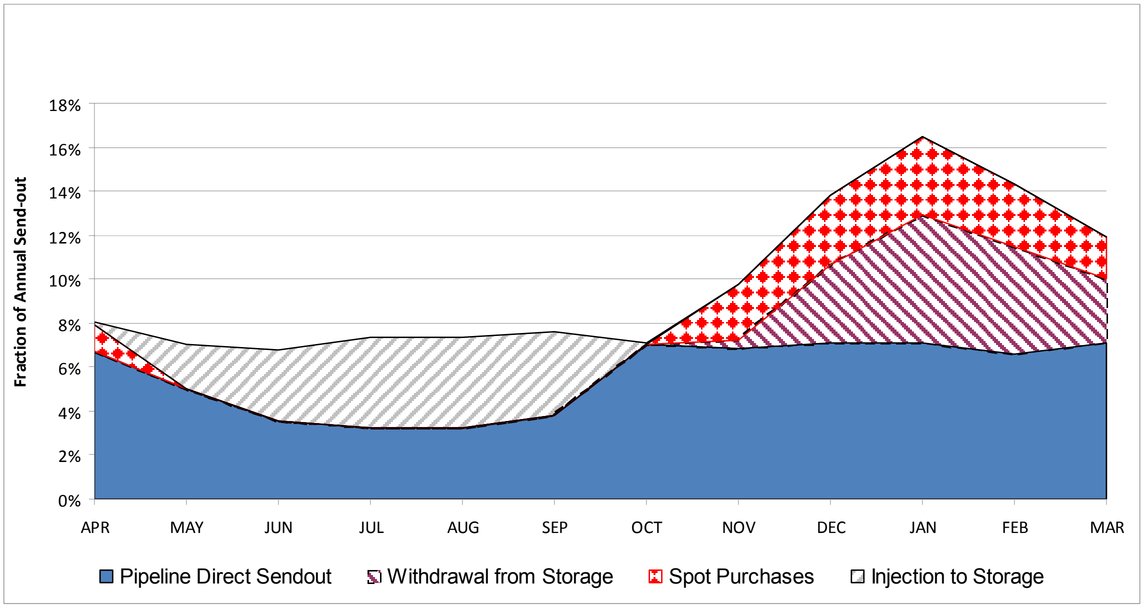
Exhibit 4-15 Vermont Gas System: Monthly Sendout Fractions by Source, Peak Month, and Storage Injection

	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR
Fractions of VGS Send-out by Source Each Month												
Pipeline Deliveries, Long-haul	85%	100%	100%	100%	100%	100%	100%	70%	51%	43%	46%	59%
Underground Storage	0%	0%	0%	0%	0%	0%	0%	4%	26%	36%	34%	25%
Spot Purchases	15%	0%	0%	0%	0%	0%	0%	26%	23%	22%	20%	16%
Total	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Fraction of Annual Sendout each Month	8%	5%	4%	3%	3%	4%	7%	10%	14%	16%	14%	12%
Monthly Sendout as a Fraction of Peak Month	48%	30%	21%	20%	20%	23%	43%	59%	84%	100%	87%	72%
Fraction of Underground Storage Injection by Month	1%	12%	18%	24%	24%	22%	1%	0%	0%	0%	0%	0%

Sources:
(a) Purchased Gas Adjustment filing by Vermont Gas Systems for year April 2007 - March 2008. Data used is for the year November 2007 - October 2008.

[74] This was the purchased-gas-adjustment filing for the year April 2007–March 2008. However, the annual period November 2007–October 2008 was used to generate the representative VGS gas supply characteristics.

Exhibit 4-16 Vermont Gas System Sendout by Source and Underground Storage Refill



Since this avoided-cost forecast was based on a forecast price of gas at the Henry Hub in Louisiana, the basis differential (price of gas in Alberta at the AECO hub minus the price at the Henry Hub) was taken from the NYMEX futures market for the two year period April 2011 through March 2013.[75] NYMEX shows a constant basis differential for the winter, November through March, and a different but constant basis differential for the summer, April through October. The average ratio of the Alberta gas price to the Henry Hub price is 0.888 for the winter and 0.876 for the summer.[76]

The pipeline-transportation rates, rates for underground storage and transporting gas to VGS from underground storage, and the rates for transporting spot gas to VGS at 100% load factor, are used in the avoided cost forecasts. They are the same rates as used in AESC 2007[77]. We assume these rates will prevail throughout the forecast period.

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[75]These ratios are estimated from NYMEX futures settlements for March 31 2009 of the AECO minus Henry Hub basis differential from the period April 2011 through March 2013 and compared to the Henry Hub futures price data for the same period.

[76]These ratios are close to those in AESC 2007: winter 0.851 and summer 0.895.

[77]?? to verify

Exhibit 4-17 Toll Rates of Vermont Gas Systems in 2009$

	Demand (a) $/DT/Month		Usage $/DT		Fuel & Loss percent	
Firm Transportation						
Long-Haul	31.836	(a)	0.088	(b)	4.30%	(c)
From Storage	6.926	(a)	0.017	(b)	0.90%	(c)
Storage						
Injection			0.005	(d)	0.60%	(d)
Space	0.040	(e)				
Withdrawal			0.005	(d)	0.60%	(d)
Spot Gas Transportation						
Parkway to Phillipsburg	6.926	(a)	0.017	(b)	0.55%	(c)

(a) TransCanada Final Tolls effective May 1, 2009
(b) TransCanada Final Tolls effective May 1, 2009
(c) TransCanada Website; estimated. Fuel is actual and changes each month.
(d) Union Gas Rate M12 effective January 1, 2009.
(e) Calculated from VGS Purchased Gas Adjustment data 2007.
Note: 1 DT = 1 MMBtu = 1.055056 Giga Joules (GJ)
1 CD$ = 0.8650 US$ (3 month forward rate as of 29 June 2009)
Thus, US$/DT is calculated as 0.9126 of CD$/GJ

Based on the VGS's purchased-gas-adjustment filing, unlike other New England LDCs (and VGS in AESC 2007), long-haul transportation is used at about 100 percent load factor in the summer months for refilling underground storage and direct deliveries of gas to VGS and at 100% load factor in the winter. The increased requirements in the winter are served by underground storage and purchases of spot gas. The costs of underground storage include the costs of transportation of gas to fill storage, the cost of storage, and the cost of transportation from storage to VGS. However, according to the purchased-gas-adjustment filing, demand charges are paid twelve months a year for the storage withdrawal capacity and transportation from storage to VGS, which are the same assumptions used for both TETCo and TGP. (Transportation of stored gas from the terminus of TETCo to LDCs on AGT uses winter service which has only five months of demand charges.) Purchases of gas in the spot market make up slightly more than 20% of the Vermont winter gas supply. The prices of these spot purchases were estimated by the ratio of (1) the estimated spot price for the winter months October 2007–March 2008 to (2) the 2007 annual Henry Hub gas price. The components of the avoided costs by the three sources of gas to Vermont are shown in Exhibit 4-18.

Exhibit 4-18 Cost From Three Sources of Supply

	units	TransCanada Pipeline January	June
Pipeline Long-haul to LDC			
Pipeline DemandCost of Gas Delivered to LDC	2009 $/DT	$1.047	$0.000
Pipeline Usage Cost	2009 $/DT	$0.088	$0.088
Ratio of Gas Purchased in Alberta to Gas Delivered to LDC		1.0449	1.0449
Delivered From Underground Storage			
Pipeline Demand Cost of Gas Delivered to LDC	2009 $/DT	$2.038	
Pipeline Commocity Cost of Gas Delivered to LDC	2010 $/DT	$1.679	
Ratio of Gas Purchased to Gas Delivered to LDC		1.0672	
Spot Purchases of Gas			
Pipeline Demand Cost of Gas Delivered to LDC	2009 $/DT	$0.546	
Pipeline Usage Cost of Gas Delivered to LDC	2009 $/DT	$0.017	
Ratio of Gas Purchased to Gas Delivered to LDC		1.0055	
Ratio of Spot Gas Price to Annual Henry Hub Price		1.230	
Peak Day in January From Underground Storage			
Pipeline Cash Demand Cost of Gas Delivered to LDC	2009 $/DT	$140.98	
Pipeline Cash Commodity Cost of Gas Delivered to LDC	2009 $/DT	$1.679	
Ratio of Gas Purchased at HH to Gas Delivered to LDC		1.0672	

Based on pipeline rates effective May 1, 2009
Note: Fuel and Loss retention is estimated as an annual average.

We used this to estimate the avoided cost of natural gas delivered to VGS by month for the forecast period as shown in Appendix D. The AESC 2007 and AESC 2009 monthly avoided costs as levelized over fifteen years are shown in Exhibit 4-4. As in the other New England sectors, the levelized avoided costs are slightly less in AESC 2009 in 2009 dollars because the pipeline-transportation and storage rates on the Trans-Canada Gas Pipeline have increased since 2007 but this increase is offset by slightly lower fuel and loss-retention requirements.

As in the other LDCs of New England, the avoided gas cost delivered to VGS's city gate by load type is shown in Appendix D. The retail avoided cost is the avoided gas cost delivered to the city gate of the LDC plus the LDC avoided margin. The LDC's avoided margin varies with load type; it is shown in Exhibit 4-13. The avoided costs to the specified load types and customer sectors are shown in Appendix D.

The levelized avoided retail costs in Vermont are less than estimated in AESC 2007; see Exhibit 4-14. The current retail end-use avoided cost, in 2009 dollars, is sometimes lower and sometimes higher than estimated in 2007 because the 4.2% increase in avoided cost from AESC 2007 to account for inflation raises AESC 2007 costs. The non-heating loads show less avoided cost in our current estimate due to the lower avoidable margin for these loads, while heating and all loads have a relatively higher end-use avoided cost for two reasons. First, the greater amount of the total retail margin that is estimated to be avoidable is greater than that of

AESC 2007. Second, compared to the AESC 2007 analysis, the avoidable trans-Canadian pipeline costs are higher.

4.6. Value of Environmental Impacts of Natural Gas Combustion

4.6.1. Pollutants Created by Combustion of Natural Gas and their Significance

Natural gas comprises methane (generally above 85 percent) and varying amounts of ethane, propane, butane, and inert gases (typically nitrogen, carbon dioxide, and helium) (EPA 1999). In general the combustion of natural gas in boilers and furnaces generate the following pollutants (EPA 1999, 1.4-2–5):

- oxides of nitrogen (NO_x)
- trace levels of sulfur oxides (SO_x)[78]
- carbon dioxide and other greenhouse gases
- trace levels of particulates
- volatile organic compounds
- carbon monoxide

The most significant of these pollutants are carbon dioxide and oxides of nitrogen. These two pollutants were determined to be the most significant based on the fact that the absolute quantities of each resulting from the combustion of natural gas are large relative to the absolute quantity of each from all sources. In other words, combustion of gas is a major source of these pollutants.

To estimate the absolute quantities of each pollutant from the combustion of natural gas relative to the absolute quantity of each from all sources we began by estimating the quantity of each that is emitted per MMBtu of fuel consumed. Exhibit 4-19 provides emissions factors for NO_x and CO_2 for on three generalized boiler type categories.

[78]Sulfur is generally added as an odorant to natural gas, which generates trace quantities of sulfur oxides when combusted.

Exhibit 4-19 Emission Rates of Significant Pollutants

Boiler Type	NO_x (lbs/mmBtu)	CO_2 (lbs/mmBtu)
Residential boilers	0.0922	118
Commercial boilers	0.0980	118
Industrial boilers	0.137	118

Notes:

NO_x emissions from industrial boilers without low NO_x burners would be 0.274 lb/MMBtu. We assumed these boilers were controlled in order to be conservative.

NO_x and CO_2 emissions factors for all boilers utilized conversion rate of 1,020 btu/scf

Sources:

Environmental Protection Agency, AP-42, Volume I, Fifth Edition, January 1995, Chapter 1, External Combustion Sources. http://www.epa.gov/ttnchie1/ap42/

We apply these pollutant emission rates to the quantity of natural gas consumed, by sector, in New England in 2007. The estimated annual quantity of each of the two pollutants from natural-gas combustion, and from other sources, is presented in Exhibit 4-20.

Exhibit 4-20 Pollutant Emissions in New England in 2007

Sector	NO_x (tons)	CO_2 (tons)
Combustion of Natural Gas in R, C & I		
Residential	8,840	11,313,250
Commercial	6,320	7,609,230
Industrial	6,160	5,305,280
R, C & I Total	***21,320***	***24,227,760***
Emissions from Electric Generation and Major Sources Excluding R,C& I		
	80,000	***42,400,000***
Source Source: Energy Information Administration. http://tonto.eia.doe.gov/dnav/ng/ng_cons_sum_a_EPG0_vrs_mmcf_a.htm		

This comparison illustrates that combustion of natural gas is a major source of each of these pollutants. Moreover, those emissions are not currently subject to regulation, as explained below.

- *CO_2*. Regional Greenhouse Gas Initiative (RGGI) applies to electric generating units larger than 25 MW. New England CO_2 emissions for 2006 were 42.4 million tons. The total CO_2 emissions from the end-use sectors above would represent about 36.3% of the total CO_2 emissions, if such emissions were included.
- *NO_x*. The Ozone Transport Commission/EPA NO_x budget program applies to electric generating units larger than 15 MW and to industrial boilers with a heat input larger than 100 MMBtu/hour. New England NO_x emissions for 2005 were approximately 80,000 tons for just the electric generating sector[79]. The total NO_x emissions from the end use sectors above would

[79]A few large sources in the industrial sector are included in the NOx budget program. These include municipal waste combustors, steel and cement plants, and large industrial boilers (such as those located at Pfizer in, New London, CT and General Electric in, Lynn, MA). However, the number of NO_x allowances used, sold, and traded for the industrial sector is very small. A few allowances in each

represent about 21% of the total NO_x budget if such emissions were included.

4.6.2. Value Associated With Mitigation of Each Significant Pollutant

We estimate the value associated with mitigation of NO_x and CO_2 based on the 2009 emissions allowance prices per short ton presented in Exhibit 2-4. As noted previously, natural-gas combustion is not a significant source of SO_2 emissions. Consequently we have not included an emission value on the pollutant.

The annual pollutant-emission values by end-use sector based upon these allowance prices and the pollutant -emission rates presented in Exhibit 4-19 are presented below in Exhibit 4-21.

Exhibit 4-21 Annual Pollutant Emission Values in 2009$/MMBtu

Pollutant Emission Values by Sector and by Year in 2009$/MMBtu						
	Residential		Commecial		Industrial	
	NO_x (2009$/MMBtu)	CO_2 (2009$/MMBtu)	NO_x (2009$/MMBtu)	CO_2 (2009$/MMBtu)	NO_x (2009$/MMBtu)	CO_2 (2009$/MMBtu)
2009	$0.096	$0.23	$0.102	$0.23	$0.142	$0.23
2010	$0.070	$0.23	$0.074	$0.23	$0.104	$0.23
2011	$0.035	$0.24	$0.037	$0.24	$0.052	$0.24
2012	$0.021	$0.24	$0.023	$0.24	$0.032	$0.24
2013	$0.027	$0.92	$0.028	$0.92	$0.039	$0.92
2014	$0.013	$1.06	$0.014	$1.06	$0.019	$1.06
2015	$0.013	$1.20	$0.014	$1.20	$0.019	$1.20
2016	$0.013	$1.34	$0.014	$1.34	$0.019	$1.34
2017	$0.013	$1.48	$0.014	$1.48	$0.019	$1.48
2018	$0.013	$1.62	$0.014	$1.62	$0.019	$1.62
2019	$0.013	$1.75	$0.014	$1.75	$0.019	$1.75
2020	$0.013	$1.89	$0.014	$1.89	$0.019	$1.89
2021	$0.013	$2.03	$0.014	$2.03	$0.019	$2.03
2022	$0.013	$2.17	$0.014	$2.17	$0.019	$2.17
2023	$0.013	$2.31	$0.014	$2.31	$0.019	$2.31
2024	$0.013	$2.45	$0.014	$2.45	$0.019	$2.45
Levelized (2009$/MMBtu)						
5 year (2010-14)	$0.034	$0.53	$0.036	$0.53	$0.050	$0.53
10 year (2010-19)	$0.024	$0.97	$0.025	$0.97	$0.036	$0.97
15 year (2010-24)	$0.021	$1.33	$0.022	$1.33	$0.031	$1.33
Notes						
Based on pollution emission rates for Natural Gas combustion						
Pollutant values based on emission allowance prices detailed in Exhibit 2-4						

The entire amount of each value should be an externality. With the exception of those industrial sources subject to the EPA NO_x budget program, which represent a small fraction of the total emissions, none of these emissions are currently subject to environmental requirements. Therefore none of these values are internalized in their market prices.

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state are allocated to non-electric generating units compared to thousands of allowances used, sold and traded for electric generating units.

Chapter 5: Forecast of New England Regional Oil Prices and Avoided Cost of Fuels by Sector

5.1. Introduction

This chapter details the development of a forecast of prices for petroleum products used in electric generation as well as in the residential, commercial and industrial sectors in New England. The scope of work requests prices for three fuel oil grades, i.e., No. 2, No. 4 and No. 6 and two biofuel blends, B5 and B20. (and also the projection of coal prices for the electric sector.) Ultimately the scope of work required a forecast of unit fuel oil costs that would be avoided by the installation of oil-saving energy efficiency measures in the commercial, industrial, and residential sectors.

The scope of work required the development of avoided costs by state, if supported by research, for other fuels used in residential heating applications. These other fuels are identified as wood, wood chips or pellets, kerosene and propane.

Our proposed AESC 2009 forecasts for crude oil and fuels by sector and region are presented in detail in Appendix E. All prices are reported in constant 2009 dollars per MMBtu except where noted otherwise.

The current forecast of fuel prices other than crude is generally higher than those of AESC 2007 by 15% over a fifteen-year period; This is primarily due to the fact that our forecasted crude oil prices are higher from 2011 onwards.

Exhibit 5-1 Summary of Other Fuel Prices: Current Forecast versus AESC 2007

	No. 2 Distillate	No. 2 Distillate	No. 6 Residual Fuel (low sulfur)	Propane	Kerosene	BioFuel	BioFuel	Wood
Sector	Res	Com	Com	Res	Res & Com	B5 Blend	B20 Blend	Res
AESC 2009 Levelized Values (2009$/MMBtu)								
2010-2024	22.82	21.68	17.52	34.01	22.17	22.82	22.82	8.22
AESC 2007 Levelized Values (2009$/MMBtu)								
2010-2024	15.31	13.50	9.15	30.99	15.92	15.31	15.31	5.48
Percent Difference from AESC 2007								
2010-2024	49.1%	60.6%	91.6%	9.8%	39.2%	49.1%	49.1%	49.9%

Notes
Res Residential Sector
Com Commercial Sector
AESC 2007 values from Exhibit 4-6 New England Average Price Forecast of Other Fuel Prices by Sector (AESC 2007)

5.2. Forecast of Crude Oil Prices

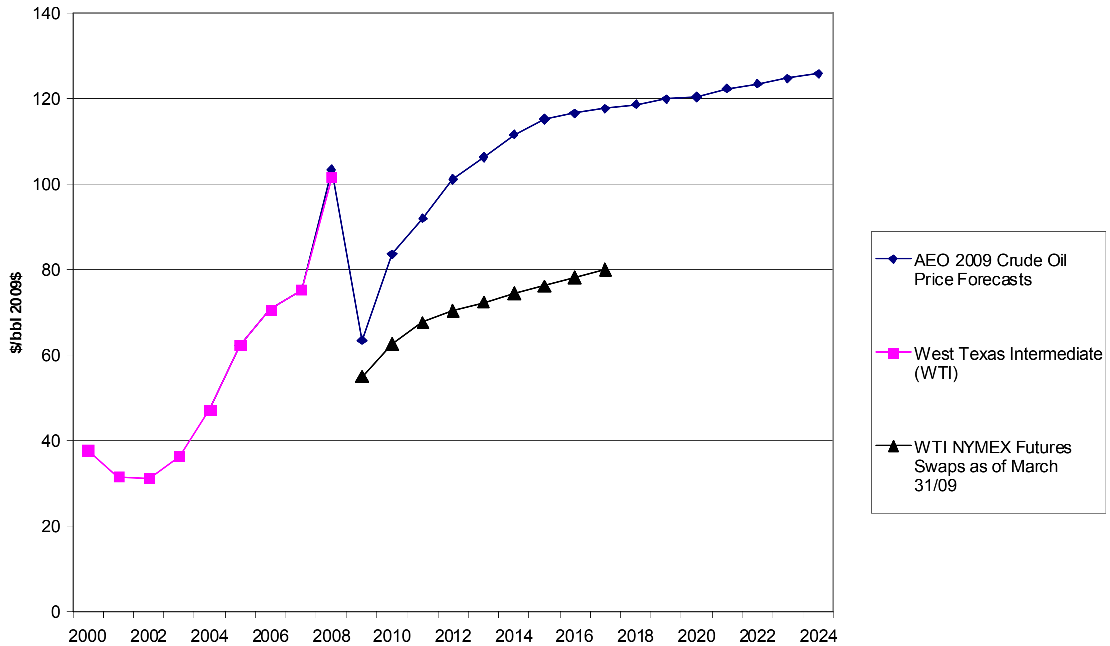
Our general approach to developing forecasts of crude-oil prices and of Henry Hub natural-gas prices is to use a set of relevant NYMEX futures prices in the near term, e.g. the first three to five years, and the relevant Energy Information Administration (EIA) Annual Energy Outlook forecast in the long term. This approach is based upon our view that futures market prices are the most-accurate estimates in the near term while projections from a forecasting model that reflects long-term demand and supply fundamentals, such as the EIA's National Energy Modeling System, are the most accurate estimates in the long term. The forecasts of petroleum products in AESC 2007 were based on that approach, i.e., NYMEX futures for West Texas Intermediate in the first five years and EIA's (2007) reference-case-forecast prices after that.

Based on that general approach, our first step in developing a forecast of crude oil prices was to review the Reference Case forecast in EIA (2009a). That forecast is in the mid-range of other long-term forecasts, as EIA (2009a, Table 16) indicates. However, there is considerable uncertainty regarding the future price of crude oil.

We next compared EIA's (2009a, 109–150) reference-case-forecast prices in the near term, i.e. 2009 through 2014, with NYMEX futures prices for West Texas Intermediate (WTI).[80] This comparison revealed a dramatic disparity between NYMEX futures for WTI in the near-term and EIA's reference-case-forecast prices in both the near and long term. That disparity is presented in Exhibit 5-2, which plots, in 2009 dollars per bbl, actual oil prices since 2000, WTI futures through 2017, and EIA's (2009a) reference-case-forecast prices through 2024.

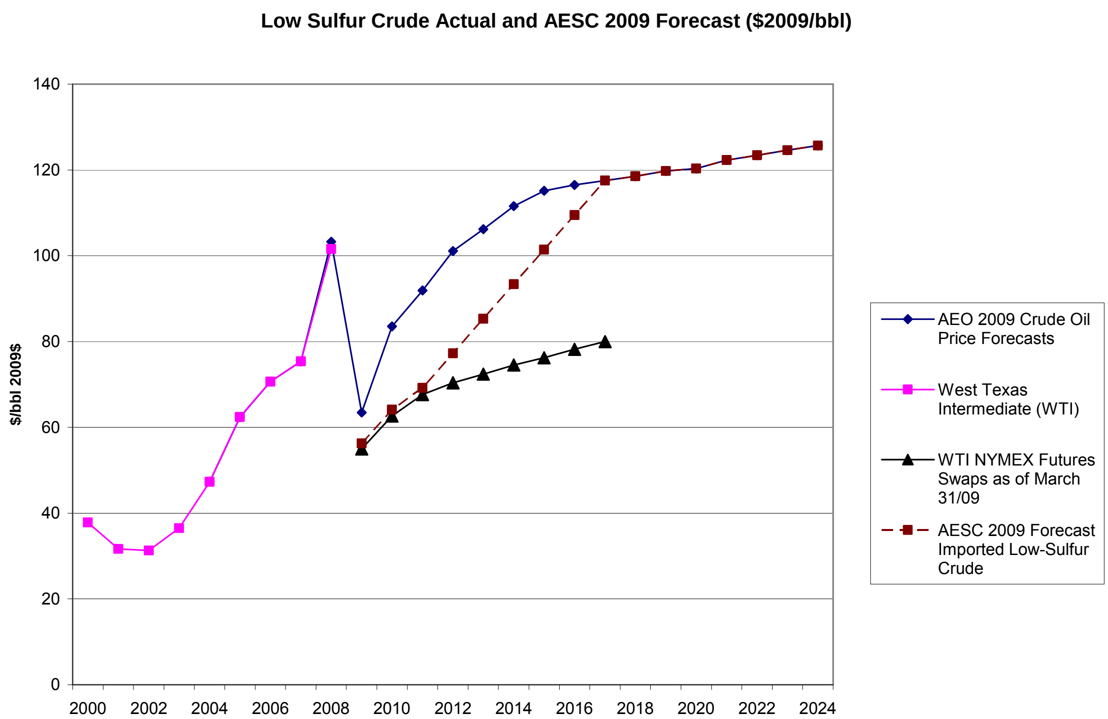
[80]NYMEX prices as of March 31, 2009. WTI was used for this comparison because it is actively traded and its price in the past has been very close to that of the low-sulfur light crude used in EIA's (2009, 109–150) Reference Case.

Exhibit 5-2: Low-Sulfur-Crude Prices, EIA v. NYMEX (2009 Dollars per bbl)



In light of that discrepancy we consulted with the Study Group and reviewed the international-oil-market and petroleum-products modules of EIA's National Energy Modeling System,. Based on that information our forecast of crude oil prices comprises NYMEX futures for WTI through 2011, an interpolation of NYMEX WTI and EIA (2009a, 109–150) reference-case-forecast prices through 2017, and EIA (2009a) reference-case-forecast thereafter. This forecast projects an escalation in crude oil prices between 2009 and 2017 that is consistent with the escalation that actually occurred between 2000 and 2008. Exhibit 5-3 depicts the AESC 2009 and AESC 2007 forecasts.

Exhibit 5-3: Low-Sulfur-Crude Prices, (2009 Dollars per bbl)



5.3. Forecast of Electric-Generation Fuel Prices in New England

The EIA (2009a) provides forecasts of regional prices for distillate, residual, and coal for electricity generation in New England. Our analysis did not identify material differences by state in the historical prices for these fuels in this sector. Therefore, we propose to adjust the corresponding EIA (2009a) regional forecasts of distillate and residual oil by the ratio of our forecast of crude oil to the EIA's (2009a) forecast of cruder oil. We use EIA's (2009a) forecast of coal prices for electric generation in New England.

Forecast Prices of Distillate and Residual.

The EIA (2009a) provides forecasts for prices of distillate and residual for electricity generation in New England. We began by calculating the forecast unit margin implicit in EIA's (2009a) forecast of those prices as a ratio to the corresponding crude oil price forecast, and comparing those ratios to the historical unit margins. That comparison indicates that the forecast margins are generally consistent with the historical margins. Our analysis did not identify material differences by state in the historical prices for these fuels in this sector. Therefore we developed a forecast of these prices by multiplying the corresponding EIA (2009a) forecast price each year times the ratio of our crude-oil forecast to the EIA (2009a) crude-oil forecast.

Forecast Prices of Coal.

The EIA (2009a, 109–150) Reference Case forecasts fairly flat prices for coal in New England. We consider this reasonable. The U.S. has substantial coal resources and coal prices have been relatively stable over a long time period without the volatility seen in oil and natural gas prices. While coal at the mine mouth is relatively cheap on an energy basis, it is expensive to transport and to burn. Coal demand is also unlikely to increase significantly because of various environmental concerns. Coal is more expensive in New England because of the transportation costs and represents a smaller fraction of annual electric generation than most other parts of the U.S. Since EIA's coal prices are essentially flat and consistent with historic experience and market behavior, we use them in this analysis.

Our proposed forecasts of prices for coal and No. 2 and No. 6 oil paid by electric generators in New England are presented in Appendix E.

5.4. Forecast of Petroleum Prices in the Residential, Commercial, and Industrial Sectors

The EIA (2009a) provides forecasts of regional prices for distillate and residual in the residential, commercial, and industrial sectors in New England. The retail price of each fuel in each sector of a given state can be separated into two major components. The first component is the price of crude oil, the underlying resource. The second component is a margin, the difference between the retail price and the crude oil price, which represents the aggregate unit costs of refining, distribution and taxes attributed to that particular fuel by sector and state. We developed our forecast of prices for fuels in each of these sectors in the following three steps.

- First, we calculate the forecast unit margin implicit in EIA's (2009a) forecast of the New England regional price for each fuel, expressed as a ratio to the crude oil price, and compare it to the historical unit margin. We develop a modified New England price for any fuel with an EIA (2009a) forecast margin that is not reasonable;
- Second, we derive our forecast of the New England price for each fuel by multiplying the corresponding EIA (2009a) forecast, as may be modified in step one, by the ratio of our crude-oil forecast to the EIA (2009a) crude-oil forecast;
- Finally, we develop our forecast of prices for each fuel by New England state from the regional forecast to the extent that historical prices for that fuel have differed materially by state.

Our analysis found material differences by state in the historical prices for some fuels in these sectors. Therefore, we adjust the corresponding EIA (2009a) regional forecasts of distillate and residual by the ratio of the AESC 2009 forecast of crude oil and EIA (2009a)'s forecast of cruder oil Then we develop a forecast of prices for each fuel by New England state from the regional forecast.

5.4.1. New England Regional Prices by Sector

The forecast of regional prices by fuel and sector in New England is presented in Appendix E.

We derived forecasts of regional petroleum-product prices by adjusting the corresponding EIA (2009a) forecasts of product prices in proportion to the ratio of our crude-oil forecast to the EIA's (2009a) crude-oil forecast. This approach is based upon our position that crude oil is the dominant component of petroleum product prices and that preparing a forecast of future absolute margins by product based upon historical absolute margins is beyond the scope of this project.

In summary our proposed AESC 2009 forecasts of regional prices of petroleum and related products by sector are based on the following approach:

- Nos. 2 and 6—EIA (2009a) forecast of regional product price adjusted for ratio of AESC 2009 crude-oil forecast to EIA (2009a) crude-oil forecast,
- No. 4—no projection. No. 4 is a blend of distillate and residual and we had no data on the relative proportions of that blend,
- B5 and B20—use our forecast of corresponding petroleum-product prices

For Nos. 2 and 6 we first calculate the forecast unit margins implicit in the EIA (2009a) forecast of those prices as a ratio to the corresponding crude oil price forecast. Next we compare the average ratio for each fuel in each sector to the corresponding historical unit margins. That comparison indicates that the forecast margins are generally consistent with the historical margins. Based upon the results of that comparison, we develop our forecast of these prices by multiplying the corresponding EIA (2009a) forecast price each year times the ratio of the our crude-oil forecast to the EIA (2009a) crude-oil forecast.

The EIA (2009a) does not provide a forecast of New England regional prices for biofuels B5 and B20. Therefore we prepared an independent analysis. B5 and B20 are each a mix of a petroleum product, such as distillate oil or diesel, and an oil-like product derived from an agricultural source (e.g. soy beans). The number in their name is the percent of agricultural-derived component. Thus "B5" and "B20" represent products with a 5% and a 20% agricultural-derived component respectively. They are both similar to No.-2 fuel oil and used primarily for heating. Each of these fuels has both advantages and disadvantages relative to #2 fuel oil.

Their advantages include lower greenhouse-gas emissions per MMBtu of fuel consumed, more efficient operation of furnaces ,and less reliance on imported crude oil. Their disadvantages include somewhat lower heat contents and concerns about the long-term supply of agricultural source feedstocks. A comparison of prices for biodiesel and regular diesel in 2008 published by the DOE Alternative Fuels and Advanced Vehicles Data Center shows that, on a heat rate basis, the price differentials for these blends have varied slightly above, and slightly below, the prices for regular diesel.[81] For B2-B5 blends the premium has varied from -3% to +5% and for B20 the premium has varied from -2% to +12%. Based upon the limited experience with these fuels to date, and their premium and sub-premium attributes relative to their comparable petroleum products, we have no basis for projecting prices materially different from their competing petroleum products. Thus, as in the AESC 2007 study, we forecast the prices of biofuels to be the same on an energy basis as their equivalent competitive petroleum products.

Since crude oil prices do not show significant variations by month or season, we have not developed monthly or seasonal price variations for petroleum products. Storage for petroleum products is relatively inexpensive and this also tends to smooth out variations in costs relative to market prices. For those reasons, and those presented in the Chapter 0 discussion of volatility in natural gas prices, our forecast does not address volatility in the prices of these fuel prices.

5.4.2. Weighted Average Avoided Costs by Sector Based on Regional Prices

We develop a weighted average costs of avoided petroleum related fuels by sector by multiplying our projected regional prices for each fuel and sector by the relative quantities of each petroleum related fuel that EIA (2009a) projects will be used in each sector. The relative quantities of each petroleum related fuel that EIA (2009a) projects for each sector, expressed as percentages, are presented in Appendix E. The resulting weighted average costs of avoided petroleum related fuels by sector are presented in Appendix E.

We estimate that the crude-oil-price component of these projected prices is the portion that society can avoid.

5.4.3. Prices by State by Sector

To determine if there were material differences by state in the historical prices for any or all of these fuels in these sectors we analyzed the actual prices by sector by state from 1999 through 2006 using data from the EIA State Energy Data System. This is the most complete and consistent source of state-level energy prices.

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[81] Data from *Clean Cities Alternative Fuel Price Report* 1/08, 4/08, 7/08, 10/08, 1/09.

We used prices in Massachusetts as the reference point for each sector. We calculated the difference between prices in other states with the prices in Massachusetts for each year in each sector. The metric we used to determine if those differences were material was the ratio of the mean difference to the standard deviation. If that ratio was greater than 2 we concluded that the differential was material. Using that test we found material differences between some states in:

- distillate prices in the commercial (Rhode Island, Vermont) and residential (New Hampshire) sectors,
- LPG prices in the commercial (New Hampshire, Rhode Island) and residential (Maine, New Hampshire) sectors,
- residual prices in the commercial sector (New Hampshire).

Given the uncertainty associated with future quantities of fuel use by state by sector, and future policies on fuel taxes by state by sector, and other uncertainties, we conclude no further precision would be obtained from an estimate of avoided petroleum related fuel prices by sector by state.

5.5. Avoided Costs of Other Residential Fuels

We developed our forecast of prices for these fuels following the same general methodology as that of AESC 2007 and as noted above for petroleum-based fuels.

For wood and kerosene, we determined the historical average ratio between the price of each fuel and the price of distillate in the residential sector. These ratios were calculated from the EIA SEDS data as 0.36 for wood and 0.97 for kerosene.[82] Then we derived AESC 2009 forecast regional prices for each of those fuels by multiplying our AESC 2009 forecast price of distillate in the residential sector each year by the historical ratio.

The wood values are for cordwood.[83] Values for wood pellets would be approximately twice as high according to the limited data on wood prices.[84] Vermont publishes prices for cord wood and wood pellets, but other New England

[82]EIA State Energy Data System, http://www.eia.doe.gov/emeu/states/_seds.html (accessed 4/24/2009).

[83] Residential customers can purchased either cord wood or wood pellets. Despite our attempts, we were unable to obtain a statistically valid set of historical prices for wood pellets by state.

[84] The Vermont cord wood price data is consistent with the EIA SEDS data, although somewhat higher. The wood pellet prices are higher than the cord wood prices but the time series of wood pellet prices is limited and the survey used to collect that data is informal.

states do not, relying instead upon prices reported by EIA.[85] Based on thies factors, we used the EIA SEDS data to develop prices for cordwood in New England.

For propane we draw upon the EIA (2009a) forecast of New England regional prices. The AESC 2009 forecast is derived from the EIA (2009a) regional forecast by multiplying it times the ratio of the AESC 2009 crude-oil forecast and the EIA (2009a) crude-oil forecast.

Our forecasts of prices for each fuel are presented in Appendix E. All prices are reported in constant 2009 dollars per MMBtu except where noted otherwise.

5.6. Environmental Impacts

We estimate the environmental benefit from reduced combustion of fuel oil due to energy efficiency programs with the following analyses:

- identifying the various pollutants created by the combustion of fuel oil, assess which of them are significant and how, if at all, the impact of those pollutants are currently internalized into the cost of fuel oil.
- finding the value associated with mitigation of each significant pollutant and portion that should be treated as an externality.

The pollutant emissions associated with the combustion of fuel oil are dependent on the fuel grade and composition, boiler characteristics and size, combustion process and sequence, and equipment maintenance (EPA 2009 1.3-2). In general these pollutants (EPA 2009 1.3-2–1.3-5) are as follows:

- oxides of nitrogen (NO_x)
- sulfur oxides
- carbon dioxide and other greenhouse gases
- particulates
- trace elements
- organic compounds
- carbon monoxide.

Of those pollutants, oxides of nitrogen, sulfur oxides, and carbon dioxide are potentially the most significant.[86] Oxides of nitrogen are precursors to the

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[85] The Vermont Department of Public Service publishes prices for cordwood and wood pellets collected by the Vermont Department of Forests through an informal survey each month. http://publicservice.vermont.gov/pub/vt-fuel-price-report.html

unhealthy concentrations of ozone that many areas in New England continue to experience. The region is also required to reduce NOx and SOx emissions by EPA programs, and the region has just commenced the first program to require mandatory reductions of CO_2 from the power sector.

The value of mitigating emissions of NO_x, SO_x, and CO_2 from the combustion of these fuels can be estimated using the forecast of emissions allowance prices presented above in Exhibit 2-4 (page 2-15).

5.6.1. Significance of Air Emissions from Combustion of Fuels by Sector

To estimate the absolute quantities of each pollutant from the combustion of fuels by sector we began by estimating the quantity of each that is emitted per MMBtu of fuel consumed.[87] The pollutant emissions associated with the combustion of wood are dependent on the species of wood, moisture content, appliance used for its combustion, combustion process and sequence and equipment maintenance. The pollutant emissions associated with the combustion of kerosene are similar to those associated with the combustion of distillate oil, and depend upon boiler characteristics and size, combustion process and sequence, and equipment maintenance (EPA 1999, 1.3-2).

Exhibit 5-4 below provides emissions factors for each fuel based on three generalized boiler-type categories.

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[86]Wood combustion may contribute to an accumulation of unhealthy concentrations of fine particulate matter ($PM_{2.5}$). This is especially true in many valleys, where pollutants accumulate during stagnant meteorological conditions. The regulation of $PM_{2.5}$ from wood combustion is a state by state process. No comparable regionally consistent or market-based program of allowances have been established for $PM_{2.5}$, like those described above for SO_x, NO_x, and CO_2.

[87]Number-6 fuel oil has about the same rate of SO_2 emissions as distillate, about twice the rate of NO_x emissions and about seven percent higher rate of CO_2 emissions.

Exhibit 5-4 Emission Rates of Significant Pollutants from Fuel Oil

Boiler type, and fuel combusted	SO_x (lbs/mmBtu)	NO_x (lbs/mmBtu)	CO_2 (lbs/mmBtu)
#2 Fuel Oil			
Residential boiler, combusting #2 oil	0.218	0.068	173
Commercial boiler, combusting #2 oil	0.218	0.136	164
Industrial boilers, combusting #2 oil	0.336	0.142	161
Kerosene—Residential heating	0.218	0.068	173
Wood—Residential heating	0.468	2.59	N/A

Notes:
For industrial boilers: assumed sulfur content = 0.3% by weight.
For residential and commercial boilers: assumed sulfur content = 0.15% by weight
Kerosene same as Residential # 2 oil

Sources:

1) Energy Information Administration, Electric Power Annual with data for 2007. Table A3 *http://www.eia.doe.gov/cneaf/electricity/epa/epata1.html* (for CO_2 for industrial boilers)

2) Environmental Protection Agency, AP-42, Volume I, Fifth Edition, January 1995, Chapter 1, External Combustion Sources. *http://www.epa.gov/ttnchie1/ap42/* (for SO_x and NO_x emissions factors for all boilers)

3) Environmental Benefits of DSM in New York: Long Island Case Study; Bruce Biewald and Stephen Bernow, Tellus Institute. Proceedings from Demand-Side Management and the Global Environment, Arlington, Virginia, April 22-23, 1991. (for CO2 emissions factors for residential and commercial boilers)

4) James Houck and Brian Eagle, OMNI Environmental Services, Inc, Control Analysis and Document for Residential Wood Combustion in the MANU-VU Region, December 19, 2006. (for wood)

Next, we applied those pollutant emission rates to the quantity of each fuel consumed by sector in New England in 2007.

Combustion of No. 2 fuel oil is a major source of each of these pollutants but kerosene and wood are not; see Exhibit 5-5 below.

Exhibit 5-5 Pollutant Emissions in New England in 2007 by Major Source

Sector	SO_2 (tons)	NO_x (tons)	CO_2 (tons)
Emissions from Electric Generation and Major Sources Excluding R,C& I			
	172,000	***80,000***	***42,4000,000***
Combustion of #2 Fuel Oil in R, C & I			
Residential	28,790	8,980	22,844,650
Commercial	7,220	4,500	5,428,400
Industrial	14,030	1,790	2,001,360
R, C & I Total	***50,040***	***15,270***	***30,274,410***
Combustion of kerosene in Residential heating	***1,392***	***434***	***1,104,660***
Combustion of wood in Residential heating	***556***	***3,081***	***N/A***

5.6.2. Value of Mitigating Each Significant Pollutant

Emissions of $NO_{x,}$ SO_x and CO_2 from the combustion of these fuels are not currently subject to regulation, as explained below.

- *SO_2 & CO_2.* The acid rain program and Regional Greenhouse Gas Initiative (RGGI) apply to electric generating units larger than 25 MW. New England SO_x emissions from electric generating units for 2005 were approximately 172,000 tons. The total SO_x emissions from the end-use sectors above would represent about 22% of the total SO_x emissions, if such emissions were included. New England CO_2 emissions for 2006 were 42.4 million tons. The total CO_2 emissions from the end-use sectors above would represent about 41.6% of the total CO_2 emissions, if such emissions were included.
- *NO_x.* The Ozone Transport Commission–EPA NO_x budget program applies to electric generating units larger than 15 MW and to industrial boilers with a heat input larger than 100 MMBtu/hour. New England NO_x emissions for

2005 were approximately 80,000 tons for just the electric generating sector[88]. The total NO_x emissions from the end use sectors above would represent about 16% of the total NO_x budget if such emissions were included.

We base the value associated with mitigation of NO_x, SO_x, and CO_2 on the 2009 emissions allowance prices per short ton presented above in Exhibit 2-4 (page 2-15).

The pollutant-emission values in 2009 based upon these allowance prices and the pollutant emission rates presented in Exhibit 5-4 are presented in Exhibit 5-6.

Exhibit 5-6: Value of Pollutant Emissions from Fuel Oil in 2009

Generalized Boiler Type by Sector	SO_2 ($/MMBtu)	NO_x ($/MMBtu)	CO_2 ($/MMBtu)
Residential boiler	0.007	0.071	0.333
Commercial boiler	0.007	0.141	0.316
Industrial boiler	0.010	0.147	0.310

The entire amount of each value should be an externality. With the exception of those industrial sources subject to the EPA NO_x budget program, which represent a small fraction of the total emissions, none of these emissions are currently subject to environmental requirements. Therefore none of these values are internalized in their market prices.

The values by year for fuel oil over the study period are presented in Appendix E.

88 A few large sources in the industrial sector are included in the NO_x budget program. These include municipal waste combustors, steel and cement plants and large industrial boilers (such as those located at Pfizer in New London, Conn., and General Electric, in Lynn, Mass.). However, the number of NO_x allowances used, sold and traded for the industrial sector is very small. A few allowances in each state are allocated to non-electric generating units compared to thousands of allowances used, sold and traded for electric generating units.

Chapter 6: Regional Electric-Energy-Supply Prices Avoided By Energy-Efficiency And Demand-Response Programs

This chapter projects electricity supply costs that would be avoided by reductions in retail energy and/or demand. Sections 6-1 through 6-3 of this chapter present the avoided electricity supply costs that are reflected or ‘internalized” in wholesale market prices for electric capacity and electric energy respectively. Section 6-4 onward presents avoided costs that are not internalized in those market prices, primarily the *renewable-energy-credit* price and *demand-reduction-induced price effects*.

6.1. Forward-Capacity Auction Prices Assuming No New Demand-Side Management

The AESC 2009 projections of FCA prices effectively begin with FCA 4. The prices in FCA 1 and FCA 2 have already been established. The price in FCA 3 will be established in October 2009 but is almost certain to be set at the floor price under the current ISO market rules. Those current rules have determined capacity prices and reserve margins (subject to minor revisions) through the third forward capacity year, ending May 2013. They are discussed in detail in Sections 2.2.1.2, 2.2.4, and 2.5.5.

The first step in the forecast of each FCA price is to forecast the physical capacity requirements and potential supply for that auction, i.e. the demand curve and the supply curve. We forecast the net installed capacity requirement (NICR) each year based upon ISO-NE’s (2009) forecast, estimated reserve requirements, and Hydro Quebec installed-capacity credits. To estimate the quantity of capacity that would potentially be available to bid into the FCM for the year starting June 2012 we begin with the capacity that cleared in FCA 2 and then make adjustments to remove the capacity reductions attributable to DSM, to add the quantity of new capacity, including renewables, that might be in-service, and to subtract capacity that we estimate might either be retired or temporarily delisted. Those annual requirements and estimates of supply are summarized below in Exhibit 6-3

The second step in the forecast of each FCA price is to forecast the price at which the FCA would clear, i.e., the intersection of demand curve and the supply curve. We forecast the prices in FCA 4 and beyond based upon the forecast annual requirements, forecast potential supply, and forecast prices that suppliers are likely to bid based upon the prices bid in FCAs 1 and 2. A key assumption is that the current ISO rules terminating floor prices for FCA 4 and later will remain in effect. That is, there will be no re-introduction of floor prices in future FCAs. This assumption is based upon conclusions of the ISO-New England Market Monitoring Unit, as related by LaPlant et al. (2009) that there is “no evidence to support continuing collar,” and that “continuing collar will raise prices in short run, discouraging retirements and likely delay new investment.” LaPlant et al. suggest that the ISO revise its rules to ensure that the capacity price is set more often by the price of rejected bids from new resources, rather than the market-clearing price resulting from existing surplus. Any such future rule changes may support higher FCM prices, but the magnitude of the effect is unclear. New demand resources have bid into the first two auctions at a range of prices; if that pattern continues, the lowest-priced rejected new resources may not be priced much higher than the market-clearing price.

The general methodology and basic assumptions underlying our forecast of FCA prices are described in Chapter 0. The discussion in this section focuses upon details that were not presented in Chapter 0.

6.1.1. Potential for a Low or Zero Price in Forward-Capacity-Auction Four and Beyond

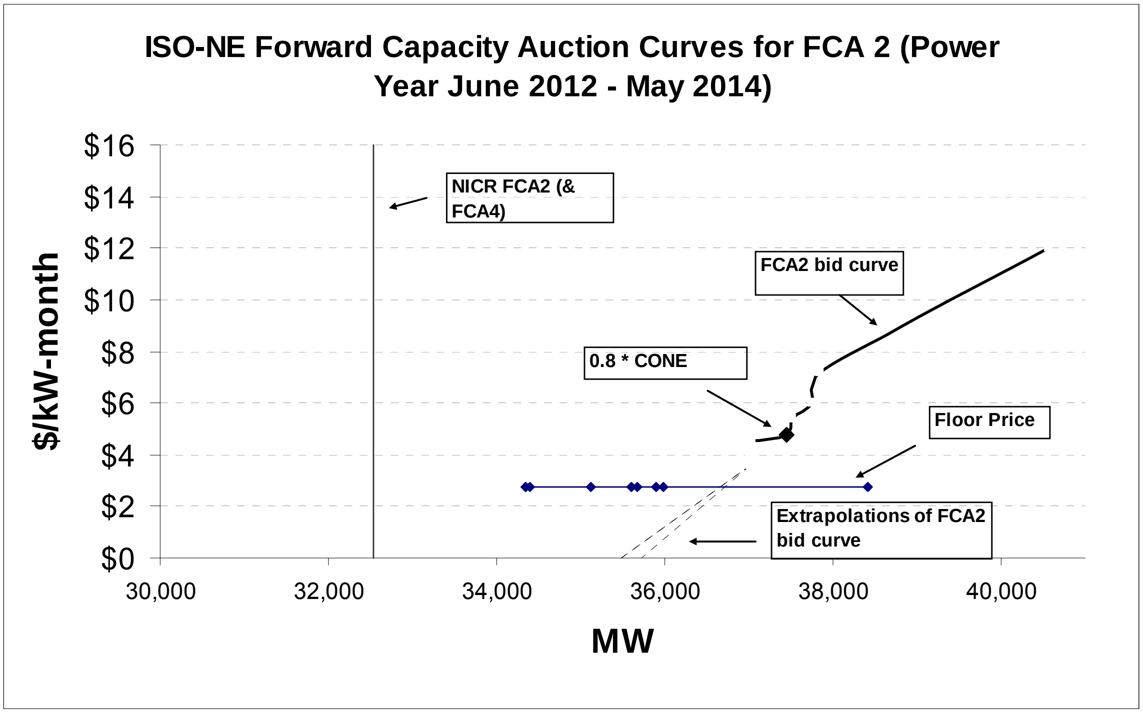
The quantity of capacity that cleared, or received payment, in FCAs 1 and 2 greatly exceeded the NICR in each of those years: there was a surplus of capacity relative to demand. This surplus is expected to occur in FCA 3 as well. It is a direct result of the imposition of a floor price, such that more capacity receives FCM payments than is needed to meet the NICR.

In contrast, with the termination of floor prices, if the same quantity of capacity that bid into FCAs 1 and/or 2 were to bid into FCA 4, the FCA-4 price could go to zero because of the magnitude of the available capacity relative to the NICR. Low or zero prices for FCA 4 and beyond would be the likely result even with the capacity retirements and deactivations that have been announced or suggested by generation owners. This result is even more likely given the additional renewable capacity that is expected to come on line in response to state RPS requirements and the fact that some new capacity under contract in Connecticut will not be on line in time to be included in the first two auctions. Moreover, this surplus is likely even if no new DSM resources bid into future FCAs.

The potential for low or zero prices from FCA 4 is illustrated in Exhibit 6-1 below. This exhibit shows the NICR for FCA 2 and FCA 4, both of which are approximately the same, as a vertical curve. It also shows the supply curves for FCA 2, from its start point at twice the ISO-defined *cost of new entry* (CONE) to the floor price. It also shows the price and quantity for a bid at 0.8 × CONE, the highest price at which most existing resources are allowed to delist. Prices above 0.8 × CONE are predominantly bids from new resources.

As shown in Exhibit 6-1, the supply available in FCA 2 was still well above the NICR at the FCA 2 floor price. This Exhibit also shows two extrapolations of the FCA 2 supply curve, one at the average slope from the starting point to the floor price and the other at the average slope from 0.8 × CONE to the floor price. These curves and extrapolations indicate that if the relationships between price and supply remain constant, the capacity offered in FCA 2 would have remained above the NICR all the way to a price of $0/kW-month.

Exhibit 6-1: ISO-NE FCA 2 Supply Curves



6.1.2. *Potential for Surplus Capacity in FCA 4 and Possible Resolution*

The potential for a large capacity surplus for capacity year 2013-14 (FCA 4), the first auction without a floor price, is shown in Exhibit 6-2:

Exhibit 6-2: Potential Capacity Surplus, FCA 4

Resource Type	MW	Source
Net Installed Capacity Requirement, FCA 4	32,731	Appendix C
Estimate of FCM Capacity Available		
Capacity cleared in FCA 2	38,194[89]	Bacon (2009)
Minus Energy-Efficiency Resources from Capacity Cleared in FCA 2	−747	Winkler (2009)
Minus Reserve Credit for Demand Resources in FCA 2	−304	ISO-New England Inc. and New England Power Pool, Tariff Revisions Regarding Elimination of the Reserve Margin Gross-Up for Demand Resources, Docket No.ER09-209-000, filed October 31, 2008
Plus Connecticut Additions post-FCA 2	281	2009 Connecticut IRP
Plus Renewable Additions post-FCA 2	375	See Chapter 6
Less Salem 1–4 Retirement	−753	Submitted static delist bids of $6.72–$9.835/kW-month in FCA 3
Less Wyman 1 and 2 Retirement	−114	Submitted Request for Determination of Need, 12/11/2008
Sub-Total—Capacity Available to bid at $3.60/kW-month or less in FCA 4	36,932	
Potential Capacity Surplus	4,201	

In each FCA, an existing resource may identify a price at which it would elect to "delist," or withdraw its capacity from the auction. A delisted generation resource may operate in the ISO-NE energy and reserve markets, without capacity obligations or it may sell into markets outside of New England.

- generation resources located in New England can operate in the ISO-NE energy and reserve markets and export capacity to a more favorable market, deactivate until market prices justify reactivating the resource or deactivate and retire the resource.[90]
- Imports can continue operating in their local energy market and sell capacity in that market or export capacity to some other market.

6.1.2.1. Resources outside the region that currently sell capacity into New England.

[89]This value includes all Maine resources that cleared at $3.60/kW-month, but includes only 600 MW of real-time emergency generation, pursuant to ISO rules.

[90]The ISO requires specific procedures in the event of a permanent retirement, to ensure resource adequacy.

To date ISO-NE has been an attractive export market for generators in New York, Ontario and Quebec. Through 2012, ISO-NE offers the most attractive capacity prices in the Northeast, exceeding those of the NYISO and PJM, and attracting capacity imports to New England. For example, the NYISO Rest of State (ROS) capacity price has been about $2/kW-month in 2007–2009 (NYISO does not currently have a forward capacity market), and PJM's RTO price (outside the constrained areas) has been about $3–3.50/kW-month, but will fall to about $0.50/kW-month in 2012/13.[91] In contrast, ISO-NE has been offering $4.10/kW-month in 2009/10, $4.25 in 2010/11, and $3.12 in 2011/12.[92] At the floor price, the 2012/13 ISO-NE effective price to generators would be about $2.70/kW-month, even without new energy-efficiency programs.

As a result of these higher capacity prices in ISO-NE about 2,300 MW of imports cleared in FCA 2. These included:

- About 370 MW of long-term contracts from HQ to the Vermont utilities and from the New York Power Authority to various public entities in ISO-NE.
- About 770 MW of other contracts flowing through New York (Constellation New York imports, Erie Boulevard New York hydropower assets, and HQ imports reported to flow through New York).
- About 1,160 MW of imports from Ontario and HQ, some of which flows over the HQ Phase I/II line, some of which may flow through the New York Independent System Operator (NYISO).

With the end of the ISO-NE FCM floor prices in June 2013, and the prospect of lower capacity prices in FCA 4 and beyond, we expect a large quantity of current import resources will no longer sell into New England. About 600 MW should be able to sell into the NYISO capacity market without reducing prices there below an average of about $1/kW-month.

If none of the resources currently providing capacity to the NYISO short-term market and the ISO-NE forward capacity market withdraw, the price of capacity would fall below $1/kW-month. It is not at all clear how resources will respond as prices fall. Very little generation retired in the 2003–2006 period, when New York capacity prices were about $1/kW-month and New England prices fell well below

[91] In 2012/13, the forward capacity price for eastern PJM (Maryland, New Jersey, Delaware, and most of Pennsylvania) will be about $4–$4.50/kW-month, but that price is not available to imports.

[92] The ISO-NE prices have been prorated, but each resource has the option of reducing its capacity obligation, rather than its price. The imports would likely choose to prorate capacity obligation.

$0.50/kW-month. These prices appear to be far below the fixed O&M costs for steam plants.[93]

We assume that imports will start to delist from New England at $2.40/kW-month (approximately current prices in NYISO), reaching 670 MW of delists when prices fall to $1/kW-month, and declining linearly down to $0/kW-month.

6.1.2.2. Existing resources within the region that bid into FCA 2

We assume that the New England nuclear, coal, hydro, waste-fueled, renewable, cogeneration, combined-cycle and recent (post-1980) gas-turbine resources that cleared in FCA 2 will continue operating and participating in the FCM regardless of the capacity price, supported by a combination of energy revenues, tipping fees, RECs, steam sales, and reserve payments.[94] The combustion turbines, in particular, are likely to receive forward and real-time reserve payments, while many hydro units will receive significant reserve payments.

That leaves the following resources that may delist, along with their approximate capacity in FCA 2:

- 1,000 MW of demand response (adjusted for the loss of the reserve-margin credit in FCA 3). About 250 MW of demand response delisted in FCA 1 and another 170 MW or so in FCA 2, offsetting large fractions of the new demand response added in those auctions.
- 780 MW of emergency generation, only 600 MW of which the ISO counts in meeting resource requirements.
- 6,000 MW of oil- and gas-fired steam plants. Salem Harbor #4 (431 MW) proposed a static delist bid of $7.644/kW-month for FCA 3, which was rejected by the ISO.
- 700 MW of older combustion turbines, including some (about 200 MW in Connecticut and others required for black-start of steam plants) that are not likely to delist.

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[93]About 2,200 MW of ISO-NE steam capacity received significant support through reliability contracts. It is not clear whether those payments were actually necessary. Many other units, including Canal 1 & 2, Wyman 1–4, Brayton 4 and Mystic 7, stayed in operation despite the low capacity prices, without special contracts.

[94]The exception to this pattern would be the Salem 1–3 coal units, which proposed static delist bids at $9.835/kW-month for Salem 1–2 and $6.72/kW-month for Salem 3. The ISO has rejected these static delist bids, perhaps due to local reliability concerns (although ISO found no need for Mystic 7, also in NEMA), and perhaps due to insufficient cost justification for a delist bid over 80% of CONE, or $3.93/kW-month. If the latter, these units will still be free to delist at $3.93, well above the floor price (and likely clearing price) of $2.95.

Some of this capacity is likely to delist at prices considerably below \$3/kW-month, but it is very difficult to estimate how much will delist at what price. For the purpose of this analysis, we assume:

- Demand response will delist linearly from \$3/kW-month down to \$0.
- Emergency generation, which customers will generally keep in service regardless of FCM payments, will delist linearly from 600 MW (the maximum recognized in the FCM) at \$2/kW-year down to \$0.
- Half the oil- and gas-fired steam capacity will delist linearly from \$3/kW-month down to zero. Since so much capacity did not delist in the early 2000s, and since some steam plants (such as Montville 5) are likely to convert to partial biomass firing, we assume the other half of capacity would remain on line even with very low capacity payments.
- 400 MW of the combustion turbines will delist linearly from \$1.50/kW-month to zero.

6.1.3. *Forecast Supply and prices for FCA 4 and future Auctions*

Based on our analysis of the strategies available to supply and demand that bid into FCA 2 we assume about 3,000 MW of capacity delisting in FCA 4. Over the next decade, with the ISO's projected growth in capacity requirements, net of our forecast of renewable additions, about 200 MW of additional capacity could clear each year while the capacity price gradually rises to around \$2.40/kW-month. Assuming that some 700 MW of the capacity never returns (New England generators retire, New York generators continue to sell capacity in New York), prices would start rising faster in 2024, reaching the cost of new peakers (about \$8/kW-month) about 2030.

Exhibit 6-3 summarizes these assumptions. Column c shows our forecast of the ISO Installed Capacity Requirement (ICR), which is derived by increasing the 2009 CELT forecast by the required reserve margin and netting out the Installed Capacity Credits (ICCs) from the HQ Phase I/II connection.[95] Columns d to h provide our estimates of additions and reductions in resources clearing in the market.

- The additions in column d are the projects under contract in Connecticut (the New Haven peaker and the Project 150 units).
- The retirements in column e represents the attrition of older combustion turbines.

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[95]This credit varies from year to year. We used the HQ ICC credit that the ISO used in setting the net ICR in FCA 2.

- The delists in column f reflects the anticipated delisting of Salem 1–4 in FCA 3 and the rest of the resource surplus in FCA 4. After FCA 4, with load growth, varying amounts of previously delisted resources once again clear in the market (the positive values). The returning resources are about 1,500 MW less than the delistings, representing resources permanently lost to the market.
- The renewables in column g presents the capacity of the renewables that would enter the market due to RPS requirements, as discussed in detail later in this Chapter and summarized in Exhibit 7-4. For this computation, we assumed that the wind plants would be qualified at 20% of nameplate capacity, which is roughly the average ratio for the wind resources cleared in FCA 2, and that solar PV would be qualified at 50% of nameplate capacity.[96]
- the Demand Response in column h reflects the ISO's decision to eliminate the reserve-margin credit for demand resources. This adjustment also removes the new energy-efficiency resources that cleared in FCA 1 and FCA 2 in order to estimate capacity costs without any new energy-efficiency programs.

[96]The average insolation level on a horizontal surface during the summer on-peak hours used to rate intermittent resources in Boston is approximately 50%. Specific capacity values will vary with installation orientation, shading and technology.

Exhibit 6-3: Capacity-Price Forecast

Power Year Starting	FCA	Peak Demand (CELT 09)	Reserve Margin including HQ	Net Installed Capacity Req	Surplus Cleared	Resource Adjustments					Capacity Cleared	FCM Prices	
						Additions		Removals					
						Non-Renewable	Renewable	Retirements	delist	DSM		Nominal$	2009$
		MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	$ / kw-month	
		a	b	c= a*(1+e)-911	d	e	f	g	h	i	j = prior year +(e + f+ g + h + i)	*k*	l
6/1/2010	*1*	*28,160*		*32,305*	*1,772*						*34,077*	*$4.50*	*$4.38*
6/1/2011	*2*	*28,575*	*13.7%*	*32,528*	*4,487*						*37,015*	*$3.60*	*$3.43*
6/1/2012	3	29,020	14.4%	32,276	3,317	156	235	-10	-753	-1050	35,593	$2.95	$2.76
6/1/2013	4	29,365	14.6%	32,731	0	125	310	-10	-3,287		32,731		$1.30
6/1/2014	5	29,750	14.6%	33,183	0		282	-10	180		33,183		$1.30
6/1/2015	6	30,115	14.7%	33,628	0		228	-10	227		33,628		$1.40
6/1/2016	7	30,415	14.9%	34,027	0		327	-10	83		34,027		$1.50
6/1/2017	8	30,695	15.0%	34,374	0		197	-10	160		34,374		$1.50
6/1/2018	9	30,960	*15.1%*	34,709	0		281	-10	64		34,709		$1.60
6/1/2019	10	*31,270*	*15.2%*	35,097	0		274	-10	123		35,097		$1.60
6/1/2020	11	*31,566*	*15.3%*	35,469	0		262	-10	120		35,469		$1.70
6/1/2021	12	*31,860*	*15.4%*	35,840	0		207	-10	173		35,840		$1.80
6/1/2022	13	*32,158*	*15.4%*	36,216	0		87	-10	299		36,216		$1.90
6/1/2023	14	*32,465*	*15.5%*	36,602	0		169	-10	228		36,602		$2.00
6/1/2024	15	*32,771*	*15.6%*	36,988	0		153	-10	243		36,988		$2.10

a. CELT 2009

b. RSP 2008 to 2017, extrapolated 2018–2030

c. a × (1+b)–911 MW of HQ ICCs

d. Connecticut contract resources

e. Older combustion turbine attrition

f. Negative numbers are delistings of resources (Salem in FCA 3, all surplus in FCA 4). Positive numbers are return of delisted resources.

g. From Exhibit 6-4.

h. Removes energy-efficiency resources and reserve margin on demand response (no longer counted by ISO after FCA 2).

i. Actual for FCA 1 and FCA 2, computed for FCA 3.

j. FCA 1–FCA 3: Floor prices deflated to 2009$.

FCA 4–FCA 15: Price at which market would clear, given assumptions in text.

FCA 16–FCA 21: Linear interpolation to cost of new peakers.

Exhibit 6-4: Renewable Contribution to FCM

	Solar	Wind	Other renewables	FCM Effective Capacity
2010	44	143	110	160
2011	65	249	266	348
2012	93	444	448	583
2013	123	836	665	894
2014	163	1,082	877	1,175
2015	213	1,287	1,039	1,403
2016	273	1,362	1,321	1,730
2017	343	1,467	1,462	1,927
2018	423	1,885	1,620	2,209
2019	513	2,277	1,771	2,483
2020	613	2,469	1,945	2,745
2021	723	2,512	2,089	2,953
2022	843	2,572	2,104	3,040
2023	973	2,897	2,142	3,208
2024	1,113	3,236	2,157	3,361

These projections are subject to a wide range of uncertainties, including the effect of environmental regulation on older generators, the willingness of generators and demand-response providers to continue providing capacity at falling prices, the willingness and ability of generators to deactivate generators and return them to service, the alternative markets for capacity, the retention of generation for local reliability issues,[97] and the potential for changes in ISO rules to increase capacity payments to existing generators.

Based on these assumptions, we project the following prices

- prices for FCA 1 through FCA 3 are determined by the ISO-established floor prices, and would be the same with or without the energy-efficiency resources.
- A price of $1.30 per kw-month in FCA 4
- Prices in FCA 4 through FCA 15 will be set by the delist bid of the marginal existing resource required to clear the market

[97]The ISO has found that Wyman 1 and 2 are needed to support the 115 kV system in southern Maine and NH, pending transmission upgrades. (Evaluation of Need, Yarmouth 1 and 2, May 27, 2009, ISO-NE System Planning).

- Prices in FCA 16, in 2025, start to rise above the floor price of FCA 3 to reach the costs of new peakers in 2030.

(a) Comparison to AESC 2007

These values are much lower than the AESC 2007 projections. For example, the fifteen year (2010-2024) levelized avoided capacity cost to load for AESC 2009 is $17.81 (2009$) versus $116.94 (2009$) for AESC 2007. The lower projected values reflect the empirical information now available on the actual operation of the FCM after two FCAs, the quantity of existing capacity available to bid relative to the quantity required and the projected quantity of renewable resource capacity expected over the study period.

6.2. Avoided Capacity Costs Per MW Reduction in Peak Demand

As described in Chapter 2, a kw reduction from an EE measure in a given year can avoid wholesale capacity costs through two broad categories of approaches, i.e., bidding in to FCAs as a resource or reducing the ISO-NE forecast of peak load for which capacity has to be acquired. The unit values of avoiding capacity costs under each approach are summarized in Exhibit 6-5 below.

If the kw reduction from an EE measure in a given year is bid into FCA for that year its avoided capacity cost is the FCA price for that year and adjusted for an ISO-NE loss factor of 8% and reserve margins for FCA 1 and FCA 2. The FCA price forecasts are presented in column b of Exhibit 6-5.

If the kw reduction from an EE measure in a given year reduces the peak load that ISO-NE forecasts to be served in that year, its avoided capacity cost is the FCA price for that year adjusted upward by the reserve margin ISO-NE requires for that year. The reserve margin is the ratio of the Installed Capacity Requirement (ICR) to forecast peak load that ISO-NE sets each year. The ISO has published reserve margins for 2010/11 and 2011/12, and has provided indicative reserve margins through 2017/18 in the Regional Supply Plans. Those reserve margins are applied to the FCA prices to calculate the avoided capacity cost to load each year, and are presented in the last column of Exhibit 6-5. The forecast of avoided unit capacity cost to load also reflects a 1.9% adjustment for marginal losses on the pool transmission facilities and the applicable wholesale risk premium (9%).

Exhibit 6-5: Forecast of Avoided Unit Capacity Costs

Capacity Year Starting	FCA	FCA Prices (*forecast in Italics)*		Required Reserve	Avoided Capacity Cost to Load $/kW-year
		$/kW-month	$/kW-year		
		a	b = a×12	c	d =b×(1+c)× (1.019)x(1.09)
6/1/2010	1	$4.38	$52.51	16.1%	$67.71
6/1/2011	2	$3.43	$41.18	13.7%	$52.02
6/1/2012	3	$2.76	$33.09	14.4%	$42.03
6/1/2013	4	$1.30	$15.60	14.6%	$19.85
6/1/2014	5	$1.30	$15.60	14.6%	$19.86
6/1/2015	6	$1.40	$16.80	14.7%	$21.40
6/1/2016	7	$1.50	$18.00	14.9%	$22.97
6/1/2017	8	$1.50	$18.00	15.0%	$22.98
6/1/2018	9	$1.60	$19.20	15.1%	$24.54
6/1/2019	10	$1.60	$19.20	15.2%	$24.56
6/1/2020	11	$1.70	$20.40	15.3%	$26.11
6/1/2021	12	$1.80	$21.60	15.4%	$27.67
6/1/2022	13	$1.90	$22.80	15.4%	$29.24
6/1/2023	14	$2.00	$24.00	15.5%	$30.80
6/1/2024	15	$2.10	$25.20	15.6%	$32.37

Chapter 2 provided an illustration of three different approaches that a program administrator could choose for avoiding wholesale capacity costs via a 100 kw reduction from a hypothetical EE measure over the period 2010 to 2014. Those approaches are as follows:

- Bid 100% of the projected reduction into each of the relevant FCAs
- Bid none of the projected reductions into any FCA
- Bid 50% of the projected reduction into each of the relevant FCAs

In Exhibit 6-6 below, we estimate the value of each of those illustrative approaches.[98] Bidding 100% of the reduction into each of the relevant FCAs produces the highest avoided capacity costs, over $17,000 as indicated in column e, but carries the highest associated financial risk. Bidding none of the reductions into any FCA produces the lowest amount, column h, approximately $ 1,800 but has no financial risk. Bidding 50% of the reduction into each of the relevant FCAs

98 PA should include wholesale risk premium in their calculations of avoided capacity cost to load.

produces a value of approximately $9,700, mid-way between the other two approaches with low or no financial risk.

Exhibit 6-6: Value of Illustrative Alternative Approaches to Avoiding Capacity Costs via Efficiency Measure Reductions in Peak Demand

Hypothetical measure assumptions - Installation in 2010, peak reduction of 100 kw, 5 year measure life												
	Values per ISO-NE NICR and FCA			Example 1 - PA bids 100% of expected demand reduction into each corresponding FCA			Example 2 - PA bids zero expected demand reduction into each corresponding FCA			Example 3 - PA bids 50% of expected demand reduction into each corresponding FCA		
	FCA #	FCA Price(1)	Avoided Capacity Cost to Load(2)	Reduction Bid into FCA	Impact of Reduction on NICR set for power year	Value of Reduction in Peak demand	Reduction Bid into FCA	Impact of Reduction on NICR set for power year	Value of Reduction in Peak demand	Reduction Bid into FCA	Impact of Reduction on NICR set for power year	Value of Reduction in Peak demand
Units		$ per kw-yr	$ per kw-yr	kw	kw		kw	kw		kw	kw	
Year		a	b	c	d	e = (a * c) + (b* d)	f	g	h = (a * f) + (b*g)	i	j	k = (a * i) + (b*j)
2010	1	$65.84	$67.71	100	0	$ 6,584	0	0	$ -	50	0	$ 3,292
2011	2	$50.58	$52.02	100	0	$ 5,058	0	0	$ -	50	0	$ 2,529
2012	3	$35.74	$42.03	100	0	$ 3,574	0	0	$ -	50	0	$ 1,787
2013	4	$16.85	$19.85	100	0	$ 1,685	0	0	$ -	50	0	$ 842
2014	5	$16.85	$19.86	100	0	$ 1,685	0	100	$ 1,986	50	50	$ 1,835
Net Present Value @ 2.2% discount rate						**$ 17,688**			**$ 1,781**			**$ 9,734**

(1) FCA Price Reflects ISO NE 1.08% loss factor and reserve margins for 2010 and 2011 only
(2) Includes wholesale risk premium of 9.0%

6.3. Forecast of Energy Prices Assuming No New DSM

The projected energy prices presented below are outputs from the Market Analytics simulation model for a hypothetical future in which no new energy efficiency resources are implemented from 2010 onward. As such, they represent the wholesale price of avoided energy in a future with no new efficiency. These prices are NOT meant to be used as projections of energy prices in the most likely future, i.e., one in which there will be some level of new energy efficiency measures installed each year over the planning horizon.

Chapter 0 describes the Market Analytics model and the major input assumptions underlying these projections. In that deliverable we discussed the structure of the electric energy market, and the model and inputs that were to be used to represent it. These key inputs are:

a. projected loads–derived from the latest ISO-NE CELT report;

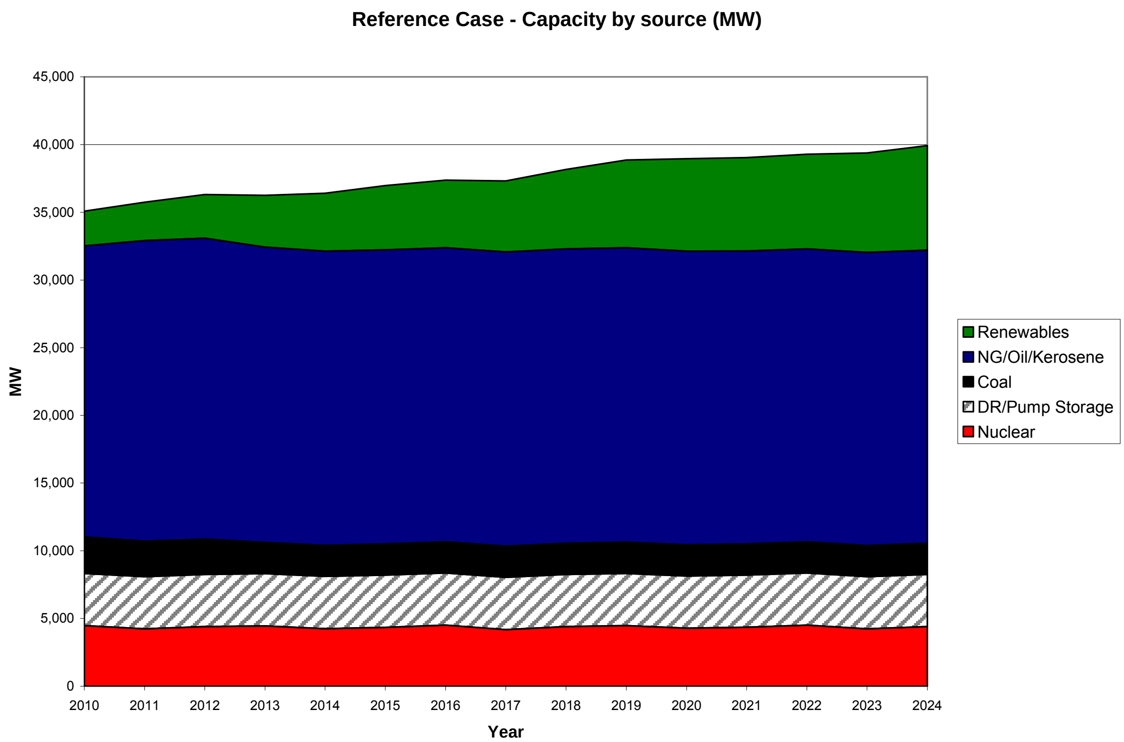
b. projected resources—based on available public information such as the capacity auctions and the current state RPS requirements for renewables

c. forecast prices for natural gas, coal and oil, and

d. forecast emission regulation compliance costs for CO_2, SO_2 and NO_x.

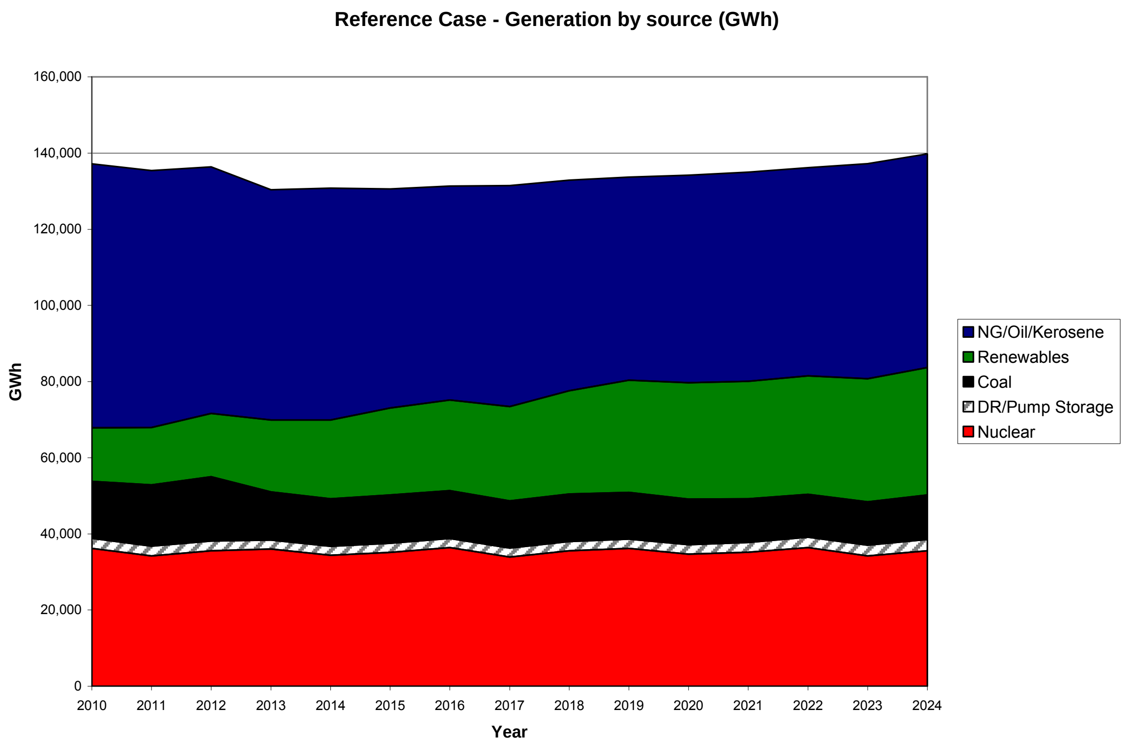
The projected level and mix of capacity in the Reference Case is presented in Exhibit 6-7 below. The only capacity additions through 2024 are renewable resources, top row, to comply with RPS requirements.

Exhibit 6-7: Reference-Case Capacity by Source (MW)



The projected level and mix of generation in the Reference Case is presented in Exhibit 6-8 below Reference Case Generation by source. Generation from nuclear and coal units remain. Generation from natural gas is the dominant marginal resource but the quantity of gas-fired generation declines over time as more generation is acquired from renewable resources in compliance with RPS requirements. Note that the coal generation also declines in response to the additional renewable resources.

Exhibit 6-8: Reference-Case Generation by Source (GWh)



The prices projected in the Reference Case are:

- on a levelized annual basis 4.1% below those from AESC 2007, although the differences are somewhat larger for specific periods (see Exhibit 6-13);[99]
- for the near-term period of 2010-2011 above the ISO-NE futures as of March 31, 2009 by 8%, but only 0.2% above the futures as of May 15, 2009;
- below the EIA AEO March 2009 projections on a levelized basis by 3.5% over the 2010-2024 period, but nearly identical for years 2014 and later;

6.3.1. Forecast of Wholesale Electric Energy Prices

The scope of work requests streams of energy values for all of New England in the form of "the hub price". It requests forecasts for the following four streams—summer on peak, summer off-peak, winter on-peak, winter off-peak.

The hub price representing the ISO-NE Control Area is located in central Massachusetts and the Central Massachusetts zone in Market Analytics model is used as the proxy for that location. Exhibit 6-9 below presents summer and winter,

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[99] All levelized values have been calculated using a 2.2% discount rate for illustrative purposes.

on-peak and off-peak energy prices as produced by the model through 2024 for Central Massachusetts.

Exhibit 6-9**: Energy Price Forecast for Central Massachusetts**

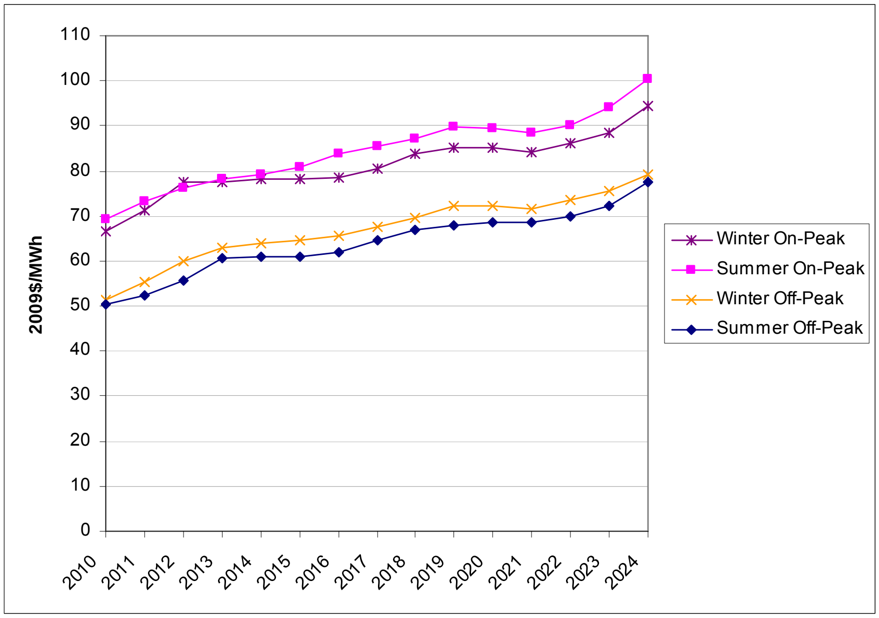


Exhibit 6-10 provides the prices in tabular form.

Exhibit 6-10: Energy Price Forecast for Central Massachusetts

Year	Summer Off-Peak	Summer On-Peak	Summer All-Hours	Winter Off-Peak	Winter On-Peak	Winter All-Hours
2010	$50.2	$69.3	$59.3	$51.2	$66.8	$58.6
2011	52.5	73.3	62.4	55.4	71.2	62.9
2012	55.7	76.2	65.5	59.8	77.5	68.2
2013	60.8	78.3	69.1	63.0	77.5	69.9
2014	60.9	79.1	69.6	63.9	78.0	70.7
2015	61.0	80.9	70.5	64.6	78.2	71.1
2016	62.1	83.8	72.4	65.7	78.6	71.9
2017	64.6	85.5	74.6	67.5	80.4	73.7
2018	66.9	87.0	76.5	69.5	83.8	76.3
2019	67.8	89.7	78.2	72.1	85.3	78.4
2020	68.6	89.5	78.5	72.1	85.3	78.4
2021	68.5	88.6	78.1	71.6	84.2	77.6
2022	69.8	90.2	79.6	73.6	86.1	79.5
2023	72.3	94.1	82.7	75.4	88.4	81.6
2024	77.4	100.5	88.4	79.1	94.5	86.4
Levelized[100]	63.3	83.7	73.0	66.3	80.5	73.0
All prices expressed in 2009$ per MWh.						

6.3.2. Analysis of Forecasts of Wholesale Electric Energy Prices

The scope of work requests the following analyses of the forecast:

- Comparisons with other trends and forecasts, including comparisons to a trend of actual monthly prices (real time) from ISO-NE for 2007-08, a forecast as represented by the NYMEX futures market and the most recent EIA forecast;
- A high level discussion of reasons for differences identified in the comparisons; and
- Explanation of any apparent price spikes and key variables that affect the outcome, as well as identification of potential scenarios worthy of investigation.

[100] Levelized values are calculated using a 2.22% real discount rate. The choice of the actual discount rate has little effect on these levelized values. For example, doubling the discount rate to 4.44% changes the summer off-peak levelized value from 62.0 to 61.5 .

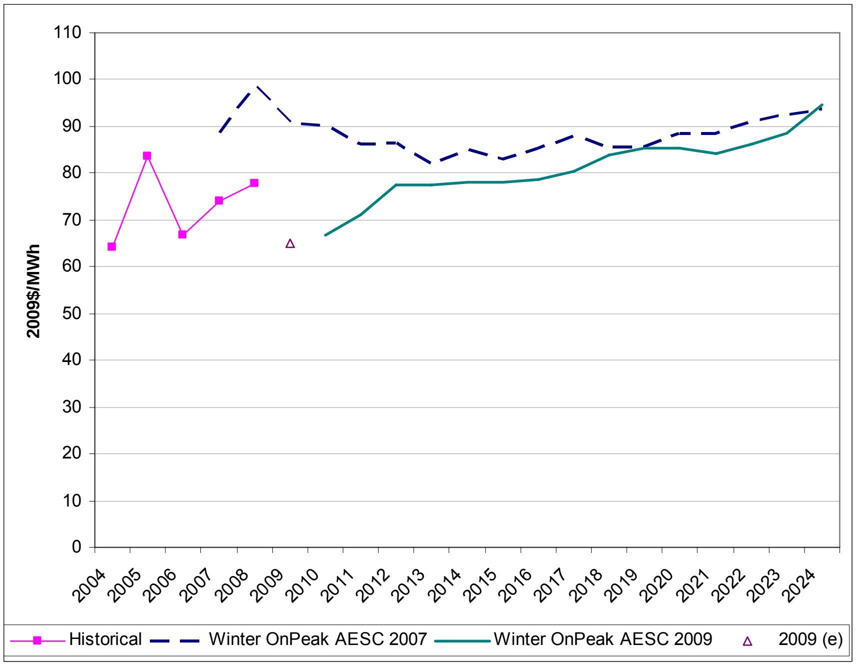
6.3.2.1. Comparison with the AESC 2007 Forecast and Historical Values

Exhibit 6-11 provides a comparison of historical prices and AESC forecasts for the Winter On-peak period in the Central Massachusetts zone. This exhibit corresponds to Exhibit 5-13 in AESC 2007 (5-21), which in turn provides a comparison with the AESC 2005 forecast (AESC 2007 treated Western Massachusetts and Central Massachusetts as a combined zone, whereas they are now being modeled separately).

This chart indicates that our forecast is consistent with historical prices and the AESC 2007 forecast. Winter period prices from 2004 through 2008 have ranged from $64 per MWh to $84 per MWh (2009 dollars) with a five year average of $73.2/MWh. The AESC 2007 of $90/MWh and above is based on average natural gas winter prices in the range of $9/mmBtu. Although natural gas prices have fluctuated significantly reaching levels above $11/mmBtu in the Summer of 2008, they have not maintained such high levels for any length of time.

The economic events of the last year have caused a significant decline in natural gas and petroleum prices. The AESC 2009 near term natural gas forecast starts a little above $6/mmBtu in 2010, rises to the mid $7 levels in 2012, and then to a bit above $8 by 2024. This is reflected in the electricity price forecast which is considerably lower until 2012 and then reaches comparable levels. The hills and valleys in the annual electricity price curve primarily represent the natural gas price changes, although the 2024 rise is also associated with lower reserve margins.

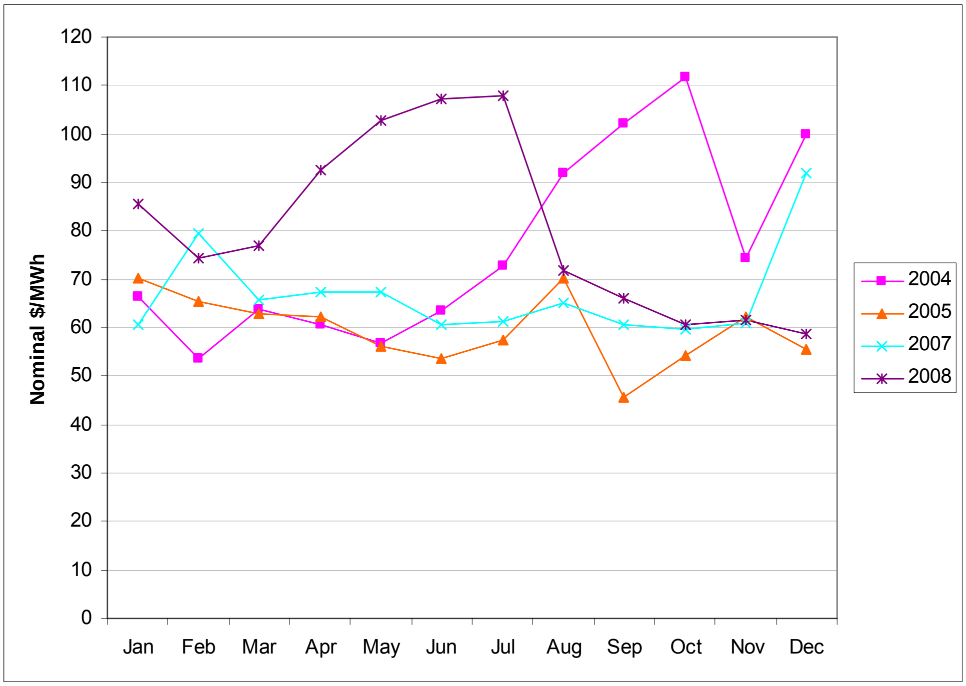
Exhibit 6-11: Historical and AESC Forecasts–Winter On-Peak Prices



6.3.2.2. Comparison with Trends in ISO-NE Prices

Trends in ISO-NE monthly prices for the recent historical period due to factors other than natural gas prices appear to be very much hidden in the noise. Exhibit 6-12 shows the variation in monthly prices in each of the last four calendar years. Although one might expect prices to be higher in the summer and winter months, that has not generally been the case. The big peak in the summer of 2008 is associated with what is now identified as a natural gas price bubble that collapsed last fall. Likewise any solid trend from year to year as shown in Exhibit 6-12 can not really be determined, although the price appears to be moving upward.

Exhibit 6-12: ISO-NE Control Area Monthly Real-Time Prices



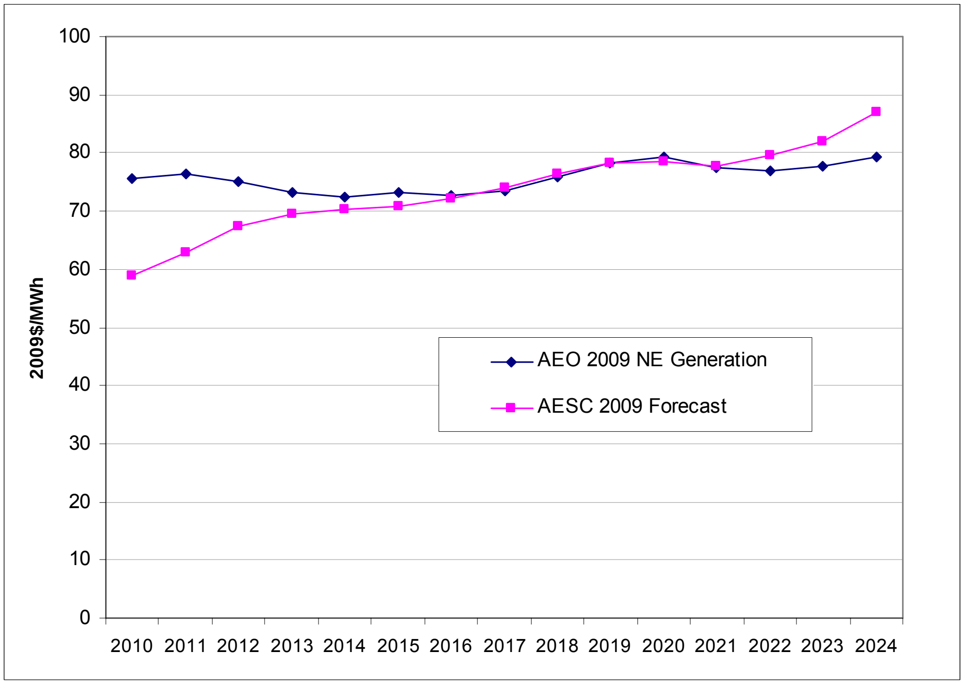
Comparison with Other Forecasts

The following section details comparisons of the AESC 2009 forecast with other forecasts.

Comparison with EIA (2009a) Forecast

The Annual Energy Outlook is produced every year by the EIA and forecasts energy usage and price for the U.S. as a whole and for its constituent regions. Table 78 of that report presents generation, capacity and prices for New England. Although the AEO does not produce a market price per se, the generation service category price comes fairly close. The exhibit below compares that generation price with the current AESC forecast. Although AEO is significantly higher for the near-term years 2010-2012, afterwards the forecasts are nearly identical reflecting in large part the common underlying natural price forecast. The primary cause of the differences in the near-term years is related to the natural gas price differences as the AEO forecast was put together in the Fall of 2008 before the sharp decline of near-term natural gas prices.

Exhibit 6-13: Forecast Comparison with EIA (2009a)



In April of 2009 EIA released an update of the AEO forecast (EIA 2009b), which has lower near-term natural gas prices and lower New England generation prices for 2010 and 2011 that nearly match those of the AESC electricity price forecast. That AEO forecast also has significantly lower natural gas (and electricity prices) for the year 2013-2020 which are not supported by the natural gas futures market, and we do not find credible for a number of reasons having to do with their assumptions and the underlying fundamentals (see Chapter 0).

Comparison with NYMEX Futures Markets for Electricity in New England

NYMEX maintains a futures market for electricity prices at the New England Hub. There is a moderate amount of trading out about a year or two, but further out the market is quite thin. Nevertheless it does provide one source of comparison with the AESC forecast. In the spirit of presenting the most recent data, the NYMEX market as of 5/15/09 is the comparison date.

The following exhibits show the comparisons on a monthly basis corresponding to the NYMEX products which are often based on multiple months. Considering the volatility of the futures markets the correspondence is amazingly close. A source of differences for the 2012 prices is that the AESC 2012 natural gas price based on fundamentals is a little higher than the futures price for the same year. Further discussion of the differences in found in the next section.

Exhibit 6-14: AESC Peak Forecast vs. NYMEX New Eng Futures

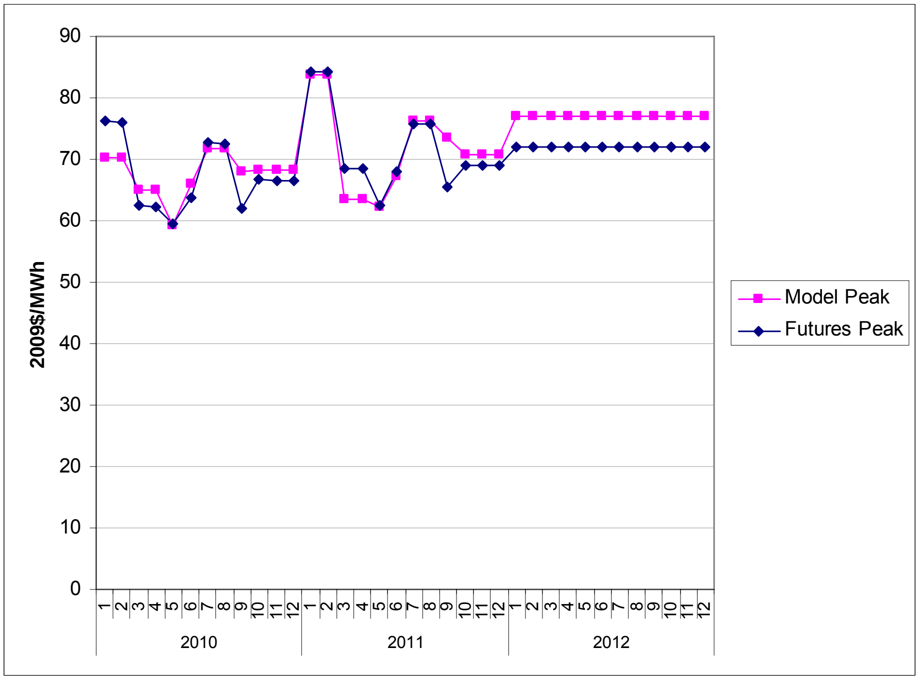
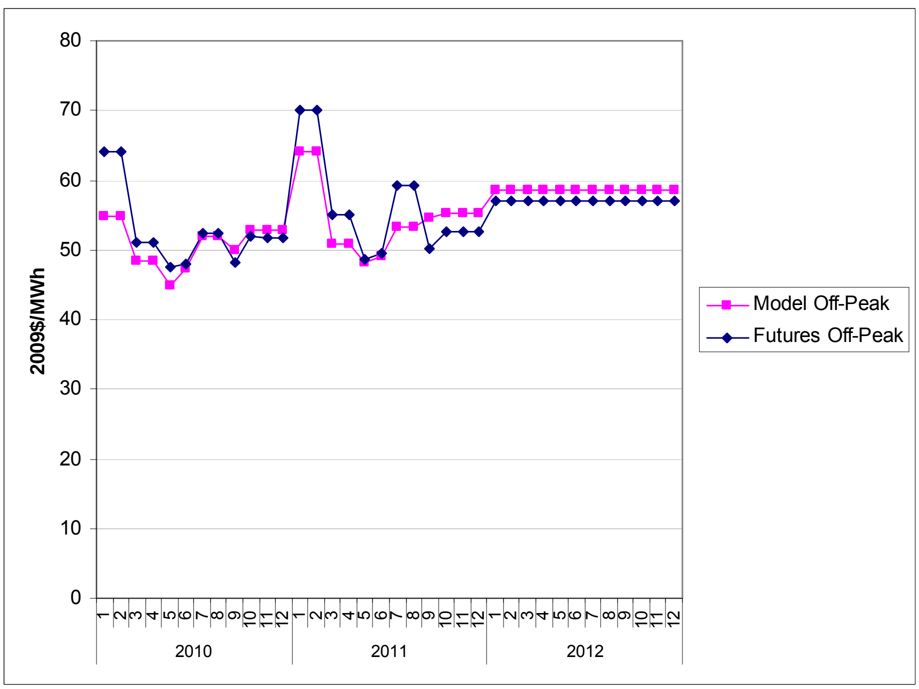


Exhibit 6-15: AESC Off-Peak Forecast vs. NYMEX New Eng Futures



6.3.3. Discussion of Forecast Differences

The following section summarizes forecast differences between AESC 2009 and AESC 2007.

6.3.3.1. AESC 2007

Exhibit 7-11 compares the two AESC forecasts on a levelized basis. The major differences between the two forecasts occur in the near-term years (2010-2012) and in the peak periods.

Exhibit 6-16: Levelized Cost Comparison for Central Massachusetts 2010-2024 (2009$/MWh)

	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy
AESC 2009	81.0	66.3	80.2	62.0
AESC 2007	87.3	64.0	94.2	63.3
% Difference	-7.2%	3.3%	-14.8%	-2.0%

There are several key factors causing the current forecast to differ from that of AESC 2007:

- Lower Load – Peak load levels in 2010 are about 900 MW below those used in the previous study. That difference grows by about 100 MW per year which reduces overall load levels and market prices.
- RPS requirements – Renewable resources are greater in this forecast and as price takers tend to lower market prices.
- Natural gas price – The near-term price is substantially lower while the longer-term price is slightly higher. (See Exhibit 3-8 and the discussion on page 3-16)
- CO_2 price – The near-term price is lower but is moderately higher in 2013 and later years. [101]

The impact of each of these factors is discussed in more detail below.

Load Forecast

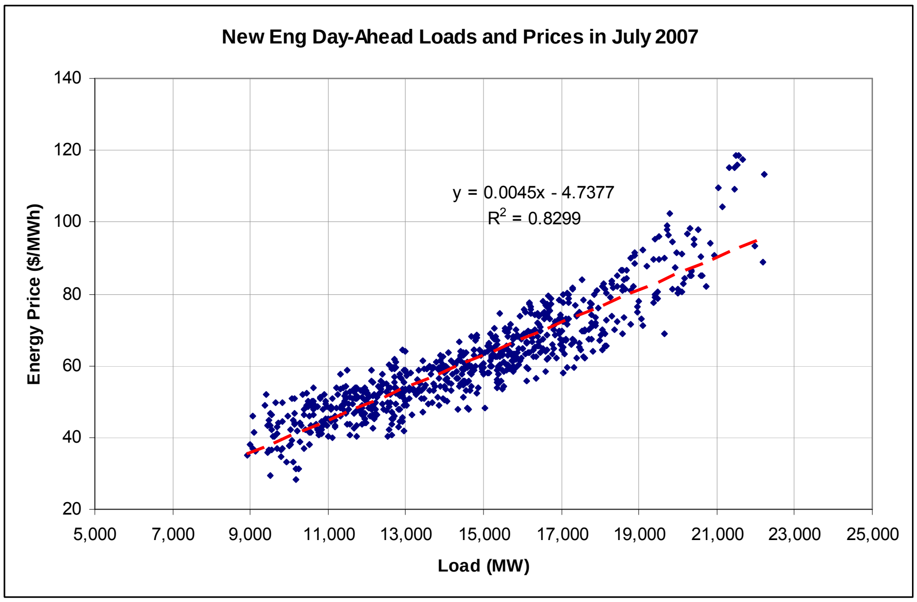
Load levels have an effect on market prices. Higher load levels have associated higher market prices as less efficient and more costly generating resources are brought online to meet the greater load. This is illustrated in the following exhibit which illustrates a de facto supply curve for a single month.

This exhibit below shows hourly electricity loads and hourly prices for a single summer month. The month of July 2007 was chosen because NG prices were

[101] See Exhibit 2-4 and associated text.

relatively stable during that season and that month, and in a range close to our current forecast.[102] This graph shows that even with a stable NG price, changes in hourly loads result in different hourly electricity market prices throughout the month, with higher loads associated with higher prices and vice versa. Most of the higher loads occur in the peak periods explaining the higher peak period prices, although there can be some overlap.

Exhibit 6-17: Historical Hourly Loads and Prices for July 2007

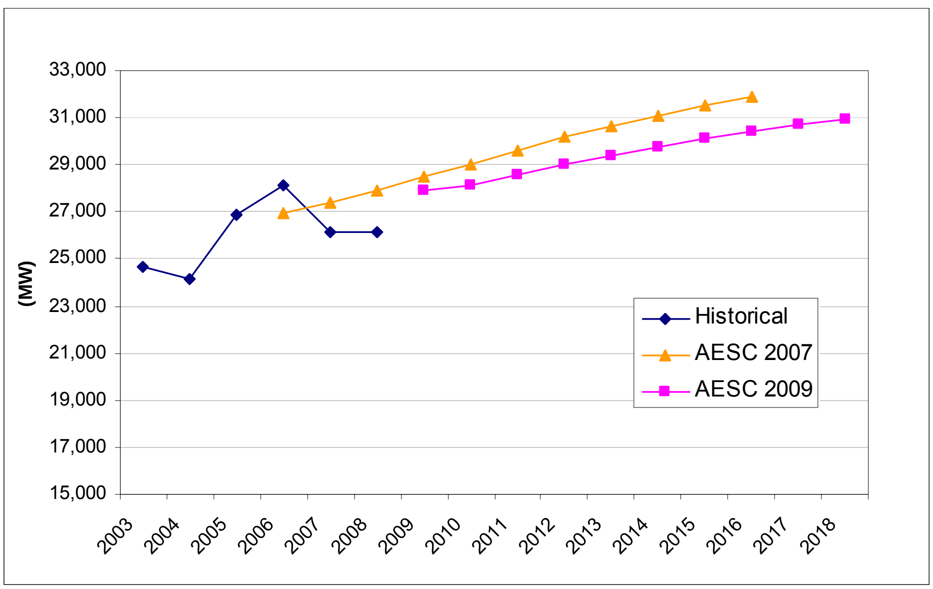


[102]During July 2007 the natural gas daily market prices in New England averaged $6.82/mmBtu with a standard deviation of $0.40/mmBtu (2007$). (Reference file: Daily Gas Prices In New England July 2007.xls)

Although the precise load-price effect is difficult to determine, a very rough estimation can be based on the July 2007 hourly loads and prices presented previously. A regression analysis of that data gives a slope coefficient of 0.0045. Thus a 1000 MW reduction in load would translate into a $4.5/MWh reduction in the electricity price (all else being equal).

While long-term market behavior is not the same as observed in a shorter period such as a single month, reduced load levels will be associated with lower prices until there are changes in generating capacity such as retirements or additions that establish a new balance point. The exhibit below shows that the current peak load forecast is significantly below that used for AESC 2007, with the difference of the period 2010 through 2016 going from 875 to 1470 MW, and increasing at about 100 MW/year thereafter. This will have an effect on load levels in all hours and reduce the energy prices as well.

Exhibit 6-18: Comparison of Historical Loads and Peak Load Forecasts



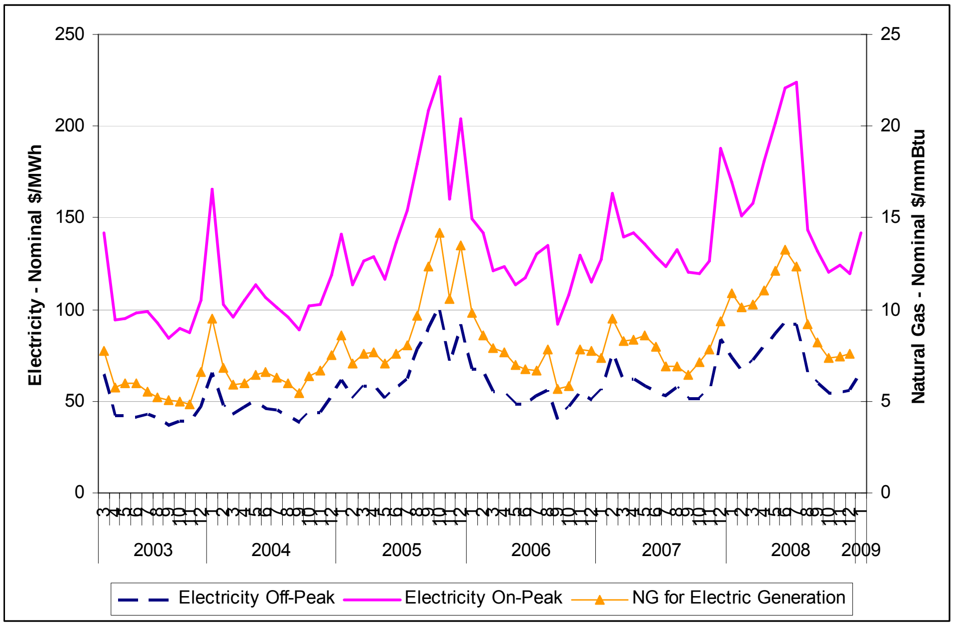
RPS Requirements.

The renewable resources are price takers and their presence in the resource mix also tends to reduce market prices by pushing up the supply curve. RPS requirements in New England have increased since 2007 and thus are a factor lowering market prices. For example in 2018, RPS requirements represent more than 13% of the total energy load.

Natural Gas Price Forecast

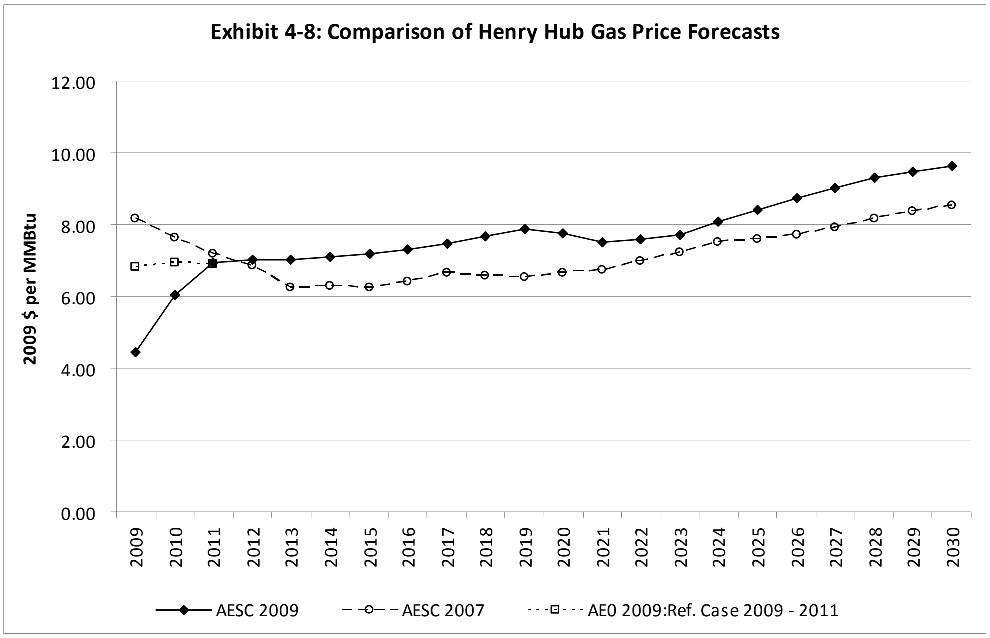
Prices in the New England electricity energy market have been historically very volatile. This volatility is very strongly linked to the price that electric generators pay for natural gas as reported to the EIA. The graph below shows these prices on a monthly average basis for the previous six years. One thing to note is that although electricity loads are higher in the summer the maximum amount of generation is available then to meet those loads.

Exhibit 6-19: Historical New England Electricity and Natural Gas Prices



The following exhibit compares the Henry Hub natural gas forecast for this report compared to that of AESC 2007. The AESC 2009 forecast has much lower prices in 2009 and 2010, but then over the longer term average about $0.50/mmBtu higher compared to the previous forecast. The shape of the electricity price forecast curve in Exhibit 6-11 from 2010 through 2024 closely mirrors that of the natural gas prices. Based on natural gas prices alone one might expect electricity prices to be about $5/MWh higher than in AESC 2007, but that appears to be offset by other factors as discussed next.

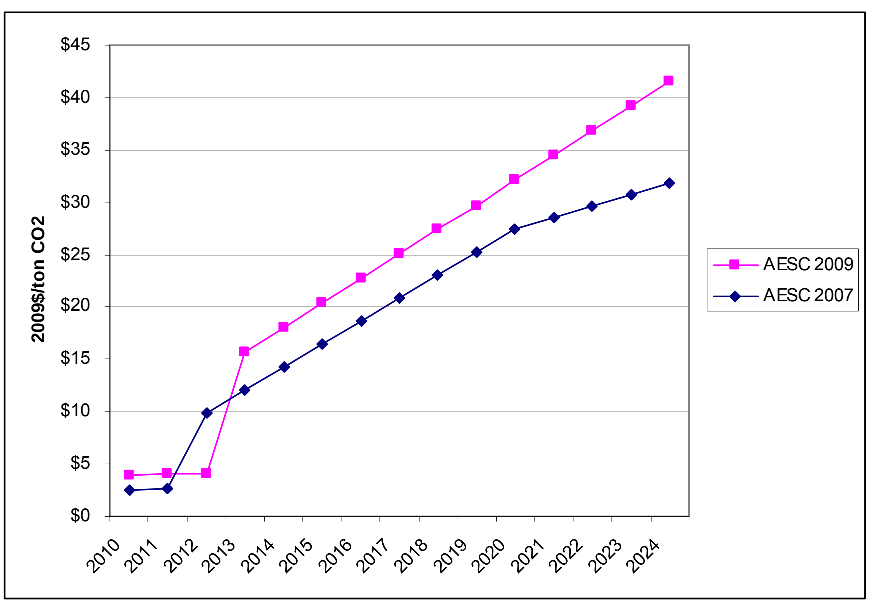
Exhibit 6-20: AESC 2009 vs. AESC 2007 Gas Price Forecast Comparison



CO_2 Price Forecast

The CO_2 Price forecast used for AESC 2009 is slightly higher than that used for AESC 2007, but not until 2013 and not significantly so until after 2020 as shown in the following exhibit. The levelized cost for the period 2010-2024 in AESC 2009 is $22.75/ton compared to $18.85/ton for AESC 2007, a 21% increase that occurs mostly in later years.

Exhibit 6-21: AESC 2009 vs. AESC 2007 CO2 Price Forecast Comparison



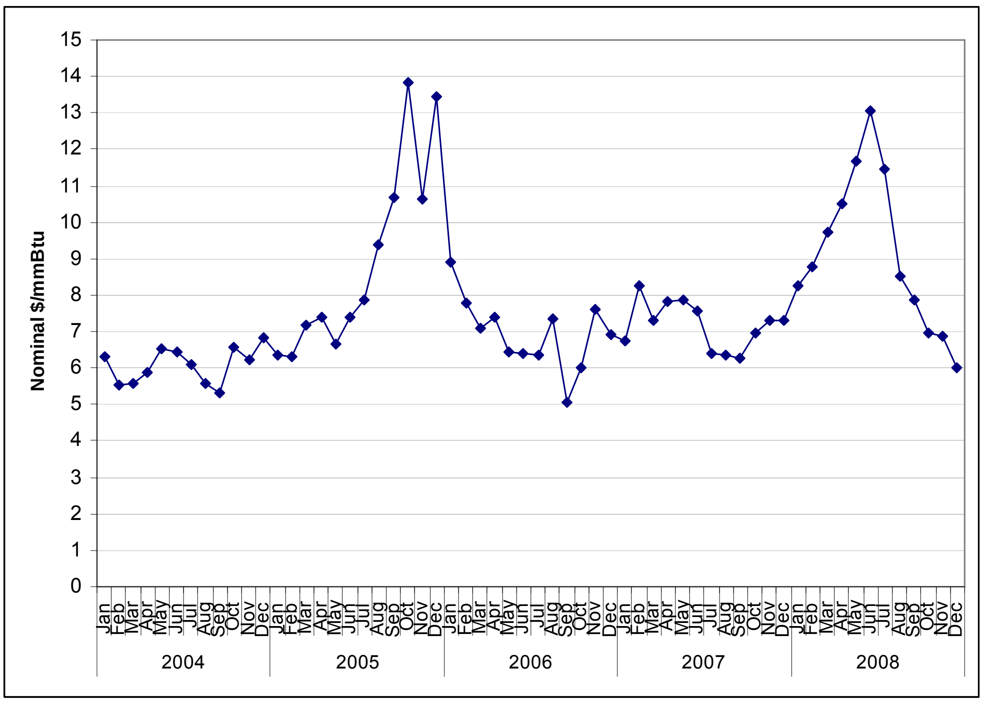
6.3.3.2. NYMEX Futures for Electricity in New England

There are two NYMEX futures products particularly relevant to the New England electricity prices: (1) New England Hub electricity and (2) Henry Hub natural gas.

The natural gas price is primary since the large majority of marginal generation in New England is natural gas fired and the resulting bid (and market) prices largely reflect the natural gas costs. The cost of natural gas for New England generators is based on the Henry Hub price plus a basis differential for delivery to New England and a transport cost to the plant. This is discussed more in the following section.

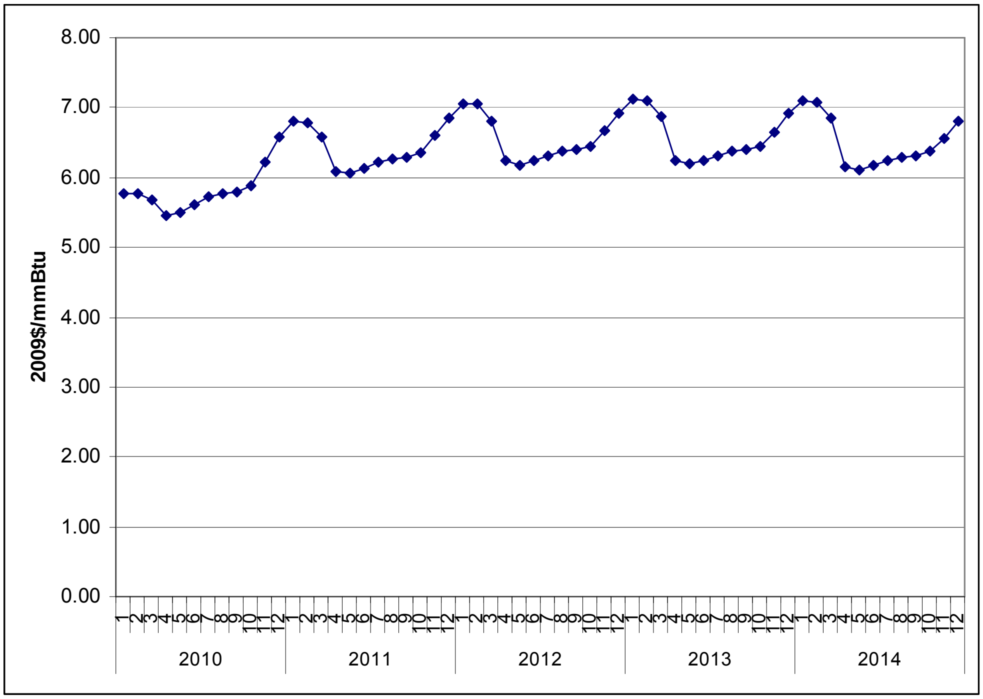
It is important though to discuss though the monthly variations in the Henry Hub prices. The volatility of historical prices is reflected in the following exhibit. Even adjusting to annual averages, no consistent month to month pattern emerges from this data.

Exhibit 6-22: Historical Henry Hub Natural Gas Prices



However the HH futures have a very consistent and regular monthly price pattern as shown in the following exhibit. In developing the future monthly natural gas prices for the modeling we used the monthly pattern as reflected in the futures since natural gas demand is much higher in the winter and it is reasonable to expect that prices will be as well.

Exhibit 6-23: Henry Hub Natural Gas Futures



The New England electricity futures are based on the market perceptions of the Henry Hub natural gas prices, the additional costs for transport to New England, the efficiency of natural gas generators and the electric market behavior.

As noted in the previous comparison of the AESC price forecast with the electricity futures, there is a general consistency between those two. A major factor behind the differences in 2012 is that the AESC Henry Hub natural gas forecast based on fundamentals and AEO 2009 is approximately 7% higher than the NYMEX futures for that year.

But too much weight should not be placed on this since the electricity futures like the natural gas futures markets tend to be volatile and short-sighted. There is also the general tendency for longer-term future prices to reflect the near-term prices rather than longer term conditions.

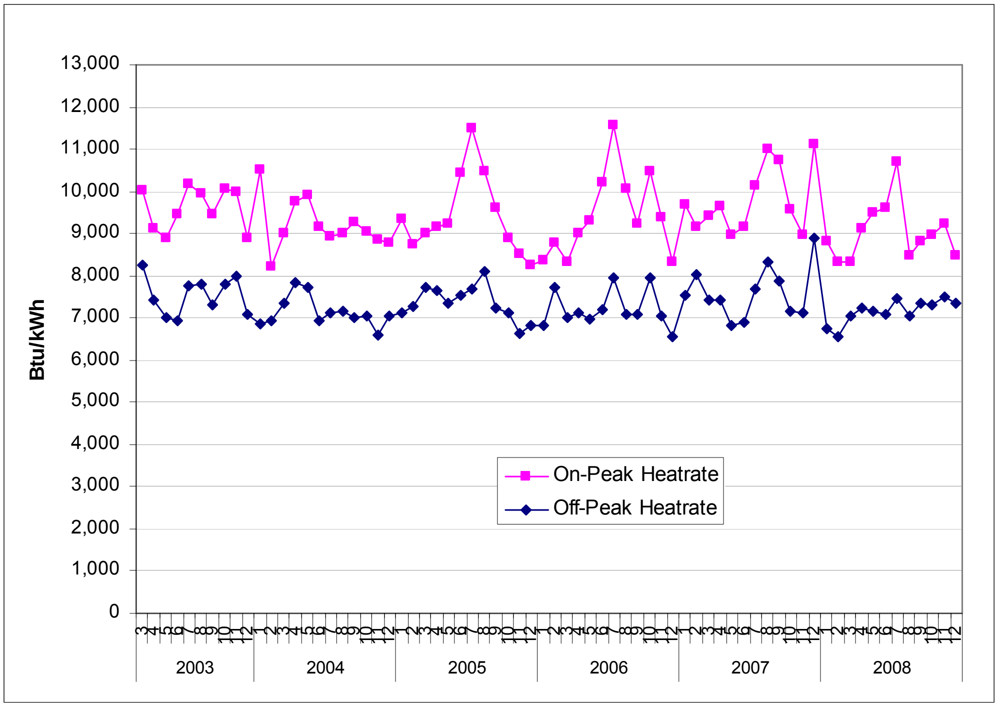
Natural Gas and Electricity Prices

Historically there has been a strong and fairly consistent relationship between the cost of natural gas to New England generators and electricity market prices. Nearly all of peak period electric generation in New England is from natural gas powered units, as is a majority of the off-peak generation. The historical relationship between natural gas prices to generators and electricity market prices in pear and off-peak periods is represented in Exhibit 6-24. This relationship is expressed as an implied heat rate which represents a ratio of the electricity to natural gas prices.[103]

These implied heat rates can be viewed as proxies for the average marginal generating unit in peak and off-peak periods. As expected the ratios are higher for the peak periods when more expensive less-efficient units are on the margin. The average monthly peak period value is 9,410 Btu/kWh representing a mix of units. The monthly standard deviation is 783 Btu/kWh representing a modest variability in the data. For the off-peak period the average implied heat rate is 7,324 Btu/kWh with a standard deviation of 455 Btu/kWh representing more efficient natural gas units and a mix of coal plants as well. One can also observe a tendency for the heat rates to increase in the summer reflecting increased loads and the use of less-efficient resources. There are definitely patterns here, but a lot of variability as well.

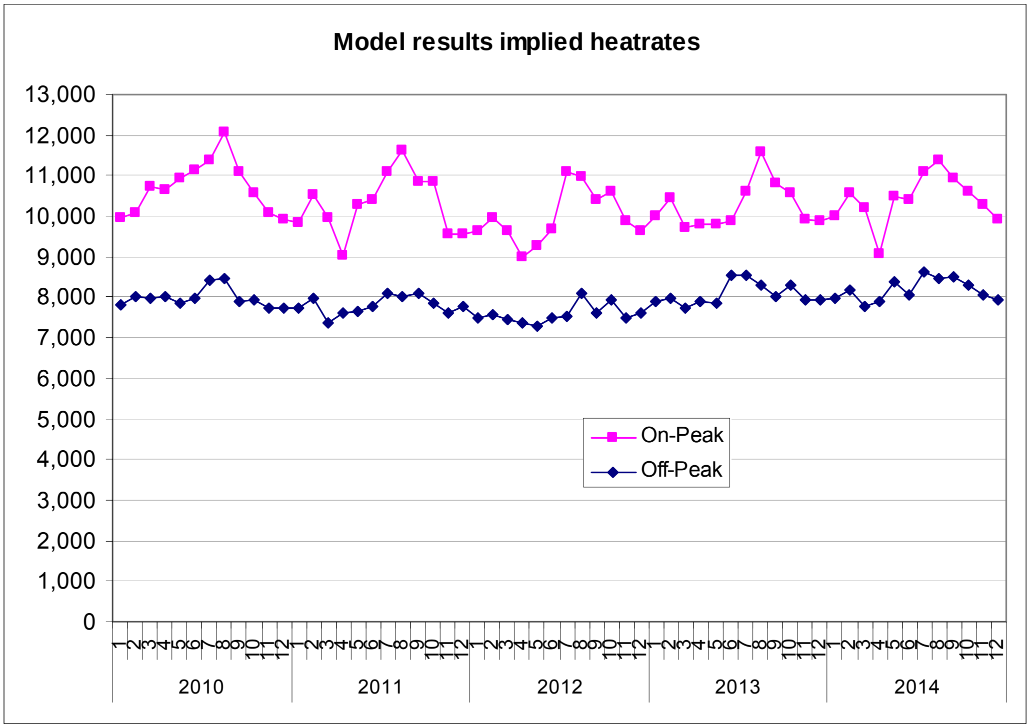
[103]The natural gas prices used are those reported by EIA as representing the prices paid by electric generators in New England and thus do not always reflect the reported market prices. An analysis of the two types of prices indicated that the EIA prices corresponded much better to electricity prices than the NG market prices.

Exhibit 6-24: Historical Relationship of Monthly Natural Gas and Electricity Prices



We have also compared the model results and natural gas price inputs on an equivalent basis and find similar patterns but with less variability and somewhat more regular. The off-peak ratios have significantly less variability. The on-peak ratios show definite summer peaks with a low price point often occurring in April. The average ratios of 10,249 Btu/kWh (peak) and 8,082 Btu/kWh (off-peak) are a little higher than the historical averages but not unreasonably so.

Exhibit 6-25: Model Relationship of Monthly Natural Gas and Electricity Prices



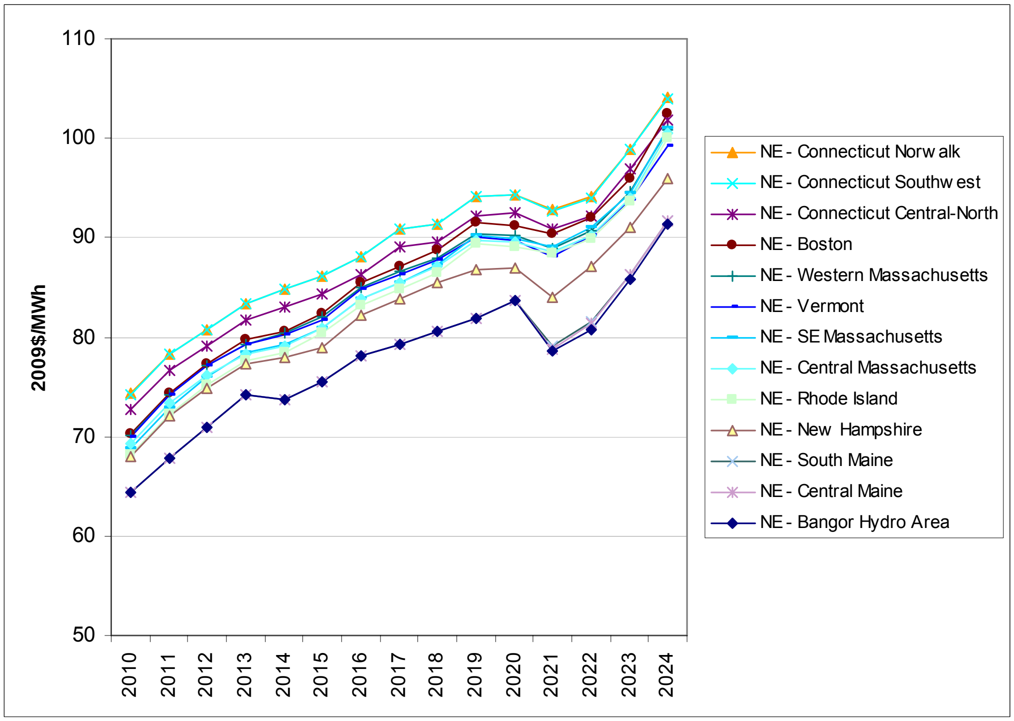
6.3.4. Forecast of Electric Energy Prices by State

The forecast of energy values by zone by year fore each period i.e., summer on peak, summer off-peak, winter on-peak, winter off-peak are presented in Appendix C.

Exhibit 6-26 illustrates the summer peak period prices in descending order by model locations.[104] Note how some zones have nearly identical prices. The highest price group being southwestern Connecticut and the lowest price group representing Maine. The price dip after 2020 is related to the underlying Henry Hub natural gas price discussed previously.

[104]The prices for the Bangor Hydro Area in 2024 are somewhat anomalous and will be corrected.

Exhibit 6-26: New England Summer Peak Locational Price Forecast



6.3.5. Transmission Energy Losses

Our forecast for marginal energy clearing prices includes inter-area losses for energy coming inside the load area from outside for flows across transmission links between modeling zones. These losses are not reported by the model by time of day; therefore we have presented the loss factors for summer and winter periods only. The losses presented in Exhibit 6-27 represent losses as a percentage of imports into each zone or state.

Exhibit 6-27 Modeling Zone and State Transmission Losses

Modeling Zone Losses		
Modeling Zone	**Summer**	**Winter**
BHE	5.60%	5.56%
BOST	0.99%	0.89%
CMA	4.72%	5.04%
CMP	0.00%	0.00%
CT	1.20%	0.88%
CTSW	2.00%	2.00%
ME	0.00%	0.00%
NH	8.54%	7.96%
NOR	0.10%	0.10%
RI	1.53%	1.79%
SEMA	0.52%	0.60%
SME	0.92%	0.53%
VT	4.87%	4.76%
WEMA	1.45%	1.41%
New England Average	2.23%	2.31%
State Losses		
State	**Summer**	**Winter**
CT	1.25%	1.19%
MA	2.46%	2.62%
ME	0.49%	0.43%
NH	8.54%	7.96%
RI	1.53%	1.79%
VT	4.87%	4.76%
New England Average	2.23%	2.31%

6.4. Avoided Cost of Compliance with RPS

Our estimate of avoided costs includes the cost of avoiding additional costs under the RPS imposed by five of the New England states, and assuming that the Vermont renewables mandate will be converted into an RPS. The annual quantity of renewable energy that LSEs need to acquire in order to comply with RPS requirements is directly proportional to the annual load that the LSEs supply. All but Vermont currently require the use and retirement of NEPOOL Generation Information System (GIS) certificates, commonly referred to as Renewable Energy Certificates (RECs) to demonstrate compliance.[105]

[105]Currently, Vermont's requirement will allow RECs to be sold off elsewhere (presumably for compliance in other states), therefore not leading to incremental renewable energy additions beyond what would be predicted in the presence of other states' requirements (although it has been argued that the Vermont requirements will support financing and therefore lead to more renewables being built, and therefore less reliance on Alternative Compliance Payments). We assume that by 2012, Vermont's standard will be altered to require retirement of RECs, and thereby add to the total RPS additions projected.

To the extent that the price of renewable energy exceeds the market price of electric energy, LSEs incur a cost to meet the RPS target. That incremental unit cost is the price of a REC. This annual compliance cost ($) equals the quantity of renewable energy purchased (kWH) multiplied by the REC price ($/kWh).

Energy-efficiency programs reduce the cost of compliance with RPS requirements by reducing the total load, or kWh, that must be supplied. Reduction in load due to DSM will reduce the RPS requirements of load serving entities (LSE) and therefore reduce the costs they seek to recover associated with complying with these requirements. The RPS compliance costs that retail customers avoid through reductions in their energy usage is equal to the price of renewable energy in excess of market prices multiplied by the portion of retail load that a supplier must meet from renewable energy under the RPS.

This section forecasts those avoided RPS costs. The key input to those calculations is a forecast of the price of renewable energy in excess of market prices each year, i.e. the forecast price of RECs. This sub-section presents a forecast of the price of renewable energy, from which we will deduct the market price of energy in order to calculate the forecast price of RECs by year. The forecast price of renewable energy through 2011 is based on broker quotes as presented in Section 2.5.4. The forecast price of renewable energy from 2012 onward is based upon our estimates of the cost of entry for *new* or *incremental* renewable resources each year.

6.4.1. New or Incremental Renewables Dominate Annual Additions To RPS Supply

Our general approach to estimating the prices of renewable supply is described in Chapter 2. We assume that after 2011, the price of renewable energy will be set at the cost of new entry for *new* or *incremental* renewable resources.

New or *incremental* renewable resources are those which qualify as “Class I” in CT, MA, NH, ME, as ‘new” in RI and as ‘Class II’ (solar) in New Hampshire. We refer to those categories in those states collectively as Class I. We assume that REC prices will be driven by the costs of those resources because they dominate the total kWh of renewable energy that has to be added each year to comply with RPS requirements.

The fact that Class I resources dominate the total kWh of renewable energy added each year is shown in Exhibit 6-28. This Exhibit summarizes the total New England renewable-energy requirements by year based on RPS goals by state and on ISO-NE (2009a) as discussed in Chapter 0. Exhibit 6-28 distinguishes between the quantity of Class I renewables that are required and the aggregate quantity of all other classes of renewables. This summary demonstrates that the Class I resources will be the major quantity of new renewables each year.

Exhibit 6-28 Supply of New Renewables Resources in New England by Class

New England Annual RPS Requirements

Year	**Class I (GWh)**	**Other Classes (GWh)**	**Total (GWh)**
2009	4,566	10,396	14,962
2010	5,628	10,821	16,449
2011	6,856	10,989	17,844
2012	8,120	11,118	19,237
2013	9,494	11,133	20,627
2014	10,951	11,215	22,167
2015	12,645	11,275	23,919
2016	14,344	11,365	25,709
2017	16,105	11,434	27,539
2018	17,651	11,500	29,151
2019	19,156	11,510	30,666
2020	20,606	11,462	32,068
2021	21,523	11,487	33,010
2022	22,460	11,510	33,970
2023	23,416	11,534	34,950
2024	24,392	11,557	35,949

Notes
Class I also inlcude voluntary demand
Calculations based on CELT forecast and RPS requirements summarized in Task 3

The requirements for each class of new renewable generation resources was derived by multiplying the load of obligated entities (those retail load-serving entities subject to RPS requirements, often excluding public power) by the applicable annual RPS percentage target for New Renewables RPS Tiers. The RPS requirements by class and year are listed on page Appendix C. The load by state is based on ISO-NE (2009a) as discussed in detail in Chapter 0. An estimate of modest voluntary requirements for new renewables met from RPS-eligible supply is also presented in Appendix C.

The major types of renewable supply forecast to be used to meet the RPS requirements by year are shown in Exhibit 6-29. The major types are wind, solar, biomass, natural gas and fuel cells, and hydro.

The requirements for each class of new renewable generation resources was derived by multiplying the load of obligated entities (those retail load-serving entities subject to RPS requirements, often excluding public power) by the applicable annual RPS percentage target for New Renewables RPS Tiers. The RPS requirements by class and year are listed in Appendix C. The load by state is based on ISO-NE (2009a) as discussed in detail in Chapter 0. An estimate of modest voluntary requirements for new renewables met from RPS-eligible supply is also presented in Appendix C.

The major types of renewable supply forecast to be used to meet the RPS requirements by year are shown in Exhibit 6-29. The major types are wind, solar, biomass, natural gas and fuel cells, and hydro.

Exhibit 6-29: Supply of New Renewables Resources in New England by Source

Major Types of Renewable Energy Supply (GWh)						
	Wind	**Solar**	**Biomass**	**NGFC**	**Hydro**	**Total**
Year	a	b	c	d	e	g = sum a to e
2009						
2010	389	46	382	110	51	979
2011	674	71	562	208	55	1,569
2012	1,196	104	912	326	58	2,596
2013	2,350	143	1,490	444	74	4,502
2014	3,079	197	2,072	563	79	5,989
2015	3,680	266	2,284	681	79	6,990
2016	3,890	354	3,356	799	79	8,478
2017	4,200	446	3,356	918	115	9,034
2018	5,539	551	3,393	1,036	198	10,717
2019	6,738	669	3,393	1,154	279	12,234
2020	7,338	801	3,695	1,272	279	13,385
2021	7,464	945	4,654	1,391	279	14,733
2022	7,632	1,103	4,654	1,509	279	15,176
2023	8,544	1,274	4,654	1,627	375	16,474
2024	9,421	1,458	4,654	1,745	375	17,653
Based on data provided by SEA						

The major sources of Class I renewable energy each year are summarized in Exhibit 6-30 below. These sources are as follows:

- existing eligible generation already operating (including biomass co-firing in existing facilities)
- the current level of RPS imports
- the assumed incremental level of RPS imports
- The assumed incremental renewable resources by source.

Exhibit 6-30: Calculated Incremental Renewables: New and Import

Year	Supply of Class I Requirements					
	New England		IMPORTS		Total	Renewable Surplus (Shortfall)
	Existing	New	Existing	New		
	a	b	c	d	e= sum(a to d)	f=e-Class I RPS Requirement
2009	3,035	0	1825	0	4,860	294
2010	3,035	979	1825	61	5,900	272
2011	3,035	1569	1825	305	6,734	(121)
2012	3,035	2596	1825	549	8,005	(114)
2013	3,035	4502	1825	793	10,155	661
2014	3,035	5989	1825	1037	11,886	935
2015	3,035	6990	1825	1281	13,131	487
2016	3,035	8478	1825	1524	14,862	517
2017	3,035	9034	1825	1768	15,662	(443)
2018	3,035	10717	1825	2012	17,589	(62)
2019	3,035	12234	1825	2256	19,350	194
2020	3,035	13385	1825	2500	20,745	139
2021	3,035	14733	1825	2500	22,093	570
2022	3,035	15176	1825	2500	22,536	77
2023	3,035	16474	1825	2500	23,834	418
2024	3,035	17653	1825	2500	25,013	621

Over time, the net Requirements to be met by resources within ISO-New England will further reduced by an estimate of *additional* RPS-eligible imports over existing tie lines, phased in at a rate consistent with the recent historical rate of increase in RPS-eligible imports over a ten-year period.

In addition to *new* or *incremental* renewables, several states also have minimum requirements for existing renewable energy sources, or other eligible sources. The eligibility details and target percentages are summarized in Appendix C.

6.4.2. Estimated Cost of Entry for New or Incremental Renewable Energy

Our general approach to estimating renewable supply is described in Deliverable 3-1. We assume that, after a few years of transition, the price of renewable energy will be set at the cost of new entry. To estimate the new or incremental REC cost of entry[106], we constructed a supply curve for incremental New England renewable energy potential based on various resource potential studies that sorts

[106]The derivation of costs for NH Class II (solar) were performed separately.

the supply resources from the lowest cost of entry to the highest cost of entry.[107] The resources in the supply curve model are represented by 135 blocks of supply potential from resource studies, each with total MW capacity, capacity factor, and cost of installation and operation applicable to projects installed in each year.

The supply curve consists of land-based wind, biomass, hydro, landfill gas, offshore wind and tidal resources. Land-based wind is the largest source by far, modeled as 86 blocks, varying by state, number and size of turbines in each project, wind speed and distance from transmission,

The price for each block of the supply curve is estimated for each year. For each generator, we determined the levelized REC premium for market entry by subtracting the nominal levelized value of production consistent with the AESC 2009 projection of wholesale electric energy prices from the nominal levelized cost of marginal resources.[108]

- the nominal levelized cost of marginal resources is the amount the project needs in revenue on a levelized $/MWh basis;
- The nominal levelized value of production is the amount the project would receive from selling its commodities (energy, capacity, ancillary services) into the various wholesale markets; and
- The difference between the levelized cost and the levelized value represents the additional revenue the project requires to attract financing.

Unless the revenue from REC prices can make up that difference, the project is unlikely to be developed. Resource blocks are sorted from low to high REC price, and the intersection between incremental supply and incremental demand determines the market-clearing REC price for market entry. Our projections assume that REC prices for new renewables will not fall below $2/MWh, the estimated transaction cost associated with selling renewable resources into the wholesale energy market. This estimate is consistent with market floor prices observed in various markets for renewable resources.

[107]These assumptions are based on technology assumptions compiled by Sustainable Energy Advantage, LLC from a range of studies and interviews with market participants. Some characteristics are adapted from those used in a New England renewable energy supply curve analysis prepared by Sustainable Energy Advantage, LaCapra Associates and AWS Truewind in late 2007 and early 2008 for the Maine Governors Wind Task Force Study on behalf of the Natural Resources Council of Maine. Typical generator sizes, heat rates, availability and emission rates are consistent with technology assumptions used by ISO-New England in its scenario planning process.

[108]SEA calculated these levelized analyses using discount rates representative of the cost of capital to a developer of renewable resource projects.

The estimated levelized cost of marginal resources is based on several key assumptions, including projections of capital costs, financing assumption (cost of debt and equity, debt-equity, debt term, depreciation) reflected as a carrying charge, fixed and variable operations and maintenance costs, transmission and interconnection costs (as a function of voltage and distance from transmission), and wind integration[109] costs. The Federal Production Tax Credit is assumed to be phased out over a five year period following 2013. This is consistent with the phase-in of Federal Carbon Cap & Trade value implicit in the energy prices used for the AESC analysis, which would provide a similar level of support. Capital and operating costs were escalated over time using inflation.

The levelized commodity revenue over the life of each resource was determined based on the sum of energy and capacity prices, both utilizing preliminary AESC 2009 reference-case estimates of the FCM price and all-hour zonal LMP estimates from early May 2009.

Revenues for wind resources were adjusted in three ways:

- The value of wind energy was adjusted to reflect wind's variability, production profile, and historical discount of the real-time market (in which wind plants will likely sell a significant portion of their output) versus the day-ahead market.
- Energy prices were further discounted to reflect the lower prices typical in long-term contracts, especially for wind plants, with their fluctuating energy output.[110]
- Wind generators were assumed to receive FCM revenues corresponding to only 15% of nameplate capacity, reflecting the poor performance of most on-shore wind plants on summer afternoons. This assumption may be conservatively low for commercial wind farms, reflecting developer, investor and lender risk-aversion regarding future capacity valuation.

Resources from the supply curve are modeled to meet net demand (as described earlier), which consists of the gross demand for new or incremental renewables, less:

(a) existing eligible generation already operating (including biomass co-firing in existing facilities);

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[109] We assume that reinforcement of major transmission facilities (e.g., improved connections between Maine and the rest of New England) will be socialized.

[110] Our forecast of REC prices assumes that most renewables will be financed with long-term contracts for most of their capacity and/or RECs.

(b) the current level of RPS imports; and

(c) additional imports over existing interties to neighboring control areas.

In addition, for solar and fuel-cell resources, which tend not to be resource-constrained, we separately estimated the amounts that would be driven by various policy initiatives; these amounts were also netted from gross demand.

Our projection of the cost of new entry is summarized in below in Exhibit 6-31.

Exhibit 6-31: REC Premium for Market Entry ($/MWh)

	REC Premium for Market Entry (2009$/MWh)
2012	$24.26
2013	26.87
2014	28.61
2015	26.76
2016	26.92
2017	32.30
2018	32.54
2019	26.90
2020	23.97
2021	18.67
2022	15.65
2023	10.96
2024	3.25

These results are highly dependent upon the forecast of wholesale electric energy market prices, including the underlying forecasts of natural gas and carbon allowance prices, as well as the forecast of inflation used by SEA. A lower forecast of market energy prices would yield higher REC prices than shown, particularly in the long term.

In contrast to the long-term REC cost of entry, spot prices in the near term will be driven by supply and demand, but are also influenced by REC market dynamics and to a lesser extent to the expected cost of entry (through banking), as follows:

- Market shortage: Prices approach the cap or Alternative Compliance Payment

- Substantial market surplus, or even modest market surplus without banking: Prices crash to ~$0.50-$2/MWh, reflecting transaction and risk management costs
- Market surplus with banking: prices tend towards the cost of entry, discounted by factors including the time-value of money, the amount of banking that has taken place, expectations of when the market will return to equilibrium, and other risk management factors.

Detailed projections of REC prices by state for Class I renewables are presented in Appendix C.

6.4.3. Avoided RPS Compliance Cost per MWh Reduction

The RPS compliance costs that retail customers avoid through reductions in their energy usage is equal to the price of renewable energy in excess of market prices multiplied by the portion of retail load that a supplier must meet from renewable energy under the RPS. In other words,

$$\frac{\sum_{n} \mathrm{P}_{n,i} \times R_{n,i}}{1-l}$$

where:

i = year

n = RPS classes

$P_{n,i}$ = projected price of RECs for RPS class *n* in year *i,*

$R_{n,i}$ = RPS requirement for RPS class *n* in year *i,* from Exhibit 3-9 in Deliverable 3-1.

l = losses from ISO wholesale load accounts to retail meters

For example, in a year in which REC prices are $30/MWh and the RPS percentage is 10%, the avoided RPS cost to a retail customer would be $30 × 10% = $3/MWh. Detailed results are presented in the Appendix B worksheets. The year-by-year RPS percentages for each RPS tier are shown in Appendix C.

6.5. Demand-Reduction-Induced Price Effects for Energy and Capacity

The Demand-Reduction-Induced Price Effect (DRIPE) is the reduction in prices in the wholesale energy and capacity markets, relative to those forecast in the Reference Case, resulting from the reduction in need for energy and/or capacity due to efficiency and/or demand response programs. This section describes our estimates of energy DRIPE and capacity DRIPE.

Our estimates indicate that the DRIPE effects are very small when expressed in terms of an impact on market prices, i.e., reductions of a fraction of a percent. Moreover, we project that those effects will dissipate over time as the market reacts to the new, lower level of energy and capacity required. **(**To estimate this dissipation one must estimate the material differences in actions that suppliers would take each year relative to the actions they are projected to take under the Reference Case.) However, the DRIPE impacts are significant when expressed in absolute dollar terms. Very small impacts on market prices, when applied to all energy and capacity being purchased in the market, translate into large absolute dollar amounts.

6.5.1. Capacity DRIPE

One would expect the reduction of load due to efficiency programs to reduce capacity prices in the forward capacity market as well as electric energy prices in the wholesale energy markets. Reductions in demand from energy-efficiency programs bid into a FCA will explicitly reduce the clearing price in that FCA. Reductions in demand from energy-efficiency programs that are not bid into FCAs but that reduce the ISO's forecast of peak load and hence of installed capacity requirement in the FCA will implicitly reduce the FCA price.[111]

Since the forward capacity market will set prices via FCAs roughly three years in advance of the actual power year, we do not expect that capacity prices set in FCAs will be very sensitive to small changes in load growth. Once load and supply are roughly balanced, the market requires some generic new capacity, and the FCM price is tied closely to the cost of new entry. Nonetheless, even a small change in market capacity prices could have significant cumulative effects across New England.

AESC 2007 accounts for capacity DRIPE by estimating the slope of the FCA supply curve in the region representing new generic-type entries (i.e., peakers and combined-cycle plants without special revenue sources). We estimated that each MW of DSM bid into the market would reduce the market-clearing price by about $0.006/MW-year. Now, in AESC 2009, we do not expect those demand and supply conditions will occur until after 2020 even in the no-DSM base case

[111]The ISO has not yet developed a method for explicitly recognizing energy-efficiency installations that are not bid into the market until they occur and reduce metered load. Those effects may be delayed, since the effect on pricing will occur starting with the first FCM auction after implementation, when the DSM reduces load and the ISO reduces the installed-capacity requirement for the capacity auctions two or three years later. In contrast, bid DSM will affect the FCM price for the auction into which it is bid, potentially reducing prices in the year the DSM is implemented.

assumed in our analysis. Thus, that section of the capacity supply curve is of limited importance.

For AESC 2009, we expect that the quantity of existing capacity will be much higher than demand, in the form of the ISO-NE installed capacity requirement, for many years. Through May 2013, prices will be set at the ISO-established floors. For several years thereafter, prices will be set by delisting of existing resources, primarily steam plants, imports and demand response. Section 2.2 discusses our assumptions regarding the prices at which generators will delist, and the resulting base-case prices. Every MW of load reduction from energy-efficiency will reduce the amount of resources required, allowing one more MW of existing resource to delist. Adding up the number of MW of various resources that we assume would delist for a dollar reduction in price, we find that the change in price per MW of load reduction would be about $0.0005/kW-month, or about 70¢/kW-year for every 100 MW, including reserves and PTF losses.

As difficult as it is to estimate the pace at which energy DRIPE will dissipate, i.e. the pace at which the energy market will respond to the reductions from energy-efficiency resources with a different set of actions to offset the impact on prices, it is even more difficult to project dissipation of capacity DRIPE. Our best estimate, using the limited historical experience with response of the capacity markets to over- and under-building situations, is that the capacity DRIPE will dissipate linearly over the fourth and fifth years following the implementation of the energy-efficiency measures.[112]

The resulting gross capacity DRIPE, before any offset for utility entitlements, is shown in Exhibit 6-32 below. The values for 2013 are $0.70 × 7⁄12, since the FCM floor price will be in place through May 2013 and DRIPE effects will start in June. Due to the uncertainties in capacity DRIPE initial effect and decay, we do not believe that using separate price effects for the two installation years is worth the additional complexity.

[112] We assume capacity DRIPE will dissipate faster than energy DRIPE due to three factors. First, permanent removal of some types of capacity resources—demand response, emergency generation, old peaking units— will reduce the capacity DRIPE but will have little or no effect in reducing energy DRIPE. Second, owners of capacity which is temporarily removed from the FCM may have to bid high prices to the FCM in order to cover the costs of reactivating those resources. In contrast, energy DRIPE is caused primarily by reduced usage of generating units rather than mothballing those units. Thus, prices in the energy market are less likely to increase due to the costs of producing more generation from those units. Third, the future structure and operation of the FCM is so uncertain that assuming a long duration for capacity DRIPE would be highly speculative.

Exhibit 6-32: Gross Capacity DRIPE ($/kW-year per 100 MW)

	Installations in		
	2010	2011	Average
2010	$—	$—	$—
2011	$—	$—	$—
2012	$—	$—	$—
2013	$0.41	$0.41	$0.41
2014	$0.50	$0.70	$0.60
2015	$0.30	$0.50	$0.40
2016	$—	$0.30	$0.15

These prices must be multiplied by the amount of capacity paid the market price by load in each state. For most utilities, we assume that the share of capacity purchased in the market is the same as the amount of energy estimated in Exhibits 6-32 and 6-33 averaged over 2013–2016, the period in which we assume capacity DRIPE. Connecticut has contracted for about 670 MW of peaking capacity, which have a much larger effect on capacity supply than on energy supply.[113] Including the peakers, the Kleen combined-cycle plant, Project 150, and CL&P's remaining IPP contracts, about 17% of Connecticut's total capacity requirement for 2013–2016 will be met by long-term IOU contracts. Exhibit 6-33 provides our estimate of the average market capacity purchases by state, using the 2009 CELT forecast, a 12% average reserve margin, and our estimate of the share of the capacity requirement purchased at market prices

Exhibit 6-33: Capacity Purchased at Market Prices by State, 2013–18

	MA	RI	ME	CT	NH	VT
2013-16 peak	13,921	2,004	2,236	7,910	2,695	1,143
Market Capacity Share	86%	95%	94%	79%	42%	60%
Market Capacity MW	13,426	2,132	2,343	7,034	1,260	768

Exhibit 6-34 combines the price reductions from 2010/11 installations in Exhibit 6-32 and the capacity purchases from Exhibit 6-33 to estimate the retail capacity-cost reduction per kW-year of load reduction by state. A load reduction anywhere in New England would have these effects on the capacity bills in the various states.

[113]These are the existing Waterside plant, plus new units at Waterbury, Devon, Middletown and New Haven Harbor.

Exhibit 6-34: Capacity DRIPE benefit by State, 2010 installations, $/kW-year

	MA	RI	ME	CT	NH	VT
2013	$55	$9	$10	$29	$5	$3
2014	$81	$13	$14	$42	$8	$5
2015	$54	$9	$9	$28	$5	$3
2016	$20	$3	$4	$11	$2	$1

These estimates indicate that, in some years, the statewide bill effect in Massachusetts and Connecticut (and the region-wide effect) from the DRIPE of a peak load reduction in ISO-NE would exceed the bill reduction to the participating customer.

6.5.1.1. Comparison to 2007 AESC DRIPE Estimates

The 2007 AESC study estimated capacity DRIPE based on assumptions regarding the differences in bid prices between marginal new generic generation resources. As noted above, we do not expect new generic generation to set the capacity price for over a decade.

In 2007, we estimated that each MW of DSM bid into the market would reduce the market-clearing price by an average of $0.0057/kW-year per MW of load reduction. Our current estimate of capacity DRIPE is slightly higher at its maximum, but starts later, due to the floor on prices through May 2013.

6.5.2. Energy DRIPE

Energy-efficiency measures installed in any one year will have an immediate downward effect on energy prices because the lower load growth will allow lower-cost resources to be at the margin—and set the price—in more hours. This impact is referred to as energy DRIPE. Those price effects will not necessarily persist as long as the underlying energy savings. The lower energy prices will tend to change the mix of generation used to supply the market, which in turn will eventually lead to higher prices, erasing the effects of lower loads.

DRIPE in the energy market was estimated based on the following three factors:

- The effect of load reduction on market energy prices, if all energy traded in the spot market and the supply system did not change as a result of DRIPE effects. We are estimating these effects using both historical data and modeling of future production costs.
- The pace at which supply will adapt to energy-efficiency load reductions; and
- The percentage of power supply to retail customers that is subject to market prices in the current year and each future year.

Thus total energy DRIPE is the product of the direct effect from the first factor, times the percent of the effect not yet eliminated by supply adaptation from the second factor, times the percentage of power supply that is subject to market prices from the third factor. The DRIPE value may differ by month (or season) and zone.

6.5.2.1. Estimation of energy DRIPE via Analysis of Historical Data

Our first approach to estimation of energy DRIPE starts with an analysis of the historical variation in locational energy market prices as a function of variation in zonal and regional loads. This approach is similar to that in AESC 2007.

The basic form of this historical analysis was a regression of day-ahead hourly zonal price in dollars per MWh against both day-ahead load in the zone and day-ahead load in the rest of the ISO control area (rest of pool, or ROP). If one of the resulting coefficients was implausible, the zonal price was regressed based on total pool load and the resulting coefficient was then used for both the own-zone and ROP load. These analyses were performed separately for on- and off-peak hours, since we expected (and generally observed) that the slope of market price as a function of load would be higher on-peak.

To minimize the effect of changes in fuel prices,

- each month was analyzed separately,
- we used data from December 2005 through April 2009, covering both high- and low-priced period,
- we normalized the DRIPE coefficient for each of the 29 months by dividing the load coefficient by the average Hub price for the month, and
- we averaged the normalized DRIPE coefficient over the three or four years of regressions.

The regressions were calculated for on-peak and off-peak periods by month by state. The results by energy pricing zone show the change in the energy price in the zone as a result of a one-megawatt change in load in the zone or a one-megawatt change in load elsewhere in the ISO (the rest of pool or ROP). These results indicate that each additional MWh of hourly load in a zone typically increases price in that zone by between 0.3¢/MWh and 5¢/MWh in that hour, depending on the zone and month. An additional MWh of load elsewhere in the Pool typically increases prices from 0.1¢/MWh to 1.3¢/MWh. The price effect is typically higher in the on-peak period than in the off-peak period. Both intrastate and rest of pool results are presented in Appendix C.

The total effect on the regional prices in a particular month, if all transactions moved with the day-ahead market price, would be the sum of the following two components:

- the average hourly load in the zone times the zonal effect, and
- the sum over zones of the average hourly zonal load times the effect of ROP load on that zone.

Exhibit 6-35 shows our estimate of the total effect of a MWh on-peak reduction in Connecticut in October, for an LMP of $66/MWh.

Exhibit 6-35: Effects of CT On-Peak Load Reductions on Prices and Costs, October

Zone	Coefficients % of Hub Price Own Load	Coefficients % of Hub Price ROP	Average Hourly Load MWh	Potential DRIPE from CT DSM $/MWh
CT	0.009%		3,508	21.0
ME		0.006%	1,385	5.9
NH		0.007%	1,384	6.4
RI		0.007%	1,031	4.5
VT		0.007%	626	3.0
NEMA		0.007%	3,057	14.1
SEMA		0.006%	1,389	5.2
WCMA		0.007%	2,101	9.4
Total				$69.5

In this example, reducing Connecticut load by one MWh on-peak would reduce regional power bills for the remaining load by about $69.5, if all load paid day-ahead market prices, or if the load reduction were anticipated at the time a longer-term supply contract was negotiated.

Exhibit 6-36 below summarizes our results for potential DRIPE effects, by month and annualized (using historical average ratios of monthly forwards to annual averages), expressed as a multiple of the Hub price in the corresponding period. Under each state, Exhibit 6-36 shows the price savings for consumers in that state and in the rest of the pool. For example, averaged over the year, a MWh saved on-peak in Maine would reduce Maine market energy bills by about 0.19 or 19% of the Hub price for a MWh of energy and bills in the rest of the pool about 1.38 or

138% of the Hub price. A MWh saved in Connecticut on-peak would save about once the Hub price in Connecticut, and a similar amount in the rest of the pool.

Exhibit 6-36: Potential DRIPE as Multiple of Hub Price, in-State and Rest of Pool

	ME		NH		VT		CT		RI		MA	
	ME	ROP	NH	ROP	VT	ROP	CT	ROP	RI	ROP	MA	ROP
On-Peak												
Jan	0.28	1.71	0.47	1.70	0.10	1.76	1.28	1.28	0.42	1.76	1.46	1.09
Feb	0.18	1.72	0.35	1.72	0.09	1.78	1.49	1.37	0.17	1.75	1.37	1.02
Mar	0.20	1.33	0.42	1.34	0.14	1.40	1.14	1.16	0.39	1.38	1.19	0.82
Apr	0.11	0.84	0.18	0.83	0.05	0.86	0.51	0.59	0.28	0.85	0.48	0.54
May	0.05	0.91	0.28	0.92	0.05	0.92	0.59	0.53	0.33	0.93	0.66	0.62
Jun	0.08	1.33	0.33	1.31	0.07	1.34	0.79	0.87	0.09	1.33	0.81	0.88
Jul	0.16	1.61	0.58	1.63	0.10	1.68	1.22	1.28	0.14	1.64	1.06	1.02
Aug	0.13	1.52	0.47	1.52	0.09	1.56	1.05	1.14	0.18	1.54	1.00	0.97
Sep	0.22	1.39	0.12	1.37	0.19	1.43	0.53	0.96	0.14	1.40	0.85	0.88
Oct	0.29	1.22	0.14	1.21	0.15	1.27	0.42	0.91	0.09	1.25	0.91	0.78
Nov	0.12	1.21	0.40	1.22	0.08	1.25	0.89	0.97	0.28	1.25	0.81	0.75
Dec	0.42	1.51	0.45	1.49	0.20	1.53	1.20	1.23	1.02	1.52	1.15	0.80
Off-peak												
Jan	0.22	1.37	0.25	1.38	0.11	1.40	0.90	1.26	0.21	1.39	0.92	1.14
Feb	0.10	1.37	0.22	1.38	0.07	1.41	0.95	1.23	0.57	1.40	0.31	1.13
Mar	0.20	1.33	0.25	1.33	0.05	1.36	0.64	1.19	0.30	1.36	0.85	1.09
Apr	0.16	1.48	0.42	1.49	0.12	1.53	0.67	1.37	0.21	1.52	0.63	1.24
May	0.11	1.14	0.31	1.15	0.07	1.17	0.49	0.98	0.12	1.15	0.70	0.91
Jun	0.09	1.12	0.24	1.13	0.06	1.16	0.61	0.91	0.08	1.15	0.85	0.90
Jul	0.12	0.70	0.40	0.73	0.07	0.73	0.79	0.61	0.08	0.72	0.45	0.50
Aug	0.11	0.95	0.33	0.98	0.05	0.99	0.81	0.95	0.18	0.98	0.51	0.78
Sep	0.17	1.43	0.14	1.42	0.13	1.46	0.43	1.18	0.10	1.45	0.56	1.19
Oct	0.11	1.56	0.33	1.59	0.15	1.61	0.45	1.22	0.09	1.59	0.73	1.30
Nov	0.11	1.11	0.43	1.15	0.07	1.16	0.53	0.97	0.27	1.15	1.55	0.89
Dec	0.30	0.92	0.30	0.92	0.06	0.94	0.64	0.78	0.45	0.93	1.05	0.71
Average Annual												
On-Peak	0.19	1.38	0.36	1.38	0.11	1.42	0.96	1.05	0.30	1.41	1.00	0.86
Off-peak	0.12	1.11	0.27	1.12	0.08	1.14	0.60	0.97	0.18	1.13	0.67	0.91

These bill effects are potential values assuming that load purchased all of its energy from competitive market and that neither demand nor supply adapts to the price reductions. We consider the impact of adjustments for those two factors in Sections 6.5.2.3 and 6.5.2.4, below.

6.5.2.2. Estimation of energy DRIPE via M-A Model simulation

Our second approach to estimation of energy DRIPE was to use the M-A model to estimate energy prices for a future scenario with slightly lower load than the Reference Case. Unfortunately the modeling results were inconclusive. These results are primarily due to the small load decrement tested, a flat 2% reduction, and the inability of the model to operate in multi-iteration convergence mode.

6.5.2.3. Energy Market Adaptation to Load Reductions

As noted above, a reduction in load will reduce actual and projected prices relative to the levels in the Reference Case. More expensive generators will be used less often, high-prices price-responsive demand response will be called less often.

That reduction in prices will then tend to change the mix of resources available to supply the market. This response to lower prices is referred to as *supply adaptation.* One can think of this analysis of dissipation in terms of the following three cases:

- **The energy Reference Case, which is a** projection of the mix of supplies, and resulting energy prices, to meet the Reference Case load forecast. Those energy prices are influenced by a number of assumptions regarding decisions and actions by suppliers. In particular decisions by suppliers regarding the quantity and type of new capacity that they will bring on-line each year influences the projected quantity of generation from that new capacity by year, and decisions by suppliers regarding the quantity and type of existing capacity that they will delist or retire each year influences the projected quantity of generation that will be removed from the total supply by year
- **An energy DRIPE scenario** that projects energy prices in a future with a lower load forecast and the same supply curve, i.e., no reaction by suppliers. This scenario projects somewhat lower energy prices.
- **An energy DRIPE adaptation or offset scenario** that projects changes in the supply curve over time that offset the impact of the lower load forecast. This scenario projects the number of years it will take for the energy DRIPE to dissipate, i.e. for energy prices to hit the levels forecast in the Reference Case. To estimate this dissipation one must estimate the material differences in actions that suppliers would take relative to the actions they are projected to take under the Reference Case. Specifically decisions by suppliers to change the quantity, type and /or timing of new capacity that will materially reduce the projected quantity of generation from new capacity by year, and

decisions by suppliers to change the quantity, type and/or timing of delisting or retiring existing capacity that will materially increase the projected quantity of generation that will be removed from the total supply by year

For example, the lower prices due to energy-efficiency investments may cause the following changes over time in the supply of conventional generation:

- A merchant developer may choose to develop a combustion turbine (CT) rather than a combined-cycle (CC) unit, if the CC's reduced energy revenues do not seem likely to cover its additional fixed costs;
- The developer of a potential combined-cycle unit will generally bid a higher price for its capacity (since energy revenues will cover less of the cost), resulting in selection of a combustion turbine in the FCM auction and hence construction of a CT rather than a CC;
- The owner of an old plant (such as a coal plant) that has low variable production costs but requires operational or environmental investments may decide to retire or mothball the plant, due to the lower energy revenues from continued operation;[114] and/or
- The owner of a baseload or intermediate plant may decide to defer spending that would maintain or increase its capacity or reliability, or shorter maintenance outages, since the incremental revenues would not justify the expenditures.

A recent Credit Suisse analysis (Eggers 2009) illustrates two of these scenarios, a base case and an adaptation case, which Eggers refers to as a new HQ import case. In his base case 600 MW of combined-cycle capacity is added in 2016 and another 200 MW in 2017. In his new HQ-import case 1,125 MW of additional hydro energy is imported from HQ to ISO-NE over a new line starting in 2014. Eggers does not specify the quantity of energy that would be provided by either the HQ line or the combined-cycle units. In the new HQ capacity case the market responds by canceling the 600 MW of combined-cycle capacity planned for 2016 and the 200 MW planned for 2017 under his base case.[115]

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[114]This is not an entirely hypothetical concern, given the costs of upgrading existing coal (and some oil- and gas-fired steam) plants to meet tighter limits on air emissions and/or use of cooling water. Lower energy prices are less likely to result in repowering or other compliance strategies leading to restart at Somerset 6 and Salem 1–3, which we expect to shut down in the next few years.

[115]The Credit Suisse report refers to those combined-cycle additions, and further additions in 2018–2020 as "NE-ISO published" and references "Company information" (apparently referring to Northeast UtilitiesNU and NStar), but we are not aware of any such ISO or utility publication.

The result of the change in the supply additions, Eggers (2009) estimates that the energy price in New England would be reduced from the base case by

- $5.05/MWh in 2014 and 2015 (HQ added, no supply offset).[116]
- $2.19/MWh in 2016 (600 MW of combined-cycle removed).
- $1.37/MWh in 20172020 (combined total of 800 MW of combined-cycle removed)

Credit Suisse's estimate of the price effect of changes in this base/intermediate capacity is essentially linear, with energy price declining about $0.0045/MWh for each MW of capacity added and rising the same amount for each MW removed. In periods with no additional offsetting changes in capacity (2014–15 and 2017–2020), the market price effect of the HQ line does not change.

Unfortunately, the results of the Credit Suisse report are not useful for estimating energy DRIPE dissipation in this report. Our Reference Case does not anticipate that the 800 MW of new combined-cycle assumed by Credit Suisse to come online in 2016 and 2017 in its base case.

Energy DRIPE adaptation or offset scenario. As the supply and demand changes in these and similar ways, energy prices will tend to increase back towards reference case levels. Once this supply adaptation has caused energy prices to recover from the effects of the load reduction, the future decisions by consumers, developers, owners and the ISO should be essentially the same as they would have been without the load reduction. Thus, supply and demand adaptation ceases once the price effect has been extinguished.

Two sets of events must occur before the wholesale markets can respond to the energy-efficiency investments installed in a given year. First, market participants (particularly owners of existing generation, developers of new generation, municipal utilities, and investor-owned utilities and regulators considering long-term energy contracts) must become aware of that energy prices have fallen (or will fall) due to the load reductions. In AESC 2007, we assumed that the energy market would not be aware of energy-efficiency installations until they occurred. We now believe that the market will be able to anticipate most energy-efficiency load reductions. For energy-efficiency programs bid into the forward capacity auctions, market participants will have some information about planned savings three years in advance.[117] With state mandates, the Connecticut IRP, and long-

[116]The report authored by Eggers does not indicate whether these prices are real or nominal, but they appear to be real.

[117]The FCM bids specify only seasonal peak reductions, and thus provide limited information about energy savings.

term DSM plans from the Connecticut Energy Conservation Management Board, Massachusetts Energy Efficiency Advisory Board and various program administrators, market participants are likely to have even more than three years of advance notice. On the other hand, changes in energy-efficiency policy (such as the passage of the Green Communities Act), implementation and participation rates may result in some energy-efficiency savings coming on line before the market participants have been able to anticipate their effect. Overall, we believe that information lag will have a relatively small effect on market response to decreases in energy prices following implementation of energy-efficiency measures.

Second, some event must occur that can be influenced by the lower market energy price. If regional supply and demand were in balance, with growing load, and developers were adding a mix of peak, intermediate and baseload plants, load reductions expected in (for example) 2014 would tend to shift the mix of new generation clearing in the 2011 forward capacity auction towards peakers, roughly offsetting the price effect of the efficiency. While peaking combustion turbines and intermediate combined-cycle plants can be built in three years, baseload generation (whatever that may be in the future) may have a longer lead time, resulting in some lag before the mix of new generation additions fully responds to the reduction in load. These equilibrium conditions are not likely to occur for many years.

In addition to the changes in conventional supply, energy DRIPE will be damped by two other factors:

- lower prices will tend to encourage higher usage, and
- reduced loads will reduce the amount of new renewable generation required for RPS compliance.

Through about 2022, energy prices are likely to affect primarily customer usage, RPS requirements, generator deactivations (and reactivations) and incremental improvements, and possibly the timing of municipally-owned generation additions. We examine those effects in order.

Estimating the extent of delay in adaptation of the energy market to efficiency-related load reductions is subject to considerable uncertainty, particularly in this period of capacity surplus.

Demand Elasticity

The 2009 ISO-NE forecast is based on an econometric model that estimates a short-run price elasticity of -0.118 and a long-run price elasticity of -0.231. Since the wholesale price of energy has been about half the total retail price of electricity (which also includes transmission, distribution, energy-efficiency and renewable charges, stranded costs, capacity, reserves, and ISO costs), a 1% reduction in market energy prices would result in a 0.5% reduction in electric rates. These estimates result in the following pattern of rebound in the energy price:

Exhibit 6-37: Demand-rebound in DRIPE from DSM in year 1

Year	DRIPE Reduction
1	5.7%
2	8.4%
3	9.7%
4	10.3%
5	10.6%
6	10.8%
7	10.8%
8+	10.9%

Deferral of Renewables

Weighting the state Class-I RPS requirements (plus the NH solar requirement) in Exhibit 3-16 by forecast state energy load, net of exempt load, produces the following offset to DRIPE due to reduced renewable additions.

Exhibit 6-38: Regional Average RPS

	Average Regional Class-I RPS
2009	3.6%
2010	4.5%
2011	5.5%
2012	6.4%
2013	7.5%
2014	8.5%
2015	9.7%
2016	10.9%
2017	12.1%
2018	13.1%
2019	14.2%
2020	15.1%
2021	15.6%
2022	16.1%
2023	16.7%
2024	17.2%

The renewable-offset effect will vary among states; we used a regional average for simplicity.

Some RPS requirements, other than the Class I requirements for new renewables and NH's Class II solar requirement, may also bring additional energy sources on line. The Connecticut Class III requirement can be met with cogeneration, but it is likely to be met entirely with credits from energy-efficiency projects that would proceed without the RECs. The Massachusetts APS is more difficult to assess, since the requirement can be met from gasification projects, cogeneration, flywheel storage, paper-derived fuel and (once regulations are developed) efficient steam technology. It is not clear to what extent this standard will be decisive in bringing on new generation. If the APS resources are flywheels, they will have little effect on overall energy price.

Generator Deactivations and Incremental Improvements

In order for generator deactivation and reactivation decisions to dampen DRIPE, the reduced energy prices must change the mix of units that clear in the future capacity auctions, the delisted units must decide to shut down and not sell into the energy market, and the shut-down units must have a significant effect on energy prices. It is not clear to what extent any of these criteria will be met. In particular, most of the generators facing decisions about whether to retire operate at low capacity factors, so energy prices have limited effect on their economics and their presence or absence has limited effects on energy prices.

While generators face many decisions about performance improvements, maintenance, the duration of outages, it is very difficult to estimate the effect of energy prices on those decisions and the resulting feedback to energy prices.

Considering the range of possible effect and the uncertainties, we combine the combined effects on existing generation as a 1% offset in the first year, rising 1% annually, plus 5% starting in 2014, reflecting the end of the FCM floor and the beginning of large delists of existing resources.

Deferral of New Units

We do not believe that the energy-efficiency programs planned or proposed have discouraged or will discourage any conventional energy-producing generation resources through 2012. No merchant conventional generation appears to be needed until after 2020 and perhaps much later, depending on the amount of resources that remain in or return to service after the 2014 capacity glut.

Municipal utilities can finance new generation less expensively than investor-owned utilities, independent power producers, and especially merchant developers, and may build generation well before 2020. The Massachusetts Municipal Wholesale Electric Company is planning to add a 280 MW combined-cycle Stony Brook 3 plant in 2013; reduced energy prices could conceivably cause MMWEC to delay that unit, offsetting some DRIPE.[118] It is not clear whether enough municipal utilities will find that Stony Brook 3 meet their investment criteria to get the plant built in 2013 in the reference case.[119] Nor is it clear how much energy prices would need to fall to change the timing of Stony Brook 3.

[118]Several municipal utilities (e.g., Braintree, Vermont Public Power, CMEEC) have added generation in recent years or have generation under construction.

[119]The 2013 in-service date appears optimistic. The ISO rejected Stony Brook 3 in FCA 1, because transmission upgrades would be required before the unit could operate safely. ("Informational Filing for Qualification in the Forward Capacity Market," ISO-NE, FERC Docket No. ER08-190-000, November 6, 2007) MMWEC has indicated that it believes the first candidate for an upgrade that would solve this problem would be the Greater Springfield Reliability Project (estimated at about $728 million), which is still in the permitting process. It is not clear whether MMWEC could secure ISO approval to bring Stony Brook 3 on line prior to solution of the transmission issues.

The Taunton municipal utility has proposed a 250 MW combined-cycle unit at its Cleary-Flood plant, to be on line in 2015. This unit also awaits transmission studies. Both units have attracted extensive interest from public utilities, but neither has firm ownership or purchase contracts for the full plant output.

With all those caveats, we assume a 50% probability that the energy DRIPE of any particular increment of energy efficiency will be offset by delay of Stony Brook 3.[120] In subsequent years, we assume the probability of an offset increases by 5% each year, reaching 100% in 2023.

Summary of Energy DRIPE

Combining these four effects, we get the following pattern of energy DRIPE extinction. The demand elasticity in Exhibit 6-39 is for installations in 2010.[121]

Exhibit 6-39: Energy DRIPE Decay

		Energy DRIPE Dissipation Factor				
	Year	Demand Elasticity	RPS	Existing Generation	New Generation	Total DRIPE Offset**
2010	1	5.7%	4.5%	1.0%		11%
2011	2	8.4%	5.5%	2.0%		15%
2012	3	9.7%	6.4%	3.0%		18%
2013	4	10.3%	7.5%	4.0%	50.0%	60%
2014	5	10.6%	8.5%	10.0%	55.0%	67%
2015	6	10.8%	9.7%	11.0%	60.0%	71%
2016	7	10.8%	10.9%	12.0%	65.0%	76%
2017	8	10.9%	12.1%	13.0%	70.0%	80%
2018	9	10.9%	13.1%	14.0%	75.0%	83%
2019	10	10.9%	14.2%	15.0%	80.0%	87%
2020	11	10.9%	15.1%	16.0%	85.0%	90%
2021	12	10.9%	15.6%	17.0%	90.0%	94%
2022	13	10.9%	16.1%	18.0%	95.0%	97%
2023	14	10.9%	16.7%	19.0%	100.0%	100%

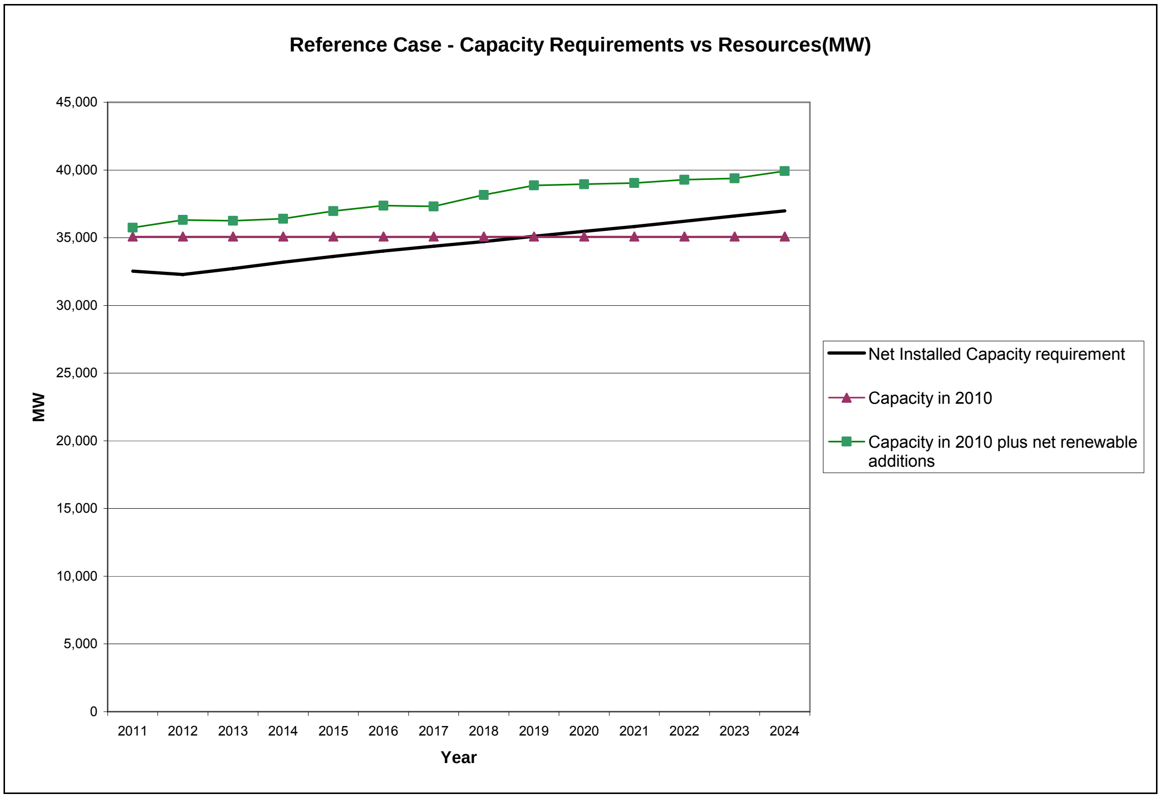
** Total = 1–(the product of (1-factor%) over the four factors).

This anticipated longer duration of energy DRIPE is consistent with the results of our Reference Case, which indicate a significant excess of capacity relative to Net Installed Capacity requirements through 2024 due to additions of renewable resources to comply with RPS requirements. That excess is shown in Exhibit 6-40 below.

[120] That 50% probability might result from, for example, a 70% chance that the unit would be built with the reference-case energy prices, and a 70% chance that it would be delayed by lower prices.

[121] For installations in 2011, the demand elasticity column would be shifted down one year, and the total effect would be reduced about 5% in 2011, 2% in 2012, and less than 1% thereafter.

Exhibit 6-40: Reference Case—Capacity Requirements vs. Resources (MW)



Comparison to AESC 2007

AESC 2007 assumed that the energy DRIPE cumulative offset would be 0% in the first two years following an energy-efficiency installation, 35% in the third year, 65% in the forth year, and 100% thereafter. This estimate was based on the assumption that energy-efficiency installations would not be anticipated in the generation market, and that the generation supply would be in equilibrium in the near term. Our perspectives on these issues have changed, as discussed above.

Since we now forecast energy DRIPE will last a much longer period, the effect will be somewhat larger than that projected in AESC 2007. The assumptions in AESC 2007 would have produced a present value of about 2.7 years. In AESC 2009, for installations in 2010, the present value of the offset (discounted at 5% real) would be about 3.4 years; for installations in 2011, the present value would be about 2.8 years.

6.5.2.4. Share of Retail Power Supply at Current Market Prices

Were all retail power supply provided under cost-of-service pricing or long-term contracts, a short-term reduction in wholesale market prices would have little effect on retail supply prices paid by customers. At the other extreme, if retail customers were being supplied 100% from the spot market and paying spot-market prices, they would experience the benefits of short-term reductions in wholesale market prices fully and immediately. The actual mix of power supply under contract for various periods into the future varies among the states, among the utilities within some states, between municipal utilities and independently owned utilities (IOUs), and between customers on standard utility offer (standard service, default service, last-resort service, etc.) and those served by competitive suppliers. The standard-offer mixes are subject to legislative and/or regulatory change.

In addition, most restructured IOUs have contracts with generators for energy, which is sold into the market for the benefit of customers. These contracts include pre-restructuring contracts with independent power producers, restructuring-related contracts with the purchasers of plants (particularly Vermont Yankee), and post-restructuring contracts in Connecticut (for peakers at Devon, Middletown and New Haven and several smaller baseload renewable and fuel cell plants selected in the Project 150) process.

The non-restructured utilities in New England comprise PSNH, the Vermont utilities, and the municipal and co-op utilities in Massachusetts, Connecticut, Rhode Island and Maine.

- For PSNH, we estimate that 70% of energy requirements are served from owned generation and long-term contracts. In 2005 through 2008, the annual PSNH FERC Forms report that purchases for less than one year ranged from 25% to 30% of PSNH's sales plus losses. We assume the percent of short-term supply will stay around 30%, rising with the end of the Vermont Yankee contract and the loss of net output due to environmental controls on Merrimack and falling to the extent that PSNH develops renewables or contracts for energy from new renewables.
- For Vermont, we estimate that 95% of energy requirements are served from owned generation and long-term contracts in 2009–2011. The contract between Vermont Yankee and the Vermont utilities ends in March 2012, reducing the portion of supply under contract by about 35% of Vermont's total needs (Vermont Department of Public Service 2008, III-65). The Vermont utilities' long-term contracts with Hydro Quebec, now representing roughly another 35% of power supply, phase out from 2013 through 2016. Hence, we estimate the portion of Vermont supply whose price will not be affected by post-2009 DSM to be about 95% in 2010 and 2011, 70% in 2012, 55% in 2013, 45% in 2014, 35% in 2015, and 25% in and after 2016.
- We have no comprehensive information about the energy supplies of the publicly-owned utilities. Various municipal utilities have wholly-owned generation (mostly peaking), shares in generators owned by MMWEC and

CMEEC, ownership interests in Seabrook and Millstone, long-term contracts for the output for particular generators, contracts for supply from the New York Power Authority, and various firm purchase arrangements. Lacking any more specific information, we assume that 95% of municipal-utility and co-op energy supply is under contract for 2010, decreasing 5% annually through 2019, and remaining at 50% thereafter.

We did not receive data from the sponsors, other than NStar, on the energy that utilities sell into the market from pre-restructuring contracts. From utility filings with regulators, we have determined that United Illuminating has no such sales after 2009, and have extracted energy sales projections for CL&P and WMECo. National Grid market sales (from its NEPCo and Montaup subsidiaries) are not listed in its Massachusetts transition-charge filings. We have not been able to find Fitchburg G&E's transition-charge filings on the DPU web site, but its 2008 FERC Form 1 lists the long-term unit purchase of 14 MW and 107 GWh from Pinetree Power; we do not know how long that purchase continues, or whether the energy has been resold under a long-term contract. Similarly, CMP's 2008 FERC Form shows 1,467 GWh of long-term IPP purchases, BHE's shows 306 GWh, and NEPCo's shows 858 GWh that appear to be from long-term contracts, but we do not have any information on the duration of those purchases or any confirmation that the sales are made into short-term or spot markets.

Exhibit 6-41: Utility Entitlements Sold into Market (GWh)

					Old IPP Contracts				Restructured Utility	Connecticut Contracts		
Year	CL&P	UI	NStar	WMECo	National Grid	CMP	BHE	Unitil	Vermont Yankee shares	Peakers	Project 150	Total
2009	2,749	-	2,480	56	?	?	?	?	1,531	-	-	6,895
2010	2,511	-	2,480	56	?	?	?	?	1,459	16	63	6,665
2011	2,355	-	2,480		?	?	?	?	1,459	33	181	6,588
2012	2,308	-	1,889		?	?	?	?	349	44	682	5,351
2013	2,244	-	1,883		?	?	?	?		44	1,183	5,432
2014	1,876	-	1,870		?	?	?	?		44	1,183	5,052
2015	571	-	1,870		?	?	?	?		44	1,183	3,747
2016	307	-	1,082		?	?	?	?		44	1,183	2,694
2017	167	-	96		?	?	?	?		44	1,183	1,569
2018	156	-	96		?	?	?	?		44	1,183	1,519
2019	123	-	96		?	?	?	?		44	1,183	1,446
2020	113	-	96		?	?	?	?		44	1,183	1,436
2021	6	-	96		?	?	?	?		44	1,183	1,328
2022	6	-	96		?	?	?	?		44	1,183	1,328
2023	6	-	32		?	?	?	?		44	1,183	1,264
2024	0	-	0		?	?	?	?		44	1,183	1,227

Notes: Vermont Yankee output excludes Vermont and PSNH entitlements.

Connecticut contracts are estimated at 1% capacity factor for peakers and 90% for Project 150.

The quantified contracts amount to about 5% of New England energy load; the contracts of the unquantified utilities might make that 7%. The contracts decline to less than 1% of load by 2020. Since in many cases the load that benefits from these sales is in a different zone or even state from the zone in which the resource is located (which determines the change in price received for the contract energy), we apply the contract offset as an ISO-wide average.

Most of the utilities also receive revenues from the use of Hydro-Quebec tie lines; it is not clear how those revenues are determined, or whether they vary with energy prices in New England.

In AESC 2007, we estimated the portion of each state's energy supply that was served under intermediate-term purchases, such as from competitive retail marketers and suppliers of the utilities' wholesale full-requirement services, and assumed that energy-efficiency program do not affect the prices of those contracts. Since we now assume that market prices reflect expected program savings a few years into the future, these adjustments are not necessary.

Multiplying the share of the load exposed to market prices by the portion of the price effect not yet offset by supply adaptation produces an estimate of the percent of load affected by DRIPE. This can be expressed as a formula:

$$\textit{\% of load subject to energy DRIPE} = \textit{(1 − market response)} \times \textit{\% of power supply prices at market}$$

Exhibit 6-42 summarizes the combined effect of DRIPE decay and market exposure, for each of four consumer groups: PSNH, the Vermont utilities, other municipal utilities (and the Maine coops), and the restructured investor-owned utilities (and the NH Co-op). The DRIPE decay in the first column is one minus the total DRIPE offset from Exhibit 6-39, above. The Net DRIPE Effect in Exhibit 6-42 is the produce of the DRIPE Decay and the market exposure for the various customer groups.

Exhibit 6-42: Summary of Energy DRIPE Response

		Market-Exposed Supply of Non-Restructured Utilities			Unhedged Portion of	Net DRIPE Effect			
	DRIPE Decay	PSNH	Vermont	Other Munis	Restructured Utility Supply	PSNH	VT	Other Munis	Restructured
2010	84%	30%	5%	5%	93%	25%	4%	4%	78%
2011	78%	30%	5%	10%	94%	23%	4%	8%	73%
2012	74%	30%	30%	15%	95%	22%	22%	11%	70%
2013	36%	30%	45%	20%	95%	11%	16%	7%	34%
2014	30%	30%	55%	25%	96%	9%	16%	7%	28%
2015	26%	30%	65%	30%	97%	8%	17%	8%	25%
2016	22%	30%	75%	35%	98%	7%	16%	8%	21%
2017	18%	30%	75%	40%	98%	5%	14%	7%	18%
2018	15%	30%	75%	45%	99%	4%	11%	7%	15%
2019	12%	30%	75%	50%	100%	3%	9%	6%	12%
2020	8%	30%	75%	50%	100%	3%	6%	4%	8%
2021	6%	30%	75%	50%	100%	2%	4%	3%	6%
2022	3%	30%	75%	50%	100%	1%	2%	1%	3%

Applying those percentages to the potential energy DRIPE produces the energy DRIPE. In the spreadsheets accompanying the final report, we will calculate the energy DRIPE effects of a 1 MWh reduction in energy uses in each zone, by month.

6.6. Avoided Transmission-and-Distribution Costs

We surveyed the sponsoring electric utilities to determine (1) the avoided T&D capacity cost estimates used in the valuation of 2009 DSM programs and (2) the methodology on which these estimates were based. Table 1 summarizes the information provided:

Exhibit 6-43: Summary of Electric Utilities' T&D Estimates

Company	Year $	Transmission $kW-year	Distribution $kW-year	Source	Documentation
NStar	2008	15.39	76.34	ICF model	Workbook provided
WMECo	2009	19.44	58.30	ICF model	None
CL&P	2009	17.20	37.99	ICF model	None
National Grid MA	2009	25.16	50.47	ICF model	Workbook provided
National Grid RI	2009	25.16	59.40	ICF model	None
NH Blended	2009	13.38	41.28	unknown	None
UI	2009	$17.20	$37.99	ICF model	None
FG&E	?	18.90	171.71	not ICF	None

The Vermont and Maine program administrators did not respond to our inquiry.

Beyond the survey, we also reviewed the ICF model in general and in its use by the two utilities that provided their versions of the workbook.[122] Based on this review, we make the following observations about the model that could be addressed to improve the model's effectiveness (ICF made a number of errors in its spreadsheet. Some of these errors were corrected by one or both of the utilities that documented their estimates),

- Weather-normalized load. The basis for the load forecast and the DSM savings estimates should be consistent. Since DSM savings are generally estimated for normal peak weather, the divisor in the $/kW computation should be normal peak growth. The ICF documentation suggests that the choice of using normal or extreme weather load data in the analysis should be consistent with the T&D planning load assumptions. ICF is incorrect. The basis for the load forecast and the DSM savings estimates should be consistent. Since DSM savings are generally estimated for normal peak weather, the divisor in the $/kW computation should be normal peak growth.
- Load-growth assumption. ICF assumes that the system peak loads (on page 401 of the FERC Form 1) drive both transmission and distribution capacity. For transmission, that assumption is a reasonable approximation. But the load growth on the utility's distribution system is lower, since many large customers provide some or all of their own distribution and are served at various transmission or primary-distribution voltages.

[122] A description of this model was detailed in the AESC 2005 report.

- The percentages of O&M assumed to be load-related. ICF does not explain why the fraction of O&M that is avoided by a load reduction would be so different from the fraction of capital equipment avoided.[123]
- Income taxes. The ICF model assumes that income taxes are charged only on the real equity return.[124] In fact, income taxes are charged on the full nominal return. ICF also appears to have double-counted the debt-interest deduction, by adjusting for it in both lines 1 (the real after-tax cost of financing) and 6 (income tax expense).
- Insurance expense. The ICF model incorrectly cites page 323, line 156 of the FERC Form 1 as the source of Total Plant Annual Insurance Costs. National Grid corrected the citation in its spreadsheet.
- Spreadsheet errors. The ICF model spreadsheet contains cell-reference errors that excludes depreciation expense and the cost of capital from the distribution carrying charge, but adds in the state income tax rate. NStar corrected the cost-of-capital and tax rate errors, while National Grid corrected all three errors on its spreadsheet.

In addition to the general observations about the model, a number of differences in assumptions were evident in the workbooks of the two utilities that provided them. Some of these are illustrated in Exhibit 6-44.

Exhibit 6-44: Selected Inputs to ICF Model

Assumption	Company	
	NStar	National Grid MA
Depreciation life of transmission	30 years	45 years
Depreciation life of distribution	30 years	45 years
Avoidable % of transmission O&M	1%	42%
Avoidable % of distribution S/S and line O&M	17%	21%
Avoidable % of distribution investment	100%	25%
Avoidable % of transmission investment	100%	25%
Weighting of historic and projected	50/50	50/50

Our observations on these two applications of the ICF model include the following:

[123] ICF simply states that a "Majority of expenses will be considered fixed and will not be affected by normal new investment in equipment."

[124] See Line 6 in ICF's Carrying Charge spreadsheet.

- Transmission plant generally has longer average life than distribution plant. The choice of equal lives is non-standard.
- The National Grid estimate of distribution equipment life is much higher than the ratio of depreciation expense (about $100 M) to gross plant in service (about $2.7 billion) reported in National Grid's FERC Form 1 for 2008, which suggests an average life of 27 years.
- The difference in the share of transmission O&M treated as avoidable is due to NStar's assumption that transmission by others is not avoidable and National Grid's assumption that it is 100% avoidable.[125]
    - The cost of transmission by others should be offset by revenues from transmission for others.
    - Both transmission by others and transmission for others include capital recovery, so adding and subtracting these costs to O&M may result in misleading values.
- NStar's treatment of 100% of investment as avoidable is implausible, since
    - Some investment replaces retired equipment in kind, some of which burns out due to usage levels, but much of which is retired due to time-related deterioration (e.g., rusting), accident, or relocation (e.g., for highway widening).
    - Distribution includes meters and street lighting, for which investment is not reduced by energy efficiency, and other equipment (e.g., service drops) that are only partially load-related.
- National Grid's treatment of just 25% of investment as avoidable appears low.
- Rather than explicitly weighting historical and forecast investment costs in dollars per kW-year, National Grid sums its historical and forecast investment and divides by the sum of historical and forecast load growth. Depending on the reliability of the forecast data, this may be a more appropriate computation than ICF's suggested weighting.
- Both utilities' calculations of the transmission carrying charge (but not the distribution charge) substitute the nominal debt rate for the real debt rate in ICF's tax expense formula, further reducing the estimate of tax expense.

[125]The NStar worksheet notes that transmission by others "doesn't relate to investment," presumably meaning NStar's investment, but it is a cost that varies with load.

Standardization or joint review of these input assumptions, or of the company-specific derivation of the assumptions, may be helpful.

6.7. Externalities

Externalities are impacts from the production of a good or service that **are not** reflected in price of that good or service, and that are **not** considered in the decision to provide that good or service.[126] Air pollution is a classic example of an externality since pollutants released from a facility impose health impacts on a population, cause damage to the environment, or both. The costs of those health impacts and/or ecosystem damages are not reflected in the price of the product and are generally not borne by the owner of the pollutant source, and are thus external to the financial decisions pertaining to the source of the pollutant. Thus externalities equal the value of the adverse impacts minus the value of those impacts reflected in market prices.

In Chapter 2, we identify the impacts of pollutants that **are** reflected in market prices. NO_x, SO_x, Mercury, and CO_2 as significant air pollutants associated with electric generation that are subject to Federal and/or state regulation. Our electric market simulation model uses assumptions regarding compliance costs for those emissions as part of its estimation of the market price of electricity. The simulation model includes the costs associated with each of these emissions when calculating bid prices and making commitment and dispatch decisions.

The scope of work asks for the heat rates, fuel sources, and emissions of NO_x, SO_x, CO_2, and mercury of the marginal units during each of the energy and capacity costing periods in the 2010 base year. It also asks for the quantity of environmental benefits that would correspond to energy efficiency and demand reductions, in lbs/MWh and lbs/kWh, respectively, during each costing period.

We began by identifying the marginal unit in each hour in each transmission area. The model reports the marginal unit for each hour in each transmission area. Once the marginal units were identified we drew their heat rates, fuel sources, and emission rates for NO_x, SO_x, CO_2, and mercury from the database of input assumptions used in our Market Analytics simulation of the New England wholesale electricity market. The marginal units and their characteristics are presented in Exhibit 6-45 and Exhibit 6-46.

[126] In economics, an externality can be positive or negative; in this discussion we are focusing on negative externalities.

Exhibit 6-45 2010 New England Marginal Heat Rate by Pricing Period (Btu/kWh)

	Season				
	Summer		Winter		Grand Total
	Off Peak	On Peak	Off Peak	On Peak	
Average Heat Rate (BTU/kWh)	9,044	10,555	8,627	9,921	**9,417**

Exhibit 6-46 2010 New England Marginal Fuel Type

	Season and Period				
	Summer		Winter		Grand Total
Fuel Type	Off Peak	On Peak	Off Peak	On Peak	
Natural Gas	67.61%	48.97%	73.04%	58.75%	**63.74%**
NG/Oil Dual	9.07%	22.48%	8.94%	13.57%	**12.58%**
Oil	1.42%	1.56%	2.02%	6.73%	**3.34%**
DR	8.59%	20.53%	5.97%	15.81%	**11.86%**
Coal	13.31%	6.47%	9.89%	5.14%	**8.44%**
Other	0.00%	0.00%	0.14%	0.00%	**0.05%**
Grand Total	**100%**	**100%**	**100%**	**100%**	**100%**

We then calculated the physical environmental benefits from energy efficiency and demand reductions by calculating the emissions of each of those marginal units in terms of lbs/MWh and lbs/kWh. We did this by multiplying the quantity of fuel each marginal unit burned by the corresponding emission rate for each pollutant for that type of unit and fuel.

The calculations for each pollutant in each hour are as follows:

Marginal Emissions = (Fuel Burned$_{MU}$ (MMBtu) x Emission Rate$_{MU}$ (lbs/MMBtu) x 1 ton/2000 lbs)/Generation$_{MU}$ (MWh)

where

Fuel Burned$_{MU}$ = the fuel burned by the marginal unit in the hour in which that unit is on the margin,

Emission Rate$_{MU}$ = the emission rate for the marginal unit, and

Generation$_{MU}$ = Generation by the marginal unit in the hour in which that unit is on the margin.

The avoided emissions values shown in the exhibits below represent the averages for each pollutant over each costing period for all of New England. The first four exhibits show the avoided emissions values in lbs/MWh and the second four exhibits show the avoided emissions values in lbs/kWh. We report the emission rates by modeling zone, however the differences between zones are generally insignificant.

Exhibit 6-47: 2010 New England Avoided CO_2 Emissions by Modeling Zone and Pricing Period (lbs/MWh)

Carbon Dioxide (lbs/MWh)	Summer		Winter		Grand Total
Transarea	Off Peak	On Peak	Off Peak	On Peak	
NE - Bangor Hydro Area	1,064	996	1,025	1,025	**1,027**
NE - Boston	1,083	991	1,035	1,021	**1,032**
NE - Central Maine	1,064	996	1,025	1,025	**1,027**
NE - Central Massachusetts	1,073	995	1,032	1,013	**1,027**
NE - Connecticut Central-North	1,065	989	1,041	1,015	**1,029**
NE - Connecticut Norwalk	1,062	989	1,041	1,015	**1,028**
NE - Connecticut Southwest	1,062	989	1,041	1,015	**1,028**
NE - New Hampshire	1,075	1,000	1,040	1,025	**1,035**
NE - Rhode Island	1,077	991	1,030	1,015	**1,027**
NE - SE Massachusetts	1,080	991	1,030	1,017	**1,028**
NE - South Maine	1,064	996	1,025	1,025	**1,027**
NE - Vermont	1,074	1,000	1,046	1,019	**1,035**
NE - Western Massachusetts	1,074	996	1,044	1,019	**1,034**
Average	**1,070**	**994**	**1,035**	**1,019**	**1,030**

Exhibit 6-48: 2010 New England Avoided NO_x Emissions by Modeling Zone and Pricing Period (lbs/MWh)

NO_X (lbs/MWh)	Summer		Winter		Grand Total
Transarea	Off Peak	On Peak	Off Peak	On Peak	
NE - Bangor Hydro Area	0.636	0.674	0.524	0.658	**0.610**
NE - Boston	0.628	0.695	0.520	0.698	**0.623**
NE - Central Maine	0.636	0.674	0.524	0.658	**0.610**
NE - Central Massachusetts	0.617	0.706	0.515	0.684	**0.616**
NE - Connecticut Central-North	0.615	0.707	0.523	0.693	**0.622**
NE - Connecticut Norwalk	0.613	0.707	0.523	0.693	**0.622**
NE - Connecticut Southwest	0.613	0.707	0.523	0.693	**0.622**
NE - New Hampshire	0.618	0.708	0.529	0.684	**0.622**
NE - Rhode Island	0.622	0.695	0.512	0.686	**0.615**
NE - SE Massachusetts	0.625	0.695	0.512	0.687	**0.616**
NE - South Maine	0.636	0.674	0.524	0.658	**0.610**
NE - Vermont	0.610	0.712	0.541	0.695	**0.629**
NE - Western Massachusetts	0.610	0.706	0.544	0.696	**0.629**
Average	**0.621**	**0.697**	**0.524**	**0.683**	**0.619**

Exhibit 6-49: 2010 New England Avoided SO_2 Emissions by Modeling Zone and Pricing Period (lbs/MWh)

SO_2 (lbs/MWh)	Summer		Winter		Grand Total
Transarea	Off Peak	On Peak	Off Peak	On Peak	
NE - Bangor Hydro Area	1.954	1.333	1.401	1.657	**1.568**
NE - Boston	2.141	1.334	1.314	1.792	**1.613**
NE - Central Maine	1.954	1.333	1.401	1.657	**1.568**
NE - Central Massachusetts	2.027	1.366	1.276	1.728	**1.565**
NE - Connecticut Central-North	1.911	1.379	1.280	1.790	**1.568**
NE - Connecticut Norwalk	1.883	1.379	1.280	1.790	**1.563**
NE - Connecticut Southwest	1.883	1.379	1.280	1.790	**1.563**
NE - New Hampshire	2.099	1.428	1.484	1.839	**1.695**
NE - Rhode Island	2.083	1.334	1.269	1.744	**1.572**
NE - SE Massachusetts	2.112	1.334	1.269	1.777	**1.587**
NE - South Maine	1.954	1.333	1.401	1.657	**1.568**
NE - Vermont	2.028	1.434	1.444	1.776	**1.650**
NE - Western Massachusetts	2.028	1.366	1.359	1.776	**1.609**
Average	**2.004**	**1.364**	**1.343**	**1.752**	**1.592**

Exhibit 6-50: 2010 New England Avoided Mercury (Hg) Emissions by Modeling Zone and Pricing Period (lbs/MWh)

Mercury (lbs/MWh)	Season				Grand Total
	Summer		Winter		
Transarea	Off Peak	On Peak	Off Peak	On Peak	
NE - Bangor Hydro Area	3.42E-06	2.05E-06	2.98E-06	1.01E-06	**2.28E-06**
NE - Boston	3.21E-06	1.99E-06	3.18E-06	1.22E-06	**2.37E-06**
NE - Central Maine	3.42E-06	2.05E-06	2.98E-06	1.01E-06	**2.28E-06**
NE - Central Massachusetts	3.17E-06	2.17E-06	3.09E-06	1.21E-06	**2.36E-06**
NE - Connecticut Central-North	2.94E-06	2.34E-06	3.06E-06	1.30E-06	**2.37E-06**
NE - Connecticut Norwalk	2.83E-06	2.34E-06	3.06E-06	1.30E-06	**2.35E-06**
NE - Connecticut Southwest	2.83E-06	2.34E-06	3.06E-06	1.30E-06	**2.35E-06**
NE - New Hampshire	3.17E-06	2.19E-06	3.12E-06	1.22E-06	**2.38E-06**
NE - Rhode Island	3.19E-06	1.99E-06	3.09E-06	1.22E-06	**2.34E-06**
NE - SE Massachusetts	3.20E-06	1.99E-06	3.09E-06	1.21E-06	**2.34E-06**
NE - South Maine	3.42E-06	2.05E-06	2.98E-06	1.01E-06	**2.28E-06**
NE - Vermont	3.13E-06	2.19E-06	3.17E-06	1.21E-06	**2.38E-06**
NE - Western Massachusetts	3.13E-06	2.17E-06	3.35E-06	1.21E-06	**2.44E-06**
Average	**3.16E-06**	**2.14E-06**	**3.09E-06**	**1.19E-06**	2.35E-06

Exhibit 6-51 2010 New England Avoided CO_2 Emissions by Modeling Zone and Pricing Period (lbs/kWh)

Carbon Dioxide (lbs/kWh)	Summer		Winter		Grand Total
Transarea	Off Peak	On Peak	Off Peak	On Peak	
NE - Bangor Hydro Area	1.064	0.996	1.025	1.025	**1.027**
NE - Boston	1.083	0.991	1.035	1.021	**1.032**
NE - Central Maine	1.064	0.996	1.025	1.025	**1.027**
NE - Central Massachusetts	1.073	0.995	1.032	1.013	**1.027**
NE - Connecticut Central-North	1.065	0.989	1.041	1.015	**1.029**
NE - Connecticut Norwalk	1.062	0.989	1.041	1.015	**1.028**
NE - Connecticut Southwest	1.062	0.989	1.041	1.015	**1.028**
NE - New Hampshire	1.075	1.000	1.040	1.025	**1.035**
NE - Rhode Island	1.077	0.991	1.030	1.015	**1.027**
NE - SE Massachusetts	1.080	0.991	1.030	1.017	**1.028**
NE - South Maine	1.064	0.996	1.025	1.025	**1.027**
NE - Vermont	1.074	1.000	1.046	1.019	**1.035**
NE - Western Massachusetts	1.074	0.996	1.044	1.019	**1.034**
Average	**1.070**	**0.994**	**1.035**	**1.019**	**1.030**

Exhibit 6-52 2010 New England Avoided NO_x Emissions by Modeling Zone and Pricing Period (lbs/kWh)

NO_X (lbs/kWh)	Summer		Winter		Grand Total
Transarea	Off Peak	On Peak	Off Peak	On Peak	
NE - Bangor Hydro Area	0.00064	0.00067	0.00052	0.00066	**0.00061**
NE - Boston	0.00063	0.00070	0.00052	0.00070	**0.00062**
NE - Central Maine	0.00064	0.00067	0.00052	0.00066	**0.00061**
NE - Central Massachusetts	0.00062	0.00071	0.00051	0.00068	**0.00062**
NE - Connecticut Central-North	0.00062	0.00071	0.00052	0.00069	**0.00062**
NE - Connecticut Norwalk	0.00061	0.00071	0.00052	0.00069	**0.00062**
NE - Connecticut Southwest	0.00061	0.00071	0.00052	0.00069	**0.00062**
NE - New Hampshire	0.00062	0.00071	0.00053	0.00068	**0.00062**
NE - Rhode Island	0.00062	0.00070	0.00051	0.00069	**0.00062**
NE - SE Massachusetts	0.00062	0.00070	0.00051	0.00069	**0.00062**
NE - South Maine	0.00064	0.00067	0.00052	0.00066	**0.00061**
NE - Vermont	0.00061	0.00071	0.00054	0.00069	**0.00063**
NE - Western Massachusetts	0.00061	0.00071	0.00054	0.00070	**0.00063**
Average	**0.00062**	**0.00070**	**0.00052**	**0.00068**	**0.00062**

Exhibit 6-53 2010 New England Avoided SO_2 Emissions by Modeling Zone and Pricing Period (lbs/kWh)

SO_2 (lbs/kWh)	Summer		Winter		Grand Total
Transarea	Off Peak	On Peak	Off Peak	On Peak	
NE - Bangor Hydro Area	0.0020	0.0013	0.0014	0.0017	**0.0016**
NE - Boston	0.0021	0.0013	0.0013	0.0018	**0.0016**
NE - Central Maine	0.0020	0.0013	0.0014	0.0017	**0.0016**
NE - Central Massachusetts	0.0020	0.0014	0.0013	0.0017	**0.0016**
NE - Connecticut Central-North	0.0019	0.0014	0.0013	0.0018	**0.0016**
NE - Connecticut Norwalk	0.0019	0.0014	0.0013	0.0018	**0.0016**
NE - Connecticut Southwest	0.0019	0.0014	0.0013	0.0018	**0.0016**
NE - New Hampshire	0.0021	0.0014	0.0015	0.0018	**0.0017**
NE - Rhode Island	0.0021	0.0013	0.0013	0.0017	**0.0016**
NE - SE Massachusetts	0.0021	0.0013	0.0013	0.0018	**0.0016**
NE - South Maine	0.0020	0.0013	0.0014	0.0017	**0.0016**
NE - Vermont	0.0020	0.0014	0.0014	0.0018	**0.0016**
NE - Western Massachusetts	0.0020	0.0014	0.0014	0.0018	**0.0016**
Average	**0.0020**	**0.0014**	**0.0013**	**0.0018**	**0.0016**

Exhibit 6-54 2010 New England Avoided Mercury (Hg) Emissions by Modeling Zone and Pricing Period (lbs/kWh)

Mercury (lbs/kWh)	Season				
	Summer		Winter		Grand Total
Transarea	Off Peak	On Peak	Off Peak	On Peak	
NE - Bangor Hydro Area	3.42E-09	2.05E-09	2.98E-09	1.01E-09	**2.28E-09**
NE - Boston	3.21E-09	1.99E-09	3.18E-09	1.22E-09	**2.37E-09**
NE - Central Maine	3.42E-09	2.05E-09	2.98E-09	1.01E-09	**2.28E-09**
NE - Central Massachusetts	3.17E-09	2.17E-09	3.09E-09	1.21E-09	**2.36E-09**
NE - Connecticut Central-North	2.94E-09	2.34E-09	3.06E-09	1.30E-09	**2.37E-09**
NE - Connecticut Norwalk	2.83E-09	2.34E-09	3.06E-09	1.30E-09	**2.35E-09**
NE - Connecticut Southwest	2.83E-09	2.34E-09	3.06E-09	1.30E-09	**2.35E-09**
NE - New Hampshire	3.17E-09	2.19E-09	3.12E-09	1.22E-09	**2.38E-09**
NE - Rhode Island	3.19E-09	1.99E-09	3.09E-09	1.22E-09	**2.34E-09**
NE - SE Massachusetts	3.20E-09	1.99E-09	3.09E-09	1.21E-09	**2.34E-09**
NE - South Maine	3.42E-09	2.05E-09	2.98E-09	1.01E-09	**2.28E-09**
NE - Vermont	3.13E-09	2.19E-09	3.17E-09	1.21E-09	**2.38E-09**
NE - Western Massachusetts	3.13E-09	2.17E-09	3.35E-09	1.21E-09	**2.44E-09**
Average	**3.16E-09**	**2.14E-09**	**3.09E-09**	**1.19E-09**	**2.35E-09**

In this 2009 AESC report, we find that CO_2 has the most significant externality. We also conclude that the long-run marginal abatement cost of CO_2 is a practical and conservative measure of the full cost of carbon. In updating our recommendation from the 2007 AESC report, we review current literature on emissions reductions necessary to avoid the most dangerous impacts of climate change, as well as analyses of technologies available to achieve those emission reductions. We recommend that the Study Group uses a marginal abatement cost value which is based on the cost of controlling emissions. (This is an alternative to setting value based on monetized estimates of damages.)

For AESC 2009 we recommend using a long-run marginal abatement cost (2009$) of $80 per short ton of CO2. This estimate is one-third higher than the value of $60 (2007$) per short ton recommended in AESC 2007.[127] In 2009 approximately 5% of that $80/ton is internalized in the market price of electricity, through RGGI, and 95% is an externality. By 2024, we estimate that approximately 40% of that amount will be internalized.

6.7.1. History of Environmental Externalities–Policies in New England

AESC (2007, 7-6–7-8) provides a detailed description of the history of electricity generation environmental externalities and policies in New England. In the 1990's several New England states had proceedings dealing with externalities that influence current utility planning and decision-making. In Massachusetts, dockets DPU 89-239 and 91-131 served as models for other states. Docket DPU 89-239 was opened to develop "Rules to Implement Integrated Resource Planning" (IRP) and included consideration of many aspects of IRP including determination and application of environmental externalities values. This docket adopted a set of dollar values for air emissions, including a CO_2 value of $22 per ton of CO_2 (in 1989 dollars) (Exhibit DOER-3, Exhibit. BB-2, p. 26).

Docket DPU 91-131 examined environmental externalities to develop recommendations of various approaches for quantifying the CO_2 externality value. Experts from recommended damage cost and control cost approaches to value the externality. Mr. Biewald presented a report (Biewald et al. 1991) which outlined the different methods for monetizing externalities, and recommended $23 per ton of CO_2 (in 1990 dollars).

The Department's Order in Docket DPU 91-131 was noteworthy for its foresight regarding climate change, albeit optimistic about the timing of recognition of climate change into policies and regulation in the United States. The Department, in its November 10 1992 order, concluded:

> "The record in this docket indicates that the scientific community believes that continued CO_2 emissions will raise global temperatures significantly, with potentially significant damage to many aspects of society. CO_2 currently is not regulated in the United States, but efforts are underway in the United States and internationally to develop regulations to reduce emissions of CO_2 in the atmosphere. The generation of electricity contributes significantly to the buildup of CO_2 in the atmosphere. The electricity generation industry is likely to be substantially affected by efforts to regulate, tax, or otherwise limit emissions of

[127] $60 per short ton converts to about $63 per short ton in 2009 dollars.

> CO_2. Clearly, it would be prudent for current and future suppliers of electricity to anticipate that CO_2 regulations will be promulgated in the United States and/or internationally in the future, and that such regulations will affect resource options which might be considered in IRM resource solicitations.
>
> The Department has recognized the large degree of uncertainty associated with estimating (1) the future damages from CO_2 emissions and (2) the future costs to control or otherwise regulate CO_2 emissions. The parties in this proceeding agree that estimating the net damages associated with expected global warming is fraught with uncertainty. They disagree, however, about how much uncertainty should be attached to estimates of future global warming. They disagree even more on the likely damages from future global warming. Consequently, the Department has been presented with a wide range of estimated external cost values for CO_2, from a negative value to many times the current value."[128]
>
> "In this case, the Department will determine whether it has been demonstrated that any proposed damage estimates for CO_2 are comprehensive and reliable, or, if not, are more reasonable than the Department's current value." [129]

Based on information in the record, the Department reaffirmed the CO_2 value it had adopted in the previous case, $22 per ton (in 1989 dollars).[130]

One of the important dynamics that can be observed in the evolution of environmental policies is the time lag between (1) the recognition of an environmental or health hazard, (2) the scientific study and documentation of the impacts, (3) the development and implementation of regulations to address the harm, and (4) the adjustment of the regulations to recognize evolving understanding of the impacts and the changing political consensus. The history of acid rain regulation provides a good example of this time lag. Acid rain was recognized as early as the mid-nineteenth century in England; however, it wasn't until the 1960s that the science and impacts of acid rain were widely studied. In 1980 Congress established a ten year research program, the National Acidic Precipitation Assessment Program to understand and quantify acid rain impacts. The Clean Air Act Amendments of 1990 included provisions for SO_2 emission caps to be implemented beginning in 1995 ("phase 1") for the largest sources, and 2000 ("phase 2") for other sources. More recently, the Clean Air Interstate Rule, passed by Congress in March 2005, adjusts the SO_2 emissions cap downward with an ultimate effect of reducing SO_2 emissions about 73% from 2003 levels, in order

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[128]DPU 86-36-G, pp.86-87

[129]DPU 86-36-G, pp.73-74 Is this still part of the "conclusion?" It precedes the previous quoted paragraphs. Why do we present it that way? Do we even need it at all?

[130]DPU 86-36-G, pp.76

to address severe interstate pollutant transport issues that were not effectively addressed by prior regulation.

Action to address the depletion of the stratospheric ozone layer was more rapid, demonstrating the international community's ability to act relatively swiftly when convinced that urgent action is required. In the early 1970s two scientists identified compounds that were depleting the ozone layer; by 1985 scientists had observed and documented an "Antarctic Ozone Hole" during springtime. In 1987 international action resulted in the negotiation of the Montreal Protocol to regulate the use and production of ozone-depleting substances. In terms of climate change and carbon dioxide regulations in the United States, we are currently at the early stages of a similar ongoing and evolving process. The regulatory history of acid rain and of ozone depletion contributed important foundations for efforts to regulate greenhouse gas emissions (federal government role in addressing pollution, and framework for international negotiations on pollutants, respectively).

The experience with acid rain and with stratospheric ozone are two examples where policy to recognize and internalize environmental externalities evolved gradually over time. For greenhouse gas emissions and climate policy we are currently on a path of this type. Great progress has been made over the past couple of decades, particularly on scientific understanding, and progress will be made in the coming decades, particularly on but not limited to development of technologies and policies.

6.7.2. Carbon Dioxide

Carbon dioxide will be the dominant externality from electricity production and use in New England over the study period.

As noted in our 2007 AESC report, externalities associated with electricity production and uses include a wide variety of air pollutants, water pollutants, and land use impacts. The principle air pollutants that have externalities include carbon dioxide, sulfur dioxide, nitrogen oxides and ozone, particulates, and mercury. Add additional language on other pollutants. Need price estimates from model results

There have been several fairly comprehensive studies that assess the full range of environmental impacts from electricity generation and use (Ottinger et al. 1990; RCG/Tellus 1993–95; Woolf et al. 1994; Oak Ridge National Laboratory 1991–94; International Energy Association 2002).

The list of externalities from energy production and use is quite long, and includes the following:

- Air emissions (including SO_2, NO_x, particulates, mercury, lead, other toxins, and greenhouse gases) and the associated health and ecological damages;
- Fuel cycle impacts associated with "front end" activities such as mining and transportation, and waste disposal;
- Water use and pollution;
- Land use;
- Aesthetic impacts of power plants and related facilities;
- Radiological exposures related to nuclear power plant fuel supply and operation (routine and accident scenarios);
- Other non-environmental externalities such as economic impacts (generally focused on employment), energy security, and others.

Many of these externalities have been reduced over time, as regulations limiting emission levels have forced suppliers and buyers to consider at least a portion of those costs in their production and use decisions, thereby "internalizing" a portion of those costs. For example, the Clean Air Interstate Rule, while vacated and remanded by the federal court, would have adjusted the SO_2 emissions cap downward with an ultimate effect of reducing SO_2 emissions about 73% from 2003 levels. The first phase of CAIR is effective for 2009, but the long-term SO_x and NO_x reduction goals remain uncertain as EPA has yet to address the US District Court of Appeals decision. As a result, while there remain some "external costs" associated with the residual NO_x and SO_2 pollution, these externalities are now relatively small.

We anticipate in the 2009 AESC that the "carbon externality" will continue to be the dominant externality associated with marginal electricity generation in New England. This is the case for two main reasons. First, regulations to address the greenhouse gas emissions responsible for global climate change have yet to be adopted with sufficient stringency to link science with long-term policy that would enable carbon-free resources to replace fossil-based generation lag, particularly in the United States.[131] The damages from criteria air pollutants are relatively bounded, and to a great extent "internalized," as a result of existing regulations. In contrast, global climate change is a problem on an unprecedented scale with far-

[131]On April 17, 2009; EPA issued a proposed finding that concluded that greenhouse gases posed an endangerment to public health and welfare under the Clean Air Act ("Proposed Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act" 74 Fed. Register 78: 18886–18910). This proposed finding initiates the process of potentially regulating greenhouse gases as an air pollutant. http://epa.gov/climatechange/endangerment.html

reaching and potentially catastrophic implications. Second, New England avoided electric energy costs over the study period are likely to be dominated by natural gas-fired generation, which has minimal SO_2, mercury, and particulate emissions and relatively low NO_x emissions. Hence, spending extensive time reviewing the latest literature on externality values for these emissions would not be cost effective. Based on knowledge of the electric system, and review of model runs, it is believed that the dominant environmental externality in New England over the study period will be the un-internalized cost of carbon dioxide emissions. The current RGGI auctions and any federal CO_2 regulations will only internalize a portion of the "greenhouse gas externality," particularly in the near term.

The California PUC has directed electric companies to include a value for carbon dioxide in their avoided cost determination and long-term resource procurement. The California PUC (R.04-04-003, Appendix B, p. 5.) found:

> In terms of specific pollutants, of significant concern to regulators and the public today is the environmental damage caused by carbon dioxide (CO_2) emissions—an inescapable byproduct of fossil fuel burning and by far the major contributor to greenhouse gases. Unlike other significant pollutants from power production, CO_2 is currently an unpriced externality in the energy market…. CO_2 is not consistently regulated at either the Federal or State levels and is not embedded in energy prices….

For the above reasons, values were developed for the one major emission associated with avoided electricity costs for which the near-term internalized cost most significantly understates the value supported by current science.

6.7.3. General Approaches to Monetizing Environmental Externalities

There are various methods available for monetizing environmental externalities such as air pollution from power plants. These include various "damage costing" approaches that seek to value the damages associated with a particular externality, and various "control cost" approaches that seek to quantify the marginal cost of controlling a particular pollutant (thus internalizing a portion or all of the externality).

The "damage costing" methods generally rely on travel costs, hedonic pricing, and contingent valuation in the absence of market prices. These are forms of "implied" valuation, asking complex and hypothetical survey questions, or extrapolating from observed behavior. For example, data on how much people will spend on travel, subsistence, and equipment, can be used to measure the value of those fish, or more accurately the value of *not* killing fish via air pollution. Human lives are sometimes valued based upon wage differentials for jobs that expose workers to different risks of mortality. In other words, comparing two jobs, one with higher hourly pay rate and higher risk than the other can serve as a measure of the compensation that someone is “willing to accept” in order to be exposed to the risk.

There are myriad problems with these approaches, two of which will be discussed here. First, the damage costing approaches are, in the case of global climate change, simply subject to too many problematic assumptions. We do not subscribe to the view that a reasonable economic estimate of the “damages” around the world can be developed and used as a figure for the externalities associated with carbon dioxide emissions. In other words, estimating damage is a moving target–it depends upon what concentrations we ultimately reach (or what concentrations we reach and reduce from). This is exacerbated by the fact that we do not fully understand what changes in the earth’s climate might occur assuming carbon dioxide concentrations continue to increase past the current 380 parts per million, toward a projected 450 parts per million (or even higher),climate change, and cannot project with certainty the levels at which certain impacts will occur. A further complicating factor is that different emissions concentrations create different damages for different regions and different groups of people. Thus, such exercises, while interesting, are fraught with difficulties including: (a) identifying the categories of changes to ecosystems and societies around the planet; (b) estimating magnitudes of impacts; (c) valuing those impacts in economic terms; (d) aggregating those values across countries with different currency exchange rates and different cultures; (e) addressing the non-linear and catastrophic aspects of the climate change damage; and (f) dealing with the paradoxes and conundrums involved in applying financial discount rates to effects stretching over centuries. Second, the fact that the “regulators’ revealed preferences” approach is unavailable, as regulators have not established relevant reference points, complicates the task of determining a carbon externality cost.

The “control cost” methods generally look at the *marginal* cost of control. That is, the cost of control valuations look at the last (or most expensive) unit of emissions reduction required to comply with regulations. The cost of control approach can be based upon a “regulators’ revealed preference” concept. That is, if “air regulators” are requiring a particular technology with a cost per ton of $X to be installed at power plants, then this can be taken as an indication that the value of those reductions is perceived to be at or above the cost of the controls. The cost of control approach can also be based upon a “sustainability target” concept. With the sustainability target, we start with a level of damage or risk that is considered to be acceptable, and then estimate the marginal cost of achieving that target. It is important to note that, at this stage in our collective understanding of the science of climate change, as well as its social, economic, and physical impacts, the notion of a “sustainability target” is a construct useful for discussion, but not yet firmly established.

The "sustainability target" approach relies on the assumption that the nations of the world will not tolerate unlimited damages. It also relies partly on an expectation that policy leaders will realize that it is cheaper to reduce emissions now and achieve a sustainability target than it is not to address climate change. It is worth noting that a cost estimate based on a sustainability target will be a bit lower than a damage cost estimate because the "sustainability target" is going to be a calculus of what climate change the planet is already committed to, and what additional change we are willing to live with (again complicated by the fact that different regions will see different impacts, and have different ideas about what is dangerous and what is sustainable).

While we do not use a damage cost estimate, it is informative to consider damages to get a sense of the scale of the problem. In October 2006 a major report to Prime Minister Tony Blair stated that "the benefits of strong and early action far outweigh the economic costs of not acting." Based on its review of results from formal economic models, the Stern Review on the Economics of Climate Change estimated that in the absence of efforts to curb climate change, the overall costs and risks of climate change will be equivalent to losing at least 5% of global GDP each year, now and forever, and could be as much as 20% of GDP or more. In contrast, the Stern Review suggested that the costs of action to curb climate change can be limited to around 1% of global GDP each year.

6.7.4. Estimation of CO_2 Environmental Costs

Based upon our review of the merits of those various approaches, we selected an approach that estimates the cost of controlling, or stabilizing, global carbon emissions at a "sustainable level" or sustainability target. To develop that estimate, the most recent science regarding the level of emissions that would be sustainable was reviewed, as well as the literature on costs of controlling emissions at that level.

The conceptual and practical challenges for estimating a carbon externality price include the following:

- The damages are very widely distributed in time (over many decades or even centuries) and space (across the globe);
- The "physical damages" include some impacts that are very difficult to quantify and value, such as flooding large land areas; changes to local climates; species range migration; increased risk of flood and drought; changes in the amount, intensity, frequency, and type of precipitation; changes in the type, frequency, and intensity of extreme weather events (such as hurricanes, heat waves, and heavy precipitation);

- This list of “physical damages” includes some that are extremely difficult, perhaps impossible, to reasonably express in monetary terms;
- The scientific understanding of the climate change process and climate change impacts is evolving rapidly;
- There may well be reasons (not considered here) that the environmental cost value could have a shape that starts lower and increases faster, or vice versa, having to do with periods in which rates of change are most problematic;
- The scale of the impact on the world economies associated with the impacts of climate change and/or associated with the transformations of economies to reduce greenhouse gas emissions are so large that using terms and concepts such as “marginal” can be problematic; and
- The impacts of climate change are non-linear and non-continuous, including “feedback cycles” that can most reasonably be thought of in terms of thresholds beyond which there are “run away damages” such as irreversible melting of the Greenland ice sheet and the West Antarctic ice sheet, and collapse of the Atlantic thermohaline circulation—a global ocean current system that circulates warm surface waters.

Given the daunting challenge of valuing climate damages in economic terms, we propose taking a practical approach consistent with the concepts of “sustainability” and “avoidance of undue risk.” Specifically, the carbon externality can be valued by looking at the marginal costs associated with controlling total carbon emissions at, or below, the levels that avoid the major climate change risks according to current expectations.

Nonetheless, because the environmental costs of energy production and use are so significant, and because the climate change impacts associated with power plant carbon dioxide emissions are urgently important, it is worthwhile to attempt to estimate the externality price and to put it in dollar terms that can be incorporated into electric system planning.

6.7.4.1. What is Current Understanding of the Correct Level of CO_2 Emissions?

In order to determine what is currently deemed a reasonable sustainability target, we reviewed current science and policy. In 1992, over 160 nations (including the United States) agreed to “to achieve stabilization of atmospheric concentrations of greenhouse gases at levels that would prevent dangerous anthropogenic (human-induced) interference with the climate system….” (United Nations Framework Convention on Climate Change).[132] Achieving this commitment requires

[132]There are currently over 180 signatories.

determining the maximum temperature increase above which impacts are anticipated to be dangerous, the atmospheric emissions concentration that is likely to lead to that temperature increase, and the emissions pathway that is likely to limit atmospheric concentrations and temperature increase to the desired levels.

The definition of what level of temperature change constitutes a dangerous climate change will ultimately be established by politicians, as it requires value judgments about what impacts are tolerable regionally, globally, and over time.[133] We expect that such a definition and decision will be based upon what climate science tells us about expected impacts and mitigation opportunities.

While uncertainty and research continue, a growing number of studies identify a global average temperature increase of 2ºC above pre-industrial levels as the temperature above which dangerous climate impacts are likely to occur.(see Mastrandrea and Schneider 2006). Temperature increases greater than 2^{o}C above pre-industrial levels are associated with multiple impacts including sea level rise of many meters, drought, increasing hurricane intensity, stress on and possible destruction of unique ecosystems (such as coral reefs, the Arctic, alpine regions), and increasing risk of extreme events (Schnellnhuber et al. 2006). The European Union has adopted a long-term policy goal of limiting global average temperature increase to below 2^{o}C above pre-industrial levels.[134]

Because of multiple uncertainties, it is difficult to define with certainty what future emissions pathway is likely to avoid exceeding that temperature increase. We reviewed several sources to determine reasonable assumptions about what level of concentrations are deemed likely to achieve the sustainability target, and what emission reductions are necessary to reach those emissions levels. The Intergovernmental Panel on Climate Change's most recent Assessment Report (IPCC 2007a, 15) indicates that concentrations of 445-490 ppm CO_2 equivalent correspond to 2^o–2.4^{o}C increases above pre-industrial levels. A comprehensive assessment of the economics of climate change, Stern (2007) proposes a long-term goal to stabilize greenhouse gases at between the equivalent of 450 and 550 ppm CO_2. Recent research indicates that achieving the 2^{o}C goal likely requires stabilizing atmospheric concentrations of carbon dioxide and other heat-trapping gases near 400 ppm carbon dioxide equivalent (Meinshausen 2006).

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[133]For multiple discussions of the issues surrounding dangerous climate change, see Schnellnhuber et al. (2006).

[134]The European Union first adopted this goal in 1996 in "Communication of the Community Strategy on Climate Change." Council conclusions. European Council. Brussels, Council of the EU. The EU has since reiterated its long-term commitment in 2004 and 2005 (*see*, *e.g.* Council of the European Union, Presidency conclusions, March 22–-23.)

The Intergovernmental Panel on Climate Change (IPCC 2007, Table SPM5) indicates that reaching concentrations of 450-490 ppm CO_2-eq requires reduction in global CO_2 emissions in 2050 of 50-85 percent below 2000 emissions levels. Stern (2007, xi) says that global emissions would have to be 70% below current levels by 2050 for stabilization at 450ppm CO_2-equivalent. To accomplish such stabilization, the United States and other industrialized countries would have to reduce greenhouse gas emissions on the order of 80–90% below 1990 levels, and developing countries would have to achieve reductions from their baseline trajectory as soon as possible (den Elzen and Meinshausen, 306). In the United States, several states have adopted state greenhouse gas reduction targets of 50% or more reduction from a baseline of 1990 levels or then-current levels by 2050 (California, Connecticut, Illinois, Maine, New Hampshire, New Jersey, Oregon, and Vermont). In 2001, the Conference of New England Governors and Eastern Canadian Premiers (2001) also adopted a long-term policy goal of reductions on the order of 75-80% of then-current emission levels.[135]

For example, the impact of increased acidity, and the possibility of altered circulation patterns. But even this relationship between emissions and atmospheric abundance is fraught with uncertainty because scientists are still working to understand factors. For example, scientists do not know the ultimate GHG absorption capacity of the oceans, how the oceans will change with increasing acidity or altered circulation patterns, and what system feedback loops might be affected. Modeling studies suggest that (1) the slow and predictable impacts increase with increasing CO_2 abundance in the atmosphere, and (2) the likelihood of catastrophic impacts (i.e., hitting thresholds) is lower with lower CO_2 in the atmosphere.

On this second point, the IPCC has determined that a 2°C temperature increase is the level at which we are unlikely to hit the thresholds and the impacts will be more manageable.

The sobering news is that a long term stabilization goal of even 400 ppm may not be sufficient:. Bauer and Mastrandrea (2006, 7) conclude, for example, that “while very rapid reductions can greatly reduce the level of risk, it nevertheless remains the case that, even with the strictest measures we model, the risk of exceeding the 2ºC threshold is in the order of 10 to 25 per cent.” Similarly, Meinshausen et al. (2009) estimate that if global emissions in 2050 are half 1990 levels, there is a 12–45% probability of exceeding 2°C. Further, the 2ºC threshold may not be sufficient to avoid severe impacts.[136] Nevertheless, the goal of policymakers seems to be

[135]The Conference reiterated this commitment in June 2007 through its Resolution 31-1, which states, in part, that the long term reduction goals should be met by 2050.

[136]See recent research by James Hansen, Goddard Space Flight Institute.

coalescing around maintaining global temperatures increases at or below 2°C above pre-industrial levels.

6.7.4.2. Cost of Stabilizing CO_2 Emissions

There have been several efforts to estimate the costs of achieving a variety of atmospheric concentration targets. The most comprehensive effort is the work of the Intergovernmental Panel on Climate Change. The IPCC was established by the World Meteorological Organization and UNEP in 1988 to provide scientific, technical and methodological support and analysis on climate change. IPCC has issued four assessment reports on the science of climate change, climate change impacts, and on mitigation and adaptation strategies (in 1990, 1995, 2001, 2007). IPCC (2007a) indicates that reductions on the order of 34 gigatons would be necessary to achieve an 80% reduction below current emission levels. [137] IPCC (2007b, p. 45) estimates that up to 31 gigatons in reductions are available for $97 per short ton of CO_2 or less (Working Group III Summary for Policy Makers) in 2009 dollars.[138] For the 2009 AESC, we have examined other more recent studies on the costs of achieving stabilization targets that include the following and converted to 2009$ per short ton of CO_2:

- The International Energy Agency (IEA 2008a) has modeled the implications and results of two international policy framework scenarios: (1)the ACT Scenario that achieves a 550 ppm (to limit temperature increases to 3°C) target, and (2) the Blue Scenario that achieves a 450 ppm (to limit temperature increase to 2°C) target. IEA projects that a cap and trade program would result in carbon prices of $85 per short ton of CO_2 in 2030 under the 550 ppm scenario, and $170 per short ton of CO_2 in 2030 under the 450 ppm scenario.[139]
- In its Technology Perspectives 2008, IEA (2008b) projects that the marginal cost of technologies necessary to reduce emissions in 2050 to current levels (the ACT Map Scenario) would be $50 per short ton CO_2.[140] The marginal cost of technologies necessary to reduce emissions in 2050 to 50% below current levels (the Blue Scenario, and the low end of what IPCC projects is

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[137] 2000 emissions levels were 43Gt CO_2-eq. IPCC (2007a).

[138] This value, expressed in Table TS.3 in 2006 dollars per metric ton, is $97 per short ton of CO_2 in 2009 dollars ($100 metric ton of CO_2 × 1.07 [2006 to 2009 GDP values] × (1 metric ton/1.102 short ton)).

[139] IEA values originally expressed in 2007 dollars$ per metric ton of CO_2 of $90 and $180 per metric ton.

[140] Costs originally presented $50 per metric ton in real 2005 US dollars. Projected costs under the Blue Map Scenario were originally reported as $200/metric ton and $500 per metric ton for the pessimistic scenario.

necessary for a 2-ºC temperature increase) would equate to \$200 per short ton of CO_2 when fully commercialized. If technological progress fails to meet expectations, marginal costs could be as high as \$501 per short ton CO_2. IEA notes that its marginal cost figure for the Act Scenario is nearly double its 2006 marginal-cost figure, primarily due to accelerated trends in CO_2 emissions and an approximate doubling of engineering costs.

- McKinsey & Company (McKinsey 2009) has released a second version of its Global Greenhouse Gas Abatement Cost Curve.[141] In this analysis, McKinsey determines that two scenarios, "Global Action" and "Green World," are consistent with a sustainability goal of avoiding more than a 2-ºC temperature increase. The "Green World" scenario, the most aggressive scenario, all countries would implement one hundred percent of all abatement options that cost \$75 per short ton or less, and all technical potential costing up to \$125 per short ton of CO_2 and all behavioral change potential would be captured.[142] McKinsey states that transaction and program costs, that are not part of the abatement cost curve, are often estimated at an average between one and eight percent per ton of CO_2 abated.

Earlier studies referenced in the 2007 AESC report included the following:

- A Vattenfalls study of abatement potential estimates that about 30 Gt reduction would be necessary for stabilization at 450 ppm, and about 27Gt are available for around \$50/tCO_2–so cost would go above \$50/t in 2007\$.;[143]
- McKinsey & Company's first version of the abatement cost curve indicated that stabilization at 450 ppm would have a marginal abatement cost of about \$50/t in 2007\$, and stabilization at 400 ppm would have a marginal abatement cost of over \$60/tCO_2; and
- Barker et al. (2006, 38) find that "even stringent stabilization targets can be met without materially affecting world GDP growth, at low carbon tax rates or permit prices, at least by 2030 (in \$US(2000), less than \$15/tCO_2 for 550ppmv and \$50/tCO_2 for 450ppmv for CO_2) expressed in 2007\$.

[141] In 2007, McKinsey developed a global greenhouse-gas-abatement database to provide a quantitative basis for international discussions of greenhouse gas emissions reduction targets. This current version incorporates updated and more sophisticated assessment of low-carbon technologies, regional and industry-specific abatement opportunities, and investment and financing needs, as well as review of implementation scenarios.

[142] The report values are expressed in 2005 Euros per metric ton of CO_2 of 60 and 100 Euros respectively.

[143] *Vattenfalls Global Climate Impact Abatement Map* http://www.vattenfall.com/climatemap/ accessed May 30, 2009.

The IPCC (2007, 29 (references omitted)) suggested that an effective carbon-price signal could realize significant mitigation potential in all sectors.

Modeling studies show carbon prices (2009 dollars) rising to $19 to $78 US$/short tCO_2-eq by 2030 and $29 to $151 US$/short tCO_2-eq by 2050 are consistent with stabilization at around 550 ppm CO_2-eq by 2100. For the same stabilization level, studies since the Third Assessment Report that take into account induced technological change lower these price ranges to $5 to $63 US$/short tCO_2eq in 2030 and $15 to $126 US$/short tCO_2-eq in 2050.

- Most top-down, as well as some 2050 bottom-up assessments, suggest that real or implicit carbon prices of $19 to $49 US$/short tCO_2-eq, sustained or increased over decades, could lead to a power generation sector with low-greenhouse gas emissions by 2050 and make many mitigation options in the end-use sectors economically attractive.

Exhibit 6-55 Summary Table of Studies

Study Source	Study	Analysis End Year	Scenario	Value	Units	Value (2009$/short ton CO_2)
McKinsey & Company	Version 2 of the Global Greenhouse Gas Abatement Cost Curve	2030	Global Action	€ 60.00	2005 Euro/metric ton CO_2	$74.87
		2030	Greenworld	€ 100.00	2005 Euro/metric ton CO_2	$124.78
Internation Energy Agency	World Energy Outlook 2008	2030	550 ppm	$90.00	$2007/metric ton CO_2	$85.07
		2030	450 ppm	$180.00	$2007/metric ton CO_2	$170.14
Internation Energy Agency	Energy Technology Perspective 2008	2050	ACT Map	$50.00	$2005/metric ton CO_2	$50.10
		2050	Blue Map	$200.00	$2005/metric ton CO_2	$200.38
			Average			$117.56

Notes

2005 Euros converted to 2005 US dollars based on average exchange rate of 1:1.245 Euro to Dollars from www.oanda.com
2007$ converted to 2009$ based on common assumptions
One metric ton equals 1.102 short tons

Based on a review of these different sources, we believe that it is reasonable to use an estimated long-term marginal abatement cost (LT MAC) of $80/short tCO_2-eq in evaluating the cost-effectiveness of energy efficiency measures. This value is comfortably within the range of current estimates of the long run marginal abatement costs for achieving a stabilization target that is likely to avoid temperature increases higher than 2^oC above pre-industrial levels.

We recommend that the estimated long-run marginal abatement cost be used as a practical and reasonable measure of the societal cost of carbon dioxide emissions. This can be applied to carbon dioxide emissions reductions in order to quantify their “full value.” A portion of this value will be reflected in the allowance price for emissions, the balance may be referred to as an externality. Clearly, some estimates are lower, and some estimates are much higher, reflecting a variety of effects including assumptions about technological innovation, emission reduction targets, technical potential of certain technologies, international and national policy initiatives, and the list goes on. Of course, selection of this value requires multiple assumptions and cannot be definitive given the quickly evolving combination of scientific understanding of the causes, effects and scale of climate change, international policy initiatives, and technological advances. It will be necessary to continuously review available information, and determine what value is reasonable given information available at the time of reviews.

6.7.5. Estimating CO_2 Environmental Costs for New England

Our estimates of the “external” or additional cost associated with emissions of carbon dioxide in New England are based upon the sustainability target and the forecast of carbon emission regulation in New England over the study period. The externality value for carbon dioxide in each year was calculated as the estimated long term marginal abatement cost of $80/short ton minus the annual allowance values internalized in the projected electric energy market prices. For AESC 2009, we repeat this calculation process for the RGGI only scenario. These values are summarized in Exhibit 6-56.

Exhibit 6-56 CO_2 Externality Calculations

	LT MAC ($/short ton)	2009 AESC Reference Allowance Price ($/short ton)	2009 AESC Reference Externality ($/short ton)	RGGI Only Scenario Allowance Price ($/short ton)	RGGI Only Scenario Externality ($/short ton)
	a	b	c=a-b	d	e=a-d
2009	$80	$3.85	***$76.15***	$3.85	***$76.15***
2010	$80	$3.91	***$76.09***	$3.91	***$76.09***
2011	$80	$4.02	***$75.98***	$4.02	***$75.98***
2012	$80	$4.00	***$76.00***	$4.00	***$76.00***
2013	$80	$15.63	***$64.37***	$4.00	***$76.00***
2014	$80	$18.03	***$61.97***	$4.00	***$76.00***
2015	$80	$20.32	***$59.68***	$4.00	***$76.00***
2016	$80	$22.72	***$57.28***	$4.00	***$76.00***
2017	$80	$25.01	***$54.99***	$4.00	***$76.00***
2018	$80	$27.41	***$52.59***	$4.00	***$76.00***
2019	$80	$29.70	***$50.30***	$4.00	***$76.00***
2020	$80	$32.10	***$47.90***	$4.00	***$76.00***
2021	$80	$34.49	$45.51	$4.00	***$76.00***
2022	$80	$36.79	$43.21	$4.00	***$76.00***
2023	$80	$39.18	$40.82	$4.00	***$76.00***
2024	$80	$41.48	$38.52	$4.00	***$76.00***

Notes

Values expressed in 2009 Dollars

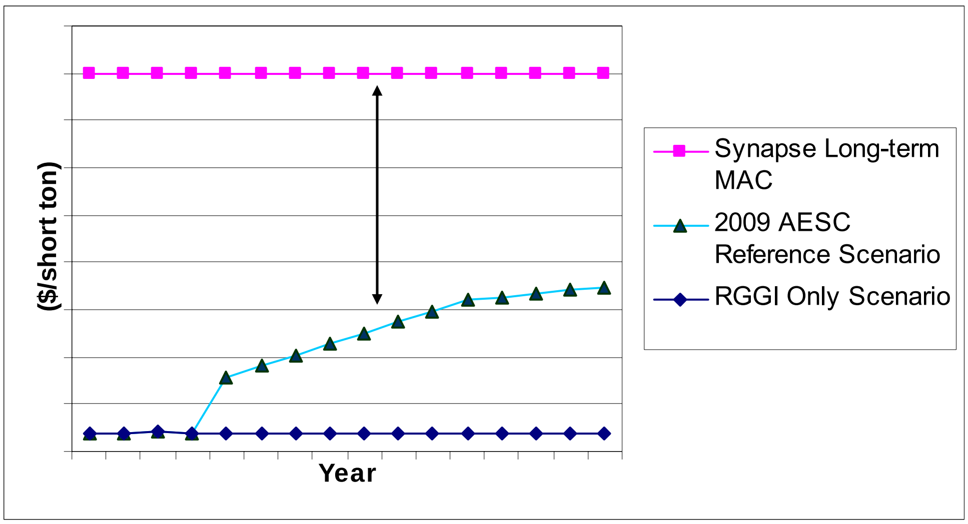
Allowance Prices from Exhibit 2-4

Inflation rate of 2%

The annual allowance values internalized in the projected electric energy market prices are shown in Exhibit 2-4. These values are based upon a Synapse (Synapse 2008) forecast of the carbon trading price associated with anticipated carbon regulations. That carbon price was included in the dispatch model runs (in the generators' bids) and hence is embedded within the AESC 2009 avoided electricity costs. The additional value in each year is the difference between the estimate of long run marginal abatement cost ($80/ton CO_2) and the value of the carbon trading price embedded in the projection of wholesale electric energy prices.

Exhibit 6-57 illustrates how the additional CO_2 cost was determined. The line for the allowance price is based on the forecast of carbon allowance costs, illustrating the notion that the United States will gradually move to incorporate the climate externality into policy. The "externality" is simply the difference between the estimate of the long-term marginal abatement cost (LT MAC) and the anticipated allowance cost; that is, the area above the line with triangles and below $80/ton in the graph (shown between the double arrowed vertical line).

Exhibit 6-57: Determination of the Additional Cost of CO2 Emissions



The carbon dioxide externality price forecast is presented above as a single simple price. This is for ease of application and because doing something more complex such as varying the shape over time or developing a distribution to represent uncertainty would go beyond the scope of this project and would stretch the available information upon which the externality price is based. We fully acknowledge the many complexities involved in estimating a carbon price, both conceptual and practical.

With regard to environmental costs, AESC 2009 focuses on the externality value of carbon dioxide for the purpose of screening DSM programs. There are of course many impacts of electric power production. A number of those impacts are listed above in Chapter 2. However, the bulk of displaced generation in New England will be from existing and future natural gas plants. For these, CO_2 emissions are the dominant non-internalized environmental cost.

6.7.6. Applying CO_2 Costs in Evaluations of DSM Programs

The externality values from Exhibit 6-56 above will be incorporated in the avoided electricity cost workbooks. They will be expressed as dollar per kWh based upon our analysis of the CO_2 emissions of the marginal generating units in each year of the study period.

At a minimum program administrators should calculate the costs and benefits of DSM programs without, and then with, these values in order to assess their incremental impact on the cost-effectiveness of programs. However, we recommend the program administrators include these values in their analyses of DSM, unless specifically prohibited from doing so by state or local law or regulation. The next section explains why a DSM program could result in CO_2 emission reductions even under a cap and trade regulatory framework.

6.7.7. Impact of DSM on Carbon Emissions Under a Cap and Trade Regulatory Framework

The Regional Greenhouse Gas Initiative is a cap and trade greenhouse gas program for power plants in the northeastern United States. Participant states include Connecticut, Delaware, Maine, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, Vermont, and Maryland. Pennsylvania, the District of Columbia, the Eastern Canadian Provinces, and New Brunswick are official "observers" in the RGGI process. Two rounds of auctions have currently occurred.

As currently designed, the program will:

- stabilize CO_2 emissions from power plants at current levels for the period 2009-2015, followed by a 10% reduction below current levels by 2019;
- allocate a minimum of 25% of allowances for consumer benefit and strategic energy purposes. Allowances allocated for consumer benefit will be auctioned and the proceeds of the auction used for consumer benefit and strategic energy purposes; and
- include certain offset provisions that increase flexibility to include opportunities outside the capped electricity generation sector.

With carbon dioxide emissions regulated under a cap and trade system, as assumed in this market price analysis, it is conceivable that a load reduction from a DSM program will not lead to a reduction in the amount of total system carbon dioxide emissions. The annual total system emissions for the affected facilities in the relevant region are, after all, capped. In the analysis that was documented in this report, the relevant cap and trade regulation is the Regional Greenhouse Gas Initiative (RGGI) for the period 2009 to 2012 and the assumed national cap and trade system thereafter. However, there are a number of reasons why a DSM program could result in CO_2 emission reductions, specifically:

- Reduction in load that reduces the cost (marginal or total cost) of achieving an emissions cap can result in a tightening of the cap. This is a complex interaction between the energy system and political and economic systems, and is difficult or impossible to model, but the dynamic may reasonably be assumed to exist;
- Specific provisions in RGGI provide for a tightening or loosening of the cap (via adjustments to the offset provisions that are triggered at different price levels). It is unknown at this point whether and to what extent such "automatic" adjustments might be built into the US carbon regulatory system;
- It is also possible that DSM efforts will be accompanied by specific retirements or allocations of allowances that would cause them to have an impact on the overall system level of emissions (effectively tightening the cap); and
- To the extent that the cap and trade system "leaks" because of its geographic boundaries, one would expect the benefits of a carbon emissions reduction resulting from a DSM program to similarly "leak." That is, a load reduction in New York could cause reductions in generation (and emissions) at power plants in New York, Pennsylvania, and elsewhere. Because New York is in the RGGI cap and trade system, the emissions reductions realized at New York generating units may pop up as a result of increased sales of allowances from NY to other RGGI states. But because Pennsylvania is not in the RGGI system, the emissions reductions at Pennsylvania generating units would be true reductions attributable to the DSM program.
    - The first three of these points, above, would also apply to a national CO_2 cap and trade program. The fourth point, about leakage and boundaries, would apply as well, but to a lesser extent.

Chapter 7: Sensitivity Scenarios

In general, the reasons to analyze sensitivity cases are to understand the potential impacts of changes in key uncertain input assumptions and to increase the shelf life (or period of usability) of the report given changing markets and forecasts over time. The latter reason is particularly relevant to AESC 2009, which will not be revised for two years. Market developments between the time this report is distributed and the time these estimates are next updated can lead to questions about the robustness and validity of the analysis.

With this in mind, we have prepared sensitivity analyses for changes in natural-gas and carbon-allowance prices. We have prepared analyses for changes in those input assumptions because of their volatile and uncertain nature and their large and direct impact on avoided electric-energy costs.

Those analyses reach the following two conclusions:

- The annual average wholesale price of electric energy in New England would be approximately 14% higher than our Reference Case forecast were Henry Hub prices 20% higher than the Reference Case.
- The annual average wholesale price of electric energy in New England would change by \$0.46/MWh relative to the Reference Case forecast for every dollar-per-ton change in the allowance price for CO_2 relative to the Reference Case.

7.1.1. Sensitivity of Wholesale Electric Energy Prices to Changes in Natural Gas Prices at Henry Hub

As documented in previous chapters, natural-gas prices have a large, direct impact on the avoided electric-energy costs.

AESC 2009 tested the sensitivity of wholesale electric energy prices to a relatively wide range of possible changes in natural gas prices in light of the uncertainty in long-run forecasts of gas prices and to allow users of the report to estimate the impacts of other assumed changes via interpolation. To choose this range we first examined the high- and low-natural-gas-prices cases EIA (2009a). These are presented in Exhibit 3-11 (page 3-19). Our assessment is that for sensitivity-analysis purposes the EIA high and low cases are too narrow (less than about 10 percent, varying by year).

Thus, our analyses test sensitivity for changes in long-term Henry Hub gas prices of plus and minus 20 percent of those used in the Reference Case. Because of transportation costs, that change in Henry Hub prices translates into an impact of plus or minus 18.4% on the prices of natural gas delivered to electric generation units in New England, i.e. burner-tip prices.

The Reference Case Henry Hub natural-gas-price assumption and our low and high sensitivity assumptions are shown in Exhibit 7-1. For the modeling we just replaced the reference case Henry Hub natural gas prices with those indicated below. This then affected the delivered prices of natural gas in New England and the other modeled neighboring regions.

Exhibit 7-1: Henry Hub Reference and Sensitivity Case Prices

Henry Hub Natural Gas Prices (2009$/mmBtu)			
	Low	**Reference**	**High**
2010	$4.56	$5.70	$6.84
2011	5.03	6.29	7.55
2012	5.52	6.90	8.28
2013	5.52	6.90	8.28
2014	5.58	6.97	8.37
2015	5.64	7.05	8.46
2016	5.73	7.17	8.60
2017	5.87	7.33	8.80
2018	6.03	7.54	9.04
2019	6.18	7.73	9.27
2020	6.07	7.59	9.11
2021	5.90	7.38	8.85
2022	5.96	7.45	8.94
2023	6.05	7.56	9.07
2024	6.35	7.94	9.52

The 20-percent variation is not intended to represent short run (e.g., weekly, monthly, or even annual) price volatility, but rather to provide a sufficiently wide range to represent uncertainty in the long-run prices. Our expectation is that any revised forecasts of long-term Henry Hub gas prices made prior to the 2011 revision of this report would fall within this band, allowing users to estimate revised avoided electric energy costs by interpolation.

Exhibit 7-2 below shows the effects on the New England electricity wholesale price of a 20% change in the Henry Hub prices. For example, a 20% reduction in the Henry Hub 2014 natural-gas price is associated with a 15.1% reduction in the all-hours electricity price. A 20% increase for the same year would produce a 13.8% electricity price increase. Note that the positive and negative effects are quite symmetrical, but with the low side impacts slightly greater. The results are also fairly consistent from year to year, but with a slight decline over time.

Exhibit 7-2: New England Energy Price Impacts of 20% Henry Hub Price Changes

Energy Price Impacts of 20% Henry Hub Natural Gas Price Changes		
Year	**Low NG**	**High NG**
2010	-15.9%	16.0%
2011	-15.6%	15.3%
2012	-16.7%	15.6%
2013	-15.7%	13.8%
2014	-15.1%	13.8%
2015	-14.9%	14.1%
2016	-14.3%	14.0%
2017	-14.6%	13.0%
2018	-14.3%	13.2%
2019	-14.4%	14.1%
2020	-14.3%	13.1%
2021	-13.7%	13.8%
2022	-14.0%	13.2%
2023	-14.4%	13.9%
2024	-14.2%	14.2%
Average	**-14.8%**	**14.1%**

Exhibit 7-3 breaks out the impacts by season and time period. Again the relative impacts are very much the same between these categories. The only noticeable difference is that the winter off-peak price shows overall the least impact.

Exhibit 7-3: Seasonal and Time Period Impacts of 20% Henry Hub Price Changes

Seasonal and Time Period Impacts of Changes to Henry Hub Price			
Season	**Time of Day**	**Low Natural Gas Price**	**High Natural Gas Price**
Winter	Off-Peak	-14.7%	13.3%
	On-Peak	-14.9%	14.4%
	All-Hours	-14.8%	13.9%
Summer	Off-Peak	-14.8%	14.2%
	On-Peak	-14.7%	14.5%
	All-Hours	-14.7%	14.4%

7.1.2. Sensitivity of Wholesale Electric-Energy Prices to Changes in Carbon-Dioxide-Allowance Prices

We tested the sensitivity of wholesale electric-energy prices to a range of possible changes in carbon-allowance prices in light of the uncertainty in long-run forecasts of those allowances. Again, one goal is to allow users of the report to estimate the impacts of other assumed changes via interpolation.

For the low case we used the "RGGI only" set of carbon dioxide allowance prices required under the scope of work. It provides a lower bound of CO_2 allowance prices for sensitivity analysis purposes. We also present a "high CO_2 allowance price scenario" developed by Schlissel et al. (2008). As with the range of natural gas prices used in our sensitivity analyses, this range of CO_2 prices is not intended to represent near term volatility in CO_2 allowance prices, but rather to represent a reasonable range of trends in long-run prices.

The assumed values for carbon allowance prices are presented in Exhibit 7-4. For the modeling we just replaced the reference case CO_2 prices with those indicated below. This was then applied to New England and the other modeled regions.

Exhibit 7-4: Carbon Dioxide Reference and Sensitivity Case Prices

Carbon Dioxide Price Sensitivity Scenarios			
Year	Synapse Reference Case (2009$)	RGGI Only Case (2009$)	High CO_2 Allowance Price Scenario (2009$)
2009	$3.85	$3.85	$3.85
2010	$3.91	$3.91	$3.91
2011	$4.02	$4.02	$4.02
2012	$4.00	$4.00	$4.00
2013	$15.63	$4.00	$31.26
2014	$18.03	$4.00	$33.66
2015	$20.32	$4.00	$35.95
2016	$22.72	$4.00	$37.31
2017	$25.01	$4.00	$40.64
2018	$27.41	$4.00	$43.04
2019	$29.70	$4.00	$45.33
2020	$32.10	$4.00	$47.73
2021	$34.49	$4.00	$50.13
2022	$36.79	$4.00	$52.42
2023	$39.18	$4.00	$54.82
2024	$41.48	$4.00	$57.11
Source: Schlissel et al. (2008). Values converted from 2007 dollars to 2009 dollars.			

Exhibit 7-5 shows the annual CO_2 price differences relative to the Reference case and their impacts on the average annual wholesale energy prices.

Exhibit 7-5: Energy Price Impacts of CO_2 Price Changes

	Low CO_2 Price		High CO_2 Price	
Year	CO_2 Price Change ($/ton)	Energy Price Change ($/MWh)	CO_2 Price Change ($/ton)	Energy Price Change ($/MWh)
2010	0.0	0.0	0.0	0.0
2011	0.0	0.0	0.0	0.0
2012	0.0	0.0	0.0	0.0
2013	-11.4	-6.0	15.3	6.5
2014	-13.8	-6.9	15.3	7.2
2015	-16.0	-7.9	15.3	6.9
2016	-18.4	-8.6	15.3	6.9
2017	-20.6	-10.2	15.4	6.6
2018	-23.0	-11.3	15.3	6.5
2019	-25.2	-12.2	15.4	6.5
2020	-27.6	-13.6	15.3	6.4

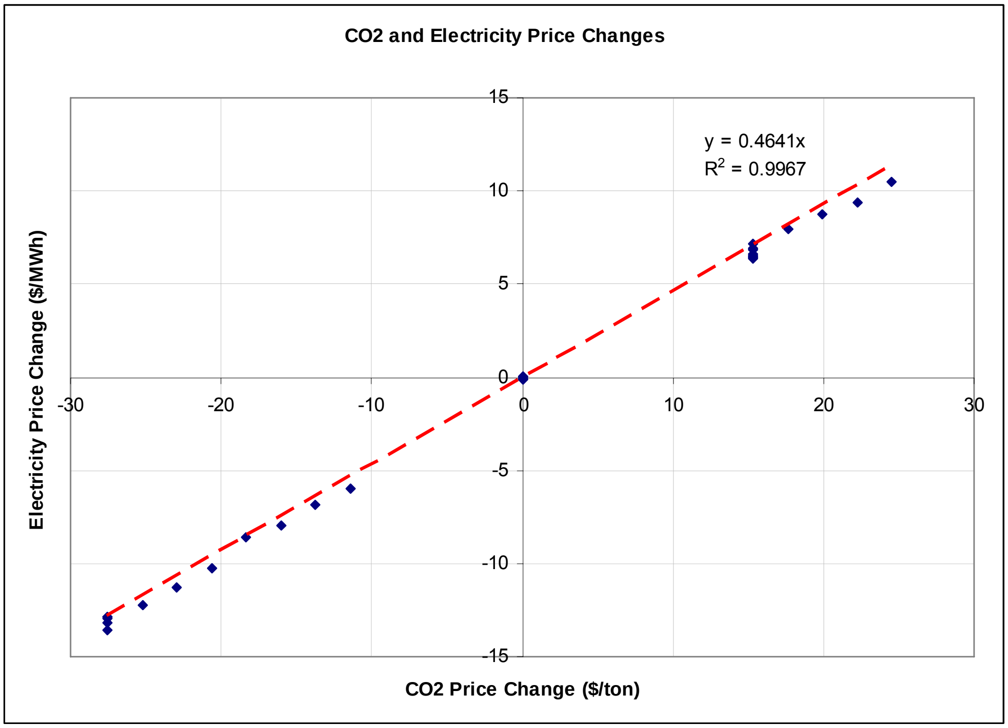
Unlike the high- and low-natural-gas-price sensitivity cases, the CO_2 prices for the RGGI-only and the High-CO_2-allowance sensitivity cases presented in Exhibit 7-5 do not show a consistent change relative to reference-case prices each year. Therefore, we analyzed the change in the annual wholesale electric-energy price resulting from changes in the annual CO_2 allowance prices on a year by year absolute basis.

Exhibit 7-6 below shows a plot and a regression of the relationship between change in the annual wholesale electric energy price and changes in annual CO_2 allowance prices. That relationship shows an excellent linear fit (R^2=0.9967) over a range of CO_2 price changes of ±$25/ton. That relationship can be expressed as:

$$\text{Electricity Price Change} = 0.4641 \times CO_2 \text{ Price Change.}$$

This equation means that for every dollar-per-ton change in the price of $CO_{2,}$ measured relative to the Reference Case, the wholesale electric energy price will change by $0.46/MWh, measured relative to the Reference Case. These results are equivalent to the wholesale electric price being set, on average, by a natural-gas plant with an average heat rate of about 8,000 Btu/kWh.

Exhibit 7-6: CO_2 and Electric Price Sensitivities



Chapter 8: Usage Instructions: Avoided Costs of Electricity

8.1. Introduction

The tables of avoided electricity costs are presented in Appendix B. There is a table for each New England state as well as for specific regions within Connecticut and Massachusetts.

The Connecticut regions with their own tables are as follows:

- Norwalk/Stamford
- Southwest Connecticut, including Norwalk/Stamford
- Southwest Connecticut, excluding Norwalk/Stamford
- Connecticut excluding all of Southwest Connecticut

The Massachusetts regions with their own tables are as follows:

- Statewide
- SEMA (Southeast Massachusetts)
- WCMA (West-Central Massachusetts)
- NEMA (Northeast Massachusetts)
- Massachusetts excluding NEMA

Each table has also been provided to Study Group members electronically in Excel format.

Each table provides values for avoided electric energy costs, avoided capacity costs, energy and capacity DRIPE and carbon externalities for each year from 2010 to 2039. All values are reported in 2009 dollars. Users have the ability to choose which of these avoided costs to include in their analyses.

Each table provides illustrative levelized values for each category of avoided cost at the bottom of each cost column. These are computed using a real discount rate of 2.22%.

The tables present value for costing periods as defined by ISO-NE. These costing periods are as follows:

- Summer Peak The 16-hour block 6am–10pm (the hours ended 700 through 2200), Monday–Friday (except ISO holidays), in the months of June–September.[144]
- Summer Off-Peak All other hours–10pm–6am (the hours ended 2300 through 600), Monday–Friday, all day on Saturday and Sunday, and ISO holidays in the months of June–September.
- Winter Peak The 16-hour block 6am–10pm (the hours ended 700 through 2200), Monday–Friday (except ISO holidays), in the months of January–May and October–December.
- Winter Off-peak All other hours–10pm—6am (the hours ended 2300 through 600), Monday–Friday, all day on Saturday and Sunday, and ISO holidays–in the months of January–May and October–December.

The development of the various inputs used to calculate those avoided costs is described in Chapters Two and Six. The projections of avoided wholesale electric energy costs, avoided wholesale electric capacity costs and REC costs are presented in summary tables in Appendix C.

8.2. Guide to Applying the Avoided Costs

8.2.1. User-Specified Inputs

The workbook is designed to allow Program Administrators to specify values for the wholesale risk premium and the real discount rate. The user-defined values for these inputs are provided at the top of each worksheet and linked to the avoided cost calculations for that worksheet. If a user wishes to specify a different value for either of those inputs the value should be entered directly within the worksheet.

Program administrators are responsible for developing and applying estimates of avoided transmission and distribution costs for their specific system.

8.2.2. Wholesale Capacity Costs Avoided by Reductions in Peak Demand

The benefit of a reduction in peak demand, excluding capacity DRIPE, in a given year will depend upon the approach the PA has taken and/or will take towards bidding the reduction in demand from the efficiency program in that year into the applicable FCAs. As discussed in Sections 2.2 and 6.2, a PA may achieve avoided capacity costs from reductions in peak demand through a range of approaches.

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[144] ISO-NE holidays are New Year's Day, Memorial Day, July 4th, Labor Day, Thanksgiving Day, and Christmas.

These approaches range from bidding 100% of the anticipated demand reduction for one year from a program into the relevant Forward Capacity auction for the first power year in which the reduction will occur to not bidding any reduction into any FCA in advance of the first program year. (Recall that an FCA for a given power year is held up to three years in advance of that power year, and that a PA who elects to bid a reduction into a FCA will incur a financial penalty if it fails to achieve that reduction)

Following are descriptions of how a PA can calculate the avoided cost of reductions in peak demand for each extreme in that range of approaches.

8.2.2.1. Bid full demand reduction from first program year into the first relevant FCA

A PA will obtain the highest benefit, and some associated financial risk[145], for the reductions in peak demand from an energy efficiency program by bidding the full anticipated reduction into the FCA for the first power year in which that program would produce reductions. Thus, a PA responsible for an efficiency program that is expected to start January 2010 would have had to have bid 100% of the anticipated reduction in demand from that program into FCA 1, which was held in 2008.

In order to bid a demand reduction into a FCA, ISO-NE procedures require a PA to

- Estimated the anticipated demand reduction at the customer meter[146],
- ISO-NE designates the demand reduction as either an On Peak resource or a Seasonal Peak resource. A reduction from an On-Peak resource is the average MW reduction during Demand Resource On-Peak Hours which are June, July, and August from 1pm to 5pm (4 hours) and December and January from 5pm to 7pm (2 hours). A reduction from a Seasonal Peak resource is defined as the average MW reduction during all Demand Resource Seasonal Peak Hours which are hours where actual peak load is at least 90% of the most recent 50/50 peak load forecast for that season (summer or winter).

[145]Bidding anticipated reductions from a program that has not been approved into a FCA three years in advance of the power year incurs several major risks including program rejection by regulator, program failure to perform as expected and changes to ISO-NE rules

[146] Note that ISO-NE automatically increases that reduction by 8% as a standard allowance for losses between the ISO-NE delivery points and end use (i.e. PTF plus local T&D),

The benefit of a reduction in peak demand from either an On-Peak or a Seasonal Peak resource in a given year starting 2010 is estimated as the result of:

Average MW reduction at the meter for the relevant period in a given year

× the *Annual Market Capacity Value* for that year

In this situation, the *Annual Market Capacity Value* avoided cost is calculated as the market-clearing price in the forward capacity market, increased by the required reserve margin for only FCA 1 & 2 and an ISO-NE loss factor of 8%.

If the benefits of demand reductions are to include capacity DRIPE, the benefits calculated above should be increased by the estimate of capacity DRIPE allowed under the regulatory framework applicable to that screening zone as follows:

Average MW reduction at the meter bid into FCA for given year

× capacity DRIPE for that year

8.2.2.2. Bid no demand reduction into any FCA

A PA will obtain the lowest benefit, with no financial risk, for the reductions in peak demand from an energy efficiency program if it does not bid any of the reduction into any FCA.

The annual capacity requirement for load is generally determined by the load's contribution to the system coincident peak, which occurs on a summer weekday, usually in the months of July and August, in the hours ending 1500–1700.[147]

For an efficiency program that produces reductions starting in 2010, there is no benefit of a reduction in peak demand until 2014, at which point the annual benefit is calculated as follows:

MW reduction at the meter during system peak in a given year

× summer peak-hour losses from the ISO delivery points to the end use
× the *Annual Market Capacity Value* for that year

The *Annual Market Capacity Value* for a kW reduction that reduces the peak load ISO-NE forecasts to be served in a year is the FCA price for that year adjusted

[147] In the last ten years, the coincident peak has occurred outside these hours only twice, at hour ending 1300 in late June and at hour ending 1400 in July.

upward by the reserve margin that ISO-NE requires for that year, by the PTF losses, and the wholesale risk premium.

If the benefits of demand reductions are to include capacity DRIPE, the benefits calculated above should be increased by the estimate of capacity DRIPE allowed under the regulatory framework applicable to that screening zone as follows:

MW reduction at the meter during system peak in a given year

× summer peak-hour losses from the ISO delivery points to the end use
× capacity DRIPE for that year

8.2.3. Local T&D Capacity Costs Avoided by Reductions in Peak Demand

If the benefits of peak demand reductions are to include avoided local transmission and distribution costs, the benefits calculated above should be increased as follows:

Reduction in the peak demand used in estimating avoided transmission and distribution costs at the end use

× the utility-specific estimate of avoided T&D costs in $/kW-year.[148]

8.2.4. Costs avoided by reductions in energy

The benefits of energy reductions, excluding energy DRIPE and carbon externalities, in a given year should be estimated as follows:

1. reduction in winter peak energy at the end use
   × winter peak energy losses from the ISO delivery points to the end use[149]
   × the *Winter Peak Energy* value for that year;

2. reduction in winter off-peak energy at the end use
   × winter off-peak energy losses from the ISO delivery points to the end use
   × the *Winter Off-Peak Energy* value for that year;

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[148]Most demand-response and load-management programs will not avoid transmission and distribution costs, since they are as likely to shift local loads to new hours as to reduce local peak load.

[149]Each set of losses should be computed by the Program Administrator for its specific system. The loss factors relevant throughout this list should be (power at ISO delivery) ÷ (power at the end use), and will be between 1.00 and 1.20. For some utilities, losses are reported separately as percentage losses (a) from ISO delivery to the distribution substation, and (b) from the substation to the customer; the overall loss factor can be computed as [1 + (a)] × [1 + (b)].

3. reduction in summer peak energy at the end use
× summer peak energy losses from the ISO delivery points to the end use
× the *Summer Peak Energy* value for that year;

4. reduction in summer off-peak energy at the end use
× summer peak off-energy losses from the ISO delivery points to the end use
× the *Summer Off-Peak Energy* value for that year

If the benefits of energy reductions are to include energy DRIPE, the benefits calculated in items 1 to 4 should be increased by the estimate of energy DRIPE allowed under the regulatory framework applicable to that screening zone as follows:

1. reduction in annual winter peak energy at the end use
× winter peak energy losses from ISO delivery to the end use
× the DRIPE Winter Peak Energy;

2. reduction in annual winter off-peak energy at the end use
× winter off-peak energy losses from ISO delivery to the end use
× the DRIPE Winter Off-Peak Energy;

3. reduction in annual summer peak energy at the end use
× summer peak energy losses from ISO delivery to the end use
× the DRIPE Summer Peak Energy;

4. reduction in annual summer off-peak energy at the end use
× summer off-peak energy losses from ISO delivery to the end use
× the DRIPE Summer Off-Peak Energy;

If the benefits of energy reductions are to include carbon externalities, the avoided costs should be increased as follows:[150]

1. reduction in winter peak energy at the end use
× winter peak energy losses from the ISO delivery points to the end use
× the *CO_2 Externality Winter Peak Energy* value for that year,

2. reduction in winter off-peak energy at the end use
× winter off-peak energy losses from the ISO delivery points to the end use
× the *CO_2 Externality Winter Off-Peak Energy* value for that year,

3. reduction in summer peak energy at the end use
× summer peak energy losses from the ISO delivery points to the end use
× the *CO_2 Externality Summer Peak Energy* value for that year,

[150]One could also make an adjustment for losses from the generator to the PTF, but that is likely more precision than is warranted by the externality value itself.

4. reduction in summer off-peak energy at the end use
× summer off-peak energy losses from the ISO delivery points to the end use
× the *CO_2 Externality Summer Off-Peak Energy* value for that year,

8.3. Worksheet Structure and Terminology

- *Table One—Avoided Cost of Electricity Results*

Each table of avoided electricity costs, and corresponding worksheet, follows the same structure as shown in Appendix B. Reading from left to right of a worksheet, the structure is as follows:

8.3.1.1. Avoided Cost of Electricity: Energy $/kWh (Columns A through D)

The avoided energy costs are computed for the aggregate load shape in each zone by costing period, and are applicable to DSM programs reducing load roughly in proportion to existing load. Other resources, such as load management and distributed generation, may have very different load shapes and significantly different avoided energy costs. Baseload resources, such as combined-heat-and-power (CHP) systems, would tend to have lower avoided costs per kWh. Peaking resources, such as most non-CHP distributed generation and load management, would tend to have higher avoided costs per kWh.

Avoided energy costs are presented by year for the four energy costing periods–Winter Peak, Winter Off-Peak, Summer Peak, and Summer Off-Peak. The generalized avoided energy cost in each period is calculated as (modeled avoided wholesale energy cost + renewable energy certificate cost) * (1 + wholesale risk premium).

8.3.1.2. Avoided Cost of Electricity: Capacity, in $/kW-yr (Columns E and F)

The avoided electric capacity costs reported in columns e and f are for demand reductions bid into an FCA and for avoided capacity purchases from an FCA respectively. They differ basically in their adjustment for line losses to the ISO delivery points.

- The *Annual Market Capacity Value* in column e for demand reductions bid into an FCA reflect an 8% adjustment to reflect losses from the customer meter to the ISO-NE delivery point and for power years 2010-2011 and 2011-2012, an adjustment for reserve margins.
- The *Annual Market Capacity Value* in column f for avoided capacity purchases from an FCA reflects upward adjustments for the wholesale risk premium, the reserve margin in that year, and also an 1.9% adjustment to reflect PTF losses.

8.3.1.3. Demand-Reduction-Induced Price Effects (DRIPE) (Columns G through P)

Separate projections of energy DRIPE and capacity DRIPE are provided for measures implemented in 2010 and in 2011 respectively. The values reported reflect the relevant state regulations governing treatment of DRIPE in the screening zone. For Massachusetts and Connecticut zones, the values are intrastate values while for Maine, Vermont, Rhode Island and New Hampshire they are total values (intrastate plus rest of pool). It is recommended that these values be included in estimation of efficiency program benefits unless specifically excluded by state or local law or regulation.

8.3.1.4. Carbon Dioxide Avoided Externality Costs $/kWh (Columns Q through T)

This section of the worksheet provides estimates of CO_2 externality values developed for this Study (values for RI are from the RGGI only scenario). CO_2 externality values are presented by year for each of the four energy costing periods. As with the DRIPE values, it is recommended that these be included in analyses of DSM, unless specifically excluded by state or local law or regulation.

- *Table Two- Inputs to Avoided Cost Calculations*

(b) Wholesale Zonal Avoided Costs of Electricity (Columns U through Y)

Energy dollars per kWh (Columns U through X)

The wholesale electric energy prices are from the Market Analytics simulation runs described in Section 6.3.1 (values for RI are from the RGGI only scenario). Users should not normally need to use the input values directly, or to modify these values.

8.3.1.5. Capacity costs dollars per kWh–year (Column Y and Z)

The wholesale electric capacity prices and reserve margin requirements are from the Exhibit 6-5. Users should not normally need to use the input values directly, or to modify these values.

8.3.1.6. Avoided REC Costs to Load $/kWh (Column AA)

The REC prices are described in detail in Appendix C. Users should not normally need to use the input values directly, or to modify these values.

8.4. Levelization Calculations

Real-levelized costs for each of the direct avoided costs along the bottom of each worksheet. These values are calculated for three periods (2010-2019, 2010-24, and 2010-39), using a 2.22% real discount rate and a 2.0% inflation rate assumed throughout this project.

For levelization calculations outside the three periods documented in the workbook, the following inputs are required:

- The real discount rate of 2.22% or other user specified discount rate
- The number or periods over the levelizing time frame. For instance, the period 2010-2014 contains 5 periods
- The avoided costs within the levelizing period

The Excel formula used to calculate levelized values in the workbook is:

$$\text{Present Value} = -PMT(Discount\_Rate, Period, (NPV(Discount\_Rate, Annual\_\cos ts\_within\_period)$$

8.5. Converting Constant 2009 Dollars to Nominal Dollars

Unless specifically noted, all dollar values in AESC 2009 are presented in 2009 constant dollars. To convert constant dollars into nominal (current) dollars by the formula:

$$\text{Nominal Value} = \frac{\text{Constant Value}_{2009\$}}{\textit{Conversion Factor to } 2009\$}$$

For instance, in 2010; what would be the current value of $1 from the AESC values that are expressed in 2009 dollars. Using the conversion factors detailed in Appendix C, the AESC conversion factor from 2009 to 2010 is 0.98. Inserting the conversion factor into the equation above (Nominal Value = ($1/0.98)) results in a value of $1.02 in 2010 nominal dollars.

8.6. Utility-Specific Costs to be Added/Considered by Program Administrators Not Included in Worksheets

This section details additional inputs that are not specifically included in the worksheet, but should be considered by program administrators.

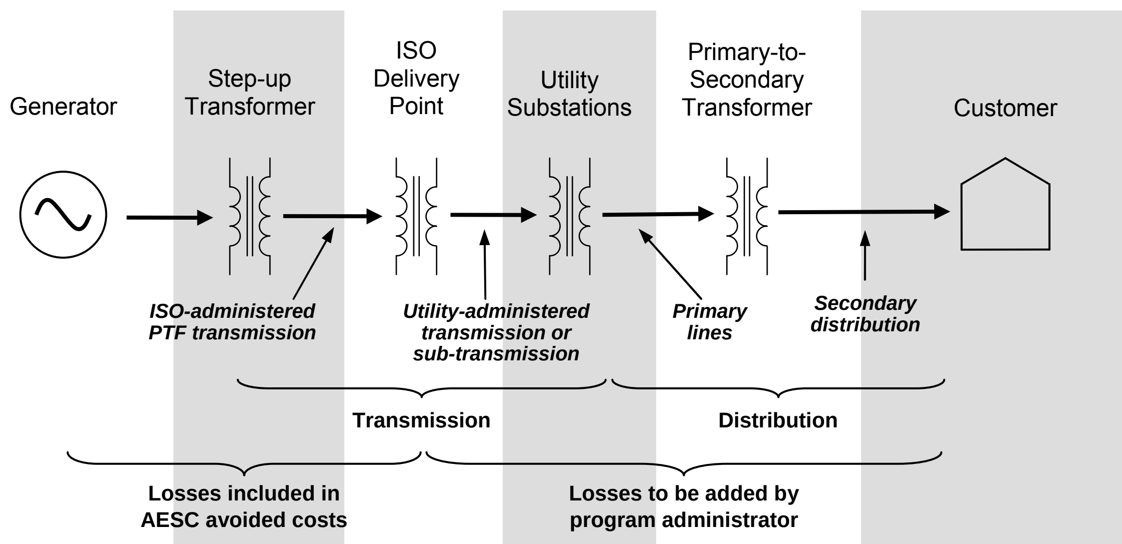
- *Losses from the ISO Delivery Point to the End Use*

The avoided energy and capacity costs, and the estimates of DRIPE, include energy and capacity losses on the ISO-administered pool transmission facilities (PTF), from the generator to the delivery points at which the PFT system connects to local non-PTF transmission or to distribution substations. The exhibits *do not* include the following losses:

- Losses over the non-PTF transmission substations and lines to distribution substations;
- Losses in distribution substations,
- Losses from the distribution substations to the line transformers on primary feeders and laterals,[151]
- Losses from the line transformers over the secondary lines and services to the customer meter,[152]
- Losses from the customer meter to the end use.

See Exhibit 8-1, taken from Exhibit 2-14 and described in Chapter 2 schematically illustrates the many types of losses on transmission and distribution systems highlighted in the list above.

Exhibit 8-1: Delivery-System Structure and Losses



Reproduced from taken from Exhibit 2-14 and described in Chapter 2

In most cases, DSM program administrators measure demand savings from DSM programs at the end use. To be more comprehensive, the program administrator

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[151]In some cases, this may involve multiple stages of transformers and distribution, as (for example) power is transformed from 115kV transmission to 34kV primary distribution and then to 14 kV primary distribution and then to 4 kV primary distribution, to which the line transformer is connected.

[152]Some customers receive their power from the utility at primary voltage. Since virtually all electricity is used at secondary voltages, these customers generally have line transformers on the customer side of the meter and secondary distribution within the customer facility.

should estimate the losses from delivery points to the end uses. For example, if the energy delivered to the utility at the PTF is *a*, losses are *b*, and the customer received energy is *c*,

- losses as a fraction of deliveries to the utility are $b \div a$,
- losses as a fraction of deliveries to customers are $b \div c$.

Hence, each kilowatt or kilowatt-hour saved at the end use saves $1 + b/c$. The program administrator should estimate that ratio and multiply the end-use savings or benefits by that loss ratio. Loss ratios will be generally higher for higher-load periods than lower-load periods, since losses in wires (both within transformers and in lines) vary with the square of the load, for a given voltage and conductor type.

If the change in load does not change the capacity of the transmission and distribution system, then the losses should be computed as marginal losses, which are roughly twice the percentage as average line losses for the same load level.[153] Energy savings and/or growth do not generally result in changing the wire sizes. Hence, for energy avoided costs, losses are estimated on a marginal basis, so *a, b*, and *c* above are increments or derivatives, rather than total load values.

If the change in load results in a proportional change in transmission and distribution capacity, losses should be computed as the average losses for that load level. If the program administrator treats all load-carrying parts of the transmission and distribution as avoidable and varying with peak load, then only average losses should be applied to avoided capacity costs.

8.6.1. Avoided Transmission-and-Distribution Costs

The avoided costs developed for AESC 2009 do not include any avoided transmission and distribution (T&D) costs. As part of the scope of work, utility T&D costs were surveyed and presented in Exhibit 6-43.

Some utilities have estimated marginal or avoidable T&D investments from projections of investments over the next five or ten years. If those projections are comprehensive, they can be used in much the same manner as the historical data.[154]

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[153] In this sense, "line losses" does not include the no-load losses that result from eddy currents in the cores of transformers. These are often called "iron" losses (since transformer cores were historically made of iron), in contrast to the load-related "copper" losses of the lines and transformer windings.

[154] The system load data may require adjustments for customers served at transmission voltage, migration of wholesale customers to wheeling service, and changes in geographical service territory.

Each program administrator should add applicable avoided T&D costs, in $/kW of reduced summer and/or winter peak demand, as appropriate for the specific service territories.[155] In southern New England, the vast majority of distribution equipment peaks in the summer, so allocating all avoided T&D costs to the summer would be reasonable. In northern New England, especially where areas have significant electric heating load, much of the T&D costs will be driven by winter peaks.

Some T&D additions are required regardless of load growth, while other expenditures are required just to replace retirements of existing plant. The T&D cost data should be adjusted to remove (1) replacements of retired plant and (2) customer-related distribution costs.[156]

Replacements. Since the actual replacement is likely to have greater capacity than the original installation (to accommodate the load growth that has occurred the preceding years), the cost of replacement equipment will tend to overstate the portion of investment costs attributable to unavoidable retirements. In the estimate of the replacement cost (the original cost inflated to current dollars), the incremental cost of any equipment upgrades is correctly treated as a load-related cost.[157]

The inflated retirement cost should be based on the average age, not the useful life, of the plant. If all plant survived to the end of its useful life, 30 to 40 years for T&D, the replacement-to-original cost ratio would be large, and the net load-related additions (net of retirements) would be small. But, the average age of retired plant is much lower than the useful life.[158] Retirements in any year reflect a

[155]Avoided transmission costs and avoided distribution costs are usually calculated separately, but may be combined in the evaluation of efficiency measures.

[156]The categories used in T&D budgeting do not always fit cleanly into categories useful for determining avoidable costs. For example, a “reliability project” may consist of replacing aging cable that has been causing outages (a replacement), addition of protective systems that were omitted when the substation or feeder was originally built (a deferred cost of earlier growth), or looping feeders to reduce outage rates (which may be driven by rising loads on the feeders or by changing attitudes towards outages). The first example is not avoidable, the second example is a measure of future upgrades that may be needed for today’s load-related projects, and the third may be load related or not, depending on the justification for improving reliability on this part of the distribution system. The identification of avoidable investments in T&D planning documents requires thoughtful review, and the process will vary among utilities, due to differences in the planning documents and system conditions.

[157]Some replacements may actually be load-related. For example, some equipment may wear out prematurely because of overloading, or retired prematurely in order to replace it with larger capacity equipment.

[158]The depreciation study will be useful in determining the average age of retired plant.

mixture of vintages and most of the equipment in the system is relatively new. Further, the younger equipment is a higher percentage of the dollars retired than it is of the number of items retired, since the younger installations were built in inflated dollars.

Customer-Related Distribution Costs. Some investments, such as meters, are required primarily to serve new customers, regardless of demand levels. A portion of distribution poles, lines and line transformers are also necessary to reach new customers, especially in rural areas.

The T&D investments are rarely classified in a manner consistent with determining whether they are avoidable through load reductions. For example, a reliability problem may arise due to higher loads, and some of the investment added to serve “new business” may be avoidable by reducing the load of the new customer and its neighbors. As an approximation, two adjustments can be made to the net distribution additions (net of retirements):

- Omit expenditures on meters, services, installations and leased property on customer premises, and street lighting and signal systems, even though a portion of service costs are load-related (especially where services are being upgraded to carry higher amperage).
- Reduce expenditures in all distribution accounts except substations by a percentage determined to be customer-related.

The “minimum system” method is frequently used to estimate the portion of plant that is not avoidable. It attempts to estimate the cost of the distribution system as if each unit of equipment were the minimum-sized unit that would ever be used. The demand-related portion of the investment is the increment over the cost of the minimum-sized equipment. To maintain consistency in the computation of avoidable cost per kilowatt, the loads served by that minimum-sized equipment should be removed along with the cost of that equipment.

It is likely that multiplying the cost of the minimum-sized equipment times the number of units overstates the customer-related distribution investment, since demand affects the number of transformers and the feet of conductor and conduit, as well as the size of the transformers and lines.

Avoidable Percent of T&D Capital. The percent of T&D capital expenditures that is avoidable would be the value estimated from the adjustment above for replacements and customer-related plant, divided by the gross expenditures. This percentage is not really needed once the adjusted investments have been estimated. An avoidable percentage estimated from one data set (e.g., historical FERC data) should not be applied to a different data set (e.g., current utility forecasts), unless the two data sets can be determined to be equally comprehensive.

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Appendix A: Value of Economic Development for Massachusetts

Table of Contents

I. Background

This memorandum represents the following subset of the Task 7 deliverable:

- Task A: The Value of Economic Development for the 2010-2012 Massachusetts Joint Statewide Three-Year Electric and Gas Efficiency Plans.

II. Summary

Exhibit A - 1 summarizes the key results requested in the RFP for Task A, i.e., “the economic activity and number of jobs generated by each $1 million of investment in energy efficiency as the sum of the direct and indirect jobs supported by $ investment in energy efficiency plus the jobs supported by the spending of the energy cost savings in the economy.”[1]

Exhibit A - 1: Economic Development Impacts of Massachusetts Electric and Gas Energy Efficiency (EE) (Net Impact Multipliers per $1 million)[2]

	Electric EE Net Impact	Gas EE Net Impact
MULTIPLIERS (per $1 million, 2009 $)		
Employment (job-years)	22.9	19.1
Earnings	$1,126,900	$885,200
Value-Added	$1,478,300	$891,500

The Electric EE (Energy Efficiency) Net Impact column contains multipliers for the economic activity (Employment, Earnings and Value-Added) related to each $1 million of investment in Electric energy efficiency. Similarly, the Gas EE Net

[1] Unless otherwise stated, this analysis was conducted in terms of real 2009 $, undiscounted. Likewise, unless otherwise stated, all results are also presented in terms of real 2009 $, undiscounted.

[2] The EE Net Impact Multipliers are a function of both the multipliers and the expenditure amounts for EE, Avoided Supply and Respending, as will be explained in more detail in Section V Results.

Impact column contains multipliers for the economic activity (Employment, Earnings and Value-Added) related to each $1 million of investment in Gas energy efficiency.

The exhibit indicates that the Net Employment Impact of Electric EE is 22.9 job-years per $1 million. In terms of other economic activity, Electric EE expenditures of $1 million yield Earnings of $1,126,900 and Value-Added of $1,478,300. On the Gas side, the Net Employment Impact of Gas EE is 19.1 job-years per $1 million. In terms of other economic activity, Gas EE expenditures of $1 million yield Earnings of $885,200 and Value-Added of $891,500.

Earnings is included in Value-Added, so the multipliers for Earnings and Value-Added are not additive. The economic development multipliers will be explicitly defined in Section III. Results will be further explained in Section V.

Exhibit A - 2 provides the multipliers on a physical unit basis (Electric EE Net Impact per lifetime GWh and Gas EE Net Impact per million lifetime therms). The economic development impacts of a given amount of EE can be calculated on the basis of: (a) expenditures or (b) physical units. The impacts as calculated on the basis of (a) or (b) are not additive.

Exhibit A - 2: Economic Development Impacts of Massachusetts Electric and Gas Energy Efficiency (EE) (Net Impact Multipliers per GWh and million therms)

	Electric EE Net Impact (per lifetime GWh)	**Gas EE Net Impact (per lifetime million therms)**
MULTIPLIERS		
Employment (job-years)	1.09	7.8
Earnings (2009 $)	$53,300[a]	$362,800[b]
Value-Added (2009 $)	$69,900[a]	$365,300[b]

[a] Expressed per lifetime kWh, the Electric EE Net Impact Multipliers are $0.053 for Earnings and $0.070 for Value-Added (multiplier per kWh = multiplier per GWh/1,000,000).
[b] Expressed per lifetime dekatherm, the Gas EE Net Impact Multipliers are $3.63 for Earnings and $3.65 for Value-Added (multiplier per dekatherm = multiplier per million therms/100,000).

As discussed in Section V, investment in Electric and Gas EE results in a shift of activity out of environmentally stressful, low multiplier supply into more environmentally benign, high multiplier EE, as well as a large amount of respending. Cost-effective energy efficiency reduces the cost of living and operating businesses and thus promotes economic development in Massachusetts. It increases the efficiency of the overall economy and makes the state a more attractive place for residents and businesses. Moreover, given the current economic downturn and the potential for continued high unemployment rates (particularly in construction) over the next several years, EE represents an excellent and very timely opportunity for Massachusetts.

III. Study Approach

A. Analytical Framework

This analysis calculates the economic impact of Massachusetts energy efficiency (EE) programs in terms of three macroeconomic indicators, i.e., Employment, Earnings and Value-Added. This analysis is undertaken for both electricity and natural gas EE programs. Changes in these macroeconomic indicators (i.e., economic development impacts) from the net effect of energy efficiency are calculated as the sum of the following three components:

> [1] the *increase* in economic activity as a result of expenditures on energy efficiency programs;[3]
>
> [2] the *decrease* in economic activity as a result of decreased expenditures on energy supply; and
>
> [3] *"respending,"* the *increase* in economic activity as consumers *increase* their spending for other goods and services (to the extent that efficiency programs reduce consumers' overall costs, these savings are available for other spending).

The value of changes in each macroeconomic indicator is calculated using multipliers expressed in units per $1 million of energy efficiency expenditures.[4] The three multipliers provided in this analysis are:

- Employment (job-years);[5]
- Earnings ($);[6]

---

[3] Efficiency expenditures include direct utility costs and evaluation, plus customer contributions.

[4] The RFP for Task A specifies that results will optionally be stated on a per-kWh or per-therm basis, based on statewide energy efficiency savings. Study results for Electric EE are provided on per-dollar, per-kWh and per-kW bases. Study results for Gas EE are provided on per-dollar and per-therm bases.

[5] Employment: one job-year = one full-time job for one person for one year.

- Value-Added ($).[7]

These multipliers are estimated using an input-output model of the Massachusetts economy.[8]

The equation presented above (i.e., the sum of [1] - [2] + [3]) is the framework for this economic development impact analysis. Key inputs to the equation are derived from:

- the 2010-2012 Massachusetts Joint Statewide Three-Year Electric and Gas Efficiency Plans (EE Plans);
- Synapse's 2009 Avoided Cost Study (Avoided Cost Study) assumptions and results.

The EE Plans translate dollars of EE expenditures into specific efficiency activities and resulting physical energy savings. The Avoided Cost Study translates these physical energy savings into specific avoided energy supply activities and values them in dollars. The Avoided Cost Study is necessary to determine the EE Plans' cost-effectiveness (i.e., the net benefit, as measured by the Total Resource Cost (TRC) Test). The Avoided Cost Study is also necessary to determine what specific types of supply are avoided.

To recap, the economic development analysis uses multipliers to estimate impacts (i.e., Employment, Earnings, and Value-Added) for each of the following three components:

1. EE expenditures;
2. Avoided Supply expenditures;
3. Respending.

(footnote continued from previous page)

[6] Earnings: the compensation associated with Employment, including both employee compensation and proprietary income (earnings from self-employment).

[7] Value-Added: the difference between the value of output (sales) and the cost of intermediate inputs (goods and services purchased from other businesses). Stated another way, it represents the value that is added by the application of labor and capital in converting intermediate inputs to finished products. Summed across all industries, as it has been here, Value-Added is a measure of overall economic activity, which includes Earnings (compensation for Employment), interest, and profits. Value-Added at the national level is equivalent to GDP (Gross Domestic Product). Value-Added at the state level is equivalent to GSP (Gross State Product).

[8] As will be discussed below in the Modeling of Economic Development Impacts, Section III.B, the IMPLAN model is utilized.

As such, TGG's economic development analysis is based upon both the EE Plans and the Avoided Cost Study. The EE Plans data provide the composition of the spending (dollars of EE expenditures), as well as the physical energy saved. The Avoided Cost Study assumptions and results provide the amount and composition of avoided supply expenditures (dollars of avoided supply expenditures). Respending (dollars of consumer spending) is a function of EE net benefits (avoided cost, less EE cost, as measured by the TRC Test)**.** So both the EE Plans and Avoided Cost Study are inputs for determining respending.

B. Modeling of Economic Development Impacts

To estimate the economic development impacts, TGG uses an input-output model. As indicated in TGG's proposal, the Massachusetts version of the IMPLAN input-output model was selected by TGG for this analysis.[9]

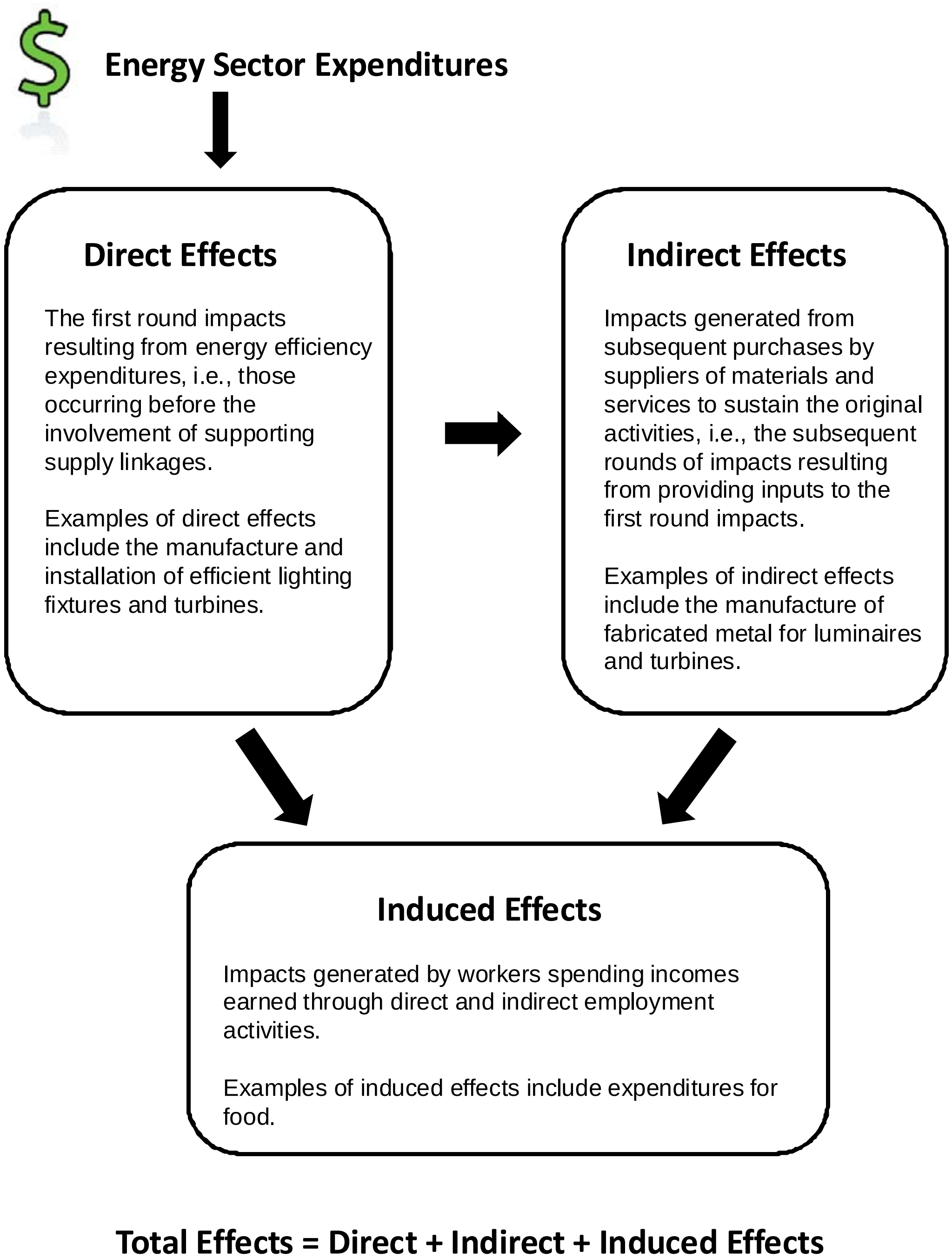
Input-output analyses include the following categories of effects:

> *Direct Effects* — first round impacts of a set of expenditures, i.e. those occurring before the involvement of supporting supply linkages;
>
> *Indirect Effects* — impacts generated through subsequent purchases by suppliers of materials and services to sustain the original activities;
>
> *Induced Effects* — impacts generated by workers spending incomes earned through direct and indirect employment activities;
>
> *Total Effects* — the sum of the *Direct*, *Indirect*, and *Induced Effects*.

Energy sector expenditures (including both energy efficiency and avoided supply) have direct, indirect, and induced effects. Respending has induced effects, and may also have direct and indirect effects. Exhibit A - 3 illustrates the economic supply linkages associated with these categories of effects, using Electric energy efficiency (lighting) and energy supply (turbine) expenditures as examples.

[9] This input-output model was developed at the US Forest Service and University of Minnesota and is now maintained by Minnesota IMPLAN Group. See <http://implan.com/index.php?option=com_content&task=blogcategory&id=83&Itemid=28>, <http://implan.com/downloads/documents/implan_io_system_description.pdf>.

Exhibit A - 3: Economic Effects



As discussed in Section IV Input Assumptions, in order to use the input-output model to value the economic development impacts for the Massachusetts EE Electric and Gas Plans, various specific input data are required.

IV. Input Assumptions

Commercially available input-output models do not provide specific multipliers for the various energy efficiency or supply options. To develop these specific input-output multipliers, the total expenditures for each type of energy efficiency and supply activity must be disaggregated into expenditures for each of the specific industries represented in the input-output model. The data used to perform this translation for each activity is called a bill of goods (BOG), i.e., the allocation of expenditures for each type of energy efficiency and supply technology. The BOG data that are utilized were developed by TGG in an extensive research effort ongoing since 1992.[10]

TGG's BOG data provide a high level of expenditure detail for a comprehensive set of electric and gas efficiency and supply options. For efficiency technologies, BOG data were principally derived from Massachusetts Electric[11] accounting records, which incorporated all aspects of costs (program administration, overhead, labor, and consulting services, as well as materials and equipment). For electricity supply technologies, BOG data were largely based on (1) engineering studies performed by Oak Ridge National Laboratories for inclusion in the U.S. Department of Energy (DOE) Energy Economic Database, (2) utility accounting records, and (3) Electric Power Research Institute (EPRI) Technology Assessment Guide (TAG) data.

A. Electricity Inputs

In order to use the input-output model to value the economic development impacts for the 2010-2012 Massachusetts Electric EE Plan, various input data are required. These data include EE expenditure allocations by end use from the EE programs in the Plan ("Efficiency Inputs"); the electricity supply that will be avoided by these programs ("Avoided Supply Inputs"); and, finally, data on the net benefits associated with these programs ("Respending Inputs").

[10] BOG data are key elements of TGG's extensive database, which supports its regional economic development research. This database offers a high level of regional specificity (and hence more precise results in evaluating regional economic impacts) because it has been developed using state-specific data and leveraging TGG's extensive expertise in energy efficiency, regional economics and utility operations.

[11] This is the name under which National Grid previously operated in Massachusetts.

1. Efficiency

The data underlying determination of the Electric EE expenditure allocations by end use are based on EE spending allocation data from previous economic development studies for National Grid programs in Rhode Island over the 1990-2005 period, as well as for Massachusetts programs statewide in 1998.[12] TGG has developed allocation assumptions based on these historical program data, together with the program descriptions for the 2010-2012 Massachusetts EE Electric programs, and the MA EE Advisory Council Consultant's recommendations.[13]

While program descriptions in the Massachusetts Statewide Electric EE Plan do not provide cost allocations, they are suggestive of emphasis on certain end uses. Moreover, TGG has been guided by the Plan's theme of comprehensive programs, a corollary of which is to address end uses more broadly. Following input from the AESC 2009 Study Group and further consideration by TGG, draft allocations of Electric EE expenditures by end use were revised for the Residential sector.

Taking into account all of the above inputs, TGG has developed the following allocations for Electric energy efficiency expenditures by end use (Exhibit A - 4):

[12] See footnotes 64, 65, and 66.

[13] <http://www.ma-eeac.org/docs/090324-SavingsContext-ElectGas.pdf>, Slide 10.

Exhibit A - 4: Electric EE Expenditure Allocations by End Use

Residential	
Appliance	13%
Lighting	35%
Water Heating	5%
Building Shell	20%
HVAC	27%
Commercial	
Lighting	66%
Water Heating	2%
Building Shell	5%
HVAC	15%
Other[14]	12%
Industrial	
Lighting	45%
HVAC	24%
Motors	6%
Process	25%

Allocation between Commercial and Industrial EE Expenditures

In order to allocate Electric efficiency expenditures by end use for the Commercial and Industrial (C&I) sectors, overall expenditures for C&I programs must first be allocated by sector. TGG has developed the following allocations for overall C&I expenditures:

72% Commercial

28% Industrial.

[14] The "Other" category in the Commercial sector includes end uses such as refrigeration, cooking equipment, and motors.

TGG has developed these allocation assumptions based on data from previous economic development studies for National Grid programs in Rhode Island over the 1990-2005 period, as well as for Massachusetts programs statewide in 1998.[15] A 72:28 expenditure split is also a reasonable reflection of the split of overall electricity consumption between the commercial and industrial sectors.

2. Avoided Electricity Supply

As with the efficiency expenditures, employment and other economic development impacts vary across different energy supply options. Avoided energy supply expenditures must be assigned to the relevant types of activity and associated BOG (e.g., construction and operation of gas combined cycle and wind generation). This requires several intermediate steps and coordination to maintain consistency with Synapse's main study avoided cost analysis.

First, it is necessary to determine the energy and capacity (physical unit) savings associated with efficiency expenditures.

Second, the savings data reported in terms of physical units at the customer meter are then adjusted (grossed up) to determine overall supply-side savings with a credit for transmission losses, reserves, and any other relevant factors.

Third, the overall supply-side physical unit savings have to be translated into avoided types of supply and amount of associated expenditures. The modeling of avoided supply considers the regional energy system, the location of avoided supply, and the load factor of overall Massachusetts energy efficiency programs and other state-specific averages.

The electric sector has a complex intra-region supply chain, such that efficiency can avoid a range of activities including construction and operation of various types of generation, as well as transmission and distribution facilities. TGG's experience with past analyses is that a substantial amount of translation and abstraction is required to develop the inputs needed for economic development modeling from avoided cost studies.[16]

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[15] See footnotes 64, 65, and 66.

[16] Previous TGG studies of New England efficiency programs relied upon previous AESC reports. See footnotes 64, 65, and 66.

In this analysis, TGG has utilized a hybrid approach relying upon information from the Electric EE Plan and Synapse's 2007 and 2009 Avoided Cost Studies. The existing 2010-2012 Electric EE Plan (April 30, 2009) has valued the benefits of avoided supply based on the 2007 Avoided Cost Study. Synapse's 2009 Avoided Cost Study will be used in cost-effectiveness analyses included in the Program Administrator-specific EE filings to be submitted in October 2009.

As described at the beginning of this subsection, there are several steps in modeling the avoided types of supply and amount of expenditures. The cost-effectiveness analyses prepared for the EE plans incorporate the following steps:

- determine the physical unit savings at the customer meter;
- adjust (gross up) to determine overall supply-side savings;
- value these overall savings using the appropriate avoided cost factors.

Rather than duplicate these cost-effectiveness analyses, TGG has used the benefits estimated for the TRC Test in the April 30, 2009 Electric EE Plan[17] as a starting point for modeling avoided supply. But in allocating these avoided supply benefits to specific activities, TGG has also taken into account the relevant assumptions from the 2009 Avoided Cost Study.

Therefore TGG has reviewed Synapse's draft avoided cost results as of May 29, 2009 to develop the inputs required for Task A.[18] TGG's treatment of avoided supply costs is highly simplified in comparison with the main study. This is appropriate for Task A, where the purpose of the avoided cost analysis is to determine a few essentials (notably an overall expenditure mix for avoided supply).

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[17] Pages 60-61.

[18] TGG has reviewed all files posted on the Project website. The following were specifically relied upon in developing inputs for Task A:

File: AESC 2009 Task 7A and B Energy Price Forecast Draft 2009-05-22.pdf

File: Draft Deliverable 7-C AESC 2009 20090517.pdf

File: AESC 2009 Task 7 A and B Draft 2009-05-09.pdf

File: Deliverable 3-1 AESC 2009 20090508.pdf

File: Task 4 Gas Forecast Background 20090511.pdf

File: Task 5 Sector Specific Fuel Oil Forecast by State 2009 05 29.pdf.

File: Common Financial Parameters 2009-04-03.xls

A hybrid allocation process was selected:

- to develop data and methodology (based on the data available to TGG prior to the release of the 2009 Avoided Cost Study) that can be used together with the final results of the 2009 Avoided Cost Study, and cost-effectiveness analyses based on these new avoided costs;
- to develop the inputs needed for economic development modeling, using the information now available from the 2009 Avoided Cost Study, supplemented as required by information based on the 2007 Avoided Cost Study.

In undertaking this allocation process for avoided supply, TGG maintained a focus that this process was merely an intermediate step in the economic development modeling. In effect, the allocations are used as "weights" for the mix of activities comprising a set of expenditures. Based on these allocations, weighted average multipliers are then developed and applied to estimate economic development impacts for the set of expenditures.

The purpose of the allocation process is to facilitate development of reasonably accurate weighted average multipliers. As such, it is not vital that the allocation process always achieve a high level of accuracy.[19] So especially when the available data do not permit a high level of accuracy, the allocation process has been based on reasonable judgment and approximation.

As noted above, TGG has utilized the EE Plan cost-effectiveness analysis as a starting point. In particular, for allocating avoided supply, TGG has begun with the benefits estimated for the TRC Test. It would be preferable to use benefits data based on the 2009 Avoided Cost Study. However, such data will only become available later this year, notably in the Program Administrator-specific EE filings to be submitted in October 2009.

So TGG has started with the benefits from the cost-effectiveness analysis conducted within the April 30, 2009 Electric EE Plan. As shown in Exhibit A - 5, the benefits for avoided electric supply are mostly Generation-related, but also

[19] To the extent that various avoided supply activities have similar multipliers, estimates of economic development impacts will not be highly sensitive to the mix of activities assumed. While EE activities often have relatively similar multipliers, there is a wider variation across avoided supply activities. Still, there are supply activities (e.g., wind generation and T&D) that have broad similarities in terms of overall multipliers.

include substantial amounts of T&D (Transmission and Distribution) and DRIPE (Demand Reduction Induced Price Effects).

Exhibit A - 5: Avoided Electric Supply Allocations by Major Cost Component

Major Cost Component	% of Total Avoided Electric Supply
T&D (Transmission and Distribution)	15.4%
DRIPE (Capacity and Energy)	7.7%
Generation (Capacity and Energy)	76.9%

The allocation process for each major component of avoided electric supply is described below.

a) T&D

The avoided T&D benefits in the Electric EE plan were calculated based upon utility-specific estimates. The Synapse Avoided Cost Study does not develop avoided T&D costs, but it does provide some description of the methodology and data for the utility-specific estimates.[20]

As with other aspects of avoided electric supply, T&D entails a variety of activities, which differ in terms of their economic development impacts. In order to allocate T&D to specific activities, TGG reviewed the avoided T&D estimates ($/kW-year) provided by Massachusetts utilities, as well as the spreadsheets underlying these estimates for National Grid and NStar.

This review identified an issue with broader implications for analyses of economic development impacts. T&D is a capital-intensive activity, and much of the estimated avoided costs relate to the financing and other carrying costs attributable to utilities.

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[20] File: Draft Deliverable 7-C AESC 2009 20090517.pdf, p. 27.

Meanwhile, EE cost-effectiveness is not evaluated using the distribution company's weighted average cost of capital. As per the Guidelines established in D.P.U. 08-50-A,[21] EE costs and benefits for both utilities and customers are evaluated with a low-risk discount rate, such as that represented by the yield on Treasury securities.[22]

Thus, to the extent that the utility cost of capital (used to develop the T&D avoided costs) is higher than the discount rate (used to evaluate EE cost effectiveness), this difference in rates results in a higher amount of benefits calculated under the TRC Test. Especially for capital-intensive activities such as T&D, this raises a concern about possible overstatement of economic development impacts.

As shown in Exhibit A - 5, T&D accounts for over 15% of avoided electric supply costs as estimated in the Electric EE Plan. Clearly some of this represents T&D capital and O&M (Operations and Maintenance) costs. These are activities with a large component of on-site work and thus relatively high multipliers (Massachusetts economic development impacts per $1 million). But some of the T&D avoided costs represent financing which may contribute little (if anything) to Massachusetts economic activity.

In light of the above considerations, T&D benefits were allocated as shown in Exhibit A - 6. 30% of costs were attributed to activities (notably financing) assumed to have no economic development impacts within Massachusetts and are thus assigned multipliers of zero.[23] The remaining 70% was split 80:20 to capital and O&M.

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[21] <http://www.mass.gov/Eoeea/docs/dpu/electric/08-50/82208dpunoi.pdf>

[22] For the April 30, 2009 EE Plans, a real discount rate was calculated based on a 3.66% nominal rate (calculated by DOER for ten year Treasury notes) and 2.50% inflation.

[23] In TGG's modeling of Avoided Supply impacts, all activities assumed to have no economic development impacts in Massachusetts are assigned multipliers of zero for Employment, Earnings and Value-Added, respectively, and are designated as "zero-multiplier activities". Investments in these zero-multiplier activities thus have the effect of lowering the average multipliers for Avoided Supply. In addition to T&D Financing, as described above, zero-multiplier activities include DRIPE, Risk Premium/Retail Adder, and Emissions Allowances, as will be discussed below.

Exhibit A - 6: T&D Allocations by Activity

Activity	% of T&D Costs
Financing/Zero Multiplier	30%
Capital	56%
O&M	14%

b) DRIPE

Based on the Synapse 2007 Avoided Cost Study, DRIPE (capacity and energy) accounted for 7.7% of the avoided electric supply benefits in the April 30, 2009 EE Plan (see Exhibit A - 5). The 2009 Avoided Cost Study will provide new estimates of DRIPE. The Order in D.P.U. 08-50-A specifies that only the value of DRIPE associated with Massachusetts energy efficiency should be included in Massachusetts cost-effectiveness analyses. The 2009 Avoided Cost Study will provide "Massachusetts only" values of DRIPE to use in the Program Administrator-specific EE filings to be submitted in October 2009 and future benefit-cost analyses.

Aside from the shift to Massachusetts-only values for DRIPE, there have been numerous changes in capacity and energy markets since the 2007 Avoided Cost Study. Given that DRIPE is a relatively small component of overall avoided electric supply benefits, TGG has adopted a relatively simple approach for DRIPE. TGG has not attempted to estimate whether there will be significant shifts in this component of avoided supply costs, and has assumed an allocation for DRIPE (7.7%) based on the April 30, 2009 EE Plan cost effectiveness analysis.

DRIPE is a price effect involving revenues to generators (including those located outside of Massachusetts). As such, TGG assumed that DRIPE entails no reduction of economic development impacts within Massachusetts. In other words, while DRIPE is a benefit to the Massachusetts economy in terms of lower electricity costs, there is no associated foregone economic activity within the state. This is similar to the assumption that 30% of T&D costs is attributable to financing and other activities, which are assigned multipliers of zero.[24]

[24] See footnote 23.

c) Generation (Capacity and Energy)

Based on the Synapse 2007 Avoided Cost Study, Generation (Capacity and Energy) accounted for approximately 77% of the avoided electric supply benefits in the April 30, 2009 EE Plan (see Exhibit A - 5). So this component is by far the most important in terms of avoided electric supply (and Electric EE benefits overall). Moreover, avoided Generation is unusually complex in terms of the variety and diversity of associated economic activities. Estimates of economic development impacts can differ substantially depending upon the assumptions for avoided generation.

As previously noted in the discussion of DRIPE, there have been numerous changes in capacity and energy markets since the 2007 Avoided Cost Study.

TGG has thus reviewed the materials prepared to date regarding Synapse's draft 2009 avoided cost results.[25]

Since the 2007 Avoided Cost Study, various factors have combined to create a large and ongoing supply surplus. Actual and forecasted demand have been reduced owing to economic conditions and enhanced codes and standards. Meanwhile, Renewable Portfolio Standards (RPS) in Massachusetts and the rest of New England require steadily increasing amounts of qualified generation. As a result, any need to add conventional new supply has receded far into the future. Given that the 2010-2012 Electric EE Plan Programs have an average measure life of 10.7 years, the avoided generation will be mainly existing supply and renewables, as opposed to new conventional supply (typically gas combined cycle and combustion turbines).

Based on the Synapse 2007 Avoided Cost Study, Generation Capacity accounted for over 15% of overall avoided electric supply benefits in the April 30, 2009 EE Plan; Capacity was about 20% as a share of overall Generation avoided supply benefits (Capacity and Energy). Given the supply surplus, avoided costs for Capacity are low and expected to remain low throughout the average measure lifetime of the 2010-2012 Electric EE Plan. So in the cost-effectiveness analyses based on the 2009 Avoided Cost Study, it is likely that benefits from

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[25] The relevant files are listed in footnote 18.

avoided Generation Capacity will be substantially lower than in the April 30, 2009 EE Plan (based on the 2007 Avoided Cost Study).

On the other hand, relative to the 2007 Study, avoided costs for Generation Energy appear to be similar or higher in the 2009 Avoided Cost Study. Thus, the combined values for Generation Capacity and Energy appear to have been much more stable from the 2007 Study to the 2009 Avoided Study (compared to more significant changes in the respective values for Generation Capacity and Energy). Accordingly, TGG has based its allocation process for avoided electric supply on the combined values for Capacity and Energy. As a surrogate for the not yet available cost effectiveness analyses based on the 2009 Avoided Cost Study, TGG has started with an allocation based on the April 30, 2009 cost-effectiveness analysis. As shown in Exhibit A - 5, Generation Capacity and Energy are a combined 76.9% share of total avoided electric supply.

Based on a review of the ongoing 2009 Avoided Cost Study, TGG has allocated avoided generation costs as shown in Exhibit A - 7.

Exhibit A - 7: Avoided Electric Generation (Capacity & Energy) Allocations by Cost Component and Activity

Cost Component	Activity	% of Total	Basis for Allocation / Comments
Wholesale Risk Premium/ Retail Adder	Zero Multiplier[26]	8.26%	1- (1/(1+.9)) = 8.26%; 9% Default Adder 2009 AESC File: Deliverable 3-2 AESC 2009 20090508.pdf, p. 8
RPS Compliance	Total	14.68%	16% * (Total - Retail Adder); Model as New Wind
	Capital	12.48%	85% * Total New Wind Cost
	O&M	2.20%	15% * Total New Wind Cost
Emissions Allowances	Zero Multiplier[26]	11.01%	12% * (Total - Retail Adder)
Existing Gas Generation	Total	59.45%	90% * (Total - Retail Adder-RPS - Allowances)
	Fuel	57.96%	97.5% * Total Existing Gas Generation Cost
	O&M	1.49%	2.5% * Total Existing Gas Generation Cost
Existing Oil Generation	Total	6.61%	10% * (Total - Retail Adder-RPS - Allowances)
	Fuel	6.34%	96.0% * Total Existing Oil Generation Cost
	O&M	0.26%	2.5% * Total Existing Gas Generation Cost
TOTAL		100.00%	

[26] See footnote 23.

Combined Capacity and Energy costs (i.e. avoided generation costs) were allocated into five types, and then (where appropriate) subdivided into capital, fuel, and non-fuel O&M activities. The allocation process for avoided generation costs was hierarchical and will be described from top down.

(1) Wholesale Risk Premium/Retail Adder

As per the 2009 Avoided Cost Study,[27] a 9% value was applied as a Wholesale Risk Premium/Retail Adder. This is equivalent to 8.26% of total avoided generation costs.[28]

As a Risk Premium/Retail Adder, this cost has been assumed to entail no economic development impacts within Massachusetts. This is similar to the assumption that all DRIPE and 30% of T&D costs are attributable to financing and other activities, which are assigned multipliers of zero.[29]

(2) RPS Cost of Compliance/Wind Generation

As assumed in the 2009 (and 2007) Studies, EE benefits include the Avoided Cost of RPS Compliance. Massachusetts Class 1 requirements (as a % of energy) are 4% in 2009 and increase by 1% annually.[30] Given that the 2010-2012 Electric EE Plan Programs have an average measure life of 10.7 years, the mid-point of the effects would be around 2017, when RPS requirements are 12% of load. The 2009 Avoided Cost Study assumes that the cost of generation from renewables will exceed the market cost of energy; EE avoids this premium, as well as the market cost of energy.

TGG assumed that the Avoided Cost of RPS Compliance (together with the associated market cost of energy) accounted for 14.68% of total avoided generation cost. This was computed as 16% of avoided generation costs remaining after the previous allocation of 8.26% to the Wholesale Risk Premium/Retail Adder.

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[27] File: Deliverable 3-2 AESC 2009 20090508.pdf, pp. 6-8.

[28] 1- (1/(1+.09)).

[29] See footnote 23.

[30] File: Draft Deliverable 7-C AESC 2009 20090517.pdf, pp. 3-13.

The 16% value was selected to incorporate a premium above the RPS requirements (described above as about 12% of load over the EE Plan measure life). While this may seem a modest premium, it is applied to the combined Avoided Generation Capacity and Energy Costs (including a sizable Capacity component in the overall allocation based on the 2007 Avoided Costs).

The next step was to allocate these renewables costs to specific activities. In practice, qualified renewables include a mix of technologies. Based on a quick review of multipliers, economic development impacts appeared broadly similar for various renewables. Given the major role of wind generation as a qualified renewable in Massachusetts and elsewhere, the entire renewables cost was assigned to wind. This cost was then split 85:15 to capital and O&M.

Finally, there is the issue of generation location. Avoided renewables may be located outside of Massachusetts, either elsewhere in New England, or in adjacent jurisdictions. In fact, given the compact and highly integrated nature of New England and especially the regional electricity system, there are many interactions between Massachusetts and its neighbors. EE may avoid generation outside of Massachusetts. And even if the avoided generation is in a neighboring area, some economic impacts may flow back to Massachusetts.

Still, it is fair to assume that avoided generation outside of Massachusetts will have much less impact on the Massachusetts economy than does generation located within Massachusetts. And given the study definition and the input-output model of the Massachusetts economy utilized, this analysis will consider only impacts associated with changes in economic activity situated within Massachusetts. Put more simply, if avoided generation is assumed to be located outside of Massachusetts, it will also be assumed to be a zero-multiplier activity.

Given the approximate nature of allocation process, TGG has selected the simplifying assumption that avoided renewables will be located wholly within Massachusetts. This assumption is intended to provide a meaningful comparison between the impacts of EE and avoided supply. If all of the avoided supply is assumed to be outside of Massachusetts, the economic development modeling will not provide any information regarding the impacts of avoided in-state generation. This analysis has assumed that significant portions of avoided electric supply costs (e.g., T&D financing, DRIPE, and Wholesale Risk Premium/Retail Adder) are zero-multiplier activities. So in the case of avoided renewables, TGG has adopted the simple convention that all avoided generation is within Massachusetts. This assumption should not be viewed in isolation, but considered in the context of the entire allocation process.

(3) Emissions Allowances

As will be described in Subsection (4) below, this allocation process assumes that most of the generation avoided by Electric EE is gas- and oil-fired. As such, there will also be avoided costs for Emissions Allowances. The 2009 Avoided Cost Study includes an extensive consideration of such costs.[31] A new Federal regulatory framework for CO_2 is assumed, with allowance costs starting at $15.63 in 2013 and escalating to $32.10 in 2020.[32] Other allowance costs (NO_x, SO_2, RGGI[33] CO_2) appear to have only a very small impact on overall generation avoided costs for the 2010-2012 EE Plan.

Once again, given the approximate nature of this allocation process, TGG has adopted simplifying assumptions regarding Allowance Costs. TGG assumed that the avoided cost of Federal CO_2 allowances and other emissions allowances (NO_x, SO_2, RGGI CO_2) accounted for 9.39% of total avoided generation cost. This was computed as Allowance Costs being 12% of the avoided generation costs remaining after the previous allocation of 8.26% to the Wholesale Risk Premium/Retail Adder.

Next, there is the issue of how Allowance Costs should be treated for the purposes of economic development modeling. To the extent that Allowance Costs represent funds that leave the Massachusetts economy and are not returned, they are another zero-multiplier activity. But to the extent that revenues from Allowance Costs are recycled back to Massachusetts, it could be argued that they are not an avoided cost from a Massachusetts economic modeling perspective.

At this point, there is no finalized Federal regulatory framework for CO_2, so it is unknown to what extent and in what manner (if any) the revenues might be returned to Massachusetts. In any event, Massachusetts policy and practice is that that Emissions Allowance Costs are properly included in avoided costs used to evaluate EE cost-effectiveness; these Emissions Allowance Costs include

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[31] File: Deliverable 3-1 AESC 2009 20090508.pdf, pp.13-16.

[32] 2009 $; File: Deliverable 3-1 AESC 2009 20090508.pdf, pp.13.

[33] Regional Greenhouse Gas Initiative.

RGGI, which is being used to fund EE.[34] So for the purposes of this analysis, Allowance Costs are treated as another zero-multiplier activity.[35]

(4) Existing Gas- and Oil-Fired Generation

At this point, approximately one third (32.33%) of avoided generation costs have been allocated. TGG assumed the remainder was allocated to existing generation, split 90:10 to gas- and oil-fired units.

The 2009 Avoided Cost Study will provide more precise information regarding marginal generation sources, but the key and consistent finding is that natural gas generation is very predominant.[36] There may also be some coal-fired generation sometimes on the margin off-peak, but it did not seem warranted to include this relatively small share of output in the allocation.

For gas-fired units, costs were then split 97.50:2.50 to fuel and non-fuel O&M. So TGG assumed that existing gas-fired generation accounted for 60.90% of total avoided generation cost, with 59.38% of the total going to fuel and 1.52% for non-fuel O&M.

For oil-fired units, costs were then split 96:4 to fuel and non-fuel O&M.

So TGG assumed that existing oil-fired generation accounted for 6.77% of total avoided generation cost, with 6.50% of the total going to fuel and 0.27% for non-fuel O&M.

As with renewables, there is the issue of location for existing gas- and oil-fired generation. Much, but certainly not all, of New England's existing gas- and oil-fired capacity is located in Massachusetts.

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[34] <http://www.mass.gov/Eoeea/docs/dpu/electric/08-50/82208dpunoi.pdf>. As noted there and in <http://www.mass.gov/Eoeea/docs/dpu/gas/07-49/1908dpuord.pdf>, Federal costs and benefits are not to be included in the Massachusetts TRC Test.

[35] See footnote 23.

[36] File: AESC 2009 Task 7A and B Energy Price Forecast Draft 2009-05-22.pdf, pp. 11-16.

Given the approximate nature of allocation process, TGG has also selected the simplifying assumption that the existing gas- and oil-fired generation avoided by Massachusetts EE will be located wholly within Massachusetts. Once again, this assumption is intended to provide a meaningful comparison between the impacts of EE and avoided supply. This analysis has assumed that significant portions of avoided electric supply costs (e.g., T&D Financing, DRIPE, Wholesale Risk Premium/Retail Adder, and Emissions Allowances) are zero-multiplier activities. So in the case of avoided gas- and oil-fired generation, TGG has adopted the simple convention that all avoided generation is within Massachusetts. This assumption should not be viewed in isolation, but considered in the context of the entire allocation process.

3. Respending

In one sense, respending is straightforward to analyze. After calculating expenditures on efficiency, and avoided expenditures on energy supply, the difference between these two types of expenditures is the amount of energy cost savings available for respending. The complexity that arises concerns how to model the economic development impacts associated with this respending. And this is an issue of substantial importance, since respending typically accounts for a large portion of the overall economic development impacts estimated for efficiency.

For residential energy users, it is reasonable to assume that they will respend their energy cost savings similarly to how they generally spend money: on a wide mix of consumer goods and services, with some assigned to savings. And because much of consumer spending goes to local businesses (such as restaurants), it produces a substantial amount of in-state jobs per dollar. So within input-output modeling, residential energy cost savings can be analyzed as household/personal consumption expenditures.

But in New England and especially Massachusetts, commercial and industrial (C&I) customers account for a large portion of energy usage and cost savings associated with efficiency. And compared with residential customers, it is much harder to know what effect energy cost savings will have on C&I customers and where respending will be directed. Some may result in increased profits, and these profits will flow to business owners, who may or may not be within Massachusetts. Some may result in lower prices for what the C&I customers are producing, and the benefits of these lower prices will flow to both the in-state and other purchasers of these products.

Of course, if the C&I customers lower their prices, they might be able to sell more of whatever they are producing. And this could lead to increased production either in-state or outside to satisfy the increased demand. And the C&I customers might make investments to upgrade and expand their facilities (in-state and outside), to satisfy increased demand (possibly from lower prices) or in pursuit of other corporate goals.

The description above deals with for-profit businesses, and the C&I sector also includes government (public sector entities), and institutions (such as universities) and other non-profits. But in broad terms, the description above does capture the range of how any C&I customer might react to changes in energy costs (e.g., government could react to lower costs by expanding services, reducing debt, or by reducing taxes).

In advance (or even after the fact), it can be difficult to determine how C&I customers react to changes in energy costs. Input-output models (such as IMPLAN and US Department of Commerce RIMS) do not provide any direct mechanisms or guidance as to how to analyze respending of energy cost savings by C&I customers. In previous studies relying upon these kinds of input-output models, TGG has calculated the economic development impacts for respending by C&I customers based on multipliers for capital spending (new plant and equipment). The multipliers for such spending are intermediate between the results for various assumptions regarding the possible impacts of such respending, and as such appear reasonable (and possibly conservative).

To analyze respending for Task A, the methodology utilized is the same as described above for previous studies. C&I energy cost savings are modeled as capital spending (new plant and equipment), and residential savings as household/personal consumption expenditures. The modeling of respending is tailored to reflect Massachusetts-specific factors (notably the allocation of respending between residential and C&I customers).

TGG assumes a direct cost allocation by sector, in which EE program cost allocation is based on spending allocation. So C&I customers pay for C&I programs, and Residential (including Low Income and Non-Low Income) customers pay for Residential programs.

B. Gas Inputs

In order to use the input-output model to value the economic development impacts for the 2010-2012 Massachusetts Gas EE Plan, various input data are required. These data include EE expenditure allocations by end use from the EE programs in the Plan ("Efficiency Inputs"); the gas supply that will be avoided by these programs (as well as other resource benefits associated with the programs) ("Avoided Supply and Other Benefits Inputs"); and, finally, data on the net benefits associated with these programs ("Respending Inputs").

1. Efficiency

The data underlying TGG's determination of the Gas EE allocations by end use are based on answers to TGG's information requests provided by Bay State Gas (BSG), NSTAR Gas, and Berkshire Gas. Specifically, the underlying data are based on each utility's allocation of Gas EE expenses (including customer contribution, administrative and general (A&G), and evaluation costs) by end use.

TGG's allocations are also based on review of program descriptions in the 2010-2012 Massachusetts Statewide Gas EE Plan. Though these descriptions do not provide costs, they are suggestive of emphasis on certain end uses. Moreover, TGG has been guided by the Plan's theme of comprehensive programs, a corollary of which is to address end uses more broadly.

Finally, TGG also reviewed the most recent breakdowns of Gas EE potential by end use for Residential, Commercial, and Industrial sectors in Massachusetts[37] to check the directional consistency of TGG's allocations against the state's economic potential for Gas efficiency. Draft allocations of Gas EE expenditures by end use were submitted for review by the AESC 2009 Study Group and no modifications were requested.

Taking into account all of the above inputs, TGG has developed the following allocations for Gas energy efficiency expenditures by end use (Exhibit A - 8):

[37] "Natural Gas Energy Efficiency Potential in Massachusetts Final Report", GDS Associates, Inc. and Summit Blue Consulting, April 2009, pp. 25, 42 and 59. According to p 21 of the Massachusetts Gas EE Plan, this report is currently available on the web at www.richmaylaw.com/eeplan (on an interim basis), and will be made available on the Council's website www.ma-eeac.org.

Exhibit A - 8: Gas EE Expenditure Allocations by End Use

Residential	
Appliance	0%
Water Heating	10%
Building Shell	55%
HVAC	35%
Commercial	
Water Heating	3%
Building Shell	10%
HVAC	84%
Other[38]	3%
Industrial	
Process	15%
Steam	85%

Allocation between Commercial and Industrial EE Expenditures

In order to allocate Gas efficiency expenditures by end use for the Commercial and Industrial sectors, overall expenditures for C&I programs must first be allocated by sector. TGG has developed the following allocations for overall C&I expenditures:

80% Commercial

20% Industrial.

TGG has developed these allocation assumptions based on analysis of Massachusetts gas usage, as well as the data regarding EE program expenditures provided in answers to TGG's information requests by BSG and NSTAR Gas.

[38] The "Other" category in the Commercial sector includes end uses such as cooking equipment.

2. Avoided Gas Supply

As in the case of avoided electricity supply impact modeling (described in Section IV.A.2), modeling the impacts of avoided gas supply involves the assignment of avoided gas supply expenditures to the relevant type of activity. However, this assignment is much more straightforward for avoided gas supply and does not require the specialized modeling that was undertaken for avoided electricity supply (which included several intermediate steps and coordination to maintain consistency with Synapse's main study avoided cost analysis). Avoided gas supply expenditures can simply be assigned to the natural gas utility industry within the Massachusetts version of IMPLAN.

The greater complexity in modeling avoided electricity supply is due to the fact that the electric sector has a complex intra-region supply chain, such that efficiency can avoid a variety of activities including power plant construction and operation. By comparison, the gas sector has a much more limited intra-region supply chain; efficiency displaces a much smaller set of activities that can result in regional economic activity. As such, avoided gas supply modeling is a much simpler undertaking.

3. Respending

The general respending assumptions are the same for Gas as for Electric EE programs as described in Section IV.A.3 in the Electricity Inputs discussion.

TGG assumes a direct cost allocation by sector, in which EE program cost allocation is based on spending allocation. So C&I customers pay for C&I programs, and Residential (including Low Income and Non-Low Income) customers pay for Residential programs.

V. Results

A. Electricity

Exhibit A - 9 contains the results for the economic development impacts of the 2010-2012 Massachusetts Electric EE Plan. This exhibit contains the key data requested in the RFP for Task A, i.e., “the economic activity and number of jobs generated by each $1 million of investment in energy efficiency as the sum of the direct and indirect jobs supported by $ investment in energy efficiency plus the jobs supported by the spending of the energy cost savings in the economy."[39]

Exhibit A - 9: Economic Development Impacts of Massachusetts Electric Energy Efficiency (EE) (Multipliers per $1 million)

	EE	Avoided Supply	Respending	EE Net Impact
MULTIPLIERS (per $1 million, 2009 $)				
Employment (job-years)	9.8	3.9	9.9	22.9[40]
Earnings	$658,600	$274,300	$539,100	$1,126,900[40]
Value-Added	$965,900	$473,900	$825,600	$1,478,300[40]
EXPENDITURES (2009 $, undiscounted)	$1,000,000	$3,804,300	$2,804,300	$1,000,000
IMPACTS	[1]	[2]	[3]	[1 - 2 + 3]
Employment (job-years)	9.8	14.8	27.9	22.9
Earnings	$658,600	$1,043,500	$1,511,800	$1,126,900
Value-Added	$965,900	$1,802,900	$2,315,200	$1,478,300

Note: Components may not add to totals due to rounding.

The first three rows represent the multipliers for the economic activity (Employment, Earnings and Value-Added) related to each $1 million of investment in energy efficiency.[41] As explained in more detail in Section VI, this

[39] As per footnote 1, unless otherwise stated, this analysis was conducted in terms of real 2009 $, undiscounted. Likewise, unless otherwise stated, all results are also presented in terms of real 2009 $, undiscounted.

[40] The EE Net Impact Multipliers are a function of both the multipliers and the expenditure amounts for EE, Avoided Supply and Respending. Hence, as illustrated in the exhibit under Impacts, with EE expenditures of $1 million, EE Net Impacts are a summation of EE, Avoided Supply and Respending. In this case (i.e., $1 million in EE expenditures), EE Net Impacts match EE Net Impact Multipliers.

[41] Employment, Earnings and Value-Added are defined in footnotes 5, 6, and 7. Earnings is the compensation associated with Employment. Value-Added is a measure of overall economic activity, including value from labor (Earnings) and capital (interest and profits). Earnings is included in Value-Added, so the multipliers for Earnings and Value-Added are not additive.

exhibit is also provided in spreadsheet form and Program Administrators can use it as a tool to modify various input assumptions, including EE expenditure levels and the Benefit/Cost ratio (which determines expenditure levels for Avoided Supply and Respending).

Exhibit A - 9 reflects that the 2010-2012 Electric Energy Efficiency Plan is highly cost effective: each $1 million in EE expenditures is estimated to result in $3.8 million of Avoided Supply and $2.8 million of Respending. So the impacts of EE spending are far larger than would be indicated just by looking at the EE activities themselves.

Each $1 million spent on EE results in 9.8 job-years due to the activities themselves, plus 27.9 additional job-years from the $2.8 million of Respending. The Net Employment Impact of EE spending is 22.9 job-years per $ 1 million. This reflects the EE activities themselves (9.8 job-years), plus Respending (27.9 job-years), minus the Avoided Supply (14.8 job-years).

So for Electric EE, the main impact on jobs relates to Respending. Per $1 million spent, Electric EE activities themselves have very similar multipliers to those for Respending (9.8 job-years vs. 9.9 job-years). However, each $1 million of EE results in $2.8 million of Respending, so the total effect of Respending (27.9 job-years) is greater than EE (9.8 job-years).

EE has a very large effect on Avoided Supply expenditures, with each $1 million of EE avoiding $3.8 million of supply. But Avoided Supply has much lower multipliers for jobs: 3.9 job-years vs. 9.8 for EE (and 9.9 for Respending).

Exhibit A - 9 also provides the results for two other measures of economic development: Earnings and Value-Added. Earnings is included in Value-Added, so the results for Earnings and Value-Added are not additive.[42]

The results for Earnings and Value-Added follow a pattern similar to that just described for Employment. The Earnings and Value-Added Multipliers are much lower for Avoided Supply than the Earnings and Value-Added Multipliers for EE and Respending, respectively. Electric EE is highly cost-effective, so the main impact on Earnings and Value-Added relates to Respending. The Net Impact per

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[42] See footnotes 6, 7, and 41.

$1 million of EE spending is Earnings of $1,126,900 and Value-Added of $1,478,300.

Thus, investment in Electric EE results in a shift of activity out of environmentally stressful, low multiplier supply into more environmentally benign, high multiplier EE, as well as a large amount of respending. Cost-effective energy efficiency reduces the cost of living and operating businesses and thus promotes economic development in Massachusetts. It increases the efficiency of the overall economy and makes the state a more attractive place for residents and businesses.

The benefits calculated for these programs in the existing 2010-2012 Massachusetts Electric Plan (April 30, 2009) were valued using the AESC 2007 Avoided Costs. But in allocating those costs, notably on the Electric side, TGG has taken into account the relevant Avoided Cost assumptions in the AESC 2009 Study. In particular, electricity Avoided Supply mainly consists of the operation of existing generation (principally gas-fired plants), new renewables, and transmission and distribution costs. The cost of operating existing gas- and oil-fired plants is mainly fuel. Natural gas and oil are costly, come from out of state, and generate few jobs. This explains why the Employment Multipliers for Avoided Supply are so much lower, and the costs of Avoided Supply are so much higher.

Even lower multipliers could have been used for Avoided Supply. The cost of compliance with RPS requirements is projected to be a major component of the Avoided Costs. TGG has assumed that the renewables avoided by Massachusetts EE would be built in-state, but this is not necessarily the case. If the renewables avoided are outside Massachusetts, then the Employment and other Multipliers for Avoided Supply would be lower.

More generally, TGG has assumed that all of the electric generation avoided by Massachusetts EE would be in-state, but much of it may actually be elsewhere in New England, or even outside the region.

In modeling avoided supply, TGG has selected assumptions that result in higher multipliers. But there are other assumptions that could be made that would result in higher multipliers for Avoided Supply (e.g., building new gas-fired plants or cost-effective renewables instead of burning gas in existing plants). However, because EE is so cost effective with relatively high multipliers, EE is economically advantageous by almost any reasonable sensitivity test.[43] As such, TGG is confident that the multipliers provided in this memorandum are reasonable numbers for policy-making.

Exhibit A - 10 provides two groups of multipliers (per lifetime GWh and per lifetime MW) to express the results on a physical unit basis, as requested in the RFP. Each of the two groups represents an alternative method of estimating the same economic development impacts of EE. Thus, the economic development impacts of a given amount of EE can be calculated on the basis of: (a) expenditures; or (b) lifetime GWh; or (c) lifetime MW.[44] The impacts as calculated on the basis of (a), (b), or (c) are not additive.

Exhibit A - 10: Economic Development Impacts of Massachusetts Electric Energy Efficiency (EE) (Multipliers per GWh and MW)

	EE	**Avoided Supply**	**Respending**	**EE Net Impact**
MULTIPLIERS (per lifetime GWh)	[1]	[2]	[3]	[1 - 2 + 3]
Employment (job-years)	0.46	0.70	1.32	1.09
Earnings (2009 $)	$31,200	$49,400	$71,500	$53,300
Value-Added (2009 $)	$45,700	$85,300	$109,500	$69,900
Cost ($/lifetime MWh, 2009 $, undiscounted)	$47.30	$179.94	$132.64	$47.30
MULTIPLIERS (per lifetime MW)	[1]	[2]	[3]	[1 - 2 + 3]
Employment (job-years)	2.9	4.3	8.2	6.7
Earnings (2009 $)	$193,300	$306,300	$443,700	$330,700
Value-Added (2009 $)	$283,500	$529,200	$679,500	$433,900
Cost ($/lifetime kW, 2009 $, undiscounted)	$293.51	$1,116.60	$823.09	$293.51

[43] The discount rate sensitivity analysis results presented in Section V.D support this point by demonstrating that Electric EE programs are highly cost effective and have large economic development benefits across a wide range of discount rates.

[44] As explained in more detail in Section VI, this exhibit is also provided in spreadsheet form and Program Administrators can use it as a tool to modify various input assumptions.

Note: Components may not add to totals due to rounding.

Finally, it is very helpful to step back from the details, and consider what these results mean for policy-making. Especially given the current economic downturn and the potential for continued high unemployment rates (particularly in construction) over the next several years, EE is an excellent and very timely opportunity for Massachusetts. But even if the construction industry is depressed, this does not assure that the underutilized resources are qualified to do EE. Good planning and understanding of the employment benefits of EE can help Massachusetts to maximize the employment advantages of these programs.

B. Gas

Exhibit A - 11 contains the results for the economic development impacts of the 2010-2012 Massachusetts Gas EE Plan. Like Exhibit A - 9, this exhibit contains the key data requested in the RFP for Task A, i.e., “the economic activity and number of jobs generated by each $1 million of investment in energy efficiency as the sum of the direct and indirect jobs supported by $ investment in energy efficiency plus the jobs supported by the spending of the energy cost savings in the economy.”

Exhibit A - 11: Economic Development Impacts of Massachusetts Gas Energy Efficiency (EE) (Multipliers per $1 million)

	EE	Avoided Supply	Respending	EE Net Impact
MULTIPLIERS (per $1 million, 2009 $)				
Employment (job-years)	11.0	3.5	9.9	19.1[45]
Earnings	$680,000	$276,500	$536,700	$885,200[45]
Value-Added	$949,200	$551,800	$818,700	$891,500[45]
EXPENDITURES (2009 $, undiscounted)	$1,000,000	$2,851,300	$1,851,300	$1,000,000
IMPACTS	[1]	[2]	[3]	[1 - 2 + 3]
Employment (job-years)	11.0	10.1	18.2	19.1
Earnings	$680,000	$788,400	$993,600	$885,200
Value-Added	$949,200	$1,573,300	$1,515,700	$891,500

Note: Components may not add to totals due to rounding.

The first three rows represent the multipliers for the economic activity (Employment, Earnings and Value-Added) related to each $1 million of investment in energy efficiency.[46] As explained in more detail in Section VI, this exhibit is also provided in spreadsheet form and Program Administrators can use it as a tool to modify various input assumptions, including EE expenditure levels and the Benefit/Cost ratio (which determines expenditure levels for Avoided Supply and Respending).

The Massachusetts Gas EE Plan is also very cost-effective – though somewhat less so than the Electric EE Plan. In the Gas Plan, $1 million in EE expenditures

[45] The EE Net Impact Multipliers are a function of both the multipliers and the expenditure amounts for EE, Avoided Supply and Respending. Hence, as illustrated in the exhibit under Impacts, with EE expenditures of $1 million, EE Net Impacts are a summation of EE, Avoided Supply and Respending. In this case (i.e., $1 million in EE expenditures), EE Net Impacts match EE Net Impact Multipliers.

[46] Employment, Earnings and Value-Added are defined in footnotes 5, 6, and 7. Earnings is the compensation associated with Employment. Value-Added is a measure of overall economic activity, including value from labor (Earnings) and capital (interest and profits). Earnings is included in Value-Added, so the results for Earnings and Value-Added are not additive.

is equivalent to $2.9 million in Avoided Supply and $1.9 million in Respending. In terms of jobs per $1 million in EE investment, the Net Employment Impact of the Massachusetts Gas Program is 19.1 job-years per $1 million.

Relative to the Electric EE analyzed in Exhibit A - 9, the Employment Multiplier for Gas EE activities (by themselves) is somewhat higher: 11.0 job-years per $1 million vs. 9.8 for Electric EE. This reflects that Gas EE tends to involve more on-site installation, labor, and sometimes overhead, compared with Electric EE.

However, because the Gas EE Plan is less cost-effective than the Electric EE Plan, Respending impacts are relatively lower, with Respending generating an impact of 18.2 job-years, which brings the Net Employment Impact of Gas EE to 19.1 job-years per $1 million. While this Multiplier is lower than the Net Employment Impact of the Electric EE expenditures (22.9 job-years), but nonetheless a very positive indicator.[47]

Thus, investment in Gas EE results in a shift of activity out of environmentally stressful, low multiplier supply into more environmentally benign, high multiplier EE, as well as a large amount of respending. As was the case for the Electric EE Plan, cost-effective energy efficiency for Gas also reduces the cost of living and operating businesses and thus promotes economic development in Massachusetts. It increases the efficiency of the overall economy and makes the state a more attractive place for residents and businesses.

The benefits calculated for these programs in the existing 2010-2012 Massachusetts Gas Plan (April 30, 2009) were valued using the AESC 2007 Avoided Costs. But any changes in avoided costs are unlikely to have any major effect in terms of altering the multipliers or overall results of this analysis.

Compared to electricity generation, gas supply is a more generic and stable technology. The calculation of Gas Avoided Costs is less complex and is driven mainly by changes in gas prices. Thus the Avoided Cost assumptions (and resulting multipliers) are more stable for gas than for electricity.

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[47] Compared with Electric EE, Gas EE also has lower Net Impact Multipliers for Earnings and Value-Added. These differences in Multipliers reflect the different characteristics of the underlying supply activities, as well as the different customer mix of the respending.

Gas Avoided Supply consists mainly of fuel costs. Natural gas is costly, comes from out of state, and generates few jobs. This explains why the Employment Multipliers for Avoided Supply are so much lower, and the costs of Avoided Supply are higher. Because Gas EE is cost effective with relatively high multipliers, it is economically advantageous by almost any reasonable sensitivity test.[48] As such, TGG is confident that the multipliers provided in this memorandum are reasonable numbers for policy-making.

The final group of multipliers in Exhibit A - 12 (per lifetime million therms) expresses the results on a physical unit basis, as requested in the RFP. The economic development impacts of a given amount of EE can be calculated on the basis of: (a) expenditures; or (b) lifetime therms.[49] The impacts as calculated on the basis of (a) or (b) are not additive.

Exhibit A - 12: Economic Development Impacts of Massachusetts Gas Energy Efficiency (EE) (Multipliers per lifetime million therms)

	EE	**Avoided Supply**	**Respending**	**EE Net Impact**
MULTIPLIERS (per lifetime million therms)	[1]	[2]	[3]	[1 - 2 + 3]
Employment (job-years)	4.5	4.1	7.5	7.8
Earnings (2009 $)	$278,700	$323,100	$407,200	$362,800
Value-Added (2009 $)	$389,000	$644,700	$621,100	$365,300
Cost ($/lifetime therm, 2009 $, undiscounted)	$0.41	$1.17	$0.76	$0.41

Note: Components may not add to totals due to rounding.

Finally, as with the case of Electric EE, it is very helpful to step back from the details, and consider what these results mean for policy-making. Especially given the current economic downturn and the potential for continued high unemployment rates (particularly in construction) over the next several years, Gas EE, with its high weighting on short-term employment, is also an excellent

[48] The discount rate sensitivity analysis results presented in Section V.D support this point by demonstrating that Gas EE programs are cost effective across a wide range of discount rates.

[49] As explained in more detail in Section VI, this exhibit is also provided in spreadsheet form and Program Administrators can use it as a tool to modify various input assumptions.

and very timely opportunity for Massachusetts. But even if the construction industry is depressed, this does not assure that the underutilized resources are qualified to do Gas EE. Good planning and understanding of the employment benefits of Gas EE can help Massachusetts to maximize the employment advantages of these programs.

C. Employment Duration: Jobs Versus Job-Years

This analysis has measured the economic development impacts of EE related to Employment in terms of job-years. A job-year is equivalent to one full-time job for one person for one year.[50] Analyses of economic development impacts often measure employment in terms of job-years, since this provides a convenient way of comparing part- and full-time jobs, as well as short- and long-term jobs.

Measuring employment in terms of job-years provides a convenient way of comparing various types of jobs, but most jobs do not last for just one year. So to estimate the number of jobs produced by EE programs, it is necessary to divide the number of job-years by the average job duration. For both the Electric and Gas EE programs, 10 years is a reasonable and useful approximation of the average job duration. As will be further explained in Section V.C.1, an average job duration of 10 years reflects the mix and duration of both short and long-term impacts from EE, avoided supply, and respending.

As detailed in the preceding sections, the Net Employment Impact of EE is 22.9 job-years per $1 million for Electric EE and 19.1 job-years per $1 million for Gas EE. Therefore, the Net Employment Impact of Electric EE is 2.3 jobs (lasting 10 years) per $1 million. The Net Employment Impact of Gas EE is 1.9 average jobs (lasting 10 years) per $1 million.

Based on the 10-year average job duration assumption, the 2010-2012 Massachusetts Electric and Gas EE Programs result in approximately 3500 jobs. This is equivalent to roughly 0.1% of Massachusetts employment and labor force.

1. Estimation of 10-Year Average Job Duration for EE

Calculating the number of jobs produced by EE programs is not as simple a matter as dividing the number of job-years by the length of the program (3 years

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[50] As defined in footnote 5.

in the case of the 2010-2012 Massachusetts EE Plans). EE programs produce a mix of short-term and long-term jobs. The short-term jobs relate directly to the implementation of the programs, so their duration is closely related to length of the program implementation period.[51]

The Massachusetts EE Plan programs also generate longer-term jobs as a result of respending. As long as consumer savings result from EE programs, there will be employment impacts in the form of long-term jobs related to this respending. The duration of respending jobs is thus related to the average measure life of the EE programs.[52]

Likewise, the Massachusetts EE Plan programs result in energy savings over the lifetime of the installed measures. This avoids energy supply activities and the associated jobs. So EE programs also have a longer-term impact in terms of avoided supply jobs, once again related to the average measure life of the EE programs.

So in relating job-years to jobs, it is necessary to determine an average job duration that reflects the mix of both short- and long-term effects from EE, Avoided Supply, and Respending. For the purposes of estimating average job duration, jobs related to EE program implementation can be treated as short-term, while jobs related to Avoided Supply and Respending can be treated as long-term.

On this basis, a 43:57 mix of short- and long-term jobs was estimated for Electric EE programs,[53] while a 57:43 mix was estimated for Gas EE programs.[54]

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[51] For the purposes of estimating average job duration, short-term EE jobs are assumed to have an average duration of 4 years. This assumption is based on the 3-year duration of the 2010-2012 EE Plan program implementation, plus one year to account for lags as effects ripple through the economy, as well as any program start-up and wind down.

[52] For the purposes of estimating average job duration, long-term EE jobs are assumed to have an average duration of 14 years for Electric EE and 20 years for Gas EE. The average measure life is 10.7 years for the 2010-2012 Electric EE programs and 17.1 years for the 2010-2012 Gas EE programs. The assumptions for average job duration of long-term EE jobs are based on the average measure life, plus approximately 3 years to account for the 3-year duration of the 2010-2012 EE Plan program implementation, and lags as effects ripple through the economy.

[53] As per Exhibit A - 9, the Net Employment Impact of Electric EE spending is 22.9 job-years per $ 1 million. This reflects the EE activities themselves (9.8 job-years), plus Respending (27.9 job-years), minus the Avoided Supply (14.8 job-years). So in the mix of short- and long-term jobs from Electric EE, short-term jobs have a weighting of 43% (9.8/22.9 = 43%); and long-term jobs have a weighting of 57% ((27.9-14.8)/22.9 = 57%).

Electric EE programs are more cost-effective than Gas EE, so result in more long-term Respending impacts. Moreover, the Employment Multiplier for EE activities (by themselves) is somewhat lower for Electric than for Gas (9.8 job-years per $1 million vs. 11.0). So compared with Gas, Electric EE has relatively less short-term Employment Impacts from program implementation.

The above methodology indicates that the average job relating to Electric EE lasts slightly less than 10 years,[55] and the average Gas-side job lasts slightly more than 10 years.[56] Compared with Electric EE programs, Gas EE programs have a much longer average measure life: 17.1 years for Gas EE vs. 10.7 years for Electric EE. But the effect of measure life upon average job duration is largely offset by the effect of job mix. Gas EE has a 57:43 mix of short- and long-term jobs vs. a 43:57 mix for Electric EE. In light of all these factors, TGG recommends that 10 years is a reasonable and useful approximation of the average job duration for both the Electric and Gas EE programs.

D. Discount Rate Sensitivity Analysis

The results provided in Exhibit A - 9 through Exhibit A - 12 above measure economic development impacts aggregated over the entire duration of those impacts. Employment, Earnings, and Value-Added are summed over time. The analysis was conducted in real 2009 $, undiscounted. As such, the baseline case for this analysis is with a zero discount rate.

This approach is consistent with the methodology typically utilized in studies of economic development impacts performed by TGG and others. In these studies, employment is generally the impact of greatest interest. It is not standard

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(footnote continued from previous page)

[54] As per Exhibit A - 11, the Net Employment Impact of Gas EE spending is 19.1 job-years per $ 1 million. This reflects the EE activities themselves (11.0 job-years), plus Respending (18.2 job-years), minus the Avoided Supply (10.1 job-years). So in the mix of short- and long-term jobs from Gas EE, short-term jobs have a weighting of 57% (11.0/19.1 = 57%); and long-term jobs have a weighting of 43% ((18.2-10.1)/19.1 = 43%).

[55] As per footnote 53, Electric EE programs have a 43:57 mix of short- and long term jobs. As per footnotes 51 and 52, short- and long-term jobs from Electric EE have durations of 4 years and 14 years, respectively. So the average job duration for Electric EE is estimated to be 9.7 years ((43% * 4) + (57% * 14) = 9.7 years).

[56] Gas EE programs have a 53:47 mix of short- and long term jobs. As per footnotes 51 and 52, short- and long-term jobs from Gas EE have durations of 4 years and 20 years, respectively. So the average job duration for Gas EE is estimated to be 10.9 years ((57% * 4) + (43% * 20) = 10.9 years).

practice to apply discounting to non-monetary measures such as jobs and job-years.[57]

In response to a request from the 2009 AESC Study Group, a discount rate sensitivity analysis was undertaken. Sensitivity analyses were conducted for both the Electric and Gas economic development impact results (expressed in multipliers per $1 million). The range of real discount rates used for the analyses included the following:

- 0.00% (the baseline);
- 1.13% (the discount rate used in the 2010-2012 EE Plans);[58]
- 1.74% (the discount rate generally used in the AESC 2009 study); [59]
- 7.32% (as per the Study Group's request).[60]

The results of the discount rate sensitivity analysis for the Electric EE programs are presented in Exhibit A - 13.

[57] Other economic development impacts (such as Earnings and Value-Added) are monetary measures, and discount rates are often applied to monetary measures. However to facilitate comparability, a consistent approach has been adopted in this analysis; all measures of economic development impacts are undiscounted.

[58] The April 30, 2009 EE Plans used a real discount rate based on a 3.66% nominal rate (calculated by DOER for ten year Treasury notes) and 2.50% inflation. See Electric EE Plan (pp. 67-68), Gas EE Plan (p. 50) and footnote 21.

[59] File: Common Financial Parameters 2009-04-03.xls.

[60] A discount rate of 10.00% was requested. This was assumed to be a nominal rate, with 2.50% inflation as assumed in the April 30, 2009 EE Plans.

Exhibit A - 13: Economic Development Impacts of Massachusetts Electric Energy Efficiency (EE) Sensitivity Analysis: Net Present Value Expenditures & Employment Impacts vs. Discount Rate

	Real Discount Rate	EE	Avoided Supply	Respending	EE Net Impact
MULTIPLIERS (per $1 million, 2009 $)					
Employment (job-years)		9.8	3.9	9.9	variable[61]
EXPENDITURES (2009 $, net present value)					
	0.00%	$1,000,000	$3,804,300	$2,804,300	$1,000,000
	1.13%	$1,000,000	$3,572,700	$2,572,700	$1,000,000
	1.74%	$1,000,000	$3,456,600	$2,456,600	$1,000,000
	7.32%	$1,000,000	$2,633,400	$1,633,400	$1,000,000
IMPACTS (net present value)		[1]	[2]	[3]	[1 - 2 + 3]
Employment (job-years)					
	0.00%	9.8	14.8	27.9	22.9
	1.13%	9.8	13.9	25.6	21.5
	1.74%	9.8	13.4	24.4	20.8
	7.32%	9.8	10.2	16.2	15.8

Note: Components may not add to totals due to rounding.

For the Electric EE Plan, the discount rate sensitivity analysis indicates that at low discount rates, i.e., at the range from 0.00% to 1.74% real discount rates, there is very little effect on the Employment (and other economic development) impacts. The Net Employment Impact drops from 22.9 job-years per $1 million (at a 0.00% real discount rate) to 20.8 (at a 1.74% real discount rate).

[61] The EE Net Impact Multipliers vary depending upon the discount rate. As explained in footnote 45, the EE Net Impact Multipliers are a function of both the multipliers and the expenditure amounts for EE, Avoided Supply and Respending. As illustrated in this exhibit under Expenditures, Net Present Value expenditures for Avoided Supply and Respending vary depending upon discount rate. In this exhibit (with $1 million in EE expenditures), EE Net Impact Multipliers match EE Net Impacts for each discount rate.

When the discount rate is increased to 7.32% real, the Net Employment Impact drops significantly, but is still 15.8 job-years per $1 million.

The Benefit/Cost ratio (i.e., Avoided Supply Expenditures divided by EE Expenditures) drops from 3.8 (at a 0.00% real discount rate) to 3.5 (at a 1.74% real discount rate) to 2.6 (at a 7.32% real discount rate). Thus even at a significantly higher discount rate, the Benefit/Cost ratio remains very attractive.

The sensitivity analysis demonstrates that even with a considerable increase in the discount rate, EE expenditures in the Massachusetts Electric EE Plan are highly beneficial in terms of cost effectiveness and economic development impacts.

The results of the discount rate sensitivity analysis for the Gas EE programs are presented in Exhibit A - 14.

Exhibit A - 14: Economic Development Impacts of Massachusetts Gas Energy Efficiency (EE) Sensitivity Analysis: Net Present Value Expenditures & Employment Impacts vs. Discount Rate

	Real Discount Rate	EE	Avoided Supply	Respending	EE Net Impact
MULTIPLIERS (per $1 million, 2009 $)					
Employment (job-years)		11.0	3.5	9.9	variable[62]
EXPENDITURES (2009 $, net present value)					
	0.00%	$1,000,000	$2,851,300	$1,851,300	$1,000,000
	1.13%	$1,000,000	$2,593,900	$1,593,900	$1,000,000
	1.74%	$1,000,000	$2,468,700	$1,468,700	$1,000,000
	7.32%	$1,000,000	$1,657,500	$657,500	$1,000,000
IMPACTS (net present value)		[1]	[2]	[3]	[1 - 2 + 3]
Employment (job-years)					
	0.00%	11.0	10.1	18.2	19.1
	1.13%	11.0	9.2	15.7	17.5
	1.74%	11.0	8.7	14.5	16.7
	7.32%	11.0	5.9	6.5	11.6

Note: Components may not add to totals due to rounding.

As was the case for the Electric EE Plan, the discount rate sensitivity analysis for the Gas EE Plan indicates that at low discount rates, i.e., at the range from 0.00% to 1.74% real discount rates, there is little effect on the Employment (and other economic development) impacts. The Net Employment Impact drops from 19.1 job-years per $1 million (at a 0.00% real discount rate) to 16.7 (at a 1.74% real discount rate).

[62] The EE Net Impact Multipliers vary depending upon the discount rate. As explained in footnote 45, the EE Net Impact Multipliers are a function of both the multipliers and the expenditure amounts for EE, Avoided Supply and Respending. As illustrated in this exhibit under Expenditures, Net Present Value expenditures for Avoided Supply and Respending vary depending upon discount rate. In this exhibit (with $1 million in EE expenditures), EE Net Impact Multipliers match EE Net Impacts for each discount rate.

When the discount rate is increased to 7.32% real, then the Net Employment Impact drops to 11.6 job-years per $1 million. Therefore a large increase in the discount rate on the Gas-side creates a relatively more significant impact than on the Electric-side. High discount rates have a greater impact on Gas EE programs because they have a much longer average measure life: 17.1 years for Gas EE vs. 10.7 years for Electric EE.

The Benefit/Cost ratio (i.e., Avoided Supply Expenditures divided by EE Expenditures) drops from 2.9 (at a 0.00% real discount rate) to 2.5 (at a 1.74% real discount rate) to 1.7 (at a 7.32% real discount rate). Though the Benefit/Cost ratio remains advantageous for Gas EE, the cost-effectiveness of the Gas EE Plan is much more sensitive to high discount rates. Again this increased sensitivity can be attributed to the much longer average measure life for Gas EE.

The sensitivity analysis for the Gas EE Plan demonstrates that even with a considerable increase in the discount rate, Gas EE expenditures remain beneficial in terms of cost effectiveness and economic development impacts. However the Gas EE Plan is significantly more sensitive to increases in the discount rate than is the Electric EE Plan.

E. Comparison with Other Studies

Consistent with numerous previous studies for Massachusetts and other jurisdictions, this analysis has also found that EE spending produces more economic development benefits than expenditures for a comparable amount of energy supply. The simple explanation is that Electric and Gas supply include a large fuel cost component, but spending on fuels that are produced outside of the state contributes little to the local economy.

The other key factor in favor of EE is cost-effectiveness. EE is typically significantly less expensive than avoided supply, and thus gives rise to substantial respending and associated economic development benefits. And once again, this is largely due to fuel costs. In particular, natural gas accounts for the bulk of avoided supply costs for both Electric and Gas EE.

In recent years, electric and gas supply costs have increased substantially, owing in large part to higher natural gas prices. This has further enhanced the cost-effectiveness of EE, and thus increased respending impacts.

Higher fuel prices have also had the effect of reducing the average multipliers (per $1 million dollar of spending) associated with avoided supply. As noted above, fuel costs (notably for gas and oil) contribute little to the local economy and thus have low multipliers. By comparison, the non-fuel components of energy supply costs (notably those which involve infrastructure within the state such as building and operating generation and T&D) have multipliers that are almost as high as those for implementation of EE activities.

So as fuel costs have risen, they account for a larger share of overall avoided supply costs. This gives more weight to fuel costs which have low multipliers and less weight to other avoided supply activities with relatively higher multipliers.

To summarize, natural gas and oil are costly, come from out of state, and generate few jobs. This explains why, in comparison with EE, Avoided Supply has multipliers which are so much lower, and costs which are so much higher.

These relationships and trends are clearly visible in the results of this and other studies analyzing the economic development impacts of EE. Exhibit A - 15 compares Electric EE multipliers (per $1 million) from this analysis with those from four other studies of Massachusetts and Rhode Island Electric EE programs:

- Massachusetts Statewide 2010-2012 (AESC 2009);
- Massachusetts Statewide 2003-2005;[63]
- Rhode Island National Grid 1990-2005;[64]
- Rhode Island National Grid 1990-2000;[65]
- Massachusetts Statewide1998.[66]

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[63] Massachusetts Saving Electricity: A Summary of the Performance of Electric Efficiency Programs Funded by Ratepayers Between 2003 and 2005, Executive Office of Energy and Environmental Affairs Massachusetts Division of Energy Resources, April 2, 2007. <http://www.mass.gov/Eoeea/docs/doer/electric_deregulation/ee03-05.pdf>.

[64] National Grid's Energy Efficiency Programs: Benefits for Rhode Island's Economic Development and Environment, prepared for National Grid USA, July 28, 2006. <http://www.thegoodman.com/pdf/081010033713_TGG20060728_NGridRI_Jobs.pdf>.

[65] Narragansett Electric's Energy Efficiency Programs: Benefits for Rhode Island's Economic Development and Environment, prepared for Narragansett Electric Company, August 14, 2001.

[66] DOER Report: 1998 Energy Efficiency Activities, Winter 2000. <http://www.mass.gov/Eoeea/docs/doer/electric_deregulation/ee-long.pdf>.

Except for the Massachusetts Statewide 2003-2005 study, all of these studies were performed by TGG.[67]

[67] TGG's analysis of Massachusetts 1998 EE programs did not appear as a separate report, but was instead incorporated into DOER's Annual Report to the Legislature (footnote 66).

Exhibit A - 15: Economic Development Impacts of Massachusetts Electric Energy Efficiency (EE): Comparison of AESC 2009 Results with Other Studies of New England Electric EE Programs (Multipliers per $1 million)

	EE	Avoided Supply	Respending	EE Net Impact
MULTIPLIERS (per $1 million, 2009 $)				
Employment (job-years)				
MA Statewide 2010-2012	9.8	3.9	9.9	22.9[68]
MA Statewide 2003-2005	NA	NA	NA	19.6[68]
RI National Grid 1990-2005	11.8	5.7	10.3	11.3[68]
RI National Grid 1990-2000	12.1	6.8	10.5	8.4[68]
MA Statewide 1998	11.7	7.4	11.5	5.9[68]
EXPENDITURES (2009 $, undiscounted)				
MA Statewide 2010-2012	$1,000,000	$3,804,300	$2,804,300	$1,000,000
MA Statewide 2003-2005	$1,000,000	$3,299,500	$2,299,500	$1,000,000
RI National Grid 1990-2005	$1,000,000	$2,119,400	$1,119,400	$1,000,000
RI National Grid 1990-2000	$1,000,000	$1,835,600	$835,600	$1,000,000
MA Statewide 1998	$1,000,000	$1,402,200	$402,200	$1,000,000
IMPACTS	[1]	[2]	[3]	[1 - 2 + 3]
Employment (job-years)				
MA Statewide 2010-2012	9.8	14.8	27.9	22.9
MA Statewide 2003-2005	NA	NA	NA	19.6
RI National Grid 1990-2005	11.8	12.1	11.5	11.3
RI National Grid 1990-2000	12.1	12.5	8.8	8.4
MA Statewide 1998	11.7	10.4	4.6	5.9

Note: Components may not add to totals due to rounding.

[68] The EE Net Impact Multipliers are a function of both the multipliers and the expenditure amounts for EE, Avoided Supply and Respending. Hence, as illustrated in the exhibit under Impacts, with EE expenditures of $1 million, EE Net Impacts are a summation of EE, Avoided Supply and Respending. In this case (i.e., $1 million in EE expenditures), EE Net Impacts match EE Net Impact Multipliers.

In Exhibit A - 15, the ordering of the studies is based on the implementation period (final year) of the Electric EE programs being analyzed. The current study of 2010-2012 programs appears at the top, with studies of earlier programs below. Put another way, the studies are listed in reverse chronological order, latest on top and earliest on the bottom.

For EE, Employment Multipliers range from 12.1 job-years per $1 million down to 9.8 (in the current study). Some of these differences reflect program mix, and Massachusetts vs. Rhode Island. Still, there does seem to be a slight downward trend over time. And all else equal, Employment Multipliers (in terms of job-years per constant $1 million) would be expected to gradually decline over time as productivity increases.

For Avoided Supply, Employment Multipliers range from 7.4 job-years per $1 million down to 3.9 (in the current study). Compared with EE, there is a clearer and more significant downward trend over time. As previously discussed,[69] this reflects important shifts in the nature of Avoided Supply activities. As fuel costs have risen, these low-multiplier activities account for a larger share of overall Avoided Supply costs. Meanwhile, the need for conventional new generation has receded far into the future, and Avoided Supply thus has less of the relatively high-multiplier activities related to building new supply.

For Respending, Employment Multipliers are similar to those for EE, ranging from 11.5 job-years per $1 million down to 9.9 (in the current study). As with EE, there seems to be a slight downward trend over time, which is to be expected as productivity increases.

For EE Net Impact, Employment Multipliers range from 5.9 job-years per $1 million <u>up</u> to 22.9 (in the current study). Compared with all of the other Employment Multipliers (EE, Avoided Supply, and Respending), there is a clear and dramatic upward trend over time for EE Net Impacts.

The upward trend in EE Net Impacts stems, in part, from the downward trend in Avoided Supply Multipliers. In effect, EE results in a shift of expenditures from Avoided Supply to EE and Respending. Over time, as Avoided Supply Multipliers have fallen, there is a larger difference between them and the Multipliers for EE and Respending. So each dollar shifted from Avoided Supply to EE and Respending results in a higher overall EE Net Impact.

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[69] See earlier in this Section V.E, and Section IV.A.2.

But the decline in Avoided Supply Multipliers is not the only, or even the main, factor driving the upward trend in EE Net Impacts. The most important factor is the dramatic upward trend in EE cost-effectiveness. This can be clearly seen In the Expenditures data in Exhibit A - 15.

The Benefit/Cost ratio (i.e., Avoided Supply Expenditures divided by EE Expenditures) has risen to 3.8 (at a 0.00% real discount rate) in the current study vs. only 1.4 for 1998 Massachusetts EE programs. So the 2010-2012 EE Programs result in $2.8 million of Respending per $1 million of EE vs. only $0.4 million for the 1998 programs.

Thus, per $1 million of EE, Respending Expenditures in the current study ($2.8 million) are 7.0 times the Respending Expenditures ($0.4 million) for the 1998 programs. Meanwhile, also per $1 million of EE, Avoided Supply Expenditures in the current study ($3.8 million) are also higher than for the 1998 programs ($1.4 million), but the increase is only a factor of 2.4.

The other studies in Exhibit A - 15 are intermediate in terms of their pattern of expenditures, but the overall trend is clear. The earlier three studies have Benefit/Cost ratios of 1.4 to 2.1, while the two most recent studies have ratios of 3.3 to 3.8. The EE Net Impact Employment Multipliers for the earlier three studies are 5.9 to 11.3 job-years per $1 million vs. 19.6 to 22.9 for the two most recent studies.

The upward trend in EE Net Impacts is principally due to the dramatic upward trend in EE cost-effectiveness. But as noted above, the upward trend in EE Net Impacts also stems, in part, from the downward trend in Avoided Supply Multipliers. In fact, the trends in EE cost-effectiveness and Avoided Supply Multipliers are related, and they have a synergistic effect to increase EE Net Impacts. Basically, the underlying driver in all these trends is the rise in avoided supply costs, mostly due to higher fuel costs.

The synergistic effect of these trends is clearly visible in the Exhibit A - 15 data for Employment Impacts. For the earlier three studies, each $1 million spent on EE resulted in about 12 job-years due to the activities themselves, minus a similar amount of job-years for Avoided Supply (ranging from 10.4 to 12.5 job-years). EE was becoming more cost-effective as Avoided Supply costs increased, and the Employment Multipliers for Avoided Supply were falling. Overall, the jobs implementing EE were similar in number to the jobs associated with Avoided Supply.

But as EE became more cost-effective, the Impacts from Respending in the earlier three studies increased, from 4.6 job-years up to 11.5 job-years. And since Employment Impacts were similar (and offsetting) for EE and Avoided Supply, the EE Net Employment Impacts were similar to Employment Impacts from Respending. So for the three earlier studies, EE Net Employment Impacts increase from 5.9 to 11.3 job-years.

By comparison, the EE Net Employment Impact in the current study is 22.9 job-years per $ 1 million. This reflects the Impact of the EE activities themselves (9.8 job-years), minus the Avoided Supply (14.8 job-years), plus Respending (27.9 job-years).

Relative to the three earlier studies, EE has become much more cost-effective as Avoided Supply costs have continued to increase, and the Employment Multipliers for Avoided Supply have continued to drop. But the increase in Avoided Supply costs has been more significant than the fall in Employment Multipliers for Avoided Supply. So per $1 million of EE expenditures, the Employment Impact from EE in the current study (9.8 job-years) is more than offset by the Employment Impact from Avoided Supply (14.8 job-years). EE is highly cost-effective, resulting in an Employment Impact for Respending of 27.9 job-years. So the Net Employment Impact of EE is 22.9 job-years (9.8 EE-14.8 Avoided Supply+27.9 Respending).

In contrast with the three earlier studies, the current study estimates that the Employment Impact from Avoided Supply (14.8 job-years) will actually be significantly larger than the Employment Impact from Electric EE (9.8 job-years). These results could potentially raise some concerns that implementation of the 2010-2012 Electric EE programs will actually provide less jobs than would the Avoided Supply.[70]

But actually, the overall results for the 2010-2012 Electric EE Programs are quite positive in regard to economic development impacts. In particular, the EE Net Employment Impacts estimated in the current study (22.9 job-years per $1 million) reflect that the 2010-2012 Massachusetts Electric EE Programs are very

[70] Such concerns are less likely to arise for Gas EE. As shown in Exhibit A - 11, each $1 million spent on 2010-2012 Gas EE programs results in 11.0 job-years due to the activities themselves, minus the Avoided Supply (10.1 job-years), plus Respending (18.2 job-years), for a Net Impact of 19.1 job-years.

cost-effective. Due to high fuel costs and other factors, avoided supply costs are high, but contribute little to the Massachusetts economy. So it is important to consider the entire set of economic development impacts associated with EE, rather than focus on any single aspect.

It is also important to consider that the Impacts from EE and Avoided Supply have very different time patterns. As discussed in Section V.C.1, the Employment Impacts from EE program implementation will take place over the next few years. Given the current economic downturn and the potential for continued high unemployment rates (particularly in construction) over the next several years, EE represents an excellent and very timely opportunity for Massachusetts.

By comparison, the Employment Impacts from Avoided Supply will be spread out over the entire period when the 2010-2012 EE Programs are reducing the need for energy supply. So the Employment Impacts from Avoided Supply will take place over a period of about 14 years and will be quite small in any one year. And any Employment Impacts from Avoided Supply will be more than offset by the very large positive Employment Impacts from Respending.

The energy situation is very dynamic and factors such as fuel costs can be highly volatile. So it is reassuring to note that the results in the current study are consistent with numerous previous studies for Massachusetts and other jurisdictions. As summarized in Exhibit A - 15, EE spending produces more economic development benefits than a comparable amount of energy supply.

It is further reassuring that another recent study of Massachusetts Electric EE estimated that the 2003-2005 Programs would have results almost as favorable as those estimated for the 2010-2012 Programs in the current study.[71] TGG did not participate in the study of 2003-2005 Programs, so in that regard it also provides an independent consistency check for the results of the current study.

Consistent with numerous previous studies for Massachusetts and other jurisdictions, the current study has also found that EE results in a shift of activity out of environmentally stressful, low multiplier Avoided Supply into more

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[71] As shown in Exhibit A - 15, the two most recent studies have Benefit/Cost ratios of 3.3 to 3.8 and EE Net Impact Employment Multipliers of 19.6 to 22.9 job-years per $1 million.

environmentally benign, high multiplier EE, as well as a large amount of respending.

Cost-effective energy efficiency reduces the cost of living and operating businesses and thus promotes economic development in Massachusetts. It increases the efficiency of the overall economy and makes the state a more attractive place for residents and businesses. And especially given the current economic downturn and the potential for continued high unemployment rates (particularly in construction) over the next several years, EE represents an excellent and very timely opportunity for Massachusetts.

VI. Usage Guide for Economic Development Multipliers

A. Introduction

The tables of economic development impacts are presented in Section V. Results for the 2010-2012 Massachusetts Electric EE Plan are provided in Exhibit A - 9 (Multipliers per $1 million) and Exhibit A - 10 (Multipliers per GWh and MW). Results for the 2010-2012 Massachusetts Gas EE Plan are provided in Exhibit A - 11 (Multipliers per $1 million) and Exhibit A - 12 (Multipliers per lifetime million therms).

Each of these tables is also provided electronically within a workbook. The first worksheet contains the two Electric EE tables (Exhibit A - 9 and Exhibit A - 10). The second worksheet contains the two Gas EE tables (Exhibit A - 11 and Exhibit A - 12).

Users have the ability to modify various input assumptions, including EE expenditure levels and the Benefit/Cost ratio (which determines expenditure levels for Avoided Supply and Respending). For the Electric EE worksheet, the default user-specified values are those assumed in Exhibit A - 9 and Exhibit A - 10. For the Gas EE worksheet, the default user-specified values are those assumed in Exhibit A - 11 and Exhibit A - 12.

Unless specifically noted, the AESC 2009 Economic Development analysis was conducted in real 2009 $, undiscounted. As further discussed in Section V.D, the baseline case for this analysis is with a zero discount rate.

Thus, in the Electric and Gas worksheets, all monetary data in the user-specified inputs (EE Expenditures, Avoided Supply Expenditures, Other Costs, and Other

Benefits) should be provided in 2009 $, undiscounted.[72] Likewise, all results in these worksheets for dollar values are in 2009 $, undiscounted.

Similarly, in the Electric and Gas worksheets, all physical unit data in the user-specified inputs (Energy Savings and Capacity Savings) should be provided in terms of lifetime avoided physical units of energy supply (MWh, kW, and therms). Thus, inputs for physical unit savings should be aggregated (undiscounted) over the lifetime of the EE measures. Likewise, all results in these worksheets for cost of energy and capacity savings are in terms of $ per lifetime physical units (MWh, kW, and therms), 2009 $, undiscounted.

A single analysis of Electric EE or Gas EE can include multiple programs and multiple years of program implementation. However, as specified above, all monetary inputs should be in 2009 $, undiscounted; physical units should be aggregated (undiscounted) over the lifetime of the EE measures.

B. User-Specified Inputs

In the Electric EE worksheet, the six inputs that users can specify are:

- EE Expenditures (2009 $, undiscounted)
- Avoided Supply Expenditures (2009 $, undiscounted)
- Other Costs (2009 $, undiscounted)
- Other Benefits (2009 $, undiscounted)
- Energy Savings (lifetime kWh)
- Capacity Savings (lifetime kW).

In the Gas EE worksheet, the five inputs that users can specify are:

- EE Expenditures (2009 $, undiscounted)
- Avoided Supply Expenditures (2009 $, undiscounted)
- Other Costs (2009 $, undiscounted)
- Other Benefits (2009 $, undiscounted)
- Energy Savings (lifetime therms).

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[72] Appendix C (Common Modeling Assumptions) provides Conversion Factors to 2009 $.

The user-specified values for these inputs are provided at the top of each worksheet and linked to the economic development impact calculations for that worksheet. If a user wishes to specify a different value for any of those inputs, that user-specified value should be entered directly within the worksheet.

Additional detail regarding each user-specified input is provided below.

1. EE Expenditures

For analysis of economic development impacts, EE Expenditures (for both Electric and Gas EE) include all direct utility costs, plus customer contributions, associated with program implementation. Thus, EE Expenditures include the following budget categories:

- Program Planning and Administration ("PP&A")
- Marketing and Advertising
- Customer Incentive
- Sales, Technical & Training
- Evaluation & Market Research.

As further discussed in Section VI.B.3, Shareholder Performance Incentives are assigned to the "Other Costs" category, and thus should not be included in EE Expenditures.

Lost Base Revenue should not be included in EE Expenditures, and more generally should not be included within analysis of economic development impacts.

In both the Electric and Gas EE worksheets, the default value for EE Expenditures is $1 million (2009 $, undiscounted).

2. Avoided Supply Expenditures

For analysis of economic development impacts, Avoided Supply Expenditures for Electric and Gas EE include Avoided Electricity Supply, Avoided Gas Supply, and any other Resource Benefits.

As further discussed in Section IV.A.2, in the 2010-2012 Massachusetts Electric EE Plan, Avoided Electricity Supply for Electric EE includes the following categories:

- T&D (Transmission and Distribution)
- DRIPE (Capacity and Energy)
- Generation (Capacity and Energy).[73]

In the 2010-2012 Massachusetts Gas EE Plan, Avoided Electricity Supply for Gas EE includes only the following categories:

- Capacity
- Energy.

In the 2010-2012 EE Plans, Avoided Gas Supply (for both Electric and Gas EE) is not further disaggregated.

Other Resource Benefits (for both Electric and Gas EE) include the following:

- Other Fuels (No. 2 Distillate Oil, No. 4 Fuel Oil, No. 6 Fuel Oil, Propane, Kerosene, Wood, Biofuels)[74]
- Water and Sewage[75].

As further discussed in Section VI.B.4, Non-Resource Benefits are assigned to the "Other Benefits" category, and thus should not be included in Avoided Supply Expenditures.

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[73] In the 2010-2012 Massachusetts Electric EE Plan, Generation Capacity data are always provided for Summer, and sometimes also for Winter; Generation Energy data are always provided for Annual, and sometimes also for Winter Peak, Winter Off-Peak, Summer Peak, and Summer Off-Peak.

[74] In the 2010-2012 Massachusetts Electric EE Plan, Other Fuels data are provided for No. 2 and No. 4 Oil, Propane, Kerosene, and Wood; on p. 70 there is reference to Biofuels, but no data are provided. In the 2010-2012 Massachusetts Gas EE Plan, Other Fuels data are provided for No. 2, No. 4, and No. 6 Oil, Propane, Kerosene, and Wood.

[75] The 2010-2012 Massachusetts Electric EE Plan (pp. 67, 70, and 226) documents that the Resource Benefit for Water includes Sewage and is based on a survey of public water and sewer rates in Massachusetts cites and towns. The 2010-2012 Massachusetts Gas EE Plan (p. 175) cites the same survey of water and sewer rates.

Users can specify Avoided Supply Expenditures using either:

- direct entry of a dollar amount for Avoided Supply Expenditures, or
- EE Expenditures * EE Benefit/Cost ratio.[76]

As noted in Section VI.A, the default user-specified values for Electric EE are those assumed in Exhibit A - 9. Thus, in the Electric worksheet, the default value for Avoided Supply Expenditures is specified as EE Expenditures ($1,000,000) * EE Benefit/Cost ratio (3.8043) = $3,804,300.[77]

As also noted in Section VI.A, the default user-specified values for Gas EE are those assumed in Exhibit A - 11. Thus, in the Gas worksheet, the default value for Avoided Supply Expenditures is specified as EE Expenditures ($1,000,000) * EE Benefit/Cost ratio (2.8513) = $2,851,300.[78]

3. Other Costs

For the purposes of the TRC Test, Shareholder Performance Incentives are included as EE Costs, together with program and participant costs. But for analysis of economic development impacts, Shareholder Performance Incentives can be more readily modeled separately from EE program and participant costs.

Thus, as described in Section VI.B.1 above, EE program and participant costs are assigned to the “EE Expenditures” category. And as will be further explained below, Shareholder Performance Incentives are assigned to the “Other Costs” category, and Other Costs are treated as a decrease in Respending.

[76] For analysis of economic development impacts, the EE Benefit/Cost ratio equals Avoided Supply Expenditures (2009 $, undiscounted) divided by EE Expenditures (2009 $, undiscounted).

[77] As noted in Section VI.B.1, the default value for Electric EE Expenditures equals $1,000,000. Based on the AESC 2009 analysis of the 2010-2012 Electric EE programs, there are $3,804,300 of Avoided Supply Expenditures per $1 million of EE Expenditures. Thus, the default value for EE Benefit/Cost ratio equals 3.8043 ($3,804,300/$1,000,000).

[78] As noted in Section VI.B.1, the default value for Gas EE Expenditures equals $1,000,000. Based on the AESC 2009 analysis of the 2010-2012 Gas EE programs, there are $2,851,300 of Avoided Supply Expenditures per $1 million of EE Expenditures. Thus, the default value for EE Benefit/Cost ratio equals 2.8513 ($2,851,300/$1,000,000).

Shareholder Performance Incentives do not have the same pattern of economic development impacts as do EE implementation activities. EE program and participant costs relate to specific EE implementation activities (e.g., manufacturing and installation of luminaires) that are included in TGG's BOG data for EE. These are activities with a large component of on-site work and relatively high multipliers.

By comparison, Shareholder Performance Incentives are transfers of funds to utility shareholders. For a variety of reasons, it is difficult to estimate how incentives to utility shareholders will contribute to economic activity within Massachusetts.[79] TGG has adopted the reasonable (and possibly conservative) assumption that Shareholder Performance Incentives have no economic development impacts within Massachusetts and are thus designated as "zero-multiplier activities".[80]

But even if incentives to utility shareholders are "zero-multiplier activities", there is still an impact in terms of Respending. Shareholder Performance Incentives are costs borne by utility customers. So in the calculation of Respending, Shareholder Performance Incentives result in a decrease in Respending. Thus, prior to considering Other Benefits in Section VI.B.4 below, Respending equals Avoided Supply Expenditures minus EE Expenditures minus Other Costs (Shareholder Performance Incentives).

As noted in Section VI.A, the default user-specified values for Electric EE are those assumed in Exhibit A - 9. Thus, in the Electric worksheet, the default value for Other Costs is specified as $58,700 (2009 $, undiscounted).[81]

[79] Utility shareholders may not be within Massachusetts. Some of Shareholder Performance Incentives will go to taxes, including to the US federal government and other jurisdictions outside of Massachusetts. A portion of any funds received by utility shareholders will be saved (including for long-term purposes such as retirement).

[80] As discussed in Section IV.A.2 and specifically footnote 23, all activities assumed to have no economic development impacts in Massachusetts are assigned multipliers of zero for Employment, Earnings and Value-Added, respectively, and are designated as "zero-multiplier activities". In TGG's modeling of Avoided Supply impacts, zero-multiplier activities include T&D Financing, DRIPE, Risk Premium/Retail Adder, and Emissions Allowances.

[81] As noted in Section VI.B.1, the default value for Electric EE Expenditures equals $1,000,000. Based on the AESC 2009 analysis of the 2010-2012 Electric EE programs, there are $58,700 of Other Costs (Shareholder Performance Incentives) per $1 million of EE Expenditures.

As also noted in Section VI.A, the default user-specified values for Gas EE are those assumed in Exhibit A - 11. Thus, in the Gas worksheet, the default value for Other Costs is specified as $54,400 (2009 $, undiscounted).[82]

4. Other Benefits

For the purposes of the TRC Test, Non-Resource Benefits are included as EE Benefits, together with Resource Benefits (Avoided Supply for Electricity, Gas, other fuels, and water/sewage).[83] But for analysis of economic development impacts, Non-Resource Benefits can be more readily modeled separately from EE Resource Benefits.

Thus, as described in Section VI.B.2 above, EE Resource Benefits are assigned to the "Avoided Supply Expenditures" category. And as will be further explained below, EE Non-Resource Benefits are assigned to the "Other Benefits" category, and Other Benefits are treated as an increase in Respending.

EE Non-Resource Benefits do not have the same pattern of economic development impacts as do Avoided Supply Expenditures. EE Resource Benefits relate to specific Avoided Supply activities (e.g., manufacturing and installation of turbines) that are included in TGG's BOG data for Avoided Supply.

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[82] As noted in Section VI.B.1, the default value for Gas EE Expenditures equals $1,000,000. Based on the AESC 2009 analysis of the 2010-2012 Gas EE programs, there are $54.400 of Other Costs (Shareholder Performance Incentives) per $1 million of EE Expenditures.

[83] As per the Guidelines (§3.3.3) established in D.P.U. 98-100:

> Participant Non-Resource Benefits shall include factors such as, but not limited to, (i) reduced costs for operation and maintenance associated with efficient equipment or practices; (ii) the value of longer equipment replacement cycles and/or productivity improvements associated with efficient equipment; (iii) reduced environmental and safety costs, such as those for changes in a waste stream or disposal of lamp ballasts or ozone-depleting chemicals; and (iv) reduced disconnections for inability to pay.

<http://www.mass.gov/Eoeea/docs/dpu/energy_efficiency/energy_efficiency_legislation_and_regulations/investigation_to_establish_methods_and_procedures_to_evaluate_and_approve_energy_efficiency_programs_DTE_98-100_2000.pdf>

While some of these Avoided Supply activities have a large component of on-site work and relatively high multipliers, some have low multipliers.[84] And some Avoided Supply activities are assumed to have no economic development impacts within Massachusetts and are thus designated as "zero-multiplier activities".[85]

But for all Avoided Supply Expenditures (including those for "zero-multiplier activities"), there is still an impact in terms of Respending. Avoided Supply Expenditures are costs which do not have to be borne by utility customers. So in the calculation of Respending, all Avoided Supply Expenditures result in an increase in Respending.

Following the above summary of the economic development impacts of Avoided Supply Expenditures, the impacts of EE Non-Resource Benefits can be compared. EE Non-Resource Benefits are reductions in customer costs (and otherwise benefits for customers). EE Non-Resource Benefits can include a variety of factors, ranging from reduced customer O&M costs to reduced disconnections for inability to pay.[86] The 2010-2012 Massachusetts Electric and Gas EE Plans do not provide detail as to the composition of Non-Resource Benefits. It is thus difficult to estimate how Non-Resource Benefits will affect economic activity within Massachusetts.

Given these uncertainties, TGG has adopted the assumption that Non-Resource Benefits have no economic development impacts within Massachusetts and are thus designated as "zero-multiplier activities".[87] But since Non-Resource Benefits are reductions in customer costs (and otherwise benefits for customers),

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[84] The non-fuel components of energy supply costs (notably those which involve in-state infrastructure, such as building and operating generation and T&D) have multipliers that are almost as high as those for implementation of EE activities. But a major portion of Avoided Supply Expenditures are fuel costs (notably for gas and oil) which contribute little to the local economy and thus have low multipliers.

[85] As discussed in Section IV.A.2 and specifically footnote 23, all activities assumed to have no economic development impacts in Massachusetts are assigned multipliers of zero for Employment, Earnings and Value-Added, respectively, and are designated as "zero-multiplier activities". In TGG's modeling of Avoided Supply impacts, zero-multiplier activities include T&D Financing, DRIPE, Risk Premium/Retail Adder, and Emissions Allowances.

[86] See footnote 83.

[87] As discussed in Section IV.A.2 and specifically footnote 23, all activities assumed to have no economic development impacts in Massachusetts are assigned multipliers of zero for Employment, Earnings and Value-Added, respectively, and are designated as "zero-multiplier activities". In TGG's modeling of Avoided Supply impacts, zero-multiplier activities include T&D Financing, DRIPE, Risk Premium/Retail Adder, and Emissions Allowances.

Non-Resource Benefits result in (at least to some extent) an increase in Respending. Thus, Respending equals Avoided Supply Expenditures minus EE Expenditures minus Other Costs (Shareholder Performance Incentives) plus Other Benefits (Non-Resource Benefits).

As discussed above, it is difficult to estimate how Non-Resource Benefits will affect economic activity within Massachusetts. Thus, TGG recommends the reasonable (and possibly conservative) convention that Non-Resource Benefits be included as an increase in Respending only to the extent that they offset the decrease in Respending from Other Costs (Shareholder Performance Incentives).

As noted in Section VI.A, the default user-specified values for Electric EE are those assumed in Exhibit A - 9. Thus, in the Electric worksheet, the default value for Other Benefits is specified as $58,700 (2009 $, undiscounted).[88]

As also noted in Section VI.A, the default user-specified values for Gas EE are those assumed in Exhibit A - 11. Thus, in the Gas worksheet, the default value for Other Benefits is specified as $54,400 (2009 $, undiscounted).[89]

5. EE Energy Savings

Users can specify Electric EE Energy Savings (lifetime MWh) using either:

- direct entry of a MWh amount for EE Energy Savings, or
- EE Expenditures / EE Energy Cost.[90]

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[88] As noted in Section VI.B.1, the default value for Electric EE Expenditures equals $1,000,000. The 2010-2012 Electric EE programs are estimated to have $181,900 of Non-Resource Benefits per $1 million of EE Expenditures (2009 $, undiscounted). But as discussed in Section VI.B.3 and specifically footnote 81, there are $58,700 of Other Costs (Shareholder Performance Incentives) per $1 million of EE Expenditures. Thus, in Exhibit A - 9 and in the default user-specified values for Electric EE, the amount of Non-Resource Benefits has been limited to $58,700.

[89] As noted in Section VI.B.1, the default value for Gas EE Expenditures equals $1,000,000. The 2010-2012 Gas EE programs are estimated to have $82,100 of Non-Resource Benefits per $1 million of EE Expenditures (2009 $, undiscounted). But as discussed in Section VI.B.3 and specifically footnote 82, there are $54,400 of Other Costs (Shareholder Performance Incentives) per $1 million of EE Expenditures. Thus, in Exhibit A - 11 and in the default user-specified values for Gas EE, the amount of Non-Resource Benefits has been limited to $54,400.

Users can specify Gas EE Energy Savings (lifetime therm) using either:

- direct entry of a therm amount for EE Energy Savings, or
- EE Expenditures / EE Energy Cost.[91]

As noted in Section VI.A, the default user-specified values for Electric EE are those assumed in Exhibit A - 9 and Exhibit A - 10. Thus, in the Electric worksheet, the default value for Energy Savings is specified as EE Expenditures ($1,000,000) / EE Energy Cost ($47.30/lifetime MWh, 2009 $, undiscounted) = 21,142 lifetime MWh.[92]

As noted in Section VI.A, the default user-specified values for Gas EE are those assumed in Exhibit A - 11 and Exhibit A - 12. Thus, in the Gas worksheet, the default value for Energy Savings is specified as EE Expenditures ($1,000,000) / EE Energy Cost ($0.41/lifetime therm, 2009 $, undiscounted) = 2,439,024 lifetime therms.[93]

6. EE Capacity Savings

Users can specify Electric EE Capacity Savings (lifetime kW) using either:

- direct entry of a kW amount for EE Capacity Savings, or

(footnote continued from previous page)

[90] For analysis of economic development impacts for Electric EE, the EE Energy Cost ($/lifetime MWh, 2009 $, undiscounted) equals EE Expenditures (2009 $, undiscounted) divided by EE Energy Savings (lifetime MWh).

[91] For analysis of economic development impacts for Gas EE, the EE Energy Cost ($/lifetime therm, 2009 $, undiscounted) equals EE Expenditures (2009 $, undiscounted) divided by EE Energy Savings (lifetime therms).

[92] As noted in Section VI.B.1, the default value for Electric EE Expenditures equals $1,000,000. Based on the AESC 2009 analysis of the 2010-2012 Electric EE programs, there are 21,142 lifetime MWh of EE Energy Savings per $1 million of EE Expenditures. Thus, the default value for EE Energy Cost equals $47.30/lifetime MWh ($1,000,000/21,142 MWh).

[93] As noted in Section VI.B.1, the default value for Gas EE Expenditures equals $1,000,000. Based on the AESC 2009 analysis of the 2010-2012 Gas EE programs, there are 2,439,024 lifetime therms of EE Energy Savings per $1 million of EE Expenditures. Thus, the default value for EE Energy Cost equals $0.41/lifetime therms ($1,000,000/2,439,024 therms).

- EE Expenditures / EE Capacity Cost.[94]

As noted in Section VI.A, the default user-specified values for Electric EE are those assumed in Exhibit A - 9 and Exhibit A - 10. Thus, in the Electric worksheet, the default value for Energy Savings is specified as EE Expenditures ($1,000,000) / EE Capacity Cost ($293.51/lifetime kW, 2009 $, undiscounted) = 3,407 lifetime kW.[95]

C. Worksheet Structure

Multipliers per $1 million for EE, Avoided Supply, and Respending are results from the IMPLAN model. These results, and their bases, are documented in Sections III, IV, and V above. Users should not normally need to modify these values.

The Expenditure amounts are determined by the user-specified values (for EE Expenditures, Avoided Supply Expenditures, Other Costs, and Other Benefits). The EE Net Impact Multipliers per $1 million are a function of both the Multipliers and the Expenditure amounts for EE, Avoided Supply and Respending. As such, the EE Net Impact Multipliers per $1 million will vary as the Expenditure amounts vary based on the user-specified values (for EE Expenditures, Avoided Supply Expenditures, Other Costs, and Other Benefits).

Likewise, Impacts are a function of both the Multipliers and the Expenditure amounts. As such, Impacts will vary as the Expenditure amounts vary based on the user-specified values (for EE Expenditures, Avoided Supply Expenditures, Other Costs, and Other Benefits).

Physical unit Multipliers (per lifetime GWh, per lifetime MW, and per lifetime therm) are a function of the Multipliers per $1 million, the Expenditure amounts, and the physical unit savings (EE Energy and Capacity Savings). As such, physical unit Multipliers will vary based on the user-specified values.

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[94] For analysis of economic development impacts, the EE Capacity Cost ($/lifetime kW, 2009 $, undiscounted) equals EE Expenditures (2009 $, undiscounted) divided by EE Capacity Savings (lifetime kW).

[95] As noted in Section VI.B.1, the default value for Electric EE Expenditures equals $1,000,000. Based on the AESC 2009 analysis of the 2010-2012 Electric EE programs, there are 3,407 lifetime kW of EE Capacity Savings per $1 million of EE Expenditures. Thus, the default value for EE Capacity Cost equals $293.51/lifetime kW ($1,000,000/3,407 kW).

Table One: Avoided Cost of Electricity (2009$) Results : Maine

State ME

User-defined Inputs	
Wholesale Risk Premium (WRP)	9%
Real Discount Rate	2.22%

	Avoided Unit Cost of Electric Energy[1]				Avoided Unit Cost of Electric Capacity[2]		DRIPE: 2010 vintage measures Total					DRIPE: 2011 vintage measures Total					Avoided Externality Costs			
							Energy				Capacity (See note 2)	Energy				Capacity (See note 2)				
	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	kW sold into FCA (PA to determine quantity)[3]	kW purchased from FCA (PA to determine quantity)	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Annual Value	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Annual Value	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kw-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh
Period:	a	b	c	d	e=y*1.08	f=y*(1+z)*(1+PTF Loss)*(1+WRP)	g	h	i	j	k	l	m	n	o	p	q	r	s	t
2009	0.000	0.000	0.000	0.000													0.039	0.039	0.038	0.041
2010	0.070	0.056	0.071	0.054	65.84	0.00	0.067	0.042	0.073	0.045		0.000	0.000	0.000	0.000		0.039	0.039	0.038	0.041
2011	0.074	0.060	0.075	0.057	50.58	0.00	0.069	0.043	0.074	0.045		0.071	0.045	0.077	0.047		0.039	0.039	0.038	0.041
2012	0.079	0.064	0.079	0.061	35.74	0.00	0.075	0.047	0.078	0.048		0.076	0.048	0.079	0.049		0.039	0.039	0.038	0.041
2013	0.080	0.068	0.083	0.067	16.85	0.00	0.037	0.024	0.039	0.026	10.00	0.037	0.025	0.040	0.026		0.033	0.033	0.032	0.034
2014	0.081	0.070	0.083	0.067	16.85	19.86	0.032	0.021	0.034	0.022	14.00	0.034	0.022	0.036	0.023	10.00	0.032	0.032	0.031	0.033
2015	0.081	0.070	0.085	0.068	18.14	21.40	0.028	0.019	0.031	0.020	9.00	0.028	0.019	0.031	0.020	14.00	0.030	0.031	0.030	0.032
2016	0.082	0.072	0.088	0.070	19.44	22.97	0.025	0.017	0.028	0.017	4.00	0.025	0.017	0.028	0.018	9.00	0.029	0.030	0.028	0.031
2017	0.085	0.074	0.090	0.072	19.44	22.98	0.022	0.015	0.024	0.015		0.022	0.015	0.024	0.016	4.00	0.028	0.028	0.027	0.029
2018	0.087	0.076	0.091	0.075	20.74	24.54	0.018	0.013	0.020	0.013		0.018	0.013	0.020	0.013		0.027	0.027	0.026	0.028
2019	0.087	0.076	0.092	0.075	20.74	24.56	0.015	0.010	0.016	0.011		0.015	0.010	0.016	0.011		0.026	0.026	0.025	0.027
2020	0.086	0.076	0.094	0.074	22.03	26.11	0.011	0.008	0.012	0.008		0.011	0.008	0.012	0.008		0.024	0.025	0.024	0.026
2021	0.085	0.075	0.088	0.075	23.33	27.67	0.007	0.005	0.008	0.005		0.007	0.005	0.008	0.005		0.023	0.024	0.023	0.024
2022	0.086	0.077	0.090	0.076	24.62	29.24	0.004	0.003	0.004	0.003		0.004	0.003	0.004	0.003		0.022	0.022	0.021	0.023
2023	0.088	0.076	0.095	0.075	25.92	30.80	0.000	0.000	0.000	0.000		0.000	0.000	0.000	0.000		0.021	0.021	0.020	0.022
2024	0.092	0.078	0.100	0.080	27.22	32.37											0.020	0.020	0.019	0.021
2025	0.094	0.079	0.102	0.081	40.18	47.82											0.020	0.020	0.019	0.021
2026	0.095	0.080	0.104	0.083	53.14	63.31											0.020	0.020	0.019	0.021
2027	0.097	0.081	0.107	0.085	66.10	78.81											0.020	0.020	0.019	0.021
2028	0.098	0.082	0.109	0.087	79.06	94.35											0.020	0.020	0.019	0.021
2029	0.100	0.083	0.111	0.088	92.02	109.91											0.020	0.020	0.019	0.021
2030	0.102	0.085	0.114	0.090	103.68	123.95											0.020	0.020	0.019	0.021
2031	0.103	0.086	0.116	0.092	103.68	124.05											0.020	0.020	0.019	0.021
2032	0.105	0.087	0.119	0.094	103.68	124.16											0.020	0.020	0.019	0.021
2033	0.107	0.089	0.121	0.096	103.68	124.27											0.020	0.020	0.019	0.021
2034	0.109	0.090	0.124	0.098	103.68	124.37											0.020	0.020	0.019	0.021
2035	0.110	0.091	0.127	0.100	103.68	124.48											0.020	0.020	0.019	0.021
2036	0.112	0.093	0.130	0.102	103.68	124.59											0.020	0.020	0.019	0.021
2037	0.114	0.094	0.132	0.105	103.68	124.69											0.020	0.020	0.019	0.021
2038	0.116	0.095	0.135	0.107	103.68	124.80											0.020	0.020	0.019	0.021
2039	0.118	0.097	0.138	0.109	103.68	124.91											0.020	0.020	0.019	0.021
Levelized Costs																				
10 years (2010-2019)	0.080	0.068	0.083	0.066	29.21	12.99	0.040	0.026	0.043	0.027	3.97	0.033	0.022	0.036	0.023	3.97	0.032	0.033	0.032	0.034
15 years (2010-2024)	0.083	0.070	0.086	0.069	27.83	17.81	0.029	0.019	0.032	0.020	2.79	0.025	0.016	0.027	0.017	2.79	0.029	0.030	0.029	0.031
30 years (2010-2039)	0.092	0.077	0.100	0.079	53.65	55.24											0.025	0.026	0.025	0.027

NOTES:

General All Avoided Costs are in Year 2009 Dollars

ISO NE periods: Summer is June through September, Winter is all other months. Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are all other hours

1 Avoided cost of electric energy = (wholesale energy avoided cost + REC cost to load) * risk premium, e.g. A= (U + AB) * (1+Wholesale Risk Premium)

2 Absolute value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year, PA strategy re bidding that reduction into applicable FCAs, and unit values in columns e, f, k and p.

3 For only 2010 and 2011; proceeds from selling into the FCM include the reserve margin, in addition to the ISO-NE loss factor of 8%

Table Two: Inputs to Avoided Cost Calculations

Zone: Maine

	Wholesale Avoided Costs of Electricity						Avoided REC Costs to Load
	Energy				Capacity		
	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	FCA Price	Reserve Margin	REC Costs
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	%	$/kWh
Period:	u	v	w	x	y	z	aa
2009							
2010	0.063	0.050	0.064	0.048	52.51	16.1%	0.0011
2011	0.067	0.053	0.068	0.051	41.18	13.7%	0.0012
2012	0.071	0.057	0.071	0.054	33.09	14.4%	0.0012
2013	0.072	0.061	0.074	0.060	15.60	14.6%	0.0016
2014	0.072	0.062	0.074	0.059	15.60	14.6%	0.0020
2015	0.073	0.062	0.075	0.060	16.80	14.7%	0.0021
2016	0.073	0.064	0.078	0.062	18.00	14.9%	0.0024
2017	0.075	0.065	0.079	0.063	18.00	15.0%	0.0032
2018	0.077	0.066	0.081	0.066	19.20	15.1%	0.0033
2019	0.077	0.067	0.082	0.066	19.20	15.2%	0.0027
2020	0.077	0.068	0.084	0.065	20.40	15.3%	0.0024
2021	0.076	0.067	0.079	0.067	21.60	15.4%	0.0019
2022	0.077	0.069	0.081	0.068	22.80	15.4%	0.0016
2023	0.080	0.069	0.086	0.067	24.00	15.5%	0.0011
2024	0.084	0.071	0.092	0.073	25.20	15.6%	0.0003
2025	0.086	0.072	0.094	0.074	37.20	15.7%	0.0003
2026	0.087	0.073	0.096	0.076	49.20	15.8%	0.0002
2027	0.089	0.074	0.098	0.078	61.20	15.9%	0.0002
2028	0.090	0.075	0.100	0.079	73.20	16.0%	0.0002
2029	0.092	0.076	0.102	0.081	85.20	16.1%	0.0002
2030	0.093	0.078	0.104	0.083	96.00	16.2%	0.0002
2031	0.095	0.079	0.107	0.084	96.00	16.3%	0.0002
2032	0.096	0.080	0.109	0.086	96.00	16.4%	0.0002
2033	0.098	0.081	0.111	0.088	96.00	16.5%	0.0002
2034	0.099	0.082	0.114	0.090	96.00	16.6%	0.0002
2035	0.101	0.083	0.116	0.092	96.00	16.7%	0.0002
2036	0.103	0.085	0.119	0.094	96.00	16.8%	0.0002
2037	0.105	0.086	0.121	0.096	96.00	16.9%	0.0002
2038	0.106	0.087	0.124	0.098	96.00	17.0%	0.0002
2039	0.108	0.089	0.127	0.100	96.00	17.1%	0.0002
Levelized Costs							
10 years (2010-2019)	0.072	0.060	0.074	0.059	25.502	14.8%	0.002
15 years (2010-2024)	0.074	0.063	0.077	0.061	24.682	15.0%	0.002
30 years (2010-2039)	0.083	0.070	0.090	0.072	49.045	15.6%	0.001

NOTES: General — All Avoided Costs are in Year 2009 Dollars

ISO NE periods: Summer is June through September, Winter is all other months. Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are all other hours

Table One: Avoided Cost of Electricity (2009$) Results : Vermont

State VT

User-defined Inputs	
Wholesale Risk Premium (WRP)	11%
Real Discount Rate	2.22%

	Avoided Unit Cost of Electric Energy[1]				Avoided Unit Cost of Electric Capacity[2]		DRIPE: 2010 vintage measures Total					DRIPE: 2011 vintage measures Total					Avoided Externality Costs			
							Energy				Capacity (See note 2)	Energy				Capacity (See note 2)				
	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	kW sold into FCA (PA to determine quantity)[3]	kW purchased from FCA (PA to determine quantity)	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Annual Value	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Annual Value	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak
Units:	**$/kWh**	**$/kWh**	**$/kWh**	**$/kWh**	**$/kW-yr**	**$/kW-yr**	**$/kWh**	**$/kWh**	**$/kWh**	**$/kWh**	**$/kw-yr**	**$/kWh**	**$/kWh**	**$/kWh**	**$/kWh**	**$/kW-yr**	**$/kWh**	**$/kWh**	**$/kWh**	**$/kWh**
Period:	**a**	**b**	**c**	**d**	**e=y*1.08**	**f=y*(1+z)*(1+PTF Loss)*(1+WRP)**	**g**	**h**	**i**	**j**	**k**	**l**	**m**	**n**	**o**	**p**	**q**	**r**	**s**	**t**
2009	0.000	0.000	0.000	0.000													0.039	0.039	0.038	0.041
2010	0.075	0.058	0.078	0.057	65.84	*0.00*	0.062	0.040	0.071	0.043		0.000	0.000	0.000	0.000		0.039	0.039	0.038	0.041
2011	0.080	0.063	0.082	0.060	50.58	*0.00*	0.064	0.042	0.072	0.043		0.066	0.043	0.075	0.045		0.039	0.039	0.038	0.041
2012	0.087	0.068	0.086	0.063	35.74	*0.00*	0.070	0.045	0.076	0.046		0.071	0.046	0.078	0.047		0.039	0.039	0.038	0.041
2013	0.088	0.072	0.089	0.070	16.85	0.00	0.035	0.024	0.039	0.025	3.00	0.035	0.024	0.039	0.025		0.033	0.033	0.032	0.034
2014	0.089	0.074	0.090	0.071	16.85	19.33	0.030	0.020	0.033	0.021	5.00	0.032	0.022	0.036	0.023	3.00	0.032	0.032	0.031	0.033
2015	0.090	0.075	0.093	0.071	18.14	20.74	0.027	0.018	0.031	0.019	3.00	0.027	0.018	0.031	0.019	5.00	0.030	0.031	0.030	0.032
2016	0.091	0.077	0.097	0.073	19.44	22.18	0.024	0.016	0.028	0.017	1.00	0.024	0.016	0.028	0.017	3.00	0.029	0.030	0.028	0.031
2017	0.093	0.080	0.099	0.077	19.44	22.20	0.020	0.014	0.024	0.015		0.021	0.014	0.024	0.015	1.00	0.028	0.028	0.027	0.029
2018	0.097	0.082	0.101	0.080	20.74	23.62	0.018	0.012	0.020	0.013		0.018	0.012	0.020	0.013		0.027	0.027	0.026	0.028
2019	0.097	0.083	0.103	0.080	20.74	23.64	0.014	0.010	0.016	0.010		0.014	0.010	0.016	0.010		0.026	0.026	0.025	0.027
2020	0.097	0.083	0.102	0.080	22.03	25.07	0.010	0.007	0.012	0.008		0.010	0.007	0.012	0.008		0.024	0.025	0.024	0.026
2021	0.095	0.081	0.100	0.080	23.33	26.50	0.007	0.005	0.008	0.005		0.007	0.005	0.008	0.005		0.023	0.024	0.023	0.024
2022	0.096	0.083	0.102	0.081	24.62	27.93	0.003	0.002	0.004	0.003		0.003	0.002	0.004	0.003		0.022	0.022	0.021	0.023
2023	0.098	0.083	0.105	0.083	25.92	29.37											0.021	0.021	0.020	0.022
2024	0.102	0.084	0.111	0.087	27.22	30.81											0.020	0.020	0.019	0.021
2025	0.104	0.085	0.113	0.089	40.18	44.99											0.020	0.020	0.019	0.021
2026	0.105	0.086	0.115	0.091	53.14	59.19											0.020	0.020	0.019	0.021
2027	0.107	0.088	0.118	0.093	66.10	73.42											0.020	0.020	0.019	0.021
2028	0.109	0.089	0.120	0.096	79.06	87.67											0.020	0.020	0.019	0.021
2029	0.111	0.090	0.123	0.098	92.02	101.94											0.020	0.020	0.019	0.021
2030	0.113	0.092	0.126	0.100	103.68	114.82											0.020	0.020	0.019	0.021
2031	0.114	0.093	0.128	0.103	103.68	114.92											0.020	0.020	0.019	0.021
2032	0.116	0.094	0.131	0.105	103.68	115.02											0.020	0.020	0.019	0.021
2033	0.118	0.096	0.134	0.108	103.68	115.12											0.020	0.020	0.019	0.021
2034	0.120	0.097	0.137	0.111	103.68	115.21											0.020	0.020	0.019	0.021
2035	0.122	0.099	0.140	0.113	103.68	115.31											0.020	0.020	0.019	0.021
2036	0.124	0.100	0.143	0.116	103.68	115.41											0.020	0.020	0.019	0.021
2037	0.126	0.102	0.146	0.119	103.68	115.51											0.020	0.020	0.019	0.021
2038	0.128	0.103	0.149	0.122	103.68	115.61											0.020	0.020	0.019	0.021
2039	0.131	0.105	0.152	0.125	103.68	115.70											0.020	0.020	0.019	0.021
Levelized Costs																				
10 years (2010-2019)	0.088	0.073	0.091	0.070	29.21	12.56	0.037	0.025	0.042	0.026	1.29	0.031	0.021	0.035	0.022	1.29	0.032	0.033	0.032	0.034
15 years (2010-2024)	0.091	0.076	0.095	0.073	27.83	17.11	0.028	0.018	0.031	0.019	0.91	0.023	0.016	0.026	0.016	0.91	0.029	0.030	0.029	0.031
30 years (2010-2039)	0.101	0.083	0.110	0.087	53.65	51.59											0.025	0.026	0.025	0.027

NOTES:

General All Avoided Costs are in Year 2009 Dollars

ISO NE periods: Summer is June through September, Winter is all other months. Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are all other hours

1 Avoided cost of electric energy = (wholesale energy avoided cost + REC cost to load) * risk premium, e.g. A= (U + AB) * (1+Wholesale Risk Premium)

2 Absolute value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year, PA strategy re bidding that reduction into applicable FCAs, and unit values in columns e, f, k and p.

3 For only 2010 and 2011; proceeds from selling into the FCM include the reserve margin, in addition to the ISO-NE loss factor of 8%

Table Two: Inputs to Avoided Cost Calculations

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Zone: Vermont

	Wholesale Avoided Costs of Electricity						Avoided REC Costs to Load
	Energy				Capacity		
	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	FCA Price	Reserve Margin	REC Costs
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	%	$/kWh
Period:	u	v	w	x	y	z	aa
2009							
2010	0.068	0.052	0.070	0.051	52.51	16.1%	0.0000
2011	0.072	0.056	0.074	0.054	41.18	13.7%	0.0000
2012	0.078	0.061	0.077	0.057	33.09	14.4%	0.0000
2013	0.079	0.064	0.079	0.062	15.60	14.6%	0.0005
2014	0.079	0.065	0.080	0.062	15.60	14.6%	0.0011
2015	0.079	0.066	0.082	0.062	16.80	14.7%	0.0016
2016	0.079	0.067	0.085	0.064	18.00	14.9%	0.0022
2017	0.081	0.069	0.086	0.066	18.00	15.0%	0.0032
2018	0.084	0.070	0.088	0.068	19.20	15.1%	0.0033
2019	0.085	0.072	0.090	0.069	19.20	15.2%	0.0027
2020	0.085	0.072	0.090	0.069	20.40	15.3%	0.0024
2021	0.084	0.071	0.088	0.070	21.60	15.4%	0.0019
2022	0.084	0.073	0.090	0.071	22.80	15.4%	0.0016
2023	0.087	0.074	0.094	0.073	24.00	15.5%	0.0011
2024	0.092	0.075	0.099	0.078	25.20	15.6%	0.0003
2025	0.093	0.076	0.101	0.080	37.20	15.7%	0.0003
2026	0.095	0.078	0.104	0.082	49.20	15.8%	0.0002
2027	0.096	0.079	0.106	0.084	61.20	15.9%	0.0002
2028	0.098	0.080	0.108	0.086	73.20	16.0%	0.0002
2029	0.100	0.081	0.110	0.088	85.20	16.1%	0.0002
2030	0.101	0.082	0.113	0.090	96.00	16.2%	0.0002
2031	0.103	0.083	0.115	0.092	96.00	16.3%	0.0002
2032	0.105	0.085	0.118	0.095	96.00	16.4%	0.0002
2033	0.106	0.086	0.120	0.097	96.00	16.5%	0.0002
2034	0.108	0.087	0.123	0.099	96.00	16.6%	0.0002
2035	0.110	0.089	0.126	0.102	96.00	16.7%	0.0002
2036	0.112	0.090	0.128	0.104	96.00	16.8%	0.0002
2037	0.114	0.091	0.131	0.107	96.00	16.9%	0.0002
2038	0.115	0.093	0.134	0.110	96.00	17.0%	0.0002
2039	0.117	0.094	0.137	0.112	96.00	17.1%	0.0002
Levelized Costs							
10 years (2010-2019)	0.078	0.064	0.081	0.061	25.502	14.8%	0.001
15 years (2010-2024)	0.080	0.067	0.084	0.065	24.682	15.0%	0.001
30 years (2010-2039)	0.090	0.074	0.098	0.077	49.045	15.6%	0.001

NOTES: General All Avoided Costs are in Year 2009 Dollars

ISO NE periods: Summer is June through September, Winter is all other months. Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are all other hours

Table One: Avoided Cost of Electricity (2009$) Results : New Hampshire

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State NH

User-defined Inputs	
Wholesale Risk Premium (WRP)	9%
Real Discount Rate	2.22%

	Avoided Unit Cost of Electric Energy[1]				Avoided Unit Cost of Electric Capacity[2]		DRIPE: 2010 vintage measures Total					DRIPE: 2011 vintage measures Total					Avoided Externality Costs			
							Energy				Capacity (See note 2)	Energy				Capacity (See note 2)				
	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	kW sold into FCA (PA to determine quantity)[3]	kW purchased from FCA (PA to determine quantity)	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Annual Value	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Annual Value	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kw-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh
Period:	a	b	c	d	e=y*1.08	f=y*(1+z)*(1+PTF Loss)*(1+WRP)	g	h	i	j	k	l	m	n	o	p	q	r	s	t
2009	0.000	0.000	0.000	0.000													0.039	0.039	0.038	0.041
2010	0.072	0.056	0.075	0.055	65.84	*0.00*	0.065	0.043	0.076	0.043		0.000	0.000	0.000	0.000		0.039	0.039	0.038	0.041
2011	0.077	0.060	0.079	0.057	50.58	*0.00*	0.067	0.045	0.077	0.044		0.069	0.047	0.080	0.045		0.039	0.039	0.038	0.041
2012	0.084	0.065	0.082	0.061	35.74	*0.00*	0.073	0.049	0.080	0.047		0.075	0.050	0.082	0.048		0.039	0.039	0.038	0.041
2013	0.085	0.069	0.085	0.067	16.85	0.00	0.036	0.025	0.041	0.025	5.00	0.037	0.026	0.041	0.025		0.033	0.033	0.032	0.034
2014	0.086	0.071	0.087	0.068	16.85	19.86	0.031	0.022	0.035	0.021	8.00	0.033	0.023	0.037	0.023	5.00	0.032	0.032	0.031	0.033
2015	0.086	0.072	0.088	0.068	18.14	21.40	0.028	0.020	0.032	0.019	5.00	0.028	0.020	0.032	0.019	8.00	0.030	0.031	0.030	0.032
2016	0.087	0.073	0.092	0.070	19.44	22.97	0.024	0.018	0.029	0.017	2.00	0.024	0.018	0.029	0.017	5.00	0.029	0.030	0.028	0.031
2017	0.089	0.076	0.094	0.073	19.44	22.98	0.021	0.015	0.025	0.015		0.021	0.015	0.025	0.015	2.00	0.028	0.028	0.027	0.029
2018	0.092	0.078	0.096	0.076	20.74	24.54	0.018	0.013	0.021	0.013		0.018	0.013	0.021	0.013		0.027	0.027	0.026	0.028
2019	0.092	0.079	0.098	0.077	20.74	24.56	0.014	0.011	0.017	0.010		0.014	0.011	0.017	0.010		0.026	0.026	0.025	0.027
2020	0.093	0.080	0.098	0.076	22.03	26.11	0.011	0.008	0.012	0.008		0.011	0.008	0.013	0.008		0.024	0.025	0.024	0.026
2021	0.091	0.079	0.094	0.077	23.33	27.67	0.007	0.005	0.008	0.005		0.007	0.005	0.008	0.005		0.023	0.024	0.023	0.024
2022	0.092	0.080	0.097	0.078	24.62	29.24	0.004	0.003	0.004	0.003		0.004	0.003	0.004	0.003		0.022	0.022	0.021	0.023
2023	0.095	0.080	0.101	0.079	25.92	30.80											0.021	0.021	0.020	0.022
2024	0.099	0.082	0.105	0.084	27.22	32.37											0.020	0.020	0.019	0.021
2025	0.100	0.083	0.107	0.086	40.18	47.82											0.020	0.020	0.019	0.021
2026	0.102	0.084	0.109	0.088	53.14	63.31											0.020	0.020	0.019	0.021
2027	0.104	0.085	0.112	0.090	66.10	78.81											0.020	0.020	0.019	0.021
2028	0.106	0.087	0.114	0.093	79.06	94.35											0.020	0.020	0.019	0.021
2029	0.108	0.088	0.117	0.095	92.02	109.91											0.020	0.020	0.019	0.021
2030	0.109	0.090	0.119	0.097	103.68	123.95											0.020	0.020	0.019	0.021
2031	0.111	0.091	0.122	0.100	103.68	124.05											0.020	0.020	0.019	0.021
2032	0.113	0.093	0.125	0.102	103.68	124.16											0.020	0.020	0.019	0.021
2033	0.115	0.094	0.127	0.105	103.68	124.27											0.020	0.020	0.019	0.021
2034	0.117	0.096	0.130	0.108	103.68	124.37											0.020	0.020	0.019	0.021
2035	0.119	0.097	0.133	0.111	103.68	124.48											0.020	0.020	0.019	0.021
2036	0.122	0.099	0.136	0.113	103.68	124.59											0.020	0.020	0.019	0.021
2037	0.124	0.100	0.139	0.116	103.68	124.69											0.020	0.020	0.019	0.021
2038	0.126	0.102	0.142	0.119	103.68	124.80											0.020	0.020	0.019	0.021
2039	0.128	0.104	0.145	0.122	103.68	124.91											0.020	0.020	0.019	0.021
Levelized Costs																				
10 years (2010-2019)	0.084	0.070	0.087	0.067	29.21	12.99	0.039	0.027	0.045	0.026	2.15	0.033	0.023	0.037	0.022	2.15	0.032	0.033	0.032	0.034
15 years (2010-2024)	0.087	0.073	0.091	0.070	27.83	17.81	0.029	0.020	0.033	0.019	1.51	0.024	0.017	0.028	0.016	1.51	0.029	0.030	0.029	0.031
30 years (2010-2039)	0.098	0.081	0.105	0.084	53.65	55.24											0.025	0.026	0.025	0.027

NOTES:

General — All Avoided Costs are in Year 2009 Dollars

ISO NE periods: Summer is June through September, Winter is all other months. Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are all other hours

1 Avoided cost of electric energy = (wholesale energy avoided cost + REC cost to load) * risk premium, e.g. A= (U + AB) * (1+Wholesale Risk Premium)

2 Absolute value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year, PA strategy re bidding that reduction into applicable FCAs, and unit values in columns e, f, k and p.

3 For only 2010 and 2011; proceeds from selling into the FCM include the reserve margin, in addition to the ISO-NE loss factor of 8%

Table Two: Inputs to Avoided Cost Calculations

Zone: New Hampshire

	Wholesale Avoided Costs of Electricity						
	Energy				Capacity		Avoided REC Costs to Load
	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	FCA Price	Reserve Margin	REC Costs
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	%	$/kWh
Period:	u	v	w	x	y	z	aa
2009							
2010	0.065	0.051	0.068	0.050	52.51	16.1%	0.0004
2011	0.070	0.055	0.072	0.052	41.18	13.7%	0.0006
2012	0.076	0.059	0.075	0.055	33.09	14.4%	0.0007
2013	0.077	0.063	0.077	0.060	15.60	14.6%	0.0011
2014	0.077	0.064	0.078	0.061	15.60	14.6%	0.0014
2015	0.077	0.064	0.079	0.061	16.80	14.7%	0.0016
2016	0.078	0.065	0.082	0.062	18.00	14.9%	0.0019
2017	0.079	0.067	0.084	0.064	18.00	15.0%	0.0026
2018	0.082	0.069	0.086	0.066	19.20	15.1%	0.0029
2019	0.082	0.070	0.087	0.068	19.20	15.2%	0.0027
2020	0.082	0.071	0.087	0.068	20.40	15.3%	0.0026
2021	0.081	0.070	0.084	0.068	21.60	15.4%	0.0022
2022	0.082	0.072	0.087	0.069	22.80	15.4%	0.0020
2023	0.085	0.072	0.091	0.071	24.00	15.5%	0.0015
2024	0.090	0.074	0.096	0.076	25.20	15.6%	0.0005
2025	0.092	0.076	0.098	0.078	37.20	15.7%	0.0004
2026	0.093	0.077	0.100	0.080	49.20	15.8%	0.0004
2027	0.095	0.078	0.102	0.082	61.20	15.9%	0.0003
2028	0.097	0.079	0.105	0.085	73.20	16.0%	0.0003
2029	0.098	0.081	0.107	0.087	85.20	16.1%	0.0003
2030	0.100	0.082	0.109	0.089	96.00	16.2%	0.0003
2031	0.102	0.083	0.111	0.091	96.00	16.3%	0.0003
2032	0.104	0.085	0.114	0.094	96.00	16.4%	0.0003
2033	0.106	0.086	0.116	0.096	96.00	16.5%	0.0003
2034	0.107	0.087	0.119	0.099	96.00	16.6%	0.0003
2035	0.109	0.089	0.122	0.101	96.00	16.7%	0.0003
2036	0.111	0.090	0.124	0.104	96.00	16.8%	0.0003
2037	0.113	0.092	0.127	0.106	96.00	16.9%	0.0003
2038	0.115	0.093	0.130	0.109	96.00	17.0%	0.0003
2039	0.117	0.095	0.133	0.112	96.00	17.1%	0.0003
Levelized Costs							
10 years (2010-2019)	0.076	0.062	0.078	0.060	25.502	14.8%	0.002
15 years (2010-2024)	0.078	0.065	0.082	0.063	24.682	15.0%	0.002
30 years (2010-2039)	0.089	0.073	0.095	0.076	49.045	15.6%	0.001

NOTES: General All Avoided Costs are in Year 2009 Dollars
ISO NE periods: Summer is June through September, Winter is all other months. Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are all other hours

Table One: Avoided Cost of Electricity (2009$) Results : Connecticut (Statewide)

State CT

User-defined Inputs	
Wholesale Risk Premium (WRP)	9%
Real Discount Rate	2.22%

	Avoided Unit Cost of Electric Energy[1]				Avoided Unit Cost of Electric Capacity[2]		DRIPE: 2010 vintage measures Intrastate					DRIPE: 2011 vintage measures Intrastate					Avoided Externality Costs			
							Energy				Capacity (See note 2)	Energy				Capacity (See note 2)				
	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	kW sold into FCA (PA to determine quantity)[3]	kW purchased from FCA (PA to determine quantity)	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Annual Value	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Annual Value	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kw-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh
Period:	a	b	c	d	e=y*1.08	f=y*(1+z)*(1+PTF Loss)*(1+WRP)	g	h	i	j	k	l	m	n	o	p	q	r	s	t
2009	0.000	0.000	0.000	0.000													0.039	0.039	0.038	0.041
2010	0.078	0.060	0.082	0.059	65.84	*0.00*	0.044	0.028	0.048	0.020		0.000	0.000	0.000	0.000		0.039	0.039	0.038	0.041
2011	0.083	0.065	0.087	0.062	50.58	*0.00*	0.044	0.028	0.048	0.020		0.046	0.030	0.050	0.021		0.039	0.039	0.038	0.041
2012	0.090	0.070	0.090	0.065	35.74	*0.00*	0.047	0.030	0.049	0.021		0.048	0.031	0.050	0.021		0.039	0.039	0.038	0.041
2013	0.091	0.075	0.093	0.072	16.85	0.00	0.023	0.015	0.024	0.011	29.00	0.023	0.015	0.024	0.011		0.033	0.033	0.032	0.034
2014	0.093	0.076	0.095	0.073	16.85	19.86	0.019	0.013	0.021	0.009	42.00	0.021	0.014	0.022	0.010	29.00	0.032	0.032	0.031	0.033
2015	0.093	0.077	0.097	0.073	18.14	21.40	0.018	0.012	0.019	0.008	28.00	0.018	0.012	0.019	0.009	42.00	0.030	0.031	0.030	0.032
2016	0.094	0.079	0.099	0.075	19.44	22.97	0.015	0.011	0.017	0.007	11.00	0.015	0.011	0.017	0.008	28.00	0.029	0.030	0.028	0.031
2017	0.097	0.083	0.104	0.079	19.44	22.98	0.013	0.009	0.015	0.007		0.013	0.009	0.015	0.007	11.00	0.028	0.028	0.027	0.029
2018	0.101	0.085	0.105	0.082	20.74	24.54	0.011	0.008	0.012	0.006		0.011	0.008	0.012	0.006		0.027	0.027	0.026	0.028
2019	0.102	0.087	0.107	0.083	20.74	24.56	0.009	0.006	0.010	0.004		0.009	0.006	0.010	0.004		0.026	0.026	0.025	0.027
2020	0.102	0.087	0.107	0.084	22.03	26.11	0.007	0.005	0.007	0.003		0.007	0.005	0.007	0.003		0.024	0.025	0.024	0.026
2021	0.099	0.085	0.104	0.082	23.33	27.67	0.004	0.003	0.005	0.002		0.004	0.003	0.005	0.002		0.023	0.024	0.023	0.024
2022	0.100	0.087	0.105	0.083	24.62	29.24	0.002	0.002	0.002	0.001		0.002	0.002	0.002	0.001		0.022	0.022	0.021	0.023
2023	0.102	0.088	0.109	0.086	25.92	30.80											0.021	0.021	0.020	0.022
2024	0.107	0.090	0.113	0.089	27.22	32.37											0.020	0.020	0.019	0.021
2025	0.109	0.092	0.115	0.091	40.18	47.82											0.020	0.020	0.019	0.021
2026	0.111	0.094	0.118	0.094	53.14	63.31											0.020	0.020	0.019	0.021
2027	0.114	0.096	0.120	0.096	66.10	78.81											0.020	0.020	0.019	0.021
2028	0.116	0.098	0.122	0.099	79.06	94.35											0.020	0.020	0.019	0.021
2029	0.118	0.101	0.125	0.101	92.02	109.91											0.020	0.020	0.019	0.021
2030	0.121	0.103	0.128	0.104	103.68	123.95											0.020	0.020	0.019	0.021
2031	0.123	0.105	0.130	0.107	103.68	124.05											0.020	0.020	0.019	0.021
2032	0.125	0.107	0.133	0.110	103.68	124.16											0.020	0.020	0.019	0.021
2033	0.128	0.110	0.136	0.113	103.68	124.27											0.020	0.020	0.019	0.021
2034	0.131	0.112	0.139	0.116	103.68	124.37											0.020	0.020	0.019	0.021
2035	0.133	0.115	0.142	0.119	103.68	124.48											0.020	0.020	0.019	0.021
2036	0.136	0.117	0.145	0.122	103.68	124.59											0.020	0.020	0.019	0.021
2037	0.139	0.120	0.148	0.126	103.68	124.69											0.020	0.020	0.019	0.021
2038	0.141	0.123	0.151	0.129	103.68	124.80											0.020	0.020	0.019	0.021
2039	0.144	0.125	0.154	0.132	103.68	124.91											0.020	0.020	0.019	0.021
Levelized Costs																				
10 years (2010-2019)	0.092	0.075	0.095	0.072	29.21	12.99	0.025	0.017	0.027	0.012	11.81	0.021	0.014	0.022	0.010	11.81	0.032	0.033	0.032	0.034
15 years (2010-2024)	0.095	0.079	0.099	0.076	27.83	17.81	0.019	0.012	0.020	0.009	8.30	0.015	0.010	0.017	0.007	8.30	0.029	0.030	0.029	0.031
30 years (2010-2039)	0.107	0.091	0.113	0.090	53.65	55.24											0.025	0.026	0.025	0.027

NOTES:

General — All Avoided Costs are in Year 2009 Dollars

ISO NE periods: Summer is June through September, Winter is all other months. Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are all other hours

1 Avoided cost of electric energy = (wholesale energy avoided cost + REC cost to load) * risk premium, e.g. A= (U + AB) * (1+Wholesale Risk Premium)

2 Absolute value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year, PA strategy re bidding that reduction into applicable FCAs, and unit values in columns e, f, k and p.

3 For only 2010 and 2011; proceeds from selling into the FCM include the reserve margin, in addition to the ISO-NE loss factor of 8%

Table Two: Inputs to Avoided Cost Calculations

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Zone: Connecticut (Statewide)

	Wholesale Avoided Costs of Electricity						
	Energy				Capacity		Avoided REC Costs to Load
	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	FCA Price	Reserve Margin	REC Costs
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	%	$/kWh
Period:	u	v	w	x	y	z	aa
2009							
2010	0.070	0.053	0.074	0.052	52.51	16.1%	0.0019
2011	0.074	0.057	0.078	0.055	41.18	13.7%	0.0020
2012	0.081	0.062	0.080	0.058	33.09	14.4%	0.0022
2013	0.081	0.066	0.083	0.063	15.60	14.6%	0.0027
2014	0.082	0.067	0.084	0.064	15.60	14.6%	0.0031
2015	0.082	0.067	0.085	0.064	16.80	14.7%	0.0033
2016	0.082	0.069	0.087	0.065	18.00	14.9%	0.0038
2017	0.084	0.071	0.090	0.068	18.00	15.0%	0.0050
2018	0.088	0.073	0.090	0.070	19.20	15.1%	0.0055
2019	0.089	0.075	0.093	0.071	19.20	15.2%	0.0050
2020	0.089	0.075	0.093	0.072	20.40	15.3%	0.0048
2021	0.087	0.075	0.092	0.072	21.60	15.4%	0.0037
2022	0.089	0.077	0.093	0.073	22.80	15.4%	0.0031
2023	0.092	0.079	0.098	0.076	24.00	15.5%	0.0022
2024	0.098	0.082	0.103	0.081	25.20	15.6%	0.0007
2025	0.100	0.084	0.105	0.083	37.20	15.7%	0.0005
2026	0.102	0.086	0.107	0.085	49.20	15.8%	0.0004
2027	0.104	0.088	0.110	0.088	61.20	15.9%	0.0004
2028	0.106	0.090	0.112	0.090	73.20	16.0%	0.0004
2029	0.108	0.092	0.114	0.093	85.20	16.1%	0.0004
2030	0.110	0.094	0.117	0.095	96.00	16.2%	0.0004
2031	0.112	0.096	0.119	0.098	96.00	16.3%	0.0004
2032	0.115	0.098	0.122	0.100	96.00	16.4%	0.0004
2033	0.117	0.100	0.124	0.103	96.00	16.5%	0.0004
2034	0.119	0.103	0.127	0.106	96.00	16.6%	0.0004
2035	0.122	0.105	0.130	0.109	96.00	16.7%	0.0004
2036	0.124	0.107	0.132	0.112	96.00	16.8%	0.0004
2037	0.127	0.110	0.135	0.115	96.00	16.9%	0.0004
2038	0.129	0.112	0.138	0.118	96.00	17.0%	0.0004
2039	0.132	0.115	0.141	0.121	96.00	17.1%	0.0004
Levelized Costs							
10 years (2010-2019)	0.081	0.066	0.084	0.063	25.502	14.8%	0.003
15 years (2010-2024)	0.084	0.069	0.087	0.066	24.682	15.0%	0.003
30 years (2010-2039)	0.097	0.081	0.102	0.080	49.045	15.6%	0.002

NOTES: General: All Avoided Costs are in Year 2009 Dollars

ISO NE periods: Summer is June through September, Winter is all other months. Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are all other hours

Table One: Avoided Cost of Electricity (2009$) Results : Massachusetts (Statewide)

State MA

User-defined Inputs	
Wholesale Risk Premium	9%
Real Discount Rate	2.22%

	Avoided Unit Cost of Electric Energy[1]				Avoided Unit Cost of Electric Capacity[2]		DRIPE: 2010 vintage measures Intrastate					DRIPE: 2011 vintage measures Intrastate					Avoided Externality Costs			
							Energy				Capacity (See note 2)	Energy				Capacity (See note 2)				
	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	kW sold into FCA (PA to determine quantity)[3]	kW purchased from FCA (PA to determine quantity)	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Annual Value	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Annual Value	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kw-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh
Period:	a	b	c	d	e=y*1.08	f=y*(1+z)*(1+PTF Loss)*(1+WRP)	g	h	i	j	k	l	m	n	o	p	q	r	s	t
2009	0.000	0.000	0.000	0.000													0.039	0.039	0.038	0.041
2010	0.075	0.056	0.076	0.055	65.84	*0.00*	0.056	0.043	0.062	0.032		0.000	0.000	0.000	0.000		0.039	0.039	0.038	0.041
2011	0.080	0.060	0.080	0.057	50.58	*0.00*	0.058	0.045	0.063	0.032		0.060	0.046	0.066	0.034		0.039	0.039	0.038	0.041
2012	0.087	0.065	0.084	0.061	35.74	*0.00*	0.063	0.048	0.066	0.034		0.064	0.049	0.067	0.035		0.039	0.039	0.038	0.041
2013	0.088	0.069	0.086	0.067	16.85	0.00	0.031	0.025	0.033	0.018	55.00	0.031	0.025	0.034	0.019		0.033	0.033	0.032	0.034
2014	0.089	0.070	0.087	0.067	16.85	19.86	0.026	0.021	0.028	0.016	81.00	0.028	0.023	0.030	0.017	55.00	0.032	0.032	0.031	0.033
2015	0.089	0.071	0.089	0.067	18.14	21.40	0.023	0.019	0.026	0.014	54.00	0.023	0.019	0.026	0.014	81.00	0.030	0.031	0.030	0.032
2016	0.090	0.073	0.092	0.068	19.44	22.97	0.020	0.017	0.023	0.012	20.00	0.020	0.017	0.023	0.012	54.00	0.029	0.030	0.028	0.031
2017	0.093	0.075	0.094	0.071	19.44	22.98	0.018	0.015	0.020	0.011		0.018	0.015	0.020	0.011	20.00	0.028	0.028	0.027	0.029
2018	0.097	0.077	0.096	0.074	20.74	24.54	0.015	0.013	0.017	0.009		0.015	0.013	0.017	0.009		0.027	0.027	0.026	0.028
2019	0.098	0.080	0.099	0.075	20.74	24.56	0.012	0.010	0.014	0.008		0.012	0.010	0.014	0.008		0.026	0.026	0.025	0.027
2020	0.098	0.080	0.099	0.076	22.03	26.11	0.009	0.008	0.010	0.006		0.009	0.008	0.010	0.006		0.024	0.025	0.024	0.026
2021	0.096	0.079	0.098	0.075	23.33	27.67	0.006	0.005	0.007	0.004		0.006	0.005	0.007	0.004		0.023	0.024	0.023	0.024
2022	0.098	0.081	0.100	0.077	24.62	29.24	0.003	0.003	0.003	0.002		0.003	0.003	0.003	0.002		0.022	0.022	0.021	0.023
2023	0.100	0.084	0.104	0.080	25.92	30.80	0.000	0.000	0.000	0.000		0.000	0.000	0.000	0.000		0.021	0.021	0.020	0.022
2024	0.105	0.087	0.111	0.085	27.22	32.37											0.020	0.020	0.019	0.021
2025	0.107	0.089	0.113	0.088	40.18	47.82											0.020	0.020	0.019	0.021
2026	0.109	0.092	0.116	0.090	53.14	63.31											0.020	0.020	0.019	0.021
2027	0.112	0.094	0.119	0.093	66.10	78.81											0.020	0.020	0.019	0.021
2028	0.114	0.096	0.122	0.095	79.06	94.35											0.020	0.020	0.019	0.021
2029	0.116	0.098	0.125	0.098	92.02	109.91											0.020	0.020	0.019	0.021
2030	0.119	0.100	0.128	0.100	103.68	123.95											0.020	0.020	0.019	0.021
2031	0.121	0.102	0.131	0.103	103.68	124.05											0.020	0.020	0.019	0.021
2032	0.124	0.105	0.134	0.106	103.68	124.16											0.020	0.020	0.019	0.021
2033	0.126	0.107	0.137	0.109	103.68	124.27											0.020	0.020	0.019	0.021
2034	0.129	0.110	0.141	0.112	103.68	124.37											0.020	0.020	0.019	0.021
2035	0.132	0.112	0.144	0.115	103.68	124.48											0.020	0.020	0.019	0.021
2036	0.135	0.115	0.148	0.118	103.68	124.59											0.020	0.020	0.019	0.021
2037	0.137	0.117	0.151	0.121	103.68	124.69											0.020	0.020	0.019	0.021
2038	0.140	0.120	0.155	0.124	103.68	124.80											0.020	0.020	0.019	0.021
2039	0.143	0.123	0.159	0.128	103.68	124.91											0.020	0.020	0.019	0.021
Levelized Costs																				
10 years (2010-2019)	0.088	0.069	0.088	0.066	29.21	12.99	0.033	0.026	0.036	0.019	22.55	0.028	0.022	0.030	0.016	22.55	0.032	0.033	0.032	0.034
15 years (2010-2024)	0.092	0.073	0.092	0.070	27.83	17.81	0.025	0.019	0.027	0.014	15.84	0.020	0.016	0.022	0.012	15.84	0.029	0.030	0.029	0.031
30 years (2010-2039)	0.105	0.086	0.109	0.085	53.65	55.24											0.025	0.026	0.025	0.027

NOTES:

General All Avoided Costs are in Year 2009 Dollars

ISO NE periods: Summer is June through September, Winter is all other months. Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are all other hours

1 Avoided cost of electric energy = (wholesale energy avoided cost + REC cost to load) * risk premium, e.g. A= (U + AB) * (1+Wholesale Risk Premium)

2 Absolute value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year, PA strategy re bidding that reduction into applicable FCAs, and unit values in columns e, f, k and p.

3 For only 2010 and 2011; proceeds from selling into the FCM include the reserve margin, in addition to the ISO-NE loss factor of 8%

Table Two: Inputs to Avoided Cost Calculations

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Zone: Massachusetts (Statewide)

	Wholesale Avoided Costs of Electricity						Avoided REC Costs to Load
	Energy				Capacity		
	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	FCA Price	Reserve Margin	REC Costs
Units:	**$/kWh**	**$/kWh**	**$/kWh**	**$/kWh**	**$/kW-yr**	**%**	**$/kWh**
Period:	**u**	**v**	**w**	**x**	**y**	**z**	**aa**
2009							
2010	0.067	0.051	0.070	0.050	52.51	16.1%	0.0018
2011	0.072	0.055	0.074	0.053	41.18	13.7%	0.0018
2012	0.078	0.060	0.077	0.056	33.09	14.4%	0.0017
2013	0.078	0.064	0.079	0.061	15.60	14.6%	0.0022
2014	0.079	0.065	0.080	0.061	15.60	14.6%	0.0026
2015	0.079	0.065	0.082	0.062	16.80	14.7%	0.0027
2016	0.080	0.067	0.085	0.063	18.00	14.9%	0.0030
2017	0.081	0.069	0.086	0.065	18.00	15.0%	0.0039
2018	0.085	0.071	0.088	0.068	19.20	15.1%	0.0042
2019	0.086	0.073	0.091	0.069	19.20	15.2%	0.0038
2020	0.086	0.073	0.091	0.069	20.40	15.3%	0.0036
2021	0.085	0.073	0.090	0.069	21.60	15.4%	0.0030
2022	0.087	0.075	0.091	0.071	22.80	15.4%	0.0027
2023	0.090	0.077	0.095	0.073	24.00	15.5%	0.0020
2024	0.096	0.080	0.102	0.078	25.20	15.6%	0.0006
2025	0.098	0.082	0.104	0.080	37.20	15.7%	0.0005
2026	0.100	0.084	0.107	0.083	49.20	15.8%	0.0004
2027	0.102	0.086	0.109	0.085	61.20	15.9%	0.0004
2028	0.104	0.088	0.112	0.087	73.20	16.0%	0.0004
2029	0.106	0.090	0.115	0.090	85.20	16.1%	0.0004
2030	0.109	0.092	0.117	0.092	96.00	16.2%	0.0004
2031	0.111	0.094	0.120	0.095	96.00	16.3%	0.0004
2032	0.113	0.096	0.123	0.097	96.00	16.4%	0.0004
2033	0.116	0.098	0.126	0.100	96.00	16.5%	0.0004
2034	0.118	0.101	0.129	0.102	96.00	16.6%	0.0004
2035	0.121	0.103	0.132	0.105	96.00	16.7%	0.0004
2036	0.123	0.105	0.135	0.108	96.00	16.8%	0.0004
2037	0.126	0.108	0.139	0.111	96.00	16.9%	0.0004
2038	0.128	0.110	0.142	0.114	96.00	17.0%	0.0004
2039	0.131	0.113	0.146	0.117	96.00	17.1%	0.0004
Levelized Costs							
10 years (2010-2019)	0.078	0.064	0.081	0.060	25.502	14.8%	0.003
15 years (2010-2024)	0.081	0.067	0.085	0.064	24.682	15.0%	0.003
30 years (2010-2039)	0.094	0.079	0.100	0.078	49.045	15.6%	0.002

NOTES: General

All Avoided Costs are in Year 2009 Dollars

ISO NE periods: Summer is June through September, Winter is all other months. Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are all other hours

Table One: Avoided Cost of Electricity (2009$) Results : Rhode Island RGGI Only Scenario

State RI

User-defined Inputs	
Wholesale Risk Premium (WRP)	9%
	2.22%

	Avoided Unit Cost of Electric Energy[1]				Avoided Unit Cost of Electric Capacity[2]		DRIPE: 2010 vintage measures Total					DRIPE: 2011 vintage measures Total					Avoided Externality Costs			
							Energy				Capacity (See note 2)	Energy				Capacity (See note 2)				
	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	kW sold into FCA (PA to determine quantity)[3]	kW purchased from FCA (PA to determine quantity)	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Annual Value	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Annual Value	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kw-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh
Period:	a	b	c	d	e=y*1.08	f=y*(1+z)*(1+PTF Loss)*(1+WRP)	g	h	i	j	k	l	m	n	o	p	q	r	s	t
2009	0.000	0.000	0.000	0.000													0.039	0.039	0.038	0.041
2010	0.072	0.056	0.075	0.055	65.84	*0.00*	0.076	0.054	0.074	0.046		0.000	0.000	0.000	0.000		0.039	0.039	0.038	0.041
2011	0.078	0.061	0.080	0.058	50.58	*0.00*	0.078	0.056	0.075	0.047		0.081	0.058	0.078	0.048		0.039	0.039	0.038	0.041
2012	0.086	0.066	0.084	0.061	35.74	*0.00*	0.086	0.061	0.079	0.050		0.088	0.062	0.080	0.051		0.039	0.039	0.038	0.041
2013	0.081	0.065	0.079	0.061	16.85	0.00	0.039	0.029	0.036	0.024	9.00	0.040	0.029	0.037	0.024		0.039	0.039	0.038	0.041
2014	0.080	0.066	0.080	0.062	16.85	19.86	0.033	0.024	0.031	0.021	13.00	0.035	0.026	0.033	0.022	9.00	0.039	0.039	0.038	0.041
2015	0.080	0.066	0.082	0.061	18.14	21.40	0.028	0.021	0.028	0.018	9.00	0.029	0.021	0.028	0.018	13.00	0.039	0.039	0.038	0.041
2016	0.080	0.067	0.083	0.062	19.44	22.97	0.025	0.019	0.024	0.016	3.00	0.025	0.019	0.025	0.016	9.00	0.039	0.039	0.038	0.041
2017	0.084	0.070	0.086	0.065	19.44	22.98	0.022	0.016	0.021	0.014		0.022	0.016	0.021	0.014	3.00	0.039	0.039	0.038	0.041
2018	0.086	0.071	0.088	0.068	20.74	24.54	0.018	0.013	0.018	0.012		0.018	0.013	0.018	0.012		0.039	0.039	0.038	0.041
2019	0.087	0.072	0.089	0.068	20.74	24.56	0.014	0.011	0.014	0.009		0.014	0.011	0.014	0.009		0.039	0.039	0.038	0.041
2020	0.086	0.070	0.087	0.067	22.03	26.11	0.010	0.008	0.010	0.007		0.010	0.008	0.010	0.007		0.039	0.039	0.038	0.041
2021	0.083	0.069	0.085	0.065	23.33	27.67	0.007	0.005	0.007	0.004		0.007	0.005	0.007	0.004		0.039	0.039	0.038	0.041
2022	0.083	0.070	0.086	0.065	24.62	29.24	0.003	0.003	0.003	0.002		0.003	0.003	0.003	0.002		0.039	0.039	0.038	0.041
2023	0.084	0.070	0.088	0.067	25.92	30.80											0.039	0.039	0.038	0.041
2024	0.088	0.072	0.093	0.070	27.22	32.37											0.039	0.039	0.038	0.041
2025	0.089	0.073	0.094	0.070	40.18	47.82											0.039	0.039	0.038	0.041
2026	0.089	0.073	0.095	0.071	53.14	63.31											0.039	0.039	0.038	0.041
2027	0.090	0.074	0.096	0.072	66.10	78.81											0.039	0.039	0.038	0.041
2028	0.091	0.075	0.097	0.072	79.06	94.35											0.039	0.039	0.038	0.041
2029	0.092	0.076	0.098	0.073	92.02	109.91											0.039	0.039	0.038	0.041
2030	0.093	0.076	0.099	0.074	103.68	123.95											0.039	0.039	0.038	0.041
2031	0.094	0.077	0.100	0.075	103.68	124.05											0.039	0.039	0.038	0.041
2032	0.095	0.078	0.101	0.075	103.68	124.16											0.039	0.039	0.038	0.041
2033	0.096	0.079	0.102	0.076	103.68	124.27											0.039	0.039	0.038	0.041
2034	0.097	0.079	0.103	0.077	103.68	124.37											0.039	0.039	0.038	0.041
2035	0.098	0.080	0.104	0.078	103.68	124.48											0.039	0.039	0.038	0.041
2036	0.099	0.081	0.105	0.078	103.68	124.59											0.039	0.039	0.038	0.041
2037	0.100	0.082	0.106	0.079	103.68	124.69											0.039	0.039	0.038	0.041
2038	0.101	0.083	0.107	0.080	103.68	124.80											0.039	0.039	0.038	0.041
2039	0.102	0.083	0.108	0.081	103.68	124.91											0.039	0.039	0.038	0.041
Levelized Costs																				
10 years (2010-2019)	0.081	0.066	0.082	0.062	29.21	12.99	0.043	0.031	0.041	0.026	3.65	0.036	0.026	0.034	0.022	3.65	0.039	0.039	0.038	0.041
15 years (2010-2024)	0.082	0.067	0.084	0.063	27.83	17.81	0.032	0.023	0.030	0.019	2.56	0.026	0.019	0.025	0.016	2.56	0.039	0.039	0.038	0.041
30 years (2010-2039)	0.087	0.071	0.091	0.068	53.65	55.24											0.039	0.039	0.038	0.041

NOTES:

General All Avoided Costs are in Year 2009 Dollars

ISO NE periods: Summer is June through September, Winter is all other months. Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are all other hours

1 Avoided cost of electric energy = (wholesale energy avoided cost + REC cost to load) * risk premium, e.g. A= (U + AB) * (1+Wholesale Risk Premium)

2 Absolute value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year, PA strategy re bidding that reduction into applicable FCAs, and unit values in columns e, f, k and p.

3 For only 2010 and 2011; proceeds from selling into the FCM include the reserve margin, in addition to the ISO-NE loss factor of 8%

Table Two: Inputs to Avoided Cost Calculations

Page Two of Two

Zone: Rhode Island **RGGI Only Scenario**

	Wholesale Avoided Costs of Electricity						Avoided REC Costs to Load
	Energy				Capacity		
	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	FCA Price	Reserve Margin	REC Costs
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	%	$/kWh
Period:	u	v	w	x	y	z	aa
2009							
2010	0.066	0.050	0.068	0.049	52.51	16.1%	0.0009
2011	0.071	0.055	0.072	0.052	41.18	13.7%	0.0012
2012	0.077	0.059	0.075	0.055	33.09	14.4%	0.0015
2013	0.072	0.058	0.071	0.054	15.60	14.6%	0.0021
2014	0.071	0.058	0.071	0.054	15.60	14.6%	0.0026
2015	0.070	0.058	0.072	0.053	16.80	14.7%	0.0032
2016	0.070	0.057	0.072	0.053	18.00	14.9%	0.0039
2017	0.072	0.059	0.074	0.054	18.00	15.0%	0.0051
2018	0.073	0.059	0.075	0.057	19.20	15.1%	0.0060
2019	0.074	0.060	0.075	0.056	19.20	15.2%	0.0060
2020	0.073	0.059	0.074	0.056	20.40	15.3%	0.0057
2021	0.071	0.058	0.073	0.054	21.60	15.4%	0.0050
2022	0.072	0.060	0.075	0.055	22.80	15.4%	0.0046
2023	0.073	0.060	0.077	0.057	24.00	15.5%	0.0040
2024	0.077	0.063	0.082	0.061	25.20	15.6%	0.0030
2025	0.078	0.064	0.083	0.062	37.20	15.7%	0.0029
2026	0.079	0.064	0.084	0.062	49.20	15.8%	0.0028
2027	0.080	0.065	0.085	0.063	61.20	15.9%	0.0027
2028	0.081	0.066	0.086	0.064	73.20	16.0%	0.0027
2029	0.082	0.067	0.087	0.064	85.20	16.1%	0.0026
2030	0.083	0.067	0.088	0.065	96.00	16.2%	0.0025
2031	0.084	0.068	0.089	0.066	96.00	16.3%	0.0025
2032	0.085	0.069	0.090	0.067	96.00	16.4%	0.0024
2033	0.086	0.070	0.091	0.067	96.00	16.5%	0.0023
2034	0.087	0.071	0.092	0.068	96.00	16.6%	0.0023
2035	0.088	0.071	0.093	0.069	96.00	16.7%	0.0022
2036	0.089	0.072	0.094	0.070	96.00	16.8%	0.0021
2037	0.090	0.073	0.095	0.070	96.00	16.9%	0.0021
2038	0.091	0.074	0.096	0.071	96.00	17.0%	0.0020
2039	0.092	0.075	0.098	0.072	96.00	17.1%	0.0020
Levelized Costs							
10 years (2010-2019)	0.071	0.057	0.073	0.054	25.502	14.8%	0.003
15 years (2010-2024)	0.072	0.058	0.074	0.055	24.682	15.0%	0.004
30 years (2010-2039)	0.077	0.063	0.080	0.060	49.045	15.6%	0.003

NOTES: General All Avoided Costs are in Year 2009 Dollars

ISO NE periods: Summer is June through September, Winter is all other months. Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are all other hours

Table One: Avoided Cost of Electricity (2009$) Results : SEMA (Southeast Massachusetts)

State MA

User-defined Inputs	
Wholesale Risk Premium (WRP)	9%
Real Discount Rate	2.22%

	Avoided Unit Cost of Electric Energy[1]				Avoided Unit Cost of Electric Capacity[2]		DRIPE: 2010 vintage measures Intrastate					DRIPE: 2011 vintage measures Intrastate					Avoided Externality Costs			
							Energy				Capacity (See note 2)	Energy				Capacity (See note 2)				
	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	kW sold into FCA (PA to determine quantity)[3]	kW purchased from FCA (PA to determine quantity)	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Annual Value	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Annual Value	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kw-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh
Period:	a	b	c	d	e=y*1.08	f=y*(1+z)*(1+PTF Loss)*(1+WRP)	g	h	i	j	k	l	m	n	o	p	q	r	s	t
2009	0.000	0.000	0.000	0.000													0.039	0.039	0.038	0.041
2010	0.074	0.057	0.077	0.056	65.84	*0.00*	0.056	0.043	0.062	0.032		0.000	0.000	0.000	0.000		0.039	0.039	0.038	0.041
2011	0.079	0.062	0.081	0.058	50.58	*0.00*	0.058	0.045	0.063	0.032		0.060	0.046	0.066	0.034		0.039	0.039	0.038	0.041
2012	0.086	0.067	0.085	0.062	35.74	*0.00*	0.063	0.048	0.066	0.034		0.064	0.049	0.067	0.035		0.039	0.039	0.038	0.041
2013	0.088	0.071	0.088	0.068	16.85	0.00	0.031	0.025	0.033	0.018	55.00	0.031	0.025	0.034	0.019		0.033	0.033	0.032	0.034
2014	0.088	0.073	0.089	0.069	16.85	19.86	0.026	0.021	0.028	0.016	81.00	0.028	0.023	0.030	0.017	55.00	0.032	0.032	0.031	0.033
2015	0.089	0.074	0.091	0.069	18.14	21.40	0.023	0.019	0.026	0.014	54.00	0.023	0.019	0.026	0.014	81.00	0.030	0.031	0.030	0.032
2016	0.090	0.076	0.095	0.071	19.44	22.97	0.020	0.017	0.023	0.012	20.00	0.020	0.017	0.023	0.012	54.00	0.029	0.030	0.028	0.031
2017	0.093	0.079	0.097	0.074	19.44	22.98	0.018	0.015	0.020	0.011		0.018	0.015	0.020	0.011	20.00	0.028	0.028	0.027	0.029
2018	0.097	0.081	0.100	0.077	20.74	24.54	0.015	0.013	0.017	0.009		0.015	0.013	0.017	0.009		0.027	0.027	0.026	0.028
2019	0.099	0.084	0.102	0.078	20.74	24.56	0.012	0.010	0.014	0.008		0.012	0.010	0.014	0.008		0.026	0.026	0.025	0.027
2020	0.098	0.084	0.102	0.079	22.03	26.11	0.009	0.008	0.010	0.006		0.009	0.008	0.010	0.006		0.024	0.025	0.024	0.026
2021	0.097	0.083	0.100	0.078	23.33	27.67	0.006	0.005	0.007	0.004		0.006	0.005	0.007	0.004		0.023	0.024	0.023	0.024
2022	0.099	0.084	0.102	0.079	24.62	29.24	0.003	0.003	0.003	0.002		0.003	0.003	0.003	0.002		0.022	0.022	0.021	0.023
2023	0.100	0.086	0.105	0.081	25.92	30.80	0.000	0.000	0.000	0.000		0.000	0.000	0.000	0.000		0.021	0.021	0.020	0.022
2024	0.105	0.088	0.111	0.085	27.22	32.37											0.020	0.020	0.019	0.021
2025	0.108	0.090	0.113	0.088	40.18	47.82											0.020	0.020	0.019	0.021
2026	0.110	0.092	0.116	0.090	53.14	63.31											0.020	0.020	0.019	0.021
2027	0.112	0.094	0.119	0.092	66.10	78.81											0.020	0.020	0.019	0.021
2028	0.115	0.097	0.122	0.095	79.06	94.35											0.020	0.020	0.019	0.021
2029	0.117	0.099	0.125	0.097	92.02	109.91											0.020	0.020	0.019	0.021
2030	0.120	0.101	0.128	0.100	103.68	123.95											0.020	0.020	0.019	0.021
2031	0.122	0.103	0.131	0.103	103.68	124.05											0.020	0.020	0.019	0.021
2032	0.125	0.106	0.134	0.106	103.68	124.16											0.020	0.020	0.019	0.021
2033	0.128	0.108	0.138	0.109	103.68	124.27											0.020	0.020	0.019	0.021
2034	0.130	0.111	0.141	0.112	103.68	124.37											0.020	0.020	0.019	0.021
2035	0.133	0.113	0.145	0.115	103.68	124.48											0.020	0.020	0.019	0.021
2036	0.136	0.116	0.148	0.118	103.68	124.59											0.020	0.020	0.019	0.021
2037	0.139	0.119	0.152	0.121	103.68	124.69											0.020	0.020	0.019	0.021
2038	0.142	0.121	0.156	0.124	103.68	124.80											0.020	0.020	0.019	0.021
2039	0.145	0.124	0.160	0.128	103.68	124.91											0.020	0.020	0.019	0.021
Levelized Costs																				
10 years (2010-2019)	0.088	0.072	0.090	0.068	29.21	12.99	0.033	0.026	0.036	0.019	22.55	0.028	0.022	0.030	0.016	22.55	0.032	0.033	0.032	0.034
15 years (2010-2024)	0.091	0.076	0.094	0.072	27.83	17.81	0.025	0.019	0.027	0.014	15.84	0.020	0.016	0.022	0.012	15.84	0.029	0.030	0.029	0.031
30 years (2010-2039)	0.105	0.088	0.111	0.086	53.65	55.24											0.025	0.026	0.025	0.027

NOTES:

General All Avoided Costs are in Year 2009 Dollars

ISO NE periods: Summer is June through September, Winter is all other months. Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are all other hours

1 Avoided cost of electric energy = (wholesale energy avoided cost + REC cost to load) * risk premium, e.g. A= (U + AB) * (1+Wholesale Risk Premium)

2 Absolute value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year, PA strategy re bidding that reduction into applicable FCAs, and unit values in columns e, f, k and p.

3 For only 2010 and 2011; proceeds from selling into the FCM include the reserve margin, in addition to the ISO-NE loss factor of 8%

Table Two: Inputs to Avoided Cost Calculations

Zone: SEMA (Southeast Massachusetts)

	Wholesale Avoided Costs of Electricity						
	Energy				Capacity		Avoided REC Costs to Load
	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	FCA Price	Reserve Margin	REC Costs
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	%	$/kWh
Period:	u	v	w	x	y	z	aa
2009							
2010	0.066	0.050	0.069	0.049	52.51	16.1%	0.0018
2011	0.071	0.055	0.073	0.052	41.18	13.7%	0.0018
2012	0.078	0.060	0.076	0.055	33.09	14.4%	0.0017
2013	0.078	0.063	0.078	0.060	15.60	14.6%	0.0022
2014	0.078	0.064	0.079	0.060	15.60	14.6%	0.0026
2015	0.079	0.065	0.081	0.061	16.80	14.7%	0.0027
2016	0.079	0.067	0.084	0.062	18.00	14.9%	0.0030
2017	0.081	0.069	0.085	0.064	18.00	15.0%	0.0039
2018	0.085	0.071	0.087	0.067	19.20	15.1%	0.0042
2019	0.087	0.074	0.090	0.068	19.20	15.2%	0.0038
2020	0.087	0.073	0.090	0.069	20.40	15.3%	0.0036
2021	0.086	0.073	0.089	0.069	21.60	15.4%	0.0030
2022	0.088	0.075	0.091	0.070	22.80	15.4%	0.0027
2023	0.090	0.077	0.095	0.073	24.00	15.5%	0.0020
2024	0.096	0.080	0.101	0.078	25.20	15.6%	0.0006
2025	0.098	0.082	0.104	0.080	37.20	15.7%	0.0005
2026	0.100	0.084	0.106	0.082	49.20	15.8%	0.0004
2027	0.103	0.086	0.109	0.084	61.20	15.9%	0.0004
2028	0.105	0.088	0.111	0.087	73.20	16.0%	0.0004
2029	0.107	0.090	0.114	0.089	85.20	16.1%	0.0004
2030	0.109	0.092	0.117	0.091	96.00	16.2%	0.0004
2031	0.112	0.094	0.120	0.094	96.00	16.3%	0.0004
2032	0.114	0.097	0.123	0.097	96.00	16.4%	0.0004
2033	0.117	0.099	0.126	0.099	96.00	16.5%	0.0004
2034	0.119	0.101	0.129	0.102	96.00	16.6%	0.0004
2035	0.122	0.104	0.132	0.105	96.00	16.7%	0.0004
2036	0.125	0.106	0.136	0.108	96.00	16.8%	0.0004
2037	0.127	0.108	0.139	0.111	96.00	16.9%	0.0004
2038	0.130	0.111	0.142	0.114	96.00	17.0%	0.0004
2039	0.133	0.114	0.146	0.117	96.00	17.1%	0.0004
Levelized Costs							
10 years (2010-2019)	0.078	0.063	0.080	0.060	25.502	14.8%	0.003
15 years (2010-2024)	0.081	0.067	0.084	0.063	24.682	15.0%	0.003
30 years (2010-2039)	0.095	0.079	0.100	0.077	49.045	15.6%	0.002

NOTES: General

All Avoided Costs are in Year 2009 Dollars

ISO NE periods: Summer is June through September, Winter is all other months. Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are all other hours

Table One: Avoided Cost of Electricity (2009$) Results : WCMA (West-Central Massachusetts)

State MA

User-defined Inputs	
Wholesale Risk Premium (WRP)	9%
Real Discount Rate	2.22%

	Avoided Unit Cost of Electric Energy[1]				Avoided Unit Cost of Electric Capacity[2]		DRIPE: 2010 vintage measures Intrastate					DRIPE: 2011 vintage measures Intrastate					Avoided Externality Costs			
					kW sold into FCA (PA to determine quantity)[3]	kW purchased from FCA (PA to determine quantity)	Energy				Capacity (See note 2)	Energy				Capacity (See note 2)				
	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak			Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Annual Value	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Annual Value	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kw-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh
Period:	a	b	c	d	e=y*1.08	f=y*(1+z)*(1+PTF Loss)*(1+WRP)	g	h	i	j	k	l	m	n	o	p	q	r	s	t
2009	0.000	0.000	0.000	0.000													0.039	0.039	0.038	0.041
2010	0.075	0.058	0.078	0.057	65.84	*0.00*	0.056	0.043	0.062	0.032		0.000	0.000	0.000	0.000		0.039	0.039	0.038	0.041
2011	0.080	0.063	0.082	0.060	50.58	*0.00*	0.058	0.045	0.063	0.032		0.060	0.046	0.066	0.034		0.039	0.039	0.038	0.041
2012	0.087	0.068	0.085	0.063	35.74	*0.00*	0.063	0.048	0.066	0.034		0.064	0.049	0.067	0.035		0.039	0.039	0.038	0.041
2013	0.087	0.072	0.088	0.070	16.85	0.00	0.031	0.025	0.033	0.018	55.00	0.031	0.025	0.034	0.019		0.033	0.033	0.032	0.034
2014	0.089	0.073	0.090	0.070	16.85	19.86	0.026	0.021	0.028	0.016	81.00	0.028	0.023	0.030	0.017	55.00	0.032	0.032	0.031	0.033
2015	0.089	0.074	0.092	0.071	18.14	21.40	0.023	0.019	0.026	0.014	54.00	0.023	0.019	0.026	0.014	81.00	0.030	0.031	0.030	0.032
2016	0.090	0.076	0.095	0.072	19.44	22.97	0.020	0.017	0.023	0.012	20.00	0.020	0.017	0.023	0.012	54.00	0.029	0.030	0.028	0.031
2017	0.092	0.079	0.098	0.076	19.44	22.98	0.018	0.015	0.020	0.011		0.018	0.015	0.020	0.011	20.00	0.028	0.028	0.027	0.029
2018	0.096	0.081	0.100	0.079	20.74	24.54	0.015	0.013	0.017	0.009		0.015	0.013	0.017	0.009		0.027	0.027	0.026	0.028
2019	0.097	0.084	0.102	0.079	20.74	24.56	0.012	0.010	0.014	0.008		0.012	0.010	0.014	0.008		0.026	0.026	0.025	0.027
2020	0.097	0.084	0.102	0.080	22.03	26.11	0.009	0.008	0.010	0.006		0.009	0.008	0.010	0.006		0.024	0.025	0.024	0.026
2021	0.095	0.082	0.100	0.079	23.33	27.67	0.006	0.005	0.007	0.004		0.006	0.005	0.007	0.004		0.023	0.024	0.023	0.024
2022	0.097	0.084	0.102	0.080	24.62	29.24	0.003	0.003	0.003	0.002		0.003	0.003	0.003	0.002		0.022	0.022	0.021	0.023
2023	0.099	0.085	0.105	0.083	25.92	30.80	0.000	0.000	0.000	0.000		0.000	0.000	0.000	0.000		0.021	0.021	0.020	0.022
2024	0.104	0.088	0.110	0.086	27.22	32.37											0.020	0.020	0.019	0.021
2025	0.106	0.090	0.113	0.089	40.18	47.82											0.020	0.020	0.019	0.021
2026	0.108	0.092	0.115	0.091	53.14	63.31											0.020	0.020	0.019	0.021
2027	0.110	0.094	0.118	0.093	66.10	78.81											0.020	0.020	0.019	0.021
2028	0.112	0.096	0.121	0.096	79.06	94.35											0.020	0.020	0.019	0.021
2029	0.114	0.098	0.124	0.098	92.02	109.91											0.020	0.020	0.019	0.021
2030	0.117	0.100	0.127	0.101	103.68	123.95											0.020	0.020	0.019	0.021
2031	0.119	0.102	0.130	0.104	103.68	124.05											0.020	0.020	0.019	0.021
2032	0.122	0.105	0.133	0.106	103.68	124.16											0.020	0.020	0.019	0.021
2033	0.124	0.107	0.136	0.109	103.68	124.27											0.020	0.020	0.019	0.021
2034	0.127	0.109	0.139	0.112	103.68	124.37											0.020	0.020	0.019	0.021
2035	0.129	0.112	0.142	0.115	103.68	124.48											0.020	0.020	0.019	0.021
2036	0.132	0.114	0.146	0.118	103.68	124.59											0.020	0.020	0.019	0.021
2037	0.135	0.117	0.149	0.121	103.68	124.69											0.020	0.020	0.019	0.021
2038	0.137	0.120	0.153	0.125	103.68	124.80											0.020	0.020	0.019	0.021
2039	0.140	0.122	0.156	0.128	103.68	124.91											0.020	0.020	0.019	0.021
Levelized Costs																				
10 years (2010-2019)	0.088	0.072	0.091	0.069	29.21	12.99	0.033	0.026	0.036	0.019	22.55	0.028	0.022	0.030	0.016	22.55	0.032	0.033	0.032	0.034
15 years (2010-2024)	0.091	0.076	0.095	0.073	27.83	17.81	0.025	0.019	0.027	0.014	15.84	0.020	0.016	0.022	0.012	15.84	0.029	0.030	0.029	0.031
30 years (2010-2039)	0.104	0.088	0.110	0.087	53.65	55.24											0.025	0.026	0.025	0.027

NOTES:

General — All Avoided Costs are in Year 2009 Dollars

ISO NE periods: Summer is June through September, Winter is all other months. Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are all other hours

1 Avoided cost of electric energy = (wholesale energy avoided cost + REC cost to load) * risk premium, e.g. A= (U + AB) * (1+Wholesale Risk Premium)

2 Absolute value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year, PA strategy re bidding that reduction into applicable FCAs, and unit values in columns e, f, k and p.

3 For only 2010 and 2011; proceeds from selling into the FCM include the reserve margin, in addition to the ISO-NE loss factor of 8%

Table Two: Inputs to Avoided Cost Calculations

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Zone: WCMA (West-Central Massachusetts)

	Wholesale Avoided Costs of Electricity						
	Energy				Capacity		Avoided REC Costs to Load
	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	FCA Price	Reserve Margin	REC Costs
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	%	$/kWh
Period:	u	v	w	x	y	z	aa
2009							
2010	0.067	0.052	0.070	0.051	52.51	16.1%	0.0018
2011	0.072	0.056	0.074	0.053	41.18	13.7%	0.0018
2012	0.078	0.061	0.077	0.056	33.09	14.4%	0.0017
2013	0.078	0.064	0.079	0.062	15.60	14.6%	0.0022
2014	0.079	0.065	0.080	0.062	15.60	14.6%	0.0026
2015	0.079	0.066	0.082	0.062	16.80	14.7%	0.0027
2016	0.079	0.067	0.084	0.063	18.00	14.9%	0.0030
2017	0.081	0.069	0.086	0.066	18.00	15.0%	0.0039
2018	0.084	0.070	0.088	0.068	19.20	15.1%	0.0042
2019	0.086	0.073	0.090	0.069	19.20	15.2%	0.0038
2020	0.086	0.073	0.090	0.070	20.40	15.3%	0.0036
2021	0.084	0.073	0.089	0.070	21.60	15.4%	0.0030
2022	0.086	0.074	0.091	0.071	22.80	15.4%	0.0027
2023	0.089	0.076	0.094	0.074	24.00	15.5%	0.0020
2024	0.095	0.080	0.101	0.079	25.20	15.6%	0.0006
2025	0.096	0.082	0.103	0.081	37.20	15.7%	0.0005
2026	0.098	0.084	0.106	0.083	49.20	15.8%	0.0004
2027	0.100	0.086	0.108	0.085	61.20	15.9%	0.0004
2028	0.103	0.088	0.111	0.088	73.20	16.0%	0.0004
2029	0.105	0.090	0.113	0.090	85.20	16.1%	0.0004
2030	0.107	0.092	0.116	0.092	96.00	16.2%	0.0004
2031	0.109	0.094	0.119	0.095	96.00	16.3%	0.0004
2032	0.111	0.096	0.121	0.097	96.00	16.4%	0.0004
2033	0.113	0.098	0.124	0.100	96.00	16.5%	0.0004
2034	0.116	0.100	0.127	0.103	96.00	16.6%	0.0004
2035	0.118	0.102	0.130	0.105	96.00	16.7%	0.0004
2036	0.121	0.105	0.133	0.108	96.00	16.8%	0.0004
2037	0.123	0.107	0.137	0.111	96.00	16.9%	0.0004
2038	0.126	0.109	0.140	0.114	96.00	17.0%	0.0004
2039	0.128	0.112	0.143	0.117	96.00	17.1%	0.0004
Levelized Costs							
10 years (2010-2019)	0.078	0.064	0.080	0.061	25.502	14.8%	0.003
15 years (2010-2024)	0.081	0.067	0.084	0.064	24.682	15.0%	0.003
30 years (2010-2039)	0.093	0.079	0.100	0.078	49.045	15.6%	0.002

NOTES: General All Avoided Costs are in Year 2009 Dollars

ISO NE periods: Summer is June through September, Winter is all other months. Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are all other hours

Table One: Avoided Cost of Electricity (2009$) Results : NEMA (Northeast Massachusetts)

State MA

User-defined Inputs	
Wholesale Risk Premium (WRP)	9%
Real Discount Rate	2.22%

	Avoided Unit Cost of Electric Energy[1]				Avoided Unit Cost of Electric Capacity[2]		DRIPE: 2010 vintage measures Intrastate					DRIPE: 2011 vintage measures Intrastate					Avoided Externality Costs			
							Energy				Capacity (See note 2)	Energy				Capacity (See note 2)				
	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	kW sold into FCA (PA to determine quantity)[3]	kW purchased from FCA (PA to determine quantity)	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Annual Value	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Annual Value	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kw-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh
Period:	a	b	c	d	e=y*1.08	f=y*(1+z)*(1+PTF Loss)*(1+WRP)	g	h	i	j	k	l	m	n	o	p	q	r	s	t
2009	0.000	0.000	0.000	0.000													0.039	0.039	0.038	0.041
2010	0.075	0.058	0.079	0.057	65.84	*0.00*	0.056	0.043	0.062	0.032		0.000	0.000	0.000	0.000		0.039	0.039	0.038	0.041
2011	0.080	0.062	0.083	0.059	50.58	*0.00*	0.058	0.045	0.063	0.032		0.060	0.046	0.066	0.034		0.039	0.039	0.038	0.041
2012	0.087	0.067	0.086	0.063	35.74	*0.00*	0.063	0.048	0.066	0.034		0.064	0.049	0.067	0.035		0.039	0.039	0.038	0.041
2013	0.088	0.072	0.089	0.069	16.85	0.00	0.031	0.025	0.033	0.018	55.00	0.031	0.025	0.034	0.019		0.033	0.033	0.032	0.034
2014	0.089	0.073	0.091	0.070	16.85	19.86	0.026	0.021	0.028	0.016	81.00	0.028	0.023	0.030	0.017	55.00	0.032	0.032	0.031	0.033
2015	0.090	0.074	0.093	0.070	18.14	21.40	0.023	0.019	0.026	0.014	54.00	0.023	0.019	0.026	0.014	81.00	0.030	0.031	0.030	0.032
2016	0.091	0.076	0.096	0.072	19.44	22.97	0.020	0.017	0.023	0.012	20.00	0.020	0.017	0.023	0.012	54.00	0.029	0.030	0.028	0.031
2017	0.094	0.079	0.099	0.075	19.44	22.98	0.018	0.015	0.020	0.011		0.018	0.015	0.020	0.011	20.00	0.028	0.028	0.027	0.029
2018	0.098	0.082	0.101	0.078	20.74	24.54	0.015	0.013	0.017	0.009		0.015	0.013	0.017	0.009		0.027	0.027	0.026	0.028
2019	0.099	0.084	0.104	0.079	20.74	24.56	0.012	0.010	0.014	0.008		0.012	0.010	0.014	0.008		0.026	0.026	0.025	0.027
2020	0.099	0.084	0.103	0.080	22.03	26.11	0.009	0.008	0.010	0.006		0.009	0.008	0.010	0.006		0.024	0.025	0.024	0.026
2021	0.097	0.083	0.102	0.079	23.33	27.67	0.006	0.005	0.007	0.004		0.006	0.005	0.007	0.004		0.023	0.024	0.023	0.024
2022	0.099	0.084	0.103	0.080	24.62	29.24	0.003	0.003	0.003	0.002		0.003	0.003	0.003	0.002		0.022	0.022	0.021	0.023
2023	0.100	0.086	0.107	0.082	25.92	30.80	0.000	0.000	0.000	0.000		0.000	0.000	0.000	0.000		0.021	0.021	0.020	0.022
2024	0.106	0.088	0.112	0.086	27.22	32.37											0.020	0.020	0.019	0.021
2025	0.108	0.090	0.115	0.088	40.18	47.82											0.020	0.020	0.019	0.021
2026	0.110	0.092	0.118	0.091	53.14	63.31											0.020	0.020	0.019	0.021
2027	0.112	0.094	0.121	0.093	66.10	78.81											0.020	0.020	0.019	0.021
2028	0.115	0.096	0.123	0.096	79.06	94.35											0.020	0.020	0.019	0.021
2029	0.117	0.098	0.126	0.098	92.02	109.91											0.020	0.020	0.019	0.021
2030	0.120	0.101	0.130	0.101	103.68	123.95											0.020	0.020	0.019	0.021
2031	0.122	0.103	0.133	0.104	103.68	124.05											0.020	0.020	0.019	0.021
2032	0.125	0.105	0.136	0.106	103.68	124.16											0.020	0.020	0.019	0.021
2033	0.127	0.108	0.139	0.109	103.68	124.27											0.020	0.020	0.019	0.021
2034	0.130	0.110	0.143	0.112	103.68	124.37											0.020	0.020	0.019	0.021
2035	0.133	0.113	0.146	0.115	103.68	124.48											0.020	0.020	0.019	0.021
2036	0.136	0.115	0.150	0.119	103.68	124.59											0.020	0.020	0.019	0.021
2037	0.139	0.118	0.153	0.122	103.68	124.69											0.020	0.020	0.019	0.021
2038	0.142	0.121	0.157	0.125	103.68	124.80											0.020	0.020	0.019	0.021
2039	0.145	0.123	0.161	0.128	103.68	124.91											0.020	0.020	0.019	0.021
Levelized Costs																				
10 years (2010-2019)	0.089	0.072	0.092	0.069	29.21	12.99	0.033	0.026	0.036	0.019	22.55	0.028	0.022	0.030	0.016	22.55	0.032	0.033	0.032	0.034
15 years (2010-2024)	0.092	0.076	0.096	0.072	27.83	17.81	0.025	0.019	0.027	0.014	15.84	0.020	0.016	0.022	0.012	15.84	0.029	0.030	0.029	0.031
30 years (2010-2039)	0.106	0.088	0.112	0.086	53.65	55.24											0.025	0.026	0.025	0.027

NOTES:

General All Avoided Costs are in Year 2009 Dollars

ISO NE periods: Summer is June through September, Winter is all other months. Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are all other hours

1 Avoided cost of electric energy = (wholesale energy avoided cost + REC cost to load) * risk premium, e.g. A= (U + AB) * (1+Wholesale Risk Premium)

2 Absolute value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year, PA strategy re bidding that reduction into applicable FCAs, and unit values in columns e, f, k and p.

3 For only 2010 and 2011; proceeds from selling into the FCM include the reserve margin, in addition to the ISO-NE loss factor of 8%

Table Two: Inputs to Avoided Cost Calculations

Zone: NEMA (Northeast Massachusetts)

	Wholesale Avoided Costs of Electricity						Avoided REC Costs to Load
	Energy				Capacity		
	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	FCA Price	Reserve Margin	REC Costs
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	%	$/kWh
Period:	u	v	w	x	y	z	aa
2009							
2010	0.067	0.051	0.070	0.050	52.51	16.1%	0.0018
2011	0.072	0.055	0.074	0.052	41.18	13.7%	0.0018
2012	0.078	0.060	0.077	0.056	33.09	14.4%	0.0017
2013	0.079	0.064	0.080	0.061	15.60	14.6%	0.0022
2014	0.079	0.065	0.081	0.061	15.60	14.6%	0.0026
2015	0.080	0.065	0.082	0.062	16.80	14.7%	0.0027
2016	0.080	0.067	0.085	0.063	18.00	14.9%	0.0030
2017	0.082	0.069	0.087	0.065	18.00	15.0%	0.0039
2018	0.085	0.071	0.089	0.068	19.20	15.1%	0.0042
2019	0.087	0.073	0.092	0.069	19.20	15.2%	0.0038
2020	0.087	0.073	0.091	0.069	20.40	15.3%	0.0036
2021	0.086	0.073	0.090	0.069	21.60	15.4%	0.0030
2022	0.088	0.075	0.092	0.071	22.80	15.4%	0.0027
2023	0.090	0.077	0.096	0.073	24.00	15.5%	0.0020
2024	0.096	0.080	0.102	0.078	25.20	15.6%	0.0006
2025	0.098	0.082	0.105	0.081	37.20	15.7%	0.0005
2026	0.101	0.084	0.108	0.083	49.20	15.8%	0.0004
2027	0.103	0.086	0.110	0.085	61.20	15.9%	0.0004
2028	0.105	0.088	0.113	0.087	73.20	16.0%	0.0004
2029	0.107	0.090	0.116	0.090	85.20	16.1%	0.0004
2030	0.109	0.092	0.118	0.092	96.00	16.2%	0.0004
2031	0.112	0.094	0.121	0.095	96.00	16.3%	0.0004
2032	0.114	0.096	0.124	0.097	96.00	16.4%	0.0004
2033	0.117	0.098	0.127	0.100	96.00	16.5%	0.0004
2034	0.119	0.101	0.130	0.103	96.00	16.6%	0.0004
2035	0.122	0.103	0.134	0.105	96.00	16.7%	0.0004
2036	0.124	0.105	0.137	0.108	96.00	16.8%	0.0004
2037	0.127	0.108	0.140	0.111	96.00	16.9%	0.0004
2038	0.130	0.110	0.144	0.114	96.00	17.0%	0.0004
2039	0.132	0.113	0.147	0.117	96.00	17.1%	0.0004

Levelized Costs							
10 years (2010-2019)	0.079	0.064	0.081	0.060	25.502	14.8%	0.003
15 years (2010-2024)	0.082	0.067	0.085	0.064	24.682	15.0%	0.003
30 years (2010-2039)	0.095	0.079	0.101	0.078	49.045	15.6%	0.002

NOTES: General All Avoided Costs are in Year 2009 Dollars

ISO NE periods: Summer is June through September, Winter is all other months. Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are all other hours

Table One: Avoided Cost of Electricity (2009$) Results : Rest of Massachusetts (Massachusetts excluding NEMA)

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State MA

User-defined Inputs	
Wholesale Risk Premium (WRP)	9%
Real Discount Rate	2.22%

	Avoided Unit Cost of Electric Energy[1]				Avoided Unit Cost of Electric Capacity[2]		DRIPE: 2010 vintage measures Intrastate					DRIPE: 2011 vintage measures Intrastate					Avoided Externality Costs			
							Energy				Capacity (See note 2)	Energy				Capacity (See note 2)				
	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	kW sold into FCA (PA to determine quantity)[3]	kW purchased from FCA (PA to determine quantity)	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Annual Value	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Annual Value	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kw-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh
Period:	a	b	c	d	e=y*1.08	f=y*(1+z)*(1+PTF Loss)*(1+WRP)	g	h	i	j	k	l	m	n	o	p	q	r	s	t
2009	0.000	0.000	0.000	0.000													0.039	0.039	0.038	0.041
2010	0.075	0.058	0.077	0.057	65.84	*0.00*	0.056	0.043	0.062	0.032		0.000	0.000	0.000	0.000		0.039	0.039	0.038	0.041
2011	0.080	0.063	0.082	0.059	50.58	*0.00*	0.058	0.045	0.063	0.032		0.060	0.046	0.066	0.034		0.039	0.039	0.038	0.041
2012	0.087	0.067	0.085	0.063	35.74	*0.00*	0.063	0.048	0.066	0.034		0.064	0.049	0.067	0.035		0.039	0.039	0.038	0.041
2013	0.088	0.072	0.088	0.069	16.85	0.00	0.031	0.025	0.033	0.018	55.00	0.031	0.025	0.034	0.019		0.033	0.033	0.032	0.034
2014	0.088	0.073	0.090	0.070	16.85	19.86	0.026	0.021	0.028	0.016	81.00	0.028	0.023	0.030	0.017	55.00	0.032	0.032	0.031	0.033
2015	0.089	0.074	0.092	0.070	18.14	21.40	0.023	0.019	0.026	0.014	54.00	0.023	0.019	0.026	0.014	81.00	0.030	0.031	0.030	0.032
2016	0.090	0.076	0.095	0.071	19.44	22.97	0.020	0.017	0.023	0.012	20.00	0.020	0.017	0.023	0.012	54.00	0.029	0.030	0.028	0.031
2017	0.093	0.079	0.098	0.075	19.44	22.98	0.018	0.015	0.020	0.011		0.018	0.015	0.020	0.011	20.00	0.028	0.028	0.027	0.029
2018	0.097	0.081	0.100	0.078	20.74	24.54	0.015	0.013	0.017	0.009		0.015	0.013	0.017	0.009		0.027	0.027	0.026	0.028
2019	0.098	0.084	0.102	0.079	20.74	24.56	0.012	0.010	0.014	0.008		0.012	0.010	0.014	0.008		0.026	0.026	0.025	0.027
2020	0.098	0.084	0.102	0.080	22.03	26.11	0.009	0.008	0.010	0.006		0.009	0.008	0.010	0.006		0.024	0.025	0.024	0.026
2021	0.096	0.083	0.100	0.079	23.33	27.67	0.006	0.005	0.007	0.004		0.006	0.005	0.007	0.004		0.023	0.024	0.023	0.024
2022	0.098	0.084	0.102	0.080	24.62	29.24	0.003	0.003	0.003	0.002		0.003	0.003	0.003	0.002		0.022	0.022	0.021	0.023
2023	0.099	0.086	0.105	0.082	25.92	30.80	0.000	0.000	0.000	0.000		0.000	0.000	0.000	0.000		0.021	0.021	0.020	0.022
2024	0.104	0.088	0.111	0.086	27.22	32.37											0.020	0.020	0.019	0.021
2025	0.106	0.090	0.113	0.088	40.18	47.82											0.020	0.020	0.019	0.021
2026	0.109	0.092	0.116	0.090	53.14	63.31											0.020	0.020	0.019	0.021
2027	0.111	0.094	0.118	0.093	66.10	78.81											0.020	0.020	0.019	0.021
2028	0.113	0.096	0.121	0.095	79.06	94.35											0.020	0.020	0.019	0.021
2029	0.116	0.098	0.124	0.098	92.02	109.91											0.020	0.020	0.019	0.021
2030	0.118	0.101	0.127	0.101	103.68	123.95											0.020	0.020	0.019	0.021
2031	0.120	0.103	0.130	0.103	103.68	124.05											0.020	0.020	0.019	0.021
2032	0.123	0.105	0.133	0.106	103.68	124.16											0.020	0.020	0.019	0.021
2033	0.126	0.108	0.137	0.109	103.68	124.27											0.020	0.020	0.019	0.021
2034	0.128	0.110	0.140	0.112	103.68	124.37											0.020	0.020	0.019	0.021
2035	0.131	0.113	0.143	0.115	103.68	124.48											0.020	0.020	0.019	0.021
2036	0.134	0.115	0.147	0.118	103.68	124.59											0.020	0.020	0.019	0.021
2037	0.136	0.118	0.150	0.121	103.68	124.69											0.020	0.020	0.019	0.021
2038	0.139	0.120	0.154	0.125	103.68	124.80											0.020	0.020	0.019	0.021
2039	0.142	0.123	0.158	0.128	103.68	124.91											0.020	0.020	0.019	0.021
Levelized Costs																				
10 years (2010-2019)	0.088	0.072	0.090	0.069	29.21	12.99	0.033	0.026	0.036	0.019	22.55	0.028	0.022	0.030	0.016	22.55	0.032	0.033	0.032	0.034
15 years (2010-2024)	0.091	0.076	0.094	0.072	27.83	17.81	0.025	0.019	0.027	0.014	15.84	0.020	0.016	0.022	0.012	15.84	0.029	0.030	0.029	0.031
30 years (2010-2039)	0.104	0.088	0.110	0.086	53.65	55.24											0.025	0.026	0.025	0.027

NOTES:

General All Avoided Costs are in Year 2009 Dollars

ISO NE periods: Summer is June through September, Winter is all other months. Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are all other hours

1 Avoided cost of electric energy = (wholesale energy avoided cost + REC cost to load) * risk premium, e.g. A= (U + AB) * (1+Wholesale Risk Premium)

2 Absolute value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year, PA strategy re bidding that reduction into applicable FCAs, and unit values in columns e, f, k and p.

3 For only 2010 and 2011; proceeds from selling into the FCM include the reserve margin, in addition to the ISO-NE loss factor of 8%

Table Two: Inputs to Avoided Cost Calculations

Zone: Rest of Massachusetts (Massachusetts excluding NEMA)

	Wholesale Avoided Costs of Electricity						Avoided REC Costs to Load
	Energy				Capacity		
	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	FCA Price	Reserve Margin	REC Costs
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	%	$/kWh
Period:	u	v	w	x	y	z	aa
2009							
2010	0.067	0.051	0.069	0.050	52.51	16.1%	0.0018
2011	0.071	0.056	0.073	0.053	41.18	13.7%	0.0018
2012	0.078	0.060	0.076	0.056	33.09	14.4%	0.0017
2013	0.078	0.064	0.079	0.061	15.60	14.6%	0.0022
2014	0.079	0.065	0.080	0.061	15.60	14.6%	0.0026
2015	0.079	0.065	0.081	0.061	16.80	14.7%	0.0027
2016	0.079	0.067	0.084	0.063	18.00	14.9%	0.0030
2017	0.081	0.069	0.086	0.065	18.00	15.0%	0.0039
2018	0.085	0.070	0.087	0.068	19.20	15.1%	0.0042
2019	0.086	0.073	0.090	0.069	19.20	15.2%	0.0038
2020	0.086	0.073	0.090	0.069	20.40	15.3%	0.0036
2021	0.085	0.073	0.089	0.069	21.60	15.4%	0.0030
2022	0.087	0.075	0.091	0.071	22.80	15.4%	0.0027
2023	0.089	0.077	0.094	0.073	24.00	15.5%	0.0020
2024	0.095	0.080	0.101	0.078	25.20	15.6%	0.0006
2025	0.097	0.082	0.103	0.080	37.20	15.7%	0.0005
2026	0.099	0.084	0.106	0.083	49.20	15.8%	0.0004
2027	0.101	0.086	0.108	0.085	61.20	15.9%	0.0004
2028	0.103	0.088	0.111	0.087	73.20	16.0%	0.0004
2029	0.106	0.090	0.114	0.090	85.20	16.1%	0.0004
2030	0.108	0.092	0.116	0.092	96.00	16.2%	0.0004
2031	0.110	0.094	0.119	0.094	96.00	16.3%	0.0004
2032	0.112	0.096	0.122	0.097	96.00	16.4%	0.0004
2033	0.115	0.098	0.125	0.100	96.00	16.5%	0.0004
2034	0.117	0.101	0.128	0.102	96.00	16.6%	0.0004
2035	0.120	0.103	0.131	0.105	96.00	16.7%	0.0004
2036	0.122	0.105	0.134	0.108	96.00	16.8%	0.0004
2037	0.125	0.108	0.138	0.111	96.00	16.9%	0.0004
2038	0.127	0.110	0.141	0.114	96.00	17.0%	0.0004
2039	0.130	0.113	0.144	0.117	96.00	17.1%	0.0004
Levelized Costs							
10 years (2010-2019)	0.078	0.064	0.080	0.060	25.502	14.8%	0.003
15 years (2010-2024)	0.081	0.067	0.084	0.064	24.682	15.0%	0.003
30 years (2010-2039)	0.094	0.079	0.100	0.078	49.045	15.6%	0.002

NOTES: General

All Avoided Costs are in Year 2009 Dollars

ISO NE periods: Summer is June through September, Winter is all other months. Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are all other hours

Table One: Avoided Cost of Electricity (2009$) Results : Norwalk/Stamford

State CT

User-defined Inputs	
Wholesale Risk Premium (WRP)	9%
Real Discount Rate	2.22%

	Avoided Unit Cost of Electric Energy[1]				Avoided Unit Cost of Electric Capacity[2]		DRIPE: 2010 vintage measures Intrastate Energy				DRIPE: 2010 vintage measures Intrastate Capacity (See note 2)	DRIPE: 2011 vintage measures Intrastate Energy				DRIPE: 2011 vintage measures Intrastate Capacity (See note 2)	Avoided Externality Costs			
	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	kW sold into FCA (PA to determine quantity)[3]	kW purchased from FCA (PA to determine quantity)	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Annual Value	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Annual Value	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kw-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh
Period:	a	b	c	d	e=y*1.08	f=y*(1+z)*(1+PTF Loss)*(1+WRP)	g	h	i	j	k	l	m	n	o	p	q	r	s	t
2009	0.000	0.000	0.000	0.000													0.039	0.039	0.038	0.041
2010	0.079	0.061	0.083	0.060	65.84	*0.00*	0.044	0.028	0.048	0.020		0.000	0.000	0.000	0.000		0.039	0.039	0.038	0.041
2011	0.084	0.065	0.088	0.062	50.58	*0.00*	0.044	0.028	0.048	0.020		0.046	0.030	0.050	0.021		0.039	0.039	0.038	0.041
2012	0.091	0.071	0.090	0.066	35.74	*0.00*	0.047	0.030	0.049	0.021		0.048	0.031	0.050	0.021		0.039	0.039	0.038	0.041
2013	0.092	0.075	0.094	0.073	16.85	0.00	0.023	0.015	0.024	0.011	29.00	0.023	0.015	0.024	0.011		0.033	0.033	0.032	0.034
2014	0.094	0.077	0.096	0.074	16.85	19.86	0.019	0.013	0.021	0.009	42.00	0.021	0.014	0.022	0.010	29.00	0.032	0.032	0.031	0.033
2015	0.094	0.078	0.098	0.074	18.14	21.40	0.018	0.012	0.019	0.008	28.00	0.018	0.012	0.019	0.009	42.00	0.030	0.031	0.030	0.032
2016	0.094	0.080	0.100	0.075	19.44	22.97	0.015	0.011	0.017	0.007	11.00	0.015	0.011	0.017	0.008	28.00	0.029	0.030	0.028	0.031
2017	0.098	0.083	0.105	0.080	19.44	22.98	0.013	0.009	0.015	0.007		0.013	0.009	0.015	0.007	11.00	0.028	0.028	0.027	0.029
2018	0.102	0.086	0.106	0.083	20.74	24.54	0.011	0.008	0.012	0.006		0.011	0.008	0.012	0.006		0.027	0.027	0.026	0.028
2019	0.103	0.088	0.108	0.084	20.74	24.56	0.009	0.006	0.010	0.004		0.009	0.006	0.010	0.004		0.026	0.026	0.025	0.027
2020	0.103	0.088	0.108	0.084	22.03	26.11	0.007	0.005	0.007	0.003		0.007	0.005	0.007	0.003		0.024	0.025	0.024	0.026
2021	0.100	0.086	0.105	0.083	23.33	27.67	0.004	0.003	0.005	0.002		0.004	0.003	0.005	0.002		0.023	0.024	0.023	0.024
2022	0.101	0.088	0.106	0.084	24.62	29.24	0.002	0.002	0.002	0.001		0.002	0.002	0.002	0.001		0.022	0.022	0.021	0.023
2023	0.103	0.089	0.110	0.087	25.92	30.80						0.000	0.000	0.000	0.000		0.021	0.021	0.020	0.022
2024	0.108	0.091	0.114	0.090	27.22	32.37											0.020	0.020	0.019	0.021
2025	0.110	0.093	0.116	0.092	40.18	47.82											0.020	0.020	0.019	0.021
2026	0.113	0.095	0.119	0.095	53.14	63.31											0.020	0.020	0.019	0.021
2027	0.115	0.097	0.121	0.097	66.10	78.81											0.020	0.020	0.019	0.021
2028	0.117	0.099	0.124	0.100	79.06	94.35											0.020	0.020	0.019	0.021
2029	0.119	0.102	0.126	0.102	92.02	109.91											0.020	0.020	0.019	0.021
2030	0.122	0.104	0.129	0.105	103.68	123.95											0.020	0.020	0.019	0.021
2031	0.124	0.106	0.132	0.108	103.68	124.05											0.020	0.020	0.019	0.021
2032	0.127	0.108	0.135	0.111	103.68	124.16											0.020	0.020	0.019	0.021
2033	0.129	0.111	0.137	0.114	103.68	124.27											0.020	0.020	0.019	0.021
2034	0.132	0.113	0.140	0.117	103.68	124.37											0.020	0.020	0.019	0.021
2035	0.135	0.116	0.143	0.120	103.68	124.48											0.020	0.020	0.019	0.021
2036	0.137	0.118	0.146	0.124	103.68	124.59											0.020	0.020	0.019	0.021
2037	0.140	0.121	0.149	0.127	103.68	124.69											0.020	0.020	0.019	0.021
2038	0.143	0.124	0.153	0.130	103.68	124.80											0.020	0.020	0.019	0.021
2039	0.146	0.127	0.156	0.134	103.68	124.91											0.020	0.020	0.019	0.021
Levelized Costs																				
10 years (2010-2019)	0.093	0.076	0.096	0.073	29.21	12.99	0.025	0.017	0.027	0.012	11.81	0.021	0.014	0.022	0.010	11.81	0.032	0.033	0.032	0.034
15 years (2010-2024)	0.096	0.080	0.100	0.076	27.83	17.81	0.019	0.012	0.020	0.009	8.30	0.015	0.010	0.017	0.007	8.30	0.029	0.030	0.029	0.031
30 years (2010-2039)	0.109	0.092	0.114	0.091	53.65	55.24											0.025	0.026	0.025	0.027

NOTES:

General All Avoided Costs are in Year 2009 Dollars

ISO NE periods: Summer is June through September, Winter is all other months. Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are all other hours

1 Avoided cost of electric energy = (wholesale energy avoided cost + REC cost to load) * risk premium, e.g. A= (U + AB) * (1+Wholesale Risk Premium)

2 Absolute value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year, PA strategy re bidding that reduction into applicable FCAs, and unit values in columns e, f, k and p.

3 For only 2010 and 2011; proceeds from selling into the FCM include the reserve margin, in addition to the ISO-NE loss factor of 8%

Table Two: Inputs to Avoided Cost Calculations

Zone: Norwalk/Stamford

	Wholesale Avoided Costs of Electricity						Avoided REC Costs to Load
	Energy				Capacity		
	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	FCA Price	Reserve Margin	REC Costs
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	%	$/kWh
Period:	u	v	w	x	y	z	aa
2009							
2010	0.071	0.054	0.074	0.053	52.51	16.1%	0.0019
2011	0.075	0.058	0.078	0.055	41.18	13.7%	0.0020
2012	0.081	0.063	0.081	0.058	33.09	14.4%	0.0022
2013	0.082	0.066	0.083	0.064	15.60	14.6%	0.0027
2014	0.083	0.067	0.085	0.065	15.60	14.6%	0.0031
2015	0.083	0.068	0.086	0.064	16.80	14.7%	0.0033
2016	0.083	0.069	0.088	0.065	18.00	14.9%	0.0038
2017	0.085	0.071	0.091	0.069	18.00	15.0%	0.0050
2018	0.088	0.073	0.091	0.071	19.20	15.1%	0.0055
2019	0.090	0.076	0.094	0.072	19.20	15.2%	0.0050
2020	0.090	0.076	0.094	0.073	20.40	15.3%	0.0048
2021	0.088	0.075	0.093	0.072	21.60	15.4%	0.0037
2022	0.090	0.077	0.094	0.074	22.80	15.4%	0.0031
2023	0.093	0.079	0.099	0.077	24.00	15.5%	0.0022
2024	0.099	0.083	0.104	0.082	25.20	15.6%	0.0007
2025	0.101	0.085	0.106	0.084	37.20	15.7%	0.0005
2026	0.103	0.087	0.109	0.086	49.20	15.8%	0.0004
2027	0.105	0.089	0.111	0.089	61.20	15.9%	0.0004
2028	0.107	0.091	0.113	0.091	73.20	16.0%	0.0004
2029	0.109	0.093	0.116	0.094	85.20	16.1%	0.0004
2030	0.111	0.095	0.118	0.096	96.00	16.2%	0.0004
2031	0.114	0.097	0.121	0.099	96.00	16.3%	0.0004
2032	0.116	0.099	0.123	0.101	96.00	16.4%	0.0004
2033	0.118	0.101	0.126	0.104	96.00	16.5%	0.0004
2034	0.121	0.104	0.128	0.107	96.00	16.6%	0.0004
2035	0.123	0.106	0.131	0.110	96.00	16.7%	0.0004
2036	0.126	0.108	0.134	0.113	96.00	16.8%	0.0004
2037	0.128	0.111	0.137	0.116	96.00	16.9%	0.0004
2038	0.131	0.113	0.140	0.119	96.00	17.0%	0.0004
2039	0.133	0.116	0.143	0.122	96.00	17.1%	0.0004

Levelized Costs							
10 years (2010-2019)	0.082	0.066	0.085	0.063	25.502	14.8%	0.003
15 years (2010-2024)	0.085	0.070	0.088	0.067	24.682	15.0%	0.003
30 years (2010-2039)	0.098	0.082	0.103	0.081	49.045	15.6%	0.002

NOTES: General All Avoided Costs are in Year 2009 Dollars

ISO NE periods: Summer is June through September, Winter is all other months. Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are all other hours

Table One: Avoided Cost of Electricity (2009$) Results : Southwest Connecticut, including Norwalk/Stamford

State CT

User-defined Inputs	
Wholesale Risk Premium (WRP)	9%
Real Discount Rate	2.22%

	Avoided Unit Cost of Electric Energy[1]				Avoided Unit Cost of Electric Capacity[2]		DRIPE: 2010 vintage measures					DRIPE: 2011 vintage measures					Avoided Externality Costs			
							Intrastate					Intrastate								
							Energy				Capacity (See note 2)	Energy				Capacity (See note 2)				
	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	kW sold into FCA (PA to determine quantity)[3]	kW purchased from FCA (PA to determine quantity)	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Annual Value	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Annual Value	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kw-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh
Period:	a	b	c	d	e=y*1.08	f=y*(1+z)*(1+PTF Loss)*(1+WRP)	g	h	i	j	k	l	m	n	o	p	q	r	s	t
2009	0.000	0.000	0.000	0.000													0.039	0.039	0.038	0.041
2010	0.079	0.061	0.083	0.060	65.84	*0.00*	0.044	0.028	0.048	0.020		0.000	0.000	0.000	0.000		0.039	0.039	0.038	0.041
2011	0.084	0.065	0.088	0.062	50.58	*0.00*	0.044	0.028	0.048	0.020		0.046	0.030	0.050	0.021		0.039	0.039	0.038	0.041
2012	0.091	0.071	0.090	0.066	35.74	*0.00*	0.047	0.030	0.049	0.021		0.048	0.031	0.050	0.021		0.039	0.039	0.038	0.041
2013	0.092	0.075	0.094	0.073	16.85	0.00	0.023	0.015	0.024	0.011	29.00	0.023	0.015	0.024	0.011		0.033	0.033	0.032	0.034
2014	0.094	0.077	0.096	0.074	16.85	19.86	0.019	0.013	0.021	0.009	42.00	0.021	0.014	0.022	0.010	29.00	0.032	0.032	0.031	0.033
2015	0.094	0.078	0.097	0.074	18.14	21.40	0.018	0.012	0.019	0.008	28.00	0.018	0.012	0.019	0.009	42.00	0.030	0.031	0.030	0.032
2016	0.094	0.080	0.100	0.075	19.44	22.97	0.015	0.011	0.017	0.007	11.00	0.015	0.011	0.017	0.008	28.00	0.029	0.030	0.028	0.031
2017	0.098	0.083	0.105	0.080	19.44	22.98	0.013	0.009	0.015	0.007		0.013	0.009	0.015	0.007	11.00	0.028	0.028	0.027	0.029
2018	0.102	0.086	0.106	0.083	20.74	24.54	0.011	0.008	0.012	0.006		0.011	0.008	0.012	0.006		0.027	0.027	0.026	0.028
2019	0.103	0.088	0.108	0.084	20.74	24.56	0.009	0.006	0.010	0.004		0.009	0.006	0.010	0.004		0.026	0.026	0.025	0.027
2020	0.103	0.088	0.108	0.084	22.03	26.11	0.007	0.005	0.007	0.003		0.007	0.005	0.007	0.003		0.024	0.025	0.024	0.026
2021	0.100	0.086	0.105	0.083	23.33	27.67	0.004	0.003	0.005	0.002		0.004	0.003	0.005	0.002		0.023	0.024	0.023	0.024
2022	0.101	0.088	0.106	0.084	24.62	29.24	0.002	0.002	0.002	0.001		0.002	0.002	0.002	0.001		0.022	0.022	0.021	0.023
2023	0.103	0.089	0.110	0.087	25.92	30.80	0.000	0.000	0.000	0.000		0.000	0.000	0.000	0.000		0.021	0.021	0.020	0.022
2024	0.108	0.091	0.114	0.090	27.22	32.37											0.020	0.020	0.019	0.021
2025	0.110	0.093	0.116	0.092	40.18	47.82											0.020	0.020	0.019	0.021
2026	0.112	0.095	0.119	0.095	53.14	63.31											0.020	0.020	0.019	0.021
2027	0.115	0.097	0.121	0.097	66.10	78.81											0.020	0.020	0.019	0.021
2028	0.117	0.099	0.124	0.100	79.06	94.35											0.020	0.020	0.019	0.021
2029	0.119	0.101	0.126	0.102	92.02	109.91											0.020	0.020	0.019	0.021
2030	0.122	0.104	0.129	0.105	103.68	123.95											0.020	0.020	0.019	0.021
2031	0.124	0.106	0.132	0.108	103.68	124.05											0.020	0.020	0.019	0.021
2032	0.127	0.108	0.134	0.111	103.68	124.16											0.020	0.020	0.019	0.021
2033	0.129	0.111	0.137	0.114	103.68	124.27											0.020	0.020	0.019	0.021
2034	0.132	0.113	0.140	0.117	103.68	124.37											0.020	0.020	0.019	0.021
2035	0.134	0.116	0.143	0.120	103.68	124.48											0.020	0.020	0.019	0.021
2036	0.137	0.118	0.146	0.123	103.68	124.59											0.020	0.020	0.019	0.021
2037	0.140	0.121	0.149	0.127	103.68	124.69											0.020	0.020	0.019	0.021
2038	0.143	0.124	0.152	0.130	103.68	124.80											0.020	0.020	0.019	0.021
2039	0.146	0.126	0.156	0.134	103.68	124.91											0.020	0.020	0.019	0.021
Levelized Costs																				
10 years (2010-2019)	0.093	0.076	0.096	0.073	29.21	12.99	0.025	0.017	0.027	0.012	11.81	0.021	0.014	0.022	0.010	11.81	0.032	0.033	0.032	0.034
15 years (2010-2024)	0.096	0.080	0.100	0.076	27.83	17.81	0.019	0.012	0.020	0.009	8.30	0.015	0.010	0.017	0.007	8.30	0.029	0.030	0.029	0.031
30 years (2010-2039)	0.108	0.091	0.114	0.091	53.65	55.24											0.025	0.026	0.025	0.027

NOTES:

General All Avoided Costs are in Year 2009 Dollars

ISO NE periods: Summer is June through September, Winter is all other months. Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are all other hours

1 Avoided cost of electric energy = (wholesale energy avoided cost + REC cost to load) * risk premium, e.g. A= (U + AB) * (1+Wholesale Risk Premium)

2 Absolute value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year, PA strategy re bidding that reduction into applicable FCAs, and unit values in columns e, f, k and p.

3 For only 2010 and 2011; proceeds from selling into the FCM include the reserve margin, in addition to the ISO-NE loss factor of 8%

Table Two: Inputs to Avoided Cost Calculations

Page Two of Two

Zone: Southwest Connecticut, including Norwalk/Stamford

	Wholesale Avoided Costs of Electricity						Avoided REC Costs to Load
	Energy				Capacity		
	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	FCA Price	Reserve Margin	REC Costs
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	%	$/kWh
Period:	u	v	w	x	y	z	aa
2009							
2010	0.070	0.054	0.074	0.053	52.51	16.1%	0.0019
2011	0.075	0.058	0.078	0.055	41.18	13.7%	0.0020
2012	0.081	0.063	0.081	0.058	33.09	14.4%	0.0022
2013	0.082	0.066	0.083	0.064	15.60	14.6%	0.0027
2014	0.083	0.067	0.085	0.064	15.60	14.6%	0.0031
2015	0.083	0.068	0.086	0.064	16.80	14.7%	0.0033
2016	0.083	0.069	0.088	0.065	18.00	14.9%	0.0038
2017	0.085	0.071	0.091	0.069	18.00	15.0%	0.0050
2018	0.088	0.073	0.091	0.071	19.20	15.1%	0.0055
2019	0.090	0.076	0.094	0.072	19.20	15.2%	0.0050
2020	0.090	0.076	0.094	0.073	20.40	15.3%	0.0048
2021	0.088	0.075	0.093	0.072	21.60	15.4%	0.0037
2022	0.090	0.077	0.094	0.074	22.80	15.4%	0.0031
2023	0.093	0.079	0.099	0.077	24.00	15.5%	0.0022
2024	0.099	0.083	0.104	0.082	25.20	15.6%	0.0007
2025	0.101	0.085	0.106	0.084	37.20	15.7%	0.0005
2026	0.103	0.087	0.108	0.086	49.20	15.8%	0.0004
2027	0.105	0.089	0.111	0.089	61.20	15.9%	0.0004
2028	0.107	0.091	0.113	0.091	73.20	16.0%	0.0004
2029	0.109	0.093	0.115	0.094	85.20	16.1%	0.0004
2030	0.111	0.095	0.118	0.096	96.00	16.2%	0.0004
2031	0.114	0.097	0.120	0.099	96.00	16.3%	0.0004
2032	0.116	0.099	0.123	0.101	96.00	16.4%	0.0004
2033	0.118	0.101	0.126	0.104	96.00	16.5%	0.0004
2034	0.121	0.104	0.128	0.107	96.00	16.6%	0.0004
2035	0.123	0.106	0.131	0.110	96.00	16.7%	0.0004
2036	0.125	0.108	0.134	0.113	96.00	16.8%	0.0004
2037	0.128	0.111	0.137	0.116	96.00	16.9%	0.0004
2038	0.131	0.113	0.139	0.119	96.00	17.0%	0.0004
2039	0.133	0.116	0.142	0.122	96.00	17.1%	0.0004
Levelized Costs							
10 years (2010-2019)	0.082	0.066	0.085	0.063	25.502	14.8%	0.003
15 years (2010-2024)	0.085	0.070	0.088	0.067	24.682	15.0%	0.003
30 years (2010-2039)	0.097	0.082	0.103	0.081	49.045	15.6%	0.002

NOTES: General All Avoided Costs are in Year 2009 Dollars

ISO NE periods: Summer is June through September, Winter is all other months. Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are all other hours

Table One: Avoided Cost of Electricity (2009$) Results : Southwest Connecticut, excluding Norwalk/Stamford

State CT

User-defined Inputs	
Wholesale Risk Premium (WRP)	9%
Real Discount Rate	2.22%

	Avoided Unit Cost of Electric Energy[1]				Avoided Unit Cost of Electric Capacity[2]		DRIPE: 2010 vintage measures Intrastate					DRIPE: 2011 vintage measures Intrastate					Avoided Externality Costs			
							Energy				Capacity (See note 2)	Energy				Capacity (See note 2)				
	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	kW sold into FCA (PA to determine quantity)[3]	kW purchased from FCA (PA to determine quantity)	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Annual Value	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Annual Value	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kw-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh
Period:	a	b	c	d	e=y*1.08	f=y*(1+z)*(1+PTF Loss)*(1+WRP)	g	h	i	j	k	l	m	n	o	p	q	r	s	t
2009	0.000	0.000	0.000	0.000													0.039	0.039	0.038	0.041
2010	0.079	0.061	0.083	0.060	65.84	*0.00*	0.044	0.028	0.048	0.020		0.000	0.000	0.000	0.000		0.039	0.039	0.038	0.041
2011	0.084	0.065	0.087	0.062	50.58	*0.00*	0.044	0.028	0.048	0.020		0.046	0.030	0.050	0.021		0.039	0.039	0.038	0.041
2012	0.091	0.071	0.090	0.066	35.74	*0.00*	0.047	0.030	0.049	0.021		0.048	0.031	0.050	0.021		0.039	0.039	0.038	0.041
2013	0.092	0.075	0.094	0.073	16.85	0.00	0.023	0.015	0.024	0.011	29.00	0.023	0.015	0.024	0.011		0.033	0.033	0.032	0.034
2014	0.094	0.077	0.096	0.074	16.85	19.86	0.019	0.013	0.021	0.009	42.00	0.021	0.014	0.022	0.010	29.00	0.032	0.032	0.031	0.033
2015	0.094	0.078	0.097	0.074	18.14	21.40	0.018	0.012	0.019	0.008	28.00	0.018	0.012	0.019	0.009	42.00	0.030	0.031	0.030	0.032
2016	0.094	0.080	0.100	0.075	19.44	22.97	0.015	0.011	0.017	0.007	11.00	0.015	0.011	0.017	0.008	28.00	0.029	0.030	0.028	0.031
2017	0.098	0.083	0.104	0.080	19.44	22.98	0.013	0.009	0.015	0.007		0.013	0.009	0.015	0.007	11.00	0.028	0.028	0.027	0.029
2018	0.102	0.086	0.106	0.083	20.74	24.54	0.011	0.008	0.012	0.006		0.011	0.008	0.012	0.006		0.027	0.027	0.026	0.028
2019	0.103	0.088	0.108	0.084	20.74	24.56	0.009	0.006	0.010	0.004		0.009	0.006	0.010	0.004		0.026	0.026	0.025	0.027
2020	0.103	0.088	0.108	0.084	22.03	26.11	0.007	0.005	0.007	0.003		0.007	0.005	0.007	0.003		0.024	0.025	0.024	0.026
2021	0.100	0.086	0.105	0.083	23.33	27.67	0.004	0.003	0.005	0.002		0.004	0.003	0.005	0.002		0.023	0.024	0.023	0.024
2022	0.101	0.088	0.106	0.084	24.62	29.24	0.002	0.002	0.002	0.001		0.002	0.002	0.002	0.001		0.022	0.022	0.021	0.023
2023	0.103	0.089	0.110	0.086	25.92	30.80	0.000	0.000	0.000	0.000		0.000	0.000	0.000	0.000		0.021	0.021	0.020	0.022
2024	0.108	0.091	0.114	0.090	27.22	32.37											0.020	0.020	0.019	0.021
2025	0.110	0.093	0.116	0.092	40.18	47.82											0.020	0.020	0.019	0.021
2026	0.112	0.095	0.119	0.095	53.14	63.31											0.020	0.020	0.019	0.021
2027	0.115	0.097	0.121	0.097	66.10	78.81											0.020	0.020	0.019	0.021
2028	0.117	0.099	0.124	0.100	79.06	94.35											0.020	0.020	0.019	0.021
2029	0.119	0.101	0.126	0.102	92.02	109.91											0.020	0.020	0.019	0.021
2030	0.122	0.104	0.129	0.105	103.68	123.95											0.020	0.020	0.019	0.021
2031	0.124	0.106	0.132	0.108	103.68	124.05											0.020	0.020	0.019	0.021
2032	0.127	0.108	0.134	0.111	103.68	124.16											0.020	0.020	0.019	0.021
2033	0.129	0.111	0.137	0.114	103.68	124.27											0.020	0.020	0.019	0.021
2034	0.132	0.113	0.140	0.117	103.68	124.37											0.020	0.020	0.019	0.021
2035	0.134	0.116	0.143	0.120	103.68	124.48											0.020	0.020	0.019	0.021
2036	0.137	0.118	0.146	0.123	103.68	124.59											0.020	0.020	0.019	0.021
2037	0.140	0.121	0.149	0.127	103.68	124.69											0.020	0.020	0.019	0.021
2038	0.143	0.124	0.152	0.130	103.68	124.80											0.020	0.020	0.019	0.021
2039	0.146	0.126	0.156	0.134	103.68	124.91											0.020	0.020	0.019	0.021
Levelized Costs																				
10 years (2010-2019)	0.093	0.076	0.096	0.073	29.21	12.99	0.025	0.017	0.027	0.012	11.81	0.021	0.014	0.022	0.010	11.81	0.032	0.033	0.032	0.034
15 years (2010-2024)	0.096	0.080	0.100	0.076	27.83	17.81	0.019	0.012	0.020	0.009	8.30	0.015	0.010	0.017	0.007	8.30	0.029	0.030	0.029	0.031
30 years (2010-2039)	0.108	0.091	0.114	0.091	53.65	55.24											0.025	0.026	0.025	0.027

NOTES:

General — All Avoided Costs are in Year 2009 Dollars

ISO NE periods: Summer is June through September, Winter is all other months. Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are all other hours

1 Avoided cost of electric energy = (wholesale energy avoided cost + REC cost to load) * risk premium, e.g. A= (U + AB) * (1+Wholesale Risk Premium)

2 Absolute value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year, PA strategy re bidding that reduction into applicable FCAs, and unit values in columns e, f, k and p.

3 For only 2010 and 2011; proceeds from selling into the FCM include the reserve margin, in addition to the ISO-NE loss factor of 8%

Table Two: Inputs to Avoided Cost Calculations

Zone: Southwest Connecticut, excluding Norwalk/Stamford

	Wholesale Avoided Costs of Electricity						
	Energy				Capacity		Avoided REC Costs to Load
	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	FCA Price	Reserve Margin	REC Costs
Units:	**$/kWh**	**$/kWh**	**$/kWh**	**$/kWh**	**$/kW-yr**	**%**	**$/kWh**
Period:	**u**	**v**	**w**	**x**	**y**	**z**	**aa**
2009							
2010	0.070	0.054	0.074	0.053	52.51	16.1%	0.0019
2011	0.075	0.058	0.078	0.055	41.18	13.7%	0.0020
2012	0.081	0.063	0.081	0.058	33.09	14.4%	0.0022
2013	0.082	0.066	0.083	0.064	15.60	14.6%	0.0027
2014	0.083	0.067	0.085	0.064	15.60	14.6%	0.0031
2015	0.082	0.068	0.086	0.064	16.80	14.7%	0.0033
2016	0.083	0.069	0.088	0.065	18.00	14.9%	0.0038
2017	0.085	0.071	0.091	0.068	18.00	15.0%	0.0050
2018	0.088	0.073	0.091	0.071	19.20	15.1%	0.0055
2019	0.090	0.076	0.094	0.072	19.20	15.2%	0.0050
2020	0.090	0.076	0.094	0.073	20.40	15.3%	0.0048
2021	0.088	0.075	0.093	0.072	21.60	15.4%	0.0037
2022	0.090	0.077	0.094	0.074	22.80	15.4%	0.0031
2023	0.093	0.079	0.099	0.077	24.00	15.5%	0.0022
2024	0.099	0.083	0.104	0.082	25.20	15.6%	0.0007
2025	0.101	0.085	0.106	0.084	37.20	15.7%	0.0005
2026	0.103	0.087	0.108	0.086	49.20	15.8%	0.0004
2027	0.105	0.089	0.111	0.089	61.20	15.9%	0.0004
2028	0.107	0.091	0.113	0.091	73.20	16.0%	0.0004
2029	0.109	0.093	0.115	0.094	85.20	16.1%	0.0004
2030	0.111	0.095	0.118	0.096	96.00	16.2%	0.0004
2031	0.114	0.097	0.120	0.099	96.00	16.3%	0.0004
2032	0.116	0.099	0.123	0.101	96.00	16.4%	0.0004
2033	0.118	0.101	0.126	0.104	96.00	16.5%	0.0004
2034	0.121	0.103	0.128	0.107	96.00	16.6%	0.0004
2035	0.123	0.106	0.131	0.110	96.00	16.7%	0.0004
2036	0.125	0.108	0.134	0.113	96.00	16.8%	0.0004
2037	0.128	0.111	0.137	0.116	96.00	16.9%	0.0004
2038	0.131	0.113	0.139	0.119	96.00	17.0%	0.0004
2039	0.133	0.116	0.142	0.122	96.00	17.1%	0.0004
Levelized Costs							
10 years (2010-2019)	0.082	0.066	0.085	0.063	25.502	14.8%	0.003
15 years (2010-2024)	0.085	0.070	0.088	0.067	24.682	15.0%	0.003
30 years (2010-2039)	0.097	0.082	0.103	0.081	49.045	15.6%	0.002

NOTES: General All Avoided Costs are in Year 2009 Dollars

ISO NE periods: Summer is June through September, Winter is all other months. Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are all other hours

Table One: Avoided Cost of Electricity (2009$) Results : Rest of Connecticut (Connecticut excluding all of Southwest Connecticut)

State CT

User-defined Inputs	
Wholesale Risk Premium (WRP)	9%
Real Discount Rate	2.22%

	Avoided Unit Cost of Electric Energy[1]				Avoided Unit Cost of Electric Capacity[2]		DRIPE: 2010 vintage measures Intrastate					DRIPE: 2011 vintage measures Intrastate					Avoided Externality Costs			
							Energy				Capacity (See note 2)	Energy				Capacity (See note 2)				
	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	kW sold into FCA (PA to determine quantity)[3]	kW purchased from FCA (PA to determine quantity)	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Annual Value	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Annual Value	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kw-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh
Period:	a	b	c	d	e=y*1.08	f=y*(1+z)*(1+PTF Loss)*(1+WRP)	g	h	i	j	k	l	m	n	o	p	q	r	s	t
2009	0.000	0.000	0.000	0.000													0.039	0.039	0.038	0.041
2010	0.077	0.059	0.081	0.059	65.84	*0.00*	0.044	0.028	0.048	0.020		0.000	0.000	0.000	0.000		0.039	0.039	0.038	0.041
2011	0.082	0.064	0.086	0.061	50.58	*0.00*	0.044	0.028	0.048	0.020		0.046	0.030	0.050	0.021		0.039	0.039	0.038	0.041
2012	0.089	0.069	0.089	0.065	35.74	*0.00*	0.047	0.030	0.049	0.021		0.048	0.031	0.050	0.021		0.039	0.039	0.038	0.041
2013	0.091	0.074	0.092	0.071	16.85	0.00	0.023	0.015	0.024	0.011	29.00	0.023	0.015	0.024	0.011		0.033	0.033	0.032	0.034
2014	0.092	0.075	0.094	0.072	16.85	19.86	0.019	0.013	0.021	0.009	42.00	0.021	0.014	0.022	0.010	29.00	0.032	0.032	0.031	0.033
2015	0.092	0.076	0.096	0.072	18.14	21.40	0.018	0.012	0.019	0.008	28.00	0.018	0.012	0.019	0.009	42.00	0.030	0.031	0.030	0.032
2016	0.093	0.078	0.098	0.074	19.44	22.97	0.015	0.011	0.017	0.007	11.00	0.015	0.011	0.017	0.008	28.00	0.029	0.030	0.028	0.031
2017	0.096	0.082	0.103	0.079	19.44	22.98	0.013	0.009	0.015	0.007		0.013	0.009	0.015	0.007	11.00	0.028	0.028	0.027	0.029
2018	0.100	0.084	0.104	0.082	20.74	24.54	0.011	0.008	0.012	0.006		0.011	0.008	0.012	0.006		0.027	0.027	0.026	0.028
2019	0.101	0.087	0.106	0.082	20.74	24.56	0.009	0.006	0.010	0.004		0.009	0.006	0.010	0.004		0.026	0.026	0.025	0.027
2020	0.101	0.087	0.106	0.083	22.03	26.11	0.007	0.005	0.007	0.003		0.007	0.005	0.007	0.003		0.024	0.025	0.024	0.026
2021	0.098	0.084	0.103	0.081	23.33	27.67	0.004	0.003	0.005	0.002		0.004	0.003	0.005	0.002		0.023	0.024	0.023	0.024
2022	0.099	0.086	0.104	0.082	24.62	29.24	0.002	0.002	0.002	0.001		0.002	0.002	0.002	0.001		0.022	0.022	0.021	0.023
2023	0.101	0.087	0.108	0.085	25.92	30.80	0.000	0.000	0.000	0.000		0.000	0.000	0.000	0.000		0.021	0.021	0.020	0.022
2024	0.106	0.089	0.112	0.088	27.22	32.37											0.020	0.020	0.019	0.021
2025	0.108	0.091	0.114	0.090	40.18	47.82											0.020	0.020	0.019	0.021
2026	0.110	0.093	0.116	0.093	53.14	63.31											0.020	0.020	0.019	0.021
2027	0.112	0.095	0.119	0.095	66.10	78.81											0.020	0.020	0.019	0.021
2028	0.115	0.097	0.121	0.098	79.06	94.35											0.020	0.020	0.019	0.021
2029	0.117	0.099	0.124	0.100	92.02	109.91											0.020	0.020	0.019	0.021
2030	0.119	0.102	0.126	0.103	103.68	123.95											0.020	0.020	0.019	0.021
2031	0.122	0.104	0.129	0.106	103.68	124.05											0.020	0.020	0.019	0.021
2032	0.124	0.106	0.132	0.109	103.68	124.16											0.020	0.020	0.019	0.021
2033	0.127	0.109	0.135	0.112	103.68	124.27											0.020	0.020	0.019	0.021
2034	0.129	0.111	0.137	0.115	103.68	124.37											0.020	0.020	0.019	0.021
2035	0.132	0.114	0.140	0.118	103.68	124.48											0.020	0.020	0.019	0.021
2036	0.134	0.116	0.143	0.121	103.68	124.59											0.020	0.020	0.019	0.021
2037	0.137	0.119	0.146	0.124	103.68	124.69											0.020	0.020	0.019	0.021
2038	0.140	0.121	0.149	0.128	103.68	124.80											0.020	0.020	0.019	0.021
2039	0.143	0.124	0.153	0.131	103.68	124.91											0.020	0.020	0.019	0.021
Levelized Costs																				
10 years (2010-2019)	0.091	0.074	0.094	0.071	29.21	12.99	0.025	0.017	0.027	0.012	11.81	0.021	0.014	0.022	0.010	11.81	0.032	0.033	0.032	0.034
15 years (2010-2024)	0.094	0.078	0.098	0.075	27.83	17.81	0.019	0.012	0.020	0.009	8.30	0.015	0.010	0.017	0.007	8.30	0.029	0.030	0.029	0.031
30 years (2010-2039)	0.106	0.090	0.112	0.089	53.65	55.24											0.025	0.026	0.025	0.027

NOTES:

General — All Avoided Costs are in Year 2009 Dollars

ISO NE periods: Summer is June through September, Winter is all other months. Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are all other hours

1 Avoided cost of electric energy = (wholesale energy avoided cost + REC cost to load) * risk premium, e.g. A= (U + AB) * (1+Wholesale Risk Premium)

2 Absolute value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year, PA strategy re bidding that reduction into applicable FCAs, and unit values in columns e, f, k and p.

3 For only 2010 and 2011; proceeds from selling into the FCM include the reserve margin, in addition to the ISO-NE loss factor of 8%

Table Two: Inputs to Avoided Cost Calculations

Zone: Rest of Connecticut (Connecticut excluding all of Southwest Connecticut)

	Wholesale Avoided Costs of Electricity						Avoided REC Costs to Load
	Energy				Capacity		
	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	FCA Price	Reserve Margin	REC Costs
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	%	$/kWh
Period:	u	v	w	x	y	z	aa
2009							
2010	0.069	0.053	0.073	0.052	52.51	16.1%	0.0019
2011	0.073	0.057	0.077	0.054	41.18	13.7%	0.0020
2012	0.080	0.061	0.079	0.057	33.09	14.4%	0.0022
2013	0.080	0.065	0.082	0.063	15.60	14.6%	0.0027
2014	0.081	0.066	0.083	0.063	15.60	14.6%	0.0031
2015	0.081	0.067	0.084	0.063	16.80	14.7%	0.0033
2016	0.081	0.068	0.086	0.064	18.00	14.9%	0.0038
2017	0.083	0.070	0.089	0.067	18.00	15.0%	0.0050
2018	0.087	0.072	0.090	0.069	19.20	15.1%	0.0055
2019	0.088	0.074	0.092	0.070	19.20	15.2%	0.0050
2020	0.088	0.075	0.092	0.071	20.40	15.3%	0.0048
2021	0.087	0.074	0.091	0.071	21.60	15.4%	0.0037
2022	0.088	0.076	0.092	0.072	22.80	15.4%	0.0031
2023	0.091	0.078	0.097	0.076	24.00	15.5%	0.0022
2024	0.097	0.081	0.102	0.080	25.20	15.6%	0.0007
2025	0.099	0.083	0.104	0.082	37.20	15.7%	0.0005
2026	0.101	0.085	0.106	0.085	49.20	15.8%	0.0004
2027	0.103	0.087	0.109	0.087	61.20	15.9%	0.0004
2028	0.105	0.089	0.111	0.089	73.20	16.0%	0.0004
2029	0.107	0.091	0.113	0.092	85.20	16.1%	0.0004
2030	0.109	0.093	0.116	0.094	96.00	16.2%	0.0004
2031	0.111	0.095	0.118	0.097	96.00	16.3%	0.0004
2032	0.114	0.097	0.121	0.099	96.00	16.4%	0.0004
2033	0.116	0.099	0.123	0.102	96.00	16.5%	0.0004
2034	0.118	0.101	0.126	0.105	96.00	16.6%	0.0004
2035	0.121	0.104	0.128	0.108	96.00	16.7%	0.0004
2036	0.123	0.106	0.131	0.111	96.00	16.8%	0.0004
2037	0.125	0.108	0.134	0.114	96.00	16.9%	0.0004
2038	0.128	0.111	0.137	0.117	96.00	17.0%	0.0004
2039	0.131	0.113	0.140	0.120	96.00	17.1%	0.0004
Levelized Costs							
10 years (2010-2019)	0.080	0.065	0.083	0.062	25.502	14.8%	0.003
15 years (2010-2024)	0.083	0.068	0.087	0.065	24.682	15.0%	0.003
30 years (2010-2039)	0.096	0.080	0.101	0.079	49.045	15.6%	0.002

NOTES: General All Avoided Costs are in Year 2009 Dollars

ISO NE periods: Summer is June through September, Winter is all other months. Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are all other hours

Appendix C: Selected Inputs Avoided Cost Analyses

Appendix C-1: Common Financial Parameters

Year	GDP Chain-Type Price Index	Annual Inflation	Conversion to 2009 Dollars
1985	69.71		1.791
1986	71.25	2.20%	1.752
1987	73.20	2.73%	1.706
1988	75.69	3.41%	1.650
1989	78.56	3.78%	1.589
1990	81.59	3.86%	1.530
1991	84.44	3.50%	1.479
1992	86.39	2.30%	1.445
1993	88.38	2.31%	1.413
1994	90.26	2.12%	1.383
1995	92.11	2.05%	1.356
1996	93.85	1.90%	1.330
1997	95.41	1.66%	1.309
1998	96.47	1.11%	1.294
1999	97.87	1.45%	1.276
2000	100.00	2.18%	1.249
2001	102.40	2.40%	1.219
2002	104.19	1.75%	1.198
2003	106.40	2.13%	1.173
2004	109.46	2.87%	1.141
2005	113.03	3.26%	1.105
2006	116.68	3.22%	1.070
2007	119.82	2.69%	1.042
2008	122.42	2.17%	1.020
2009	124.86	2.00%	1.000
2010	127.36	2.00%	0.980
2011	129.91	2.00%	0.961
2012	132.51	2.00%	0.942
2013	135.16	2.00%	0.924
2014	137.86	2.00%	0.906
2015	140.62	2.00%	0.888
2016	143.43	2.00%	0.871
2017	146.30	2.00%	0.853
2018	149.22	2.00%	0.837
2019	152.21	2.00%	0.820
2020	155.25	2.00%	0.804
2021	158.36	2.00%	0.788
2022	161.52	2.00%	0.773
2023	164.75	2.00%	0.758
2024	168.05	2.00%	0.743
2025	171.41	2.00%	0.728

Appendix C-2: New England Internal and External Transmission Interface Limits

	Path Name (From–To)	Capacity "From-To" (MW)	Capacity Back (MW)
Within New England			
	BHE-ME	1,200	1,050
	CMA-BOSTON	3,200	3,000
	CMA-NH	912	925
	CMA-WMA	1,360	2,000
	CT-RI	720	720
	CTSW-CT	2,000	2,500
	CTSW-NOR	1,650	1,650
	MPS-BHE	10	10
	NH-BOSTON	900	912
	NH-SME	1,400	1,575
	NH-VERMONT	720	715
	RI-BOSTON	400	400
	RI-CMA	1,480	600
	RI-SEMA	1,000	3,000
	SEMA-BOSTON	400	400
	SME-ME	1,250	1,250
	VERMONT-WMA	875	875
	WMA-CT	980[a] 1,180[b]	710
Between New England and External Control Areas			
	BHE-NBPC	425	1,000
	CMA-HYQB (Phase II)	1,570	1,600
	EMEC-NBPC	20	20
	HYQB-VT (Highgate)	216	170
	MPS-NBPC	100	90
	NOR-NYZK	100	100
	NYZD-VERMONT	150	150
	NYZF-WMA	575	650
	NYZG-CT	700	300
	NYZK-CT (CSC)	346	330

a) As of 1/1/2009
b) As of 1/1/2014

Appendix C-3: Renewable Requirements

	Connecticut			Maine		Massachusetts			New Hampshire				Rhode Island		Vermont
	I	*II*	*III*	*I*	*II*	*I*	*II*	*II WT*	*I*	*II*	*III*	*IV*	*New*	*New*	*New*
Compliance Year	2004	2004	2007	2008	2000	2003	2009	2009	2009	2009	2009	2009	2007	*2013*[2]	*2013*[2]
Fuel Type / Technology															
Biomass	✓	✓		✓	✓	✓	✓		✓		✓		✓	✓	✓
Biomass Thermal									✓						
Fuel Cells	✓	✓		✓	✓	✓	✓		✓				✓	✓	✓
Geothermal				✓	✓	✓	✓		✓				✓	✓	✓
Hydro	✓	✓		✓	✓	✓	✓		✓			✓	✓	✓	✓
Methane	✓	✓		✓	✓	✓	✓		✓		✓		✓	✓	✓
MSW & WTE		✓			✓		✓	✓							
Ocean Thermal	✓	✓				✓	✓		✓				✓		
Solar Photovoltaic	✓	✓		✓	✓	✓	✓		✓	✓			✓	✓	✓
Solar Thermal Electric	✓	✓				✓	✓		✓	✓			✓	✓	✓
Tidal	✓	✓		✓	✓	✓	✓		✓				✓		
Wave	✓	✓		✓	✓	✓	✓		✓				✓		
Wind	✓	✓		✓	✓	✓	✓		✓				✓	✓	✓

Appendix C-4: Future RPS Requirement Levels

	Connecticut			Maine		Massachusetts[1]		New Hampshire				Rhode Island		Vermont[4]
Year	I	I or II	III	I	II	I	II	I	II	III	IV	New	Existing	New
2009	6.00%	3.00%	3.00%	2.00%	30.00%	4.00%	3.60%	0.50%	0.00%	4.50%	1.00%	2.00%	2.00%	0.00%
2010	7.00%	3.00%	4.00%	3.00%	30.00%	5.00%	3.60%	1.00%	0.04%	5.50%	1.00%	2.50%	2.00%	0.00%
2011	8.00%	3.00%	4.00%	4.00%	30.00%	6.00%	3.60%	2.00%	0.08%	6.50%	1.00%	3.50%	2.00%	0.00%
2012	9.00%	3.00%	4.00%	5.00%	30.00%	7.00%	3.60%	3.00%	0.15%	6.50%	1.00%	4.50%	2.00%	0.00%
2013	10.00%	3.00%	4.00%	6.00%	30.00%	8.00%	3.60%	4.00%	0.20%	6.50%	1.00%	5.50%	2.00%	2.00%
2014	11.00%	3.00%	4.00%	7.00%	30.00%	9.00%	3.60%	5.00%	0.30%	6.50%	1.00%	6.50%	2.00%	4.00%
2015	12.50%	3.00%	4.00%	8.00%	30.00%	10.00%	3.60%	6.00%	0.30%	6.50%	1.00%	8.00%	2.00%	6.00%
2016	14.00%	3.00%	4.00%	9.00%	30.00%	11.00%	3.60%	7.00%	0.30%	6.50%	1.00%	9.50%	2.00%	8.00%
2017	15.50%	3.00%	4.00%	10.00%	30.00%	12.00%	3.60%	8.00%	0.30%	6.50%	1.00%	11.00%	2.00%	10.00%
2018	17.00%	3.00%	4.00%	10.00%	30.00%	13.00%	3.60%	9.00%	0.30%	6.50%	1.00%	12.50%	2.00%	10.00%
2019	18.50%	3.00%	4.00%	10.00%	30.00%	14.00%	3.60%	10.00%	0.30%	6.50%	1.00%	14.00%	2.00%	10.00%
2020	20.00%	3.00%	4.00%	10.00%	30.00%	15.00%	3.60%	11.00%	0.30%	6.50%	1.00%	14.00%	2.00%	10.00%
2021	20.00%	3.00%	4.00%	10.00%	30.00%	16.00%	3.60%	12.00%	0.30%	6.50%	1.00%	14.00%	2.00%	10.00%
2022	20.00%	3.00%	4.00%	10.00%	30.00%	17.00%	3.60%	13.00%	0.30%	6.50%	1.00%	14.00%	2.00%	10.00%
2023	20.00%	3.00%	4.00%	10.00%	30.00%	18.00%	3.60%	14.00%	0.30%	6.50%	1.00%	14.00%	2.00%	10.00%
2024	20.00%	3.00%	4.00%	10.00%	30.00%	19.00%	3.60%	15.00%	0.30%	6.50%	1.00%	14.00%	2.00%	10.00%

(4) Currently, non-binding goal = 20% by 2017; min obligation = incremental growth btw 2005 - 2012, or 10% of 2005 sales. No REC retirements required. Assumed that as of 2012, RPS requiring REC retirement implemented to bring percentage from 10 to 20% by 2017.

Appendix C-5: Electric Generation Fuel Price Forecast for New England
(2009 Dollars per Million BTU)

	Natural Gas[a]	Distillate Fuel Oil	Residual Fuel Oil	Steam Coal
2010	$6.34	$11.82	$7.94	$3.52
2011	7.01	12.52	8.79	3.36
2012	7.70	13.97	10.18	3.32
2013	7.71	15.09	11.26	3.28
2014	7.78	16.45	12.45	3.23
2015	7.88	17.90	13.63	3.18
2016	8.00	19.27	14.75	3.14
2017	8.19	20.55	15.80	3.11
2018	8.42	20.60	15.96	3.15
2019	8.63	20.75	16.11	3.17
2020	8.48	20.81	16.02	3.17
2021	8.23	20.88	16.21	3.15
2022	8.31	21.08	16.40	3.15
2023	8.44	20.96	16.17	3.15
2024	8.86	21.27	16.29	3.13

[a]*Price is for Dracut.*

Natural gas price is the average for New England Electric Generators

Appendix C-6: Reserve Requirements

		CELT 09	RSP 08 Reserve Requirement		Installed Capacity Requirement	Net Installed Capacity Requirement
Year		**Peak**	**Excluding HQICC**	**Including HQICC**		**Net of HQICCs**
Starting	**FCA**	MW			MW	MW
2010	1	28,160				
2011	2	28,575	10.6%	13.7%	33,439	32,528
2012	3	29,020	11.4%	14.4%	33,187	32,276
2013	4	29,365	11.6%	14.6%	33,642	32,731
2014	5	29,750	11.7%	14.6%	34,094	33,183
2015	6	30,115	11.8%	14.7%	34,539	33,628
2016	7	30,415	12.1%	14.9%	34,938	34,027
2017	8	30,695	12.2%	15.0%	35,285	34,374
2018	9	30,960	*12.3%*	*15.1%*	35,620	34,709
2019	10	*31,270*	*12.3%*	*15.2%*	36,008	35,097
2020	11	*31,566*	*12.3%*	*15.3%*	36,380	35,469
2021	12	*31,860*	*12.3%*	*15.4%*	36,751	35,840
2022	13	*32,158*	*12.3%*	*15.4%*	37,127	36,216
2023	14	*32,465*	*12.3%*	*15.5%*	37,513	36,602
2024	15	*32,771*	*12.3%*	*15.6%*	37,899	36,988

Notes

Peak load extrapolated after 2018.

HQICC refers to Hydro Quebec Installed Capacity Credits

HQ installed capacity credits assumed at 911 MW (from FCA 2) which is subtracted from the ICR to produce the NICR .

Auction is run for Net Installed Capacity Requirement. Holders of HQ ICCs are price takers.

Appendix C-9: Energy DRIPE by State

2010 Installation: Maine

	Intrastate				Rest of Pool			
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy
2010	0.011	0.006	0.009	0.006	0.056	0.036	0.064	0.039
2011	0.011	0.006	0.009	0.006	0.057	0.038	0.065	0.039
2012	0.012	0.006	0.009	0.006	0.063	0.041	0.068	0.042
2013	0.006	0.003	0.005	0.003	0.031	0.021	0.035	0.022
2014	0.005	0.003	0.004	0.003	0.027	0.018	0.030	0.019
2015	0.004	0.002	0.004	0.003	0.024	0.017	0.027	0.017
2016	0.004	0.002	0.003	0.002	0.021	0.015	0.025	0.015
2017	0.003	0.002	0.003	0.002	0.018	0.013	0.021	0.014
2018	0.003	0.002	0.002	0.002	0.016	0.011	0.018	0.012
2019	0.002	0.001	0.002	0.001	0.013	0.009	0.015	0.009
2020	0.002	0.001	0.001	0.001	0.009	0.007	0.011	0.007
2021	0.001	0.001	0.001	0.001	0.006	0.004	0.007	0.005
2022	0.001	0.000	0.000	0.000	0.003	0.002	0.004	0.002
2023	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

2011 Installation: Maine

	Intrastate				Rest of Pool			
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy
2010	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2011	0.012	0.006	0.009	0.006	0.059	0.039	0.067	0.040
2012	0.012	0.006	0.010	0.006	0.064	0.042	0.070	0.042
2013	0.006	0.003	0.005	0.003	0.031	0.022	0.035	0.023
2014	0.005	0.003	0.004	0.003	0.028	0.020	0.032	0.020
2015	0.004	0.002	0.004	0.003	0.024	0.017	0.027	0.017
2016	0.004	0.002	0.003	0.002	0.021	0.015	0.025	0.015
2017	0.003	0.002	0.003	0.002	0.018	0.013	0.022	0.014
2018	0.003	0.002	0.002	0.002	0.016	0.011	0.018	0.012
2019	0.002	0.001	0.002	0.001	0.013	0.009	0.015	0.009
2020	0.002	0.001	0.001	0.001	0.009	0.007	0.011	0.007
2021	0.001	0.001	0.001	0.001	0.006	0.004	0.007	0.005
2022	0.001	0.000	0.000	0.000	0.003	0.002	0.004	0.002
2023	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

2010 Installation: Vermont

	Intrastate				Rest of Pool			
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy
2010	0.000	0.000	0.000	0.000	0.062	0.040	0.071	0.043
2011	0.000	0.000	0.000	0.000	0.063	0.042	0.072	0.043
2012	0.002	0.001	0.002	0.001	0.068	0.044	0.074	0.045
2013	0.001	0.001	0.002	0.001	0.033	0.023	0.037	0.024
2014	0.001	0.001	0.002	0.001	0.028	0.020	0.032	0.020
2015	0.002	0.001	0.002	0.001	0.025	0.018	0.029	0.018
2016	0.001	0.001	0.002	0.001	0.022	0.016	0.026	0.016
2017	0.001	0.001	0.002	0.001	0.019	0.014	0.022	0.014
2018	0.001	0.001	0.001	0.001	0.016	0.012	0.019	0.012
2019	0.001	0.000	0.001	0.001	0.013	0.009	0.015	0.010
2020	0.001	0.000	0.001	0.000	0.010	0.007	0.011	0.007
2021	0.000	0.000	0.001	0.000	0.006	0.005	0.007	0.005
2022	0.000	0.000	0.000	0.000	0.003	0.002	0.004	0.002
2023	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

2011 Installation: Vermont

	Intrastate				Rest of Pool			
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy
2010	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2011	0.000	0.000	0.000	0.000	0.045	0.030	0.052	0.031
2012	0.002	0.001	0.002	0.001	0.050	0.032	0.054	0.033
2013	0.001	0.001	0.002	0.001	0.025	0.017	0.027	0.018
2014	0.002	0.001	0.002	0.001	0.022	0.015	0.025	0.016
2015	0.002	0.001	0.002	0.001	0.019	0.013	0.021	0.013
2016	0.002	0.001	0.002	0.001	0.016	0.012	0.019	0.012
2017	0.001	0.001	0.002	0.001	0.014	0.010	0.017	0.011
2018	0.001	0.001	0.001	0.001	0.012	0.009	0.014	0.009
2019	0.001	0.000	0.001	0.001	0.010	0.007	0.011	0.007
2020	0.001	0.000	0.001	0.000	0.007	0.005	0.008	0.005
2021	0.000	0.000	0.001	0.000	0.005	0.003	0.005	0.004
2022	0.000	0.000	0.000	0.000	0.002	0.002	0.003	0.002
2023	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

2010 Installation: New Hampshire	Intrastate				Rest of Pool			
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy
2010	0.065	0.043	0.076	0.043	0.060	0.039	0.069	0.042
2011	0.067	0.045	0.077	0.044	0.062	0.040	0.070	0.042
2012	0.073	0.049	0.080	0.047	0.068	0.044	0.073	0.045
2013	0.036	0.025	0.041	0.025	0.033	0.023	0.037	0.024
2014	0.031	0.022	0.035	0.021	0.029	0.020	0.032	0.021
2015	0.028	0.020	0.032	0.019	0.025	0.018	0.029	0.018
2016	0.024	0.018	0.029	0.017	0.022	0.016	0.026	0.016
2017	0.021	0.015	0.025	0.015	0.019	0.014	0.023	0.014
2018	0.018	0.013	0.021	0.013	0.017	0.012	0.019	0.012
2019	0.014	0.011	0.017	0.010	0.013	0.010	0.016	0.010
2020	0.011	0.008	0.012	0.008	0.010	0.007	0.011	0.007
2021	0.007	0.005	0.008	0.005	0.006	0.005	0.007	0.005
2022	0.004	0.003	0.004	0.003	0.003	0.002	0.004	0.002
2023	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

2011 Installation: New Hampshire	Intrastate				Rest of Pool			
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy
2010	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2011	0.069	0.047	0.080	0.045	0.064	0.042	0.073	0.043
2012	0.075	0.050	0.082	0.048	0.069	0.045	0.075	0.046
2013	0.037	0.026	0.041	0.025	0.034	0.023	0.038	0.024
2014	0.033	0.023	0.037	0.023	0.030	0.021	0.034	0.022
2015	0.028	0.020	0.032	0.019	0.026	0.018	0.029	0.018
2016	0.024	0.018	0.029	0.017	0.023	0.016	0.027	0.016
2017	0.021	0.015	0.025	0.015	0.020	0.014	0.023	0.015
2018	0.018	0.013	0.021	0.013	0.017	0.012	0.019	0.012
2019	0.014	0.011	0.017	0.010	0.013	0.010	0.016	0.010
2020	0.011	0.008	0.013	0.008	0.010	0.007	0.011	0.007
2021	0.007	0.005	0.008	0.005	0.006	0.005	0.007	0.005
2022	0.004	0.003	0.004	0.003	0.003	0.002	0.004	0.002
2023	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

2010 Installation: Conneticut	Intrastate				Rest of Pool			
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy
2010	0.044	0.028	0.048	0.020	0.043	0.028	0.049	0.029
2011	0.044	0.028	0.048	0.020	0.044	0.029	0.050	0.030
2012	0.047	0.030	0.049	0.021	0.049	0.032	0.053	0.032
2013	0.023	0.015	0.024	0.011	0.024	0.017	0.027	0.017
2014	0.019	0.013	0.021	0.009	0.021	0.014	0.023	0.015
2015	0.018	0.012	0.019	0.008	0.018	0.013	0.021	0.013
2016	0.015	0.011	0.017	0.007	0.016	0.012	0.019	0.012
2017	0.013	0.009	0.015	0.007	0.014	0.010	0.017	0.011
2018	0.011	0.008	0.012	0.006	0.012	0.009	0.014	0.009
2019	0.009	0.006	0.010	0.004	0.010	0.007	0.011	0.007
2020	0.007	0.005	0.007	0.003	0.007	0.005	0.008	0.005
2021	0.004	0.003	0.005	0.002	0.005	0.003	0.005	0.004
2022	0.002	0.002	0.002	0.001	0.002	0.002	0.003	0.002
2023	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

2011 Installation: Conneticut	Intrastate				Rest of Pool			
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy
2010	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2011	0.046	0.030	0.050	0.021	0.045	0.030	0.052	0.031
2012	0.048	0.031	0.050	0.021	0.050	0.032	0.054	0.033
2013	0.023	0.015	0.024	0.011	0.025	0.017	0.027	0.018
2014	0.021	0.014	0.022	0.010	0.022	0.015	0.025	0.016
2015	0.018	0.012	0.019	0.009	0.019	0.013	0.021	0.013
2016	0.015	0.011	0.017	0.008	0.016	0.012	0.019	0.012
2017	0.013	0.009	0.015	0.007	0.014	0.010	0.017	0.011
2018	0.011	0.008	0.012	0.006	0.012	0.009	0.014	0.009
2019	0.009	0.006	0.010	0.004	0.010	0.007	0.011	0.007
2020	0.007	0.005	0.007	0.003	0.007	0.005	0.008	0.005
2021	0.004	0.003	0.005	0.002	0.005	0.003	0.005	0.004
2022	0.002	0.002	0.002	0.001	0.002	0.002	0.003	0.002
2023	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

2010 Installation: Massachusetts

	Intrastate				Rest of Pool			
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy
2010	0.056	0.043	0.062	0.032	0.032	0.020	0.036	0.022
2011	0.058	0.045	0.063	0.032	0.032	0.021	0.037	0.022
2012	0.063	0.048	0.066	0.034	0.035	0.023	0.039	0.023
2013	0.031	0.025	0.033	0.018	0.018	0.012	0.020	0.013
2014	0.026	0.021	0.028	0.016	0.015	0.010	0.017	0.011
2015	0.023	0.019	0.026	0.014	0.014	0.010	0.016	0.010
2016	0.020	0.017	0.023	0.012	0.012	0.008	0.014	0.009
2017	0.018	0.015	0.020	0.011	0.010	0.007	0.012	0.008
2018	0.015	0.013	0.017	0.009	0.009	0.006	0.010	0.007
2019	0.012	0.010	0.014	0.008	0.007	0.005	0.008	0.005
2020	0.009	0.008	0.010	0.006	0.005	0.004	0.006	0.004
2021	0.006	0.005	0.007	0.004	0.003	0.002	0.004	0.003
2022	0.003	0.003	0.003	0.002	0.002	0.001	0.002	0.001
2023	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

2011 Installation: Massachusetts

	Intrastate				Rest of Pool			
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy
2010	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2011	0.060	0.046	0.066	0.034	0.033	0.022	0.038	0.023
2012	0.064	0.049	0.067	0.035	0.036	0.024	0.039	0.024
2013	0.031	0.025	0.034	0.019	0.018	0.012	0.020	0.013
2014	0.028	0.023	0.030	0.017	0.016	0.011	0.018	0.012
2015	0.023	0.019	0.026	0.014	0.014	0.010	0.016	0.010
2016	0.020	0.017	0.023	0.012	0.012	0.009	0.014	0.009
2017	0.018	0.015	0.020	0.011	0.010	0.007	0.012	0.008
2018	0.015	0.013	0.017	0.009	0.009	0.006	0.010	0.007
2019	0.012	0.010	0.014	0.008	0.007	0.005	0.008	0.005
2020	0.009	0.008	0.010	0.006	0.005	0.004	0.006	0.004
2021	0.006	0.005	0.007	0.004	0.003	0.002	0.004	0.003
2022	0.003	0.003	0.003	0.002	0.002	0.001	0.002	0.001
2023	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

2010 Installation: Rhode Island

	Intrastate				Rest of Pool			
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy
2010	0.019	0.016	0.008	0.007	0.058	0.037	0.066	0.040
2011	0.019	0.017	0.008	0.007	0.059	0.039	0.067	0.040
2012	0.021	0.018	0.008	0.007	0.065	0.042	0.070	0.043
2013	0.009	0.009	0.004	0.003	0.030	0.020	0.032	0.021
2014	0.008	0.007	0.003	0.003	0.025	0.017	0.028	0.018
2015	0.007	0.006	0.003	0.002	0.022	0.015	0.025	0.015
2016	0.006	0.005	0.002	0.002	0.019	0.013	0.022	0.013
2017	0.005	0.005	0.002	0.002	0.017	0.011	0.019	0.012
2018	0.004	0.004	0.002	0.002	0.014	0.010	0.016	0.010
2019	0.003	0.003	0.001	0.001	0.011	0.008	0.013	0.008
2020	0.002	0.002	0.001	0.001	0.008	0.006	0.009	0.006
2021	0.002	0.001	0.001	0.001	0.005	0.004	0.006	0.004
2022	0.001	0.001	0.000	0.000	0.003	0.002	0.003	0.002
2023	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

2011 Installation: Rhode Island

	Intrastate				Rest of Pool			
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy
2010	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2011	0.020	0.018	0.008	0.007	0.061	0.040	0.070	0.042
2012	0.021	0.019	0.008	0.007	0.066	0.043	0.072	0.044
2013	0.010	0.009	0.004	0.003	0.030	0.020	0.033	0.021
2014	0.008	0.008	0.003	0.003	0.026	0.018	0.029	0.019
2015	0.007	0.006	0.003	0.002	0.022	0.015	0.025	0.015
2016	0.006	0.005	0.002	0.002	0.019	0.013	0.022	0.014
2017	0.005	0.005	0.002	0.002	0.017	0.011	0.019	0.012
2018	0.004	0.004	0.002	0.002	0.014	0.010	0.016	0.010
2019	0.003	0.003	0.001	0.001	0.011	0.008	0.013	0.008
2020	0.002	0.002	0.001	0.001	0.008	0.006	0.009	0.006
2021	0.002	0.001	0.001	0.001	0.005	0.004	0.006	0.004
2022	0.001	0.001	0.000	0.000	0.003	0.002	0.003	0.002
2023	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

Appendix C-10: Carbon Dioxide Externality Costs

AESC 2009 Reference Case Carbon Externality Calculation (2009 dollars)							
	AESC Long-term Cost	AESC Allowance Price	Externality Cost	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy
	$/ton	$/ton	$/ton	$/KWh	$/KWh	$/KWh	$/KWh
	A	B	C	D	E	F	G
			a-b	c*winter_peak emission rate	c*winter_off emission rate	c*summer_peak emission rate	c*summer_off emission rate
2009	$80.00	$3.85	$76.15	$0.039	$0.039	$0.038	$0.041
2010	$80.00	$3.91	$76.09	$0.039	$0.039	$0.038	$0.041
2011	$80.00	$4.02	$75.98	$0.039	$0.039	$0.038	$0.041
2012	$80.00	$4.00	$76.00	$0.039	$0.039	$0.038	$0.041
2013	$80.00	$15.63	$64.37	$0.033	$0.033	$0.032	$0.034
2014	$80.00	$18.03	$61.97	$0.032	$0.032	$0.031	$0.033
2015	$80.00	$20.32	$59.68	$0.030	$0.031	$0.030	$0.032
2016	$80.00	$22.72	$57.28	$0.029	$0.030	$0.028	$0.031
2017	$80.00	$25.01	$54.99	$0.028	$0.028	$0.027	$0.029
2018	$80.00	$27.41	$52.59	$0.027	$0.027	$0.026	$0.028
2019	$80.00	$29.70	$50.30	$0.026	$0.026	$0.025	$0.027
2020	$80.00	$32.10	$47.90	$0.024	$0.025	$0.024	$0.026
2021	$80.00	$34.49	$45.51	$0.023	$0.024	$0.023	$0.024
2022	$80.00	$36.79	$43.21	$0.022	$0.022	$0.021	$0.023
2023	$80.00	$39.18	$40.82	$0.021	$0.021	$0.020	$0.022
2024	$80.00	$41.48	$38.52	$0.020	$0.020	$0.019	$0.021
2025	$80.00	$43.87	$36.13	$0.020	$0.020	$0.019	$0.021
2026	$80.00	$46.16	$33.84	$0.020	$0.020	$0.019	$0.021
2027	$80.00	$48.56	$31.44	$0.020	$0.020	$0.019	$0.021
2028	$80.00	$50.85	$29.15	$0.020	$0.020	$0.019	$0.021
2029	$80.00	$53.25	$26.75	$0.020	$0.020	$0.019	$0.021
2030	$80.00	$55.64	$24.36	$0.020	$0.020	$0.019	$0.021
2031	$80.00	$60.23	$19.77	$0.020	$0.020	$0.019	$0.021
2032	$80.00	$65.20	$14.80	$0.020	$0.020	$0.019	$0.021
2033	$80.00	$70.59	$9.41	$0.020	$0.020	$0.019	$0.021
2034	$80.00	$76.41	$3.59	$0.020	$0.020	$0.019	$0.021
2035	$80.00	$82.71	$0.00	$0.020	$0.020	$0.019	$0.021
2036	$80.00	$89.54	$0.00	$0.020	$0.020	$0.019	$0.021
2037	$80.00	$96.93	$0.00	$0.020	$0.020	$0.019	$0.021
2038	$80.00	$104.93	$0.00	$0.020	$0.020	$0.019	$0.021
2039	$80.00	$113.59	$0.00	$0.020	$0.020	$0.019	$0.021
				Winter Peak	Winter Off-peak	Summer Peak	Summer Off-peak
Period Emission Rates (tons per MWh)				0.5096	0.5175	0.4970	0.5352

Appendix C-11

AESC 2009 RGGI Only Case Carbon Externality Calculation							
	AESC Long-term Cost	AESC Allowance Price	$/ton externality	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy
	A	B	C	D	E	F	G
			a-b	c*winter_peak	c*winter_off	c*summer_peak	c*summer_off
2009	$80.00	$3.85	$76.15	$0.039	$0.039	$0.038	$0.041
2010	$80.00	$3.91	$76.09	$0.039	$0.039	$0.038	$0.041
2011	$80.00	$4.02	$75.98	$0.039	$0.039	$0.038	$0.041
2012	$80.00	$4.00	$76.00	$0.039	$0.039	$0.038	$0.041
2013	$80.00	$4.00	$76.00	$0.039	$0.039	$0.038	$0.041
2014	$80.00	$4.00	$76.00	$0.039	$0.039	$0.038	$0.041
2015	$80.00	$4.00	$76.00	$0.039	$0.039	$0.038	$0.041
2016	$80.00	$4.00	$76.00	$0.039	$0.039	$0.038	$0.041
2017	$80.00	$4.00	$76.00	$0.039	$0.039	$0.038	$0.041
2018	$80.00	$4.00	$76.00	$0.039	$0.039	$0.038	$0.041
2019	$80.00	$4.00	$76.00	$0.039	$0.039	$0.038	$0.041
2020	$80.00	$4.00	$76.00	$0.039	$0.039	$0.038	$0.041
2021	$80.00	$4.00	$76.00	$0.039	$0.039	$0.038	$0.041
2022	$80.00	$4.00	$76.00	$0.039	$0.039	$0.038	$0.041
2023	$80.00	$4.00	$76.00	$0.039	$0.039	$0.038	$0.041
2024	$80.00	$4.00	$76.00	$0.039	$0.039	$0.038	$0.041
2025	$80.00	$4.00	$76.00	$0.039	$0.039	$0.038	$0.041
2026	$80.00	$4.00	$76.00	$0.039	$0.039	$0.038	$0.041
2027	$80.00	$4.00	$76.00	$0.039	$0.039	$0.038	$0.041
2028	$80.00	$4.00	$76.00	$0.039	$0.039	$0.038	$0.041
2029	$80.00	$4.00	$76.00	$0.039	$0.039	$0.038	$0.041
2030	$80.00	$4.00	$76.00	$0.039	$0.039	$0.038	$0.041
2031	$80.00	$4.00	$76.00	$0.039	$0.039	$0.038	$0.041
2032	$80.00	$4.00	$76.00	$0.039	$0.039	$0.038	$0.041
2033	$80.00	$4.00	$76.00	$0.039	$0.039	$0.038	$0.041
2034	$80.00	$4.00	$76.00	$0.039	$0.039	$0.038	$0.041
2035	$80.00	$4.00	$76.00	$0.039	$0.039	$0.038	$0.041
2036	$80.00	$4.00	$76.00	$0.039	$0.039	$0.038	$0.041
2037	$80.00	$4.00	$76.00	$0.039	$0.039	$0.038	$0.041
2038	$80.00	$4.00	$76.00	$0.039	$0.039	$0.038	$0.041
2039	$80.00	$4.00	$76.00	$0.039	$0.039	$0.038	$0.041
				Winter Peak	Winter Off-peak	Summer Peak	Summer Off-peak
Period Emission Rates (tons per MWh)				0.5096	0.5175	0.4970	0.5352

Appendix C-12: Class I REC Prices and Avoided RPS Costs by New England State

REC Prices by State (2009 dollars/MWh)						
	Connecticut	Maine	Massachusetts	New Hampshire	Rhode Island	Vermont
2010	$26.47	$36.76	$35.29	$36.76	$36.76	$0.00
2011	$25.33	$30.37	$29.65	$30.37	$35.37	$0.00
2012	$24.22	$24.22	$24.22	$24.22	$34.02	$0.00
2013	$26.88	$26.88	$26.88	$26.88	$38.06	$26.88
2014	$28.62	$28.62	$28.62	$28.62	$40.67	$28.62
2015	$26.73	$26.73	$26.73	$26.73	$39.60	$26.73
2016	$26.90	$26.90	$26.90	$26.90	$40.57	$26.90
2017	$32.26	$32.26	$32.26	$32.26	$46.69	$32.26
2018	$32.55	$32.55	$32.55	$32.55	$47.70	$32.55
2019	$26.91	$26.91	$26.91	$26.91	$42.74	$26.91
2020	$23.97	$23.97	$23.97	$23.97	$40.37	$23.97
2021	$18.69	$18.69	$18.69	$18.69	$35.56	$18.69
2022	$15.62	$15.62	$15.62	$15.62	$32.93	$15.62
2023	$10.99	$10.99	$10.99	$10.99	$28.65	$10.99
2024	$3.27	$3.27	$3.27	$3.27	$21.18	$3.27
2025	$2.67	$2.60	$2.73	$2.81	$20.61	$2.69
2026	$2.19	$2.07	$2.27	$2.41	$20.06	$2.21
2027	$2.00	$2.00	$2.00	$2.08	$19.52	$2.00
2028	$2.00	$2.00	$2.00	$2.00	$18.99	$2.00
2029	$2.00	$2.00	$2.00	$2.00	$18.48	$2.00
2030	$2.00	$2.00	$2.00	$2.00	$17.99	$2.00
2031	$2.00	$2.00	$2.00	$2.00	$17.51	$2.00
2032	$2.00	$2.00	$2.00	$2.00	$17.04	$2.00
2033	$2.00	$2.00	$2.00	$2.00	$16.58	$2.00
2034	$2.00	$2.00	$2.00	$2.00	$16.14	$2.00
2035	$2.00	$2.00	$2.00	$2.00	$15.70	$2.00
2036	$2.00	$2.00	$2.00	$2.00	$15.28	$2.00
2037	$2.00	$2.00	$2.00	$2.00	$14.87	$2.00
2038	$2.00	$2.00	$2.00	$2.00	$14.47	$2.00
2039	$2.00	$2.00	$2.00	$2.00	$14.08	$2.00

Avoided RPS Requirements (2009$/KWh)						
	Connecticut	Maine	Massachusetts	New Hampshire	Rhode Island	Vermont
2010	$0.002	$0.001	$0.002	$0.000	$0.001	$0.000
2011	$0.002	$0.001	$0.002	$0.001	$0.001	$0.000
2012	$0.002	$0.001	$0.002	$0.001	$0.002	$0.000
2013	$0.003	$0.002	$0.002	$0.001	$0.002	$0.001
2014	$0.003	$0.002	$0.003	$0.001	$0.003	$0.001
2015	$0.003	$0.002	$0.003	$0.002	$0.003	$0.002
2016	$0.004	$0.002	$0.003	$0.002	$0.004	$0.002
2017	$0.005	$0.003	$0.004	$0.003	$0.005	$0.003
2018	$0.006	$0.003	$0.004	$0.003	$0.006	$0.003
2019	$0.005	$0.003	$0.004	$0.003	$0.006	$0.003
2020	$0.005	$0.002	$0.004	$0.003	$0.006	$0.002
2021	$0.004	$0.002	$0.003	$0.002	$0.005	$0.002
2022	$0.003	$0.002	$0.003	$0.002	$0.005	$0.002
2023	$0.002	$0.001	$0.002	$0.002	$0.004	$0.001
2024	$0.001	$0.000	$0.001	$0.000	$0.003	$0.000
2025	$0.001	$0.000	$0.001	$0.000	$0.003	$0.000
2026	$0.000	$0.000	$0.000	$0.000	$0.003	$0.000
2027	$0.000	$0.000	$0.000	$0.000	$0.003	$0.000
2028	$0.000	$0.000	$0.000	$0.000	$0.003	$0.000
2029	$0.000	$0.000	$0.000	$0.000	$0.003	$0.000
2030	$0.000	$0.000	$0.000	$0.000	$0.003	$0.000
2031	$0.000	$0.000	$0.000	$0.000	$0.002	$0.000
2032	$0.000	$0.000	$0.000	$0.000	$0.002	$0.000
2033	$0.000	$0.000	$0.000	$0.000	$0.002	$0.000
2034	$0.000	$0.000	$0.000	$0.000	$0.002	$0.000
2035	$0.000	$0.000	$0.000	$0.000	$0.002	$0.000
2036	$0.000	$0.000	$0.000	$0.000	$0.002	$0.000
2037	$0.000	$0.000	$0.000	$0.000	$0.002	$0.000
2038	$0.000	$0.000	$0.000	$0.000	$0.002	$0.000
2039	$0.000	$0.000	$0.000	$0.000	$0.002	$0.000

Notes

REC prices assumed to maintain floor price of $2.00/MWh
Rhode Island REC prices based on RGGI only scenario
Avoided RPS costs based on REC prices and applicable state renewable energy percentages

Appendix C-13: Locational Price Tables (2009$/MWh)

Bangor Hydro Area						
	Summer			**Winter**		
Year	Off-Peak	On-Peak	All-Hours	Off-Peak	On-Peak	All-Hours
2010	48.1	64.3	55.8	49.9	63.2	56.3
2011	50.9	67.9	59.0	53.5	67.0	59.9
2012	54.5	70.9	62.3	57.3	71.3	64.0
2013	59.5	74.2	66.5	60.6	71.8	65.9
2014	59.2	73.7	66.1	61.8	72.2	66.7
2015	60.1	75.5	67.4	62.0	72.6	67.1
2016	61.5	78.1	69.4	63.5	73.0	68.0
2017	63.1	79.3	70.8	64.5	74.9	69.5
2018	65.5	80.6	72.7	66.1	76.7	71.1
2019	66.2	81.8	73.6	66.9	76.8	71.6
2020	65.1	83.7	74.0	67.5	76.1	71.6
2021	67.2	78.6	72.6	66.9	75.9	71.2
2022	67.7	80.8	74.0	69.0	76.9	72.8
2023	67.4	85.8	76.2	68.9	79.6	74.0
2024	72.1	91.4	81.3	70.8	83.8	77.0
Levelized	61.3	77.2	68.9	62.8	73.7	68.0

Boston						
	Summer			**Winter**		
Year	Off-Peak	On-Peak	All-Hours	Off-Peak	On-Peak	All-Hours
2010	50.3	70.3	59.8	51.1	67.3	58.8
2011	52.5	74.3	62.9	55.3	71.9	63.2
2012	55.7	77.3	66.0	59.8	78.3	68.6
2013	61.2	79.7	70.0	63.7	78.8	70.9
2014	61.3	80.6	70.5	64.6	79.4	71.6
2015	61.5	82.4	71.5	65.5	79.6	72.2
2016	62.7	85.4	73.5	66.7	80.1	73.1
2017	65.2	87.1	75.7	68.6	81.9	74.9
2018	67.7	88.7	77.7	70.6	85.4	77.7
2019	68.7	91.5	79.5	73.4	87.0	79.8
2020	69.5	91.3	79.9	73.2	87.0	79.8
2021	69.3	90.4	79.3	72.8	85.9	79.0
2022	70.7	92.0	80.8	74.7	87.8	81.0
2023	73.2	95.9	84.0	76.6	90.2	83.1
2024	78.4	102.5	89.9	80.3	96.3	87.9
Levelized	63.8	85.2	74.0	67.1	81.8	74.1

Central Maine						
	Summer			**Winter**		
Year	Off-Peak	On-Peak	All-Hours	Off-Peak	On-Peak	All-Hours
2010	48.1	64.3	55.8	49.9	63.2	56.3
2011	50.9	67.9	59.0	53.5	67.0	59.9
2012	54.5	70.9	62.3	57.3	71.3	64.0
2013	59.5	74.2	66.5	60.6	71.8	65.9
2014	59.2	73.7	66.1	61.8	72.2	66.7
2015	60.1	75.5	67.4	62.0	72.6	67.1
2016	61.5	78.1	69.4	63.5	73.0	68.0
2017	63.1	79.3	70.8	64.5	74.9	69.5
2018	65.5	80.6	72.7	66.1	76.7	71.1
2019	66.2	81.9	73.6	66.9	77.0	71.7
2020	65.1	83.7	74.0	67.5	76.4	71.8
2021	67.2	78.8	72.7	66.9	76.1	71.3
2022	67.7	81.3	74.2	69.0	77.0	72.8
2023	67.4	86.3	76.4	69.0	80.0	74.2
2024	72.7	91.7	81.7	70.8	84.2	77.2
Levelized	61.3	77.3	68.9	62.8	73.8	68.0

Central Massachusetts						
	Summer			**Winter**		
Year	Off-Peak	On-Peak	All-Hours	Off-Peak	On-Peak	All-Hours
2010	50.2	69.3	59.3	51.2	66.8	58.6
2011	52.5	73.3	62.4	55.4	71.2	62.9
2012	55.7	76.2	65.5	59.8	77.5	68.2
2013	60.8	78.3	69.1	63.0	77.5	69.9
2014	60.9	79.1	69.6	63.9	78.0	70.7
2015	61.0	80.9	70.5	64.6	78.2	71.1
2016	62.1	83.8	72.4	65.7	78.6	71.9
2017	64.6	85.5	74.6	67.5	80.4	73.7
2018	66.9	87.0	76.5	69.5	83.8	76.3
2019	67.8	89.7	78.2	72.1	85.3	78.4
2020	68.6	89.5	78.5	72.1	85.3	78.4
2021	68.5	88.6	78.1	71.6	84.2	77.6
2022	69.8	90.2	79.6	73.6	86.1	79.5
2023	72.3	94.1	82.7	75.4	88.4	81.6
2024	77.4	100.5	88.4	79.1	94.5	86.4
Levelized	63.3	83.7	73.0	66.3	80.5	73.0

Connecticut Central-North						
	Summer			**Winter**		
Year	Off-Peak	On-Peak	All-Hours	Off-Peak	On-Peak	All-Hours
2010	51.9	72.8	61.8	52.7	69.1	60.5
2011	54.2	76.7	64.9	56.9	73.3	64.7
2012	57.3	79.1	67.7	61.4	79.8	70.1
2013	62.7	81.7	71.8	65.0	80.4	72.3
2014	63.2	83.1	72.7	66.0	81.1	73.2
2015	63.0	84.4	73.2	66.7	80.9	73.4
2016	64.1	86.3	74.7	68.0	81.2	74.3
2017	67.1	89.1	77.6	70.0	83.0	76.2
2018	69.3	89.5	78.9	71.8	86.6	78.9
2019	70.2	92.2	80.7	74.4	88.0	80.9
2020	71.2	92.4	81.3	74.6	87.9	80.9
2021	70.8	90.9	80.4	73.7	86.6	79.9
2022	72.2	92.2	81.7	75.8	87.7	81.5
2023	75.6	96.9	85.8	77.8	90.7	84.0
2024	80.2	101.9	90.5	81.3	96.8	88.7
Levelized	65.5	86.6	75.5	68.4	82.9	75.3

Connecticut Norwalk						
	Summer			**Winter**		
Year	Off-Peak	On-Peak	All-Hours	Off-Peak	On-Peak	All-Hours
2010	53.0	74.3	63.1	53.8	70.5	61.8
2011	55.3	78.3	66.3	58.1	74.8	66.0
2012	58.5	80.8	69.1	62.7	81.4	71.6
2013	64.0	83.4	73.3	66.4	82.1	73.8
2014	64.5	84.8	74.2	67.4	82.8	74.7
2015	64.3	86.1	74.7	68.1	82.6	75.0
2016	65.4	88.1	76.2	69.5	82.9	75.9
2017	68.6	91.0	79.2	71.5	84.7	77.8
2018	70.7	91.4	80.6	73.3	88.4	80.5
2019	71.7	94.2	82.4	76.0	89.9	82.6
2020	72.7	94.4	83.0	76.2	89.7	82.6
2021	72.3	92.8	82.1	75.3	88.4	81.5
2022	73.7	94.1	83.4	77.3	89.6	83.2
2023	77.2	98.9	87.6	79.5	92.7	85.7
2024	81.9	104.0	92.4	83.1	98.8	90.6
Levelized	66.9	88.4	77.1	69.8	84.7	76.9

Connecticut Southwest						
	Summer			**Winter**		
Year	Off-Peak	On-Peak	All-Hours	Off-Peak	On-Peak	All-Hours
2010	52.9	74.2	63.1	53.8	70.4	61.7
2011	55.3	78.2	66.2	58.0	74.7	66.0
2012	58.4	80.7	69.0	62.6	81.4	71.5
2013	64.0	83.3	73.2	66.3	82.0	73.8
2014	64.5	84.8	74.1	67.3	82.7	74.6
2015	64.2	86.1	74.6	68.0	82.5	74.9
2016	65.3	88.0	76.1	69.4	82.8	75.8
2017	68.5	90.9	79.1	71.4	84.7	77.7
2018	70.6	91.3	80.5	73.2	88.4	80.4
2019	71.6	94.1	82.3	75.9	89.8	82.5
2020	72.6	94.3	82.9	76.1	89.6	82.5
2021	72.2	92.7	82.0	75.2	88.3	81.5
2022	73.6	94.0	83.3	77.3	89.5	83.1
2023	77.2	98.8	87.5	79.4	92.6	85.7
2024	81.8	103.9	92.3	83.0	98.7	90.5
Levelized	66.8	88.3	77.0	69.7	84.6	76.8

New Hampshire						
	Summer			**Winter**		
Year	Off-Peak	On-Peak	All-Hours	Off-Peak	On-Peak	All-Hours
2010	49.9	68.1	58.6	50.8	65.5	57.8
2011	52.1	72.1	61.6	54.8	70.1	62.1
2012	55.3	74.9	64.6	59.2	75.9	67.2
2013	60.5	77.2	68.4	62.7	76.6	69.3
2014	60.7	78.0	69.0	63.7	77.1	70.1
2015	60.8	78.9	69.4	64.4	76.9	70.4
2016	61.9	82.3	71.6	65.4	77.6	71.2
2017	64.5	83.8	73.7	67.1	78.8	72.6
2018	66.5	85.5	75.5	68.6	81.7	74.9
2019	67.6	86.8	76.7	70.0	81.7	75.6
2020	67.5	86.9	76.7	70.7	82.4	76.3
2021	68.2	84.0	75.7	70.0	81.3	75.4
2022	69.4	87.2	77.9	71.6	82.1	76.6
2023	71.1	91.0	80.6	72.3	85.4	78.5
2024	76.4	95.9	85.7	74.4	90.1	81.9
Levelized	62.8	81.5	71.7	65.1	78.4	71.4

Rhode Island						
	Summer			**Winter**		
Year	Off-Peak	On-Peak	All-Hours	Off-Peak	On-Peak	All-Hours
2010	49.4	68.2	58.3	50.4	65.9	57.8
2011	51.6	72.3	61.5	54.8	70.6	62.3
2012	54.8	75.2	64.5	59.3	77.1	67.8
2013	60.1	77.7	68.5	63.2	77.7	70.1
2014	60.1	78.5	68.9	63.9	78.2	70.7
2015	60.5	80.4	70.0	65.1	78.8	71.6
2016	61.6	83.2	71.9	66.3	79.1	72.4
2017	64.2	84.9	74.0	68.2	81.0	74.3
2018	66.6	86.5	76.0	70.3	84.5	77.1
2019	67.7	89.5	78.1	73.3	86.4	79.5
2020	68.6	89.1	78.3	72.9	86.3	79.2
2021	68.3	88.3	77.9	72.7	85.3	78.7
2022	69.6	89.9	79.3	74.6	87.3	80.6
2023	72.3	93.7	82.5	76.5	89.4	82.6
2024	77.3	100.1	88.2	80.1	95.6	87.5
Levelized	62.8	83.1	72.5	66.7	80.9	73.5

SE Massachusetts						
	Summer			**Winter**		
Year	Off-Peak	On-Peak	All-Hours	Off-Peak	On-Peak	All-Hours
2010	49.5	68.8	58.7	50.4	66.2	57.9
2011	51.7	72.8	61.8	54.9	70.9	62.6
2012	55.0	76.1	65.0	59.5	77.5	68.1
2013	60.3	78.4	69.0	63.4	78.2	70.5
2014	60.3	79.3	69.4	64.1	78.5	70.9
2015	60.8	81.0	70.4	65.4	79.0	71.9
2016	61.8	83.8	72.3	66.5	79.3	72.6
2017	64.4	85.5	74.5	68.5	81.3	74.6
2018	66.9	87.3	76.6	70.5	84.9	77.4
2019	68.0	90.2	78.6	73.6	86.7	79.8
2020	68.8	90.0	78.9	73.1	86.7	79.6
2021	68.6	89.1	78.4	73.1	85.8	79.1
2022	69.9	91.0	79.9	74.8	87.7	81.0
2023	72.5	94.5	83.0	76.8	89.7	83.0
2024	77.7	101.0	88.8	80.4	96.1	87.9
Levelized	63.1	83.8	72.9	66.9	81.2	73.8

South Maine						
	Summer			**Winter**		
Year	Off-Peak	On-Peak	All-Hours	Off-Peak	On-Peak	All-Hours
2010	48.1	64.3	55.8	49.9	63.2	56.3
2011	50.9	67.9	59.0	53.5	67.0	59.9
2012	54.5	70.9	62.3	57.3	71.3	64.0
2013	59.5	74.2	66.5	60.6	71.8	65.9
2014	59.2	73.7	66.1	61.8	72.2	66.7
2015	60.1	75.5	67.4	62.0	72.6	67.1
2016	61.5	78.1	69.4	63.5	73.0	68.0
2017	63.1	79.3	70.8	64.5	74.9	69.5
2018	65.5	80.6	72.7	66.1	76.9	71.2
2019	66.2	81.9	73.7	67.2	77.4	72.0
2020	65.2	83.8	74.1	67.7	76.9	72.1
2021	67.2	79.1	72.8	67.0	76.8	71.7
2022	67.8	81.6	74.3	69.3	77.4	73.1
2023	67.6	86.3	76.5	69.4	80.4	74.6
2024	73.1	91.7	81.9	71.3	84.6	77.6
Levelized	61.4	77.3	69.0	62.9	74.0	68.2

Vermont						
	Summer			**Winter**		
Year	Off-Peak	On-Peak	All-Hours	Off-Peak	On-Peak	All-Hours
2010	51.3	70.0	60.2	52.3	67.6	59.6
2011	53.6	74.2	63.4	56.4	71.9	63.8
2012	57.0	77.2	66.6	60.8	78.2	69.1
2013	62.3	79.3	70.4	64.3	78.5	71.1
2014	62.5	80.2	70.9	65.3	79.0	71.8
2015	62.5	81.8	71.7	65.9	79.0	72.1
2016	63.6	84.8	73.7	67.1	79.4	73.0
2017	66.3	86.3	75.8	68.9	80.9	74.6
2018	68.5	87.7	77.7	70.5	84.2	77.0
2019	69.4	90.0	79.2	72.1	84.6	78.1
2020	69.4	89.7	79.0	72.2	84.8	78.2
2021	70.0	88.2	78.6	71.4	83.6	77.2
2022	71.1	90.3	80.2	73.2	84.5	78.6
2023	73.4	93.7	83.1	73.8	87.1	80.1
2024	77.9	99.2	88.0	75.3	91.6	83.1
Levelized	64.6	84.1	73.9	66.7	80.5	73.3

Western Massachusetts						
	Summer			**Winter**		
Year	Off-Peak	On-Peak	All-Hours	Off-Peak	On-Peak	All-Hours
2010	51.4	70.0	60.3	52.4	67.6	59.6
2011	53.8	74.2	63.5	56.5	72.0	63.9
2012	57.1	77.2	66.7	61.1	78.3	69.3
2013	62.4	79.3	70.5	64.5	78.6	71.2
2014	62.8	80.3	71.1	65.5	79.3	72.1
2015	62.8	82.1	72.0	66.2	79.2	72.4
2016	63.9	85.0	73.9	67.4	79.7	73.3
2017	66.7	86.6	76.1	69.3	81.3	75.0
2018	69.0	88.0	78.0	71.2	84.6	77.6
2019	69.8	90.4	79.7	73.8	85.9	79.6
2020	70.7	90.2	80.0	73.8	85.7	79.5
2021	70.5	89.0	79.3	73.2	84.5	78.6
2022	71.8	90.7	80.8	75.2	86.2	80.5
2023	74.9	94.6	84.2	77.2	88.7	82.7
2024	79.7	100.9	89.8	80.9	94.6	87.4
Levelized	65.1	84.5	74.4	67.9	81.2	74.2

Appendix D: Avoided Natural Gas Costs

Appendix D-1

AVOIDED COSTS OF GAS DELIVERED TO LDCs BY MONTH
SOUTHERN NEW ENGLAND: Gas Delivered via Texas Eastern and Algonquin Pipelines
(2009$/Dekatherm)

	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	PEAK DAY (a) Rate Type Typical	PEAK DAY (a) Rate Type Incremental	Annual Henry Hub Price (2009$)
Demand Cash Cost (b)	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.793	$1.006	$1.136	$0.840	$0.675	100.33	357.79	
Variable Cash Cost (c)	$0.074	$0.074	$0.074	$0.074	$0.074	$0.074	$0.074	$0.158	$0.325	$0.380	$0.372	$0.302	0.83	1.76	
Ratio of Gas Purchased to Delivered	1.086	1.086	1.086	1.086	1.086	1.086	1.086	1.100	1.122	1.143	1.140	1.118	1.14	1.18	
2009	4.536	4.547	4.619	4.701	4.760	4.787	4.858	5.980	6.546	7.554	7.108	6.937	106.03	364.56	4.44
2010	5.913	5.926	6.020	6.128	6.204	6.240	6.333	7.531	8.155	8.700	8.218	7.883	107.52	366.11	5.81
2011	6.525	6.541	6.645	6.763	6.848	6.888	6.990	8.221	8.871	9.420	8.919	8.565	108.19	366.80	6.42
2012	7.146	7.163	7.276	7.407	7.499	7.543	7.655	8.921	9.597	9.772	9.256	8.786	108.87	367.50	7.04
2013	7.149	7.166	7.280	7.410	7.503	7.546	7.658	8.924	9.600	9.816	9.301	8.841	108.87	367.50	7.04
2014	7.220	7.237	7.352	7.484	7.578	7.621	7.735	9.004	9.684	9.907	9.389	8.928	108.95	367.58	7.11
2015	7.304	7.321	7.437	7.570	7.665	7.710	7.824	9.099	9.781	10.025	9.504	9.046	109.04	367.67	7.19
2016	7.421	7.439	7.557	7.692	7.788	7.834	7.950	9.231	9.918	10.193	9.668	9.214	109.17	367.80	7.31
2017	7.590	7.608	7.729	7.867	7.966	8.012	8.131	9.421	10.116	10.414	9.884	9.431	109.35	367.99	7.48
2018	7.799	7.817	7.941	8.084	8.185	8.233	8.355	9.657	10.360	10.649	10.113	9.650	109.58	368.23	7.69
2019	7.993	8.012	8.139	8.285	8.389	8.438	8.563	9.876	10.587	10.675	10.135	9.615	109.79	368.45	7.88
2020	7.854	7.873	7.998	8.141	8.243	8.291	8.414	9.719	10.425	10.463	9.928	9.400	109.64	368.29	7.74
2021	7.634	7.651	7.773	7.912	8.011	8.058	8.178	9.470	10.167	10.383	9.853	9.377	109.40	368.04	7.52
2022	7.706	7.724	7.847	7.988	8.088	8.135	8.256	9.552	10.252	10.495	9.963	9.492	109.48	368.13	7.60
2023	7.825	7.843	7.968	8.111	8.213	8.260	8.383	9.686	10.391	10.793	10.255	9.821	109.61	368.26	7.71
2024	8.208	8.227	8.358	8.507	8.614	8.664	8.793	10.117	10.838	11.203	10.654	10.198	110.02	368.69	8.09
Levelized 2010-2024 (d)	7.371	7.388	7.506	7.640	7.736	7.781	7.897	9.175	9.860	10.142	9.619	9.169	109.11	367.75	
Simple Average (2010-2024)	7.419	7.437	7.555	7.690	7.786	7.832	7.948	9.229	9.916	10.194	9.669	9.216	109.16	367.80	

(a) Peak day avoided cost is calculated based on the Legacy Rates, which are the basis for the monthly avoided costs, and incremental rates, which represent rates for new
(b) The cash costs paid to pipelines as demand charges to reserve transportation and storage capacity.
(c) The variable cash cost is primarily the cash paid to pipelines for using the pipelines to transport and store natural gas plus the demand charges at 10% load factor to
(d) Real (constant $) Discount Rate %: 2.22%

Note: Users should consider appropriate end-use category.

Appendix D-2

Exhibit 6-9: AVOIDED COSTS OF GAS DELIVERED TO LDCs BY MONTH
NORTHERN and CENTRAL NEW ENGLAND: Gas Delivered via Tennessee Gas Pipeline
(2009$/Dekatherm)

	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	PEAK DAY (a) Rate Source Typical	Incremental	Annual Henry Hub Price (2009$)
Demand Cash Cost (b)	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.540	$0.713	$0.862	$0.625	$0.476	$84.79	$140.62	
Variable Cash Cost (c)	$0.150	$0.150	$0.150	$0.150	$0.150	$0.150	$0.150	$0.223	$0.367	$0.415	$0.408	$0.347	0.80	1.08	
Ratio of Gas Purchased to Delivered	1.071	1.071	1.071	1.071	1.071	1.071	1.071	1.093	1.095	1.113	1.110	1.092	1.09	1.10	
2009	4.552	4.563	4.633	4.714	4.772	4.799	4.869	5.763	6.175	7.172	6.791	6.657	90.23	146.36	4.44
2010	5.910	5.923	6.016	6.122	6.198	6.233	6.324	7.305	7.747	8.284	7.867	7.576	91.66	147.80	5.81
2011	6.514	6.529	6.632	6.749	6.833	6.872	6.973	7.992	8.446	8.986	8.551	8.243	92.30	148.44	6.42
2012	7.126	7.143	7.255	7.384	7.475	7.518	7.629	8.687	9.155	9.324	8.875	8.454	92.94	149.09	7.04
2013	7.130	7.146	7.258	7.387	7.479	7.521	7.632	8.691	9.158	9.368	8.919	8.508	92.95	149.09	7.04
2014	7.200	7.216	7.330	7.460	7.552	7.596	7.707	8.770	9.240	9.457	9.005	8.594	93.02	149.17	7.11
2015	7.282	7.299	7.414	7.545	7.639	7.683	7.796	8.864	9.335	9.572	9.118	8.709	93.11	149.25	7.19
2016	7.398	7.415	7.532	7.665	7.760	7.805	7.920	8.995	9.469	9.736	9.278	8.874	93.23	149.38	7.31
2017	7.564	7.582	7.701	7.838	7.935	7.981	8.098	9.184	9.662	9.952	9.489	9.086	93.41	149.55	7.48
2018	7.771	7.789	7.911	8.052	8.152	8.198	8.319	9.419	9.900	10.181	9.712	9.300	93.62	149.77	7.69
2019	7.962	7.981	8.106	8.250	8.353	8.401	8.525	9.636	10.122	10.204	9.731	9.263	93.82	149.97	7.88
2020	7.825	7.843	7.967	8.108	8.209	8.256	8.378	9.481	9.964	9.997	9.529	9.052	93.68	149.83	7.74
2021	7.607	7.625	7.745	7.882	7.980	8.026	8.144	9.233	9.712	9.920	9.457	9.032	93.45	149.60	7.52
2022	7.679	7.697	7.818	7.957	8.056	8.102	8.221	9.315	9.795	10.031	9.565	9.144	93.53	149.67	7.60
2023	7.796	7.815	7.938	8.078	8.179	8.226	8.347	9.448	9.930	10.323	9.852	9.468	93.65	149.80	7.71
2024	8.174	8.193	8.322	8.470	8.575	8.624	8.751	9.876	10.367	10.722	10.240	9.836	94.05	150.20	8.09
Levelized 2010-2024(d)	7.349	7.366	7.482	7.614	7.709	7.753	7.867	8.939	9.412	9.687	9.230	8.829	93.18	149.32	
Simple Average (2010-2024)	7.396	7.413	7.530	7.663	7.758	7.803	7.918	8.993	9.467	9.737	9.279	8.876	93.23	149.37	

(a) Peak day avoided cost is calculated based on the Legacy Rates, which are the basis for the monthly avoided costs, and incremental rates, which represent rates for new services.
(b) The cash costs paid to pipelines as demand charges to reserve transportation and storage capacity.
(c) The variable cash cost is primarily the cash paid to pipelines for using the pipelines to transport and store natural gas plus the demand charges at 10% load factor to store gas.
(d) Real (constant $) riskless annual rate of return in %: 2.22%

Note: Users should consider appropriate end-use category.

Appendix D-3

AVOIDED COSTS OF GAS DELIVERED TO RETAIL CUSTOMERS
SOUTHERN NEW ENGLAND BY END USE
Gas Delivered via Texas Eastern and Algonquin Gas Pipelines
(2009$/Dekatherm)

	RESIDENTIAL				COMMERCIAL & INDUSTRIAL			ALL
Year	Non Heating	Hot Water annual	Heating	All	Non Heating	Heating	All	RETAIL END USES
2009	8.55	8.55	11.74	10.71	7.02	9.05	8.41	9.46
2010	9.91	9.91	13.03	12.02	8.38	10.34	9.72	10.76
2011	10.58	10.58	13.72	12.70	9.04	11.03	10.40	11.45
2012	11.15	11.15	14.21	13.21	9.61	11.52	10.91	11.96
2013	11.16	11.16	14.23	13.24	9.62	11.55	10.93	11.98
2014	11.24	11.24	14.32	13.32	9.70	11.63	11.02	12.06
2015	11.33	11.33	14.42	13.42	9.80	11.74	11.12	12.17
2016	11.47	11.47	14.57	13.57	9.93	11.89	11.26	12.31
2017	11.66	11.66	14.78	13.77	10.12	12.09	11.46	12.51
2018	11.88	11.88	15.01	13.99	10.35	12.32	11.69	12.74
2019	12.04	12.04	15.11	14.11	10.50	12.42	11.81	12.86
2020	11.87	11.87	14.93	13.94	10.34	12.24	11.63	12.68
2021	11.68	11.68	14.78	13.78	10.15	12.09	11.47	12.52
2022	11.77	11.77	14.88	13.87	10.23	12.19	11.57	12.61
2023	11.94	11.94	15.10	14.08	10.40	12.41	11.77	12.82
2024	12.34	12.34	15.51	14.49	10.81	12.82	12.18	13.23
2025	12.46	12.46	15.64	14.61	10.92	12.95	12.31	13.35
2026	12.58	12.58	15.76	14.73	11.04	13.08	12.43	13.48
2027	12.70	12.70	15.89	14.86	11.17	13.21	12.56	13.60
2028	12.82	12.82	16.02	14.98	11.29	13.34	12.69	13.73
2029	12.94	12.94	16.15	15.11	11.41	13.47	12.82	13.86
2030	13.06	13.06	16.28	15.24	11.54	13.60	12.95	13.99
2031	13.19	13.19	16.41	15.37	11.66	13.74	13.08	14.12
2032	13.31	13.31	16.55	15.50	11.79	13.87	13.21	14.25
2033	13.44	13.44	16.68	15.63	11.92	14.01	13.35	14.39
2034	13.57	13.57	16.81	15.77	12.05	14.15	13.48	14.52
2035	13.70	13.70	16.95	15.90	12.18	14.29	13.62	14.66
2036	13.83	13.83	17.09	16.04	12.31	14.43	13.76	14.79
2037	13.96	13.96	17.23	16.17	12.45	14.57	13.90	14.93
2038	14.09	14.09	17.37	16.31	12.58	14.72	14.04	15.07
2039	14.23	14.23	17.51	16.45	12.72	14.86	14.18	15.21
Levelized (a)								
2010-2019	11.21	11.21	14.30	13.30	9.67	11.62	11.00	12.04
2010-2024	11.42	11.42	14.52	13.52	9.88	11.83	11.21	12.26
2010-2039	12.19	12.19	15.35	14.33	10.66	12.67	12.03	13.08

Notes

(a) Years 2010-2024 (15 years); Real (constant $) riskless annual rate of return in %: 2.22%
Avoided Cost estimates for 2025-2039 extrapolated from 2015-2024 compound annual growth rate

Note: Users should consider appropriate end-use category.

Appendix D-4

AVOIDED COSTS OF GAS DELIVERED TO RETAIL CUSTOMERS
NORTHERN & CENTRAL NEW ENGLAND BY END USE
Gas Delivered via Tennassee Gas Pipeline
(2009$/Dekatherm)

	RESIDENTIAL				COMMERCIAL & INDUSTRIAL			ALL RETAIL END USES
Year	Non Heating	Hot Water annual	Heating	All	Non Heating	Heating	All	
2009	8.06	8.06	10.82	9.93	7.21	9.33	8.65	9.28
2010	9.40	9.40	12.08	11.21	8.55	10.59	9.93	10.56
2011	10.05	10.05	12.76	11.88	9.20	11.27	10.60	11.23
2012	10.61	10.61	13.23	12.38	9.76	11.75	11.10	11.73
2013	10.62	10.62	13.26	12.40	9.77	11.77	11.13	11.76
2014	10.70	10.70	13.34	12.48	9.85	11.85	11.21	11.84
2015	10.79	10.79	13.45	12.58	9.94	11.96	11.31	11.94
2016	10.92	10.92	13.59	12.73	10.07	12.10	11.45	12.08
2017	11.11	11.11	13.79	12.92	10.26	12.30	11.65	12.28
2018	11.33	11.33	14.02	13.15	10.48	12.53	11.87	12.50
2019	11.48	11.48	14.12	13.26	10.63	12.63	11.99	12.62
2020	11.32	11.32	13.94	13.09	10.47	12.45	11.81	12.44
2021	11.13	11.13	13.79	12.93	10.28	12.31	11.66	12.28
2022	11.22	11.22	13.89	13.02	10.37	12.40	11.75	12.38
2023	11.39	11.39	14.11	13.23	10.54	12.62	11.95	12.58
2024	11.78	11.78	14.51	13.63	10.93	13.02	12.35	12.98
2025	11.90	11.90	14.63	13.75	11.05	13.15	12.47	13.10
2026	12.02	12.02	14.76	13.87	11.17	13.27	12.60	13.23
2027	12.13	12.13	14.88	13.99	11.29	13.40	12.72	13.35
2028	12.25	12.25	15.01	14.12	11.41	13.53	12.85	13.47
2029	12.37	12.37	15.14	14.24	11.53	13.66	12.97	13.60
2030	12.49	12.49	15.27	14.37	11.65	13.79	13.10	13.73
2031	12.62	12.62	15.40	14.50	11.77	13.92	13.23	13.86
2032	12.74	12.74	15.53	14.63	11.90	14.05	13.36	13.99
2033	12.87	12.87	15.66	14.76	12.02	14.18	13.49	14.12
2034	12.99	12.99	15.79	14.89	12.15	14.32	13.62	14.25
2035	13.12	13.12	15.93	15.02	12.28	14.46	13.76	14.38
2036	13.25	13.25	16.06	15.15	12.41	14.59	13.89	14.52
2037	13.38	13.38	16.20	15.29	12.54	14.73	14.03	14.65
2038	13.51	13.51	16.34	15.42	12.68	14.87	14.17	14.79
2039	13.64	13.64	16.48	15.56	12.81	15.01	14.31	14.93
Levelized (a)								
2010-2019	10.67	10.67	13.33	12.47	9.82	11.84	11.19	11.82
2010-2024	10.87	10.87	13.54	12.68	10.02	12.05	11.40	12.03
2010-2039	11.64	11.64	14.35	13.47	10.79	12.87	12.20	12.83

Notes

(a) Years 2010-2024 (15 years); Real (constant $) riskless annual rate of return in % 2.22%
Avoided Cost estimates for 2025-2039 extrapolated from 2015-2024 compound annual growth rate

Note: Users should consider appropriate end-use category.

Appendix D-5

AVOIDED COSTS OF GAS DELIVERED TO RETAIL CUSTOMERS
VERMONT GAS SYSTEMS BY END USE
Gas Delivered via TransCanada Gas Pipeline
(2009$/Dekatherm)

Year	RESIDENTIAL Non Heating	RESIDENTIAL Hot Water annual	RESIDENTIAL Heating	RESIDENTIAL All	COMMERCIAL & INDUSTRIAL Non Heating	COMMERCIAL & INDUSTRIAL Heating	COMMERCIAL & INDUSTRIAL All	ALL RETAIL END USES
2009	7.40	7.40	10.30	9.37	5.69	7.32	6.81	7.75
2010	8.52	8.52	11.36	10.45	6.82	8.37	7.89	8.83
2011	9.09	9.09	11.96	11.04	7.39	8.98	8.49	9.42
2012	9.56	9.56	12.34	11.45	7.86	9.35	8.89	9.82
2013	9.58	9.58	12.37	11.47	7.87	9.38	8.91	9.85
2014	9.64	9.64	12.44	11.54	7.94	9.46	8.99	9.92
2015	9.73	9.73	12.54	11.63	8.02	9.55	9.08	10.01
2016	9.84	9.84	12.67	11.76	8.14	9.69	9.21	10.14
2017	10.01	10.01	12.85	11.94	8.30	9.87	9.38	10.32
2018	10.20	10.20	13.05	12.14	8.50	10.07	9.58	10.52
2019	10.32	10.32	13.12	12.22	8.62	10.13	9.66	10.60
2020	10.18	10.18	12.95	12.06	8.47	9.97	9.50	10.44
2021	10.02	10.02	12.84	11.94	8.32	9.86	9.38	10.32
2022	10.10	10.10	12.93	12.02	8.40	9.95	9.47	10.40
2023	10.26	10.26	13.15	12.22	8.55	10.17	9.67	10.60
2024	10.60	10.60	13.50	12.57	8.90	10.52	10.02	10.95
2025	10.70	10.70	13.61	12.68	9.00	10.63	10.13	11.06
2026	10.81	10.81	13.73	12.79	9.10	10.75	10.24	11.17
2027	10.91	10.91	13.84	12.90	9.21	10.86	10.35	11.28
2028	11.02	11.02	13.96	13.01	9.32	10.98	10.46	11.40
2029	11.12	11.12	14.07	13.13	9.42	11.10	10.58	11.51
2030	11.23	11.23	14.19	13.24	9.53	11.22	10.70	11.63
2031	11.34	11.34	14.31	13.36	9.64	11.34	10.81	11.74
2032	11.45	11.45	14.42	13.47	9.75	11.46	10.93	11.86
2033	11.56	11.56	14.54	13.59	9.87	11.58	11.05	11.98
2034	11.67	11.67	14.66	13.71	9.98	11.71	11.17	12.10
2035	11.78	11.78	14.79	13.82	10.10	11.83	11.30	12.22
2036	11.89	11.89	14.91	13.94	10.21	11.96	11.42	12.34
2037	12.01	12.01	15.03	14.06	10.33	12.09	11.55	12.46
2038	12.12	12.12	15.16	14.19	10.45	12.22	11.67	12.59
2039	12.24	12.24	15.28	14.31	10.57	12.35	11.80	12.72
Levelized (a)								
2010-2019	9.62	9.62	12.44	11.53	7.92	9.46	8.98	9.91
2010-2024	9.80	9.80	12.63	11.72	8.10	9.64	9.16	10.10
2010-2039	10.47	10.47	13.36	12.44	8.78	10.39	9.89	10.82

Notes

(a) Years 2010-2024 (15 years); Real (constant $) riskless annual rate of returi 2.22%
Avoided Cost estimates for 2025-2039 extrapolated from 2015-2024 compound annual growth rate

Note: Users should consider appropriate end-use category.

Appendix E: Avoided Costs of Other Fuels

Appendix E-1: AESC 2009 Forecast Weighted Average Avoided Cost of Petroleum Fuels by Sector and Other Fuels

	Fuel Oils							Other Fuels		
	Residential	Commercial			Industrial			Residential		
Year	Distillate Fuel Oil/ Biofuels	Distillate Fuel Oil/ Biofuels	Residual Fuel	Weighted Average	Distillate Fuel Oil/ Biofuels	Residual Fuel Oil	Weighted Average	Cord Wood	Kerosene	Propane
	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu
	2009$	2009$	2009$	2009$	2009$	2009$	2009$	2009$	2009$	2009$
2009	$17.49	$12.67	$1.50	$14.17	$7.87	$3.57	$11.44	6.30	16.99	24.91
2010	$15.64	$10.67	$2.70	$13.37	$6.65	$5.75	$12.41	5.63	15.18	24.04
2011	$16.34	$11.63	$2.74	$14.37	$7.61	$5.94	$13.55	5.88	15.87	24.91
2012	$17.95	$12.72	$3.23	$15.95	$8.72	$6.49	$15.21	6.46	17.44	26.84
2013	$19.32	$13.74	$3.64	$17.38	$9.65	$7.07	$16.72	6.96	18.76	29.09
2014	$20.92	$14.86	$4.09	$18.95	$10.48	$7.81	$18.28	7.53	20.32	31.29
2015	$22.65	$16.02	$4.53	$20.55	$11.46	$8.41	$19.88	8.15	21.99	33.63
2016	$24.36	$17.26	$4.84	$22.11	$12.34	$9.05	$21.39	8.77	23.65	36.14
2017	$25.96	$18.31	$5.26	$23.57	$13.16	$9.68	$22.84	9.35	25.21	38.58
2018	$26.02	$18.32	$5.35	$23.67	$13.27	$9.72	$22.99	9.37	25.27	38.70
2019	$26.18	$18.33	$5.49	$23.82	$13.38	$9.80	$23.18	9.42	25.43	38.90
2020	$26.25	$18.32	$5.49	$23.80	$13.40	$9.72	$23.12	9.45	25.49	38.82
2021	$26.32	$18.36	$5.57	$23.93	$13.41	$9.87	$23.28	9.48	25.57	39.04
2022	$26.53	$18.54	$5.64	$24.18	$13.54	$10.00	$23.54	9.55	25.77	39.28
2023	$26.41	$18.44	$5.59	$24.03	$13.49	$9.87	$23.36	9.51	25.65	39.04
2024	$26.74	$18.65	$5.66	$24.32	$13.70	$9.92	$23.62	9.63	25.97	39.19
2025	$27.24	$18.97	$5.80	$24.77	$13.97	$10.11	$24.07	9.81	26.45	39.86
2026	$27.75	$19.29	$5.95	$25.24	$14.25	$10.29	$24.54	9.99	26.95	40.54
2027	$28.26	$19.62	$6.10	$25.72	$14.53	$10.48	$25.02	10.18	27.45	41.24
2028	$28.79	$19.96	$6.25	$26.20	$14.82	$10.68	$25.50	10.36	27.96	41.94
2029	$29.33	$20.30	$6.41	$26.70	$15.12	$10.88	$25.99	10.56	28.48	42.66
2030	$29.87	$20.64	$6.57	$27.20	$15.42	$11.08	$26.50	10.75	29.01	43.39
2031	$30.43	$21.00	$6.74	$27.72	$15.73	$11.28	$27.01	10.96	29.55	44.14
2032	$31.00	$21.35	$6.91	$28.24	$16.04	$11.49	$27.53	11.16	30.10	44.89
2033	$31.58	$21.72	$7.08	$28.77	$16.36	$11.71	$28.06	11.37	30.67	45.66
2034	$32.16	$22.09	$7.26	$29.32	$16.69	$11.92	$28.61	11.58	31.24	46.44
2035	$32.76	$22.47	$7.44	$29.87	$17.02	$12.14	$29.16	11.79	31.82	47.24
2036	$33.37	$22.85	$7.63	$30.43	$17.36	$12.37	$29.73	12.01	32.41	48.05
2037	$34.00	$23.24	$7.82	$31.01	$17.71	$12.60	$30.30	12.24	33.02	48.87
2038	$34.63	$23.63	$8.02	$31.59	$18.06	$12.83	$30.89	12.47	33.63	49.71
2039	$35.28	$24.04	$8.22	$32.19	$18.42	$13.07	$31.49	12.70	34.26	50.56
Levelized Costs										
2010-2019	$21.29	$15.02	$4.13	$19.14	$10.53	$7.88	$18.41	$7.67	$20.68	$31.87
2010-2024	$22.83	$16.04	$4.56	$20.60	$11.41	$8.47	$19.89	$8.22	$22.17	$34.02
2010-2039	$26.20	$18.23	$5.53	$23.75	$13.32	$9.72	$23.04	$9.43	$25.44	$38.50

Notes

Calculation based on fuel oil forecast percentages by sector multiplied by fuel oil forecast price by sector

2025-2039 costs extrapolated based on 2015-2024 compound annual growth rate

Appendix E-2: Crude Oil and Fuel Prices by Sector in New England - AESC 2009 Forecast (2009$)

	Crude Oil Prices				Fuel Prices for Electric Generation in			Residential			Commercial			Industrial		
Year	AEO 2009 Forecast Imported Low Sulfur Crude	WTI NYMEX Futures Swaps as of March 31/09 (e)	AESC 2009 Forecast Imported Low-Sulfur Crude	AESC 2009 Forecast Imported Low-Sulfur Crude	Distillate Fuel Oil	Residual Fuel Oil	Steam Coal	Distillate Fuel Oil	Kerosene	Cord Wood	Distillate Fuel Oil	Residual Fuel	Kerosene	Distillate Fuel Oil	Residual Fuel Oil	Kerosene
	$/bbl	$/bbl	$/bbl	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu
	2009$	2009$	2009$	2009$	2009$	2009$	2009$	2009$	2009$	2009$	2009$	2009$	2009$	2009$	2009$	2009$
2009	63.45	54.96	56.25	9.70	13.35	6.68	3.52	17.49	16.99	6.30	15.80	7.58	19.36	15.82	7.11	14.52
2010	83.54	62.67	64.13	11.06	12.32	8.28	3.52	15.64	15.18	5.63	14.17	10.93	17.36	14.04	10.93	12.89
2011	91.88	67.64	69.22	11.93	13.05	9.16	3.36	16.34	15.87	5.88	15.16	11.78	18.56	15.34	11.78	14.08
2012	101.09	70.36	77.27	13.32	14.56	10.61	3.32	17.95	17.44	6.46	16.81	13.29	20.58	17.04	13.29	15.64
2013	106.18	72.39	85.33	14.71	15.73	11.73	3.28	19.32	18.76	6.96	18.29	14.64	22.40	18.66	14.64	17.12
2014	111.54	74.51	93.38	16.10	17.14	12.98	3.23	20.92	20.32	7.53	19.94	16.05	24.42	20.40	16.05	18.73
2015	115.14	76.20	101.44	17.49	18.65	14.20	3.18	22.65	21.99	8.15	21.63	17.46	26.49	22.12	17.46	20.30
2016	116.48	78.19	109.49	18.88	20.08	15.37	3.14	24.36	23.65	8.77	23.23	18.86	28.45	23.72	18.86	21.77
2017	117.54	80.01	117.54	20.27	21.41	16.47	3.11	25.96	25.21	9.35	24.76	20.20	30.32	25.28	20.20	23.20
2018	118.50		118.50	20.43	21.47	16.63	3.15	26.02	25.27	9.37	24.85	20.36	30.44	25.40	20.36	23.31
2019	119.75		119.75	20.65	21.63	16.79	3.17	26.18	25.43	9.42	25.00	20.58	30.62	25.54	20.58	23.44
2020	120.32		120.32	20.74	21.69	16.69	3.17	26.25	25.49	9.45	25.04	20.43	30.67	25.57	20.43	23.46
2021	122.27		122.27	21.08	21.76	16.89	3.15	26.32	25.57	9.48	25.13	20.68	30.78	25.67	20.68	23.56
2022	123.41		123.41	21.28	21.96	17.09	3.15	26.53	25.77	9.55	25.41	20.87	31.13	26.00	20.87	23.86
2023	124.61		124.61	21.48	21.84	16.85	3.15	26.41	25.65	9.51	25.32	20.58	31.01	25.92	20.58	23.79
2024	125.68		125.68	21.67	22.16	16.97	3.13	26.74	25.97	9.63	25.67	20.71	31.44	26.30	20.71	24.14
Levelized Costs																
2010-2014				13.37	14.51	10.50	3.35	17.98	17.46	6.47	16.81	13.28	20.59	17.03	13.28	15.63
2010-2019				16.27	17.39	13.03	3.25	21.29	20.68	7.67	20.14	16.20	24.67	20.50	16.20	18.81
2010-2024				17.75	18.73	14.18	3.22	22.82	22.17	8.22	21.68	17.52	26.55	22.10	17.52	20.28

Notes

Crude Oil forecasts based on EIA historical and projected values from AEO 2009 Table A12; West Texas Intermediate NYMEX prices as of March 31, 2009

Electric Generation Forecast based on AEO 2009 Table S11; Sector fuel price forecast based on low-sulfur fuel price ratios relative to historic and forecast crude oil prices

Appendix E-3: Percentage of 2009 Forecast Mix of Petroleum Related Fuels by Grade by Sector

	Residential	Commercial		Industrial	
Year	Distillate Fuel Oil	Distillate Fuel Oil	Residual Fuel	Distillate Fuel Oil	Residual Fuel Oil
	Percent	Percent	Percent	Percent	Percent
2009	100%	80%	20%	50%	50%
2010	100%	75%	25%	47%	53%
2011	100%	77%	23%	50%	50%
2012	100%	76%	24%	51%	49%
2013	100%	75%	25%	52%	48%
2014	100%	75%	25%	51%	49%
2015	100%	74%	26%	52%	48%
2016	100%	74%	26%	52%	48%
2017	100%	74%	26%	52%	48%
2018	100%	74%	26%	52%	48%
2019	100%	73%	27%	52%	48%
2020	100%	73%	27%	52%	48%
2021	100%	73%	27%	52%	48%
2022	100%	73%	27%	52%	48%
2023	100%	73%	27%	52%	48%
2024	100%	73%	27%	52%	48%

Notes

Calculations based on AEO 2009 Supplemental Table One for New England Fuel and Sector Consumption

Percentages based on 2009 fuel oil forecast of consumption by sector