Synapse
Energy Economics, Inc.

Avoided Energy Supply Costs in New England:

2007 Final Report

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

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EXECUTIVE SUMMARY

This 2007 Avoided-Energy-Supply-Component (AESC) report provides projections of marginal energy supply costs which will be avoided due to savings in electricity, natural gas and other fuels resulting from energy efficiency programs offered to customers throughout New England. The 2007 AESC Study updates the 2005 AESC Study to reflect current market conditions and cost projections. The report provides detailed projections for an initial fifteen year period beginning in 2007, and escalation rates for another fifteen years from 2022 through 2037. All values are reported in 2007$ unless noted otherwise.

The 2007 AESC was sponsored by a group of electric utilities, gas utilities and other efficiency program administrators (collectively, "program administrators"). The program administrators will use these projections in their efficiency program decision-making and regulatory filings in 2008 and 2009. The sponsors, along with non-utility parties and their consultants, formed a 2007 AESC Study Group to oversee the design and execution of the report. The report was prepared by a project team from Synapse Energy Economics (Synapse), Swanson Associates and Resource Insight (Synapse project team).

Avoided Costs of Natural Gas to Retail Customers

The 2007 AESC projections of marginal natural gas supply costs to retail customers over the next fifteen years are generally 5% to 15% higher than the 2005 AESC projections, shown in Exhibit ES-1. The differences vary by costing period, and are primarily due to a higher projection for natural gas prices, discussed below.

Exhibit ES-1
COMPARISON OFLEVELIZED AVOIDED COSTS OF GAS DELIVERED TO RETAIL CUSTOMERS
BY END USE: AESC 2005 AND AESC 2007
(2007$/Dekatherm)

	RESIDENTIAL				COMMERCIAL & INDUSTRIAL		
	Existing Heating 3-mon.	New Heating 5-mon.	Hot Water annual	All 6-mon.	Non Heating annual	Heating 5-mon.	All 6-mon.
Northern & Central New England							
AESC 2005 (a)	$10.60	$10.50	$10.42	$10.50	$9.49	$9.58	$9.53
AESC 2007	$12.09	$11.92	$10.91	$11.62	$9.84	$10.84	$10.54
2005 to 2007 change	14.1%	13.4%	4.7%	10.6%	3.7%	13.2%	10.6%
Southern New England							
AESC 2005 (a)	$10.88	$10.78	$10.66	$10.78	$9.30	$9.42	$9.36
AESC 2007	$12.61	$12.39	$11.21	$12.03	$9.17	$10.35	$10.00
2005 to 2007 change	15.9%	14.9%	5.1%	11.7%	-1.4%	9.9%	6.9%
Vermont							
AESC 2005 (a)	$9.78	$9.70	$9.62	$9.70	$8.53	$8.62	$8.57
AESC 2007	$11.44	$11.20	$10.01	$10.85	$8.00	$9.19	$8.84
2005 to 2007 change	17.0%	15.4%	4.1%	11.8%	-6.2%	6.7%	3.1%

Avoided Costs of Electricity to Retail Customers

The 2007 AESC projections of marginal electric energy and capacity costs to retail customers are substantially higher than those in the 2005 AESC Study. The 15 year levelized projections of marginal electric energy costs from the 2005 and 2007 AESC studies are shown in Exhibit ES-2.

15 Year Levelized Avoided Electric Energy Costs - AESC 2005 vs AESC 2007 ($2007)

Zone	AESC 2005 (2007$)			
AESC 2005	Winter Peak Energy $/kWh	Winter Off-Peak Energy $/kWh	Summer Peak Energy $/kWh	Summer Off-Peak Energy $/kWh
Maine (ME)	0.064	0.054	0.057	0.045
Boston (NEMA)	0.068	0.055	0.063	0.046
Rest of Massachusetts*	0.068	0.055	0.063	0.046
Central & Western Massachusetts (WCMA)	0.068	0.055	0.063	0.046
New Hampshire (NH)	0.066	0.054	0.062	0.046
Rhode Island (RI)	0.067	0.055	0.063	0.047
Vermont (VT)	0.068	0.055	0.064	0.047
Norwalk (NS)	0.073	0.057	0.069	0.048
Southwest Connecticut (SWCT)	0.071	0.057	0.068	0.048
Rest of Connecticut (non-SWCT)	0.070	0.056	0.067	0.047
AESC 2007				
Maine (ME)	0.084	0.062	0.086	0.060
Boston (NEMA)	0.095	0.069	0.101	0.068
Rest of Massachusetts*	0.093	0.069	0.098	0.067
Central & Western Massachusetts (WCMA)	0.094	0.070	0.099	0.069
New Hampshire (NH)	0.090	0.067	0.093	0.065
Rhode Island (RI)	0.093	0.068	0.098	0.066
Vermont (VT)	0.096	0.070	0.101	0.069
Norwalk (NS)	0.099	0.072	0.112	0.071
Southwest Connecticut (SWCT)	0.098	0.072	0.106	0.070
Rest of Connecticut (non-SWCT)	0.097	0.071	0.104	0.069
Chamge from AESC 2005				
Maine (ME)	0.020	0.008	0.030	0.015
Boston (NEMA)	0.028	0.014	0.038	0.022
Rest of Massachusetts*	0.026	0.014	0.035	0.021
Central & Western Massachusetts (WCMA)	0.027	0.015	0.036	0.022
New Hampshire (NH)	0.024	0.012	0.031	0.019
Rhode Island (RI)	0.026	0.013	0.035	0.019
Vermont (VT)	0.028	0.015	0.036	0.022
Norwalk (NS)	0.026	0.016	0.043	0.023
Southwest Connecticut (SWCT)	0.027	0.015	0.038	0.022
Rest of Connecticut (non-SWCT)	0.026	0.015	0.037	0.022
Chamge from AESC 2005 %				
Maine (ME)	41%	25%	60%	47%
Boston (NEMA)	38%	25%	56%	45%
Rest of Massachusetts*	39%	26%	56%	47%
Central & Western Massachusetts (WCMA)	36%	23%	50%	41%
New Hampshire (NH)	39%	24%	56%	41%
Rhode Island (RI)	41%	27%	57%	48%
Vermont (VT)	36%	27%	62%	47%
Norwalk (NS)	38%	27%	56%	47%
Southwest Connecticut (SWCT)	38%	27%	56%	46%
Rest of Connecticut (non-SWCT)	38%	27%	56%	46%

The 2007 AESC avoided energy costs are about 2.2 cents/kwh higher than the 2005 AESC on an annual average basis, with even higher differentials in peak costing periods. The major factors underlying those differentials are higher projections of natural gas production prices, CO_2 regulation compliance costs and retail supply margins. As indicated in Exhibit ES-4, those three factors would account for an annual average differential of 2.5 cents/kwh assuming a marginal gas-fired unit with a heat rate of 9500 btu/kwh.

Illustrative Calculation of Differential in Avoided Energy Costs – 2007 versus 2005		
Factor	**Differential – 2007 AESC versus 2005 AESC**	**Impact on marginal electric energy supply cost (cents/kwh) assuming a gas-fired unit with 9,500 btu/kWh heat rate**
Natural Gas Prices	$ 1.25/MMBtu	1.2
CO_2 compliance costs	$9.52/ton	0.6
Retail Adder	10%	0.8
Total		2.6

The projections of marginal electric energy costs are shown in Exhibit ES-5.

Exhibit ES - 5 15 Year Levelized Avoided Electric Capacity Costs - AESC 2005 vs AESC 2007			
	Annual Market Capacity Value 2007 $/kW-yr		
Zone	**AESC 2005**	**AESC 2007**	**Change**
Maine (ME)	50.37	102.37	103%
Boston (NEMA)	77.08	105.83	37%
Rest of Massachusetts	72.02	105.83	47%
Central & Western Massachusetts (WCMA)	72.02	105.83	47%
New Hampshire (NH)	72.02	105.83	47%
Rhode Island (RI)	72.02	105.83	47%
Vermont (VT)	72.02	106.90	48%
Norwalk (NS)	81.62	105.83	30%
Southwest Connecticut (SWCT)	76.54	105.83	38%
Rest of Connecticut (non-SWCT)	74.81	105.83	41%

The 2007 AESC projections of marginal electric capacity costs are higher than those in the 2005 AESC due primarily to the assumption that prices in the Forward Capacity Market (FCM) will be set by gas fired peaking combustion turbines.

1. Introduction

A. Background to report

This 2007 Avoided-Energy-Supply-Component (AESC) report provides projections of marginal energy supply costs which will be avoided due to savings in electricity, natural gas and other fuels resulting from energy efficiency programs offered to customers throughout New England. The program administrators will use these projections in their efficiency program decision-making and regulatory filings in 2008 and 2009. Those program administrators, along with non-utility parties and their consultants, formed a 2007 AESC Study Group to oversee the design and execution of the report.

The 2007 AESC sponsors include Berkshire Gas Company, KeySpan Energy Delivery New England (Boston Gas Company, Essex Gas Company, Colonial Gas Company, and EnergyNorth Natural Gas, Inc.), Cape Light Compact, National Grid USA, New England Gas Company, NSTAR Electric & Gas Company, New Hampshire Electric Co-op, Bay State Gas and Northern Utilities, 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 and Unitil Energy Systems, Inc.), United Illuminating, Southern Connecticut Gas and Connecticut Natural Gas, the State of Maine, and the State of Vermont. The following agencies or organizations are represented in the Study Group: Connecticut Energy Conservation Management Board, Massachusetts Department of Telecommunications and Energy, Massachusetts Division of Energy Resources, Massachusetts Low-Income Energy Affordability Network (LEAN) and other Non-Utility Parties, New Hampshire Public Utilities Commission, and Rhode Division of Public Utilities and Carriers.

The 2007 AESC Study Group specified the scope of work, presented in Appendix F, selected the Contractor and monitored progress of the study. The Synapse project team presented its analyses and projections to the 2007 AESC Study Group in nine substantive analyses, each of which was reviewed in a conference call.

The report was prepared by a project team from Synapse Energy Economics (Synapse), Swanson Associates and Resource Insight (Synapse project team). Dr. Carl Swanson lead the analysis of avoided natural gas costs, Dr. David White was lead investigator on projections of prices of oil and other fuels. Mr. Michael Drunsic was responsible for projecting electricity prices with advice from Bruce Biewald, Paul Chernick and Dr. White. Mr. Doug Hurley provided advice on the structure and operation of the New England market, including ICAP and LICAP issues. Paul Chernick developed zonal avoided electric costs by costing period, including analyses of DRIPE. Bruce Biewald, Paul Chernick and Lucy Johnston developed estimates of environmental externalities. Jennifer Kallay will provide research and analytic support including data collection, literature searches, spreadsheet analyses, documentation and drafting. Rick Hornby served as project manager and editor.

B. Organization of report and link to Project Deliverables

The report provides detailed projections of marginal energy supply costs for an initial fifteen year period beginning in 2007, and escalation rates for another fifteen years from 2022 through 2037. All values are reported in 2007$ unless noted otherwise.

The report is organized as follows:

- Chapter 2 - projection of natural gas prices for electric generation as well as a projection of avoided natural gas costs by retail end-use sector. (Deliverable 2 – Gas Forecast Background and Deliverable 3 – Gas Forecast)
- Chapter 3 - projection of crude oil prices.
- Chapter 4 - projection of fuel prices by retail end-use sector (Deliverable 4 and 9)
- Chapter 5 - projection of electric energy prices and a description of the modeling methodology and assumptions. (Deliverable 6 - Electric Avoided Costs)
- Chapter 6 - projection of avoided electricity costs and a description of the underlying assumptions. (Deliverable 6 a – Interim Electric Avoided Costs by Zone and Costing Period, Deliverable 7 – Avoided Energy supply Components)
- Chapter 7 - projection of environmental effects and environmental externality (Deliverable 10 –Environmental Effects)
- Appendix A – derivation of common modeling assumptions (Deliverable 8 – Miscellaneous Support)
- Appendix B – forecasts of monthly natural gas prices
- Appendix C – detailed input assumptions for electric energy price forecasts
- Appendix D – Usage Guide for Avoided Electricity Supply Costs (Deliverable 8 – Miscellaneous Support)
- Appendix E –Avoided Electricity Supply Costs (Deliverable 7)
- Appendix F – 2007 AESC Scope of work

2. Natural Gas Price Forecast

This Chapter provides a projection of natural gas prices for electric generation as well as a projection of avoided natural gas costs by retail end-use sector. (Deliverable 2 – Gas Forecast Background and Deliverable 3 – Gas Forecast)

A. Overview of New England Gas Market

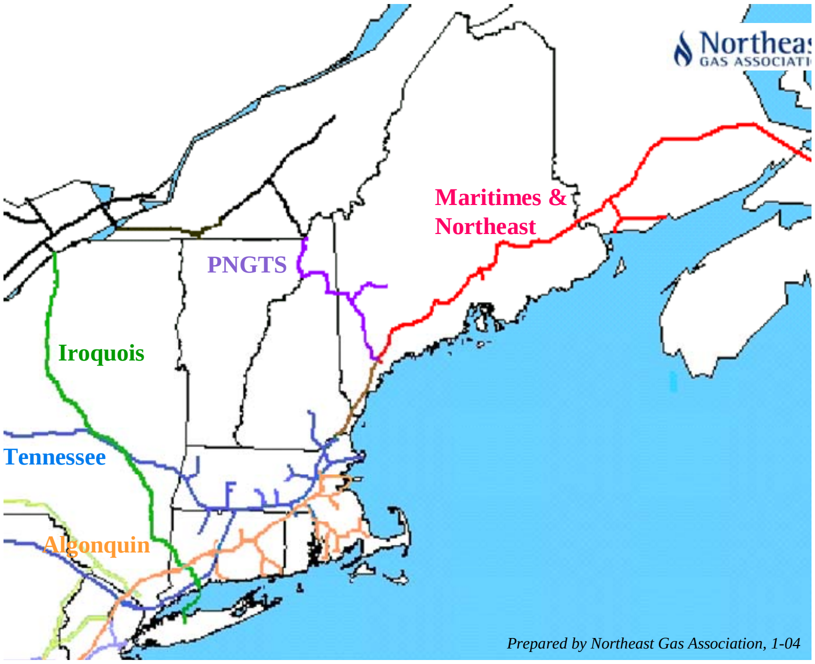
Natural gas arrived later in New England than in much of the rest of America because of its distance from the major supplies of natural gas in the southwest. Now, however, natural gas is about 23 percent of New England energy consumption, which is the same fraction of energy consumption as in the U.S. as a whole. Gas consumption has been and is expected to continue to grow in New England with electricity generation the most rapidly growing sector. Most of the gas purchased by consumers in New England is delivered by local distribution companies (LDCs), but some is delivered directly by pipelines, usually to electric generation facilities.

Because of the large seasonal temperature changes in New England and the amount of heating load, natural gas use is seasonal. On average about twice as much gas is used in January than in the summer months. However, much of the summer natural gas consumption is for electricity generation. Since generators often receive gas directly from pipelines, the LDCs have a much greater swing of gas load; a LDCs January gas load can be five times its summer load. Because of these large swings in gas load, LDCs must have gas stored in the summer to serve customer gas requirements in the winter. This stored gas is mostly stored in underground facilities; many of which are depleted natural gas producing fields. Most of the underground storage facilities that serve the New England LDCs are located in Pennsylvania although storage facilities in New York, Michigan or Ontario are also used. Since these underground storage facilities are relatively far from New England, LNG and propane stored in New England are used to meet the peak customer requirement on the colder days of the winter.

Originally the natural gas delivered in New England came from the supply areas of Appalachia or the Southwest. New England's natural gas supply has diversified; gas also now comes from western Canada, from Nova Scotia and by ship as LNG from Trinidad and Tobago, Nigeria, Algeria and other LNG exporting countries.

The physical system through which gas is delivered to and within the New England region currently consists of five pipelines and one liquid natural gas (LNG) terminal deliver gas to New England, excluding Vermont. They are Tennessee, Algonquin, Maritimes & Northeast, Portland Natural Gas, Iroquois and Distrigas, respectively. The five pipelines are shown in the exhibit below. Distrigas receives LNG by tanker in Boston Harbor and delivers that supply as gas into Algonquin, the Keyspan system, the Mystic Electric Generating Station and as LNG by truck to local distribution company (LDC) storage tanks throughout the region.

Exhibit 2-1. Pipelines Supplying New England



Tennessee and Algonquin deliver the majority of the natural gas that comes into New England. These two pipelines also deliver gas directly to a number of electric generating units and certain very large customers, as well as indirectly through deliveries to LDCs who in turn distribute that gas to retail customers.

A more extensive discussion of the New England gas industry and gas supply is published by the Northeast Gas Association (NEGA).[1]

1 Northeast Gas Association, "Statistical Guide to the Northeast U.S. Natural Gas Industry 2006" (NEGA Statistics 2006).

B. Forecast of Regional Price of Gas in New England

i. Development of Henry Hub Natural Gas Price Forecast

The forecasted price of gas in New England was based on the forecasted price of gas at the Henry Hub. It was assumed that the Henry Hub domestic price point was the most relevant pricing point to current and future US supply costs. AEO 2007 forecasts through 2020 indicate that the production from the lower 48 states represent at least 70% of US supply with the remaining coming from imports via pipeline and imports via liquid natural gas terminals (LNG). AEO 2007 projects US production will increase to approximately 80% of total supply by 2020 due to an increase in US production from forecast deliveries of Alaskan natural gas to the lower 48 states beginning in 2018 and a decline in imports via pipeline due to declines in Canadian production and increases in Canadian consumption. AEO 2007 also projects imports via LNG to increase by a factor of almost six relative to 2005 levels requiring the expansion of existing terminals and the construction of new terminals. However, even with this increase, LNG will still represent less than 15% of US supply as shown in the Exhibit below.

Exhibit 2-2. Sources of US Natural Gas Supply 2005 and 2020[2] (tcf)

Sources of Supply	2005 (actual)	2020 (Reference Case forecast)	Change 2020 vs. 2005
U.S. Production	18.30	20.86	2.56
Imports via Pipeline	3.01	1.65	(1.36)
Imports via LNG	0.57	3.69	3.12
Total	21.87	26.21	4.34

Henry Hub natural gas prices make a good starting point for the forecast for other reasons as well; the North American natural gas market is highly integrated, the Henry Hub is located in the U.S. Gulf Coast area which is the dominant producing region of the United States, the Henry Hub is the most liquid trading hub with the longest history of public trading on NYMEX and market prices of gas produced in other regions of the United States and Canada reflect Henry Hub prices with an adjustment for their location, referred to as a basis differential. A basis differential is defined as the natural gas price in a market location minus the gas price at the Henry Hub.

The first step towards projecting New England natural gas prices was to develop an annual Henry Hub natural gas price forecast. The natural gas price forecast at the Henry Hub was based on data from the Energy Information Administration's (EIA) Annual

[2] EIA, AEO 2007, Table A13, page 159.

Energy Outlook 2007 (AEO 2007)[3]. The AEO 2007 was the optimal starting point because it is public, it is transparent and it incorporates the long-term feedback mechanisms of energy prices upon supply, demand and competition among fuels. AEO 2007 is comprised of 34 different forecast cases, each incorporating different assumptions.[4] The most likely case is called a Reference Case. The Reference Case assumes U.S. economic growth of 2.9% per year and oil and gas prices that decline from current levels and then begin a slow rise. By 2030, the AEO 2007 expects the Reference Case average crude oil prices to be about $59.00 per barrel and U.S. wellhead natural gas prices to be $5.80 per Mcf in 2007 dollars.

A review of the Henry Hub natural gas prices in AEO 2007 found that none of the AEO forecasts of Henry Hub gas prices over the long-term was supportable. A major source of disagreement with the AEO 2007 forecasting was with the EIA's assumptions about technological progress in oil and gas finding. The Reference Case assumed that, due to technical progress, drilling costs will go down and finding rates will go up. However, these assumptions were found to be inconsistent with recent trends. As shown in the exhibit below, the cost per foot of drilling exploration wells doubled since the mid-1990s and the cost per foot of development wells more than doubled from 1995 to 2004. The reserves found per foot drilled for development wells dropped 40% while the productivity of exploration drilling dropped about two-thirds since the mid-1990s. Consequently, the drilling cost per Mcf of natural gas reserves found[5] increased from about $0.50 per Mcf in the mid-1990s to over $3.00 per Mcf for exploratory wells and to slightly under $2.00 per Mcf for development wells (all in 2000$).

The EIA did make some effort to consider observed trends. As stated in the AEO 2007, "…for the AEO 2007 projections, the reestimations capture all the cost increases and outcomes for the E & P activity that occurred through December 31, 2004." However, analysis and experience indicated that the EIA's reestimations were not sufficient to capture the recent facts and likely future reality regarding oil and gas drilling costs and productivity over the next several years. This is shown by the large differences between recent facts and the EIA assumptions about finding rates and drilling costs in the exhibit below.

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3 AEO 2007 prices are expressed in 2005$. Those prices are converted into 2007$ using the indexes and conversion factors specified as major assumptions.

4 See AEO 2007 Appendix E and especially Table E1, page 212.

5 These drilling costs do not include the costs of buying leases, performing geophysical surveys, or the costs, including royalty and taxes, of producing gas.

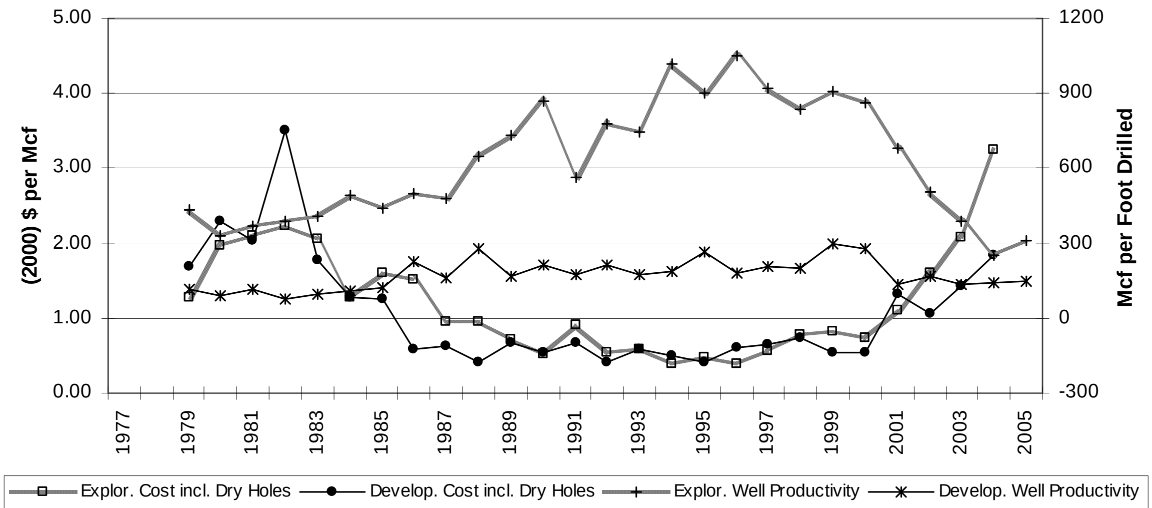
Exhibit 2-3. Comparison of AEO 2007 Assumptions About Improvements in Gas Finding Productivity and Drilling Costs (Reference Case) With Actual Data from 1994 to 2004

		Average Annual Improvement	
		Forecast	Actual
		AEO 2007 Reference Case	1994-1996 to 2003-2004
	Units	(a)	(b)
Annual Improvement in Success Rates of Oil and Gas Drilling			
Exploratory Wells	% per year	0.5 to 1.0	5.0
Development Wells	% per year	0.5	1.1
Improvement in Finding Rates for Gas			
Exploratory Wells	% per year	0.0 to 3.0	-12.4
Development Wells	% per year	1.0	-4.9
Reduction in Drilling Costs			
Exploratory Wells	% per year	0.9 to 1.0	-8.3
Development Wells	% per year	0.9 to 1.0	-9.5

As shown in this exhibit, AEO 2007 assumed that the success rate of oil and gas drilling would be less than the rate experienced on average from 1994-1996 through 2003-2004. However, this assumption merely reflected the fact that success rates are now relatively high, about 50% for exploratory wells and about 90% for development wells. It is true that oil and gas drilling technology is improving and there have been a higher percentage of successful wells over time as evidence of this trend (the exhibit below provides more detail). North America is now experiencing a gas drilling boom similar to that of the late 1970s and early 1980s. After the drilling boom of the late 1970s and early 1980s, drilling costs did decrease and drilling productivity did increase and such may happen again. Thus, it is also reasonable to expect that as the number of drilling rigs and experienced crews grows to fill the demand and as technology and knowledge improves in finding and developing non-conventional gas reservoirs, declining drilling costs and increasing productivity of drilling could be experienced in the future.

However, one cannot ignore the reduced finding rate and greater costs of finding gas, it is simply becoming increasing difficult and expensive to extend existing reservoirs and find new ones. New reservoirs are smaller, deeper in the sea, in more remote areas and have less permeability in the reservoirs. Thus, even though technology is improving, the data shows that the difficulty in accessing new or extended reservoirs for gas is offsetting any gains made through technological improvements. In addition, the increase in the number of wells and footage drilled led to price increases for drilling and this was accompanied by price increases for other items (i.e., steel) which were caused by worldwide economic growth. In short, further strong improvement in success rates, especially for development wells, will be difficult. AEO 2007's assumed improvements in finding rates of 0 to 3% per year and reductions in drilling costs of about 1% per year were not consistent with the actual rates experienced on average from 1994-1996 through 2003-2004. To the contrary, finding rates over that period fell sharply and drilling costs escalated sharply.

Exhibit 2-4. US Gas Wells Drilling Productivity (Mcf per foot drilled) and Drilling Cost of Reserves (2000$ per Mcf)



Fortunately, AEO 2007 provided alternate scenarios including the Oil and Gas Slow Technology Case and the Oil and Gas Rapid Technology Case. The AEO 2007's Oil and Gas Rapid Technology Case had 50% more rapid cost reduction and drilling productivity improvement than the Reference Case. Conversely, the AEO 2007's Oil and Gas Slow Technology Case assumed that cost and drilling productivity improvement were 50% less than the Reference Case. The Oil and Gas Slow Technology Case represented a more reasonable starting point than the Reference Case. In the Oil and Gas Slow Technology Case, the EIA continued to assume that technological progress would reduce drilling costs and increase drilling productivity year after year, contrary to the actual trends shown in the exhibit above. The recent rates of change for productivity improvements and drilling cost reductions are negative, not the small but positive numbers assumed by the EIA, even in its Slow Technology Case. Therefore, the Henry Hub gas price forecast leveraged the AEO 2007 Oil and Gas Slow Technology Case forecast, but it was adjusted to reflect the assumption that drilling costs would continue to increase or remain high and finding productivity per foot drilled would continue to fall or remain at current low levels for a while.

In order to develop a forecast that captured the effects of both technological progress and declining productivity and increasing costs of drilling for and finding natural gas this forecast started with the gas price forecast in the Slow Technology Case in the AEO 2007 and added to this price the difference in the price between the AEO 2007 Oil and Gas Slow Technology Case and the AEO 2007 Oil and Gas Rapid Technology Case. The difference in the two cases represents the difference in the rates of improvement (or decline) in drilling costs and drilling productivity. This difference, when added to the prices from the Slow Technology Case, provided a reasonable representation of the reality of increasing drilling costs and declining drilling productivity in the recent past and near future. The result is representative of the Henry Hub natural gas price under “a less than Slow Technology Case”. In other words, the Henry Hub natural gas price under “a less than Slow Technology Case” will be above the Slow Technology Case forecast price by the same differential as the Henry Hub natural gas price under the “Rapid Technology Case” is below the Slow Technology Case forecast price. A forecast that provided a reasonable reflection of the likely price impacts of increasing drilling costs and declining drilling productivity was developed by adding the price differential to the Slow Technology Case forecast price.

As a check on the validity of this forecast, the forecast prices for 2007-2012 were compared to the Henry Hub futures prices from NYMEX[6]. Annual averages using actual monthly NYMEX prices for January through March 2007 and NYMEX futures prices for April 2007 through December 2012[7] were calculated. This comparison indicated that near-term prices forecast under the methodology just outlined for 2007 through 2012 were, on average, 98% of the Henry Hub futures prices as of mid-March 2007[8] when expressed in 2007$. Although this is a modest discrepancy, it was determined that the optimal approach would be to leverage Henry Hub futures prices in the near-term (2007-2012) and the methodology based on the AEO 2007 Oil and Gas Slow Technology Case as described above in the long-term (2013-2022).

ii. Annual Henry Hub Natural Gas Price Forecast

The AESC 2007 Henry Hub annual natural gas price forecast is shown in the exhibit below relative to the actual Henry Hub prices from 1992 through 2006. Actual Henry Hub prices were in the $3.00/MMBtu (2007$) range from 1992 through 1999, and have increased steadily since then. The AESC 2007 forecast projects that prices decline to the $6.00 to $7.00/MMBtu range, and then stabilize at that level through 2022.

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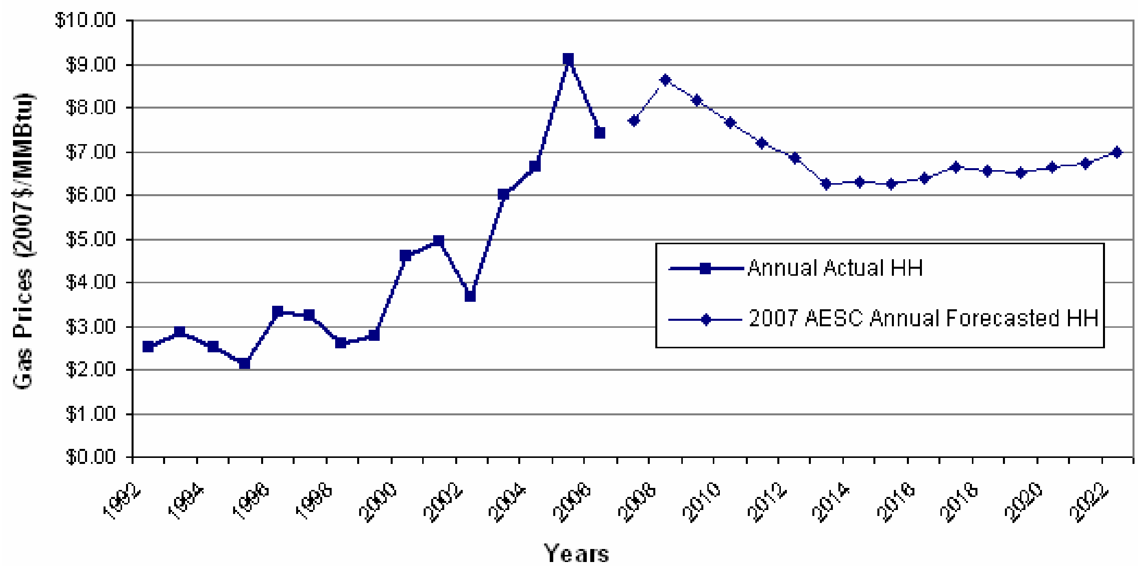
6 The futures market represents the consensus of market participants who do have a reasonable knowledge of near-term market and industry facts. See the paper by Adam Sieminski, “Varying Views on the Future of the Natural Gas Market: Secrets of Energy Price Forecasting”, 2007 EIA Energy Outlook, Modeling and Data Conference, Washington DC, March 28, 2007. Available at www.eia.doe.gov/oiaf/aeo/conf/index.htm.

7 As of May 2, 2007.

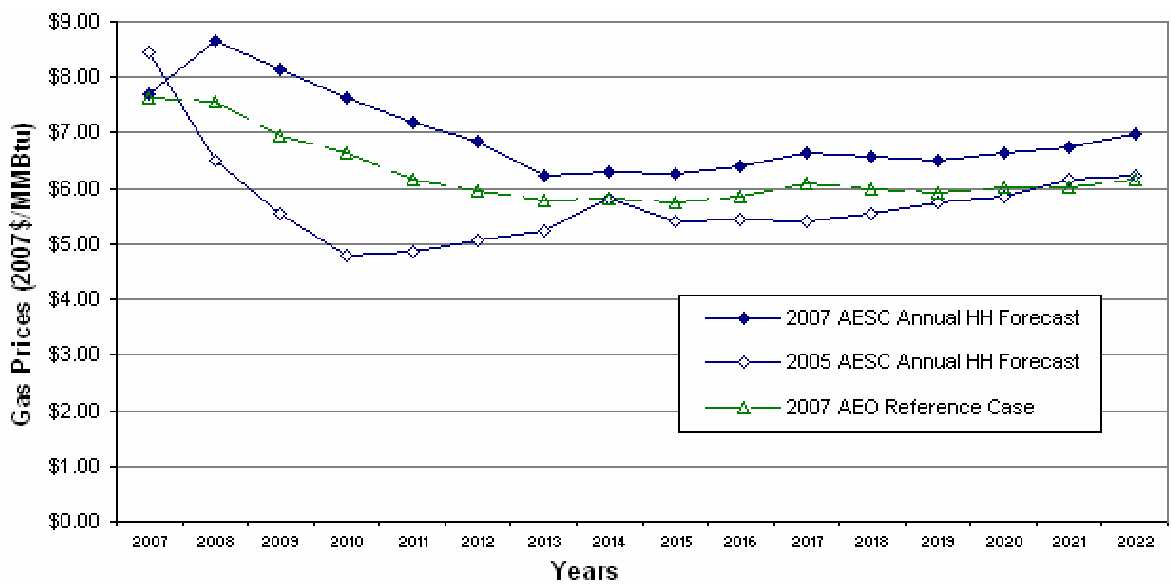
8 NYMEX ClearPort market prices as of 5/2/07.

Exhibit 2-5. Annual Actual and Forecasted Henry Hub Natural Gas Prices (2007$/MMBtu)



The AESC 2007 forecast is approximately 9% higher than the AEO 2007 Reference Case on average over the forecast period as shown in the exhibit below.

Exhibit 2-6. Comparison of Henry Hub Gas Price Forecasts (2007$/MMBtu)



C. Forecast of High and Low Gas Prices at the Henry Hub

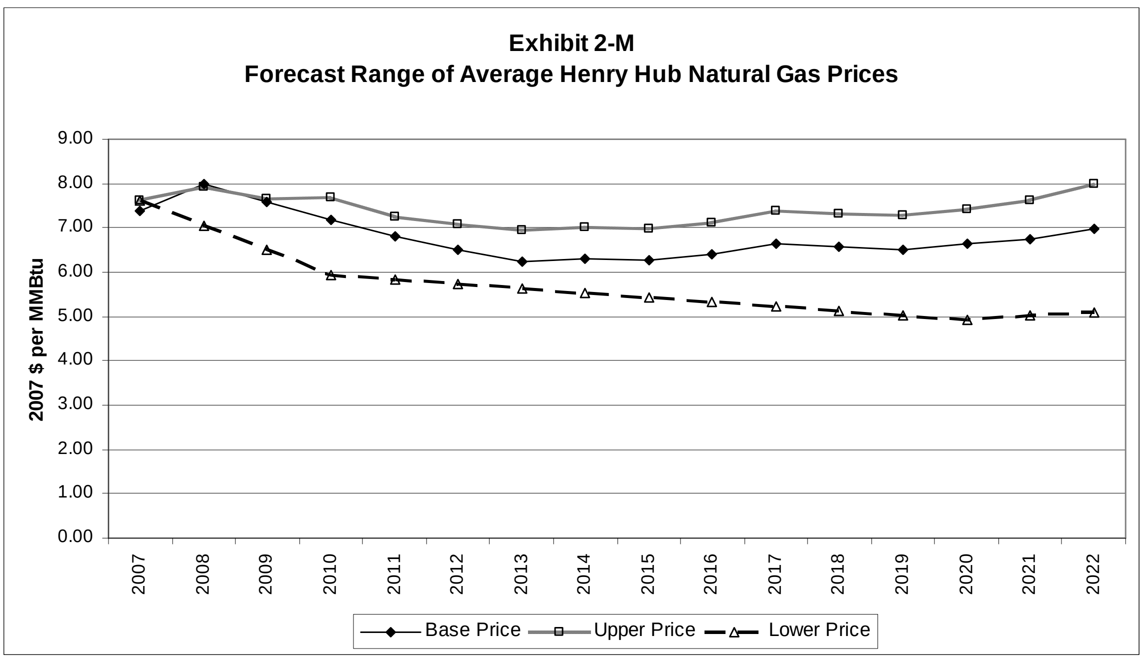
In this section higher and lower gas price cases are presented. Similar to the base price forecast, these forecasts were derived from various price cases presented in AEO 2007. The volatility of those prices is also discussed.

(a) Higher Price Case

In addition to its reference case, AEO 2007 presents summary results for 33 additional cases. These cases have widely varying assumptions about economic growth, oil and gas resources, energy efficiency in consuming sectors and technological development in the various energy supply sectors.[9] The AEO 2007 case which produced the highest oil and gas prices is called the "high price case". In that case, the quantity of oil and gas resources[10] in the US and worldwide are assumed to be 15 percent less than in the reference case. This assumption produces a crude oil price of 2005 $100/bbl in 2030 compared with the reference case price of 2005 $59/bbl in 2030.

The difference between the Henry Hub natural gas price forecast under the AEO 2007 "high price case" and the AEO 2007 reference case is a measure of the impact of the 15 percent reduction in the available oil and natural gas resources. That difference is 2005 $0.63/MMBtu in 2010 and 2005 $0.75/MMBtu in 2020. This differential was used to develop the AESC 2007 higher price case. Thus, the AESC 2007 higher gas price case equals the AESC 2007 base forecast price in each year plus the difference between the AEO 2007 "high price case" and "reference case" in that year. The resulting AESC 2007 higher price forecast is shown in Exhibit 2- M. The AESC 2007 higher price case represents a future with both slower technological progress in finding oil and gas than under the base forecast, and fewer oil and gas resources than expected in the AEO 2007 reference case.

Exhibit 2 – M **Range of Henry Hub Gas Prices**



[9] AEO 2007 Appendix E, Exhibit E1.

[10] Resources are proved reserves plus potential, possible and speculative resources that are recoverable under adequate economic conditions and current or foreseeable technology.

(b) Lower Price Case

The AEO 2007 “low price case” forecast was used for the AESC 2007 lower price case. This case assumes future levels of oil and natural gas resources 15 percent higher than under the AEO 2007 reference case. This assumption produces a crude oil price in 2030 of 2005$36/bbl compared with the reference case crude oil price in 2030 of 2005$59/bbl. In addition to higher levels of oil and gas resources, the AEO 2007 “low price case” differs from the AESC 2007 base price in that it assumes new oil and gas reserves will be found more easily and at less cost. The AESC 2007 lower price case is also shown in Exhibit 2-M.

D. Representation of Volatility In Gas Prices

The AESC 2007 forecast natural gas prices; base case, upper and lower cases; should be viewed as expected average annual prices. In contrast, actual gas prices are volatile. Thus, it is reasonable to expect actual prices to vary around these expected annual average prices. The upper and lower price cases are not intended to show the range of volatility of gas prices. Gas price have changed by a factor of two or more during a year and they can stay above or below the “expected” price for periods longer than a year.

Pindyck argues that oil, coal and natural gas prices tend to move toward long-run total marginal cost.[11] 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.[12]

Thus, assuming that the AESC 2007 base price forecast is correct, one should expect that the random movements in gas prices could send the gas price above the upper gas price shown in the Exhibit above for several months or in some case for more than a year. For example examine the year 2015; the base price forecast is $6.25 per MMBtu (in 2007$). A 12% random increase in that year would make the price $7.00, which is slightly greater than the $6.98 forecast for the “higher” price. 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.

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 the hurricane Katrina in 2005 is illustrative. Katrina hit the Gulf Coast on August 29, 2005. One month earlier on July 29, 2005 the NYMEX gas futures contract for September 2005

[11] Robert S. Pindyck, “The Long-Run Evolution of Energy Prices”, *The Energy Journal*, Vol. 20, No. 2 pages 1-27 (1999).

[12] Pindyck 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, pages 24-25 and 6.

delivery was priced at $7.885 per MMBtu. On December 13, 2005 the NYMEX January 2006 gas futures contract settlement price was $15.378. Six months after Katrina struck the Gulf Coast, that is, on March 1, 2006, the April 2006 gas futures contract was priced at $6.733 per MMBtu. Subsequently 2006 experienced few hurricanes and on September 27, 2006 the October 2006 gas futures contract closed at $4.210 per MMBtu. But these prices were short lived and on March 1, 2007 the April 2007 gas futures contract settled at a price of $7.288. In this example a shock that removed 5 Bcf per day of natural gas supply produced a strong increase in prices, but 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 December 2005 peak. Such shocks and gas price volatility should be expected in the future. Nonetheless, the AESC 2007 base gas price forecast should be viewed as an average or expected Henry Hub gas price forecast.

An adjustment to the gas price forecast was not developed for price spikes for several reasons. First, there was little, if any, analytical work publicly available on this issue. Second, the prices should be used as the basis for avoided energy supply costs in evaluating the economic value of long-term investments in energy efficiency. It is not anticipated that the levelized price of gas over the long-term, e.g., 10 to 20 years, would 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 increase following Hurricane Katrina in the fall of 2005. Reasonably high gas prices are already being forecast for the future, and it was believed that investment decisions were unlikely to be affected by accounting for price spikes. Moreover, it is also possible that gas prices could fall below the levels of this forecast (a U.S. recession could lead to a drop in natural gas prices).

E. Monthly New England Regional Natural Gas Price Forecast

i. Monthly Henry Hub Natural Gas Price Forecast

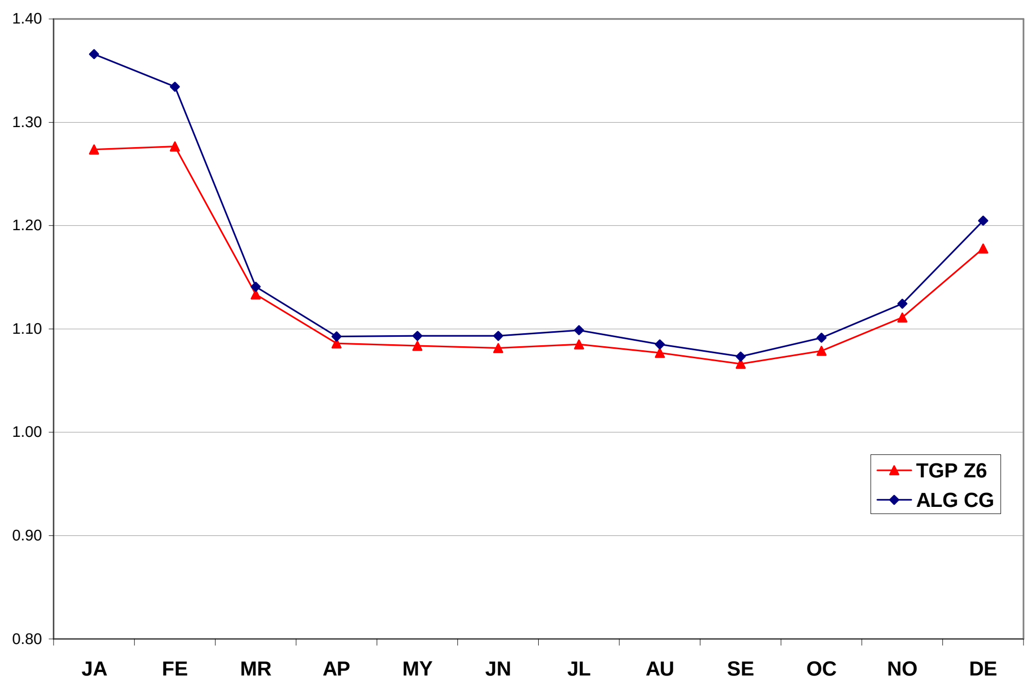
The second step towards producing New England forecasted natural gas prices was to translate the annual Henry Hub natural gas price forecast into a monthly Henry Hub natural gas price forecast. The monthly NYMEX actual prices from January 2007 through May 2007 and the forecasted prices from June 2007 through December 2012 were used to develop ratios of the prices in each month of a year to the annual average for that year. These ratios were applied to the forecast of annual prices from 2013 through 2022 to develop forecasts of monthly prices in each of those years.

ii. Monthly New England Regional Natural Gas Price Forecast

In order to forecast natural gas prices for electric generation in New England we applied a ratio reflecting the historical average basis differential between the Henry Hub natural gas price and the regional natural gas price to the monthly Henry Hub natural gas price forecasts. The regional natural gas price for most of New England can be represented by two major regional pricing points; Tennessee Gas Pipeline Zone 6 (TGP Z6) and

Algonquin Gas Pipeline City Gate (ALG)[13]. As a result, the forecast of natural gas prices for electric generation in New England, with the exception of Vermont, was calculated by taking the average of the forecasts for prices of spot gas delivered from TGP Z6 and ALG. The average of forecast gas prices for these two zones was appropriate for several reasons. An analysis of spot gas prices delivered from TGP Z6 and ALG between January 2000 and March 2007, presented below, showed no material difference between prices on the two pipelines in most months, which was not surprising. There was 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. If the price on these two pipelines diverged by too much, arbitrage would reduce the price difference. In addition, arbitration panels rely upon the average of these two price indices, TGP Z6 and ALG, 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.

Exhibit 2-7. Average Actual Basis Differential Ratios – TGP Z6 vs. ALG



Forecast prices for natural gas and for electricity generation in Vermont were not developed because Vermont currently does not have adequate pipeline capacity to support a major gas-fired generating unit. Currently, Vermont Gas receives gas from TransCanada pipeline at Highgate on the VT/Canadian border and distributes that gas to

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[13] Zone 6 of the Tennessee Gas Pipeline is the section serving New England. Algonquin is a regional pipeline serving New England.

customers in northern Vermont. It is not connected to the rest of the New England gas pipeline network.

In order to adjust the Henry Hub natural gas prices as accurately as possible, both actual monthly basis differentials (the absolute difference between TGP Z6 and ALG and Henry Hub prices in $/MMBtu) and monthly basis differential ratios (TGP Z6 and ALG versus Henry Hub prices) were calculated over the period January 2000 – March 2007. In the end, the basis differential ratios were utilized instead of the actual monthly basis differentials due to the fact that they were more stable over time. The average monthly basis differential ratios for TGP Z6 and ALG were applied to the monthly forecast of Henry Hub natural gas prices to develop monthly prices for TGP Z6 and TLG over the forecast period.

Despite the fact that a basis differential ratio was used to calculate average monthly basis differentials in AESC 2007 while the actual basis differential was used in AESC 2005, the two approaches were still comparable. The average monthly basis differentials from AESC 2005 were compared to the average monthly basis differentials as calculated from basis differential ratios for AESC 2007 as presented in the exhibit below. The AESC 2007 average monthly basis differentials were substantially higher than the AESC 2005 values in most months. The difference was primarily attributable to the fact that the AESC 2007 forecast of Henry Hub natural gas prices was higher than the AESC 2005 forecast and that the forecast average monthly basis differentials were calculated from a ratio rather than from a single absolute difference applied over the forecast period.

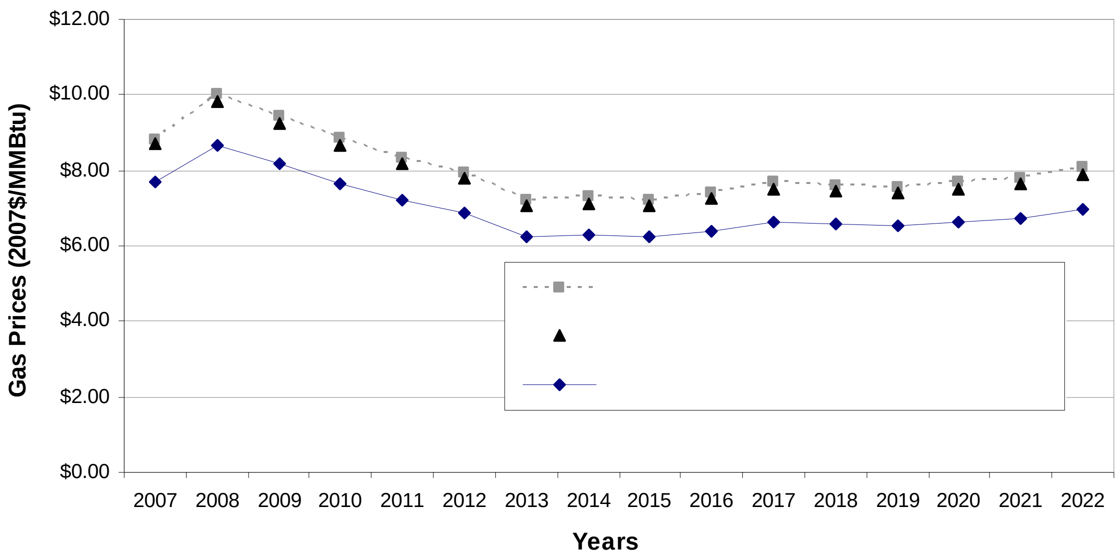
Exhibit 2-8. Comparison of Forecast Average Monthly Basis Differentials for Power Generators (2007$/MMBtu)

	AESC 2005	AESC 2007	AESC 2007 vs. AESC 2005	AESC 2005	AESC 2007	AESC 2007 vs. AESC 2005
Month	**Southern NE**	**ALG**		**Central NE**	**TGP Z6**	
1	3.06	2.44	-20%	2.64	2.44	-8%
2	1.38	2.40	74%	1.26	2.40	90%
3	0.81	1.02	26%	0.76	1.02	35%
4	0.53	0.58	10%	0.47	0.58	22%
5	0.43	0.56	31%	0.39	0.56	45%
6	0.37	0.57	54%	0.30	0.57	86%
7	0.42	0.60	44%	0.34	0.60	79%
8	0.39	0.53	38%	0.32	0.53	70%
9	0.33	0.46	43%	0.32	0.46	48%
10	0.39	0.58	48%	0.34	0.58	71%
11	0.53	0.84	60%	0.48	0.84	74%
12	1.20	1.44	20%	0.90	1.44	60%

Lastly, a lateral commodity charge for the delivery of the gas from the pipeline to the generating plant was added to the forecasted regional gas price. ALG has a firm transportation rate schedule, AFT-CL, for laterals that connect ALG's mainline with several electric generating stations and one manufacturing plant. The 100% load factor rates for firm service to the electric generating plants under rate schedule AFT-CL range in price from $0.0229 to $0.1093 per MMBtu.[14] Considering that the deliveries are likely to be at less than 100 percent load factor, the $0.07 per MMBtu lateral charge used in AESC 2005 was reasonable and was adopted in AESC 2007.

The AESC 2007 Henry Hub annual natural gas price forecast is shown in the exhibit below relative to the ALG annual natural gas price forecast and the TGP Z6 annual natural gas price forecast.

Exhibit 2-9. Henry Hub and New England Natural Gas Price Forecasts (2007$/MMBtu)



The forecasts of monthly prices for natural gas prices at the Henry Hub, ALG, TGP Z6 and for electric generation in New England are presented in Appendix B.

F. Impact of New Regional Supplies on Regional Price of Natural Gas

It was thought that the addition of a significant quantity of new supply could put downward pressure on regional prices by reducing the basis differential of New England spot gas prices relative to Mid-Atlantic pricing points such as TETCO M-3[15]. New gas supply is expected to enter New England from one or more of the new LNG import terminals proposed for Massachusetts as well as from Phase IV of the Maritime and Northeast Pipeline. Since Encana has announced plans to develop Deep Panuke off Nova Scotia, and since the Canaport LNG terminal in New Brunswick is under construction, it is expected that additional gas will be delivered to New England through the Maritimes and Northeast pipeline. How many, and which of the other proposed LNG terminals will

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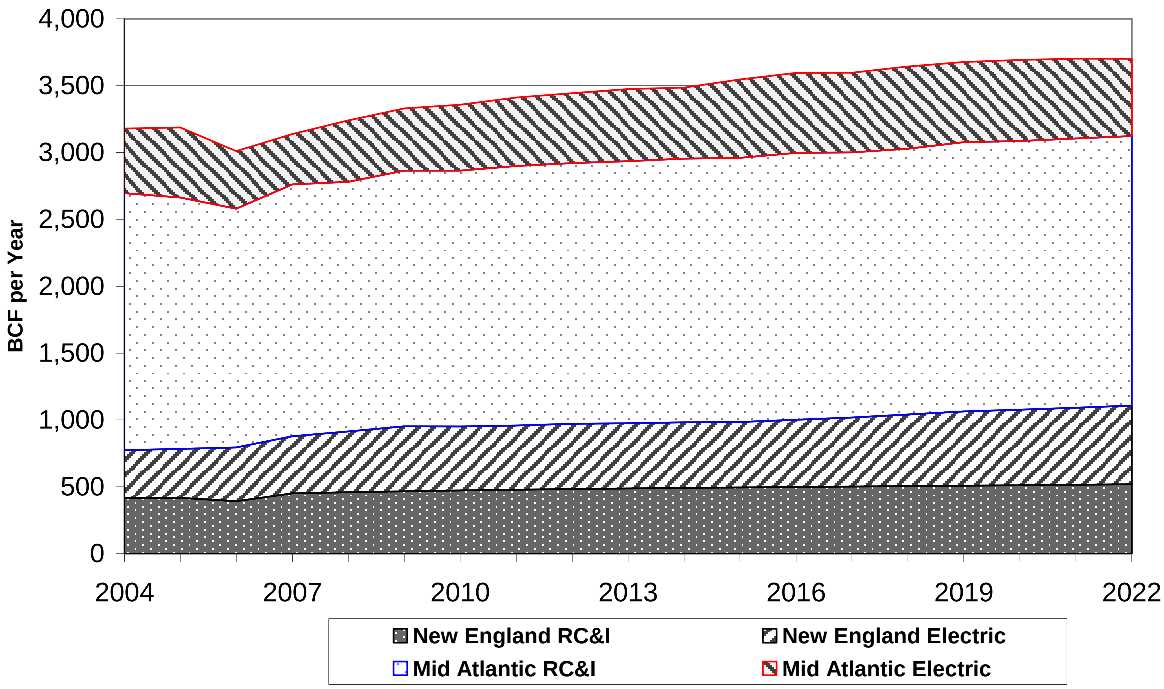
14 Algonquin Gas Transmission, LLC FERC Gas Tariff sheets No. 36 and 37 effective October 1, 2006.

15 TETCO M3 is Texas Eastern Transmission Company, market zone 3. Zone M3 includes parts of Pennsylvania and ends in New Jersey.

be completed is uncertain, as is the annual quantity of LNG that will actually be delivered to each terminal.[16] Nevertheless, it was reasonable to expect some additional annual quantity of LNG to be delivered into New England consistent with the national supply assumptions from AEO 2007 presented in the Exhibit above. However, these new projects wouldn't necessarily result in a major reduction in regional prices for electric generation in New England, since load is projected to grow in both New England and the Mid-Atlantic, and since the mid-Atlantic market is several times larger than New England as depicted in the figure below.

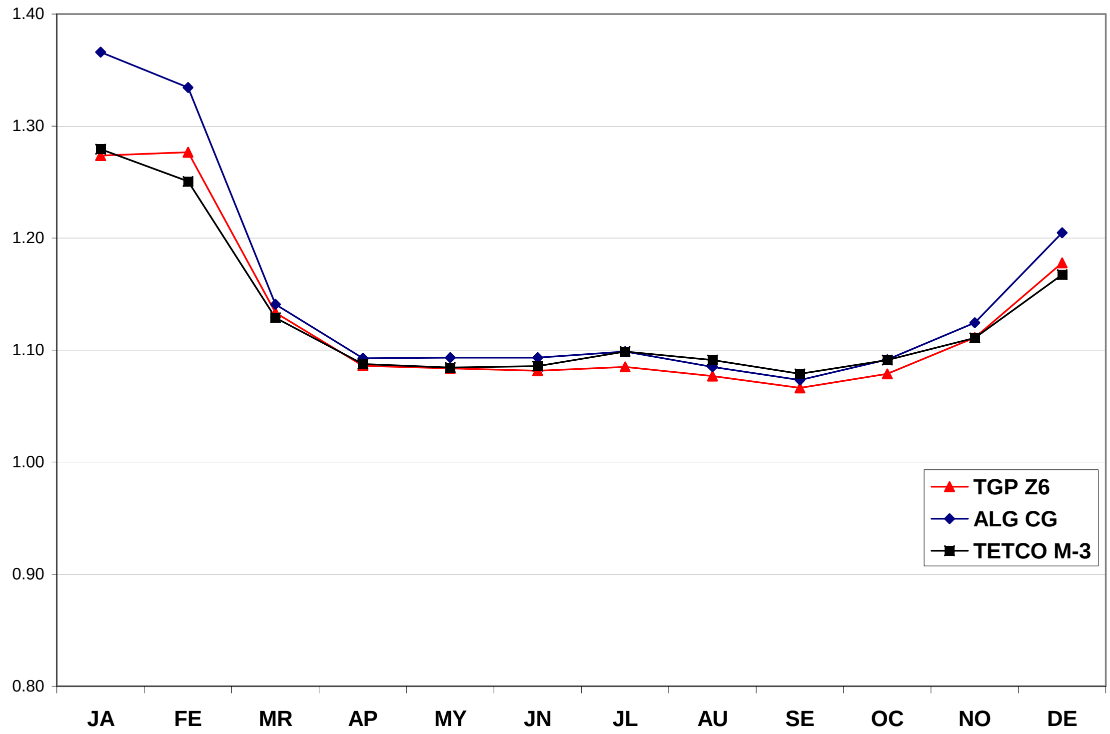
Figure x. AEO 2007 Projections of Gas Demand in New England and the Mid-Atlantic (Bcf per year)



Major reductions in regional prices for electric generation in New England were also not anticipated since the average monthly basis differential at TETCO M-3 relative to the Henry Hub natural gas price, measured as a ratio to HH prices, was not materially different from the basis differentials for the corresponding months at the ALG pricing point and was only slightly less than the TGP Z6 pricing point for most months over the past 7 years. On average, the ALG average monthly basis differential ratio relative to Henry Hub was higher than that of TETCO M-3 in the months of January and February. This was not surprising since TETCO M-3 feeds gas into ALG. The surprise was that the New England average monthly basis differential ratio relative to Henry Hub was similar to that of TETCO M-3 in the majority of months.

[16] For a discussion of the near-term LNG market and the difficulty of forecasting LNG imports into the U.S. see: EIA, 'Short-Term Energy Outlook Supplement: U.S. LNG Imports – The Next Wave" January 2007.

Figure x. Average Actual Basis Differential Ratios – TGP Z6 vs. ALG vs. TETCO M-3



Further analysis indicated that the minimal average monthly basis differential between New England and the Mid-Atlantic area over the last several years can be explained by increased supply into New England since 2000. The Exhibit below compares the actual annual average of gas imports into New England to the average daily gas consumption in New England during the lowest months of consumption (June through September). As can be seen for the recent past, imports into New England were close to the daily average consumption during June – September. Thus, especially during the summer, there wasn't a need to bring significant gas from the Mid-Atlantic to New England. One would not expect the New England spot price to be much higher than Mid-Atlantic prices under these conditions. This was consistent with the findings concerning the prices in New England and at TETCO M-3 as shown in the figure above.

In order to determine how much of an impact additional supply may have on New England prices, a scenario in which at least one of the three proposed Massachusetts terminals is completed, bringing an additional 0.4 Bcf/day of gas to New England, was analyzed. In this scenario, it was assumed that the existing import pipelines continued to supply gas as they have recently. It was also assumed that 46% of the gas throughput on the Iroquois Pipeline was sent to Connecticut and Massachusetts. This estimate was based upon the fact that in 2007 about 46% of the firm contracts on Iroquois delivered gas to Connecticut and Massachusetts.[17] It was also assumed that gas consumption in

[17] From the Iroquois Pipeline website: www.iroquois.com

New England during June – September would increase through 2010 and 2020 as projected by the AEO 2007. The results of this analysis are shown in the Exhibit below.

Exhibit x. Average Annual Gas Imports Entering New England Compared to Average Consumption in Summer (June-September; Bcf per day)

	Actual Avg.	Projection	Projection
	2004-2006	**2010**	**2020**
Pipeline Supply (a)			
Iroquois Pipeline to NE (c)	0.416	0.391	0.391
PNGTS, Pittsburg, NH	0.070	0.085	0.085
M&N: Excluding Canaport, LNG	0.296	0.301	0.301
Pipeline Volumes Entering NE First	**0.782**	**0.777**	**0.777**
LNG Imports			
Distrigas Imports (a)	0.433	0.466	0.466
Canaport Imports to US	0.000	0.500	0.500
One of the Proposed Mass. LNG Projects Completed	0.000	0.320	0.400
LNG Volumes Entering New England	**0.433**	**1.286**	**1.366**
Total Gas Entering New England First (a)	**1.215**	**2.063**	**2.143**
New England Gas Consumption June-Sept (b)			
Residential, Commercial & Industrial	0.511*	0.590	0.640
Electric Generation	1.140*	1.451	1.714
New England Consumption (June-Sept)	**1.651***	**2.041**	**2.354**

** Actual Avg. for New England Gas Consumption June-Sept is from 2002-2006*
a Gas supply projections assume no growth in each supply source. Historical data; EIA Natural Gas Annual 2005 and USDOE Fossil Energy, Natural Gas Import & Export Regulation.
b Gas consumption projections based on 2002-06 actuals and growth rates in EIA Annual Energy Outlook 2007.
c Fraction of Iroquois supply to New England is the fraction of firm transportation contracts which deliver to Massachusetts and Connecticut during 2007.

Under these assumptions the projected growth in new supply essentially matches and is offset by the projected growth in demand. There is no major surplus of imports over New England summer gas consumption in 2010 or 2020. Consequently, there was no compelling reason to assume that future gas price basis differentials between New England and the Henry Hub would be materially less in the future than they were in the past due to the delivery of additional supply from new LNG terminals proposed for New England and New Brunswick.

To be sure that the impact on pricing is not significant, a second scenario was analyzed where most or all of the proposed Massachusetts LNG terminals came on line. In this event, the sum of pipeline and LNG imports into New England could exceed consumption in New England in summer months. If that were to occur, the excess supply would need to be transported from New England to the Mid-Atlantic either for direct sale or injection into storage. This could cause New England spot gas prices to decline relative to TETCO M-3 prices in those months. However, the decline would likely be on the order of a few percent because rates for pipeline transportation capacity would be discounted in the summer and some transportation would be by backhaul and exchange. Alternatively, the LNG suppliers might choose not to deliver supplies in excess of New England demand at a price less than TETCO M-3, and instead sell some of that supply in markets with higher prices such as Europe.

G. Forecast of Price for Retail Sectors

(a) Cost to Supply Natural Gas to LDCs

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 (LNG) and/or propane in tanks located in the LDC service territories throughout New England.

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

- the cost of the gas commodity, which in this study is purchased at the Henry Hub in Louisiana;
- the fixed demand cost of holding pipeline transportation capacity and of storage and withdrawal capacity;
- the usage (volumetric) charges for transporting gas on a pipeline and for storage injections and withdrawals; and
- 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.

The LDCs generally own the LNG and/or propane tanks and accompanying liquefaction and vaporization facilities. Since the bulk of the New England peak gas supply comes from LNG facilities, AESC 2007 focuses on them 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.

Because of the significantly increased level of winter season requirements and the variation in winter day requirements according to temperature, LDCs develop a portfolio among the three gas supply resources in order to optimize reliability and cost. Generally, long-haul pipeline transportation is used to meet customer gas requirements each month of the year and to refill underground storage and sometimes LNG tanks during the summer months. Much of the increased winter, November – March, gas demand from customers is met by transporting gas from the underground storage facilities, often located in Pennsylvania, to the LDC in New England.[18] LNG and propane facilities meet daily peaking and seasonal requirements during the heaviest demand period, December through February.

i. Sector-Specific Avoided Natural Gas Price Forecast

This section discusses forecasts of the avoided costs of natural gas saved by energy efficiency programs for the period 2007 through 2022 for both (1) gas delivered to New England local distribution companies (LDCs) and (2) the avoided cost of gas at the retail level delivered to end-users of gas. The avoided costs are calculated as a weighted average cost of the marginal natural gas supply sources during specified seasonal and peak-day costing periods.

The avoided cost of gas to a LDC is the cost of the marginal source of supply for the relevant cost period. For this analysis, the long-run avoided cost was estimated because efficiency improvement is a long-term effect that can allow an LDC to avoid both the short-run variable costs and also some, but not all, of the long-term fixed costs of gas supply sources. The marginal cost (avoided cost) was computed for each month and for the peak day. The avoided cost is the cost of delivering one dekatherm of gas to the LDC via the three resources in any month. For each of the winter months, November through March, when gas is supplied by the three resources, the marginal cost is the weighted average of the costs for each supply source depending upon the fraction of total volumes of sendout provided by each source. By computing the weighted average, the approach taken in AESC 2005 was mirrored by assuming that the LDCs have optimized the mix of supply sources and thus, both fixed and variable costs are avoided in the mix of all three of the supply sources for a long-term efficiency improvement.[19]

In this forecast, the approach of AESC 2005 was applied in some areas, but not in others. For example, a different approach was taken when computing the avoided cost of each cost period. AESC 2007 estimates the avoided cost for each month and averages the monthly avoided costs.

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[18] LDCs acquire pipeline and storage services through a portfolio of contracts whose terms and conditions are regulated by the Federal Energy Regulatory Commission (FERC).

[19] 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.

Similar to AESC 2005, it was assumed that the marginal source of gas to New England LDCs from the Henry Hub is transportation and storage on either of 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. While proposed LNG receiving and re-gasification terminals in New England and 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 supplied by TGP Z6 and TETCO-ALG.[20]

Exhibit 2-10. Comparison of the Levelized[21] Avoided Costs for LDCs from AESC 2005 and AESC 2007 (2007$/dekatherm[22])

	WINTER					SUMMER				
	Peak Day	3 Months Dec-Feb	5 Months Nov-Mar	6 Months Nov-Apr	7 Months Oct-Apr	5 Months May-Sep	6 Months May-Oct	7 Months Apr-Oct	9 Months Mar-Nov	Annual Average
		Northern and Central New England				Tennessee Gas Pipeline				
AESC 2005 (a)	(b)	10.26	9.15	8.84	8.57	6.79	6.77	6.74	(b)	8.06
AESC 2007	92.78	9.10	8.92	8.62	8.45	7.18	7.22	7.21	7.53	7.92
Percent difference 2005 to 2007	na	-11.3%	-2.5%	-2.4%	-1.4%	5.7%	6.6%	6.9%	na	-1.7%
		Southern New England				Texas Eastern & Algonquin Route				
AESC 2005 (a)	(b)	10.88	9.55	9.18	8.88	6.89	6.87	6.82	(b)	8.12
AESC 2007	110.11	9.47	9.25	8.90	8.69	7.20	7.24	7.23	7.60	8.07
Percent difference 2005 to 2007	na	-13.0%	-3.1%	-3.1%	-2.1%	4.5%	5.5%	5.9%	na	-0.7%

Source of the AESC 2005 levelized cost is Exhibit 1-19 of the AESC 2005 report, page 38.
(a) Factor to convert 2005$ to 2007 $ 1.0547
(b) Levelized costs were not provided in the AESC 2005 report, Exhibit 1-19.
Note: AESC 2005 levelized costs over the years 2005 - 2025. AESC 2007 levelized costs over the years 2007 - 2022.

The avoided costs were generally similar for AESC 2005 and AESC 2007. The winter season avoided costs in AESC 2007 were up to 13% less than in AESC 2005 since AESC 2005 allocated all 12 months of pipeline demand costs to pipeline transportation for each of the cost periods in the winter of 3, 5, 6 and 7 months. Also the avoided cost of peaking service was much greater in AESC 2005. In contrast, AESC 2007 allocated winter and 20% of summer pipeline demand costs to winter season, November – March, long-haul transportation. In AESC 2007, pipeline demand charges were also allocated to long-haul pipeline transportation to fill storage in the summer and to the winter period

[20] 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.

[21] Costs were levelized over the years 2005 – 2025 in AESC 2005 and the years 2007 – 2022 for AESC 2007.

[22] One DT is one million BTU.

transportation from underground storage to the LDC. Thus, the avoided cost of underground storage service was greater in AESC 2007 than in AESC 2005. Similar to AESC 2005, no demand charges were allocated to long-haul transportation in the summer season, April – October. AESC 2007 summer season avoided costs were 1% to 7% greater than those in AESC 2005, due mostly to the higher forecast Henry Hub gas price in AESC 2007. In the exhibit above, the avoided cost in Southern New England is greater than that in Northern and Central New England due to the greater demand and usage rates of TETCO and AGT relative to those of TGP.

(a) Representative New England Local Distribution Company

For this avoided cost analysis a representative New England LDC was used 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 the exhibit below.

Exhibit 2-11. Representative New England Local Gas Distribution Company Monthly Characteristics of Send-Out by Source, Peak Month and Storage Injection

Fractions of LDC Send-out by Source Each Month	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MA
Pipeline Deliveries, Long-haul	1.00	1.00	1.00	1.00	0.86	0.64	0.50	0.52	0.68	1.00	1.0
Underground Storage	0.00	0.00	0.00	0.00	0.11	0.33	0.40	0.39	0.30	0.00	0.0
LNG and Propane Peaking Supply	0.00	0.00	0.00	0.00	0.03	0.03	0.10	0.09	0.02	0.00	0.0
Total	**1.00**	**1.00**	**1.00**	**1.00**	**1.00**	**1.00**	**1.00**	**1.00**	**1.00**	**1.00**	**1.0**
Fraction of Annual Sendout each Month	0.032	0.034	0.036	0.062	0.096	0.143	0.174	0.151	0.114	0.077	0.04
Monthly Sendout as a Fraction of Peak Month	0.184	0.195	0.207	0.356	0.552	0.822	1.000	0.868	0.655	0.443	0.26
Fraction of Underground Storage Injection by Month	0.170	0.170	0.140	0.100	0.000	0.000	0.000	0.000	0.000	0.080	0.17

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

The fractions portraying the representative New England LDC were essentially an average of the data in Cost of Gas Adjustment filings for Yankee Gas Services Company, Connecticut Natural Gas Corporation, Bay State Gas Company, NSTAR Gas Company and Keyspan Energy Delivery in New England.

(b) Avoided Cost of Gas from Each of the Three Sources

As described above, the avoided cost (marginal cost) consisted of the commodity cost of gas, the demand charges of pipeline transportation and storage, the volumetric cash costs of pipeline transportation and storage and the fuel and loss retention for the various parts of bringing gas to a LDC.

(c) Commodity Cost Inputs

For this avoided cost analysis it was assumed that the marginal cost of the gas commodity was the monthly price of gas at the Henry Hub.

(d) Pipeline Rates

As described above, it was assumed 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 the exhibit below. It was assumed that these rates and retention percentages would persist for the forecast period, 2007 – 2022. This was the same assumption as in AESC 2005.

Exhibit 2-12. Pipeline Rates for Transportation and Storage

	Demand	Usage	Fuel & Loss (a)	
	$/DT/month	$/DT	Winter %	Summer %
Texas Eastern Transmission, L.P. (b)				
Transportation: FT-1, WLA - M3			Dec - Mar	Apr - Nov
WLA-AAB	2.6030			
ELA-AAB	2.1520			
M1 - M3	10.5770			
Total Demand	15.3320			
WLA - M3 usage (c)		0.0590	8.88	7.34
Storage & Transportation: SS-1				
Reservation,	5.6560			
Space ($/DT/year)	0.1293		0.06	0.06
Injection		0.0324	0.89	0.89
Withdrawal (c)		0.0483	3.93	3.42
Algonquin Gas Transmission LLC (d)				
Transportation: AFT-1 (FT-1,WS-1)	6.5854		Dec - Mar	Apr - Nov
Usage (c)		0.0128	1.37	0.66
Tennessee Gas Pipeline Company (e)				
Transportation FT-A			Nov - Mar	Apr - Oct
Zone 1 (LA) to 6	15.15	0.1503	7.82	6.67
Zone 1 (LA) to 4	10.77	0.1014	5.90	5.06
Zone 4 to 6	5.89	0.0834	2.17	1.92
Storage FS - Market Area				
Reservation	1.15			
Space	0.0185			
Injection		0.0102	1.49	1.49
Withdrawal		0.0102		

Sources and Notes:
(a) Fuel and loss is applied to volumes received.
(b) FT-1: Tariff Sheet Nos. 30 & 31 effective February 1, 2007 and Sheet Nos. 126 & 127 effective December 1, 2006.
SS-1: Tariff SheetNo. 52 effective February 1, 2007 and Sheet Nos. 126 & 127 effective December 1, 2006.
(c) Includes ACA charge of $0.0016 per DT, which are included in TGP listed rates.
(d) AFT-1: Tariff Sheet No. 22 effective October 1, 2006.
(e) FT-A: Tariff Sheet Nos. 23 effective July 1, 2006, Sheet No. 23A effective October 1, 2006 and
Sheet No. 29 effective March 1, 1997; FS: Sheet No. 27 effective July 1, 2006.

(e) 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.[23] "Cash cost" means the avoided cost of transportation arising from pipeline usage charges, which are paid for each DT 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

[23] Rates 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.

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

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

The exhibit shows the avoided costs by gas source and pipeline route.

Exhibit 2-13. Comparison of Avoided Costs of Delivering One Dekatherm of Gas to a New England Local Distribution Company from Three Sources of Natural Gas and Peak Day

		Texas Eastern & Algonquin		Tennessee Gas Pipeline	
		January	June	January	June
	units				
Pipeline Long-haul to LDC					
Total Demand Cost of Gas Delivered to LDC	2007 $/DT	$0.98	$0.00	$0.67	$0.00
Total Usage Cash Cost of Gas delivered to LDC	2007 $/DT	$0.07	$0.07	$0.15	$0.15
Ratio of Gas Purchased at HH to Gas Delivered to LDC		1.113	1.086	1.085	1.071
Delivered From Underground Storage					
Total Demand Cost of Gas Delivered to LDC from UG Storage	2007 $/DT	$1.39		$1.16	
Total Cash cost for refill + Usage Cost of Gas delivered to LDC	2007 $/DT	$0.83		$0.80	
Ratio of Gas Purchased to Gas Delivered to LDC		1.149		1.093	
LNG Regasified into LDC System					
Total Demand Cost of Gas Delivered to LDC for LNG refill	2007 $/DT	$0.90		$0.62	
Total Usage Cash Cost of Gas delivered to LDC for LNG refill	2007 $/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					
Pipeline Cash Demand Cost of Gas Delivered to LDC	2007 $/DT	$101.73		$84.79	
Pipeline Cash Commodity Cost of Gas Delivered to LDC	2007 $/DT	$0.83		$0.80	
Ratio of Gas Purchased at HH to Gas Delivered to LDC		1.149		1.093	

Based on pipeline rates effective April 25, 2007

AESC 2007 computed the demand cost of long-haul transportation differently from AESC 2005 in the winter period. For the summer period, April – October, AESC 2007 had a similar assumption to AESC 2005, but a different result due to differing implementation of the assumption.

(f) Summer

AESC 2005 assigned no demand charges to the avoided cost during the summer periods (5, 6, 7 and 9 months) based upon an assumption that the market value of pipeline capacity release in the summer would be zero. AESC 2007 also assumed that the value of pipeline capacity release is zero in the summer, but only for the months of April – October, which is a seven month period. The assumption that demand charges cannot be avoided in the summer was supported by the 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.

Thus, AESC 2005 and AESC 2007 were in agreement that there is no avoided cost of long-haul pipeline transportation for the 7-month summer period of April – October. This forecast differs in that AESC 2005 allocated no demand costs to the month of November and March for the 9-month summer period of March – November. In contrast, AESC 2007 considered November and March part of the winter period and did allocate demand charges to those two months as described in the next section.

LDCs use their long-haul pipeline transportation in the summer to fill underground, and sometimes LNG storage. Thus, some long-haul pipeline capacity is needed and used in the summer in addition the direct transportation to the LDC from the Henry Hub. Consequently, in AESC 2007 the costs of demand and usage charges and the fuel and loss fraction for pipeline transportation from the Henry Hub to refill storage were allocated to the avoided cost of underground storage.

(g) Winter

AESC 2005 assumed that the full twelve months of pipeline demand charges was assigned to each of the winter periods (3, 5, 6 and 7 months). Thus, saving a dekatherm each day of a 3-month winter period allows a reduction of twelve months of long-haul demand charges, and reducing one dekatherm per month over five months reduced twelve months of demand charges, etc. It was believed that the AESC 2005 assumption was aggressive since long-haul pipeline transportation is used throughout the year, in part for storage fill.

Based on the typical New England LDC send-out and storage refill shown in the exhibit entitled 'Comparison of the Levelized Avoided Costs for LDCs from AESC 2005 and AESC 2007' above, approximately 20% of the long-haul pipeline capacity used in the winter period was not used either for direct transportation to the LDC or for storage refill during the seven-month summer period. The pipeline transportation demand charges during the summer for this 20% of unused capacity were allocated to the winter period in order to calculate avoided costs in AESC 2007.

The use of the long-haul transportation capacity in the winter varies from about 85% in February and March to 100% in December. In AESC 2007, the pipeline transportation demand charges, including the 20% from summer demand charges, were allocated to each of the five winter months according to the use of the capacity by month. As a result, the avoided transportation demand cost varied among the five winter months with the month of heaviest use, December, receiving the largest allocation of demand charges.

(h) Underground Storage

Natural gas is delivered to the LDC from underground storage during the five winter months of November through March as shown in the exhibit entitled 'Representative New England Local Gas Distribution Company Monthly Characteristics of Send-Out by Source, Peak Month and Storage Injection' 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 the exhibit above.

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, 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.[24]

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[24] 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,

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, 0.937 of the annual cost, because gas is purchased for injection during the summer months when the price of gas is less than average.

Since the demand charges for the withdrawal of gas from storage and transportation to the LDC are levied 12 months a year, the full year of those withdrawal and transportation demand charges were allocated to the five winter months.[25] Then these demand charges were allocated to each of the five winter months by the use of the capacity in each month. As shown in the exhibit entitled 'Representative New England Local Gas Distribution Company Monthly Characteristics of Send-Out by Source, Peak Month and Storage Injection' above, January is the peak send-out month; the other winter months, especially November and March experience less send-out. 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 were assigned to the cost of withdrawing and transporting gas to the LDC in January.

(i) LNG 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 peak shaving avoided costs are based only on LNG in AESC 2007. 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 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.

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.

[25] 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 5 winter months, and this fact is included in the AESC 2007 demand charges.

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,[26] and then the variable costs of liquefaction and re-gasification.[27] 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.

The estimated avoided cost of LNG peaking service is shown in the exhibit above. The avoided cost of LNG peaking service was materially different, much smaller, from that of AESC 2005, which spread the cost of 12 month storage service at the Distrigas LNG facility over the various winter periods. However, Distrigas no longer offers open access LNG storage service, and a public tariff and accompanying rates are not currently available.

(j) Peak-Day Avoided Cost

LNG peaking facilities are generally used to meet the peak-day requirements of a New England LDC. The fixed costs were excluded from the estimate of the avoided costs for the LNG facilities. This modest cost, which excludes fixed costs, did not properly capture the high avoided costs that were expected for peak day service.

Consequently, peak-day avoided costs were estimated based on the costs of underground storage. It was assumed 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 12 months.[28] Thus, in calculating the peak-day avoided cost the demand charges for all 12 months were allocated to the one-day peak. The estimate of peak-day avoided costs is shown in the above exhibit for both the TETCO-ALG and the TGP Z6 routes.

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 for the eight years prior to 2007 occurred on January 15, 2004.[29] During that day the spot price of gas in ALG was $63.42 per dekatherm, and the spot price at TGP Z6 was $49.81 per dekatherm. These prices are slightly more than one-half of the AESC 2007 estimates of peak-day avoided costs shown in the exhibit above and the two exhibits below, but they of the same general magnitude.

The peak-day avoided cost estimates in AESC 2007 for Southern New England and Northern and Central New England were slightly less than one-half of the peak-day

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[26] 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.

[27] 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.

[28] 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.

[29] NEGA Statistics 2006, page 59.

avoided cost estimates in AESC 2005.[30] AESC 2005 did not specify how the peak-day avoided cost was calculated. However, the spot gas prices in New England for the highest peak-day of the last 8 years supported the estimates of AESC 2007.

(k) Avoided Cost Forecast by Seasonal Cost Periods

In this step, the avoided costs of natural gas were determined by costing period 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 in this section. The avoided cost of natural gas by costing period was calculated as the average of the avoided cost in each of the months that comprise the costing period. As described earlier, the avoided cost in any month was 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 the exhibit entitled 'Representative New England Local Gas Distribution Company Monthly Characteristics of Send-Out by Source, Peak Month and Storage Injection' above.[31]

As was done in AESC 2005, it was assumed that the avoided cost in Southern New England was the cost of gas delivered to LDCs by the Texas Eastern and Algonquin pipeline route. Similarly, it was assumed 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 seasonal cost periods for Southern New England is shown in the first exhibit below. Also shown 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.

Similarly, the second exhibit below shows the avoided cost of natural gas delivered to LDCs in Northern and Central New England via the Tennessee Gas Pipeline.

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[30] AESC 2005 Exhibits 1-15 and 1-16, pages 35 and 36.

[31] The summer periods all fall within a single calendar year; thus, the commodity cost of gas is based on the Henry Hub price for that calendar year. However, the winter periods 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 is based on the Henry Hub price from the year in which the winter delivery period begins.

Exhibit 2-14. Avoided Costs of Gas Delivered to LDCs via Texas Eastern and ALG Pipelines by Season and Cost Period (2007$/dekatherm)

		WINTER				SUMMER					
Year	Peak Day	3 Months Dec-Feb	5 Months Nov-Mar	6 Months Nov-Apr	7 Months Oct-Apr	5 Months May-Sep	6 Months May-Oct	7 Months Apr-Oct	9 Months Mar-Nov	Annual Average	Annual Henry Hub Price
2007	110.87	10.28	10.05	9.68	9.47	7.91	7.95	7.94	8.33	8.82	7.71
2008	111.88	11.37	11.13	10.74	10.51	8.86	8.91	8.90	9.31	9.82	8.65
2009	111.35	10.80	10.56	10.18	9.97	8.36	8.41	8.39	8.80	9.30	8.16
2010	110.79	10.20	9.97	9.60	9.39	7.84	7.88	7.87	8.26	8.74	7.65
2011	110.31	9.68	9.46	9.10	8.89	7.38	7.43	7.41	7.79	8.26	7.20
2012	109.95	9.29	9.07	8.72	8.52	7.04	7.08	7.07	7.44	7.90	6.86
2013	109.28	8.58	8.36	8.02	7.83	6.41	6.45	6.44	6.79	7.24	6.24
2014	109.34	8.64	8.42	8.09	7.89	6.47	6.51	6.50	6.85	7.30	6.30
2015	109.29	8.59	8.37	8.04	7.84	6.42	6.46	6.45	6.80	7.25	6.25
2016	109.44	8.75	8.53	8.19	7.99	6.56	6.60	6.59	6.95	7.40	6.39
2017	109.70	9.03	8.81	8.47	8.27	6.81	6.85	6.84	7.20	7.66	6.64
2018	109.62	8.94	8.72	8.38	8.18	6.73	6.77	6.76	7.12	7.58	6.56
2019	109.58	8.89	8.67	8.33	8.13	6.69	6.73	6.72	7.08	7.53	6.52
2020	109.70	9.03	8.81	8.47	8.26	6.81	6.85	6.84	7.20	7.66	6.63
2021	109.81	9.15	8.92	8.58	8.38	6.91	6.95	6.94	7.31	7.77	6.73
2022	110.08	9.43	9.21	8.86	8.65	7.16	7.21	7.19	7.57	8.03	6.98
Levelized (a)	110.11	9.47	9.25	8.90	8.69	7.20	7.24	7.23	7.60	8.07	7.02

(a) 2.2165%

Exhibit 2-15. Avoided Costs of Gas Delivered to LDCs via TGP Z6 Pipeline by Season and Cost Period (2007$/dekatherm)

		WINTER				SUMMER					
Year	Peak Day	3 Months Dec-Feb	5 Months Nov-Mar	6 Months Nov-Apr	7 Months Oct-Apr	5 Months May-Sep	6 Months May-Oct	7 Months Apr-Oct	9 Months Mar-Nov	Annual Average	Annual Henry Hub Price
2007	93.49	9.89	9.71	9.40	9.22	7.88	7.92	7.91	8.25	8.66	7.71
2008	94.45	10.96	10.77	10.44	10.25	8.82	8.87	8.85	9.22	9.65	8.65
2009	93.95	10.40	10.22	9.89	9.71	8.32	8.37	8.36	8.71	9.13	8.16
2010	93.42	9.81	9.64	9.32	9.15	7.81	7.86	7.84	8.18	8.59	7.65
2011	92.96	9.31	9.13	8.83	8.65	7.36	7.40	7.39	7.72	8.12	7.20
2012	92.62	8.92	8.75	8.45	8.28	7.02	7.06	7.05	7.37	7.76	6.86
2013	91.98	8.22	8.05	7.77	7.60	6.40	6.44	6.43	6.73	7.10	6.24
2014	92.04	8.28	8.11	7.83	7.67	6.46	6.50	6.49	6.79	7.16	6.30
2015	91.99	8.23	8.06	7.78	7.62	6.41	6.45	6.44	6.74	7.12	6.25
2016	92.13	8.39	8.22	7.93	7.77	6.55	6.59	6.58	6.88	7.26	6.39
2017	92.39	8.67	8.49	8.20	8.04	6.80	6.84	6.82	7.14	7.52	6.64
2018	92.31	8.58	8.41	8.12	7.95	6.72	6.76	6.75	7.06	7.44	6.56
2019	92.26	8.53	8.36	8.07	7.91	6.68	6.72	6.70	7.01	7.39	6.52
2020	92.38	8.67	8.49	8.20	8.03	6.80	6.84	6.82	7.14	7.52	6.63
2021	92.49	8.78	8.61	8.31	8.15	6.90	6.94	6.92	7.24	7.62	6.73
2022	92.74	9.06	8.89	8.59	8.42	7.14	7.19	7.17	7.50	7.89	6.98
Levelized	92.78	9.10	8.92	8.62	8.45	7.18	7.22	7.21	7.53	7.92	7.02

(a) 2.2165%

The levelized avoided cost is the cost for which the present value at the real risk less rate of return of 2.2165 percent has the same present value as the estimated avoided costs for the years 2007 through 2022 at the same rate of return.

(I) Comparison with the AESC 2005 Avoided Cost Calculations for a LDC

The avoided cost calculations in the two exhibits above were generally higher for the summer periods since the Henry Hub price of gas was higher than in AESC 2005.[32] For the winter periods, the avoided cost estimates were lower than those in AESC 2005 because less of the summer period (April – October) demand charges were allocated to the winter period (November – March). 20% of the summer period demand charges were allocated to the winter period because the remaining 80% of the capacity was used for long-haul transportation to the LDC or to refill storage. In contrast, AESC 2005 allocated twelve months of long-haul pipeline transportation demand charges (that is, 100% of the summer period demand costs and in the case of the 3-month, December – February, cost period, 100% of the November and March pipeline demand costs were also allocated to it) to each of the winter cost periods in computing avoided long-haul transportation costs.

The exhibit below compares the avoided cost estimates for the three sources of natural gas used by AESC 2005 and AESC 2007: pipeline long-haul, underground storage, and LNG peaking supply during the three-month winter period (December – February) as well as peak day supply. 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.

[32] See AESC 2005 Exhibit 1-15 to compare with Exhibit 3-5 for the TETCO AGT route and AESC 2005 Exhibit 1-16 to compare with Exhibit 3-6 for the TGP route.

Exhibit 2-16. Comparison of AESC 2005 and AESC 2007 Costs of Delivering One Dekatherm of Gas to a New England Local Distribution Company via the TETCO – ALG Route December-February from Three Sources of Natural Gas and Peak Day

	units	AESC 2005	AESC 2007
Pipeline Long-haul to LDC			
Pipeline Demand Cost	2007$/DT	$2.772	$0.866
Pipeline Variable Cash Cost	2007$/DT	$0.096	$0.072
Ratio of Gas Purchased at HH to Gas Delivered	fraction	1.095	1.113
Delivered From Underground Storage			
Pipeline Demand Cost	2007$/DT	$0.886	$0.953
Pipeline Variable Cash Cost (a)	2007$/DT	$0.000	$0.832
Ratio of Gas Purchased at HH to Gas Delivered	fraction	1.000	1.149
LNG Regasified into LDC System			
Pipeline Demand Cost	2007$/DT	$8.693	
Pipeline Variable Cash Cost (a)	2007$/DT	$0.000	$0.899
Ratio of Gas Purchased at HH to Gas Delivered	fraction	1.000	1.349
Peak Day			
Pipeline Demand Cost	2007$/DT	$260.521	$101.727
Pipeline Variable Cash Cost (a)	2007$/DT		$0.832
Ratio of Gas Purchased at HH to Gas Delivered	fraction		1.149

Source: AESC 2005 TETCO and AGT charges taken from Exhibit 1-14a, Monthly Pipeline Costs, page 34.
AESC 2005 peak day costs from Exhibit 1-15, page 35.
Note: Conversion from 2004$ and 2005$ to 2007$ used conversion factors of 1.0867 and 1.0547 respectively.
Note: Ratio of gas purchased at Henry Hub to Gas Delivered to the LDC for AESC 2005 is the stated fuel and loss retention plus one (1), which is consistent with the calculations in the AESC 2005 worksheets.
(a) In AESC 2007 the pipeline variable cash costs include pipeline demand charges for refill of storage, but not the demand costs for delivery to the LDC from underground storage.

AESC 2005 estimated the demand cost of long-haul pipeline transportation at more than three times that shown for AESC 2007; due, as mentioned above, to the allocation of twelve months of demand charges to the cost period. However, AESC 2007 had a higher fuel and loss retention ratio.

The AESC 2005 underground storage cost estimates were much lower because they did not fully include the cost of transportation to and from underground storage. Similarly, AESC 2005 had no fuel retention for underground storage on TETCO while AESC 2007 had a large fuel and loss retention due to including transportation and the compounding effect upon total fuel and loss retention of the gas moving from one rate schedule to another as it is transported to and from storage and also injected and withdrawn from underground storage.

The cost estimate for LNG peaking in AESC 2007 was much lower than that in AESC 2005 because AESC 2007 only considered the variable costs of LDC LNG facilities as being avoidable and AESC 2005 used a tariff of Distrigas LNG storage as the basis of its estimate. However, Distrigas no longer offers any open access LNG storage service with a published tariff.

Finally, AESC 2007 presented an avoided cost estimate of peak-day gas supply which is large but about one-half that in AESC 2005.

(m) Avoided Costs by End-Use

The avoided costs to an LDC by seasonal costing periods have been presented in the exhibit above. The end-use avoided costs are provided in the exhibit below, which shows the cross walk of end uses to the seasonal cost periods.

Exhibit 2-17. End-Use Consumption Avoidable Cost Cross Walk

End-Use Types	Period	Months
Commercial and Industrial, non-heating	Annual	Jan – Dec
Commercial and industrial, heating	5 month	Nov – Mar
Existing residential heating	3 month	Dec – Feb
New residential heating	5 month	Nov – Mar
Residential domestic hot water	Annual	Jan – Dec
All commercial and industrial	6 month	Nov – Apr
All residential	6 month	Nov – Apr
All retail end uses	5 month	Nov – Mar

This cross walk exhibit is the same as presented in AESC 2005. There may be a difference in the way the 6-month winter period was defined. The AESC 2005 report did not specify the months of each of its winter periods; however, it was confirmed that the 6-month period in AESC 2005 was October through March. This analysis followed the approach of specifying each of the winter periods as including the coldest months in that period or the months of highest gas send-out. In New England, April is a colder month than October as measured by heating degree-days and April has a greater send-out than October. Consequently, April was included and October was excluded in the 6-month winter period.

(n) Avoided Gas Costs for Each End Use Sector

The Scope of Work for this project specifies that the sponsoring gas utilities will provide distribution charges applicable from the city gate to the burner tip in the defined regions (presumably Southern New England, Rhode Island and Connecticut; and Northern New England, Massachusetts, New Hampshire and Maine) that will be added to the LDC avoided costs to compute the end-use avoided costs.

Some LDCs in New England have performed studies of incremental costs, that is, the cost of distribution which is incurred as demand increases. The conclusion was that the incremental cost of distribution was approximately one-half of the embedded cost. This was the same assumption employed in AESC 2005. As in AESC 2005 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.[33]

The exhibit below shows the estimated avoidable LDC costs, measured as 2007$ per dekatherm, by each of the customer end-use types and combination of types listed in the exhibit above.

Exhibit 2-18. Estimated Avoidable LDC Margins 2001-2005 Average (2007$/dekatherm)

	Southern NE	**Northern and Central NE**
Average City Gate 2001-05	7.82	8.05
Ave. Residential Margin	6.28	5.98
Avoidable	**3.14**	**2.99**
Ave. Commercial Margin	3.08	4.46
Avoidable	**1.54**	**2.23**
Ave. Industrial Margin	0.70	3.20
Avoidable	**0.35**	**1.60**
Ave. Commercial and Industrial	2.21	3.83
Avoidable	**1.11**	**1.92**
All retail avoidable margin	**2.00**	**2.41**

The exhibit below shows the total avoided costs by the various retail end-use types and combination of types for Southern New England. The avoided cost for each retail end-use type is the sum of the avoided cost of gas delivered to an LDC for the cost period associated with the end-use type plus the avoided LDC margin for the associated end-use type as shown in the exhibit above.

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

Exhibit 2-19. Avoided Costs of Gas Delivered to Retail Customers in Southern New England via Texas Eastern and ALG Pipelines by End Use (2007$/dekatherm)

	RESIDENTIAL				COMMERCIAL & INDUSTRIAL			ALL RETAIL
	Existing Heating	New Heating	Hot Water	All	Non Heating	Heating	All	
Year	3-mon.	5-mon.	annual	6-mon.	annual	5-mon.	6-mon.	5-mon.
2007	13.42	13.19	11.96	12.82	9.92	11.16	10.79	12.04
2008	14.51	14.27	12.96	13.88	10.93	12.23	11.84	13.12
2009	13.94	13.70	12.44	13.32	10.40	11.67	11.29	12.56
2010	13.34	13.11	11.88	12.74	9.85	11.08	10.71	11.97
2011	12.82	12.60	11.40	12.24	9.37	10.56	10.21	11.45
2012	12.43	12.21	11.04	11.86	9.01	10.17	9.83	11.06
2013	11.71	11.50	10.38	11.16	8.34	9.46	9.13	10.35
2014	11.78	11.56	10.44	11.23	8.41	9.53	9.20	10.42
2015	11.73	11.51	10.39	11.18	8.36	9.48	9.14	10.37
2016	11.89	11.67	10.53	11.33	8.50	9.63	9.30	10.52
2017	12.17	11.95	10.80	11.61	8.77	9.92	9.57	10.81
2018	12.08	11.86	10.72	11.52	8.69	9.83	9.49	10.72
2019	12.03	11.81	10.67	11.47	8.64	9.78	9.44	10.67
2020	12.17	11.95	10.80	11.61	8.76	9.91	9.57	10.80
2021	12.29	12.06	10.91	11.72	8.87	10.03	9.69	10.92
2022	12.57	12.35	11.17	12.00	9.14	10.32	9.97	11.20
Levelized (a)	12.61	12.39	11.21	12.03	9.17	10.35	10.00	11.24

(a) Real (constant $) riskless annual rate of return in %: 2.2165%

The exhibit below shows the total avoided cost by the various retail end-use types for Northern and Central New England. The avoided cost is the sum of the avoided cost of gas delivered to an LDC in Northern and Central New England plus the associated avoided LDC margin shown in the exhibit entitled ‘Estimated Avoidable LDC Margins 2001-2005 Average’ above.

Exhibit 2-20. Avoided Costs of Gas Delivered to Retail Customers in Northern & Central New England via the TGP Z6 Pipeline by End Use (2007$/dekatherm)

Exhibit 3-11
AVOIDED COSTS OF GAS DELIVERED TO RETAIL CUSTOMERS
Northern & Central New England BY END USE
Gas Delivered via Tennessee Gas Pipeline
(2007$/Dekatherm)

	RESIDENTIAL				COMMERCIAL & INDUSTRIAL			ALL RETAIL
Year	Existing Heating 3-mon.	New Heating 5-mon.	Hot Water annual	All 6-mon.	Non Heating annual	Heating 5-mon.	All 6-mon.	5-mon.
2007	12.88	12.71	11.65	12.39	10.58	11.63	11.32	12.12
2008	13.95	13.77	12.65	13.43	11.57	12.69	12.35	13.18
2009	13.39	13.21	12.13	12.88	11.05	12.14	11.81	12.63
2010	12.81	12.63	11.58	12.31	10.51	11.55	11.24	12.04
2011	12.30	12.12	11.11	11.82	10.03	11.05	10.74	11.54
2012	11.92	11.74	10.75	11.44	9.68	10.67	10.37	11.16
2013	11.21	11.04	10.10	10.76	9.02	9.97	9.68	10.46
2014	11.28	11.11	10.16	10.82	9.08	10.03	9.75	10.52
2015	11.23	11.06	10.11	10.77	9.03	9.98	9.70	10.47
2016	11.38	11.21	10.25	10.92	9.18	10.13	9.85	10.62
2017	11.66	11.49	10.51	11.20	9.44	10.41	10.12	10.90
2018	11.57	11.40	10.43	11.11	9.36	10.33	10.04	10.82
2019	11.52	11.35	10.39	11.06	9.31	10.28	9.99	10.77
2020	11.66	11.49	10.51	11.19	9.44	10.41	10.12	10.90
2021	11.77	11.60	10.62	11.30	9.54	10.52	10.23	11.01
2022	12.05	11.88	10.88	11.58	9.80	10.81	10.51	11.30
Levelized	12.09	11.92	10.91	11.62	9.84	10.84	10.54	11.33
(a)					2.2165%			

ii. Avoided Gas Costs in Vermont

There is one LDC in Vermont, Vermont Gas Systems (VGS), which receives its gas from TransCanada Pipeline at Highgate Springs, VT. The analysis of the avoided cost to the LDC in Vermont was performed similarly to the analysis above. Based on a Purchased Gas Adjustment (PGA) filing by VGS for the year April 2007 to March 2008, the source of gas was determined for each month of the year by the fraction contribution each month, computed the marginal cost of natural gas to VGS by source for each month the source is in operation and then averaged the cost by month and by specified cost period.

Each month, Vermont receives gas purchased in Alberta 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.

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 next two years.[34] NYMEX shows a constant basis differential for the winter, November through March,

[34] NYMEX settlements for 18 May 2007 using basis data from the period November 2007 through October 2009

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 0.851 for the winter and 0.895 for the summer.

The pipeline transportation rates, rates for underground storage and transporting gas to VGS from underground storage, which are used in the avoided cost forecasts, are shown in the exhibit below. It was assumed that these rates would prevail throughout the forecast period.

Exhibit 2-21. Canadian Tolls Paid by Vermont Gas Systems (US 2007$)

	Demand (a) $/DT/Month	Usage $/DT	Fuel & Loss percent
Firm Transportation			
Long-Haul	$26.7991	$0.0670 (b)	5.00% (c)
From Storage	$6.6080	$0.0130 (b)	1.00% (c)
Storage			
Injection		$0.0058 (d)	0.60% (d)
Space	$0.0403		
Withdrawal	$4.7789	$0.0058 (d)	0.60% (d)

(a) Imputed from Vermont Gas Systems PGA filing
(b) TransCanada Approved Tolls effective April 1, 2007
(c) TransCanada Website; estimated. Fuel is actual and changes each month.
(d) Union Gas Rate M12 effective January 1, 2007.
Note: US$/DT is calculated as .96116 of CD$/GJ

Based on the VGS PGA filing, as in other New England LDCs, long-haul transportation was used at about 80 percent load factor in the summer months for refilling underground storage and direct deliveries of gas to VGS. Thus, 20% of summer pipeline demand charges were allocated to the winter long-haul pipeline transportation avoidable costs. The costs of underground storage included 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 PGA filing demand charges are paid 12 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 5 months of demand charges.) Purchases of gas in the spot market made up slightly more than 20% of the Vermont winter gas supply. The price of these spot purchases were estimated by the ratio of the estimated spot price for the October 2007 – March 2008 winter months to the 2007 annual Henry Hub gas price. The components of the avoided costs by the three sources of gas to Vermont are shown in the exhibit below.

Exhibit 2-22. Comparison of Costs of Delivering One Dekatherm of Gas to Vermont Gas Systems from Three Sources of Natural Gas and Peak Day

		TransCanada Pipeline	
	units	January	June
Pipeline Long-haul to LDC			
Pipeline DemandCost of Gas Delivered to LDC	2007 $/DT	$1.13	$0.00
Pipeline Usage Cost	2008 $/DT	$0.07	$0.07
Ratio of Gas Purchased in Alberta to Gas Delivered to LDC		1.053	1.053
Delivered From Underground Storage			
Pipeline Demand Cost of Gas Delivered to LDC	2007 $/DT	$1.98	
Pipeline Commocity Cost of Gas Delivered to LDC		$1.49	
Ratio of Gas Purchased to Gas Delivered to LDC		1.076	
Spot Purchases of Gas based on 2007 Henry Hub Price	2007$/DT	$9.49	
Peak Day in January From Underground Storage			
Pipeline Cash Demand Cost of Gas Delivered to LDC	2007 $/DT	$137.22	
Pipeline Cash Commodity Cost of Gas Delivered to LDC	2007 $/DT	$1.49	
Ratio of Gas Purchased at HH to Gas Delivered to LDC		1.076	

Based on pipeline rates effective April 1, 2007
Note: Fuel and Loss retention is estimated as an annual average.

AESC 2007 then estimated the avoided cost of natural gas delivered to VGS by month for the forecast period and summarized the avoided costs by cost period and year as shown in the exhibit below.

Exhibit 2-23. Avoided Costs of Gas Delivered to Vermont LDC via the TransCanada Pipeline by Season and Cost Period (2007$/dekatherm)

	WINTER					SUMMER					
Year	Peak Day	3 Months Dec-Feb	5 Months Nov-Mar	6 Months Nov-Apr	7 Months Oct-Apr	5 Months May-Sep	6 Months May-Oct	7 Months Apr-Oct	9 Months Mar-Nov	Annual Average	Annual Henry Hub Price
2007	145.66	9.25	9.01	8.64	8.42	6.86	6.90	6.89	7.28	7.77	7.71
2008	146.50	10.20	9.95	9.56	9.33	7.69	7.73	7.72	8.13	8.65	8.65
2009	146.06	9.70	9.46	9.08	8.86	7.25	7.30	7.28	7.68	8.19	8.16
2010	145.59	9.18	8.94	8.57	8.36	6.80	6.84	6.83	7.22	7.71	7.65
2011	145.19	8.73	8.49	8.14	7.92	6.41	6.44	6.43	6.81	7.29	7.20
2012	144.89	8.39	8.16	7.81	7.60	6.11	6.14	6.13	6.50	6.98	6.86
2013	144.33	7.76	7.54	7.20	7.00	5.56	5.60	5.59	5.94	6.40	6.24
2014	144.38	7.82	7.59	7.26	7.05	5.61	5.65	5.64	6.00	6.45	6.30
2015	144.34	7.78	7.55	7.21	7.01	5.57	5.61	5.60	5.95	6.41	6.25
2016	144.46	7.91	7.68	7.35	7.14	5.69	5.73	5.72	6.08	6.54	6.39
2017	144.68	8.16	7.93	7.59	7.38	5.91	5.94	5.93	6.30	6.77	6.64
2018	144.62	8.08	7.86	7.51	7.30	5.84	5.88	5.87	6.23	6.70	6.56
2019	144.58	8.04	7.81	7.47	7.26	5.80	5.84	5.83	6.19	6.65	6.52
2020	144.68	8.16	7.93	7.58	7.38	5.91	5.94	5.93	6.30	6.76	6.63
2021	144.77	8.26	8.03	7.68	7.47	6.00	6.03	6.02	6.39	6.86	6.73
2022	145.00	8.51	8.28	7.93	7.71	6.22	6.25	6.24	6.62	7.09	6.98
Levelized	145.03	8.55	8.31	7.96	7.75	6.24	6.28	6.27	6.65	7.12	7.02

(a) 2.2165%

As in the other LDCs of New England the avoided retail cost of gas was also estimated for VGS. The retail avoided cost is the LDC avoided cost plus the LDC avoided margin. As in the other LDCs the LDC avoided margin was estimated as one-half the embedded LDC cost as shown in the exhibit below.

Exhibit 2-24. Estimated Avoidable LDC Margins for Vermont 2001-2005 Average (2007$/dekatherm)

Average City Gate 2001-05	5.80
Ave. Residential Margin	5.78
Avoidable	**2.89**
Ave. Commercial Margin	3.37
Avoidable	**1.68**
Ave. Industrial Margin	0.23
Avoidable	**0.11**
Ave. Commercial and Industrial	1.77
Avoidable	**0.88**
All retail avoidable margin	**1.64**

The avoided costs to the specified retail customer types are shown in the exhibit below.

Exhibit 2-25. Avoided Costs of Gas Delivered to Retail Customers in Vermont via the TransCanada Pipeline by End Use (2007$/dekatherm)

	RESIDENTIAL				COMMERCIAL & INDUSTRIAL			ALL RETAIL
Year	Existing Heating 3-mon.	New Heating 5-mon.	Hot Water annual	All 6-mon.	Non Heating annual	Heating 5-mon.	All 6-mon.	5-mon.
2007	12.14	11.90	10.66	11.53	8.65	9.89	9.52	10.65
2008	13.09	12.84	11.54	12.45	9.53	10.83	10.44	11.58
2009	12.59	12.35	11.08	11.97	9.07	10.34	9.96	11.09
2010	12.07	11.83	10.60	11.47	8.59	9.82	9.46	10.58
2011	11.62	11.38	10.18	11.03	8.17	9.38	9.02	10.13
2012	11.28	11.05	9.87	10.70	7.86	9.04	8.69	9.79
2013	10.65	10.43	9.29	10.09	7.28	8.42	8.08	9.17
2014	10.71	10.49	9.34	10.15	7.33	8.48	8.14	9.23
2015	10.67	10.44	9.30	10.10	7.29	8.43	8.10	9.19
2016	10.80	10.58	9.43	10.24	7.42	8.57	8.23	9.32
2017	11.05	10.82	9.66	10.48	7.65	8.81	8.47	9.57
2018	10.98	10.75	9.59	10.40	7.58	8.74	8.40	9.49
2019	10.93	10.70	9.55	10.36	7.54	8.69	8.35	9.45
2020	11.05	10.82	9.66	10.48	7.65	8.81	8.47	9.57
2021	11.15	10.92	9.75	10.57	7.74	8.91	8.57	9.67
2022	11.40	11.17	9.98	10.82	7.97	9.16	8.81	9.92
Levelized (a)	11.44	11.20	10.01	10.85	8.00	9.19	8.84	9.95

(a) Real (constant $) riskless annual rate of return in %: 2.2165%

The levelized avoided retail costs in Vermont for AESC 2005 and AESC 2007 were compared in the exhibit below. AESC 2005 did not present the avoided gas costs to the LDC in Vermont or the LDC margins. Thus, a detailed explanation of the differences of the two forecasts was difficult. Two possible differences were: (1) the more detailed, and probably higher, pipeline transportation and storage cost estimates in AESC 2007 compared with AESC 2005 and (2) what may be quite different estimates of LDC margins.

Exhibit 2-26. Comparison of AESC 2005 and AESC 2007 Levelized Avoided Costs of Gas Delivered to Retail Customers in Vermont by End Use (2007$/dekatherm)

	RESIDENTIAL				COMMERCIAL & INDUSTRIAL			ALL RETAIL
	Existing Heating 3-mon.	New Heating 5-mon.	Hot Water annual	All 6-mon.	Non Heating annual	Heating 5-mon.	All 6-mon.	5-mon.
AESC 2005 (a)	$10.21	$10.14	$10.04	$10.13	$8.95	$9.04	$9.00	$9.62
AESC 2007	$11.44	$11.20	$10.01	$10.85	$8.00	$9.19	$8.84	$9.95
Percent difference 2005 to 2007	12.0%	10.5%	-0.3%	7.2%	-10.6%	1.7%	-1.7%	3.4%

Source of AESC 2005 levelized retail avoided costs in Vermont is Exhibit 3-29, page 39.

(a) Factor to convert 2005$ to 2007 $ 1.0547

Note: AESC 2005 levelized costs over the years 2005 - 2025. AESC 2007 levelized costs over the years 2007 - 2022.

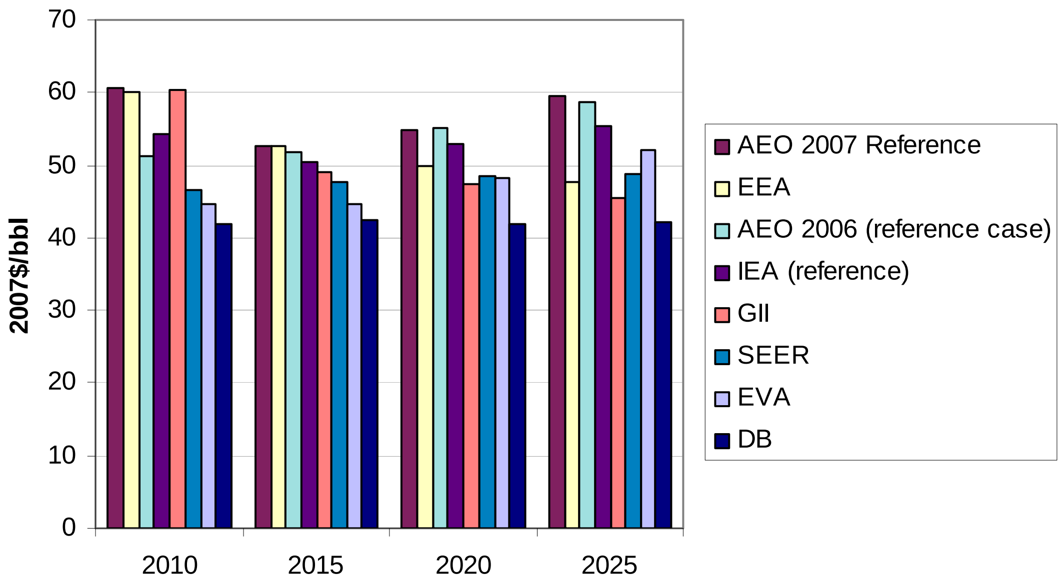
3. Crude Oil Price Forecast

This Chapter provides a projection of crude oil prices.

A. Methodology & Assumptions

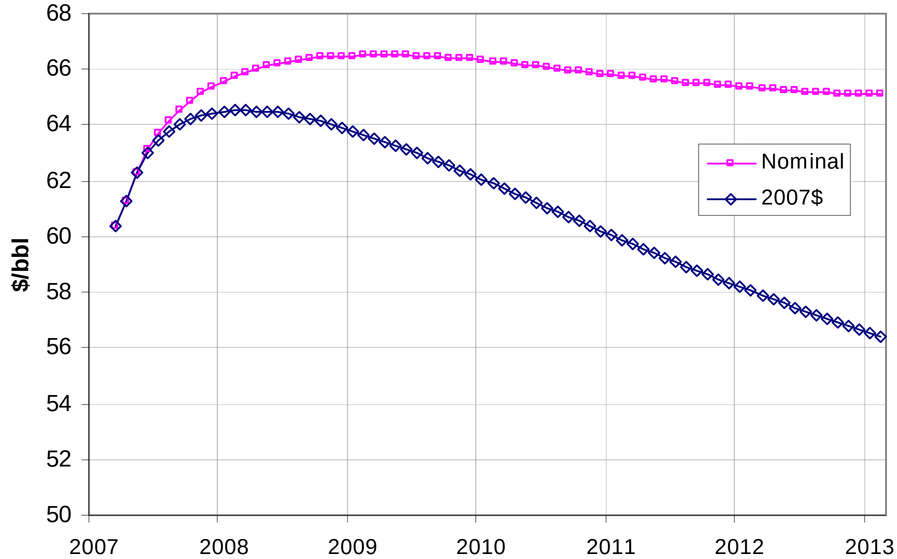
The starting point for the crude oil price forecast was the Reference Case forecast in the Energy Information Administration (EIA) Annual Energy Outlook 2007 (AEO 2007). The exhibit below shows that the AEO 2007 Reference Case forecast of low sulfur light crude oil prices through 2020 is close to, but slightly higher than, the projections from a number of other sources. Due to expectations of continued growth in world oil consumption and projected continuation of high costs of developing new reserves, the AEO 2007 Reference Case forecast of crude oil provides a good starting point for this forecast.

Exhibit 3-1. World Crude Oil Price Forecasts (2007$/bbl)



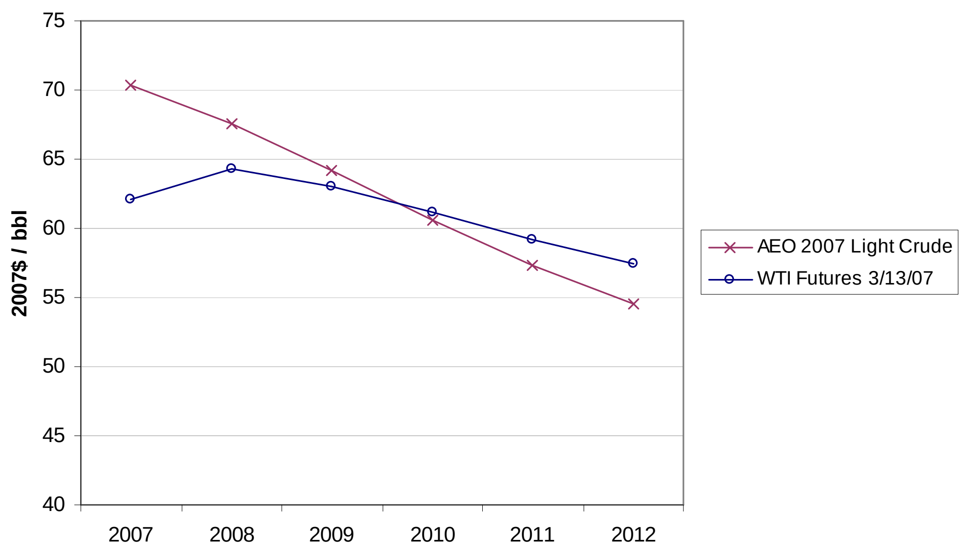
As a first step, the AEO 2007 near term prices were compared with those from the futures markets. West Texas Intermediate (WTI) crude was the futures price that was used since it is actively traded and the price in the past has been very close to that of the low-sulfur light crude used in the AEO 2007 Reference Case. The futures prices were very stable in nominal dollars for 2008 through 2012 at around $66/bbl, as shown in the exhibit below.

Exhibit 3-2. West Texas Intermediate (WTI) Crude Future Swap Prices (2007$/bbl)



By comparison, the AEO 2007 oil forecast prices for 2007 through 2009 were 14% to 3% higher than the equivalent futures prices as of mid-March 2007, as presented in the exhibit below.[35] This discrepancy was attributable to changes in the market perspectives between late 2006, when the AEO 2007 analysis was prepared, and the current outlook for crude oil.

Exhibit 3-3. Oil Price Forecast Comparison (2007$/bbl)



Taking this discrepancy into account, the forecast of crude oil prices reflects futures prices in the short term (2007-2012) and the AEO 2007 forecast in the long-term (2013-

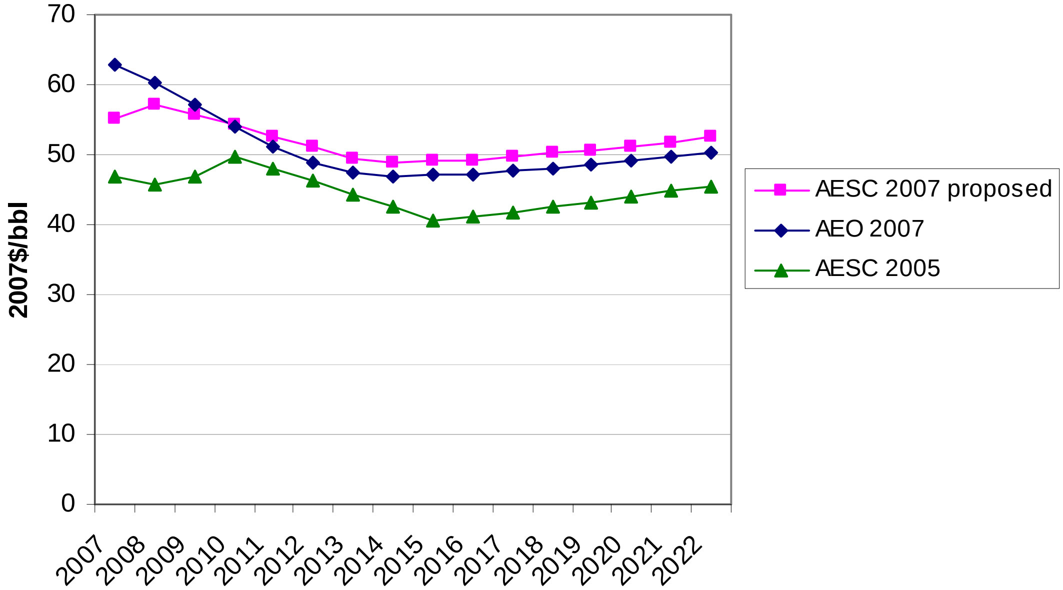
[35] NYMEX ClearPort market prices as of 3/13/07.

2022). As with the natural gas forecast, it was reasonable to adjust the near term forecast to represent current market conditions, but for the longer term use one more based on fundamentals. This adjustment followed the futures prices out through 2012 which were above the AEO price, and then followed the trend of the AEO forecast.

B. Results

The graph below presents the crude oil price forecast relative to the AEO 2007 Reference Case forecast and to the AESC 2005 forecast. Both the AESC 2005 and the AESC 2007 forecasts were at a low point around 2015 and rose slowly thereafter.

Exhibit 3-4. Price Forecast of Imported Crude Oil Price (2007$/bbl)



4. Forecasts of Other Fuel Prices

This chapter provides a projection of fuel prices for electric generation as well as for retail end-use sector (Deliverable 4 and 9)

A. Methodology & Assumptions

The starting point for the forecasts of other types of fuel oil, coal, and fuel wood prices was the Reference Case forecast in the Energy Information Administration (EIA) Annual Energy Outlook 2007 (AEO 2007). The Reference Case forecast of AEO 2007 provides forecasts for prices of residual fuel, distillate fuel and coal used to generate electricity in New England. This forecast also provides projections of petroleum product prices for the residential, commercial and industrial sectors in New England.

The AESC 2007 forecasts of petroleum product prices were derived by adjusting the AEO petroleum product prices in proportion to the difference between the AEO crude oil and the AESC 2007 crude oil forecasts. This adjustment was made because petroleum product prices strongly reflect underlying crude oil prices. The AEO coal price forecasts were not adjusted.

To identify locational differences we analyzed the actual prices by sector by state from 1970 through 2004, which was the most recent historical data available from the EIA State Energy Data System (SEDS).[36] SEDS is the most complete and consistent source of state-level energy prices. This review did not show consistent price differences between states for most products. There were two possible exceptions. One was for distillate fuel in NH which for the last ten years has been about 6% below the NE average. The other was for residential prices for LPG which has been about 10% below the NE average for NH & VT, whereas for RI they have been about 15% above the average. For commercial and industrial users the differences are much smaller and vary positive and negative from year to year. For years before 1995, the residential price differences between states were negligible and the relative rankings varied from year to year. Thus, the more recent retail locational price differences appear to be related to changes in the markups associated with competitive factors in the residential marketing and distribution systems in the various states. These differentials may or not persist in the future. For this study, it was assumed that because of fundamentals, the end-use prices for all petroleum products across New England will be roughly the same. Thus, a single New England price by sector for the various oil-based products was recommended.[37]

The SEDS data for the five years 1999-2003 was also used to analyze the markups between petroleum product prices and crude oil prices. This analysis showed that the

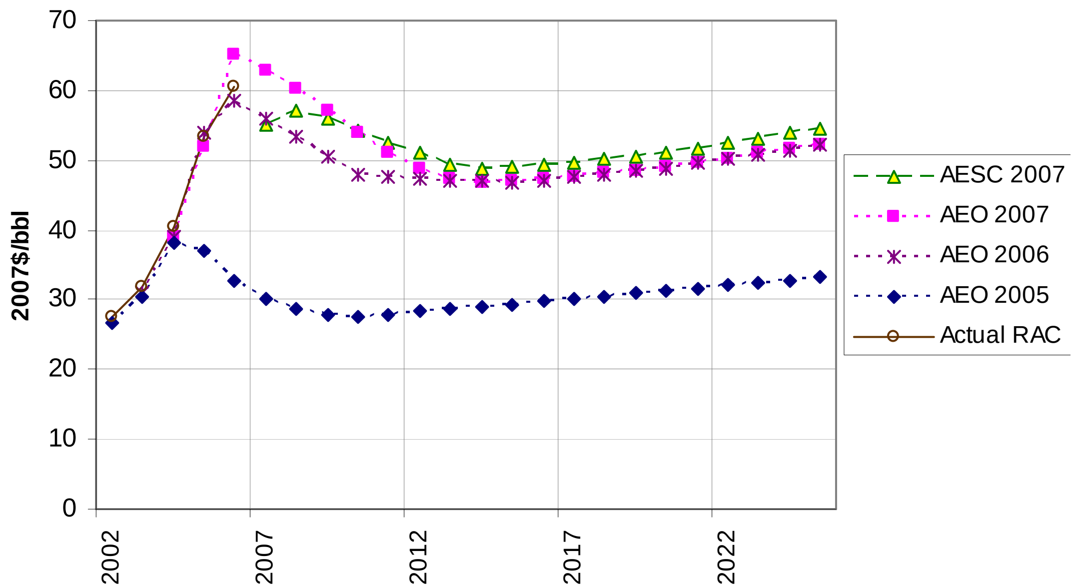
[36] http://www.eia.doe.gov/emeu/states/_seds.html

[37] The AESC 2005 report had no differences in LPG costs between parts of NE. That report did have differences in distillate oil prices that are not reflected in our analysis of the historic data.

markups had both fixed and variable components. However, the underlying crude oil prices (in real terms) for the forecast period are about twice the historic ones. Therefore, caution is appropriate when extending historic markups from a limited period to a longer future period with much higher base prices. Thus for the AESC forecasts, the AEO product vs. crude markup ratios were used to calculate future petroleum product prices relative to the cost of crude oil.

EIA forecasts have reflected the recent sharp increase in oil prices.[38] For example, the forecasts of oil prices in 2020 increased by 54% from 2005 to 2006, but are essentially unchanged in the latest AEO. These forecasts along with the actual Refiners Acquisition Cost (RAC) for 2002 through 2006 are shown in the figure below. Note the AEO 2007 estimate for 2006 was a little above the actual RAC.

Exhibit 4-2. Crude Oil Price Forecast Comparisons (2007$/bbl)



Since crude oil prices do not show a monthly/seasonal variation but rather reflect the world market, neither monthly nor seasonal price variations for petroleum products were developed. Seasonal demand for petroleum products is fairly predictable and storage for petroleum products is relatively inexpensive, which tends to smooth out variations in costs relative to market prices. Price variations can also be hedged with futures contracts and the like.

i. No. 6 Residual Fuel Oil Price Forecast

The AEO price forecast for residual oil was half the price of crude oil on a per Btu basis. While residual oil, especially high sulfur, typically sells below the price of crude oil, a

38 Crude oil products were not defined the same way in the four studies, but we have adjusted them to be comparable. AEO 2005 reported the World Oil Price. The AEO 2007 nearest equivalent was called Imported Crude Oil. The AESC 2007 price represents a conversion to the AEO 2007 Imported Crude equivalent. The AESC 2005 price was identified as the Refiners Acquisition Cost (RAC).

50% differential was not supported by any available market data. In looking at the historic ratio of residual oil to crude oil prices for the period 1992 through 2006, the high sulfur residual ratio is closer to 70%. Therefore, the price of residual oil for electric generation was calculated based on the historic price ratio.

ii. No. 2 Distillate Fuel Oil Price Forecast

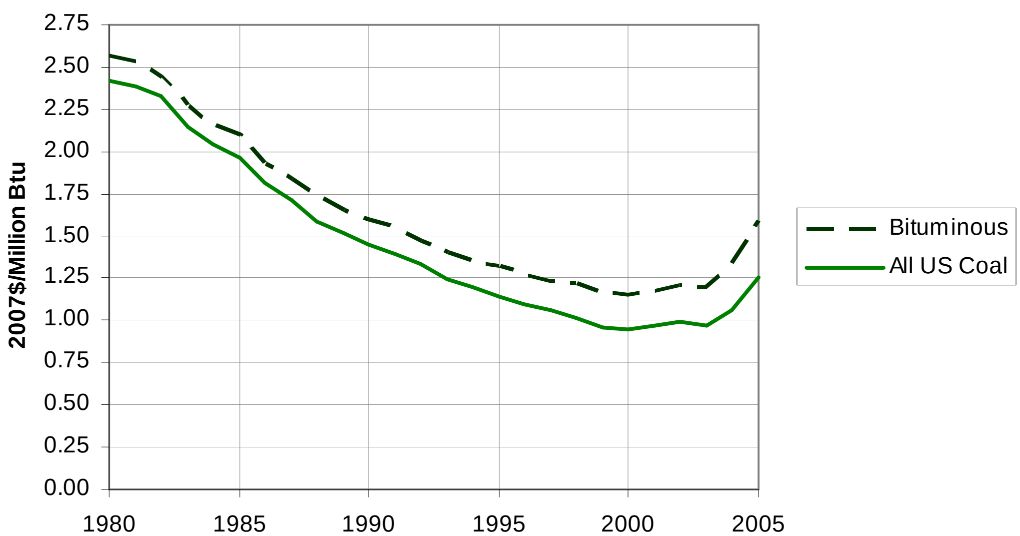
The AEO forecast price for distillate fuel falls below the forecast price for crude oil in about 2015. This was not credible. Therefore, a price for distillate oil was developed based on its recent historic ratio to the crude oil price.

iii. Coal Price Forecast

The AEO 2007 Reference Case forecasts fairly flat prices for coal in New England with a slight decline after 2010. This was determined to be a reasonable forecast. 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.

Although coal prices tend to be fairly stable now, they have changed in the past. On a real dollar basis, coal prices declined by 50% from 1980 to 2000 as shown in the exhibit below. This mainly reflects various technical efficiencies in coal mining operations and a shift to Western coals.

Exhibit 4-3. Historic Coal Prices (2007$/MMBtu)

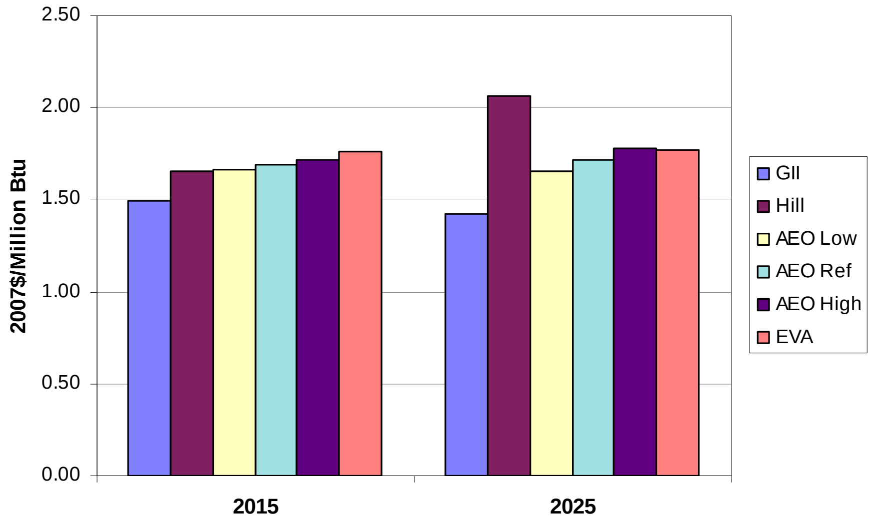


However, since 2000 coal prices have increased to levels equivalent to prices of the mid-1980's and are expected to stay at these higher levels. In 2006, coal prices stabilized and expectations are that they will remain at these levels. This was reflected in the NYMEX Central Appalachian Coal Futures through 2009. While coal at the mine mouth is relatively cheap on an energy basis, it is expensive to transport. Also, coal demand is unlikely to increase significantly because of environmental concerns. Coal is more expensive in New England because of the transportation costs and as a result provides

18% of the electric generation in New England which is a lesser fraction than most other parts of the U.S. Since AEO 2007 coal prices are essentially flat and consistent with historic experience and market behavior, they were used in this analysis.

The exhibit below compares various coal price forecasts for 2015 and 2025, showing that the AEO Reference forecast is in the middle of the range.

Exhibit 4-4. Coal Price Forecasts for Electric Generation (2007$/MMBtu) [39]



[39] EIA Annual Energy Review 2007, Table 24, Comparison of Coal Projections.

iv. Biofuel Price Forecasts

Biofuel blends are a mix of a petroleum product, such as No. 2 distillate oil or diesel, and an oil-like product derived from an agricultural source (e.g. soybeans). They are relatively new to New England and are being sold as heating fuels in competition with No. 2 distillate and as transportation fuels. These products are usually labeled "B"+"NN" where NN is the percent agricultural-derived component. Thus "B20" represents a product with a 20% bio component. The biofuel product of most interest is biodiesel. It is similar to No. 2 distillate fuel oil and used primarily for heating. Currently B20 is being sold as a heating oil product by Mass Energy at about a 9% premium to conventional heating oil on a per gallon basis. However, the biofuel heat content is about 2% greater, so the net premium is about 7%. A review of the relative national prices for biodiesel B20 compared to regular diesel from the DOE Alternative Fuels Data Center[40] shows that on a heat rate basis the relative premium over the last year has varied from -1% to +3%. Since biofuels are both premium fuels (from an environmental standpoint) and sub-premium fuels (from a performance standpoint) and compete in a much larger market, an appropriate premium (positive or negative) to apply to their prices relative to the equivalent conventional fuel cannot be determined at this time. There is also the economic argument that the prices will equilibrate in the market. Thus, the prices of biofuels are forecast to be the same on an energy basis as the equivalent competitive fuel.

v. Fuel Wood Price Forecast

Prices for fuel wood can have great variability based on location, time of year, and quality (green or dry). A number of fuel wood dealers in New England were surveyed with the result being a wide range of prices. Additionally, it was very difficult to get any information from the dealers about historical prices or future price expectations.

As a result, historical data was leveraged. The EIA SEDS data provides state fuel wood prices by sector. In reviewing this data, there was a very strong and consistent relationship between distillate oil and fuel wood prices.

The following graph shows the historic relationship between No. 2 Distillate and fuel wood prices in Massachusetts from 1991 through 2003.[41] The correlation between the two sets of prices is 99.4%. It is reasonable to conclude that this price relationship will continue into the future. As a result, the forecast for fuel wood prices was based on that for No. 2 Distillate.

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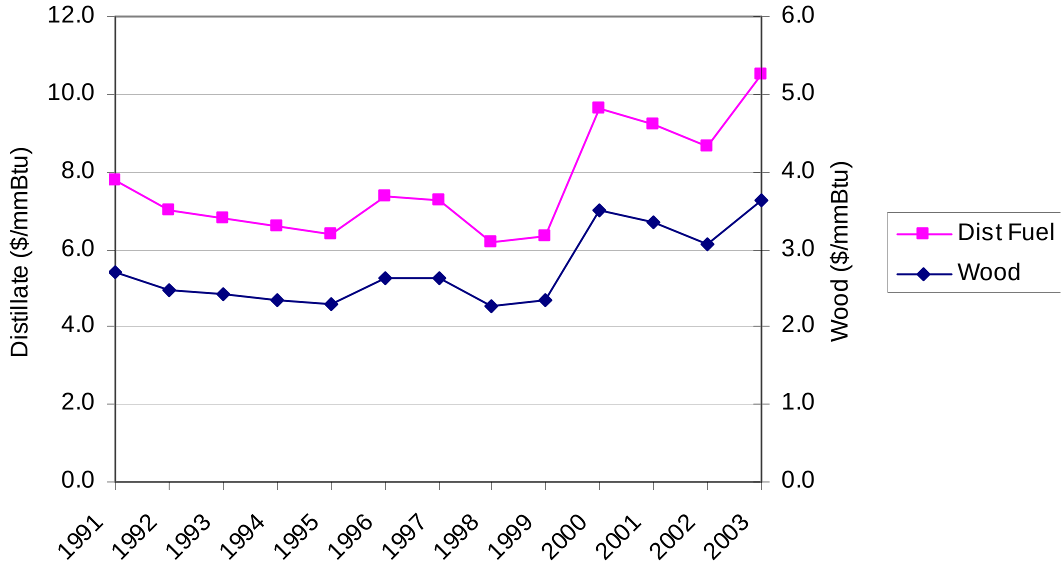
[40] "Clean Cities Alternative Fuel Price Report" for March 2007, October 2006 & June 2006. www.eere.energy.gov/afdc/

[41] Massachusetts is the largest user of residential fuel wood in New England. The EIA data also reports the same wood prices for all the NE states.

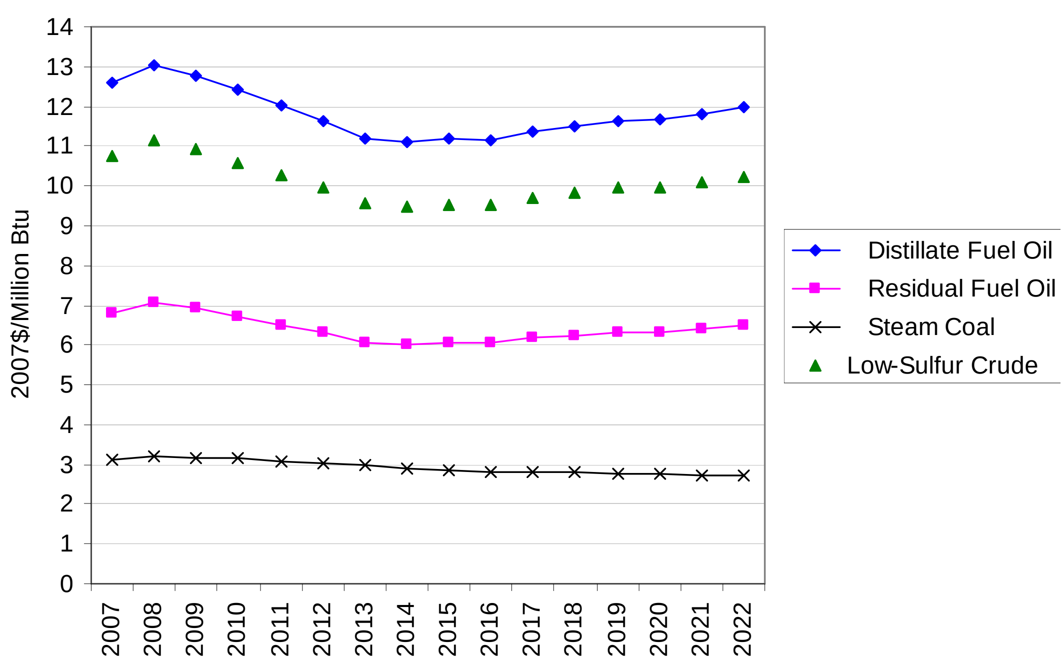
Exhibit 4-6. Massachusetts No. 2 Distillate Fuel and Fuel Wood Prices



B. Results

The forecasts for crude oil as compared to the forecasts of specific fuels including No.6 residual fuel oil and No. 2 distillate fuel oil and coal are shown in the exhibit below.

Exhibit 4-7. Price Forecasts for US Crude Oil and New England Electric Generation Fuels (2007$)



The forecasted prices are close to those in AEO 2007 and they are approximately 20% higher on average than those in AESC 2005. This is primarily due to the fact that these forecasts are based upon a higher forecasted price for crude oil than assumed in AESC 2005. The forecasts by product by year are presented in the exhibit below.

Exhibit 4-8. New England Average Price Forecast of Other Fuel Prices by Sector (2007$)

Fuel	No. 2 Distillate	No. 2 Distillate	No. 6 Residual Fuel <= 1% Sulfur	No. 4 Fuel Oil	Propane	Kerosene	BioFuel	BioFuel	Wood	Fuel
Market	Retail	Retail	Retail	Retail	Retail	Retail			Retail	Market
Sector	Residential	Commercial	Commercial	Commercial	Residential	Res & Com	B5 Blend	B20 Blend	Residential	Sector
Notes	1	1	2	3	4	5	6	6	7	Notes
Year	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	Year
2007	15.84	13.97	9.46	11.71	26.81	16.47	15.84	15.84	5.67	2007
2008	16.43	14.49	9.82	12.15	28.76	17.09	16.43	16.43	5.88	2008
2009	16.05	14.15	9.59	11.87	28.97	16.69	16.05	16.05	5.75	2009
2010	15.58	13.74	9.31	11.52	29.43	16.20	15.58	15.58	5.58	2010
2011	15.10	13.32	9.03	11.17	29.71	15.71	15.10	15.10	5.41	2011
2012	14.67	12.94	8.77	10.85	30.08	15.26	14.67	14.67	5.26	2012
2013	14.22	12.54	8.50	10.52	29.61	14.79	14.22	14.22	5.09	2013
2014	14.03	12.37	8.38	10.38	29.63	14.60	14.03	14.03	5.03	2014
2015	14.10	12.43	8.42	10.43	29.55	14.66	14.10	14.10	5.05	2015
2016	14.16	12.49	8.46	10.47	29.60	14.73	14.16	14.16	5.07	2016
2017	14.29	12.60	8.54	10.57	29.85	14.86	14.29	14.29	5.12	2017
2018	14.42	12.72	8.62	10.67	29.76	15.00	14.42	14.42	5.17	2018
2019	14.55	12.83	8.69	10.76	29.69	15.13	14.55	14.55	5.21	2019
2020	14.68	12.95	8.77	10.86	29.80	15.27	14.68	14.68	5.26	2020
2021	14.88	13.12	8.89	11.00	29.67	15.47	14.88	14.88	5.33	2021
2022	15.07	13.29	9.01	11.15	29.82	15.68	15.07	15.07	5.40	2022
Levelized	14.92	13.16	8.92	11.04		15.52	14.92	14.92	5.35	Levelized

1 Based on the adjusted AEO 2007 forecast for New England
2 The electric sector oil forecast was used as an input into the electricity price forecast
3 Adjusted AEO Electrical sector forecast
4 Adjusted AEO Commercial sector forecast

29.37

5 Based on the historic price difference relative to No. 2 Distillate
6 Based on the adjusted AEO 2007 forecast for New England
7 Based on the historic price difference relative to No. 2 Distillate
8 No premium of discount assigned for biofuels
9 Levelized using a real discount rate of 2.22%

5. Electric Energy Price Forecast

This chapter provides our projection of electric energy prices and a description of the modeling methodology and assumptions. (Deliverable 6 - Electric Avoided Costs).

A. Overview

The ISO New England market is part of the Northeast Power Coordinating Council (NPCC) and includes the states of Connecticut, Maine[42], Massachusetts, New Hampshire, Rhode Island, and Vermont. ISO New England, Inc. is the Regional Transmission Organization (RTO) for the New England power market and 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). This zonal locational marginal price-forecasting model (Market Analytics) simulates the operation of the energy and operating reserves markets, and produces forecasts of prices for each product. The model does not simulate the capacity market and, therefore, it does not require assumptions regarding the capital costs of new generation capacity, and the interconnection costs associated with such capacity. These assumptions were developed as part of the forecast of the prices for products in the capacity market and are discussed in the next section.

Market Analytics took as inputs the monthly regional fuel price forecasts reviewed in the first three sections (including the regional natural gas forecast and regional forecasts for petroleum products, coal and fuel wood). Other inputs as discussed in the Inputs section below were incorporated in order to produce an avoided electric energy cost forecast by state.

B. Zonal locational marginal price-forecasting model

The following section provides a high-level overview of the Global Energy Decisions (GED)[43] EnerPrise Market Analytics data management and production simulation model functionality. A more detailed discussion of the way this model was leveraged to produce avoided electric energy costs is presented in the Methodology section further on in this report.

The Market Analytics model was used to develop electricity avoided cost forecasts. 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.

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

[43] Formerly Henwood Energy Services, Inc.

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, consists of ten transmission areas, including SW Connecticut as a zone. The service territories of the New England distribution utilities are mapped onto the transmission areas, and hourly load data was 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 EIA, EPA, NERC, FERC, and ISO New England databases as well as various trade press announcements and Global Energy's own insight. Total existing capacity in the Market Analytics database was compared with the 2007 CELT report and found to be reasonably consistent.

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 will determine 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 load levels are entered 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[44] 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, which increases transparency and allows the system expansion plans to be specified to reflect non-market considerations. 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 de-rating 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.

C. Input Assumptions Used to Develop the Electric Energy Price Forecast

The avoided electric energy costs were strongly dependent on the quality of the input assumptions that were integrated into Global Energy's zonal price forecasting model. The input assumptions include: topology, thermal unit characteristics, conventional hydro and pumped storage unit characteristics, renewable unit characteristics, hourly load profiles, forecasted annual peak demand and total energy, transmission system paths and upgrades, Reliability-Must-Run (RMR) Contracts, reserve margin multiplier, additions, retirements, uprates, outages, environmental regulations, demand response resources, marginal cost bidding, installed capacity, and ancillary services.

[44] 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.

i. Electric Market Zone Topology

Market Analytics represents load and generation zones at various levels of aggregation. Assets within the Market Analytics 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 11 Transmission Areas that are based on the 13 load zones as defined by ISO New England for the 2006 Regional System Plan[45]. Neighboring regions that are modeled in this study are New York, Quebec, and the Maritime Provinces[46,47]. Areas outside of New England are represented with a high level of zonal aggregation to minimize model run time. The load and generation zones as they were modeled is presented in Exhibit 5-1.

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[45] Market Analytics combines western and central Maine/Saco Valley, New Hampshire and southeastern Maine to form ME-CMP and includes Norwalk/Stamford in CT-SW

[46] In our proposal, we proposed including PJM and Ontario in the modeling. However, in the interest of consistency with the 2005 AESC report and ISO New England’s planning, we have decided to only include external control areas that are directly connected to New England.

[47] The Maritimes zone includes Maine Public Service and Eastern Maine Electric Cooperative 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.

Exhibit 5-1. Zones Used to Model New England Electric Market Prices

Region	Zone Designation	Description
New England	BHE	Northeastern Maine
	ME-CMP	Southeastern Maine and western and central Maine/Saco Valley, New Hampshire
	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
	WMA	Western Massachusetts
	SEMA	Southeastern Massachusetts/Newport, Rhode Island
	RI	Rhode Island/bordering MA
	CT	Northern and eastern Connecticut
	CT-SW	Southwestern Connecticut including Norwalk/Stamford
New York	NY	NY-ISO control area
Quebec	HQ	Hydro Quebec control area
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 Global Energy 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.

ii. Existing Generating Unit Characteristics

(a) Thermal Unit Characteristics

Market Analytics models 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
- Fixed 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)

Exhibit C-2 in Appendix C summarizes the thermal unit characteristic assumptions used in our modeling.

(b) Nuclear Unit Characteristics

There are four nuclear plants in New England (Millstone, Pilgrim, Seabrook, and Vermont Yankee) with a combined capacity of 4,775 MW which is approximately 15% of the total capacity in New England. It is, therefore, important to assess whether or not these units will continue to operate during the study period. The exhibit below shows the capacity of each nuclear unit and its license expiration date.

Exhibit 5-2. New England Nuclear Unit Capacity and License Expirations

Unit	AESC Zone	Capacity MW[48]	License Expiration Year[49]
Millstone 2	CT	940	2035
Millstone 3	CT	1253	2045
Pilgrim	SEMA	670	2012
Seabrook	NH	1242	2017
Vermont Yankee	VT	670	2012

[48] Nuclear capacity values are the nameplate capacity values for these units in the Market Analytics database.

[49] Source – U. S. Nuclear Regulatory Commission: www.nrc.gov.

License renewals for the Pilgrim and Vermont Yankee plants are currently being reviewed by the Nuclear Regulatory Commission (NRC) and Seabrook will be coming up for renewal in during the study period. In the past seven years, the NRC has reviewed license extensions for 27 plants and not one of these applications was denied[50]. Based on this track record and the lack of evidence that suggests that license renewal applications for any of these plants will be denied, it was assumed that all of the nuclear plants in New England will continue to operate for the entire study period.

The owner's of Millstone have filed an application for a 70 MW uprate on Unit 3 for operation by the end of 2008[51]. Based on the fact that the NRC has never denied an uprate application[52], it was assumed that this uprate will be approved and the uprated capacity will be in operation starting in 2009.

The maintenance schedules included in the Market Analytics database are based on information from the NRC website and the trade press for re-fuelling outages as well as ISO New England and the Nuclear Energy Institute. Future outages are estimated by using typical refueling cycle, outage length, and last known outage dates of each plant to project refueling outages.

(c) Conventional Hydro and Pumped Storage Unit Characteristics

The Global Energy database was 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 the 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 (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.

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[50] Source – Nuclear Energy Institute: http://www.nei.org/documents/U.S._Nuclear_License_Renewal_Filings.pdf

[51] Source – ISO New England Generator Interconnection Queue:

[52] Source – U. S. Nuclear Regulatory Commission: www.nrc.gov.

(d) Renewable Unit Characteristics

The Global Energy database includes several existing renewable generators in New England. These include wind, biomass, landfill gas, and municipal solid waste-to-energy facilities. All of these units were modeled as thermal units with seasonal forced outage rates that reflect historic seasonal capacity factor profiles.

iii. Load Forecast

Historical profiles for each utility were developed by Global Energy Decisions based a set of annual historic 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 the 2007 CELT report and the 2006 Regional System Plan, published by ISO New England. The 2007 CELT report was released on April 18, 2007. However, the detailed load forecast data for the ISO's RSP zones (which the Market Analytics zones are based on) was not released in time to be included in the modeling. Instead, the ISO released the load forecasts for each New England state that it had used to develop the forecast presented in the 2007 CELT[53]. As a result, the load forecasts for each zone in the Market Analytics model were derived from the ISO NE 2007 CELT state-level load forecasts for 2007-2016 as summarized in the exhibits below. For 2017-2022, load in each zone is assumed to grow at the Compound Annual Growth Rate (CAGR) of the 2007-2016 period.

Exhibit 5-3. Summer Peak Forecast by State (MW) [54]

State	2007	2016	2007-2016 CAGR	2022
CT	7,317	8,475	1.6%	9,322
MA	12,623	14,595	1.6%	16,053
ME	2,033	2,400	1.9%	2,671
NH	2,444	3,000	2.3%	3,439
RI	1,877	2,185	1.7%	2,418
VT	1,067	1,230	1.6%	1,353
ISO-NE	27,360	31,885	1.7%	35,255

Note: 2017-2022 values were developed by growing 2016 values by 2007-2016 CAGR

[53] Available on the ISO New England website: http://www.isonewengland.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2007/apr52007/revised_%20pac18_preliminary_rsp_load_forecast.xls.

[54] These values are based on ISO New England's 2006 forecast for the 2006 CELT and RSP which is available in the workbook "Forecast Data 2006.xls" which can be found on the ISO New England website at: http://www.isonewengland.com/trans/celt/fsct_detail/index.html.

Exhibit 5-4. Energy Forecast by State (GWh) [55]

State	2007	2016	2007-2016 CAGR	2022
CT	33,929	38,060	1.3%	41,127
MA	60,155	65,670	1.0%	69,710
ME	11,820	13,390	1.4%	14,555
NH	11,895	13,775	1.6%	15,151
RI	8,463	9,270	1.0%	9,840
VT	6,354	7,020	1.1%	7,496
ISO-NE	132,616	147,190	1.2%	158,111

Note: 2017-2022 values were developed by growing 2016 values by 2007-2016 CAGR

Load allocation factors from the ISO New England 2006 Regional System Plan, shown in Exhibit C-1 in Appendix C, were applied to the state-level load forecasts from the 2007 CELT Report to develop the load forecasts for each transmission area. The load allocation factors represent the portion of each state's load that is mapped to each RSP sub-area[56]. The load forecasts for each zone in the Market Analytics model are summarized in the Exhibits below.

[55] These values are based on ISO New England's 2006 forecast for the 2006 CELT and RSP which is available in the workbook "Forecast Data 2006.xls" which can be found on the ISO New England website at: http://www.isonewengland.com/trans/celt/fsct_detail/index.html.

[56] Table 3-6 in the ISO New England 2006 RSP.

Exhibit 5-5. Market Analytics Modeled Summer Peak Forecast by Zone (MW)

Zone	2007	2016	2007-2016 CAGR	2022
BHE	313	370	1.9%	411
BOSTON	5,501	6,366	1.6%	7,007
CMA/NEMA	1,763	2,044	1.7%	2,253
CMP	1,730	2,045	1.9%	2,278
CT	3,612	4,184	1.6%	4,602
NH	1,963	2,404	2.3%	2,752
RI	2,489	2,891	1.7%	3,193
SEMA	2,976	3,442	1.6%	3,787
SWCT	3,632	4,207	1.6%	4,628
VT	1,246	1,460	1.8%	1,625
WMA	2,087	2,413	1.6%	2,654

Note: 2017-2022 values were developed by growing 2016 values by 2007-2016 CAGR

Exhibit 5-6. Market Analytics Modeled Energy Forecast by Zone (GWh)

Zone	2007	2016	2007-2016 CAGR	2022
BHE	1,820	2,062	1.4%	2,241
BOSTON	26,224	28,655	1.0%	30,436
CMA/NEMA	8,409	9,207	1.0%	9,791
CMP	9,999	11,335	1.4%	12,325
CT	16,749	18,789	1.3%	20,303
NH	9,631	11,130	1.6%	12,227
RI	11,418	12,494	1.0%	13,262
SEMA	14,142	15,441	1.0%	16,391
SWCT	16,843	18,894	1.3%	20,416
VT	7,063	7,888	1.2%	8,482
WMA	10,024	10,959	1.0%	11,644

Note: 2017-2022 values were developed by growing 2016 values by 2007-2016 CAGR

ISO New England changed its long-run load forecasting methodology this year to reflect the fact that DSM resources may participate in the Forward Capacity Market [57]. Under this new methodology, the load forecast reflects the future, ongoing impact of DSM programs implemented prior, and up to 2006. However, the forecast we used was not adjusted for the impact of projected future DSM programs.[58]

The load forecast we used in our simulation of the New England market deliberately does not reflect the potential impact of DSM programs that would be implemented in 2007 and beyond. This is consistent with the purpose of our study which is to forecast electric energy prices that would occur in the absence of new DSM programs.

[57] Conversation with Dave Erlich, April 9, 2007.

[58] In previous years, ISO New England developed a long-run load forecast excluding any future DSM savings from any programs, past or future, "Unadjusted Load" forecast and then subtracted forecast DSM savings to develop its "Adjusted Load" forecast.

iv. Transmission System Paths and Upgrades

Transmission path assumptions were developed by Global Energy based on the zonal transmission paths represented in the ISO-NE 2006 Regional System Plan. 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

The exhibit below shows the transmission capabilities of each path between New England zones and between New England and external areas as indicated in the Global Energy database. These capabilities are consistent with the interface limits that are used in the ISO New England 2006 RSP.

Exhibit 5-7. New England Zonal Transmission Interface Limits

Path Type	Name	"From" Zone	"To" Zone	Capacity "From-To" (MW)	Notes	Capacity Back (MW)	Notes
Transmission Paths within New England	BHE-CMP	BHE	CMP	1200		1050	
	CMA-BOSTON	CMA/NEMA	BOSTON	2800	As of 1/1/2006	3000	
				3000	As of 1/1/2008		
	CMA-NH	CMA/NEMA	NH	912		925	
	CMA-WMA	CMA/NEMA	WMA	960		2000	
	CT-RI	CT	RI	720		720	
	CTSW-CT	CTSW	CT	2000		2575	As of 1/1/2007
						3400	As of 1/1/2010
	NH-BOSTON	NH	BOSTON	900		912	
	NH-MAINE	NH	CMP	1400		1500	
	NH-VERMONT	NH	VT	720		715	
	RI-BOSTON	RI	BOSTON	400		400	
	RI-CMA	RI	CMA/NEMA	1480		600	
	RI-SEMA	RI	SEMA	1000		3000	
	SEMA-BOSTON	SEMA	BOSTON	400		400	
	VERMONT-WMA	VT	WMA	875		875	
	WEMA-CT	WMA	CT	680		710	
Transmission Paths between New England and External Control Areas	BHE-NBPC	BHE	Maritimes	600	As of 10/1/2007	1000	As of 10/1/2007
	HYQB-VT (Highgate)	HQ	VT	225	Peak month capacity	170	Peak month capacity
	CTSW-NYZK	CTSW	NY	100		100	
	MPS-BHE	Maritimes	BHE	127		127	
	NYZD-VERMONT	NY	VT	150		150	
	NYZF-WEMA	NY	WMA	275	Peak month capacity	650	
	NYZG-CT	NY	CT	700		500	
	NYZK-CT (CSC)	NY	CT	300		330	
	CMA-HYQB (Phase II)	CMA/NEMA	HQ	1300	Peak month capacity	1921	Peak month capacity

The interface limits presented in the exhibit above include the following transmission upgrades from the 2006 RSP[59]:

- **Northeast Reliability Interconnect Project –** this comprises a new 345 kV line from New Brunswick to the Orrington Substation in northern Maine and increases the transfer capability from New Brunswick to Maine by 300 MW. This project is scheduled to be online by the end of 2007.
- **NSTAR 345 kV Transmission Reliability Project –** this project involves construction of a Stoughton 345 kV station and three new underground 345 kV lines, two of which are already completed and the third is scheduled for completion by the end of 2007. This project increases the Boston import capability by approximately 1,000 MW.
- **SWCT Reliability Project –** this project includes two phases of new 345 kV circuits. The combined effect of these two phases is to increase the import capability into SWCT by approximately 1,100 MW by the end of 2009.

Transmission system upgrades beyond what was included in the Global Energy database were considered, however, no additional upgrades needed to be included.

v. Reliability-Must-Run (RMR) Contracts

Unlike the 2005 AESC study, the current study does not include any costs related to reliability contracts (sometimes called “reliability must-run” or RMR contracts) as being avoidable. The following exhibit lists the plants with reliability agreements that last beyond 2007.[60] These remaining reliability contracts are scheduled to expire in June 2010, when the FCM commences operation. Load reductions are unlikely to result in these contracts being avoided prior to 2010. If the units are needed, and market revenues do not cover their costs, new agreements may be required.

[59] The Northwest Vermont Reliability Project is not included in this list because it does not affect the import capability into Vermont.

[60] “Reliability Agreements—Annual Fixed Costs Summary,” ISO-NE, 4/19/07.

Exhibit 5-8. List of Plants with Reliability-Must-Run Contracts through 2007

Owner/Unit	Plant Type	2007 CELT Summer Cap MW	Annualized Fixed Revenue Requirement $M	$/kW-year total	$/kW-year Net of FCM
Western Central Mass					
ConEd -- W.Springfield 3	ST	94	7	$75	-
Berkshire Power	CC	229	26	$113	$13
Pittsfield Gen.--Altresco"	CC	141	13	$92	-
ConEd -- W.Springfield GT-1&2	CT	74	12	$161	$61
Sub-Total WCMA		**539**	$58 M		$8 M
Connecticut					
NRG -- Middletown 2-4, 10	ST, CT	770	50	$64	-
NRG -- Montville 5,6,10&11	ST, CT	494	29	$58	-
Milford 1 and 2	CC	492	82	$166	$66
PSEG -- New Haven Harbor	ST	448	47	$106	$6
PSEG -- Bridgeport Harbor 2	ST	130	19	$146	$46
Bridgeport Energy	CC	448	58	$129	$29
Sub-Total Connecticut		**2,782**	$284 M		$54 M

vi. New Generation Additions

In order to meet future load growth, new generation resources were added to the existing generation mix. Market Analytics is not a capacity expansion model that optimizes capacity additions by choosing among a set of resource alternatives to develop a least cost expansion plan. Therefore, three types of additions were used to manually add new resources to meet reserve needs:

- Planned Additions—Near-term proposed new additions or uprates to existing plants that were in development or advanced stages of permitting and had a high likelihood of reaching commercial operation;
- RPS Additions—Renewable generators that were added to meet existing or anticipated renewable portfolio standards (RPS) in each state; and,
- Generic Additions—New generic conventional resources that were added to meet the residual capacity need after adding planned and RPS additions.

(a) Planned Additions

The AESC 2007 forecast was based on projects in development or advanced stages of permitting, as indicated by the 2007 CELT Report, review of the current ISO New

England interconnection request queue[61], trade press, environmental permit applications to the State Departments of Environmental Protection, and internal knowledge. New entry assumptions are shown in the exhibit below. These planned additions represent the additions that ISO New England has indicated are highly likely to reach commercial operation.[62]

Exhibit 5-9. Planned Additions

Project	State	AESC Zone	Type	Fuel	Projected On-line Date	Capacity (MW)
Kleen Energy Project	CT	CT	CC	NG/DFO	8/28/2008	620
Peabody Power	MA	BOSTON	CT	NG/DFO	5/1/2008	97
Lowell Power Generators	MA	CMA/NEMA	CT	NG	1/1/2008	99
Gas Turbine	CT	SWCT	CT	NG/DFO	9/1/2007	90
Hoosac Wind Project	MA	WMA	WT	Wind	12/31/2007	30
Fitchburg Renewable Energy	MA	CMA/NEMA	IC	LFG	6/30/2007	7

(b) RPS Additions

New renewable generation resources will be added to each state to meet existing or expected renewable portfolio standards (RPS). Each state in New England has different RPS targets and different requirements for meeting these targets. The major requirements by state are detailed in Exhibit C-3 in Appendix C.

The resources that are eligible to meet these targets vary by state, however, it was assumed that RPS requirements will be met by a mix of renewable resource generation consistent with the mix of resources in the ISO NE queue (type and quantity). As a result, additions included only wind, solar, landfill gas, and biomass generators. The assumed resource mix was 65% wind, 33% biomass, 1% LFG, and 1% solar[63]. It was assumed that these proportions would remain constant throughout the study period with the following exception: the proportion of solar PV resources would initially be less than

[61] The ISO New England interconnection request queue is a list of proposed new generation resources that have submitted an Interconnection Request form to the ISO and are in various stages of the development process.

[62] From a presentation by Peter Wong to the ISO New England Planning Advisory Committee on 2/27/2007: http://www.isonewengland.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2007/feb272007/new_resources_in_the_ISO_queue.pdf.

[63] These quantities are based on the mix of renewable resources in the ISO New England interconnection queue with the additional assumption of 1% of requirements will come from solar PV. The proportion of solar PV resources will initially be less than 1% and will gradually increase over time to account for the expected cost reductions and technology improvements in future years.

1% and would gradually increase over time to account for the expected cost reductions and technology improvements in future years. It was assumed that new RPS resources would be located based on locations of projects currently in the ISO NE queue. The exception will be solar PV, which was distributed in each transmission area proportionately to load.

The operating characteristics of these resources are shown in the exhibit below. These assumptions will be based on the technology assumptions used by ISO New England in its current scenario planning process as well as other sources.

Exhibit 5-10. Operating Costs and Characteristics for New RPS Additions

Technology Type	Biomass	Landfill Gas	Wind On-shore	Wind Off-shore	Solar PV	Source
Typical Generator Size (MW)	40	5	1.5	3.5	1	1
Heat rate	14000	10500	n/a	n/a	n/a	1
Fixed O&M costs (2007$/kW-yr)	51.70	111.83	35.34	50.31	72.46	2,3,4
Variable O&M costs (2007$/MWh)	0.42	0.00	0.00	0.00	0.00	2,4
Availability	60%	90%	90%	90%	98%	1
NOx (lb/Mbtu)	0.075	0.03	0	0	0	1
SO2 (lb/Mbtu)	0.02	0.2	0	0	0	1
CO2 (lb/Mbtu)	170	0	0	0	0	1
Average Capacity Factor	n/a	n/a	35%	39%	16%	5
Peak Capacity Credit	100%	100%	19%	26%	40%	5

Sources:
1. ISO NE 2007. "Resource Assumptions" presentation for the ISO-NE Scenario Analysis Working Group, 4/2/2007
2. AESC 2005, Exhibit 2-25, 2-26 for CC, CT, Biomass, Landfill gas, on-shore wind
3. PV Fixed O&M: "Energy Cost Savings Module", Prepared for the Massachusetts DG Collaborative, Navigant Consulting, January 20, 2006.
4. Off-shore wind: "New Jersey Renewable Energy Market Assessment", Navigant Consulting, August, 2004.
5. ISO NE 2007. "Wind and Photovoltaic Assumptions" presentation for the ISO-NE Scenario Analysis Working Group, 4/2/2007

RPS additions were made to the New England system based on the annual sum of renewable requirements for each state RPS. Resources were dispersed geographically as follows:

- Wind—based on currently proposed wind farm development patterns throughout New England
- Biomass—distributed proportionately to load
- Landfill Gas (LFG)—distributed proportionately to load
- Solar—distributed proportionately to load

The operating characteristics of these resources were based on the technology assumptions used by ISO New England in its current scenario planning process as well as other resources.

(c) Generic Additions

In order to reliably serve the forecasted load in the mid- to long-term portion of the forecast period, new generic additions were added to the model. A range of generation technologies was initially considered for this purpose, including gas/oil-fired combined-cycle, gas/oil combustion turbines, conventional coal, integrated gasification combined cycle (IGCC), and nuclear. However, the development queue did not indicate that any coal or nuclear resources would be developed in New England during the forecast period. Although the region is already heavily reliant on gas-fired generation and the ISO has stated a goal of increasing the fuel diversity of the region[64], the costs and risks of investing in new coal or nuclear generators are very high. Additionally, coal and nuclear resources are generally baseload units that do not have a significant impact on marginal costs since they are rarely on the margin. Therefore, generic additions were comprised entirely of gas/oil fired 300 MW combined-cycle and 100 MW combustion turbines. The assumed mix of combined cycle and combustion units was 45%/55%. This was based on the ratio of these types of resources in the ISO New England interconnection queue as of March 30, 2007. No coal and nuclear units were added.

Generic additions were added until a system-wide reserve target of 14.3% was met. New resources were dispersed geographically based on a combination of zonal need and historic zonal capacity surplus/deficit patterns. It was anticipated that the Forward Capacity Market would provide incentive to build new generation in the constrained zones of SWCT and Boston. However, siting new plants in these zones will likely be difficult. Therefore, it was also anticipated that some new capacity will be added outside of these zones.

Distributed generation technologies (DG) were also considered as generic additions, however, based on a review of several studies of the technical and economic potential of DG in New England[65,66,67], DG resources were not included as generic additions. Although these studies suggested that DG capacity in Connecticut and Massachusetts could reach levels of a few hundred megawatts by the end of the study period, the uncertainty regarding the economics of these resources made it difficult to predict what level of DG resources will be installed. Also, the likely penetration level for DG resources is not likely to have a significant impact on the overall avoided energy costs.

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[64] ISO New England 2006 Regional System Plan

[65] Beka Kosanovic, PhD. 2007. "How Attractive is DE for Massachusetts Energy Users and Society" presented at the MTC DG Symposium on January 18, 2007

[66] Andy Brydges with KEMA, "Projections of DG in Massachusetts" presented at the MTC DG Symposium on January 18, 2007.

[67] Institute for Sustainable Energy at Eastern Connecticut State University 2004. "Distributed Generation Market Potential: 2004 Update/ Connecticut and Southwest Connecticut", available at: http://www.easternct.edu/depts/sustainenergy/publication/Press%20Releases/March%2023,%202004%20-%20DG%20Update.htm

vii. Retirements

Global Energy includes assumptions regarding retirement of existing resources. The Global Energy database uses lifetime assumptions for certain technology types to determine retirements. However, it was determined that no units should be assumed to retire given that many units will likely continue to operate for reliability and/or economic reasons.

viii. Environmental Regulations

Market Analytics has the ability to model multiple effluents and apply costs to these emissions. This model included price forecasts for SO_2, NO_X, CO_2 and Mercury. The model included the costs associated with each of these emissions when calculating bid prices and making commitment and dispatch decisions. Allowance price forecasts associated with the Ozone Transport Commission (OTC) NO_X Budget Program and the Acid Rain Program were included in unit operating costs for this study. Allowance price forecasts were also included to represent future cap-and-trade emission reduction programs for mercury and CO_2.

(a) SO_2 and NO_x

There has been a significant reduction in SO_2 and NO_x emission allowance costs over the last several years. For example consider the SO2 allowances for 2009: in mid 2005 they were selling for $670/ton, in March 2006 they were relatively unchanged at $700/ton, by September 2006 they were down to $570/ton, and by March 2007 they were down to $430/ton. Similar reductions occurred in the NOx allowance markets. These reductions are influenced by a number of factors including the decline in natural gas prices, but a significant component is that the control costs, especially for NOx, are proving to be less than previously thought. The establishment of new limits on Mercury emissions is leading to the installation of additional scrubbers which also reduce SO2 emissions. However looking to 2010 and beyond, new limits on air emissions associated with CAIR are likely to require new controls and push up allowance costs. This is reflected in the forecast of future allowance costs in the EIA's AEO 2007. However considering the significant price reductions shown in the allowance markets for years both before and after 2010, the AEO forecast which was constructed in the Fall of 2006 now seems too high. Thus we have adjusted the AEO price forecasts for after 2010 to reflect the relative changes in the markets between September 2006 and March 2007[68].

SO_2 allowance prices represent a hybrid between recently reported trading prices for SO_2 allowance futures[69] and the AEO 2007 SO_2 allowance price forecast with the adjustments described above to account for the recent drop in allowance prices. The futures prices were used for the years 2007 through 2010. The allowance prices for the years 2011 to

[68] This adjustment consisted of reducing the AEO 2007 forecasts for SO_2 and NO_x by about 20% and 35%, respectively, which represent the relative drops in the markets for these emission allowances from September, 2006 to March, 2007.

[69] As reported in *Argus Air Daily*, March 30, 2007.

2014 represent an interpolation between the 2010 futures price and the 2015 AEO 2007 forecast price. The AEO 2007 price forecast was used for the years 2015 to 2022.

NO_x allowance prices represent a hybrid between recently reported trading prices for NO_x allowance futures[70] and the AEO 2007 NO_x allowance price forecast with the adjustments described above to account for the recent drop in allowance prices. The futures prices were used for the years 2007 through 2009. The allowance prices for the years 2010 and 2011 represent an interpolation between the 2009 futures price and the 2012 AEO 2007 forecast price. The AEO 2007 price forecast was used for the years 2012 to 2022.

(b) Mercury

The Clean Air Mercury Rule (CAMR) established an mercury emission allowance cap-and-trade program that will begin in 2010.For the allowance price forecast for mercury, we used the price forecast that was developed by Global Energy Decisions for their Fall 2006 Reference Case Forecast.

(c) CO_2

The CO2 allowance price forecast is based upon the Regional Gas Greenhouse Initiative (RGGI) in the short-run and expected federal GHG regulations in the long-run. Allowance prices for each ton of CO2 emitted are based on expected RGGI prices starting in 2009 and continuing until 2012[71] by which point it is expected that a national cap and trade program will be implemented for greenhouse gases[72].

The allowance price forecast for each effluent is shown in the exhibit below.

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70 As reported in *Argus Air Daily*, March 30, 2007.

71 The RGGI forecast is from the IPM modeling results for the "RGGI Package Scenario (Updated 10/11/06)" which can be found on the RGGI website at the following link: http://www.rggi.org/docs/packagescenario_10_11_06.xls.

72 The forecast for the federal program is based on a review of several proposed federal bills aimed at reducing greenhouse gas emissions by Synapse Energy Economics. The Synapse CO_2 forecast methodology is documented in Synapse's June 8, 2006 report, "Climate Change and Power: Carbon Dioxide Emissions Costs and Electricity Resource Planning", which can be found on the Synapse website.

Exhibit 5-11. Allowance Prices for SO_2, NO_X, Mercury (Hg) and CO_2 (2007$)

	SO2	NOx	Mercury	CO2
Year	$/ton	$/ton	$milion/ton	$/ton
2007	$434	$1,013	$0.00	$0.00
2008	$433	$925	$0.00	$0.00
2009	$432	$800	$0.00	$2.21
2010	$470	$1,171	$12.66	$2.37
2011	$526	$1,715	$12.66	$2.53
2012	$563	$1,750	$12.66	$9.46
2013	$590	$1,750	$12.66	$11.56
2014	$610	$1,750	$12.66	$13.66
2015	$750	$1,750	$12.66	$15.76
2016	$750	$1,750	$12.66	$17.86
2017	$750	$1,750	$12.66	$19.96
2018	$750	$1,750	$12.66	$22.06
2019	$750	$1,750	$12.66	$24.16
2020	$750	$1,750	$12.66	$26.27
2021	$750	$1,750	$12.66	$27.32
2022	$750	$1,750	$12.66	$28.37

Exhibit 5-12. CO_2 Prices (2007$)

Year	Price ($/ton)	Source
2007	-	
2008	-	
2009	2.21	RGGI
2010	2.37	↓
2011	2.53	
2012	9.46	Synapse
2013	11.56	↓
2014	13.66	
2015	15.76	
2016	17.86	
2017	19.96	
2018	22.06	
2019	24.16	
2020	26.27	
2021	27.32	
2022	28.37	

(d) Demand Response Resources

Demand response resources that were directly modeled in this analysis included resources that were participating in the "RT 30-Minute" and "RT 2-Hour" ISO New England Demand Response programs as of March 30, 2007 and categorized as "Ready to

Respond"[73]. These resources only operate during a few hours during peak periods, therefore, they do not contribute significantly to energy prices, however, they do contribute to total capacity and affect the reserve margin and the need for peak capacity. These resources are assumed to continue participation in the ISO's demand response programs which continue until June, 2010, at which point the Forward Capacity Market will begin and these resources will be required to bid into the FCM to be eligible as capacity resources. The exhibit below shows the levels of DR that was included in the model in the 2007-2009 time period by zone.

Exhibit 5-13. Demand Response Capacity Included in the Model for 2002-2009

Zone	MW
CT	250
SWCT	250
ME	135
NEMA	70
NH	5
RI	5
SEMA	15
VT	20
WCMA	40
Total	790

These resources were modeled as generating units with very high prices ($400-600/MWh).

ix. Market Model Assumptions

(a) Marginal Cost Bidding

All generation units were assumed to bid marginal cost (opportunity cost of fuel plus 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 tend to underestimate the prices in the real markets. The energy price outputs were benchmarked against futures prices.

[73] Ready to Respond means the registration process is complete and the resource is eligible to participate in an event in which the resource may be called upon by the ISO.

(b) Installed Capacity

Installed capacity requirements of 114.3% of net internal demand are assumed for the New England Power Pool (NEPOOL).

(c) Ancillary Services

Market Analytics allows the user 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 the energy prices since units that spin cannot produce electricity under normal conditions. The energy prices are higher when reserves markets are modeled. The reserves requirements for New England were reviewed and applied to the model.

D. Results

The three charts presented in Exhibits 5-14 to 5-16 illustrate our results using *Western Massachusetts* as a representative zone. Exhibit 5-14 presents our 2007 AESC winter on-peak energy price projections for *Western Massachusetts* compared to the 2005 AESC projections for that zone.

Exhibit 5-14. AESC 2007 vs. AESC 2005 – Winter On-Peak Forecasted Prices

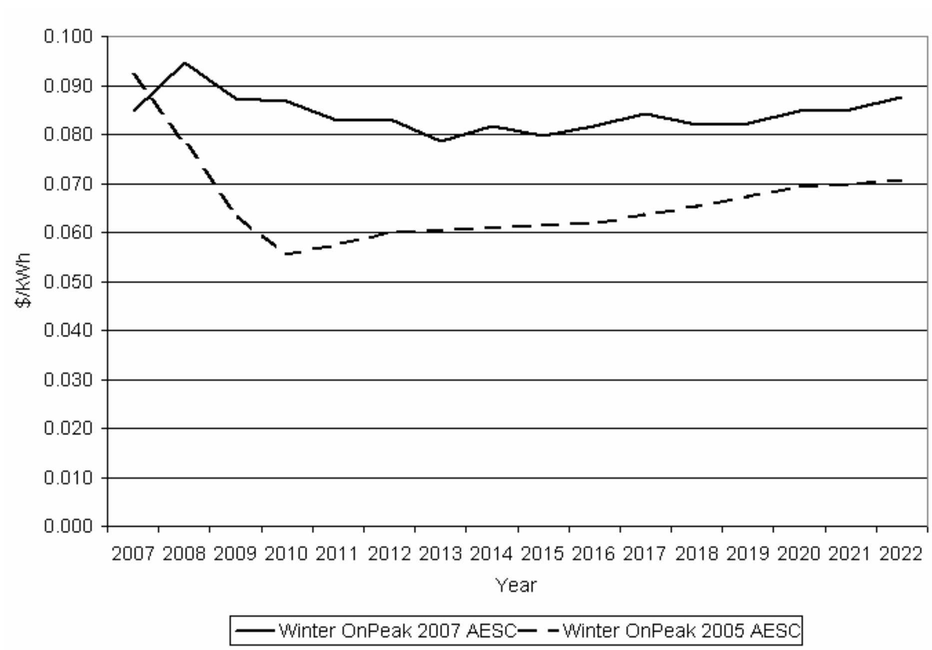


Exhibit 5-15 presents our 2007 AESC winter off-peak energy price projections for *Western Massachusetts* and the NYMEX futures for winter off-peak reported for the ISO-NE hub as of May 2, 2007.

Exhibit 5-15. Off-Peak Hub Futures Prices vs. Off-Peak West-Central Massachusetts Forecasted Prices

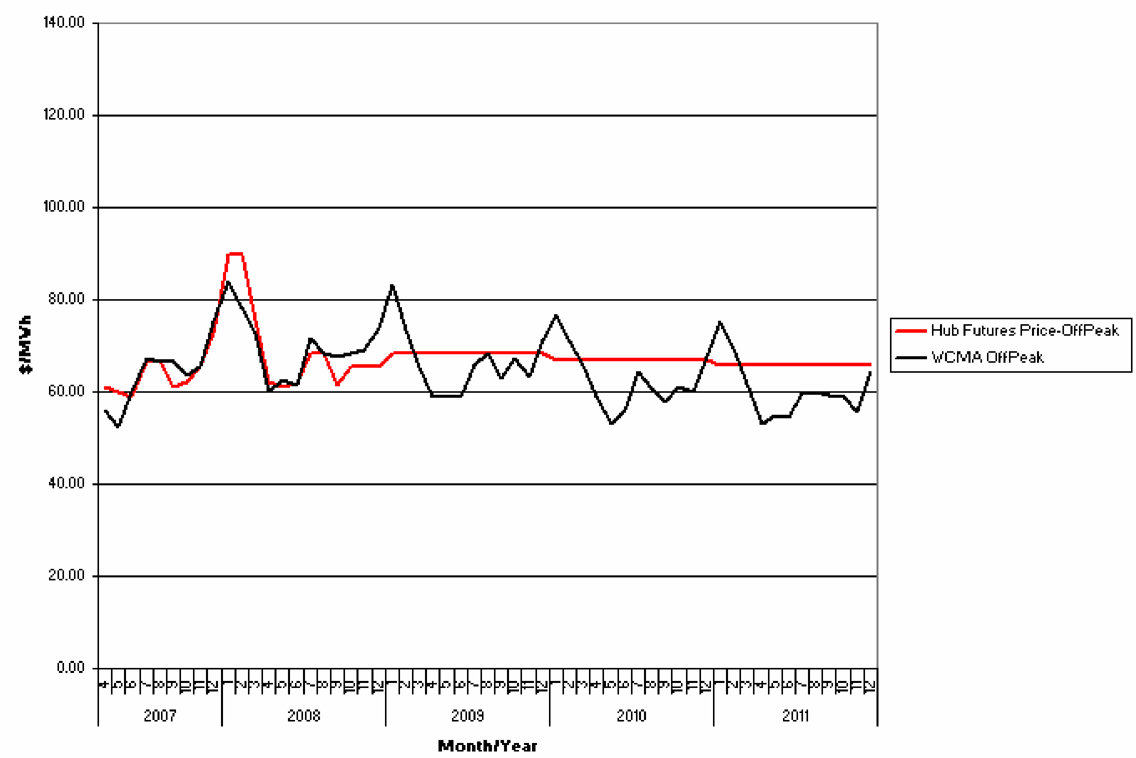
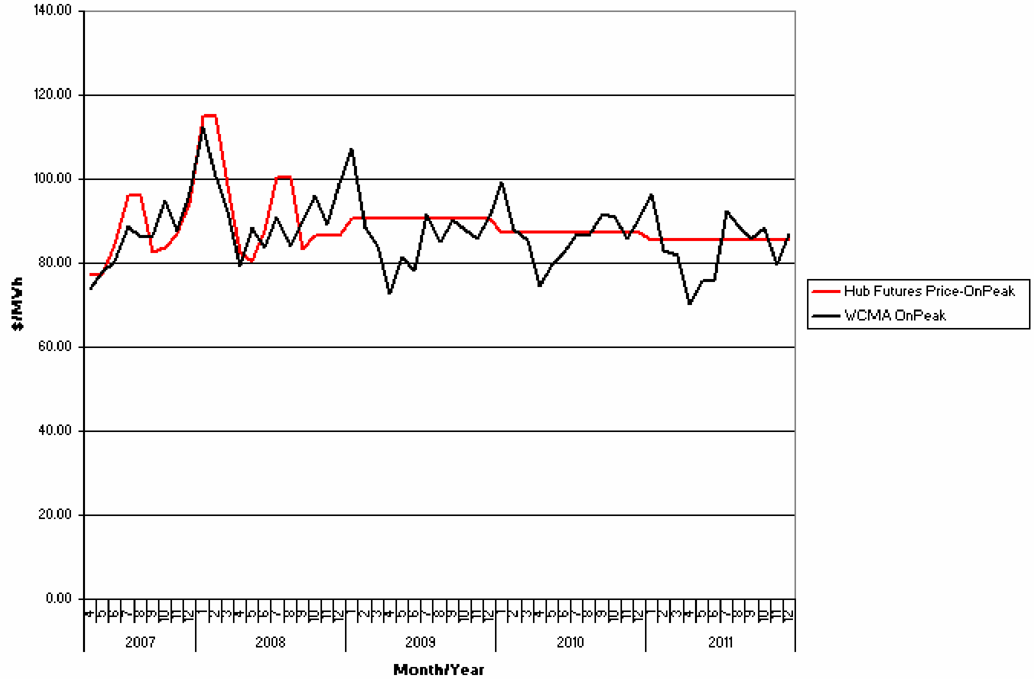


Exhibit 5-15 presents our 2007 AESC winter off-peak energy price projections for *Western Massachusetts* and the NYMEX futures for winter off-peak reported for the ISO-NE hub as of May 2, 2007.

Exhibit 5-16. On-Peak Hub Futures Prices vs. On-Peak West-Central Massachusetts Forecasted Prices



i. Difference between results in Deliverable 6a and results in Deliverable 7

The Synapse project team provided a set of interim electricity avoided costs to the 2007 AESC Study Group on May 15, 2006 in Deliverable 6a. The wholesale energy prices underlying those avoided electric energy costs are lower than our final projection of wholesale energy prices presented as part of Deliverable 7 and in this report.

Our final projection of wholesale energy prices are higher than those in Deliverable 6a because of several refinements we made to our modeling based upon our review of the Deliverable 6a projections. Our review of the Deliverable 6a wholesale energy prices revealed that the projections for certain pricing zones, primarily Vermont and CMA/NEMA, were higher, and more volatile, than expected. Further analysis indicated that these unexpected results were attributable to "unserved energy[74]" in significantly

[74] Unserved energy occurs in hours when the model does not have sufficient resources to meet load, and a portion of the forecast load is "unserved" or interrupted. Under those circumstances the model sets the price for that hour in that zone at an assumed price for unserved energy price. The default assumed price for unserved energy price.value , which was set at $920/MWh in the default dataset. Although there were very few hours in which there was unserved energy, the high price assumed for unserved energy skewed the average prices for these zones, resulting in average prices in Vermont to be significantly higher than expected. Because the projections of hours with unserved energy is tied to the projection of outages, whose timing is randomly determined, the high price of unserved energy also had the effect of causing the price streams to be highly volatile.

more hours than the remaining zones. To correct that effect, the price assumed for unserved energy was lowered from $920/MWh, the default value in the model, to $250/MWh, slightly above the highest hourly prices that were generated by supply resources setting the marginal price in New England over the study period. That adjustment reduced the volatility of the zonal prices and produced prices consistent with historical and expected levels. Then, the bid adders were increased for a selection of combined-cycle and peaking units in order to benchmark the projections in the near-term (2007-2011) with futures prices for New England[75]. The resulting projections of wholesale energy prices underlying the avoided electric energy costs were approximately 10% higher than the previously projected electric energy prices.

E. Transmission Energy Losses

Our forecast for marginal energy clearing prices includes inter-area losses 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 Exhibits 1 and 2 represent losses as a percentage of imports into each zone or state.

[75] Current futures prices are reported on a monthly basis for 2007 and 2008 and on an annual basis for 2009 through 2011. We benchmarked our prices on a monthly basis for the 2007-2008 time frame and on an annual basis for the 2009-2011 time frame..

Exhibit 5-17. Inter-Area Losses by Modeling Zone as a Percentage of Total Imports

Modeling Zone	Summer	Winter
BHE	5.12%	2.77%
BOST	0.83%	0.64%
CMA	3.15%	3.01%
CMP	0.11%	0.26%
CT	2.30%	1.89%
CTSW	2.00%	2.00%
NH	8.75%	8.66%
RI	0.79%	0.90%
SEMA	0.57%	0.76%
VT	3.29%	3.20%
WEMA	1.23%	1.23%
New England Average	2.31%	2.17%

Exhibit 5-18. Inter-Area Losses by State as a Percentage of Total Imports

State	Summer	Winter
CT	2.3%	2.3%
MA	2.8%	2.7%
ME	1.5%	1.0%
NH	2.6%	2.5%
RI	0.6%	0.8%
VT	0.9%	1.0%

F. Key Sources of Uncertainty in Forecast Energy Prices

The following variables contribute to the greatest degree of uncertainty to the final avoided electric supply costs:

- Fuel prices, particularly natural gas prices;
- Carbon emission prices; and

- Capacity prices.

Each of these components is subject to a great deal of uncertainty and make up a significant share of the total cost of electricity.

The exhibit below shows the contribution of natural gas prices and carbon prices to the total energy price. The values in this exhibit were based on a combustion turbine with a 10,000 btu/kwh heat rate operating at the margin. The three carbon prices were approximately equal to the Low, Mid, and High price projections for 2015 in the Synapse carbon price forecast.

Exhibit 5-19. Contribution of Natural Gas Prices and Carbon Prices to the Total Energy Price

Gas Price	Energy Price Fuel Component	Percent of Total Price	Carbon price	CO2 Emission Rate	Energy Price Carbon Component	Percent of Total Price	Variable O&M	Total Energy Price
$/MMBtu	**$/MWh**	**%**	**$/ton**	**lbs/MMBtu**	**$/MWh**	**%**	**$/MWh**	**$/MWh**
5.00	50.00	91%	5.00	120	3.00	5%	2.00	55.00
6.00	60.00	85%	15.00	120	9.00	13%	2.00	71.00
7.00	70.00	80%	25.00	120	15.00	17%	2.00	87.00

Capacity prices are projected to add an estimated $10-14/MWh to the energy price[76]. At a $71 energy price, the capacity prices make up 12-16% of the total electricity price.

Carbon prices and capacity prices were based on projections of markets that are not yet operating, and, therefore, there is a great deal of speculation around these prices.

[76] Connecticut Light and Power 2006 reconcilliation filing, March 30, 2007

6. Avoided Electricity Supply Costs

This chapter provides a projection of avoided electricity costs and a description of the underlying assumptions. (Deliverable 6 a – Interim Electric Avoided Costs by Zone and Costing Period, Deliverable 7 – Avoided Energy supply Components)

Our avoided electricity supply costs were developed from projections of the following components:

- Electric energy prices from section 5;
- Avoided cost of compliance with RPS
- Avoided costs from the Forward Capacity Market (FCM), adjusted for losses on the ISO-administered pool transmission facilities (PFT);
- A retail adder, reflecting the risks and costs related to power procurement.
- Demand-reduction-induced price effects (DRIPE) for energy and capacity; 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 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.

A. Avoided cost of compliance with RPS

Our estimate of avoided costs includes the cost of avoiding additional costs under the RPS in the various states that have imposed such standards. In essence, these standards imply that conventional power-supply mix imposes excessive costs and risks (which may be related to environmental damage, resource depletion, or price volatility), and that the costs of renewables are justified as mitigation. The amount of renewables required is tied to the amount of energy used, so this compliance cost is avoidable, just as is the cost of environmental compliance on avoidable energy or new capacity. Reduction in load due to DSM will reduce the RPS requirements of LSE's 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. In other words,

Avoided RPS cost = renewable energy price premium * RPS percentage

So, in a year in which the renewable energy price premium was $50/MWh (or 5 cents/kwh) and the RPS percentage was 10%, the avoided RPS cost to a retail customer would be $0.50 cents/kwh.[77]

It was relatively easy to develop assumptions for RPS percentages by state over the study period, as they are generally specified in legislation or regulations. However, research found relatively few recent public projections of renewable energy price premiums in New England. One measure of that premium is the price at which Renewable Energy Credits (RECs) are trading, and are projected to trade in the future. However, to develop an estimate of such a premium one needs to forecast prices in the wholesale energy market over the study period as well as to forecast prices in the market for "new renewables". The difference between these two projections is an estimate of the prices at which RECs will trade.

Due to the absence of a definitive forecast, two methodologies were considered. The first is drawn from a recent study by researchers at the University of New Hampshire.[78] The second simply assumes that the premium will remain at approximately $50/MWh[79] over the study period, on the assumption that policy makers may decided to increase RPS percentages during the course of the study period, particularly if RECs starting trading at much lower prices.

A comparison of the avoided RPS costs resulting from each approach for 2010 and 2020 can be found in the exhibit below.

Exhibit 6-1. Avoided RPS Costs Under Alternative Forecasts of REC Prices (Cents/kWh in $2007)

State	$50/MWH		UNH Report	
	2010	2020	2010	2020
CT	0.35	0.35	0.23	0.00
MA	0.25	0.75	0.17	0.00
ME	0.50	0.50	0.10	0.00
NH	0.05	0.57	0.03	0.00
RI	0.13	0.70	0.08	0.00
VT	0.23	0.50	0.15	0.00

77 5 cents/kwh * 10%

78 Gittell, Ross and Magnusson, Matt; *Economic Impact of a New Hampshire Renewable Portfolio Standard*, University of New Hampshire, February 2007.

79 This is the range in which RECs are currently trading and of current alternative compliance prices.

B. Avoided Capacity Costs

i. Overview of Capacity Market

NEED INTRO SENTENCE. The transition period from the current installed-capacity market to the forward capacity market (FCM) is December 2006 through May 2010. ISO-NE has set the installed-capacity (ICAP) prices to be paid to suppliers for each power year (June–May) during that period. Those prices are $3.05/kW-month through May 2008, $3.75/kW-month for June 2008 through May 2009, and $4.10/kW-month for June 2009 through May 2010. Public energy-efficiency programs that qualify for capacity payments from the ICAP system will increase the total capacity cost to load, but will receive an equal and offsetting revenue, which will be credited to consumers in various ways.

The ISO will set FCM prices for June 2010 through May 2011 for each zone in an auction to be conducted in February 2008. The basic structure for that auction has been developed, but some important inputs—especially the amount of capacity that can be imported to each zone—have not been released.

For at least the first three power years (2010–2013), the auction price will be constrained to ±40% of a reference price. The reference price will start at $90/kW-yr and gradually average in the results of the capacity auctions.

The ISO will adjust the FCM price from the auction results via the following three steps to derive the price to be paid by load:

- The auction price will be decreased to reflect penalties paid by non-performing suppliers;
- The auction price will be decreased by a portion of the energy profits (called peak energy rent, or PER) that would be earned by a generator with a 22,000 Btu/kWh.[80] The PER that the hypothetical peaker would earn in each hour will be multiplied by the ratio of load in that hour to the peak load for the power year; and
- Each kW of load on the ISO system will be required to support more than a kW of supply.

Since the capacity required in each month is based on the contribution of the load to the ISO annual peak, the total cost to load (i.e., dollars per kW times required capacity) is essentially fixed for an entire power year. The unit cost of capacity for a calendar year will be the average of five months at the cost for the power year ending in May of that calendar year and seven months for the power year starting in June.

80 "Forward Capacity Market Payments, Performance and Charges," ISO-NE, October 11, 2006, p. 9.

ii. Transition Period Price Forecast (2006 – May 2010)

Due to the fact that consumers must pay for all qualifying ICAP supply during the transition period, none of these capacity costs are avoidable.

iii. Post-Transition Period Price Forecast (May 2010 on)

There is no experience with this particular form of capacity auction, with the bidding behavior of existing generators, or the cost and bidding behavior for new resources. Any forecast of FCM prices will therefore be inherently more uncertain than a forecast for a more-established market.

Our forecast of FCM prices is based on the following assumptions:

- The FCM prices will be determined by the price of new peakers. We understand that in capacity prices in the first few years of the FCM may actually be set by lower-cost demand-response and energy-efficiency resources. However, the purpose of this study is to estimate the value of future DSM resources relative to a reference or base case that assumes no new DSM, and hence does not reflect the potential for lower post-DSM prices;
- The FCM prices will provide developers enough assurance to build enough peakers to meet the ISO-NE regional capability target, but no more; and
- Capacity will be added preferentially in the areas with the lowest reserves and the highest FCM prices, gradually equalizing reserves across the region. Connecticut and NEMA are most likely to have prices higher than average, and Maine is the zone most likely to have FCM prices below average.

The prices paid to generators should approximate the cost of new entry, which is assumed to be the fixed costs of a merchant combustion turbine, net of a conservative estimate of profits from energy sales.[81]

The three ISO adjustments to the FCM auction price were treated as follows:

(a) Non-Performance Penalties

Since bidders offering new capacity are likely to increase their bids to cover the expected level of outages and non-performance penalties, it was assumed that the price after non-performance penalties would be similar to the cost of new entry.

[81] New peakers are also likely to receive some revenues in the forward reserve market (although this would require foregoing some energy revenues) and the real-time reserve market. Since the ISO will reduce the forward reserve price by the forward capacity price, and since the forward capacity auction will be run long before the forward reserve auction, we assume that developers will not reduce their capacity bids based on potential future reserve payments.

(b) Peak Energy Rent

The PER offset is likely to be very small.[82] It was assumed that bidders will increase their bids to cover that small reduction.

(c) Reserve Margin

Each kW of load on the ISO system will be required to support more than a kW of supply. A reserve margin of 14.3% was assumed, plus an allowance for the demand-response resources that were assumed in the determination of the required reserves.

iv. Assumed Cost of a New Peaker

The following inputs for the cost of new entry into the forward capacity market were assumed:

Exhibit 6-2. Inputs for the Cost of New Entry into the Forward Capacity Market (FCM)

Parameter	Value	Source
Total Investment	$800/kW	$700: High end from ISO-NE Stakeholders Analysis Working Group, "Resource Assumptions Revised", 4/4/07 $1,000: Upstate estimate for 2xLM6000, Sargent & Lundy, NYISO ICAP Working Group, "Updated Results and Discussion: Capital Cost and Performance of New Entrant Peaking Unit" 3/22/07
Debt-equity ratio	50:50	
Cost of debt	9%	
Cost of equity	15%	
Debt maturity	20 years	
Fixed O&M	$15/kW-yr	PacifiCorp's West Valley (5xLM6000) O&M was $15/kW for 2005; increase for higher costs in Northeast & overheads; decrease for competitive incentives
Variable O&M	$5/MWh	Sargent & Lundy, op cit
Full-load clean and new heat rate	9,700	Sargent & Lundy, op cit.
EAF	95%	
Income tax rate	40%	
Property tax rate (% of investment)	2%	

The financial inputs were intended to represent the low end of merchant risk, reflecting the fact that the FCM will offer new units the equivalent of five-year fixed-price contracts,

[82] Over the period from 2005 to the present, the PER would have been less than $1/kW-year.

but that developers will be at risk for energy and reserve revenues, and for the severe penalties for failure to operate at critical hours. (As noted above, it is anticipated that bidders will take the ISO's energy-revenue credit and non-performance penalties into consideration when developing their bids.)

These inputs resulted in a real-levelized fixed cost of about $130/kW-yr, which would be offset by average net energy revenues of about $30/kW-yr, for a net bid price of about $100/kW-yr or $8.33/kw-month.[83,84] Increasing that price by a reserve margin of 14.3% results in a forecast cost to consumers of $114/kW-yr in 2007 dollars.

The maximum price under the ISO rules would start at $126/kW-yr in 2010–2011 (i.e., 1.4 × $90/kw-yr). Assuming a 5% non-performance penalty and a PER offset of $1/kW-yr and adding the 14.3% reserve margin, the maximum cost to customers would be $136/kW-yr.[85] That price would be paid only were new capacity were expensive, or less available than expected, or if inadequate transmission among zones resulted in a some zone separating from the rest of the pool.

v. Market Operation

One critical issue in the forecasting of FCM prices is whether prices will be uniform across the ISO, or whether some zones will decouple from the pool and have higher or lower prices. If the ISO sets high capacity transfer limits among zones, it is assumed that the FCM price will be set at the cost of new entry for all zones. If the capacity transfer limits are lower, FCM prices in the early years will stick at the price cap in the most capacity-constrained zones (Connecticut and possibly some Massachusetts zones), while the prices in Maine and possibly Vermont and New Hampshire may be lower than the cost of new entry.[86] In the absence of any experience with this market, estimating the lower prices is a matter of judgment. Over time, concentration of new resources in the higher-priced zones would tend to eliminate the FCM price differentials among zones.

The ISO committed to finalize the topology (which would include the local sourcing requirements and transfer limits) for the first forward-capacity auction in December 2006 and post the final assumptions early in January 2007.[87] The assumptions do not appear to have been posted yet. If the capacity transfer limits are the same as the estimates the ISO

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83 Some peakers will decide to bid into the forward reserve market. They will receive revenues from this market, but receive less in energy revenues (since they will need to bid into the energy market at more than 14,000 Btu/kWh).

84 ISO-NE is using an estimate of $7.50/kw-month.

85 (($126/kw-yr × 0.95)—$1/kw-yr) × 1.143 = $136/kw-yr.

86 The caps are 1.4 × $90/kW-yr, or $126/kW-yr in 2010–2011; 1.4 times the average of $90 and the first-year price ($126) or $151/kW-yr in 2011–2012; and 1.4 × (.25 × $90 + .75 × ($126 + $151) ÷ 2) = $177/kW-yr in 2012–2013.

87 "Establishing New England System Topology Assumptions for the Forward Capacity Market," Transmission Owners Meeting, October 19, 2006, p. 4

sponsored in the testimony of David LaPlante in the Locational ICAP Filing[88], there will be no locational zones in the FCM.[89]

Thus, our forecast of the cost of forward capacity to consumers is $114/kW-yr in 2007 dollars, based on the cost of new peakers, from June 2010 through the end of the study period. For calendar year 2010, the avoided cost would be $67/kW-year, representing seven months of the forward capacity market.

vi. Reliability-Must-Run (RMR) Contracts

Our study does not include any avoidable costs for reliability contracts for the reasons outlined herein.

The FCM price projected in this study covers the entire revenue requirement of four of the ten plants described in Exhibit 5-8, so those plants should not require reliability agreements.[90] The combined-cycle plants are likely to earn at least $80/kW-yr of profit in the energy markets, so Berkshire, Milford and Bridgeport Energy should be economic without any special treatment. With the market energy prices projected in this project, New Haven Harbor would earn net energy revenues higher than its net revenue requirement in most of the next several years; especially with some uplift compensation for cycling, this unit should receive more than its revenue requirement or at the very least roughly break even. And, the cost of keeping this unit on line is likely to be less than the revenue requirements which the ISO agreed to pay them. That leaves only the West Springfield CTs and Bridgeport Harbor 2 at risk. The FCM should be sufficient to encourage some developer to build new capacity in WCMA, if Con Edison bids West Springfield into the forward capacity auction at a price close to the $161/kW-year revenue requirement. Bridgeport Harbor 2 may not longer be needed after the operation of the Southwest Connecticut transmission upgrade and other changes in the system. At worst, the cost of the remaining reliability contract would be under $5 million for Bridgeport Harbor 2 ($46/kW-year × 130 MW). It is not clear what magnitude of load reductions would avoid the need for Bridgeport Harbor 2.

vii. Comparison to 2005 AESC Estimates of Capacity Costs

The 2005 AESC study, based on the administrative “demand-curve” method then proposed by ISO-NE for setting locational installed capacity prices, estimated capacity prices that varied by year and zone. The levelized capacity prices for 2006–2020 (in 2005 dollars, excluding reserves) were $48/kW-year for Maine, $71/kW-year–$74/kW-year in various parts of Connecticut, $72/kW-year for Boston, and $68/kW-year in other zones.

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88 FERC Docket No. ER03-563-030, August 31, 2004

89 This is also the conclusion of “Report on the Electricity Sector Needs of Connecticut, 2007–2021,” London Economics International, on behalf of the Connecticut DPUC, August 25, 2006.

90 As noted above, DSM resources may reduce actual FCM prices in the first few years of the market’s operation. If those conditions materialize, some of the RMR generators may request new contracts, creating the opportunity for additional DSM to avoid RMR costs. This factor would tend to offset the reduction in avoidable FCM prices and stabilize the value of DSM.

Even with reserves and inflation, the values from the 2005 study were lower than the current estimates, primarily due to the differences in the anticipated ISO capacity markets.

viii. Derivation of FCM Load Reduction Credits

When preparing our analysis of the FCM, we estimated the capacity credits that program administrators programs would receive if they bid DSM programs into the forward capacity auction. Those estimated capacity credits are presented in our Avoided Electricity Cost workbook in Attachment D.

Our estimation of those credits is based upon our projection of the prices in the FCM and the procedure that ISO-NE will follow to determine credits for load reduction resources from those prices.[91] Under that procedure ISO-NE will determine the credit, i.e., $/kw x kw of load reduction, to provide a load reduction resource based upon its actual performance in two key periods, a summer period of June, July and August and a winter period of December and January. In the remaining months the ISO will pay a capacity credit to that resource based on its performance in each of those periods, specifically

- In April, May, September, October, and November, the ISO will pay a credit equal to the resource's average reduction in June, July and August; and
- In February and March, the ISO will pay a credit equal to the resource's average reduction in December and January.

The following exhibit summarizes the rules for load-reduction credits:

Exhibit 6-? Procedure for Determination of Load Reduction Credits

<table>
<tr><th rowspan="2">Type of Demand Resource</th><th colspan="12">Month</th></tr>
<tr><th>Dec</th><th>Jan</th><th>Feb</th><th>Mar</th><th>Apr</th><th>May</th><th>Jun</th><th>Jul</th><th>Aug</th><th>Sep</th><th>Oct</th><th>Nov</th></tr>
<tr><td>"On-Peak"</td><td colspan="2">5 to 7 pm</td><td colspan="2" rowspan="2">Average of Dec & Jan credits</td><td colspan="2" rowspan="2">Average of Jun-Aug credits</td><td colspan="3">1 to 5 pm</td><td colspan="3" rowspan="2">Average of Jun-Aug credits</td></tr>
<tr><td>"Seasonal"</td><td colspan="2">Load>90% forecast winter peak</td><td colspan="3">Load>90% forecast summer peak</td></tr>
</table>

Thus, the actual load reduction that a resource achieves in each of the three summer months of June, July, August will determine the capacity credit it will receive for the equivalent of 2.67 months, i.e. one summer month plus 1.67 shoulder months. The 1.67 shoulder months represents one-third of the credit for each of the five months whose credit is based upon summer performance. Similarly, the actual load reduction that a

[91] For more detail and the treatment of dispatchable demand-side resources, see "Introduction to Demand Resource Participation in New England's Forward Capacity Market," ISO-NE presentation at the Sheraton Springfield Monarch Place Hotel, February 16, 2007.

resource achieves in each of the two winter months of December and January will determine the capacity credit it will receive for the equivalent of 2 months, i.e. one winter month plus 1 shoulder month. The 1 shoulder month represents one-half of the credit for each of the two months whose credit is based upon winter performance. The FCM values presented in the Avoided Electricity Cost workbook in Attachment D are the effective annual values that a resource will receive for load reduction in each summer month and in each winter month, e.g. summer value ($/kw-month) = 2.67 * ??? $/kw-month; winter value ($/kw-month) = 2.0 * ??? $/kw-month.

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

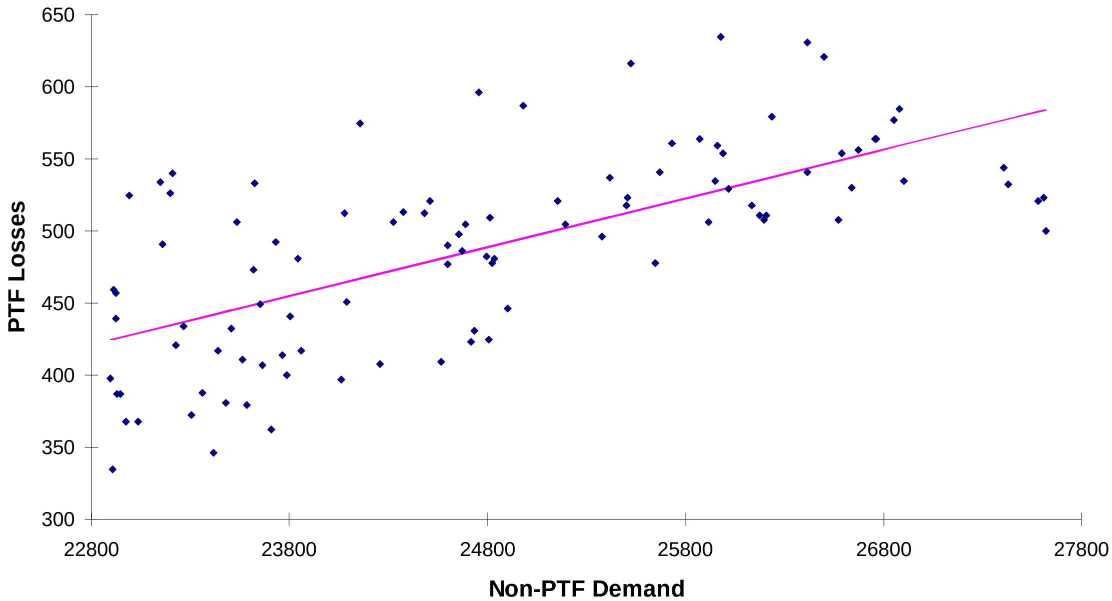
There is a loss of electricity between the generating unit and the ISO's delivery points, where power is delivered from the ISO-administered pool transmission facilities (PTF) to the distribution utility local transmission and distribution systems. Therefore, a 1 kilowatt load reduction at the ISO's delivery points, as a result of DSM, 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.[92] 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 have to be adjusted for theses losses. We are proposing that they be adjusted by a marginal demand loss factor of 3.38%.

The marginal loss of 3.38% was estimated by regressing the system losses against real-time demand for the top 100 hours in summer 2006 because the ISO does not appear to publish estimates of the losses on the ISO-administered transmission system at system peak. Losses were 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, which is apparently the term that the ISO uses for the load delivered to the distribution utilities. While PTF losses probably vary among zones, 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 the exhibit below.

[92] 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 6-3. PTF Losses vs. Non-PTF Demand for the Top 100 Summer Hours, 2006



The regression equation was PTF Losses = 0.0338 × Non-PTF Demand – 350. While the adjusted R^2 was just 0.44, the marginal demand loss factor of 3.38% had a t-statistic of 8.9 and a 95% confidence interval of 2.6% to 4.1%.

D. Retail Adder

Retail prices for full-requirements fixed-price contracts were generally higher than the sum of wholesale prices. This was shown in the 2001 AESC report, and remains true today, despite more detailed analysis of the costs of ancillary service, uplift and load shapes.

The primary factor underlying the retail adder appears to be risk. During hot summers and cold winters LSEs need to procure additional energy at shortage prices while in mild weather they tend to have energy to dump into the 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). While no utility sponsor of this project was able to provide public information on the retail adders implicit in the prices bid by suppliers, confidential data suggested that a 10% retail adder was realistic.[93] This adder was applied to the avoided wholesale energy prices and avoided wholesale capacity prices.

[93] The magnitude of the adder is smaller for near-term procurements than for power procured years in advance, and is higher for congestion into load pockets (such as Connecticut) than for supply to

The details of the risks and costs of serving load are somewhat different in Vermont and for Public Service of New Hampshire, where vertically-integrated utilities procure power from owned resources and a variety of long- and short-term contracts. These utilities face risks similar to those of the competitive suppliers in terms of weather and economic fluctuations, especially for their marginal decisions about acquiring new supply or selling existing suppliers into the market. The Vermont Public Service Board uses a risk adder for DSM avoided costs of 11.1%, slightly higher than the generic retail adder. The 10% adder was also used for Public Service of New Hampshire.

E. Demand-Reduction-Induced Price Effects (DRIPE) for Energy and Capacity

i. Overview

The Demand-Reduction-Induced Price Effect (DRIPE) is the reduction in market prices across the ISO-NE region as a result of the reduction in need for energy and/or capacity due to efficiency and/or demand response programs.

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 is referred to this as energy DRIPE. However, those price effects are not likely to persist many years, despite the persistence of 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;
- 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.

The final DRIPE was 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.

unconstrained areas. The 10% value is a reasonable estimate for the standard-service procurement schedules in most states.

(a) Effect of Load Reduction on Market Energy Prices

The determination of DRIPE starts with an analysis of the historical variation in locational energy market prices as a function of variation in zonal and regional loads. To minimize the effect of changes in fuel prices, each month was analyzed separately, over a period of at least the last year. Due to the unusual weather in the winter of 2006–7, analyses from the preceding winter were included.

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 or insignificant, the zonal price was regressed on total pool load and the resulting coefficient was used for both the own-zone and ROP load. These analyses were performed separately for on- and off-peak hours, since it was expected (and observed) that the slope of market price as a function of load would be higher on-peak.

These results indicate that each additional MW of load in a zone typically increases price in that zone by from 0.4¢/MWh to 4.5¢/MWh, depending on the zone and month. An additional MW of load in the ROP typically increases prices from 0.3¢/MWh to 2.0¢/MWh. The price effect is consistently higher on-peak than off-peak.

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.

The following coefficients result from the on-peak regressions for June 2006.

Exhibit 6-4. Coefficients from June 2006 On-Peak Regressions

	Coefficients $/MWh per MW		Average Hourly Load MWh	Potential DRIPE $/MWh
Zone	**Own Load**	**ROP**		
CT	0.0211		4,345	91.8
ME		0.0031	1,419	4.4
NH		0.0040	1,530	6.1
RI		0.0050	1,104	5.5
VT		0.0052	686	3.6
NEMA		0.0068	3,458	23.5
SEMA		0.0049	1,949	9.6
WCMA		0.0037	2,282	8.4
Total				152.8

In this example, reducing Connecticut load one on-peak MWh would reduce regional power bills for the remaining load by about $153, if all prices followed the day-ahead market.

ii. Pace at which Supply Will Adapt to Load Reductions

As noted above, a reduction in load will reduce actual and projected prices relative to the levels in the absence of that reduction (the reference case). That reduction in prices will tend to change the mix of generation used to supply the market. This is referred to this as *supply adaptation.* For example, the lower prices due to energy-efficiency investments may cause the following changes in the supply mix:

- 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 a 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[94]; and/or
- The owner of a baseload or intermediate plant may decide to defer spending that would increase its capacity or reliability, since the incremental revenues would not justify the expenditures.

As the supply mix changes in these and similar ways, energy prices would 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 developers, owners and the ISO should be essentially the same as they would have been without the load reduction. Thus, supply adaptation ceases once the price effect has been extinguished.

Supply adaptation will take several years to eliminate all DRIPE, since the supply system cannot immediately respond to the reduction in load. For example, the downward pressure on energy prices due to efficiency measures implemented in one year (e.g., 2009) may not immediately affect expectations of market energy prices. The reductions may only be reflected in decisions to bid FCM capacity in the next year (e.g., 2010) for capacity to be delivered three years later (e.g., 2013).

Estimating the extent of delay in adaptation of the energy market to efficiency-related load reductions is subject to considerable uncertainty. Considering project lead time (including the operation of the FCM market) and past experience with over- and under-building cycles, it is believed that supply adaptation will offset the price effect of DSM over a period of four years after the installation of the measure, with an offset of 0% in years one and two, 35% in year three and 65% in year four.

[94] This is not an entirely hypothetical concern, given the costs of upgrading existing coal (and some oil) plants to meet tighter limits on air emissions and (for Brayton Point) use of cooling water.

iii. 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 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.

The exhibit below summarizes the contracting patterns for power supply by state and type of utility and/or supply arrangement.

Exhibit 6-5. Share of Power Supply Under Contract

	Supply Type	Percent of state load	Share of Power Supply Under Contract[a] 1st Year	2nd Year	3rd Year
Connecticut	Standard Service[b]	62%	90%	50%	10%
	SOLR[c]	10%	50%	–	–
	Competitive Supply[d]	25%	80%	50%	20%
	Munis[e]	3%	95%	90%	85%
Maine	Residential[f]	40%	85%	10%	–
	Med & Large C&I[g]	15%	45%	–	–
	Competitive Supply	40%	80%	50%	20%
	Munis & Coops	5%	95%	90%	85%
Massachusetts	NStar + CLC Res & Sm C&I[h]	20%	90%	50%	10%
	Other Res & Sm C&I[i]	20%	70%	–	–
	Large C/I DS[j]	5%	40%	–	–
	Competitive Supply	40%	80%	50%	20%
	Munis	15%	95%	90%	85%
New Hampshire	PSNH[k]	100%	80%	75%	75%
	Other	85%	90%	50%	10%
Rhode Island	NGrid	85%	90%	50%	10%
	Pascoag	100%	95%	95%	95%
	Competitive Supply	62%	90%	50%	10%
Vermont	All	10%	50%	–	–

NOTES

[a] First year is twelve months from measure installation.

[b] Based on the current procurement pattern.

[c] Purchases six months at a time, two months before need, one month lag in load data. Depending on timing, energy-efficiency measures start to affect purchase prices in three to nine months.

[d] Assume mostly three-year large-C&I contracts, some of which will be expiring in each year. Cost under various contract reduced by flow-through of various costs (e.g., congestion). Same pattern assumed for all states.

[e] Assume mostly long-term contracts.

[f] Purchases twelve months at a time, four months before need, one month lag in load data.

[g] Purchases six months at a time, one month before need, one month lag in load data.

[h] The policy is in flux, moving to longer-term procurements. Assumed here to equal the pattern of acquisitions in Connecticut.

[i] Purchases half of requirements for next year every six months. Assume two months before need, one month lag in load data.

[j] Purchases three months at a time, two months before need, one month lag in load data. Depending on timing, energy-efficiency measures start to affect purchase prices in three to six months.

[k] From PSNH's 2005 FERC Form 1, Other Service purchased power (pp. 326–327) net of Other Service sales (pp. 310–311), which was 25% of sales + losses (p. 401). Other Service is for less than one year and/or non-firm. Since some of the Other Service may be contracted for some period within the first year, we assumed 80% was contracted in the first year and 75% thereafter.

In each state, most of the power supply for the immediate twelve months is under contract. In all states except New Hampshire and Vermont, the existing contracts expire over the next couple years, so consumers will be subject to future market prices, reflecting the effects of DSM., The below exhibit summarizes the estimated portion of retail power supplies exposed to market prices (and hence benefiting from the effect of DSM on price) over time.

Exhibit 6-6. Share of Power Supply Exposed to Market Prices

	1st Year	2nd Year	3rd Year	4th Year
Connecticut	16%	54%	86%	98%
Maine	22%	71%	88%	96%
Massachusetts	20%	56%	77%	88%
New Hampshire	20%	25%	25%	25%
Rhode Island	11%	50%	88%	100%
Vermont	5%	5%	5%	5%
Sales-Weighted Regional Average	18%	52%	74%	83%

Multiplying the first factor (the share of the load exposed to market prices) by the second factor (the portion of the price effect not yet offset by supply adaptation) produces the third factor, an estimate of the percent of load affected by DRIPE.

% of load subject to DRIPE = (1- supply response) × % of power supply prices at market

The exhibit below provides, for each state, the result of reducing the share of load exposed to market prices from the exhibit above by the supply response in the first line of the exhibit below.

Exhibit 6-7. Percent of Load Affected by Price Effect

	1st Year	2nd Year	3rd Year	4th Year
Supply Response	0%	0%	35%	65%
Retail DRIPE Effect				
Connecticut	16%	54%	56%	34%
Maine	23%	72%	57%	34%
Massachusetts	20%	57%	50%	31%
New Hampshire	20%	25%	16%	9%
Rhode Island	12%	50%	58%	35%
Vermont	5%	5%	3%	2%
Sales-Weighted Regional Average	18%	52%	48%	29%

Further combining these percentage effects with the potential DRIPE produces the price effects by zone and season presented in the exhibit below, expressed in dollars per MWh saved in each zone.

Exhibit 6-8. Price Effects by Zone (2007$ per MWh Saved)

		Zone							
Year	**Season**	**CT**	**ME**	**NH**	**RI**	**VT**	**NEMA**	**SEMA**	**WCMA**
On-Peak									
1	**Summer**	33.2	23.7	28.3	24.1	24.5	28.9	31.0	26.1
1	**Winter**	16.5	15.1	15.2	14.5	14.6	15.2	18.1	15.4
2	**Summer**	100.2	69.3	75.5	70.3	71.2	84.0	90.1	76.0
2	**Winter**	48.7	44.1	42.3	42.6	42.1	43.9	52.3	44.5
3	**Summer**	97.1	65.1	69.4	66.0	66.8	78.2	83.6	71.1
3	**Winter**	46.3	40.8	39.2	40.3	39.4	40.9	48.4	41.5
4	**Summer**	59.1	39.5	41.9	40.1	40.6	47.6	50.9	43.2
4	**Winter**	28.1	24.7	23.7	24.5	23.9	24.9	29.5	25.2
Off-Peak									
1	**Summer**	16.4	10.1	14.2	10.4	9.8	12.6	12.6	9.7
1	**Winter**	13.3	12.4	14.4	11.8	11.5	13.1	14.1	11.7
2	**Summer**	50.5	29.8	34.0	31.4	28.6	36.7	36.7	28.5
2	**Winter**	39.4	36.5	37.1	34.7	33.5	38.0	41.0	34.1
3	**Summer**	49.5	27.6	30.1	29.9	26.6	33.8	33.8	26.5
3	**Winter**	37.3	33.5	33.5	32.6	31.1	35.2	37.8	31.7
4	**Summer**	30.1	16.7	18.1	18.1	16.2	20.6	20.6	16.1
4	**Winter**	22.7	20.3	20.2	19.8	18.9	21.4	23.0	19.3

We used the same set of Massachusetts estimates of percentage load affected by price effects for all three Massachusetts zones.

iv. Capacity Demand-Reduction-Induced Price Effect

The reduction of load should reduce capacity prices in the forward capacity market as well as on electric energy prices in the wholesale energy markets. Since the forward capacity market will set prices roughly three years in advance, and is likely to be tied closely to the cost of new entry, it is expected that capacity prices will not be very sensitive to small changes in load growth, so long as the growth in load plus retirements of existing capacity continues to require some generic new capacity. Nonetheless, even a small change in market capacity prices could have significant cumulative effects across New England.

The approach to estimating capacity DRIPE was fundamentally different from that in the 2005 AESC report because ISO NE has moved from an ICAP approach to a FCM. At the time of the 2005 AESC report, ISO-NE was proposing an installed-capacity (ICAP) market with prices determined administratively, based on the ratio of capacity resources to peak load. Accordingly, the 2005 report estimated the effect of reduced peak load on the administrative determination of price. Since that time, ISO-NE has abandoned that ICAP market and replaced it with the forward capacity market. DRIPE effects in the FCM are difficult to estimate and are likely to be small.

It is expected that several generating units will bid into, and be selected under, the annual FCM auction (i.e., a supply curve). The cost of the most-expensive unit selected, the marginal new peaking unit, will set the FCM price from that auction. The capacity DRIPE was calculated by estimating the impact of energy-efficiency bid into the FCM on the FCM price. Energy efficiency will shift the supply curve to the right, potentially eliminating the need for the marginal new unit and thereby allowing the market to clear at the cost of the second most expensive peaker. While this effect is speculative, it should produce a reasonable estimate of capacity DRIPE.[95]

Our application of this approach is detailed in the following paragraphs. Our two assumptions are that the size of the peaker units that set the FCM price will be typically 200 MW, and that the difference between the bid of the most expensive unit and the bid of the next most expensive will average $1/kw-yr. Based upon those two assumptions, each MW of DSM bid into the market would reduce the market-clearing price by an average of $0.0057/MW-year.[96] Thus, each kW of DSM would reduce the market-clearing price by an average of $0.0000057/kW-year. That seems like a minute effect, but it would reduce the price of some 33,000 MW of pool-wide capacity requirement by 2011, for a total potential DRIPE effect of about $190/kW-year of load reduction.[97] We recommend that this estimate is updated by analyzing actual bids once ISO-NE releases the bids received in the FCM auction in 2008.

For the 2008 DSM program year, assuming that the savings are bid into the first FCM auction in February 2008, the capacity DRIPE effect would apply to the power year starting June 2010. Since that effect would only apply to seven months in 2010, and since the analysis that produced the Share of Power Supply Exposed to Market Prices exhibit above suggests that about 65% of ISO load (between the second and third-year results) would be exposed to the market 2½ years into the future, the capacity DRIPE for 2010 might be about $72/kW of load reduction in the 2008 program plan.[98] For 2011, capacity DRIPE might rise to $140/kW for a full year of FCM with less supply (about 25%) under

[95] These benefits might be a little lower for DSM that is not bid into the FCM. The effect of non-bid DSM 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.

[96] $1/MW-year ÷ 175 MW = $0.0057/kW-year per MW of load reduction. We divide by 175 MW, because 175 MW of load reduction, when grossed up by a reserve margin of 14.3%, would avoid the need for a 200-MW peaker.

[97] 33,000,000 kW × $0.000057/kW–yr per kW of load reduction = $ 190/kW of load reduction.

[98] $190/kW × 65% × 7/12 = $72/kw

contract.[99] The impacts of efficiency implemented under the 2009 DSM program year would be similar.

As difficult as it is to estimate the rate at which the energy market (which has operated in a similar manner for several years, and is relatively well understood) will adapt to the addition of energy-efficiency, the FCM market is much harder. The best estimate, using the limited historical experience with response of the capacity markets to over- and under-building situations, is that the FCM DRIPE will dissipate linearly over the fourth and fifth years following the implementation of the energy-efficiency measures. With these assumptions, capacity DRIPE would be as follows:

Exhibit 6-9. Capacity DRIPE by Year and Program Year (2007$/kW)

	DSM Program Year	
Year	**2008**	**2009**
2010	$72	
2011	$140	
2012	$90	$140
2013	$40	$90
2014		$40

(b) Comparison to 2005 AESC DRIPE Estimates

The 2005 AESC study, based on the administrative "demand-curve" method then proposed by ISO-NE for setting locational installed capacity prices, estimated capacity DRIPE of $278/kW-year levelized over 2006–2020 in 2005 dollars, although ICF also estimated an alternative "DRIPE light" value—reflecting the fact that not all capacity is traded in the spot market—of $81/kW-year over the same period. With 14.3% reserves and 5.5% inflation, these values would be $335/kW-year and $98/kW-year, respectively, in the units of this study. These estimates straddle the $190/kW-year potential DRIPE estimated above.

The 2005 AESC study did not anticipate any phase-out of the capacity DRIPE effect over time. Hence, the cumulative capacity DRIPE effects in the 2005 AESC study, even in the DRIPE-light case, were greater than the effects in the current case. The study authors do not believe that capacity DRIPE will continue indefinitely, although the phase-out schedule assumed above is simply one estimate from a wide range of reasonable estimates.

[99] $190/kW-yr × 75% = $140/kW-yr.

7. Environmental Effects

This section presents the findings and recommendations for Deliverable 10 under Task 7 "Environmental Effects"**.** Subsection A covers tasks 7 (a) and 7 (b). Subsection B covers Task 7 (c).

A. Physical environmental benefits from energy efficiency and demand reductions

The scope of work asks for the heat rates, fuel sources, and emissions of NOx, SOx, CO_2, and mercury of the marginal units during each of the energy and capacity costing periods in the 2007 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/kW, 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 NOx, SOx, CO_2, and mercury from our database of input assumptions. The marginal units and their characteristics are presented in Exhibits 7-1 and 7-2 below.

Exhibit 7-1. 2007 New England Marginal Heat Rate by Pricing Period (btu/kWh)

EntityName	(Multiple ns)

Average of Heat Rate (btu/kWh)	Season / Period2				
	Summer		Winter		Grand Total
	OffPeak	OnPeak	OffPeak	OnPeak	
Total	9,245	10,259	9,022	9,808	9,442

Exhibit 7-2. 2007 New England Marginal Fuel Type

Count of Marginal Unit	Season / Period2				
	Summer		Winter		Grand Total
FuelType	OffPeak	OnPeak	OffPeak	OnPeak	
Gas	63.46%	48.94%	67.36%	53.69%	60.67%
Oil	25.21%	42.56%	25.64%	37.35%	30.78%
DSM	1.34%	7.56%	2.53%	8.96%	4.29%
Coal	7.96%	0.48%	3.91%	0.00%	3.49%
LFG	0.87%	0.46%	0.45%	0.00%	0.47%
Biomass	1.15%	0.00%	0.12%	0.00%	0.30%
Grand Total	100.00%	100.00%	100.00%	100.00%	100.00%

Gas	60.67%
Oil	30.78%
DSM	4.29%
Coal	3.49%
LFG	0.47%
Biomass	0.30%
Grand Total	100.00%

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/kW. 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

- $\textit{Marginal Emissions} = (\textit{Fuel Burned}_{MU}\ (MMBtu) \times \textit{Emission Rate}_{MU}\ (lbs/MMBtu) \times 1\ ton/2000\ lbs)/\textit{Generation}_{MU}\ (MWh)$

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 Exhibits 7-3 through 7-12 below represent the averages for each pollutant over each costing period for all of New England. The first 5 exhibits show the avoided emissions values in short tons/MWh and the second 5 exhibits show the avoided emissions values in short lbs/kWh.

Exhibit 7-3. 2007 New England Summary of Avoided CO_2, NO_x, SO_2 and Mercury (Hg) Emissions Rate by Pricing Period (short tons/MWh)

EntityName	(Multiple [illegible]s)

	Season / Period2				
	Summer		Winter		Grand Total
Data	OffPeak	OnPeak	OffPeak	OnPeak	
Average of CO2(tons/MWh)	0.66	0.68	0.60	0.61	0.63
Average of NOx(tons/MWh)	0.00052	0.00074	0.00045	0.00054	0.00054
Average of SO2(tons/MWh)	0.0010	0.0014	0.0008	0.0014	0.0010
Average of Hg(tons/MWh)	9.459E-10	1.124E-11	2.81E-10	0	3.273E-10

Exhibit 7-4. 2007 New England Avoided CO_2 Emissions by Modeling Zone and Pricing Period (short tons/MWh)

Average of CO2(tons/MWh)	Season / Period2				
	Summer		Winter		Grand Total
EntityName	OffPeak	OnPeak	OffPeak	OnPeak	
NEW ENGLAND - Bangor Hydro Area	0.67	0.68	0.60	0.60	0.63
NEW ENGLAND - Boston	0.66	0.67	0.60	0.61	0.63
NEW ENGLAND - Central Maine Power Area	0.67	0.68	0.60	0.60	0.63
NEW ENGLAND - Central Massachusetts	0.66	0.67	0.60	0.61	0.63
NEW ENGLAND - Connecticut Central-North	0.66	0.67	0.60	0.60	0.63
NEW ENGLAND - Connecticut Southwest	0.66	0.67	0.60	0.60	0.63
NEW ENGLAND - New Hampshire	0.66	0.68	0.60	0.60	0.63
NEW ENGLAND - Rhode Island	0.66	0.68	0.60	0.61	0.63
NEW ENGLAND - Southeast Massachusetts	0.66	0.67	0.60	0.61	0.63
NEW ENGLAND - Vermont	0.66	0.68	0.60	0.60	0.63
NEW ENGLAND - Western Massachusetts	0.66	0.68	0.60	0.61	0.63
Grand Total	0.66	0.68	0.60	0.61	0.63

Exhibit 7-5. 2007 New England Avoided NO_x Emissions by Modeling Zone and Pricing Period (short tons/MWh)

Average of NOx(tons/MWh)	Season / Period2				
	Summer		Winter		Grand Total
EntityName	OffPeak	OnPeak	OffPeak	OnPeak	
NEW ENGLAND - Bangor Hydro Area	0.00053	0.00074	0.00045	0.00054	0.00054
NEW ENGLAND - Boston	0.00052	0.00073	0.00045	0.00055	0.00054
NEW ENGLAND - Central Maine Power Area	0.00053	0.00074	0.00046	0.00054	0.00054
NEW ENGLAND - Central Massachusetts	0.00052	0.00073	0.00045	0.00055	0.00054
NEW ENGLAND - Connecticut Central-North	0.00052	0.00075	0.00045	0.00054	0.00054
NEW ENGLAND - Connecticut Southwest	0.00052	0.00074	0.00045	0.00055	0.00054
NEW ENGLAND - New Hampshire	0.00052	0.00074	0.00045	0.00054	0.00054
NEW ENGLAND - Rhode Island	0.00052	0.00073	0.00045	0.00055	0.00054
NEW ENGLAND - Southeast Massachusetts	0.00052	0.00073	0.00045	0.00055	0.00054
NEW ENGLAND - Vermont	0.00052	0.00073	0.00045	0.00054	0.00053
NEW ENGLAND - Western Massachusetts	0.00053	0.00074	0.00045	0.00055	0.00054
Grand Total	0.00052	0.00074	0.00045	0.00054	0.00054

Exhibit 7-6. 2007 New England Avoided SO_2 Emissions by Modeling Zone and Pricing Period (short tons/MWh)

Average of SO2(tons/MWh)	Season / Period2				
	Summer		Winter		Grand Total
EntityName	OffPeak	OnPeak	OffPeak	OnPeak	
NEW ENGLAND - Bangor Hydro Area	0.0010	0.0015	0.0008	0.0014	0.0011
NEW ENGLAND - Boston	0.0010	0.0014	0.0008	0.0014	0.0010
NEW ENGLAND - Central Maine Power Area	0.0010	0.0015	0.0008	0.0014	0.0011
NEW ENGLAND - Central Massachusetts	0.0010	0.0014	0.0007	0.0014	0.0010
NEW ENGLAND - Connecticut Central-North	0.0010	0.0013	0.0007	0.0013	0.0010
NEW ENGLAND - Connecticut Southwest	0.0010	0.0013	0.0007	0.0013	0.0010
NEW ENGLAND - New Hampshire	0.0010	0.0015	0.0008	0.0014	0.0011
NEW ENGLAND - Rhode Island	0.0010	0.0014	0.0008	0.0014	0.0010
NEW ENGLAND - Southeast Massachusetts	0.0010	0.0014	0.0007	0.0014	0.0010
NEW ENGLAND - Vermont	0.0010	0.0014	0.0007	0.0013	0.0010
NEW ENGLAND - Western Massachusetts	0.0010	0.0014	0.0007	0.0014	0.0010
Grand Total	0.0010	0.0014	0.0008	0.0014	0.0010

Exhibit 7-7. 2007 New England Avoided Mercury (Hg) Emissions by Modeling Zone and Pricing Period (short tons/MWh)

Average of Hg(tons/MWh)	Season / Period2				
	Summer		Winter		Grand Total
EntityName	OffPeak	OnPeak	OffPeak	OnPeak	
NEW ENGLAND - Bangor Hydro Area	9.52E-10	1.14E-11	2.91E-10	0.00E+00	3.34E-10
NEW ENGLAND - Boston	9.52E-10	1.12E-11	2.92E-10	0.00E+00	3.32E-10
NEW ENGLAND - Central Maine Power Area	9.52E-10	1.11E-11	2.88E-10	0.00E+00	3.31E-10
NEW ENGLAND - Central Massachusetts	9.37E-10	1.13E-11	2.93E-10	0.00E+00	3.31E-10
NEW ENGLAND - Connecticut Central-North	9.43E-10	1.13E-11	2.68E-10	0.00E+00	3.22E-10
NEW ENGLAND - Connecticut Southwest	9.43E-10	1.13E-11	2.68E-10	0.00E+00	3.22E-10
NEW ENGLAND - New Hampshire	9.43E-10	1.11E-11	2.91E-10	0.00E+00	3.31E-10
NEW ENGLAND - Rhode Island	9.43E-10	1.11E-11	2.92E-10	0.00E+00	3.31E-10
NEW ENGLAND - Southeast Massachusetts	9.43E-10	1.13E-11	2.69E-10	0.00E+00	3.22E-10
NEW ENGLAND - Vermont	9.50E-10	1.14E-11	2.68E-10	0.00E+00	3.24E-10
NEW ENGLAND - Western Massachusetts	9.47E-10	1.12E-11	2.69E-10	0.00E+00	3.22E-10
Grand Total	9.46E-10	1.12E-11	2.81E-10	0.00E+00	3.27E-10

Exhibit 7-8. 2007 New England Summary of Avoided CO_2, NO_x, SO_2 and Mercury (Hg) Emissions by Pricing Period (short lbs/kWh)

EntityName	(Multiple Items)

	Season / Period2				
	Summer		Winter		Grand Total
Data	OffPeak	OnPeak	OffPeak	OnPeak	
Average of CO2(lbs/kWh)	1.32	1.35	1.20	1.21	1.26
Average of NOx(lbs/kWh)	0.00105	0.00147	0.00090	0.00109	0.00108
Average of SO2(lbs/kWh)	0.0020	0.0028	0.0015	0.0028	0.0021
Average of Hg(tons/MWh)	1.89E-09	2.25E-11	5.62E-10	0.00E+00	6.55E-10

Exhibit 7-9. 2007 New England Avoided CO_2 Emissions by Modeling Zone and Pricing Period (short lbs/kWh)

Average of CO2(lbs/kWh)	Season / Period2				
	Summer		Winter		Grand Total
EntityName	OffPeak	OnPeak	OffPeak	OnPeak	
NEW ENGLAND - Bangor Hydro Area	1.33	1.36	1.20	1.21	1.26
NEW ENGLAND - Boston	1.32	1.35	1.20	1.21	1.26
NEW ENGLAND - Central Maine Power Area	1.33	1.35	1.21	1.21	1.26
NEW ENGLAND - Central Massachusetts	1.32	1.35	1.20	1.21	1.26
NEW ENGLAND - Connecticut Central-North	1.32	1.35	1.20	1.21	1.25
NEW ENGLAND - Connecticut Southwest	1.32	1.35	1.20	1.21	1.26
NEW ENGLAND - New Hampshire	1.32	1.36	1.20	1.21	1.26
NEW ENGLAND - Rhode Island	1.32	1.35	1.20	1.21	1.26
NEW ENGLAND - Southeast Massachusetts	1.32	1.35	1.20	1.21	1.26
NEW ENGLAND - Vermont	1.32	1.35	1.20	1.21	1.26
NEW ENGLAND - Western Massachusetts	1.33	1.36	1.20	1.22	1.26
Grand Total	1.32	1.35	1.20	1.21	1.26

Exhibit 7-10. 2007 New England Avoided NO_x Emissions by Modeling Zone and Pricing Period (short lbs/kWh)

Average of NOx(lbs/kWh)	Season / Period2				
	Summer		Winter		Grand Total
EntityName	OffPeak	OnPeak	OffPeak	OnPeak	
NEW ENGLAND - Bangor Hydro Area	0.00105	0.00148	0.00090	0.00108	0.00108
NEW ENGLAND - Boston	0.00104	0.00146	0.00090	0.00109	0.00107
NEW ENGLAND - Central Maine Power Area	0.00105	0.00147	0.00091	0.00107	0.00108
NEW ENGLAND - Central Massachusetts	0.00104	0.00146	0.00090	0.00109	0.00108
NEW ENGLAND - Connecticut Central-North	0.00104	0.00150	0.00090	0.00109	0.00108
NEW ENGLAND - Connecticut Southwest	0.00104	0.00147	0.00090	0.00109	0.00108
NEW ENGLAND - New Hampshire	0.00104	0.00148	0.00091	0.00108	0.00108
NEW ENGLAND - Rhode Island	0.00104	0.00147	0.00091	0.00109	0.00108
NEW ENGLAND - Southeast Massachusetts	0.00104	0.00146	0.00090	0.00109	0.00107
NEW ENGLAND - Vermont	0.00105	0.00146	0.00090	0.00107	0.00107
NEW ENGLAND - Western Massachusetts	0.00105	0.00148	0.00089	0.00109	0.00108
Grand Total	0.00105	0.00147	0.00090	0.00109	0.00108

Exhibit 7-11. 2007 New England Avoided SO_2 Emissions by Modeling Zone and Pricing Period (short lbs/kWh)

Average of SO2(lbs/kWh)	Season Period2				
	Summer		Winter		Grand Total
EntityName	OffPeak	OnPeak	OffPeak	OnPeak	
NEW ENGLAND - Bangor Hydro Area	0.0021	0.0029	0.0016	0.0028	0.0021
NEW ENGLAND - Boston	0.0019	0.0028	0.0015	0.0028	0.0021
NEW ENGLAND - Central Maine Power Area	0.0021	0.0029	0.0016	0.0028	0.0021
NEW ENGLAND - Central Massachusetts	0.0020	0.0028	0.0015	0.0028	0.0021
NEW ENGLAND - Connecticut Central-North	0.0019	0.0026	0.0015	0.0026	0.0020
NEW ENGLAND - Connecticut Southwest	0.0019	0.0027	0.0015	0.0026	0.0020
NEW ENGLAND - New Hampshire	0.0020	0.0030	0.0016	0.0028	0.0022
NEW ENGLAND - Rhode Island	0.0020	0.0028	0.0015	0.0028	0.0021
NEW ENGLAND - Southeast Massachusetts	0.0020	0.0028	0.0015	0.0028	0.0021
NEW ENGLAND - Vermont	0.0020	0.0029	0.0015	0.0027	0.0021
NEW ENGLAND - Western Massachusetts	0.0020	0.0029	0.0015	0.0027	0.0021
Grand Total	0.0020	0.0028	0.0015	0.0028	0.0021

Exhibit 7-12. 2007 New England Avoided Mercury (Hg) Emissions by Modeling Zone and Pricing Period (short lbs/kWh)

Average of Hg(lbs/kWh)	Season Period2				
	Summer		Winter		Grand Total
EntityName	OffPeak	OnPeak	OffPeak	OnPeak	
NEW ENGLAND - Bangor Hydro Area	1.90E-09	2.27E-11	5.81E-10	0.00E+00	6.68E-10
NEW ENGLAND - Boston	1.90E-09	2.24E-11	5.84E-10	0.00E+00	6.65E-10
NEW ENGLAND - Central Maine Power Area	1.90E-09	2.23E-11	5.76E-10	0.00E+00	6.62E-10
NEW ENGLAND - Central Massachusetts	1.87E-09	2.26E-11	5.87E-10	0.00E+00	6.62E-10
NEW ENGLAND - Connecticut Central-North	1.89E-09	2.26E-11	5.36E-10	0.00E+00	6.43E-10
NEW ENGLAND - Connecticut Southwest	1.89E-09	2.25E-11	5.36E-10	0.00E+00	6.43E-10
NEW ENGLAND - New Hampshire	1.89E-09	2.23E-11	5.83E-10	0.00E+00	6.61E-10
NEW ENGLAND - Rhode Island	1.89E-09	2.23E-11	5.84E-10	0.00E+00	6.61E-10
NEW ENGLAND - Southeast Massachusetts	1.89E-09	2.25E-11	5.39E-10	0.00E+00	6.44E-10
NEW ENGLAND - Vermont	1.90E-09	2.27E-11	5.37E-10	0.00E+00	6.48E-10
NEW ENGLAND - Western Massachusetts	1.89E-09	2.24E-11	5.39E-10	0.00E+00	6.44E-10
Grand Total	1.89E-09	2.25E-11	5.62E-10	0.00E+00	6.55E-10

B. Monetized Emission Values

In the field of economics, when the production of a good imposes costs or results in harmful impacts upon persons other than the producer or on the environment, those impacts are called an "externality."[100] "Externalities" are costs that are not included in the direct costs to entities in the market. Air pollution is a classic externality. Pollutants are released from a facility, imposing health impacts on a population, causing damage to an ecosystem, or both. The costs of the health impacts or the ecosystem damage are borne by entities other than the owner of the pollutant source, and are thus external to the financial decisions pertaining to the source of the pollutant, and are not reflected in the price of the product. Also, those health impact and ecosystem damage costs are not reflected in the price paid by the buyers of the electricity from that unit.

[100] In economics, an externality can be positive or negative; in this discussion we are focusing on negative externalities.

i. History of Externalities

During the early 1990s, utilities and utility regulators in many states engaged actively in efforts to quantify environmental externalities, and to incorporate consideration of those externalities into utility planning and decision-making. Several of the New England states had proceedings dealing with externalities. In Massachusetts, a pair of related dockets (D.P.U. 89-239 and 91-131) was particularly noteworthy, for their timing, litigiousness, and thoroughness. In other states the materials from, and decisions made in, the Massachusetts dockets served as a model, sometimes adapted to the local circumstances and concerns.

In Vermont, for example, the Public Service Board adopted a policy of applying a 5% percentage adder to the cost of generation and transmission resources to reflect environmental externalities and a 10% reduction to the cost of demand side management resources in evaluating resources (VT PSB Order in Docket 5270). Vermont also held a series of workshops to discuss the development of environmental externality values for Vermont but that process did not result in a specific set of values. Instead the environmental externality values selected in Massachusetts were adopted for use in Vermont in a series of Company-specific settlement agreements.

The Massachusetts efforts to address environmental externalities will be discussed briefly here, with a focus on carbon dioxide emissions. Docket D.P.U. 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. In its order in that docket, the Department adopted a set of dollar values for air emissions based upon testimony by Bruce Biewald, a witness for the Division of Energy Resources. The CO_2 value adopted in that order was $22 per ton of CO_2 (in 1989$) and was based upon a "target" approach[101].

The Department of Public Utilities (DPU) in Massachusetts subsequently opened Docket D.P.U. 91-131 specifically to examine environmental externalities. In this docket there were 25 parties, with 21 witnesses testifying over 15 hearing days. The D.P.U. heard testimony recommending various approaches for quantifying the CO_2 externality value, including Dr. William Nordhaus testifying on behalf of Massachusetts Electric Company recommending a "damage cost approach" Bruce Biewald testifying on behalf of the Massachusetts Division of Energy Resources, and Paul Chernick testifying on behalf of Boston Gas Company, both recommending a "sustainability target approach."

Biewald presented a report which outlined the different methods for monetizing externalities, and recommended $23 per ton of CO_2 (in 1990 dollars).[102]

The Department's Order in Docket D.P.U. 91-131 was noteworthy for its foresight regarding climate change, albeit optimistic about the timing of recognition of climate

[101] Exh. DOER-3, Exh. BB-2, p. 26.

[102] "Valuation of Environmental Externalities: Sulfur Dioxide and Greenhouse Gases," by Bruce Biewald, Stephen Bernow, Kevin Gurney, Michael Lazarus, and Kristin Wulfsberg, Tellus Institute, December 13, 1991.

change into policies and regulation in the US. 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 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.[103]
>
> 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. [104]

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).[105]

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 recognized 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 1960's that the science and impacts of acid rain were widely studied. In 1980 Congress established a ten year research program, the National Acidic

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[103] D.P.U. 86-36-G, pp.86-87

[104] D.P.U. 86-36-G, pp.73-74

[105] D.P.U. 86-36-G, pp.76

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 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 1970's 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 US 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).

ii. Carbon Dioxide will be the Dominant Externality from Electricity Production and Use in New England Over the Study Period

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.

There have been several fairly comprehensive studies that assess the full range of environmental impacts from electricity generation and use. These include:

- *Environmental Costs of Electricity*, prepared by the Pace University Center for Environmental and Legal Studies: Ottinger, R, et. al,, for NYSERDA, Oceana Publications, Inc, 1990;
- The New York State Environmental Externalities Cost Study, RCG/Hagler, Bailly, Inc. and Tellus Institute, for the Empire State Electric Energy Research Corporation (ESEERCO), multiple volumes, 1994 and 1995;
- ***Non-Price Benefits of BECo Demand-Side Management Programs***, for the Boston Edison Settlement Board, Tellus No. 93-174A, July 1994.; and
- U.S.-EC Fuel Cycle Study, by Oak Ridge National Laboratory and Resources for the Future, for the U.S. Department of Energy and the Commission of the European Communities, multiple volumes, 1992 to 1994.

The list of externalities from energy production and use is quite long, and includes the following:

- Air emissions (including SO2, NOX, particulates, mercury, lead, other toxics, 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); and
- 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, 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. The Clean Air Act and the Clean Air Interstate Rule, require further reductions in emission levels over the study period. 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. In contrast, regulators are just starting to "internalize" the impacts of carbon dioxide.

It is expected that the "carbon externality" will be the dominant externality associated with marginal electricity generation in New England. This is the case for two main reasons. First, as noted above, regulations to address the greenhouse gas emissions responsible for global climate change are lagging, particularly in the United States. 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-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 a good use of time and budget. 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. RGGI 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 CA PUC 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….[106]

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.

iii. Methods for 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 "marginal control cost" approaches that seek to quantify the marginal cost of controlling a particular pollutant (thus internalizing a portion or all of the externality).

Determining the value of damage caused by a pollutant can be very difficult. 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 myriad problems with these approaches that need not be identified and discussed here. It is sufficient to point out there are many controversial aspects of this endeavor, and that when applied to climate change damages the problems are tremendous. How, for example, would we value flooding of an entire country?

The "cost of control" 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

[106] R.04-04-003, Appendix B, p. 5.

"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 for the most expensive measures need for achieving that target.

For climate change and CO_2 emissions, this sort of target approach is the most sensible for a number of reasons. The damage costing approaches are, in the case of global climate change, simply subject to too many problematic assumptions as discussed in the next paragraph. Complicating the task of determining a carbon externality cost is the fact that the "regulators' revealed preferences" approach is unavailable, as regulators have not established relevant reference points. Instead, as explained in the final paragraph of this section, we apply a "sustainability target" approach to estimating the "externalities value" associated with CO_2 emissions.

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. The damage approach presents some obvious difficulties – notably that 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 don't fully understand climate change, and can't 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.

Instead we favor using a "sustainability target" approach, estimating what it would cost to get the world to a sustainability target. 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're willing to live with (again complicated by the fact that different regions will see different impacts, and have different ideas about what's dangerous, and what's sustainable).

The "sustainability target" approach relies on the assumption that the nations of the world won't tolerate unlimited damages. It also relies partly on an expectation that policy leaders will realize that it's cheaper to reduce emissions now and achieve a sustainability target than it is not to address climate change. 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 states that the costs of action – the cost of implementing actions to curb climate change – can be limited around 1% of global GDP each year.[107]

Given the daunting challenge of valuing climate damages in economic terms, we would recommend 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 keeping total carbon emissions to levels currently expected to avoid the major climate change risks.

iv. Methodology for Estimating CO_2 Damage Costs, Control Costs, and Sustainability Targets

The first step was to develop an externality value for carbon dioxide in the absence of any carbon regulation. 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, increased frequency of extreme weather events such as hurricanes, 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 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 externality 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

[107] Stern, Sir Nicholas; *Stern Review of the Economics of Climate Change*; Cambridge University Press, 2007.

sheet, and collapse of the Atlantic thermohaline circulation – a global ocean current system that circulates warm surface waters.

Nonetheless, because the externalities 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.

There are various methods available for monetizing environmental externalities such as air pollution from power plants. The methods include various "damage costing" approaches that seek to value the damages associated with a particular externality; and various "marginal control cost" approaches that seek to quantify the marginal cost of controlling a particular pollutant (thus internalizing a portion or all of the externality). Based upon our review of the merits of those various approaches a "sustainability target" approach was selected. This approach estimates the cost of controlling, or stabilizing, global carbon emissions at a "sustainable level". 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.

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're willing to live with (again complicated by the fact that different regions will see different impacts, and have different ideas about what's dangerous, and what's sustainable).

The "sustainability target" approach relies on the assumption that the nations of the world won't tolerate unlimited damages. It also relies partly on an expectation that policy leaders will realize that it's cheaper to reduce emissions now and achieve a sustainability target than it is not to address climate change. While a damage cost estimate was not used, 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 states that the costs of action – the cost of implementing actions to curb climate change – can be limited around 1% of global GDP each year.[108]

Given the daunting challenge of valuing climate damages in economic terms, a practical approach consistent with the concepts of "sustainability" and "avoidance of undue risk" is recommended. Specifically, the carbon externality can be valued by looking at the marginal costs associated with keeping total carbon emissions to levels currently expected to avoid the major climate change risks.

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[108] Stern, Sir Nicholas; *Stern Review of the Economics of Climate Change*; Cambridge University Press, 2007.

(a) What is a Sustainable Level of CO_2 Emissions?

In order to determine what is currently deemed a reasonable sustainability target, current science and policy was reviewed. 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 or UNFCCC).[109] Achieving this commitment requires 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 and globally.[110] 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 2°C above pre-industrial levels as the temperature above which dangerous climate impacts are likely to occur.[111] Temperature increases above 2°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.[112] The European Union has adopted a long-term policy goal of limiting global average temperature increase to 2°C above pre-industrial levels.[113]

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 IPCC's most recent Assessment Report

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[109] There are currently over 180 signatories.

[110] For multiple discussions of the issues surrounding dangerous climate change, see Schnellnhuber, Cramer, Nakicenovic, Wigley and Yohe, editors; *Avoiding Dangerous Climate Change*; Cambridge University Press, 2006. This book contains the research presented at The International Symposium on Stabilisation of Greenhouse Gas Concentrations, Avoiding Dangerous Climate Change which took place in the U.K. in 2005.

[111] Mastrandrea, M. and Schneider, S; *Probabilistic Assessment of "Dangerous" Climate Change and Emissions Scenarios: Stakeholder Metrics and Overshoot Pathways;* Chapter 27 in *Avoiding Dangerous Climate Change*; Cambridge University Press, 2006.

[112] Schnellnhuber, 2006.

[113] 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.)

indicates that concentrations of 445-490 ppm CO_2 equivalent correspond to 2-2.4^oC increases above pre-industrial levels.[114] A comprehensive assessment of the economics of climate change, The Stern Review, proposes a long-term goal to stabilize greenhouse gases at between the equivalent of 450 and 550 ppm CO_2.[115] Recent research indicates that achieving the 2^oC goal likely requires stabilizing atmospheric concentrations of carbon dioxide and other heat-trapping gases near 400 ppm carbon dioxide equivalent.[116]

The IPCC indicates that reaching concentrations of 450-490ppm CO2-eq requires reduction in global CO_2 emissions in 2050 of 85-50% below 2000 emissions levels. [117] The Stern Review indicates that global emissions would have to be 70% below current levels by 2050 for stabilization at 450ppm CO_2-eq.[118] To accomplish such stabilization, the U.S. 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.[119] In the U.S., several states have adopted state GHG reduction targets of 50% or more reduction from a baseline of 1990 levels or then-current levels by 2050 (CA, CT, IL, ME, NH, NJ, VT, OR). The New England States joined with the Eastern Canadian Premiers in also adopting a long-term policy goal of reductions on the order of 75-80% of then-current emission levels.[120]

The sobering news is that a long term stabilization goal of even 400 ppm might not be sufficient: "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."[121] Similarly, the 2ºC threshold may not be sufficient to avoid severe impacts.[122]

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[114] IPCC AR4, WGIII Summary for Policy Makers, 2007. Table SPM5.

[115] Stern, Sir Nicholas; *Stern Review of the Economics of Climate Change*; Cambridge University Press, 2007.

[116] Meinshausen, M.; *What Does a 2^oC Target Mean for Greenhouse Gases? A Brief Analysis Based on Multi-Gas Emission Pathways and Several Climate Sensitivity Uncertainty Estimates;* Chapter 28 in *Avoiding Dangerous Climate Change*; Cambridge University Press, 2006.

[117] IPCC AR4, WGIII Summary for Policy Makers, 2007. Table SPM5.

[118] Stern Review, Long Executive Summary, 2007. Page xi.

[119] den Elzen, M., Meinshausen, M; *Multi-Gas Emission Pathways for Meeting the EU 2^oC Climate Target;* Chapter 31 in *Avoiding Dangerous Climate Change*; Cambridge University Press, 2006. Page 306

[120] New England Governors/Eastern Canadian Premiers, *Climate Change Action Plan 2001*, August 2001. NEG/ECP reiterated this commitment in June 2007 through Resolution 31-1, which states, in part, that the long term reduction goals should be met by 2050.

[121] Bauer and Mastrandrea; *High Stakes: Designing emissions pathways to reduce the risk of dangerous climate change;* Institute for Public Policy Research, U.K.; November 2006

[122] See recent research by James Hansen, Goddard Space Flight Institute – NASA's top climate scientist.

(b) What is the Cost of Stabilizing CO_2 Emissions at this Sustainable Level?

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 (IPCC). 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 three assessment reports on the science of climate change, climate change impacts, and on mitigation and adaptation strategies (1990, 1995, 2001), and is currently issuing its fourth assessment report. In its fourth Assessment Report, the IPCC indicates that reductions on the order of 34 gigatonnes (GT) would be necessary to achieve an 80% reduction below current.[123] That report estimates that up to 31 GT in reductions are available for \$100/tCO_2e or less (Working Group III Summary for Policy Makers). Other studies on the costs of achieving stabilization targets include 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;[124]
- McKinsey & Company have developed an abatement cost curve that indicates that stabilization at 450 ppm would have a marginal abatement cost of about \$50/t, stabilization at 400 ppm would have a marginal abatement cost of over \$60/tCO_2; and
- The Stern Review itself talks primarily about macro-economic costs; however an underlying meta-analysis of modeling literature concludes 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)."[125]

The IPCC WGIII SPM, states on page 29 (references omitted): "An effective carbon-price signal could realize significant mitigation potential in all sectors.

- Modeling studies show carbon prices rising to 20 to 80 US\$/tCO_2-eq by 2030 and 30 to 155 US\$/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 65 US\$/tCO_2eq in 2030 and 15 to 130 US\$/tCO_2-eq in 2050.

[123] 2000 emissions levels were 43Gt CO_2-eq. IPCC AR4, WGIII, Summary for Policy Makers, 2007. Page 11.

[124] *Vattenfalls Global Climate Impact Abatement Map*, accessed May 30, 2007.

[125] Barker, Terry et. al.; *A report prepared for the HM Treasury Stern Review on "The economics of climate change" The Costs of Greenhouse Gas Mitigation with Induced Technological Change: A Meta-Analysis of Estimates in the Literature*; 4 CMR, University of Cambridge.

- Most top-down, as well as some 2050 bottom-up assessments, suggest that real or implicit carbon prices of 20 to 50 US$/t$CO_2$-eq, sustained or increased over decades, could lead to a power generation sector with low-GHG emissions by 2050 and make many mitigation options in the end-use sectors economically attractive."

Based on a review of these different sources, we believe that it is reasonable to anticipate a marginal cost of control of $60/t$CO_2$-eq for achieving a stabilization target that is likely to avoid temperature increases higher than 2^oC above pre-industrial levels. Of course, selection of this value requires multiple assumptions.

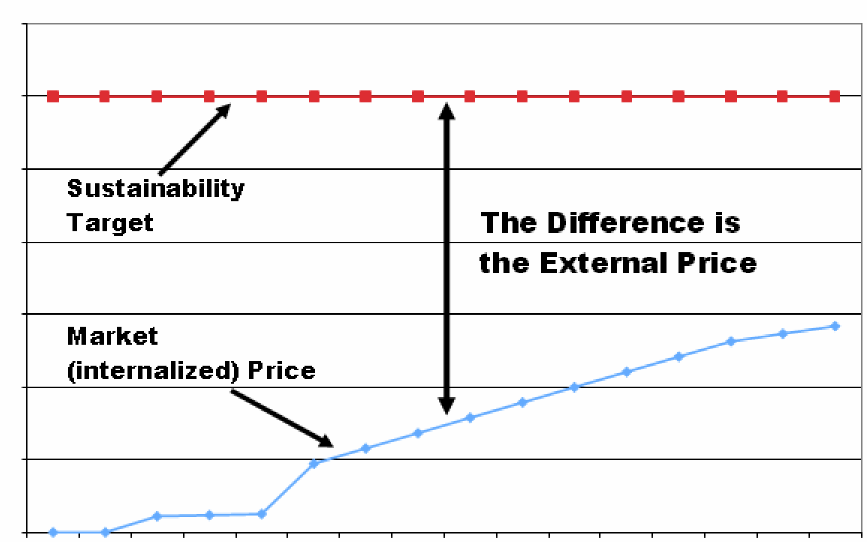
v. Estimating CO_2 Externality Values in New England

The second step was to estimate externality values for carbon dioxide in New England 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 annual sustainability target value of $60/ton minus the annual allowance values internalized in the model.

Synapse has prepared a forecast of the carbon trading price associated with anticipated carbon regulations, and that carbon price was included in the dispatch model runs (in the generators' bids). This forecast "market" price of carbon was included in the $/kWh electricity avoided cost figures that Synapse recommends for use in DSM planning. Second, there is the externality cost, that portion of the costs imposed by CO_2 emissions that is not already included in the avoided cost figures. Since a portion of the CO_2 costs were included in the avoided cost figures, it is recommended that the "externality" be priced as the difference between the estimate of marginal cost to achieve a sustainability target ($60/ton CO_2) and the value of the forecasted carbon trading price.

The exhibit below illustrates how the externality value was determined. The line for the allowance price is based on the forecast of carbon allowance costs, illustrating the notion that the U.S. will gradually move to incorporate the climate externality into policy. The "externality" is simply the difference between the estimate of the cost of achieving a sustainability target, and the anticipated allowance cost; that is, the area above the blue line (and below $60/ton) in the graph.

Exhibit 7-13. Determination of the Externality Value



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. The authors fully acknowledge the many complexities involved in estimating a carbon externality price, both conceptual and practical.

To reiterate, we recommend that the externality value of carbon dioxide be used for the purpose of screening DSM programs for two main reasons. First, the externality value of carbon dioxide is substantially greater than the externality values of the other environmental impacts of electricity generation. Second, we expect carbon dioxide to be the dominant environmental impact of the marginal sources of generation in New England over the study period. Thus, the externality value associated with carbon dioxide emissions dominates other values to an extent that justifies focusing exclusively on carbon dioxide.

The externality value for carbon dioxide in each year is an estimated annual sustainability target value of $60/ton minus the annual projected allowance values internalized in our model. Synapse reviewed science and policy to assess current emerging consensus on what is an appropriate sustainability target. The sustainability target value is an estimate of the cost of stabilizing carbon dioxide emissions at levels that seem likely, based on current science, to avoid more than a 2^{o} C increase in the global average temperature. The annual allowance values are drawn from our forecast of carbon allowance prices associated with anticipated carbon regulations over the study period. The following exhibit presents the recommended values.

Exhibit 7-14. Recommended Externality Values

Year	Sustainability Target Cost ($/ton)	Allowance Price (internalized value) Price ($/ton)	Externality (sustainability target - allowance price) ($/ton)
2007	60	0.00	60.00
2008	60	0.00	60.00
2009	60	2.21	57.79
2010	60	2.37	57.63
2011	60	2.53	57.47
2012	60	9.46	50.54
2013	60	11.56	48.44
2014	60	13.66	46.34
2015	60	15.76	44.24
2016	60	17.86	42.14
2017	60	19.96	40.04
2018	60	22.06	37.94
2019	60	24.16	35.84
2020	60	26.27	33.73
2021	60	27.32	32.68
2022	60	28.37	31.63

vi. The Impact of DSM on Carbon Emissions Under a Cap-and-Trade Regulatory Framework

With carbon dioxide emissions regulated under a cap and trade system, as is 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 reasons that a DSM program could result in emission reductions that should be considered. These include the following:

- 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
- And finally, 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 NY 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 Regional Greenhouse Gas Initiative is a cap and trade greenhouse gas program for power plants in the northeastern United States. Discussions to develop the program began in 2003, states signed a memorandum of understanding identifying the main elements of the program in December 2005 and in August 2006 they adopted a model rule for implementing the program. Currently nine states have decided to participate: CT, DE, MA, ME, NH, NJ, NY, RI and VT. Maryland passed a law in April 2006 requiring participation in RGGI. Pennsylvania, the District of Columbia, the Eastern Canadian Provinces, and New Brunswick are official "observers" in the RGGI process. Individual states are now engaged in regulatory proceedings to adopt regulations consistent with the agreement.

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 moderate price impacts and development of complimentary energy policies to improve energy efficiency, decrease the use of higher polluting electricity generation and to maintain economic growth.

A cap-and-trade program such as RGGI sets a fixed target for air emissions in a particular region. Thus, implementation of an individual DSM program will not necessarily reduce the total quantity of emissions covered by the cap. Total emissions will only be reduced if emission allowances are retired in the same quantity as emissions are avoided by the program.

However, there are some mitigating factors that mean there is still a carbon reduction value associated with the DSM program, even if the emissions allowances are not retired. Two of the primary benefits of implementing DSM programs in the RGGI region will be in the reduction of the cost of the RGGI allowances, and the reduction of imports of power from fossil-fueled power plants outside the RGGI program region.

First, the American Council for an Energy Efficiency Economy (ACEEE) has analyzed and evaluated the RGGI modeling results (Prindle et al. 2006). The ACEEE concludes that doubling efficiency spending in the RGGI region would reduce projected carbon allowance prices by about one third and would substantially reduce power imports. Lower carbon allowances prices make it more likely that the cap will be met. Under RGGI, there is a system of "safety valves" that would allow emitters to pursue alternative compliance strategies (or offsets) if the price of carbon allowances goes above certain pre-determined prices. Thus, the safety valves can result in emissions in the region being higher than the cap.

Second, one of the main concerns with RGGI is that it has the potential to increase imports of power generated by fossil fueled power plants outside the RGGI region. Such an increase could occur if power from outside the region is cheaper than power inside the region. If power imports from fossil fueled plants increase, carbon emissions will increase outside the region– negating some of the emissions reductions from the program (this effect is called "leakage").[126] Such a result would decrease the effectiveness of RGGI since the impacts of carbon emissions are global rather than regional or local. The benefits of reduced carbon allowance costs and reduced leakage mean that there is value under a cap and trade program to reducing carbon emissions through investment in DSM, though quantifying those benefits is beyond the scope of this project.

[126] Prindle, Shipley, and Elliott; Energy Efficiency's Role in a Carbon Cap-and-Trade System: Modeling Results from the Regional Greenhouse Gas Initiative; American Council for an Energy Efficient Economy, May 2006. Report Number E064. The analysis shows also that DSM investments would cut load growth by about two-thirds by 2024, and reduce capacity additions by about 8,000 MW (25% reduction from the reference case). Other results include reducing energy price growth in the region, reducing load growth by about two-thirds by 2024, reducing capacity additions by 25% from the reference case, and increasing consumer energy savings, regional economic output, personal income, and employment.

Appendix A – Common Modeling Assumptions

Inflation Rate

Inflation increased since the AESC 2005 study, which used a rate of 2.25%. Inflation was 3.03% in 2005 and 2.90% in 2006 as shown in the exhibit below. In addition, the twenty year average (1987-2006) derived from the chained GDP deflator was 2.47%. As a result, the long-term inflation rate used in this study was 2.50%.

Exhibit A-1. GDP Price Index and Inflation Rate

Year	GDP Chain-Type Price Index	Annual Inflation	Conversion to 2007
1985	69.72	3.04%	1.705
1986	71.27	2.22%	1.669
1987	73.20	2.72%	1.624
1988	75.71	3.42%	1.571
1989	78.57	3.78%	1.513
1990	**81.61**	**3.88%**	**1.457**
1991	84.46	3.48%	1.408
1992	86.40	2.30%	1.376
1993	88.39	2.30%	1.345
1994	90.27	2.12%	1.317
1995	92.12	2.05%	1.291
1996	93.86	1.89%	1.267
1997	95.42	1.66%	1.246
1998	96.48	1.11%	1.233
1999	97.87	1.44%	1.215
2000	**100.00**	**2.18%**	**1.189**
2001	102.40	2.40%	1.161
2002	104.19	1.75%	1.141
2003	106.41	2.13%	1.118
2004	109.43	2.84%	1.087
2005	112.74	3.03%	1.055
2006	116.01	2.90%	1.025
2007	118.91	2.50%	1.000
2008	121.89	2.50%	0.976
2009	124.93	2.50%	0.952
2010	**128.06**	**2.50%**	**0.929**
2011	131.26	2.50%	0.906
2012	134.54	2.50%	0.884
2013	137.90	2.50%	0.862
2014	141.35	2.50%	0.841
2015	144.89	2.50%	0.821
2016	148.51	2.50%	0.801
2017	152.22	2.50%	0.781
2018	156.03	2.50%	0.762
2019	159.93	2.50%	0.744
2020	**163.92**	**2.50%**	**0.725**
2021	168.02	2.50%	0.708
2022	172.22	2.50%	0.690

Note: Uses the BEA chain-type price index for GDP

Real Discount Rate

As in the AESC 2005 report, the real discount rate was based on recent rates of return for 30-year Treasury Bonds. The present nominal interest rate for those bonds is 4.77% as shown in the exhibit below. The nominal interest rate was calculated as the average yield for six 30-year US Treasury Bills. The nominal interest rate for those bonds was 4.32% in 2005, using the same methodology. Applying the updated discount rate results in a real interest rate of 2.22% for discounting (as compared to 2.03% in 2005).

Exhibit A-2. Risk-Free Interest Rate and Real Discount Rate Determination

30 Year US Treasury Bond 6.00 Maturity Date 2/15/2026		
Transaction Date	Price	Yield
3/21/2007	115-07+	4.78
3/20/2007	114-07+	4.79
3/19/2007	114-11	4.81
3/16/2007	115-01	4.79
3/15/2007	115-02	4.78
3/14/2007	115-14	4.78
AVERAGE		4.788

30 Year US Treasury Bond 5.50 Maturity Date 8/15/2028		
Transaction Date	Price	Yield
3/21/2007	109-07+	4.77
3/20/2007	109-06+	4.79
3/19/2007	109-10	4.8
3/16/2007	109-01	4.78
3/15/2007	109-00	4.77
3/14/2007	109-16	4.77
AVERAGE		4.780

30 Year US Treasury Bond 5.25 Maturity Date 11/15/2028		
Transaction Date	Price	Yield
3/21/2007	106-05+	4.77
3/20/2007	106-07+	4.78
3/19/2007	106-10	4.8
3/16/2007	106-01	4.77
3/15/2007	106-01	4.77
3/14/2007	106-14	4.77
AVERAGE		4.777

30 Year US Treasury Bond 5.25 Maturity Date 2/15/2029		
Transaction Date	Price	Yield
3/21/2007	106-06+	4.76
3/20/2007	106-06+	4.78
3/19/2007	106-10	4.79
3/16/2007	106-01	4.77
3/15/2007	106-01	4.77
3/14/2007	106-15	4.77
AVERAGE		4.773

30 Year US Treasury Bond 6.25 Maturity Date 5/15/2030		
Transaction Date	Price	Yield
3/21/2007	120-07+	4.75
3/20/2007	120-07+	4.76
3/19/2007	120-12	4.78
3/16/2007	120-01	4.75
3/15/2007	120-00	4.75
3/14/2007	120-18	4.75
AVERAGE		4.757

30 Year US Treasury Bond 5.375 Maturity Date 2/15/2031		
Transaction Date	Price	Yield
3/21/2007	108-07+	4.75
3/20/2007	108-06+	4.76
3/19/2007	108-11	4.78
3/16/2007	108-01	4.75
3/15/2007	108-00	4.75
3/14/2007	108-17	4.75
AVERAGE		4.757

Escalation Rate

Section 5.a.i of the RFP asks the Contractor to develop a single real escalation rate for the post forecast period (2023 through 2037). Since the primary set of avoided costs numbers proved in the AESC report are for wholesale electricity our analysis focused on that component.

The wholesale market price of electricity in New England in 2022 and beyond will be almost entirely determined by the marginal cost of natural gas combustion cycle generators (NG CC). The primary drivers of that cost are the prices of natural gas and of

CO2 emissions. The issue then is the escalation of those components and their relative weights in the electricity market price.

We looked first at the escalation for CO2 prices. For this we used the Synapse mid case forecast which was used for the previous years of the AESC analysis. The real escalation rate for CO2 prices post 2022 is 3.24% in that forecast. Regarding natural gas prices there is great uncertainty associated with reserves, production costs and world markets and there are substantial upside risks, however we took the fairly conservative approach of looking at the Annual Energy Outlook for 2007. In that study the real escalation rate for natural gas for electricity generation in New England is 1.01% for the period 2022 through 2030 which is the final forecast year. In the absence of any countervailing information we then assume that the same rate extends through 2037, although with continued depletion of natural gas reserves it could be higher.

We then looked first at the relative weight of these factors for NG CC prices in 2022. That analysis showed that fuel represented 73% and CO2 22% of the marginal generation costs. Applying those factors gives a real escalation rate of 1.45% for electricity prices post 2022.

Exhibit A-3. Marginal Cost Components for a NG CC in 2022 and Calculation of a Real Price Escalation Rate

Component	Proportion	Escalation Rate
Fuel	73%	1.01%
CO2	22%	3.24%
Other	5%	0%
Total	100%	1.45%

In comparing this with the AESC 2005 results we calculated the implied escalation rate in that study for the avoided electricity costs for the period 2023 through 2037 [127]. The annual average real escalation rate from this calculation was 0.68%. This is significantly less than the current proposed escalation rate but does not incorporate CO2 costs and reflects a more optimistic view of future energy prices.

Although there are many uncertainties associated with energy prices this far in the future, our recommendation is an real escalation rate of 1.4% for wholesale electricity prices for 2023 through 2037.

[127] Avoided energy costs from “Exhibit 1 – 2005$” from “aescpoweravoidedcostexhibitsfinal2005.xls”. Also in Exhibit 5-2 associated with Transmission and Distribution investment there is a Forecast Escalation Rate (nominal) of 3.07%. Since an inflation rate of 2.5% was used for that study this implies a real escalation rate of 0.57% which is consistent with but a little less than the rate derived from the avoided electricity costs.

Appendix B – Forecasts of Monthly Natural gas prices

Exhibit B-1. Monthly Henry Hub Natural Gas Price Forecast 2007-2022 (2007$/MMBtu)

	Monthly Adj Factor	1.1159874	1.1178952	1.0909087	0.9272738	0.9144141	0.924639	0.9358622	0.9450845	0.9538974	0.9687786	1.0250697	1.080189319
Year	HH Ann Avg Price	1	2	3	4	5	6	7	8	9	10	11	12
2007	7.71	5.84	6.93	7.55	6.96	7.11	7.77	7.92	8.02	8.06	8.15	8.81	9.46
2008	8.65	9.78	9.74	9.49	8.15	8.00	8.06	8.12	8.17	8.20	8.27	8.71	9.15
2009	8.16	9.38	9.35	9.09	7.63	7.49	7.54	7.61	7.66	7.69	7.76	8.17	8.57
2010	7.65	8.76	8.74	8.48	7.15	7.02	7.07	7.13	7.17	7.20	7.28	7.67	8.06
2011	7.20	8.24	8.21	7.98	6.73	6.60	6.66	6.72	6.75	6.78	6.86	7.24	7.62
2012	6.86	7.80	7.78	7.56	6.43	6.31	6.37	6.42	6.45	6.48	6.56	6.91	7.26
2013	6.24	6.97	6.98	6.81	5.79	5.71	5.77	5.84	5.90	5.95	6.05	6.40	6.74
2014	6.30	7.03	7.04	6.87	5.84	5.76	5.82	5.90	5.95	6.01	6.10	6.46	6.80
2015	6.25	6.98	6.99	6.82	5.80	5.72	5.78	5.85	5.91	5.97	6.06	6.41	6.76
2016	6.39	7.13	7.14	6.97	5.92	5.84	5.91	5.98	6.04	6.09	6.19	6.55	6.90
2017	6.64	7.41	7.42	7.24	6.15	6.07	6.14	6.21	6.27	6.33	6.43	6.80	7.17
2018	6.56	7.32	7.33	7.16	6.08	6.00	6.07	6.14	6.20	6.26	6.36	6.72	7.09
2019	6.52	7.27	7.28	7.11	6.04	5.96	6.03	6.10	6.16	6.22	6.31	6.68	7.04
2020	6.63	7.40	7.42	7.24	6.15	6.07	6.13	6.21	6.27	6.33	6.43	6.80	7.17
2021	6.73	7.52	7.53	7.35	6.25	6.16	6.23	6.30	6.37	6.42	6.52	6.90	7.28
2022	6.98	7.79	7.81	7.62	6.48	6.39	6.46	6.54	6.60	6.66	6.77	7.16	7.54

Notes:
1/07-5/07 are actual prices
6/07-12/12 are forecasted prices from NYMEX as of May 2, 2007
2007-2012 HH Annual Average Prices are straight averages across the months of each year
2013-2022 HH Annual Average Prices are forecasted
Prices for 1/13-12/22 are calculated by multiplying the HH Annual Average Price by the Monthly Adjustment Factor

Exhibit B-2. Monthly Regional Natural Gas Price Forecast 2007-2022 (2007$/MMBtu) – ALG

Year	Monthly Prem Factor / Ann Avg Price	1.3659648	1.3343223	1.1408184	1.0927116	1.0931588	1.0932223	1.0987813	1.0849414	1.073207	1.0915255	1.1243434	1.204758479
		1	2	3	4	5	6	7	8	9	10	11	12
2007	8.82	7.69	9.73	8.30	7.61	7.77	8.49	8.70	8.70	8.65	8.90	9.90	11.40
2008	10.01	13.35	13.00	10.82	8.90	8.75	8.81	8.92	8.87	8.80	9.03	9.80	11.02
2009	9.44	12.81	12.47	10.37	8.34	8.19	8.25	8.36	8.31	8.25	8.47	9.19	10.33
2010	8.85	11.97	11.66	9.68	7.82	7.67	7.73	7.84	7.78	7.73	7.95	8.63	9.71
2011	8.33	11.25	10.96	9.10	7.36	7.22	7.28	7.38	7.33	7.28	7.49	8.14	9.18
2012	7.94	10.65	10.38	8.62	7.03	6.90	6.96	7.05	7.00	6.96	7.16	7.77	8.75
2013	7.22	9.52	9.31	7.77	6.32	6.24	6.31	6.42	6.40	6.39	6.60	7.19	8.12
2014	7.28	9.60	9.40	7.84	6.38	6.30	6.37	6.48	6.46	6.45	6.66	7.26	8.20
2015	7.23	9.53	9.33	7.78	6.34	6.25	6.32	6.43	6.41	6.40	6.61	7.21	8.14
2016	7.39	9.74	9.53	7.95	6.47	6.39	6.46	6.57	6.55	6.54	6.76	7.36	8.32
2017	7.67	10.12	9.90	8.26	6.72	6.63	6.71	6.82	6.80	6.79	7.02	7.65	8.64
2018	7.58	10.00	9.79	8.16	6.65	6.56	6.63	6.75	6.73	6.72	6.94	7.56	8.54
2019	7.53	9.93	9.72	8.11	6.60	6.51	6.59	6.70	6.68	6.67	6.89	7.51	8.48
2020	7.67	10.11	9.90	8.26	6.72	6.63	6.71	6.82	6.80	6.79	7.02	7.65	8.63
2021	7.79	10.27	10.05	8.38	6.82	6.73	6.81	6.93	6.91	6.89	7.12	7.76	8.76
2022	8.07	10.65	10.42	8.69	7.08	6.98	7.06	7.18	7.16	7.15	7.38	8.05	9.09

Notes:
Prices for all months are calculated by multiplying the Henry Hub Monthly Price by the Monthly Factor for Algonquin City Gate
2007-2022 Annual Average Prices are straight averages across the months of each year

Exhibit B-3. Monthly Regional Natural Gas Price Forecast 2007-2022 (2007$/MMBtu) – TGP Z6

	Monthly Prem Factor	1.2735839	1.2766407	1.1333628	1.0860551	1.0837252	1.0814196	1.0849595	1.0767206	1.0662243	1.0786931	1.1111352	1.177818291
Year	Ann Avg Price	1	2	3	4	5	6	7	8	9	10	11	12
2007	8.69	7.28	9.55	8.23	7.56	7.70	8.40	8.59	8.63	8.59	8.79	9.79	11.15
2008	9.80	12.45	12.44	10.75	8.85	8.67	8.71	8.81	8.80	8.74	8.92	9.68	10.77
2009	9.25	11.95	11.93	10.30	8.29	8.12	8.16	8.25	8.24	8.20	8.37	9.08	10.10
2010	8.66	11.16	11.15	9.61	7.77	7.61	7.65	7.74	7.72	7.68	7.86	8.53	9.49
2011	8.16	10.49	10.48	9.04	7.31	7.16	7.20	7.29	7.27	7.23	7.40	8.04	8.97
2012	7.77	9.93	9.93	8.57	6.99	6.84	6.88	6.96	6.95	6.91	7.08	7.68	8.55
2013	7.07	8.87	8.91	7.72	6.29	6.19	6.24	6.34	6.35	6.35	6.52	7.11	7.94
2014	7.13	8.95	8.99	7.79	6.34	6.24	6.30	6.40	6.41	6.41	6.58	7.17	8.01
2015	7.08	8.89	8.93	7.73	6.30	6.20	6.25	6.35	6.36	6.36	6.54	7.12	7.96
2016	7.24	9.08	9.12	7.90	6.43	6.33	6.39	6.49	6.50	6.50	6.68	7.28	8.13
2017	7.51	9.43	9.47	8.20	6.68	6.58	6.64	6.74	6.75	6.75	6.93	7.56	8.44
2018	7.43	9.32	9.36	8.11	6.61	6.50	6.56	6.66	6.68	6.67	6.86	7.47	8.35
2019	7.38	9.26	9.30	8.06	6.56	6.46	6.52	6.62	6.63	6.63	6.81	7.42	8.29
2020	7.51	9.43	9.47	8.20	6.68	6.57	6.63	6.74	6.75	6.75	6.93	7.56	8.44
2021	7.63	9.57	9.61	8.33	6.78	6.67	6.73	6.84	6.85	6.85	7.04	7.67	8.57
2022	7.91	9.93	9.97	8.63	7.03	6.92	6.98	7.09	7.11	7.10	7.30	7.95	8.88

Notes:
Prices for all months are calculated by multiplying the Henry Hub Monthly Price by the Monthly Factor for Tennessee Zone 6
2007-2022 Annual Average Prices are straight averages across the months of each year

Exhibit B-4. Monthly New England Natural Gas for Electric Generation Price Forecast 2007-2022 (2007$/MMBtu)

	Monthly Prem Factor	1.365965	1.334322	1.140818	1.092712	1.093159	1.093222	1.098781	1.084941	1.073207	1.091526	1.124343	1.204758
Year	Ann Avg Price	1	2	3	4	5	6	7	8	9	10	11	12
2007	8.82	7.49	9.64	8.27	7.65	7.80	8.52	8.72	8.74	8.69	8.91	9.92	11.34
2008	9.97	12.97	12.79	10.86	8.95	8.78	8.83	8.94	8.90	8.84	9.05	9.81	10.97
2009	9.42	12.45	12.27	10.40	8.38	8.22	8.27	8.37	8.34	8.29	8.49	9.20	10.28
2010	8.83	11.64	11.47	9.72	7.86	7.71	7.76	7.86	7.82	7.78	7.97	8.65	9.67
2011	8.31	10.94	10.79	9.14	7.40	7.26	7.31	7.40	7.37	7.32	7.51	8.16	9.15
2012	7.92	10.36	10.22	8.66	7.08	6.94	6.99	7.08	7.04	7.01	7.19	7.80	8.72
2013	7.21	9.26	9.18	7.81	6.38	6.28	6.35	6.45	6.45	6.44	6.63	7.22	8.10
2014	7.28	9.35	9.26	7.88	6.43	6.34	6.40	6.51	6.50	6.50	6.69	7.29	8.18
2015	7.23	9.28	9.20	7.83	6.39	6.29	6.36	6.46	6.46	6.45	6.64	7.24	8.12
2016	7.38	9.48	9.39	8.00	6.52	6.43	6.49	6.60	6.60	6.59	6.79	7.39	8.29
2017	7.66	9.84	9.75	8.30	6.77	6.67	6.74	6.85	6.85	6.84	7.05	7.67	8.61
2018	7.58	9.73	9.64	8.21	6.70	6.60	6.67	6.77	6.77	6.76	6.97	7.59	8.51
2019	7.53	9.67	9.58	8.15	6.65	6.56	6.62	6.73	6.73	6.72	6.92	7.54	8.46
2020	7.66	9.84	9.75	8.30	6.77	6.67	6.74	6.85	6.85	6.84	7.04	7.67	8.61
2021	7.78	9.99	9.90	8.42	6.87	6.77	6.84	6.95	6.95	6.94	7.15	7.79	8.74
2022	8.06	10.36	10.26	8.73	7.12	7.02	7.09	7.21	7.20	7.20	7.41	8.07	9.06

Notes:
Prices are based on the average of the Algonquin City Gate & Tennessee Zone 6 prices along with a transportation markup.
NG markup for electric generation 0.07 $/MMBtu

Appendix C – Detailed Input Assumptions For Electric Energy Price Forecast

Exhibit C-1. Load Allocation Exhibit[128]

Modeling Zone	2006 RSP Subarea	SMD Load Zone	State	MW	State & Peak Load					
					CT	MA	ME	NH	RI	VT
					7,252	12,561	2,013	2,313	1,855	1,046
BHE	BHE	ME	Maine	310			15.4%			
CMP	ME	ME	Maine	988			49.1%			
		NH	New Hampshire	57				2.5%		
	SME	ME	Maine	665			33.0%			
NH	NH	ME	Maine	50			2.5%			
		NH	New Hampshire	1,790				77.4%		
		VT	Vermont	70						6.7%
VT	VT	NH	New Hampshire	308				13.3%		
		VT	Vermont	902						86.2%
BOSTON	BOSTON	NEMA/Boston	Massachusetts	5391		42.9%				
		NH	New Hampshire	79				3.4%		
CMA/NEMA	CMA/NEMA	WCMA	Massachusetts	1671		13.3%				
		NH	New Hampshire	79				3.4%		
WMA	WMA	CT	Connecticut	72	1.0%					
		WCMA	Massachusetts	1,929		15.4%				
		VT	Vermont	74						7.1%
SEMA	SEMA	SEMA	Massachusetts	2811		22.4%				
		RI	Rhode Island	149					8.0%	
RI	RI	SEMA	Massachusetts	759		6.0%				
		RI	Rhode Island	1706					92.0%	
CT	CT	CT	Connecticut	3580	49.4%					
SWCT	SWCT	CT	Connecticut	2,340	32.3%					
	NOR	CT	Connecticut	1,260	17.4%					

[128] From Table 3-6 of ISO New England 2006 Regional System Plan.

Exhibit C-2. Thermal Unit Characteristics

Fuel Type	Unit Type	Size Range	Forced Outage Rate	Maintenance Outage Rate	Fixed O&M ($/kw-yr)	Var. O&M ($/MWh)	Min. Down Time (hours)	Min. Up Time (hours)	Full Load HR (btu/kwh)
Coal	ST	<=50	0.074	0.070	$79.13	$3.58	24	24	12,609
		>200	0.071	0.082	$31.97	$1.81	24	24	9,811
		50-100	0.071	0.070	$23.82	$1.28	24	24	10,650
		100-200	0.064	0.070	$39.78	$1.84	24	24	10,700
Gas/Oil	GT	<=50	0.068	0.040	$29.43	$2.75	1	1	12,459
	ST	<=50	0.073	0.070	$30.43	$2.88	8	6	13,957
		>200	0.060	0.125	$18.42	$1.26	8	12	10,735
		50-100	0.142	0.070	$15.13	$1.42	8	6	11,779
		100-200	0.065	0.115	$17.21	$1.47	8	8	11,188
LFG	GT	<=50	0.063	0.030	$19.54	$3.31			10,000
	IC	<=50	0.022	0.040	$61.01	$4.34			10,036
	ST	<=50	0.068	0.070	$30.65	$3.86			11,826
MSW	ST	<=50	0.068	0.070	$24.25	$0.96	8	6	11,671
		50-100	0.068	0.070	$24.06	$0.93	8	6	11,772
Natural Gas	CC	>200	0.055	0.041	$11.42	$2.19	20	8	7,070
		50-100	0.059	0.080	$14.69	$0.88	22	8	8,070
		100-200	0.059	0.074	$22.25	$1.69	8	8	8,558
	CG	<=50	0.059	0.080	$7.57	$0.66	8	8	10,000
		50-100	0.042	0.051	$10.92	$3.53	4	4	10,928
		100-200	0.054	0.072	$12.86	$1.58	18	7	8,689
	GT	<=50	0.053	0.040	$10.08	$2.01	2	1	10,863
		50-100	0.043	0.040	$12.77	$0.59	3	2	9,919
	ST	>200	0.063	0.150	$17.00	$1.42	8	10	10,313
Nuclear	NU	>200			$92.63	$4.48		168	10,077
Oil	CC	100-200	0.059	0.080	$19.39	$2.12	8	8	8,000
	CG	<=50	0.068	0.040	$5.43	$1.62	1	1	13,726
	GT	<=50	0.065	0.034	$9.47	$2.56	1	1	13,955
		50-100	0.043	0.040	$5.66	$0.60	3	2	12,686
	IC	<=50	0.142	0.070	$20.20	$2.21	1	1	10,370
	ST	<=50	0.130	0.071	$13.97	$1.34	8	6	13,417
		>200	0.063	0.124	$17.92	$1.43	12	14	10,385
		50-100	0.142	0.070	$21.80	$1.75	8	6	10,500
		100-200	0.069	0.120	$18.18	$1.62	8	8	11,202
Other	CG	100-200	0.064	0.070	$23.74	$0.95	8	8	11,050
	ST	<=50	0.068	0.070	$23.80	$0.97	8	6	10,000
Wind	WT	<=50			$20.61	$0.00			
Wood	ST	<=50	0.068	0.070	$26.44	$1.33	8	6	11,874
		50-100	0.054	0.070	$30.45	$1.70	8	6	11,927

Exhibit C-3 Summary of State RPS Requirements and Qualifying Technology Types

Technology	CT Classes I	CT Classes II	CT Classes III	MA	ME	RI	VT	NH I New	NH II New	NH III Existing	NH IV Existing
Solar thermal	•	•		•	•	•		•			
Biomass thermal								•			
Photovoltaic	•	•		•	•	•		•	•		
Ocean thermal	•	•		•	•	•		•			
Wave	•	•		•	•	•		•			
Tidal	•	•		•	•	•	•	•	•		
Wind	•	•		•	•	•	•	•			
Biomass	Sustainable, low emission	•		Low-emission, technology	•	•	•	< = 50 MW		< = 25 MW	
Hydro	< = 5 MW	< = 5 MW			•	< = 30 MW	< = 200 MW				< = 5 MW
Landfill gas	•			•	•		•	•		•	
Sewage plant waste							•				
Fuel cells	•			w/ RE fuels	•	w/ RE fuels		w/ RE fuels			
Geothermal					•	•		•			
MSW		•			w/ recycling						
CHP			• (a)		•						
Energy efficiency			• (a)								
Percent Requirement											
Year	**I**	**II or I**	**III**		**(b)**	**(c)**		**I**	**II**	**III**	**IV**
2007	3.5%	3% in all years	1.0%	3.0%	30% in all years	3.0%	Incremental growth between 2005 and 2012	0.0%	0.0%	0.0%	0.0%
2008	5.0%		2.0%	3.5%		3.5%		0.0%	0.0%	3.5%	0.5%
2009	6.0%		3.0%	4.0%		4.0%		0.5%	0.0%	4.5%	1.0%
2010	7.0%		4.0%	5.0%		4.5%		1.0%	0.0%	5.5%	1.0%
2011	7.0%		4.0%	6.0%		5.5%		2.0%	0.1%	6.5%	1.0%
2012	7.0%		4.0%	7.0%		6.5%		3.0%	0.2%	6.5%	1.0%
2013	7.0%		4.0%	8.0%		7.5%		4.0%	0.2%	6.5%	1.0%
2014	7.0%		4.0%	9.0%		8.5%		5.0%	0.3%	6.5%	1.0%
2015	7.0%		4.0%	10.0%		10.0%		6.0%	0.3%	6.5%	1.0%
2016	7.0%		4.0%	11.0%		11.5%		7.0%	0.3%	6.5%	1.0%
2017	7.0%		4.0%	12.0%		13.0%		8.0%	0.3%	6.5%	1.0%
2018	7.0%		4.0%	13.0%		14.5%		9.0%	0.3%	6.5%	1.0%
2019	7.0%		4.0%	14.0%		16.0%		10.0%	0.3%	6.5%	1.0%
2020	7.0%		4.0%	15.0%		16.0%		11.0%	0.3%	6.5%	1.0%
2021	7.0%		4.0%	16.0%		16.0%		12.0%	0.3%	6.5%	1.0%
2022	7.0%		4.0%	17.0%		16.0%		13.0%	0.3%	6.5%	1.0%
Use Generator Information System (GIS) renewable energy certificates?	Yes			Yes	Yes	Yes	Yes	Yes			
Renewable energy certificates outside ISO New England	New York only until 2010			w/ deliverability		w/ deliverability	w/ deliverability				
Notes:											

Appendix D – Usage Guide for Avoided Energy Supply Costs

A. General

Notifications

All present values and levelized costs in the exhibits and Avoided Cost workbook were computed using a real discount rate of 2.22 percent. Present values are discounted to 2007. Inflation rates of 2.9% for 2005–2006 and 2.5% for 2006–2007 were used to compare historical prices to these forecasts.

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 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.

Inclusions

The avoided costs include the following:

- Energy and capacity costs are reported for the points at which the ISO delivers power to the utility. These costs reflect losses from the generator to the points at which the ISO delivers power to the utility. Energy loss factors are embedded in the avoided energy values reported from the Market Analytics model, while capacity costs have been adjusted for these losses. Each program administrator should add losses from the ISO delivery points to the end use for its specific utility system. This point is discussed further below;
- the costs of compliance with renewable portfolio standards;
- 10% retail adders for all zones, except for Vermont, where a risk adder of 11.1% is required by the Public Service Board (the zone-specific retail adder can be changed in any of the worksheets);
- estimates for DRIPE and CO_2 environmental externalities. It is recommended that these be included in analyses of DSM, unless specifically excluded by state or local law or regulation. It would, however, be useful in any case to show the cost-benefit results with and without the DRIPE and externalities included.

Exclusions

The avoided costs do not include

- losses from the ISO delivery points to the end use. Each program administrator should add losses from the ISO delivery points to the end use for its specific utility system;
- avoided transmission and distribution costs. Each program administrator should add estimates of those avoided-cost components for its specific system, as discussed below.

User-Specified Inputs

Users have the ability to use different values for certain inputs if appropriate for a particular application. Those inputs are the retail adder, reserve margin, capacity factor, real discount rate and the zonal summer on-peak capacity factor. The default values for these inputs are provided in the “Inputs” worksheet. The avoided cost calculations in each zonal worksheet use those default values via a link to the Inputs worksheet. If a user wishes to specify his or her own value for any of those inputs we suggest that the user-specified value be entered directly in the relevant zonal worksheet. This will preserve the default values in the Inputs worksheet.

B. Guide to Applying the Avoided Costs

The benefits of DSM should be estimated from the appropriate avoided-cost exhibit as the sum over the years of:

1. reduction in winter peak energy at the end use
   × winter peak energy losses from the ISO delivery points to the end use[129]
   × 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;
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;
5. reduction in capacity costs estimated either as

[129] Each set of losses should be computed by the program administrator for its specific system.

a) reduction at the time of summer coincident peak at the end use
× summer peak-hour losses from the ISO delivery points to the end use
× the *Annual Market Capacity Value* for that year;

or alternatively,

b) reduction in summer peak energy at the end use
× summer peak energy losses from ISO delivery to the end use
× the *On-Peak Summer Capacity Value* for that year;

6. If the avoided costs are to include DRIPE, the avoided costs should be increased as follows:

   a) If the savings persist for at least 4 years (6 years for capacity), uses the values in the columns applicable to the efficiency program implementation year to calculate the sum of:

      i. reduction in annual winter peak energy at the end use
      × winter peak energy losses from ISO delivery to the end use[130]
      × the present value line for DRIPE Winter Peak Energy;[131]

      ii. reduction in annual winter off-peak energy at the end use
      × winter off-peak energy losses from ISO delivery to the end use
      × the present value line for DRIPE Winter Off-Peak Energy;

      iii. reduction in annual summer peak energy at the end use
      × summer peak energy losses from ISO delivery to the end use
      × the present value line for DRIPE Summer Peak Energy*;*

      iv. reduction in annual summer off-peak energy at the end use
      × summer peak off-energy losses from ISO delivery to the end use
      × the present value line for DRIPE Summer Off-Peak Energy*;*

      v. reduction at the time of summer coincident peak at the end use
      × summer peak-hour losses from ISO delivery to the end use
      × the present value line for DRIPE Annual Market Capacity Value.

   b) If savings persist for shorter periods, or if inclusion of present values is inconvenient in the benefit-cost model, DRIPE should be computed in the same

[130] 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)].

[131] The user can change the real discount rate input to match the discount rate used in its benefit-cost model.

manner as the direct avoided costs, as the product of load reductions and the annual DRIPE price

7. If the avoided costs are to include externalities, the avoided costs should be increased as follows:

   a) 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,

   b) 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,

   c) 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,

   d) 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 *CO_2 Externality Summer Off-Peak Energy* value for that year,

8. If the avoided costs are to include avoided transmission and distribution costs on the program administrator's system, the avoided costs should be increased as follows:

   a) Reduction in the peak demand used in estimating avoided transmission and distribution costs at the end use
   × capacity losses at those peak hours from ISO delivery to the end use
   × the utility-specific estimate of avoided T&D costs in $/kW-year.[132]

C. Guide to Exhibit Structure and Terminology

Each of the avoided-cost Exhibits has the same structure. Reading from left to right, the structure is as follows.

[132] 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 peak hours as to reduce local peaks.

i. Avoided Costs

(a) Winter Peak Energy Avoided Cost ($/kWh) [133]

The locational market-clearing price in 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.

(b) Winter Off-Peak Energy Avoided Cost ($/kWh)

The locational market-clearing price in 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.

(c) Summer Peak Energy Avoided Cost ($/kWh)

The locational market-clearing price in the 16–hour block 6am–10pm (the hours ended 700 through 2200), Monday–Friday (except ISO holidays), in the months of June–September.

(d) Summer Off-Peak Energy Avoided Cost ($/kWh)

The locational market-clearing price in 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.

(e) Annual Market Capacity Value Avoided Cost ($/kW-yr)

The market-clearing price in the forward capacity market, estimated at the estimated cost of new entry, increased by the required reserve margin to represent costs per kilowatt of load. These values include the reserve margin and line losses to the ISO delivery points. The annual capacity requirement for load is 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.[134]

ii. Demand-Reduction-Induced Price Effects (DRIPE)

The next two sections of each exhibit provide the estimates of DRIPE developed in this project. The first section applies to measures implemented in 2008, the second to measures implemented in 2009. Each energy period and capacity has annual entries for a few years, as well as a present value at the bottom of the exhibit. As discussed below, most applications of these avoided cost components can use the present values directly,

[133] ISO holidays are New Year's Day, Memorial Day, July 4, Labor Day, Thanksgiving, and Christmas.

[134] 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.

without using the annual values. The annual values may be more convenient for use in some economic-evaluation models.

Some interpretations of the societal test and the total resource cost test will include DRIPE while others will exclude DRIPE. That choice is left to the program administrators and/or their regulators.

iii. CO_2 Externality

This section provides estimates of CO_2 externality values developed in this project. Each energy period has annual entries.

iv. Forward Capacity Market (FCM) Revenue

To the right of the CO_2 externality values, each avoided-cost worksheet provides estimates of the FCM revenues that the program administrator could receive by bidding DSM programs into the forward capacity auction. Most DSM programs are likely to participate in the FCM as either On-Peak Demand Resources (a category designed for non-weather-sensitive savings) or Seasonal Peak Demand Resources (designed for weather-sensitive savings).These revenues would be offsets to program costs for budgeting purposes. These revenues would not be TRC benefits for New England customers as a whole, since customers will be paying the FCM charges, as well as getting the benefits of the FCM revenues offsetting DSM costs.

(a) Load Reduction Value in Capacity Terms

Program administrators should multiply the unit FCM revenue values ($/kW) from the workbook by the appropriate load reduction in June, July, August, December and January. The applicable time periods for each category of resource inn those 5 months are:

- On-Peak Demand Resources - average load reduction during non-holiday weekday hours of:
    1. 1 PM to 5 PM (hours ending 1400 to 1700) in June, July and August
    2. 5 PM to 7 PM (hours ending 1800 and 1900) in December and January
- Seasonal Peak Demand Resources – the average load reduction during non-holiday weekday hours during which real-time system hourly load exceeds 90% of the most recent “50/50” System Peak Load Forecast for the season.[135]

[135] If no high-load hours occur in the month, the ISO will estimate the potential load reduction from prior experience or engineering data.

(The unit FCM revenue values in the workbook reflect the FCM revenue values that the resource will receive in the remaining months of February, March, April, May, September, October and November).

(b) Load Reduction Value in Energy Terms

As an alternative to the recommended method described above, program administrators may wish to calculate the FCM benefits in $/kWh terms. The column to the right of the FCM Revenues section in each zonal spreadsheet therefore includes the capacity avoided costs in $/kWh, computed from the 2006 summer on-peak load factor for each zone:[136]

(summer on-peak energy ÷ summer on-peak hours) ÷ load at the system peak

This value is most likely to be useful for comparing avoided capacity costs to avoided energy costs. If it is used for screening, this value should be multiplied by the summer on-peak savings.

v. Input Values

To the right of the FCM values discussed above, each zonal worksheet contains the wholesale market prices and renewable-energy-credit prices applicable to that zone. These values do not reflect the addition of losses and retail adders. Users should not normally need to use these input values directly, or to modify these values.

D. Levelization

Along the bottom of the tables in each zonal worksheet, there are real-levelized costs for each of the direct avoided costs. These values are calculated for various periods, using a 10% nominal discount rate and the 2.5% inflation rate assumed throughout this project. For DRIPE, whose effects are experienced over only a few years, the spreadsheet includes the present value of the energy effect per annual MWh and the capacity effect per kilowatt of load reduction, for the convenience of the program administrators. Inclusion of DRIPE would add roughly one to three years to the avoided-cost benefits.

E. Utility-Specific Costs to be Added/Considered by Program Administrators

i. 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 (PFT), from the generator to the delivery points at which the PFT system connects to local non-PTF

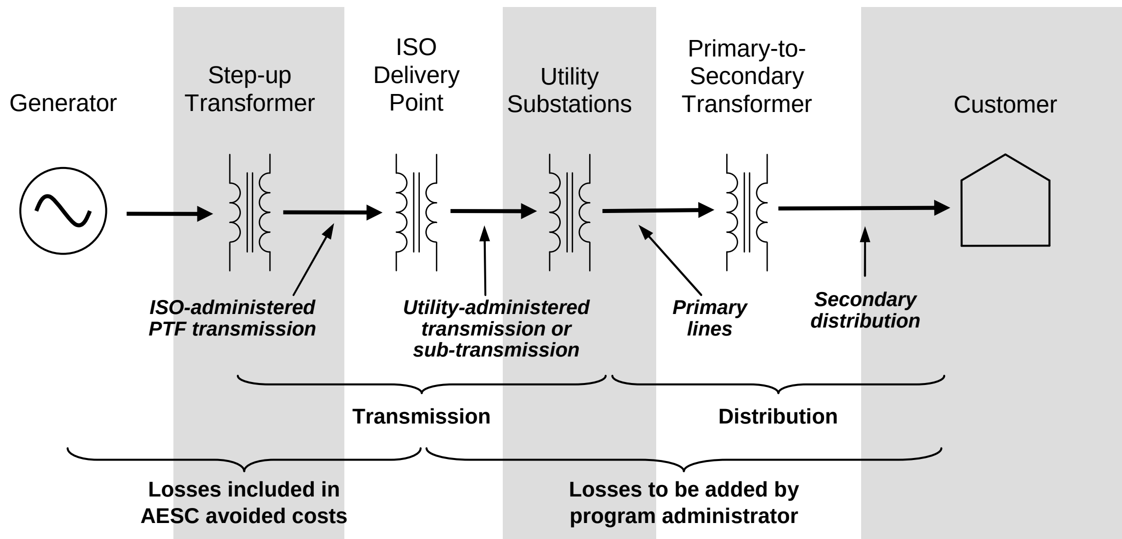
[136] Monthly on-peak energy for the Connecticut sub-zones was not readily available from the ISO, so the load factors for those sub-zones were estimated as the Connecticut summer on-peak load factor times the ratio of the sub-zone all-hours summer load factor to the Connecticut all-hours summer load factor.

transmission or to distribution substations. The Exhibits do not include the following losses:

- from the delivery points that are on the transmission system over the non-PTF transmission substations and lines to distribution substations;
- in the distribution substations,
- on the primary feeders and laterals, from the distribution substations to the line transformers,[137]
- from the line transformers over the secondary lines and services to the customer meter,[138]
- from the customer meter to the end use.

The exhibit below provides a simplified illustration of the many types of losses on transmission and distribution systems.

Exhibit D-2. Delivery System Structure and Losses



In most cases, DSM program administrators measure demand savings from DSM programs at the end use. The program administrator should estimate the losses from delivery points to the end uses. If the energy delivered to the utility at the PTF is *a*, losses are *b*, and the delivered power is *c*,

- losses as a fraction of deliveries to the utility are $b \div a$,

[137] 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.

[138] 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.

- 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 that 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, the losses should be computed as marginal losses, which are roughly twice the percentage as average line losses for the same load level.[139] 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.

ii. Avoided Transmission and Distribution Costs

The avoided costs developed in this project do not include any avoided transmission and distribution (T&D) costs. Each program administrator should add avoided T&D costs, in $/kW of reduced summer and/or winter peak demand, as appropriate for the specific service territories.[140] 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.

The following is a description of a process that could be used to estimate the percent of transmission and distribution capital expenditures that are avoidable.

The standard approach to estimating marginal or avoidable T&D cost is to estimate the following for some period of time (typically a decade):

$$\frac{\text{avoidable capital investment}}{\text{load growth}} + \text{related O \& M and overheads}$$ [141]

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[139] 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.

[140] Avoided transmission costs and avoided distribution costs are usually calculated separately, but may be combined in the evaluation of efficiency measures.

[141] This Task did not include estimation of avoidable T&D O&M expenses. These are generally estimated in $/kW-year terms, or as a percentage of plant in service, for the O&M accounts for load-related equipment.

Historical analyses generally use load and plant-additions data from the FERC Form 1 filed annually by each investor-owned utility. For comparability, the additions in each year must be restated to current dollars, such as with the Handy-Whitman indices for the various accounts.[142]

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.[143]

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.[144]

iii. 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.[145]

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.[146] Retirements in any year reflect a mixture of vintages and most of the equipment in the system is relatively new. Further, the younger equipment is a higher

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[142] Ideally, the analysis would recognize that some load is served by the utility at transmission or primary-distribution voltages, and that those customers provide transformers and internal secondary distribution, which is also an avoidable cost.

[143] 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.

[144] 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.

[145] 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.

[146] The depreciation study will be useful in determining the average age of retired plant.

percentage of the dollars retired than it is of the number of items retired, since the younger installations were built in inflated dollars.

iv. 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.

v. 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.

Appendix E –Avoided Electricity Supply Costs

Instructions

Losses

All costs include losses on the ISO-administered transmission system, to the PTF delivery nodes.
DSM savings at the meter should be increased to include avoided losses from ISO delivery points to the meter, including losses on the distribution and any transmission below the ISO level.

All avoided costs are in Year 2007 Dollars
All present values are in Year 2007 Dollars

Energy periods are:

Peak	Monday through Friday 6am - 10pm, excluding ISO holidays
Off-peak	All other hours
Summer	June through September
Winter	October through May

Capacity

Avoided capacity cost is per kW of load coincident with ISO-NE annual peak
Avoided capacity cost includes only the ISO FCM market. Avoided transmission and distribution costs should be added by the program administrator.
Avoided capacity cost is also included in $/kWh of summer peak energy, for the convenience of some program administrators.
Avoided capacity costs can be included in $/kW-yr or $/kWh, but not both.
FCM revenue is for the convenience of the program administrator, in estimating offsets to its budget. This values should not be included as an avoided cost.
FCM revenue periods

Summer	April through November
Winter	December through March

General Inputs

Retail Adder	10%	(except for Vermont)
Real Discount Rate	2.22%	
Capacity Losses to ISO delivery	3.4%	

Development of Load Factors

Summer Peak GWh	CT	ME	NH	RI	VT	NEMA	SEMA	WCMA	MA	non-NEMA
Sep-06	1,215	410	470	348	164	1,008	585	625		
Aug-06	1,742	525	610	469	278	1,374	842	881		
Jul-06	1,559	451	578	417	241	1,267	772	769		
Jun-06	1,530	500	538	389	241	1,217	686	803		
Total Summer	6,046	1,886	2,197	1,623	924	4,867	2,885	3,078	10,830	5,963
Peak 2Aug06 HE1400	7,367	2,022	2,452	1,960	1,036	5,582	3,712	3,760	13,054	7,472
Summer Peak Load Factor	60.3%	68.6%	65.9%	60.9%	65.6%	64.1%	57.2%	60.2%	61.0%	58.7%

Please note: CT subzones estimated as (CT peak lf) * (subzone summer lf)/(CT summer lf), summer lfs from ISO SMD_monthly.xls

		Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy
		tons/MWh			
		0.61	0.60	0.68	0.66
	$/ton externality	$/kWh externality			
2007	60.00	0.037	0.036	0.041	0.040
2008	60.00	0.037	0.036	0.041	0.040
2009	57.79	0.035	0.035	0.039	0.038
2010	57.63	0.035	0.035	0.039	0.038
2011	57.47	0.035	0.034	0.039	0.038
2012	50.54	0.031	0.030	0.034	0.033
2013	48.44	0.030	0.029	0.033	0.032
2014	46.34	0.028	0.028	0.032	0.031
2015	44.24	0.027	0.027	0.030	0.029
2016	42.14	0.026	0.025	0.029	0.028
2017	40.04	0.024	0.024	0.027	0.026
2018	37.94	0.023	0.023	0.026	0.025
2019	35.84	0.022	0.022	0.024	0.024
2020	33.73	0.021	0.020	0.023	0.022
2021	32.68	0.020	0.020	0.022	0.022
2022	31.63	0.019	0.019	0.022	0.021

AESC Avoided Cost Results by Screening Zone

NOTE: **All Avoided Costs are in Year 2007 Dollars; Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours**

Summer for energy values includes June through September; Winter is all other months

All Costs include losses on the ISO-administered Transmission System. DSM savings should include distribution and local transmission losses

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Retail Adder	10%
Real Discount Rate	2.2%
Capacity Losses: Generation to ISO Delivery	3.4%
Zonal On-Peak Summer Load Factor	60%

ELECTRIC AVOIDED COSTS
Wholesale Power Price

	Connecticut					DRIPE for Installations in 2008					DRIPE for Installations in 2009					CO_2 Externality				FCM Revenue			Avoided Costs before Adders					REC Costs
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Summer: June, July, August	Winter: December, January	On-Peak Summer Capacity Value[1]	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	All Energy
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-month	$/kW-month	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	¢/kWh
Period:																												
2007	0.099	0.073	0.104	0.076	-											0.037	0.036	0.041	0.040				0.089	0.064	0.093	0.067		0.175
2008	0.111	0.083	0.106	0.081	-	0.017	0.013	0.033	0.016	-	-	-	-	-	-	0.037	0.036	0.041	0.040				0.098	0.073	0.094	0.071		0.222
2009	0.104	0.079	0.107	0.073	-	0.049	0.039	0.100	0.051	-	0.017	0.013	0.033	0.016	-	0.035	0.035	0.039	0.038				0.092	0.070	0.095	0.064		0.233
2010	0.101	0.075	0.104	0.071	76.2	0.046	0.037	0.097	0.050	72	0.049	0.039	0.100	0.051	-	0.035	0.035	0.039	0.038	16.9	12.7	0.093	0.090	0.066	0.092	0.062	67	0.233
2011	0.097	0.071	0.103	0.069	129.6	0.028	0.023	0.059	0.030	140	0.046	0.037	0.097	0.050	-	0.035	0.034	0.039	0.038	28.8	21.6	0.158	0.086	0.062	0.091	0.060	114	0.211
2012	0.098	0.072	0.106	0.070	129.6					90	0.028	0.023	0.059	0.030	140	0.031	0.030	0.034	0.033	28.8	21.6	0.158	0.087	0.064	0.095	0.061	114	0.189
2013	0.093	0.066	0.100	0.065	129.6					40					90	0.030	0.029	0.033	0.032	28.8	21.6	0.158	0.083	0.059	0.090	0.058	114	0.167
2014	0.094	0.066	0.099	0.066	129.6										40	0.028	0.028	0.032	0.031	28.8	21.6	0.158	0.084	0.059	0.089	0.059	114	0.145
2015	0.092	0.066	0.100	0.065	129.6											0.027	0.027	0.030	0.029	28.8	21.6	0.158	0.082	0.059	0.090	0.058	114	0.123
2016	0.093	0.068	0.102	0.067	129.6											0.026	0.025	0.029	0.028	28.8	21.6	0.158	0.084	0.061	0.092	0.060	114	0.099
2017	0.097	0.070	0.106	0.069	129.6											0.024	0.024	0.027	0.026	28.8	21.6	0.158	0.087	0.063	0.095	0.062	114	0.074
2018	0.095	0.070	0.104	0.069	129.6											0.023	0.023	0.026	0.025	28.8	21.6	0.158	0.086	0.063	0.094	0.063	114	0.049
2019	0.094	0.068	0.104	0.068	129.6											0.022	0.022	0.024	0.024	28.8	21.6	0.158	0.085	0.062	0.095	0.061	114	0.025
2020	0.096	0.071	0.108	0.069	129.6											0.021	0.020	0.023	0.022	28.8	21.6	0.158	0.087	0.064	0.098	0.063	114	0.000
2021	0.096	0.071	0.110	0.069	129.6											0.020	0.020	0.022	0.022	28.8	21.6	0.158	0.087	0.064	0.100	0.063	114	0.000
2022	0.100	0.072	0.113	0.071	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.158	0.091	0.065	0.103	0.065	114	0.000
2023	0.100	0.072	0.113	0.071	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.158	0.091	0.065	0.103	0.065	114	
2024	0.100	0.072	0.113	0.071	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.158	0.091	0.065	0.103	0.065	114	
2025	0.100	0.072	0.113	0.071	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.158	0.091	0.065	0.103	0.065	114	
2026	0.100	0.072	0.113	0.071	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.158	0.091	0.065	0.103	0.065	114	
2027	0.100	0.072	0.113	0.071	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.158	0.091	0.065	0.103	0.065	114	
2028	0.100	0.072	0.113	0.071	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.158	0.091	0.065	0.103	0.065	114	
2029	0.100	0.072	0.113	0.071	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.158	0.091	0.065	0.103	0.065	114	
2030	0.100	0.072	0.113	0.071	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.158	0.091	0.065	0.103	0.065	114	
2031	0.100	0.072	0.113	0.071	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.158	0.091	0.065	0.103	0.065	114	
2032	0.100	0.072	0.113	0.071	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.158	0.091	0.065	0.103	0.065	114	
2033	0.100	0.072	0.113	0.071	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.158	0.091	0.065	0.103	0.065	114	
2034	0.100	0.072	0.113	0.071	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.158	0.091	0.065	0.103	0.065	114	
2035	0.100	0.072	0.113	0.071	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.158	0.091	0.065	0.103	0.065	114	
2036	0.100	0.072	0.113	0.071	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.158	0.091	0.065	0.103	0.065	114	
2037	0.100	0.072	0.113	0.071	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.158	0.091	0.065	0.103	0.065	114	
2038	0.100	0.072	0.113	0.071	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.158	0.091	0.065	0.103	0.065	114	
2039	0.100	0.072	0.113	0.071	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.158	0.091	0.065	0.103	0.065	114	
2040	0.100	0.072	0.113	0.071	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.158	0.091	0.065	0.103	0.065	114	
Levelized																												
(2008-2040)	0.099	0.072	0.109	0.070	116.7															27.1	20.3	0.139						
(2009-2040)	0.098	0.071	0.109	0.070	121.8															27.7	20.8	0.142						
5 years (2008-12)	0.102	0.076	0.105	0.073	65.4															15.2	11.4	0.019						
10 years (2008-17)	0.098	0.072	0.103	0.070	95.8															22.2	16.7	0.091						
15 years (2008-22)	0.098	0.071	0.105	0.070	105.8															24.6	18.4	0.115						
PV to 2008						0.135	0.109	0.279	0.141	318.3	0.132	0.106	0.273	0.138	243.9													
PV to 2009											0.135	0.109	0.279	0.141	249.3													

Notes:

1) Capacity price converted to $/kWh at zonal on-peak summer load factor.

AESC Avoided Cost Results by Screening Zone

NOTE: **All Avoided Costs are in Year 2007 Dollars; Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours**

Summer for energy values includes June through September; Winter is all other months

All Costs include losses on the ISO-administered Transmission System. DSM savings should include distribution and local transmission losses

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Retail Adder	10%
Real Discount Rate	2.2%
Capacity Losses to ISO Delivery	3.4%
Zonal On-Peak Summer Load Factor	69%

ELECTRIC AVOIDED COSTS
Marginal Wholesale Power Price

	Maine					DRIPE for Installations in 2008					DRIPE for Installations in 2009					CO_2 Externality				FCM Revenue			Avoided Costs before Adders					REC Costs
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Summer: June, July, August	Winter: December, January	On-Peak Summer Capacity Value[1]	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	All Energy
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-month	$/kW-month	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	¢/kWh
Period:																												
2007	0.082	0.061	0.082	0.063	0.000											0.037	0.036	0.041	0.040				0.075	0.056	0.074	0.058		0.000
2008	0.092	0.070	0.087	0.066	0.000	0.015	0.012	0.024	0.010	-	-	-	-	-	-	0.037	0.036	0.041	0.040				0.083	0.064	0.078	0.060		0.044
2009	0.089	0.068	0.083	0.063	0.000	0.044	0.037	0.069	0.030	-	0.015	0.012	0.024	0.010	-	0.035	0.035	0.039	0.038				0.080	0.061	0.075	0.057		0.078
2010	0.085	0.063	0.082	0.060	73.700	0.041	0.034	0.065	0.028	72	0.044	0.037	0.069	0.030	-	0.035	0.035	0.039	0.038	16.4	12.3	0.079	0.076	0.057	0.074	0.053	67	0.100
2011	0.081	0.061	0.081	0.058	125.400	0.025	0.020	0.040	0.017	140	0.041	0.034	0.065	0.028	-	0.035	0.034	0.039	0.038	27.9	20.9	0.134	0.073	0.055	0.072	0.051	114	0.121
2012	0.083	0.062	0.085	0.060	125.400					90	0.025	0.020	0.040	0.017	140	0.031	0.030	0.034	0.033	27.9	20.9	0.134	0.074	0.055	0.076	0.053	114	0.135
2013	0.079	0.058	0.081	0.057	125.400					40					90	0.030	0.029	0.033	0.032	27.9	20.9	0.134	0.070	0.051	0.072	0.050	114	0.143
2014	0.082	0.059	0.083	0.058	125.400										40	0.028	0.028	0.032	0.031	27.9	20.9	0.134	0.073	0.052	0.074	0.052	114	0.145
2015	0.081	0.059	0.084	0.057	125.400											0.027	0.027	0.030	0.029	27.9	20.9	0.134	0.072	0.052	0.075	0.050	114	0.141
2016	0.083	0.060	0.087	0.060	125.400											0.026	0.025	0.029	0.028	27.9	20.9	0.134	0.074	0.053	0.077	0.053	114	0.127
2017	0.085	0.062	0.089	0.060	125.400											0.024	0.024	0.027	0.026	27.9	20.9	0.134	0.076	0.056	0.080	0.054	114	0.106
2018	0.082	0.062	0.087	0.060	125.400											0.023	0.023	0.026	0.025	27.9	20.9	0.134	0.074	0.055	0.079	0.054	114	0.071
2019	0.083	0.060	0.091	0.060	125.400											0.022	0.022	0.024	0.024	27.9	20.9	0.134	0.075	0.054	0.082	0.054	114	0.035
2020	0.084	0.061	0.091	0.060	125.400											0.021	0.020	0.023	0.022	27.9	20.9	0.134	0.076	0.056	0.082	0.055	114	0.000
2021	0.085	0.063	0.093	0.061	125.400											0.020	0.020	0.022	0.022	27.9	20.9	0.134	0.078	0.057	0.085	0.055	114	0.000
2022	0.087	0.064	0.097	0.062	125.400											0.019	0.019	0.022	0.021	27.9	20.9	0.134	0.079	0.058	0.088	0.056	114	0.000
2023	0.087	0.064	0.097	0.062	125.400											0.019	0.019	0.022	0.021	27.9	20.9	0.134	0.079	0.058	0.088	0.056	114	
2024	0.087	0.064	0.097	0.062	125.400											0.019	0.019	0.022	0.021	27.9	20.9	0.134	0.079	0.058	0.088	0.056	114	
2025	0.087	0.064	0.097	0.062	125.400											0.019	0.019	0.022	0.021	27.9	20.9	0.134	0.079	0.058	0.088	0.056	114	
2026	0.087	0.064	0.097	0.062	125.400											0.019	0.019	0.022	0.021	27.9	20.9	0.134	0.079	0.058	0.088	0.056	114	
2027	0.087	0.064	0.097	0.062	125.400											0.019	0.019	0.022	0.021	27.9	20.9	0.134	0.079	0.058	0.088	0.056	114	
2028	0.087	0.064	0.097	0.062	125.400											0.019	0.019	0.022	0.021	27.9	20.9	0.134	0.079	0.058	0.088	0.056	114	
2029	0.087	0.064	0.097	0.062	125.400											0.019	0.019	0.022	0.021	27.9	20.9	0.134	0.079	0.058	0.088	0.056	114	
2030	0.087	0.064	0.097	0.062	125.400											0.019	0.019	0.022	0.021	27.9	20.9	0.134	0.079	0.058	0.088	0.056	114	
2031	0.087	0.064	0.097	0.062	125.400											0.019	0.019	0.022	0.021	27.9	20.9	0.134	0.079	0.058	0.088	0.056	114	
2032	0.087	0.064	0.097	0.062	125.400											0.019	0.019	0.022	0.021	27.9	20.9	0.134	0.079	0.058	0.088	0.056	114	
2033	0.087	0.064	0.097	0.062	125.400											0.019	0.019	0.022	0.021	27.9	20.9	0.134	0.079	0.058	0.088	0.056	114	
2034	0.087	0.064	0.097	0.062	125.400											0.019	0.019	0.022	0.021	27.9	20.9	0.134	0.079	0.058	0.088	0.056	114	
2035	0.087	0.064	0.097	0.062	125.400											0.019	0.019	0.022	0.021	27.9	20.9	0.134	0.079	0.058	0.088	0.056	114	
2036	0.087	0.064	0.097	0.062	125.400											0.019	0.019	0.022	0.021	27.9	20.9	0.134	0.079	0.058	0.088	0.056	114	
2037	0.087	0.064	0.097	0.062	125.400											0.019	0.019	0.022	0.021	27.9	20.9	0.134	0.079	0.058	0.088	0.056	114	
2038	0.087	0.064	0.097	0.062	125.400											0.019	0.019	0.022	0.021	27.9	20.9	0.134	0.079	0.058	0.088	0.056	114	
2039	0.087	0.064	0.097	0.062	125.400											0.019	0.019	0.022	0.021	27.9	20.9	0.134	0.079	0.058	0.088	0.056	114	
2040	0.087	0.064	0.097	0.062	125.400											0.019	0.019	0.022	0.021	27.9	20.9	0.134	0.079	0.058	0.088	0.056	114	
Levelized																												
(2008-2040)	0.086	0.063	0.091	0.061	112.9															25.8	19.4	0.119						
(2009-2040)	0.085	0.063	0.091	0.061	117.8															26.6	20.0	0.121						
5 years (2008-12)	0.086	0.065	0.084	0.061	63.2															14.4	10.8	0.016						
10 years (2008-17)	0.084	0.063	0.084	0.060	92.6															21.1	15.9	0.078						
15 years (2008-22)	0.084	0.062	0.086	0.060	102.4															23.4	17.5	0.098						
PV to 2008						0.120	0.099	0.191	0.081	318.3	0.118	0.097	0.187	0.080	243.9													
PV to 2009											0.120	0.099	0.191	0.081	249.3													

Notes:

1) Capacity price converted to $/kWh at zonal on-peak summer load factor.

AESC Avoided Cost Results by Screening Zone

MA

NOTE: All Avoided Costs are in Year 2007 Dollars; Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours

Summer for energy values includes June through September; Winter is all other months

All Costs include losses on the ISO-administered Transmission System. DSM savings should include distribution and local transmission losses

Retail Adder	10%
Real Discount Rate	2.2%
Capacity Losses to ISO Delivery	3.4%
Zonal On-Peak Summer Load Factor	61%

Formatted for input to DSM screening models

ELECTRIC AVOIDED COSTS

Marginal Wholesale Power Price

	All of Massachusetts					DRIPE for Installations in 2008					DRIPE for Installations in 2009					CO_2 Externality				FCM Revenue			Avoided Costs before Adders					REC Costs
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Summer: June, July, August	Winter: December, January	On-Peak Summer Capacity Value[1]	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	All Energy
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-month	$/kW-month	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	¢/kWh
Period:																												
2007	0.094	0.069	0.095	0.072	-											0.037	0.036	0.041	0.040				0.084	0.061	0.085	0.064		0.150
2008	0.105	0.078	0.097	0.074	-	0.016	0.013	0.029	0.012	-	-	-	-	-	-	0.037	0.036	0.041	0.040				0.094	0.070	0.087	0.066		0.156
2009	0.098	0.075	0.097	0.070	-	0.046	0.037	0.083	0.034	-	0.016	0.013	0.029	0.012	-	0.035	0.035	0.039	0.038				0.088	0.067	0.087	0.062		0.156
2010	0.097	0.072	0.098	0.067	76.2	0.043	0.035	0.078	0.031	72	0.046	0.037	0.083	0.034	-	0.035	0.035	0.039	0.038	16.9	12.7	0.092	0.087	0.063	0.087	0.059	67	0.167
2011	0.093	0.068	0.097	0.065	129.6	0.026	0.021	0.047	0.019	140	0.043	0.035	0.078	0.031	-	0.035	0.034	0.039	0.038	28.8	21.6	0.156	0.083	0.060	0.086	0.058	114	0.181
2012	0.094	0.070	0.098	0.068	129.6					90	0.026	0.021	0.047	0.019	140	0.031	0.030	0.034	0.033	28.8	21.6	0.156	0.083	0.062	0.088	0.060	114	0.189
2013	0.089	0.065	0.094	0.064	129.6					40					90	0.030	0.029	0.033	0.032	28.8	21.6	0.156	0.079	0.057	0.084	0.057	114	0.191
2014	0.091	0.065	0.094	0.065	129.6										40	0.028	0.028	0.032	0.031	28.8	21.6	0.156	0.081	0.057	0.084	0.058	114	0.187
2015	0.090	0.065	0.098	0.065	129.6											0.027	0.027	0.030	0.029	28.8	21.6	0.156	0.080	0.058	0.088	0.057	114	0.176
2016	0.092	0.066	0.099	0.068	129.6											0.026	0.025	0.029	0.028	28.8	21.6	0.156	0.082	0.059	0.088	0.060	114	0.155
2017	0.094	0.068	0.102	0.067	129.6											0.024	0.024	0.027	0.026	28.8	21.6	0.156	0.084	0.061	0.091	0.060	114	0.127
2018	0.092	0.068	0.100	0.068	129.6											0.023	0.023	0.026	0.025	28.8	21.6	0.156	0.083	0.061	0.090	0.061	114	0.092
2019	0.092	0.066	0.102	0.067	129.6											0.022	0.022	0.024	0.024	28.8	21.6	0.156	0.083	0.060	0.092	0.060	114	0.049
2020	0.093	0.068	0.103	0.067	129.6											0.021	0.020	0.023	0.022	28.8	21.6	0.156	0.084	0.062	0.094	0.061	114	0.000
2021	0.094	0.068	0.108	0.068	129.6											0.020	0.020	0.022	0.022	28.8	21.6	0.156	0.086	0.062	0.098	0.062	114	0.000
2022	0.097	0.070	0.109	0.069	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.156	0.088	0.063	0.099	0.063	114	0.000
2023	0.097	0.070	0.109	0.069	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.156	0.088	0.063	0.099	0.063	114	
2024	0.097	0.070	0.109	0.069	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.156	0.088	0.063	0.099	0.063	114	
2025	0.097	0.070	0.109	0.069	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.156	0.088	0.063	0.099	0.063	114	
2026	0.097	0.070	0.109	0.069	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.156	0.088	0.063	0.099	0.063	114	
2027	0.097	0.070	0.109	0.069	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.156	0.088	0.063	0.099	0.063	114	
2028	0.097	0.070	0.109	0.069	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.156	0.088	0.063	0.099	0.063	114	
2029	0.097	0.070	0.109	0.069	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.156	0.088	0.063	0.099	0.063	114	
2030	0.097	0.070	0.109	0.069	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.156	0.088	0.063	0.099	0.063	114	
2031	0.097	0.070	0.109	0.069	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.156	0.088	0.063	0.099	0.063	114	
2032	0.097	0.070	0.109	0.069	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.156	0.088	0.063	0.099	0.063	114	
2033	0.097	0.070	0.109	0.069	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.156	0.088	0.063	0.099	0.063	114	
2034	0.097	0.070	0.109	0.069	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.156	0.088	0.063	0.099	0.063	114	
2035	0.097	0.070	0.109	0.069	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.156	0.088	0.063	0.099	0.063	114	
2036	0.097	0.070	0.109	0.069	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.156	0.088	0.063	0.099	0.063	114	
2037	0.097	0.070	0.109	0.069	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.156	0.088	0.063	0.099	0.063	114	
2038	0.097	0.070	0.109	0.069	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.156	0.088	0.063	0.099	0.063	114	
2039	0.097	0.070	0.109	0.069	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.156	0.088	0.063	0.099	0.063	114	
2040	0.097	0.070	0.109	0.069	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.156	0.088	0.063	0.099	0.063	114	
Levelized																												
(2008-2040)	0.095	0.069	0.104	0.068	116.7															27.1	20.3	0.138						
(2009-2040)	0.095	0.069	0.104	0.068	121.8															27.7	20.8	0.141						
5 years (2008-12)	0.098	0.073	0.098	0.069	65.4															15.2	11.4	0.019						
10 years (2008-17)	0.095	0.070	0.098	0.068	95.8															22.2	16.7	0.090						
15 years (2008-22)	0.094	0.069	0.100	0.068	105.8															24.6	18.4	0.114						
PV to 2008						0.127	0.102	0.229	0.093	318.3	0.124	0.100	0.224	0.091	243.9													
PV to 2009											0.127	0.102	0.229	0.093	249.3													

Notes:

1) Capacity price converted to $/kWh at zonal on-peak summer load factor.

Zonal Energy

	On-Peak				Off-Peak			
	NEMA	SEMA	WCMA	MA	NEMA	SEMA	WCMA	MA
Mar-07	890	560	750		777	478	704	
Feb-07	1,049	597	635		942	533	679	
Jan-07	1,253	620	823		1,074	517	769	
Dec-06	1,149	574	718		1,129	609	815	
Nov-06	963	579	750		851	532	713	
Oct-06	994	598	579		835	514	640	
Sep-06	1,008	585	625		951	562	785	
Aug-06	1,374	842	881		993	609	789	
Jul-06	1,267	772	769		1,235	791	1,005	
Jun-06	1,217	686	803		891	524	738	
May-06	1,019	623	771		779	469	686	
Apr-06	866	527	670		837	518	757	
Summer	4,867	2,885	3,078	10,830	4,069	2,485	3,317	9,872
Winter	8,183	4,678	5,695	18,556	7,224	4,170	5,764	17,159
Summer	44.9%	26.6%	28.4%		41.2%	25.2%	33.6%	
Winter	44.1%	25.2%	30.7%		42.1%	24.3%	33.6%	

AESC Avoided Cost Results by Screening Zone

NOTE: **All Avoided Costs are in Year 2007 Dollars; Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours**
Summer for energy values includes June through September; Winter is all other months
All Costs include losses on the ISO-administered Transmission System. DSM savings should include distribution and local transmission losses

Formatted for input to DSM screening models

Retail Adder	10%
Real Discount Rate	2.2%
Capacity Losses to ISO Delivery	3.4%
Zonal On-Peak Summer Load Factor	66%

ELECTRIC AVOIDED COSTS
Marginal Wholesale Power Price

	New Hampshire					DRIPE for Installations in 2008					DRIPE for Installations in 2009				
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr
Period:															
2007	0.089	0.066	0.090	0.069	-										
2008	0.099	0.075	0.092	0.070	-	0.015	0.014	0.028	0.014	-	-	-	-	-	-
2009	0.093	0.072	0.090	0.067	-	0.042	0.037	0.076	0.034	-	0.015	0.014	0.028	0.014	-
2010	0.092	0.068	0.090	0.064	76.2	0.039	0.034	0.069	0.030	72	0.042	0.037	0.076	0.034	-
2011	0.088	0.066	0.088	0.062	129.6	0.024	0.020	0.042	0.018	140	0.039	0.034	0.069	0.030	-
2012	0.089	0.067	0.093	0.064	129.6					90	0.024	0.020	0.042	0.018	140
2013	0.085	0.062	0.088	0.061	129.6					40					90
2014	0.088	0.063	0.090	0.062	129.6										40
2015	0.086	0.063	0.091	0.062	129.6										
2016	0.088	0.064	0.093	0.065	129.6										
2017	0.091	0.067	0.097	0.065	129.6										
2018	0.089	0.066	0.094	0.065	129.6										
2019	0.088	0.064	0.097	0.065	129.6										
2020	0.089	0.066	0.098	0.065	129.6										
2021	0.090	0.067	0.100	0.065	129.6										
2022	0.092	0.068	0.103	0.066	129.6										
2023	0.092	0.068	0.103	0.066	129.6										
2024	0.092	0.068	0.103	0.066	129.6										
2025	0.092	0.068	0.103	0.066	129.6										
2026	0.092	0.068	0.103	0.066	129.6										
2027	0.092	0.068	0.103	0.066	129.6										
2028	0.092	0.068	0.103	0.066	129.6										
2029	0.092	0.068	0.103	0.066	129.6										
2030	0.092	0.068	0.103	0.066	129.6										
2031	0.092	0.068	0.103	0.066	129.6										
2032	0.092	0.068	0.103	0.066	129.6										
2033	0.092	0.068	0.103	0.066	129.6										
2034	0.092	0.068	0.103	0.066	129.6										
2035	0.092	0.068	0.103	0.066	129.6										
2036	0.092	0.068	0.103	0.066	129.6										
2037	0.092	0.068	0.103	0.066	129.6										
2038	0.092	0.068	0.103	0.066	129.6										
2039	0.092	0.068	0.103	0.066	129.6										
2040	0.092	0.068	0.103	0.066	129.6										
Levelized															
(2008-2040)	0.091	0.067	0.098	0.065	116.7										
(2009-2040)	0.091	0.067	0.098	0.065	121.8										
5 years (2008-12)	0.092	0.070	0.090	0.065	65.4										
10 years (2008-17)	0.090	0.067	0.091	0.064	95.8										
15 years (2008-22)	0.090	0.067	0.093	0.065	105.8										
PV to 2008						0.116	0.102	0.208	0.093	318.3	0.114	0.099	0.203	0.091	243.9
PV to 2009											0.116	0.102	0.208	0.093	249.3

	CO_2 Externality				FCM Revenue			Avoided Costs before Adders					REC Costs
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Summer: June, July, August	Winter: December, January	On-Peak Summer Capacity Value[1]	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	All Energy
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-month	$/kW-month	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	¢/kWh
Period:													
2007	0.037	0.036	0.041	0.040				0.081	0.060	0.081	0.063		0.000
2008	0.037	0.036	0.041	0.040				0.090	0.068	0.084	0.064		0.000
2009	0.035	0.035	0.039	0.038				0.085	0.066	0.081	0.060		0.019
2010	0.035	0.035	0.039	0.038	16.9	12.7	0.085	0.083	0.062	0.081	0.058	67	0.035
2011	0.035	0.034	0.039	0.038	28.8	21.6	0.144	0.079	0.059	0.080	0.056	114	0.063
2012	0.031	0.030	0.034	0.033	28.8	21.6	0.144	0.080	0.060	0.083	0.057	114	0.085
2013	0.030	0.029	0.033	0.032	28.8	21.6	0.144	0.076	0.055	0.079	0.054	114	0.100
2014	0.028	0.028	0.032	0.031	28.8	21.6	0.144	0.078	0.056	0.081	0.056	114	0.110
2015	0.027	0.027	0.030	0.029	28.8	21.6	0.144	0.077	0.056	0.082	0.055	114	0.111
2016	0.026	0.025	0.029	0.028	28.8	21.6	0.144	0.079	0.057	0.084	0.058	114	0.103
2017	0.024	0.024	0.027	0.026	28.8	21.6	0.144	0.082	0.060	0.087	0.058	114	0.088
2018	0.023	0.023	0.026	0.025	28.8	21.6	0.144	0.080	0.059	0.085	0.059	114	0.066
2019	0.022	0.022	0.024	0.024	28.8	21.6	0.144	0.080	0.058	0.088	0.058	114	0.036
2020	0.021	0.020	0.023	0.022	28.8	21.6	0.144	0.081	0.060	0.089	0.059	114	0.000
2021	0.020	0.020	0.022	0.022	28.8	21.6	0.144	0.082	0.061	0.091	0.059	114	0.000
2022	0.019	0.019	0.022	0.021	28.8	21.6	0.144	0.084	0.062	0.094	0.060	114	0.000
2023	0.019	0.019	0.022	0.021	28.8	21.6	0.144	0.084	0.062	0.094	0.060	114	
2024	0.019	0.019	0.022	0.021	28.8	21.6	0.144	0.084	0.062	0.094	0.060	114	
2025	0.019	0.019	0.022	0.021	28.8	21.6	0.144	0.084	0.062	0.094	0.060	114	
2026	0.019	0.019	0.022	0.021	28.8	21.6	0.144	0.084	0.062	0.094	0.060	114	
2027	0.019	0.019	0.022	0.021	28.8	21.6	0.144	0.084	0.062	0.094	0.060	114	
2028	0.019	0.019	0.022	0.021	28.8	21.6	0.144	0.084	0.062	0.094	0.060	114	
2029	0.019	0.019	0.022	0.021	28.8	21.6	0.144	0.084	0.062	0.094	0.060	114	
2030	0.019	0.019	0.022	0.021	28.8	21.6	0.144	0.084	0.062	0.094	0.060	114	
2031	0.019	0.019	0.022	0.021	28.8	21.6	0.144	0.084	0.062	0.094	0.060	114	
2032	0.019	0.019	0.022	0.021	28.8	21.6	0.144	0.084	0.062	0.094	0.060	114	
2033	0.019	0.019	0.022	0.021	28.8	21.6	0.144	0.084	0.062	0.094	0.060	114	
2034	0.019	0.019	0.022	0.021	28.8	21.6	0.144	0.084	0.062	0.094	0.060	114	
2035	0.019	0.019	0.022	0.021	28.8	21.6	0.144	0.084	0.062	0.094	0.060	114	
2036	0.019	0.019	0.022	0.021	28.8	21.6	0.144	0.084	0.062	0.094	0.060	114	
2037	0.019	0.019	0.022	0.021	28.8	21.6	0.144	0.084	0.062	0.094	0.060	114	
2038	0.019	0.019	0.022	0.021	28.8	21.6	0.144	0.084	0.062	0.094	0.060	114	
2039	0.019	0.019	0.022	0.021	28.8	21.6	0.144	0.084	0.062	0.094	0.060	114	
2040	0.019	0.019	0.022	0.021	28.8	21.6	0.144	0.084	0.062	0.094	0.060	114	
Levelized													
(2008-2040)					26.7	20.0	0.128						
(2009-2040)					27.5	20.7	0.130						
5 years (2008-12)					14.9	11.2	0.018						
10 years (2008-17)					21.9	16.4	0.084						
15 years (2008-22)					24.2	18.1	0.106						

Notes:
1) Capacity price converted to $/kWh at zonal on-peak summer load factor.

AESC Avoided Cost Results by Screening Zone

NOTE: **All Avoided Costs are in Year 2007 Dollars; Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours**

Summer for energy values includes June through September; Winter is all other months

All Costs include losses on the ISO-administered Transmission System. DSM savings should include distribution and local transmission losses

Formatted for input to DSM screening models

Retail Adder	10%
Real Discount Rate	2.2%
Capacity Losses to ISO Delivery	3.4%
Zonal On-Peak Summer Load Factor	61%

ELECTRIC AVOIDED COSTS

Marginal Wholesale Power Price

	Rhode Island					DRIPE for Installations in 2008					DRIPE for Installations in 2009					CO_2 Externality				FCM Revenue			Avoided Costs before Adders					REC Costs
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Summer: June, July, August	Winter: December, January	On-Peak Summer Capacity Value[1]	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	All Energy
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-month	$/kW-month	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	¢/kWh
Period:																												
2007	0.092	0.067	0.093	0.070	-											0.037	0.036	0.041	0.040				0.083	0.061	0.084	0.063		0.050
2008	0.105	0.077	0.096	0.072	-	0.015	0.012	0.024	0.010	-	-	-	-	-	-	0.037	0.036	0.041	0.040				0.095	0.069	0.087	0.065		0.067
2009	0.096	0.074	0.097	0.067	-	0.043	0.035	0.070	0.031	-	0.015	0.012	0.024	0.010	-	0.035	0.035	0.039	0.038				0.087	0.066	0.088	0.060		0.078
2010	0.096	0.071	0.097	0.065	76.2	0.040	0.033	0.066	0.030	72	0.043	0.035	0.070	0.031	-	0.035	0.035	0.039	0.038	16.9	12.7	0.092	0.086	0.064	0.087	0.058	67	0.083
2011	0.092	0.067	0.095	0.063	129.6	0.025	0.020	0.040	0.018	140	0.040	0.033	0.066	0.030	-	0.035	0.034	0.039	0.038	28.8	21.6	0.156	0.082	0.060	0.085	0.056	114	0.106
2012	0.093	0.069	0.095	0.065	129.6					90	0.025	0.020	0.040	0.018	140	0.031	0.030	0.034	0.033	28.8	21.6	0.156	0.083	0.061	0.085	0.058	114	0.122
2013	0.087	0.064	0.092	0.063	129.6					40					90	0.030	0.029	0.033	0.032	28.8	21.6	0.156	0.078	0.057	0.082	0.056	114	0.131
2014	0.090	0.064	0.092	0.063	129.6										40	0.028	0.028	0.032	0.031	28.8	21.6	0.156	0.081	0.057	0.083	0.056	114	0.135
2015	0.089	0.064	0.096	0.062	129.6											0.027	0.027	0.030	0.029	28.8	21.6	0.156	0.079	0.057	0.086	0.055	114	0.141
2016	0.090	0.066	0.098	0.066	129.6											0.026	0.025	0.029	0.028	28.8	21.6	0.156	0.081	0.059	0.087	0.058	114	0.134
2017	0.093	0.068	0.101	0.066	129.6											0.024	0.024	0.027	0.026	28.8	21.6	0.156	0.084	0.061	0.090	0.059	114	0.116
2018	0.092	0.067	0.098	0.067	129.6											0.023	0.023	0.026	0.025	28.8	21.6	0.156	0.083	0.060	0.088	0.060	114	0.088
2019	0.092	0.066	0.101	0.067	129.6											0.022	0.022	0.024	0.024	28.8	21.6	0.156	0.083	0.060	0.091	0.060	114	0.049
2020	0.092	0.068	0.102	0.068	129.6											0.021	0.020	0.023	0.022	28.8	21.6	0.156	0.083	0.062	0.093	0.061	114	0.000
2021	0.093	0.069	0.106	0.067	129.6											0.020	0.020	0.022	0.022	28.8	21.6	0.156	0.084	0.063	0.096	0.061	114	0.000
2022	0.098	0.069	0.108	0.070	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.156	0.089	0.063	0.098	0.064	114	0.000
2023	0.098	0.069	0.108	0.070	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.156	0.089	0.063	0.098	0.064	114	
2024	0.098	0.069	0.108	0.070	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.156	0.089	0.063	0.098	0.064	114	
2025	0.098	0.069	0.108	0.070	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.156	0.089	0.063	0.098	0.064	114	
2026	0.098	0.069	0.108	0.070	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.156	0.089	0.063	0.098	0.064	114	
2027	0.098	0.069	0.108	0.070	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.156	0.089	0.063	0.098	0.064	114	
2028	0.098	0.069	0.108	0.070	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.156	0.089	0.063	0.098	0.064	114	
2029	0.098	0.069	0.108	0.070	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.156	0.089	0.063	0.098	0.064	114	
2030	0.098	0.069	0.108	0.070	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.156	0.089	0.063	0.098	0.064	114	
2031	0.098	0.069	0.108	0.070	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.156	0.089	0.063	0.098	0.064	114	
2032	0.098	0.069	0.108	0.070	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.156	0.089	0.063	0.098	0.064	114	
2033	0.098	0.069	0.108	0.070	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.156	0.089	0.063	0.098	0.064	114	
2034	0.098	0.069	0.108	0.070	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.156	0.089	0.063	0.098	0.064	114	
2035	0.098	0.069	0.108	0.070	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.156	0.089	0.063	0.098	0.064	114	
2036	0.098	0.069	0.108	0.070	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.156	0.089	0.063	0.098	0.064	114	
2037	0.098	0.069	0.108	0.070	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.156	0.089	0.063	0.098	0.064	114	
2038	0.098	0.069	0.108	0.070	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.156	0.089	0.063	0.098	0.064	114	
2039	0.098	0.069	0.108	0.070	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.156	0.089	0.063	0.098	0.064	114	
2040	0.098	0.069	0.108	0.070	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.156	0.089	0.063	0.098	0.064	114	
Levelized																												
(2008-2040)	0.095	0.069	0.102	0.068	116.7															27.1	20.3	0.138						
(2009-2040)	0.095	0.068	0.103	0.068	121.8															27.7	20.8	0.141						
5 years (2008-12)	0.096	0.072	0.096	0.067	65.4															15.2	11.4	0.019						
10 years (2008-17)	0.093	0.068	0.096	0.065	95.8															22.2	16.7	0.091						
15 years (2008-22)	0.093	0.068	0.098	0.066	105.8															24.6	18.4	0.114						
PV to 2008						0.118	0.095	0.194	0.087	318.3	0.115	0.093	0.189	0.085	243.9													
PV to 2009											0.118	0.095	0.194	0.087	249.3													

Notes:

1) Capacity price converted to $/kWh at zonal on-peak summer load factor.

AESC Avoided Cost Results by Screening Zone

NOTE: **All Avoided Costs are in Year 2007 Dollars; Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours**

Summer for energy values includes June through September; Winter is all other months

All Costs include losses on the ISO-administered Transmission System. DSM savings should include distribution and local transmission losses

Formatted for input to DSM screening models

Retail Adder	11%	PSB risk adder
Real Discount Rate	2.2%	
Capacity Losses to ISO Delivery	3.4%	
Zonal On-Peak Summer Load Factor	66%	

ELECTRIC AVOIDED COSTS
Marginal Wholesale Power Price

	Vermont					DRIPE for Installations in 2008					DRIPE for Installations in 2009					CO_2 Externality				FCM Revenue			Avoided Costs before Adders					REC Costs
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Summer: June, July, August	Winter: December, January	On-Peak Summer Capacity Value[1]	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	All Energy
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-month	$/kW-month	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	¢/kWh
Period:																												
2007	0.096	0.071	0.097	0.073	-											0.037	0.036	0.041	0.040				0.086	0.063	0.087	0.065		0.062
2008	0.106	0.080	0.099	0.076	-	0.015	0.012	0.025	0.010	-	-	-	-	-	-	0.037	0.036	0.041	0.040				0.094	0.071	0.088	0.067		0.111
2009	0.100	0.077	0.100	0.070	-	0.042	0.034	0.071	0.029	-	0.015	0.012	0.025	0.010	-	0.035	0.035	0.039	0.038				0.088	0.068	0.089	0.062		0.140
2010	0.099	0.074	0.099	0.070	77.0	0.039	0.031	0.067	0.027	72	0.042	0.034	0.071	0.029	-	0.035	0.035	0.039	0.038	17.1	12.8	0.086	0.088	0.065	0.087	0.061	67	0.152
2011	0.094	0.070	0.097	0.066	130.9	0.024	0.019	0.041	0.016	140	0.039	0.031	0.067	0.027	-	0.035	0.034	0.039	0.038	29.1	21.8	0.147	0.083	0.061	0.086	0.058	114	0.159
2012	0.095	0.070	0.099	0.069	130.9					90	0.024	0.019	0.041	0.016	140	0.031	0.030	0.034	0.033	29.1	21.8	0.147	0.084	0.062	0.087	0.060	114	0.172
2013	0.091	0.066	0.098	0.066	130.9					40					90	0.030	0.029	0.033	0.032	29.1	21.8	0.147	0.080	0.057	0.086	0.058	114	0.180
2014	0.093	0.066	0.097	0.066	130.9										40	0.028	0.028	0.032	0.031	29.1	21.8	0.147	0.082	0.058	0.086	0.058	114	0.176
2015	0.092	0.066	0.098	0.067	130.9											0.027	0.027	0.030	0.029	29.1	21.8	0.147	0.081	0.058	0.087	0.058	114	0.176
2016	0.093	0.068	0.100	0.070	130.9											0.026	0.025	0.029	0.028	29.1	21.8	0.147	0.082	0.060	0.089	0.061	114	0.141
2017	0.097	0.070	0.102	0.069	130.9											0.024	0.024	0.027	0.026	29.1	21.8	0.147	0.086	0.062	0.091	0.061	114	0.106
2018	0.094	0.068	0.101	0.070	130.9											0.023	0.023	0.026	0.025	29.1	21.8	0.147	0.084	0.061	0.090	0.062	114	0.071
2019	0.092	0.066	0.102	0.069	130.9											0.022	0.022	0.024	0.024	29.1	21.8	0.147	0.083	0.059	0.091	0.062	114	0.035
2020	0.095	0.069	0.104	0.069	130.9											0.021	0.020	0.023	0.022	29.1	21.8	0.147	0.085	0.062	0.094	0.062	114	0.000
2021	0.098	0.069	0.107	0.069	130.9											0.020	0.020	0.022	0.022	29.1	21.8	0.147	0.088	0.062	0.097	0.062	114	0.000
2022	0.100	0.071	0.109	0.071	130.9											0.019	0.019	0.022	0.021	29.1	21.8	0.147	0.090	0.063	0.098	0.064	114	0.000
2023	0.100	0.071	0.109	0.071	130.9											0.019	0.019	0.022	0.021	29.1	21.8	0.147	0.090	0.063	0.098	0.064	114	
2024	0.100	0.071	0.109	0.071	130.9											0.019	0.019	0.022	0.021	29.1	21.8	0.147	0.090	0.063	0.098	0.064	114	
2025	0.100	0.071	0.109	0.071	130.9											0.019	0.019	0.022	0.021	29.1	21.8	0.147	0.090	0.063	0.098	0.064	114	
2026	0.100	0.071	0.109	0.071	130.9											0.019	0.019	0.022	0.021	29.1	21.8	0.147	0.090	0.063	0.098	0.064	114	
2027	0.100	0.071	0.109	0.071	130.9											0.019	0.019	0.022	0.021	29.1	21.8	0.147	0.090	0.063	0.098	0.064	114	
2028	0.100	0.071	0.109	0.071	130.9											0.019	0.019	0.022	0.021	29.1	21.8	0.147	0.090	0.063	0.098	0.064	114	
2029	0.100	0.071	0.109	0.071	130.9											0.019	0.019	0.022	0.021	29.1	21.8	0.147	0.090	0.063	0.098	0.064	114	
2030	0.100	0.071	0.109	0.071	130.9											0.019	0.019	0.022	0.021	29.1	21.8	0.147	0.090	0.063	0.098	0.064	114	
2031	0.100	0.071	0.109	0.071	130.9											0.019	0.019	0.022	0.021	29.1	21.8	0.147	0.090	0.063	0.098	0.064	114	
2032	0.100	0.071	0.109	0.071	130.9											0.019	0.019	0.022	0.021	29.1	21.8	0.147	0.090	0.063	0.098	0.064	114	
2033	0.100	0.071	0.109	0.071	130.9											0.019	0.019	0.022	0.021	29.1	21.8	0.147	0.090	0.063	0.098	0.064	114	
2034	0.100	0.071	0.109	0.071	130.9											0.019	0.019	0.022	0.021	29.1	21.8	0.147	0.090	0.063	0.098	0.064	114	
2035	0.100	0.071	0.109	0.071	130.9											0.019	0.019	0.022	0.021	29.1	21.8	0.147	0.090	0.063	0.098	0.064	114	
2036	0.100	0.071	0.109	0.071	130.9											0.019	0.019	0.022	0.021	29.1	21.8	0.147	0.090	0.063	0.098	0.064	114	
2037	0.100	0.071	0.109	0.071	130.9											0.019	0.019	0.022	0.021	29.1	21.8	0.147	0.090	0.063	0.098	0.064	114	
2038	0.100	0.071	0.109	0.071	130.9											0.019	0.019	0.022	0.021	29.1	21.8	0.147	0.090	0.063	0.098	0.064	114	
2039	0.100	0.071	0.109	0.071	130.9											0.019	0.019	0.022	0.021	29.1	21.8	0.147	0.090	0.063	0.098	0.064	114	
2040	0.100	0.071	0.109	0.071	130.9											0.019	0.019	0.022	0.021	29.1	21.8	0.147	0.090	0.063	0.098	0.064	114	
Levelized																												
(2008-2040)	0.098	0.070	0.104	0.070	117.9															27.0	20.2	0.130						
(2009-2040)	0.097	0.070	0.105	0.070	123.0															27.8	20.9	0.132						
5 years (2008-12)	0.099	0.074	0.099	0.070	66.0															15.1	11.3	0.018						
10 years (2008-17)	0.096	0.071	0.099	0.069	96.7															22.1	16.6	0.085						
15 years (2008-22)	0.096	0.070	0.101	0.069	106.9															24.4	18.3	0.107						
PV to 2008						0.116	0.092	0.196	0.078	318.3	0.113	0.090	0.192	0.077	243.9													
PV to 2009											0.116	0.092	0.196	0.078	249.3													

Notes:

1) Capacity price converted to $/kWh at zonal on-peak summer load factor.

AESC Avoided Cost Results by Screening Zone

NOTE: **All Avoided Costs are in Year 2007 Dollars; Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours**

Summer for energy values includes June through September; Winter is all other months

All Costs include losses on the ISO-administered Transmission System. DSM savings should include distribution and local transmission losses

Formatted for input to DSM screening models

Retail Adder	10%
Real Discount Rate	2.2%
Capacity Losses to ISO Delivery	3.4%
Zonal On-Peak Summer Load Factor	64%

ELECTRIC AVOIDED COSTS
Marginal Wholesale Power Price

	Northeast Massachusetts					DRIPE for Installations in 2008					DRIPE for Installations in 2009					CO_2 Externality				FCM Revenue			Avoided Costs before Adders					REC Costs
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Summer: June, July, August	Winter: December, January	On-Peak Summer Capacity Value[1]	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	All Energy
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-month	$/kW-month	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	¢/kWh
Period:																												
2007	0.094	0.069	0.096	0.072	-											0.037	0.036	0.041	0.040				0.084	0.061	0.086	0.064		0.150
2008	0.105	0.078	0.098	0.075	-	0.015	0.013	0.029	0.013	-	-	-	-	-	-	0.037	0.036	0.041	0.040				0.094	0.069	0.088	0.066		0.156
2009	0.099	0.075	0.099	0.071	-	0.044	0.038	0.084	0.037	-	0.015	0.013	0.029	0.013	-	0.035	0.035	0.039	0.038				0.088	0.067	0.088	0.063		0.156
2010	0.098	0.071	0.099	0.068	76.2	0.041	0.035	0.078	0.034	72	0.044	0.038	0.084	0.037	-	0.035	0.035	0.039	0.038	16.9	12.7	0.087	0.088	0.063	0.088	0.060	67	0.167
2011	0.094	0.068	0.098	0.066	129.6	0.025	0.021	0.048	0.021	140	0.041	0.035	0.078	0.034	-	0.035	0.034	0.039	0.038	28.8	21.6	0.148	0.084	0.060	0.087	0.059	114	0.181
2012	0.095	0.070	0.100	0.070	129.6					90	0.025	0.021	0.048	0.021	140	0.031	0.030	0.034	0.033	28.8	21.6	0.148	0.084	0.062	0.089	0.062	114	0.189
2013	0.089	0.065	0.096	0.065	129.6					40					90	0.030	0.029	0.033	0.032	28.8	21.6	0.148	0.079	0.057	0.086	0.057	114	0.191
2014	0.092	0.065	0.096	0.065	129.6										40	0.028	0.028	0.032	0.031	28.8	21.6	0.148	0.081	0.058	0.085	0.058	114	0.187
2015	0.090	0.066	0.100	0.065	129.6											0.027	0.027	0.030	0.029	28.8	21.6	0.148	0.080	0.058	0.089	0.057	114	0.176
2016	0.093	0.066	0.101	0.069	129.6											0.026	0.025	0.029	0.028	28.8	21.6	0.148	0.083	0.059	0.090	0.061	114	0.155
2017	0.095	0.068	0.103	0.067	129.6											0.024	0.024	0.027	0.026	28.8	21.6	0.148	0.085	0.061	0.092	0.060	114	0.127
2018	0.093	0.068	0.102	0.069	129.6											0.023	0.023	0.026	0.025	28.8	21.6	0.148	0.084	0.061	0.092	0.062	114	0.092
2019	0.093	0.067	0.103	0.067	129.6											0.022	0.022	0.024	0.024	28.8	21.6	0.148	0.084	0.060	0.094	0.061	114	0.049
2020	0.094	0.068	0.104	0.067	129.6											0.021	0.020	0.023	0.022	28.8	21.6	0.148	0.085	0.062	0.095	0.061	114	0.000
2021	0.095	0.069	0.109	0.068	129.6											0.020	0.020	0.022	0.022	28.8	21.6	0.148	0.087	0.063	0.099	0.062	114	0.000
2022	0.098	0.070	0.111	0.069	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.148	0.089	0.064	0.101	0.063	114	0.000
2023	0.098	0.070	0.111	0.069	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.148	0.089	0.064	0.101	0.063	114	
2024	0.098	0.070	0.111	0.069	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.148	0.089	0.064	0.101	0.063	114	
2025	0.098	0.070	0.111	0.069	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.148	0.089	0.064	0.101	0.063	114	
2026	0.098	0.070	0.111	0.069	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.148	0.089	0.064	0.101	0.063	114	
2027	0.098	0.070	0.111	0.069	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.148	0.089	0.064	0.101	0.063	114	
2028	0.098	0.070	0.111	0.069	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.148	0.089	0.064	0.101	0.063	114	
2029	0.098	0.070	0.111	0.069	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.148	0.089	0.064	0.101	0.063	114	
2030	0.098	0.070	0.111	0.069	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.148	0.089	0.064	0.101	0.063	114	
2031	0.098	0.070	0.111	0.069	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.148	0.089	0.064	0.101	0.063	114	
2032	0.098	0.070	0.111	0.069	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.148	0.089	0.064	0.101	0.063	114	
2033	0.098	0.070	0.111	0.069	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.148	0.089	0.064	0.101	0.063	114	
2034	0.098	0.070	0.111	0.069	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.148	0.089	0.064	0.101	0.063	114	
2035	0.098	0.070	0.111	0.069	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.148	0.089	0.064	0.101	0.063	114	
2036	0.098	0.070	0.111	0.069	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.148	0.089	0.064	0.101	0.063	114	
2037	0.098	0.070	0.111	0.069	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.148	0.089	0.064	0.101	0.063	114	
2038	0.098	0.070	0.111	0.069	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.148	0.089	0.064	0.101	0.063	114	
2039	0.098	0.070	0.111	0.069	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.148	0.089	0.064	0.101	0.063	114	
2040	0.098	0.070	0.111	0.069	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.148	0.089	0.064	0.101	0.063	114	
Levelized																												
(2008-2040)	0.096	0.070	0.105	0.069	116.7															26.7	20.0	0.131						
(2009-2040)	0.096	0.069	0.106	0.068	121.8															27.5	20.7	0.134						
5 years (2008-12)	0.098	0.073	0.099	0.070	65.4															14.9	11.2	0.018						
10 years (2008-17)	0.095	0.070	0.099	0.068	95.8															21.9	16.4	0.086						
15 years (2008-22)	0.095	0.069	0.101	0.068	105.8															24.2	18.1	0.108						
PV to 2008						0.121	0.104	0.230	0.100	318.3	0.118	0.102	0.225	0.098	243.9													
PV to 2009											0.121	0.104	0.230	0.100	249.3													

Notes:

1) Capacity price converted to $/kWh at zonal on-peak summer load factor.

AESC Avoided Cost Results by Screening Zone

NOTE: **All Avoided Costs are in Year 2007 Dollars; Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours**
Summer for energy values includes June through September; Winter is all other months

All Costs include losses on the ISO-administered Transmission System. DSM savings should include distribution and local transmission losses

Formatted for input to DSM screening models

Retail Adder	10%
Real Discount Rate	2.2%
Capacity Losses to ISO Delivery	3.4%
Zonal On-Peak Summer Load Factor	57%

ELECTRIC AVOIDED COSTS
Marginal Wholesale Power Price

	Southeast Massachusetts					DRIPE for Installations in 2008					DRIPE for Installations in 2009					CO_2 Externality				FCM Revenue			Avoided Costs before Adders					REC Costs
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Summer: June, July, August	Winter: December, January	On-Peak Summer Capacity Value[1]	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	All Energy
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-month	$/kW-month	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	¢/kWh
Period:																												
2007	0.093	0.068	0.094	0.070	-											0.037	0.036	0.041	0.040				0.083	0.061	0.084	0.062		0.150
2008	0.105	0.078	0.096	0.072	-	0.018	0.014	0.031	0.013	-	-	-	-	-	-	0.037	0.036	0.041	0.040				0.094	0.069	0.086	0.064		0.156
2009	0.097	0.074	0.096	0.067	-	0.052	0.041	0.090	0.037	-	0.018	0.014	0.031	0.013	-	0.035	0.035	0.039	0.038				0.087	0.066	0.086	0.060		0.156
2010	0.096	0.071	0.097	0.066	76.2	0.048	0.038	0.084	0.034	72	0.052	0.041	0.090	0.037	-	0.035	0.035	0.039	0.038	16.9	12.7	0.098	0.086	0.063	0.086	0.058	67	0.167
2011	0.091	0.067	0.094	0.063	129.6	0.030	0.023	0.051	0.021	140	0.048	0.038	0.084	0.034	-	0.035	0.034	0.039	0.038	28.8	21.6	0.167	0.081	0.059	0.084	0.056	114	0.181
2012	0.092	0.069	0.096	0.066	129.6					90	0.030	0.023	0.051	0.021	140	0.031	0.030	0.034	0.033	28.8	21.6	0.167	0.082	0.061	0.085	0.058	114	0.189
2013	0.087	0.064	0.092	0.063	129.6					40					90	0.030	0.029	0.033	0.032	28.8	21.6	0.167	0.077	0.056	0.081	0.055	114	0.191
2014	0.090	0.064	0.093	0.064	129.6										40	0.028	0.028	0.032	0.031	28.8	21.6	0.167	0.080	0.056	0.082	0.056	114	0.187
2015	0.089	0.064	0.096	0.063	129.6											0.027	0.027	0.030	0.029	28.8	21.6	0.167	0.079	0.057	0.086	0.055	114	0.176
2016	0.090	0.066	0.097	0.065	129.6											0.026	0.025	0.029	0.028	28.8	21.6	0.167	0.080	0.058	0.087	0.058	114	0.155
2017	0.093	0.067	0.100	0.066	129.6											0.024	0.024	0.027	0.026	28.8	21.6	0.167	0.083	0.060	0.090	0.059	114	0.127
2018	0.091	0.067	0.099	0.066	129.6											0.023	0.023	0.026	0.025	28.8	21.6	0.167	0.082	0.060	0.089	0.059	114	0.092
2019	0.090	0.065	0.102	0.065	129.6											0.022	0.022	0.024	0.024	28.8	21.6	0.167	0.082	0.059	0.092	0.059	114	0.049
2020	0.091	0.067	0.102	0.066	129.6											0.021	0.020	0.023	0.022	28.8	21.6	0.167	0.083	0.061	0.092	0.060	114	0.000
2021	0.093	0.068	0.107	0.067	129.6											0.020	0.020	0.022	0.022	28.8	21.6	0.167	0.084	0.061	0.097	0.061	114	0.000
2022	0.096	0.068	0.108	0.069	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.167	0.088	0.062	0.099	0.062	114	0.000
2023	0.096	0.068	0.108	0.069	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.167	0.088	0.062	0.099	0.062	114	
2024	0.096	0.068	0.108	0.069	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.167	0.088	0.062	0.099	0.062	114	
2025	0.096	0.068	0.108	0.069	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.167	0.088	0.062	0.099	0.062	114	
2026	0.096	0.068	0.108	0.069	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.167	0.088	0.062	0.099	0.062	114	
2027	0.096	0.068	0.108	0.069	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.167	0.088	0.062	0.099	0.062	114	
2028	0.096	0.068	0.108	0.069	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.167	0.088	0.062	0.099	0.062	114	
2029	0.096	0.068	0.108	0.069	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.167	0.088	0.062	0.099	0.062	114	
2030	0.096	0.068	0.108	0.069	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.167	0.088	0.062	0.099	0.062	114	
2031	0.096	0.068	0.108	0.069	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.167	0.088	0.062	0.099	0.062	114	
2032	0.096	0.068	0.108	0.069	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.167	0.088	0.062	0.099	0.062	114	
2033	0.096	0.068	0.108	0.069	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.167	0.088	0.062	0.099	0.062	114	
2034	0.096	0.068	0.108	0.069	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.167	0.088	0.062	0.099	0.062	114	
2035	0.096	0.068	0.108	0.069	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.167	0.088	0.062	0.099	0.062	114	
2036	0.096	0.068	0.108	0.069	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.167	0.088	0.062	0.099	0.062	114	
2037	0.096	0.068	0.108	0.069	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.167	0.088	0.062	0.099	0.062	114	
2038	0.096	0.068	0.108	0.069	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.167	0.088	0.062	0.099	0.062	114	
2039	0.096	0.068	0.108	0.069	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.167	0.088	0.062	0.099	0.062	114	
2040	0.096	0.068	0.108	0.069	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.167	0.088	0.062	0.099	0.062	114	
Levelized																												
(2008-2040)	0.094	0.068	0.103	0.067	116.7															27.1	20.3	0.147						
(2009-2040)	0.094	0.068	0.103	0.067	121.8															27.7	20.8	0.150						
5 years (2008-12)	0.096	0.072	0.096	0.067	65.4															15.2	11.4	0.020						
10 years (2008-17)	0.093	0.069	0.096	0.066	95.8															22.2	16.7	0.096						
15 years (2008-22)	0.093	0.068	0.098	0.066	105.8															24.6	18.4	0.122						
PV to 2008						0.143	0.112	0.247	0.100	318.3	0.140	0.109	0.241	0.098	243.9													
PV to 2009											0.143	0.112	0.247	0.100	249.3													

Notes:

1) Capacity price converted to $/kWh at zonal on-peak summer load factor.

AESC Avoided Cost Results by Screening Zone

NOTE: **All Avoided Costs are in Year 2007 Dollars; Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours**

Summer for energy values includes June through September; Winter is all other months

All Costs include losses on the ISO-administered Transmission System. DSM savings should include distribution and local transmission losses

Formatted for input to DSM screening models

Retail Adder	10%
Real Discount Rate	2.2%
Capacity Losses to ISO Delivery	3.4%
Zonal On-Peak Summer Load Factor	60%

ELECTRIC AVOIDED COSTS

Marginal Wholesale Power Price

	West-Central Massachusetts					DRIPE for Installations in 2008					DRIPE for Installations in 2009					CO_2 Externality				FCM Revenue			Avoided Costs before Adders					REC Costs
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Summer: June, July, August	Winter: December, January	On-Peak Summer Capacity Value[1]	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	All Energy
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-month	$/kW-month	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	¢/kWh
Period:																												
2007	0.095	0.070	0.096	0.073	-											0.037	0.036	0.041	0.040				0.085	0.062	0.086	0.065		0.150
2008	0.106	0.080	0.098	0.076	-	0.015	0.012	0.026	0.010	-	-	-	-	-	-	0.037	0.036	0.041	0.040				0.095	0.071	0.087	0.067		0.156
2009	0.098	0.076	0.097	0.072	-	0.045	0.034	0.076	0.029	-	0.015	0.012	0.026	0.010	-	0.035	0.035	0.039	0.038				0.087	0.068	0.086	0.064		0.156
2010	0.097	0.073	0.097	0.068	76.2	0.042	0.032	0.071	0.027	72	0.045	0.034	0.076	0.029	-	0.035	0.035	0.039	0.038	16.9	12.7	0.093	0.087	0.064	0.087	0.060	67	0.167
2011	0.093	0.070	0.096	0.066	129.6	0.025	0.019	0.043	0.016	140	0.042	0.032	0.071	0.027	-	0.035	0.034	0.039	0.038	28.8	21.6	0.158	0.083	0.062	0.086	0.058	114	0.181
2012	0.093	0.071	0.098	0.069	129.6					90	0.025	0.019	0.043	0.016	140	0.031	0.030	0.034	0.033	28.8	21.6	0.158	0.083	0.063	0.087	0.061	114	0.189
2013	0.089	0.066	0.094	0.065	129.6					40					90	0.030	0.029	0.033	0.032	28.8	21.6	0.158	0.079	0.058	0.083	0.057	114	0.191
2014	0.092	0.066	0.094	0.066	129.6										40	0.028	0.028	0.032	0.031	28.8	21.6	0.158	0.082	0.058	0.084	0.059	114	0.187
2015	0.090	0.066	0.098	0.066	129.6											0.027	0.027	0.030	0.029	28.8	21.6	0.158	0.080	0.058	0.087	0.058	114	0.176
2016	0.092	0.067	0.098	0.069	129.6											0.026	0.025	0.029	0.028	28.8	21.6	0.158	0.082	0.060	0.087	0.061	114	0.155
2017	0.094	0.069	0.101	0.069	129.6											0.024	0.024	0.027	0.026	28.8	21.6	0.158	0.084	0.062	0.091	0.061	114	0.127
2018	0.091	0.068	0.099	0.068	129.6											0.023	0.023	0.026	0.025	28.8	21.6	0.158	0.082	0.061	0.089	0.061	114	0.092
2019	0.091	0.066	0.101	0.067	129.6											0.022	0.022	0.024	0.024	28.8	21.6	0.158	0.082	0.060	0.091	0.060	114	0.049
2020	0.093	0.069	0.103	0.068	129.6											0.021	0.020	0.023	0.022	28.8	21.6	0.158	0.085	0.062	0.093	0.062	114	0.000
2021	0.093	0.069	0.106	0.068	129.6											0.020	0.020	0.022	0.022	28.8	21.6	0.158	0.085	0.062	0.097	0.062	114	0.000
2022	0.096	0.070	0.108	0.070	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.158	0.088	0.064	0.098	0.063	114	0.000
2023	0.096	0.070	0.108	0.070	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.158	0.088	0.064	0.098	0.063	114	
2024	0.096	0.070	0.108	0.070	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.158	0.088	0.064	0.098	0.063	114	
2025	0.096	0.070	0.108	0.070	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.158	0.088	0.064	0.098	0.063	114	
2026	0.096	0.070	0.108	0.070	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.158	0.088	0.064	0.098	0.063	114	
2027	0.096	0.070	0.108	0.070	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.158	0.088	0.064	0.098	0.063	114	
2028	0.096	0.070	0.108	0.070	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.158	0.088	0.064	0.098	0.063	114	
2029	0.096	0.070	0.108	0.070	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.158	0.088	0.064	0.098	0.063	114	
2030	0.096	0.070	0.108	0.070	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.158	0.088	0.064	0.098	0.063	114	
2031	0.096	0.070	0.108	0.070	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.158	0.088	0.064	0.098	0.063	114	
2032	0.096	0.070	0.108	0.070	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.158	0.088	0.064	0.098	0.063	114	
2033	0.096	0.070	0.108	0.070	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.158	0.088	0.064	0.098	0.063	114	
2034	0.096	0.070	0.108	0.070	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.158	0.088	0.064	0.098	0.063	114	
2035	0.096	0.070	0.108	0.070	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.158	0.088	0.064	0.098	0.063	114	
2036	0.096	0.070	0.108	0.070	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.158	0.088	0.064	0.098	0.063	114	
2037	0.096	0.070	0.108	0.070	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.158	0.088	0.064	0.098	0.063	114	
2038	0.096	0.070	0.108	0.070	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.158	0.088	0.064	0.098	0.063	114	
2039	0.096	0.070	0.108	0.070	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.158	0.088	0.064	0.098	0.063	114	
2040	0.096	0.070	0.108	0.070	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.158	0.088	0.064	0.098	0.063	114	
Levelized																												
(2008-2040)	0.095	0.070	0.103	0.069	116.7															27.1	20.3	0.140						
(2009-2040)	0.095	0.070	0.103	0.069	121.8															27.7	20.8	0.143						
5 years (2008-12)	0.098	0.074	0.097	0.070	65.4															15.2	11.4	0.019						
10 years (2008-17)	0.095	0.071	0.097	0.069	95.8															22.2	16.7	0.092						
15 years (2008-22)	0.094	0.070	0.099	0.069	105.8															24.6	18.4	0.115						
PV to 2008						0.122	0.093	0.209	0.078	318.3	0.120	0.091	0.204	0.076	243.9													
PV to 2009											0.122	0.093	0.209	0.078	249.3													

Notes:

1) Capacity price converted to $/kWh at zonal on-peak summer load factor.

AESC Avoided Cost Results by Screening Zone

NOTE: **All Avoided Costs are in Year 2007 Dollars; Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours**

Summer for energy values includes June through September; Winter is all other months

All Costs include losses on the ISO-administered Transmission System. DSM savings should include distribution and local transmission losses

Formatted for input to DSM screening models

	non-NE MA
Retail Adder	10%
Real Discount Rate	2.2%
Capacity Losses to ISO Delivery	3.4%
Zonal On-Peak Summer Load Factor	59%

ELECTRIC AVOIDED COSTS

Marginal Wholesale Power Price

	Massachusetts outside of Northeast Mass					DRIPE for Installations in 2008					DRIPE for Installations in 2009					CO_2 Externality				FCM Revenue			Avoided Costs before Adders					REC Costs
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Summer: June, July, August	Winter: December, January	On-Peak Summer Capacity Value[1]	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	All Energy
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-month	$/kW-month	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	¢/kWh
Period:																												
2007	0.094	0.069	0.095	0.072	-											0.037	0.036	0.041	0.040				0.084	0.061	0.085	0.064		0.150
2008	0.105	0.079	0.097	0.074	-	0.017	0.013	0.028	0.011	-	-	-	-	-	-	0.037	0.036	0.041	0.040				0.094	0.070	0.086	0.066		0.156
2009	0.097	0.075	0.096	0.070	-	0.048	0.037	0.083	0.032	-	0.017	0.013	0.028	0.011	-	0.035	0.035	0.039	0.038				0.087	0.067	0.086	0.062		0.156
2010	0.097	0.072	0.097	0.067	76.2	0.045	0.034	0.077	0.030	72	0.048	0.037	0.083	0.032	-	0.035	0.035	0.039	0.038	16.9	12.7	0.095	0.086	0.064	0.087	0.059	67	0.167
2011	0.092	0.069	0.095	0.065	129.6	0.027	0.021	0.047	0.018	140	0.045	0.034	0.077	0.030	-	0.035	0.034	0.039	0.038	28.8	21.6	0.162	0.082	0.060	0.085	0.057	114	0.181
2012	0.093	0.070	0.097	0.067	129.6					90	0.027	0.021	0.047	0.018	140	0.031	0.030	0.034	0.033	28.8	21.6	0.162	0.083	0.062	0.086	0.059	114	0.189
2013	0.088	0.065	0.093	0.064	129.6					40					90	0.030	0.029	0.033	0.032	28.8	21.6	0.162	0.078	0.057	0.082	0.056	114	0.191
2014	0.091	0.065	0.093	0.065	129.6										40	0.028	0.028	0.032	0.031	28.8	21.6	0.162	0.081	0.057	0.083	0.057	114	0.187
2015	0.089	0.065	0.097	0.064	129.6											0.027	0.027	0.030	0.029	28.8	21.6	0.162	0.079	0.058	0.087	0.057	114	0.176
2016	0.091	0.066	0.097	0.067	129.6											0.026	0.025	0.029	0.028	28.8	21.6	0.162	0.081	0.059	0.087	0.059	114	0.155
2017	0.093	0.068	0.101	0.067	129.6											0.024	0.024	0.027	0.026	28.8	21.6	0.162	0.084	0.061	0.090	0.060	114	0.127
2018	0.091	0.067	0.099	0.067	129.6											0.023	0.023	0.026	0.025	28.8	21.6	0.162	0.082	0.060	0.089	0.060	114	0.092
2019	0.091	0.066	0.101	0.066	129.6											0.022	0.022	0.024	0.024	28.8	21.6	0.162	0.082	0.059	0.092	0.059	114	0.049
2020	0.092	0.068	0.102	0.067	129.6											0.021	0.020	0.023	0.022	28.8	21.6	0.162	0.084	0.062	0.093	0.061	114	0.000
2021	0.093	0.068	0.107	0.067	129.6											0.020	0.020	0.022	0.022	28.8	21.6	0.162	0.085	0.062	0.097	0.061	114	0.000
2022	0.096	0.069	0.108	0.069	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.162	0.088	0.063	0.099	0.063	114	0.000
2023	0.096	0.069	0.108	0.069	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.162	0.088	0.063	0.099	0.063	114	
2024	0.096	0.069	0.108	0.069	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.162	0.088	0.063	0.099	0.063	114	
2025	0.096	0.069	0.108	0.069	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.162	0.088	0.063	0.099	0.063	114	
2026	0.096	0.069	0.108	0.069	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.162	0.088	0.063	0.099	0.063	114	
2027	0.096	0.069	0.108	0.069	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.162	0.088	0.063	0.099	0.063	114	
2028	0.096	0.069	0.108	0.069	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.162	0.088	0.063	0.099	0.063	114	
2029	0.096	0.069	0.108	0.069	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.162	0.088	0.063	0.099	0.063	114	
2030	0.096	0.069	0.108	0.069	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.162	0.088	0.063	0.099	0.063	114	
2031	0.096	0.069	0.108	0.069	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.162	0.088	0.063	0.099	0.063	114	
2032	0.096	0.069	0.108	0.069	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.162	0.088	0.063	0.099	0.063	114	
2033	0.096	0.069	0.108	0.069	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.162	0.088	0.063	0.099	0.063	114	
2034	0.096	0.069	0.108	0.069	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.162	0.088	0.063	0.099	0.063	114	
2035	0.096	0.069	0.108	0.069	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.162	0.088	0.063	0.099	0.063	114	
2036	0.096	0.069	0.108	0.069	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.162	0.088	0.063	0.099	0.063	114	
2037	0.096	0.069	0.108	0.069	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.162	0.088	0.063	0.099	0.063	114	
2038	0.096	0.069	0.108	0.069	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.162	0.088	0.063	0.099	0.063	114	
2039	0.096	0.069	0.108	0.069	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.162	0.088	0.063	0.099	0.063	114	
2040	0.096	0.069	0.108	0.069	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.162	0.088	0.063	0.099	0.063	114	
Levelized																												
(2008-2040)	0.095	0.069	0.103	0.068	116.7															27.1	20.3	0.143						
(2009-2040)	0.094	0.069	0.103	0.068	121.8															27.7	20.8	0.146						
5 years (2008-12)	0.097	0.073	0.097	0.069	65.4															15.2	11.4	0.020						
10 years (2008-17)	0.094	0.070	0.096	0.067	95.8															22.2	16.7	0.094						
15 years (2008-22)	0.093	0.069	0.098	0.067	105.8															24.6	18.4	0.118						
PV to 2008						0.132	0.101	0.227	0.087	318.3	0.129	0.099	0.222	0.086	243.9													
PV to 2009											0.132	0.101	0.227	0.087	249.3													

Notes:

1) Capacity price converted to $/kWh at zonal on-peak summer load factor.

Determination of SEMA and WCMA as % of non-NEMA MA Energy

	On-Peak			Off-Peak		
	SEMA	WCMA	non-NE MA	SEMA	WCMA	non-NE MA
Mar-07	560	750		478	704	
Feb-07	597	635		533	679	
Jan-07	620	823		517	769	
Dec-06	574	718		609	815	
Nov-06	579	750		532	713	
Oct-06	598	579		514	640	
Sep-06	585	625		562	785	
Aug-06	842	881		609	789	
Jul-06	772	769		791	1,005	
Jun-06	686	803		524	738	
May-06	623	771		469	686	
Apr-06	527	670		518	757	
Summer	2,885	3,078	5,963	2,485	3,317	5,802
Winter	4,678	5,695	10,373	4,170	5,764	9,935
Summer	48.4%	51.6%		42.8%	57.2%	
Winter	45.1%	54.9%		42.0%	58.0%	

AESC Avoided Cost Results by Screening Zone

NOTE: **All Avoided Costs are in Year 2007 Dollars; Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours**

Summer for energy values includes June through September; Winter is all other months

All Costs include losses on the ISO-administered Transmission System. DSM savings should include distribution and local transmission losses

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Retail Adder	10%
Real Discount Rate	2.2%
Capacity Losses to ISO Delivery	3.4%
Zonal On-Peak Summer Load Factor	60%

ELECTRIC AVOIDED COSTS
Marginal Wholesale Power Price

	Southwest Connecticut					DRIPE for Installations in 2008					DRIPE for Installations in 2009					CO_2 Externality				FCM Revenue			Avoided Costs before Adders					REC Costs
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Summer: June, July, August	Winter: December, January	On-Peak Summer Capacity Value[1]	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	All Energy
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-month	$/kW-month	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	¢/kWh
Period:																												
2007	0.100	0.073	0.105	0.076	-											0.037	0.036	0.041	0.040				0.089	0.065	0.094	0.068		0.175
2008	0.112	0.083	0.107	0.081	-	0.017	0.013	0.033	0.016	-	-	-	-	-	-	0.037	0.036	0.041	0.040				0.099	0.073	0.095	0.071		0.222
2009	0.105	0.080	0.108	0.074	-	0.049	0.039	0.100	0.051	-	0.017	0.013	0.033	0.016	-	0.035	0.035	0.039	0.038				0.093	0.070	0.096	0.065		0.233
2010	0.102	0.076	0.105	0.072	76.2	0.046	0.037	0.097	0.050	72	0.049	0.039	0.100	0.051	-	0.035	0.035	0.039	0.038	16.9	12.7	0.093	0.090	0.067	0.093	0.063	67	0.233
2011	0.097	0.071	0.104	0.069	129.6	0.028	0.023	0.059	0.030	140	0.046	0.037	0.097	0.050	-	0.035	0.034	0.039	0.038	28.8	21.6	0.158	0.087	0.063	0.092	0.061	114	0.211
2012	0.098	0.073	0.108	0.070	129.6					90	0.028	0.023	0.059	0.030	140	0.031	0.030	0.034	0.033	28.8	21.6	0.158	0.087	0.064	0.096	0.062	114	0.189
2013	0.094	0.067	0.101	0.066	129.6					40					90	0.030	0.029	0.033	0.032	28.8	21.6	0.158	0.083	0.059	0.090	0.059	114	0.167
2014	0.095	0.067	0.100	0.067	129.6										40	0.028	0.028	0.032	0.031	28.8	21.6	0.158	0.085	0.059	0.090	0.059	114	0.145
2015	0.093	0.067	0.100	0.066	129.6											0.027	0.027	0.030	0.029	28.8	21.6	0.158	0.083	0.060	0.090	0.058	114	0.123
2016	0.094	0.068	0.103	0.067	129.6											0.026	0.025	0.029	0.028	28.8	21.6	0.158	0.085	0.061	0.093	0.060	114	0.099
2017	0.098	0.070	0.107	0.070	129.6											0.024	0.024	0.027	0.026	28.8	21.6	0.158	0.088	0.063	0.097	0.063	114	0.074
2018	0.096	0.071	0.105	0.070	129.6											0.023	0.023	0.026	0.025	28.8	21.6	0.158	0.087	0.064	0.095	0.063	114	0.049
2019	0.095	0.069	0.105	0.069	129.6											0.022	0.022	0.024	0.024	28.8	21.6	0.158	0.086	0.062	0.095	0.062	114	0.025
2020	0.097	0.071	0.109	0.070	129.6											0.021	0.020	0.023	0.022	28.8	21.6	0.158	0.088	0.065	0.099	0.063	114	0.000
2021	0.097	0.072	0.111	0.070	129.6											0.020	0.020	0.022	0.022	28.8	21.6	0.158	0.088	0.065	0.101	0.063	114	0.000
2022	0.100	0.072	0.114	0.072	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.158	0.091	0.065	0.104	0.065	114	0.000
2023	0.100	0.072	0.114	0.072	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.158	0.091	0.065	0.104	0.065	114	
2024	0.100	0.072	0.114	0.072	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.158	0.091	0.065	0.104	0.065	114	
2025	0.100	0.072	0.114	0.072	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.158	0.091	0.065	0.104	0.065	114	
2026	0.100	0.072	0.114	0.072	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.158	0.091	0.065	0.104	0.065	114	
2027	0.100	0.072	0.114	0.072	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.158	0.091	0.065	0.104	0.065	114	
2028	0.100	0.072	0.114	0.072	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.158	0.091	0.065	0.104	0.065	114	
2029	0.100	0.072	0.114	0.072	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.158	0.091	0.065	0.104	0.065	114	
2030	0.100	0.072	0.114	0.072	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.158	0.091	0.065	0.104	0.065	114	
2031	0.100	0.072	0.114	0.072	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.158	0.091	0.065	0.104	0.065	114	
2032	0.100	0.072	0.114	0.072	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.158	0.091	0.065	0.104	0.065	114	
2033	0.100	0.072	0.114	0.072	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.158	0.091	0.065	0.104	0.065	114	
2034	0.100	0.072	0.114	0.072	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.158	0.091	0.065	0.104	0.065	114	
2035	0.100	0.072	0.114	0.072	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.158	0.091	0.065	0.104	0.065	114	
2036	0.100	0.072	0.114	0.072	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.158	0.091	0.065	0.104	0.065	114	
2037	0.100	0.072	0.114	0.072	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.158	0.091	0.065	0.104	0.065	114	
2038	0.100	0.072	0.114	0.072	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.158	0.091	0.065	0.104	0.065	114	
2039	0.100	0.072	0.114	0.072	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.158	0.091	0.065	0.104	0.065	114	
2040	0.100	0.072	0.114	0.072	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.158	0.091	0.065	0.104	0.065	114	
Levelized																												
(2008-2040)	0.099	0.072	0.110	0.071	116.7															26.7	20.0	0.139						
(2009-2040)	0.099	0.072	0.110	0.071	121.8															27.5	20.7	0.142						
5 years (2008-12)	0.103	0.077	0.106	0.073	65.4															14.9	11.2	0.019						
10 years (2008-17)	0.099	0.073	0.104	0.070	95.8															21.9	16.4	0.091						
15 years (2008-22)	0.098	0.072	0.106	0.070	105.8															24.2	18.1	0.115						
PV to 2008						0.135	0.109	0.279	0.141	318.3	0.132	0.106	0.273	0.138	243.9													
PV to 2009											0.135	0.109	0.279	0.141	249.3													

Notes:

1) Capacity price converted to $/kWh at zonal on-peak summer load factor.

AESC Avoided Cost Results by Screening Zone

NOTE: **All Avoided Costs are in Year 2007 Dollars; Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours**

Summer for energy values includes June through September; Winter is all other months

All Costs include losses on the ISO-administered Transmission System. DSM savings should include distribution and local transmission losses

Formatted for input to DSM screening models

Retail Adder	10%
Real Discount Rate	2.2%
Capacity Losses to ISO Delivery	3.4%
Zonal On-Peak Summer Load Factor	59%

ELECTRIC AVOIDED COSTS
Marginal Wholesale Power Price

	Norwalk-Stamford					DRIPE for Installations in 2008					DRIPE for Installations in 2009					CO_2 Externality				FCM Revenue			Avoided Costs before Adders					REC Costs
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Summer: June, July, August	Winter: December, January	On-Peak Summer Capacity Value[1]	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	All Energy
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-month	$/kW-month	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	¢/kWh
Period:																												
2007	0.104	0.075	0.116	0.078	-											0.037	0.036	0.041	0.040				0.093	0.066	0.104	0.069		0.175
2008	0.116	0.085	0.118	0.082	-	0.017	0.013	0.033	0.016	-	-	-	-	-	-	0.037	0.036	0.041	0.040				0.103	0.075	0.105	0.073		0.222
2009	0.109	0.082	0.118	0.076	-	0.049	0.039	0.100	0.051	-	0.017	0.013	0.033	0.016	-	0.035	0.035	0.039	0.038				0.096	0.072	0.105	0.067		0.233
2010	0.102	0.076	0.110	0.072	76.2	0.046	0.037	0.097	0.050	72	0.049	0.039	0.100	0.051	-	0.035	0.035	0.039	0.038	16.9	12.7	0.095	0.090	0.067	0.097	0.063	67	0.233
2011	0.097	0.071	0.109	0.069	129.6	0.028	0.023	0.059	0.030	140	0.046	0.037	0.097	0.050	-	0.035	0.034	0.039	0.038	28.8	21.6	0.161	0.087	0.063	0.097	0.061	114	0.211
2012	0.098	0.073	0.113	0.070	129.6					90	0.028	0.023	0.059	0.030	140	0.031	0.030	0.034	0.033	28.8	21.6	0.161	0.087	0.064	0.101	0.062	114	0.189
2013	0.094	0.067	0.106	0.066	129.6					40					90	0.030	0.029	0.033	0.032	28.8	21.6	0.161	0.083	0.059	0.095	0.059	114	0.167
2014	0.095	0.067	0.105	0.067	129.6										40	0.028	0.028	0.032	0.031	28.8	21.6	0.161	0.085	0.059	0.094	0.059	114	0.145
2015	0.093	0.067	0.105	0.066	129.6											0.027	0.027	0.030	0.029	28.8	21.6	0.161	0.083	0.060	0.095	0.058	114	0.123
2016	0.094	0.068	0.108	0.067	129.6											0.026	0.025	0.029	0.028	28.8	21.6	0.161	0.085	0.061	0.097	0.060	114	0.099
2017	0.098	0.070	0.112	0.070	129.6											0.024	0.024	0.027	0.026	28.8	21.6	0.161	0.088	0.063	0.101	0.063	114	0.074
2018	0.096	0.071	0.110	0.070	129.6											0.023	0.023	0.026	0.025	28.8	21.6	0.161	0.087	0.064	0.099	0.063	114	0.049
2019	0.095	0.069	0.111	0.069	129.6											0.022	0.022	0.024	0.024	28.8	21.6	0.161	0.086	0.062	0.100	0.062	114	0.025
2020	0.097	0.071	0.115	0.070	129.6											0.021	0.020	0.023	0.022	28.8	21.6	0.161	0.088	0.065	0.104	0.063	114	0.000
2021	0.097	0.072	0.116	0.070	129.6											0.020	0.020	0.022	0.022	28.8	21.6	0.161	0.088	0.065	0.106	0.063	114	0.000
2022	0.100	0.072	0.120	0.072	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.161	0.091	0.065	0.109	0.065	114	0.000
2023	0.100	0.072	0.120	0.072	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.161	0.091	0.065	0.109	0.065	114	
2024	0.100	0.072	0.120	0.072	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.161	0.091	0.065	0.109	0.065	114	
2025	0.100	0.072	0.120	0.072	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.161	0.091	0.065	0.109	0.065	114	
2026	0.100	0.072	0.120	0.072	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.161	0.091	0.065	0.109	0.065	114	
2027	0.100	0.072	0.120	0.072	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.161	0.091	0.065	0.109	0.065	114	
2028	0.100	0.072	0.120	0.072	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.161	0.091	0.065	0.109	0.065	114	
2029	0.100	0.072	0.120	0.072	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.161	0.091	0.065	0.109	0.065	114	
2030	0.100	0.072	0.120	0.072	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.161	0.091	0.065	0.109	0.065	114	
2031	0.100	0.072	0.120	0.072	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.161	0.091	0.065	0.109	0.065	114	
2032	0.100	0.072	0.120	0.072	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.161	0.091	0.065	0.109	0.065	114	
2033	0.100	0.072	0.120	0.072	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.161	0.091	0.065	0.109	0.065	114	
2034	0.100	0.072	0.120	0.072	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.161	0.091	0.065	0.109	0.065	114	
2035	0.100	0.072	0.120	0.072	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.161	0.091	0.065	0.109	0.065	114	
2036	0.100	0.072	0.120	0.072	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.161	0.091	0.065	0.109	0.065	114	
2037	0.100	0.072	0.120	0.072	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.161	0.091	0.065	0.109	0.065	114	
2038	0.100	0.072	0.120	0.072	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.161	0.091	0.065	0.109	0.065	114	
2039	0.100	0.072	0.120	0.072	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.161	0.091	0.065	0.109	0.065	114	
2040	0.100	0.072	0.120	0.072	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.161	0.091	0.065	0.109	0.065	114	
Levelized																												
(2008-2040)	0.100	0.072	0.116	0.071	116.7															27.1	20.3	0.142						
(2009-2040)	0.099	0.072	0.115	0.071	121.8															27.7	20.8	0.145						
5 years (2008-12)	0.105	0.077	0.114	0.074	65.4															15.2	11.4	0.020						
10 years (2008-17)	0.100	0.073	0.111	0.071	95.8															22.2	16.7	0.093						
15 years (2008-22)	0.099	0.072	0.112	0.071	105.8															24.6	18.4	0.118						
PV to 2008						0.135	0.109	0.279	0.141	318.3	0.132	0.106	0.273	0.138	243.9													
PV to 2009											0.135	0.109	0.279	0.141	249.3													

Notes:

1) Capacity price converted to $/kWh at zonal on-peak summer load factor.

AESC Avoided Cost Results by Screening Zone

NOTE: **All Avoided Costs are in Year 2007 Dollars; Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours**

Summer for energy values includes June through September; Winter is all other months

All Costs include losses on the ISO-administered Transmission System. DSM savings should include distribution and local transmission losses

Formatted for input to DSM screening models

Retail Adder	10%
Real Discount Rate	2.2%
Capacity Losses to ISO Delivery	3.4%
Zonal On-Peak Summer Load Factor	61%

ELECTRIC AVOIDED COSTS

Marginal Wholesale Power Price

	Southwest Connecticut except Norwalk-Stamford					DRIPE for Installations in 2008					DRIPE for Installations in 2009					CO_2 Externality				FCM Revenue			Avoided Costs before Adders					REC Costs
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Summer: June, July, August	Winter: December, January	On-Peak Summer Capacity Value[1]	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	All Energy
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-month	$/kW-month	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	¢/kWh
Period:																												
2007	0.098	0.073	0.100	0.076	-											0.037	0.036	0.041	0.040				0.088	0.064	0.089	0.067		0.175
2008	0.109	0.082	0.102	0.080	-	0.017	0.013	0.033	0.016	-	-	-	-	-	-	0.037	0.036	0.041	0.040				0.097	0.073	0.090	0.071		0.222
2009	0.102	0.079	0.102	0.074	-	0.049	0.039	0.100	0.051	-	0.017	0.013	0.033	0.016	-	0.035	0.035	0.039	0.038				0.091	0.070	0.090	0.065		0.233
2010	0.102	0.076	0.102	0.072	76.2	0.046	0.037	0.097	0.050	72	0.049	0.039	0.100	0.051	-	0.035	0.035	0.039	0.038	16.9	12.7	0.092	0.090	0.067	0.090	0.063	67	0.233
2011	0.097	0.071	0.101	0.069	129.6	0.028	0.023	0.059	0.030	140	0.046	0.037	0.097	0.050	-	0.035	0.034	0.039	0.038	28.8	21.6	0.156	0.087	0.063	0.090	0.061	114	0.211
2012	0.098	0.073	0.105	0.070	129.6					90	0.028	0.023	0.059	0.030	140	0.031	0.030	0.034	0.033	28.8	21.6	0.156	0.087	0.064	0.093	0.062	114	0.189
2013	0.094	0.067	0.098	0.066	129.6					40					90	0.030	0.029	0.033	0.032	28.8	21.6	0.156	0.083	0.059	0.088	0.059	114	0.167
2014	0.095	0.067	0.098	0.067	129.6										40	0.028	0.028	0.032	0.031	28.8	21.6	0.156	0.085	0.059	0.087	0.059	114	0.145
2015	0.093	0.067	0.098	0.066	129.6											0.027	0.027	0.030	0.029	28.8	21.6	0.156	0.083	0.060	0.088	0.058	114	0.123
2016	0.094	0.068	0.100	0.067	129.6											0.026	0.025	0.029	0.028	28.8	21.6	0.156	0.085	0.061	0.090	0.060	114	0.099
2017	0.098	0.070	0.104	0.070	129.6											0.024	0.024	0.027	0.026	28.8	21.6	0.156	0.088	0.063	0.094	0.063	114	0.074
2018	0.096	0.071	0.102	0.070	129.6											0.023	0.023	0.026	0.025	28.8	21.6	0.156	0.087	0.064	0.092	0.063	114	0.049
2019	0.095	0.069	0.102	0.069	129.6											0.022	0.022	0.024	0.024	28.8	21.6	0.156	0.086	0.062	0.093	0.062	114	0.025
2020	0.097	0.071	0.106	0.070	129.6											0.021	0.020	0.023	0.022	28.8	21.6	0.156	0.088	0.065	0.097	0.063	114	0.000
2021	0.097	0.072	0.108	0.070	129.6											0.020	0.020	0.022	0.022	28.8	21.6	0.156	0.088	0.065	0.098	0.063	114	0.000
2022	0.100	0.072	0.111	0.072	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.156	0.091	0.065	0.101	0.065	114	0.000
2023	0.100	0.072	0.111	0.072	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.156	0.091	0.065	0.101	0.065	114	
2024	0.100	0.072	0.111	0.072	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.156	0.091	0.065	0.101	0.065	114	
2025	0.100	0.072	0.111	0.072	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.156	0.091	0.065	0.101	0.065	114	
2026	0.100	0.072	0.111	0.072	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.156	0.091	0.065	0.101	0.065	114	
2027	0.100	0.072	0.111	0.072	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.156	0.091	0.065	0.101	0.065	114	
2028	0.100	0.072	0.111	0.072	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.156	0.091	0.065	0.101	0.065	114	
2029	0.100	0.072	0.111	0.072	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.156	0.091	0.065	0.101	0.065	114	
2030	0.100	0.072	0.111	0.072	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.156	0.091	0.065	0.101	0.065	114	
2031	0.100	0.072	0.111	0.072	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.156	0.091	0.065	0.101	0.065	114	
2032	0.100	0.072	0.111	0.072	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.156	0.091	0.065	0.101	0.065	114	
2033	0.100	0.072	0.111	0.072	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.156	0.091	0.065	0.101	0.065	114	
2034	0.100	0.072	0.111	0.072	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.156	0.091	0.065	0.101	0.065	114	
2035	0.100	0.072	0.111	0.072	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.156	0.091	0.065	0.101	0.065	114	
2036	0.100	0.072	0.111	0.072	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.156	0.091	0.065	0.101	0.065	114	
2037	0.100	0.072	0.111	0.072	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.156	0.091	0.065	0.101	0.065	114	
2038	0.100	0.072	0.111	0.072	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.156	0.091	0.065	0.101	0.065	114	
2039	0.100	0.072	0.111	0.072	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.156	0.091	0.065	0.101	0.065	114	
2040	0.100	0.072	0.111	0.072	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.156	0.091	0.065	0.101	0.065	114	
Levelized																												
(2008-2040)	0.099	0.072	0.106	0.071	116.7															27.1	20.3	0.138						
(2009-2040)	0.099	0.071	0.107	0.071	121.8															27.7	20.8	0.141						
5 years (2008-12)	0.102	0.076	0.102	0.073	65.4															15.2	11.4	0.019						
10 years (2008-17)	0.099	0.072	0.101	0.070	95.8															22.2	16.7	0.090						
15 years (2008-22)	0.098	0.072	0.102	0.070	105.8															24.6	18.4	0.114						
PV to 2008						0.135	0.109	0.279	0.141	318.3	0.132	0.106	0.273	0.138	243.9													
PV to 2009											0.135	0.109	0.279	0.141	249.3													

Notes:

1) Capacity price converted to $/kWh at zonal on-peak summer load factor.

AESC Avoided Cost Results by Screening Zone

NOTE: **All Avoided Costs are in Year 2007 Dollars; Peak hours are: Monday through Friday 6am - 10pm; Off-Peak Hours are: All other hours**
Summer for energy values includes June through September; Winter is all other months

All Costs include losses on the ISO-administered Transmission System. DSM savings should include distribution and local transmission losses

Formatted for input to DSM screening models

Retail Adder	10%
Real Discount Rate	2.2%
Capacity Losses to ISO Delivery	3.4%
Zonal On-Peak Summer Load Factor	60%

ELECTRIC AVOIDED COSTS
Marginal Wholesale Power Price

	Connecticut except Southwest Connecticut					DRIPE for Installations in 2008					DRIPE for Installations in 2009					CO_2 Externality				FCM Revenue			Avoided Costs before Adders					REC Costs
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Summer: June, July, August	Winter: December, January	On-Peak Summer Capacity Value[1]	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	All Energy
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-month	$/kW-month	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	¢/kWh
Period:																												
2007	0.099	0.072	0.104	0.075	-											0.037	0.036	0.041	0.040				0.088	0.064	0.092	0.066		0.175
2008	0.110	0.082	0.105	0.080	-	0.017	0.013	0.033	0.016	-	-	-	-	-	-	0.037	0.036	0.041	0.040				0.098	0.072	0.093	0.071		0.222
2009	0.103	0.079	0.106	0.073	-	0.049	0.039	0.100	0.051	-	0.017	0.013	0.033	0.016	-	0.035	0.035	0.039	0.038				0.091	0.069	0.094	0.064		0.233
2010	0.100	0.075	0.103	0.071	76.2	0.046	0.037	0.097	0.050	72	0.049	0.039	0.100	0.051	-	0.035	0.035	0.039	0.038	16.9	12.7	0.093	0.089	0.065	0.091	0.062	67	0.233
2011	0.096	0.070	0.102	0.068	129.6	0.028	0.023	0.059	0.030	140	0.046	0.037	0.097	0.050	-	0.035	0.034	0.039	0.038	28.8	21.6	0.158	0.085	0.062	0.090	0.060	114	0.211
2012	0.097	0.072	0.105	0.069	129.6					90	0.028	0.023	0.059	0.030	140	0.031	0.030	0.034	0.033	28.8	21.6	0.158	0.086	0.063	0.094	0.060	114	0.189
2013	0.092	0.066	0.100	0.065	129.6					40					90	0.030	0.029	0.033	0.032	28.8	21.6	0.158	0.082	0.058	0.089	0.057	114	0.167
2014	0.094	0.066	0.099	0.066	129.6										40	0.028	0.028	0.032	0.031	28.8	21.6	0.158	0.084	0.059	0.088	0.058	114	0.145
2015	0.091	0.066	0.100	0.065	129.6											0.027	0.027	0.030	0.029	28.8	21.6	0.158	0.082	0.059	0.089	0.057	114	0.123
2016	0.092	0.067	0.101	0.066	129.6											0.026	0.025	0.029	0.028	28.8	21.6	0.158	0.083	0.060	0.091	0.059	114	0.099
2017	0.096	0.069	0.105	0.068	129.6											0.024	0.024	0.027	0.026	28.8	21.6	0.158	0.086	0.062	0.094	0.062	114	0.074
2018	0.094	0.069	0.103	0.069	129.6											0.023	0.023	0.026	0.025	28.8	21.6	0.158	0.085	0.062	0.093	0.062	114	0.049
2019	0.093	0.068	0.104	0.067	129.6											0.022	0.022	0.024	0.024	28.8	21.6	0.158	0.084	0.061	0.094	0.061	114	0.025
2020	0.095	0.070	0.107	0.069	129.6											0.021	0.020	0.023	0.022	28.8	21.6	0.158	0.086	0.064	0.098	0.062	114	
2021	0.096	0.070	0.108	0.069	129.6											0.020	0.020	0.022	0.022	28.8	21.6	0.158	0.087	0.064	0.098	0.062	114	
2022	0.099	0.071	0.112	0.071	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.158	0.090	0.065	0.102	0.064	114	
2023	0.099	0.071	0.112	0.071	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.158	0.090	0.065	0.102	0.064	114	
2024	0.099	0.071	0.112	0.071	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.158	0.090	0.065	0.102	0.064	114	
2025	0.099	0.071	0.112	0.071	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.158	0.090	0.065	0.102	0.064	114	
2026	0.099	0.071	0.112	0.071	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.158	0.090	0.065	0.102	0.064	114	
2027	0.099	0.071	0.112	0.071	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.158	0.090	0.065	0.102	0.064	114	
2028	0.099	0.071	0.112	0.071	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.158	0.090	0.065	0.102	0.064	114	
2029	0.099	0.071	0.112	0.071	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.158	0.090	0.065	0.102	0.064	114	
2030	0.099	0.071	0.112	0.071	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.158	0.090	0.065	0.102	0.064	114	
2031	0.099	0.071	0.112	0.071	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.158	0.090	0.065	0.102	0.064	114	
2032	0.099	0.071	0.112	0.071	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.158	0.090	0.065	0.102	0.064	114	
2033	0.099	0.071	0.112	0.071	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.158	0.090	0.065	0.102	0.064	114	
2034	0.099	0.071	0.112	0.071	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.158	0.090	0.065	0.102	0.064	114	
2035	0.099	0.071	0.112	0.071	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.158	0.090	0.065	0.102	0.064	114	
2036	0.099	0.071	0.112	0.071	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.158	0.090	0.065	0.102	0.064	114	
2037	0.099	0.071	0.112	0.071	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.158	0.090	0.065	0.102	0.064	114	
2038	0.099	0.071	0.112	0.071	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.158	0.090	0.065	0.102	0.064	114	
2039	0.099	0.071	0.112	0.071	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.158	0.090	0.065	0.102	0.064	114	
2040	0.099	0.071	0.112	0.071	129.6											0.019	0.019	0.022	0.021	28.8	21.6	0.158	0.090	0.065	0.102	0.064	114	
Levelized																												
(2008-2040)	0.098	0.071	0.108	0.070	116.7															27.1	20.3	0.139						
(2009-2040)	0.097	0.071	0.108	0.069	121.8															27.7	20.8	0.142						
5 years (2008-12)	0.101	0.076	0.104	0.072	65.4															15.2	11.4	0.019						
10 years (2008-17)	0.097	0.071	0.102	0.069	95.8															22.2	16.7	0.091						
15 years (2008-22)	0.097	0.071	0.104	0.069	105.8															24.6	18.4	0.115						
PV to 2008						0.135	0.109	0.279	0.141	318.3	0.132	0.106	0.273	0.138	243.9													
PV to 2009											0.135	0.109	0.279	0.141	249.3													

Notes:

1) Capacity price converted to $/kWh at zonal on-peak summer load factor.

REQUEST FOR PROPOSAL

RFP 29-07

SCOPE OF WORK

AVOIDED ENERGY SUPPLY COMPONENTS FOR USE IN ENERGY-EFFICIENCY PROGRAM COST-EFFECTIVENESS ANALYSES "2007 AESC STUDY"

Estimation of Marginal Supply Costs

Avoided By Electricity, Natural Gas, Fuel Oil, Biofuels, Propane, Kerosene, and Wood Savings from

Program Administrator Energy-Efficiency Activities

PURPOSE

Energy efficiency programs are being offered to customers throughout New England, generally by electric and gas utilities, as well as by other program administrators (collectively, "administrators"). Ratepayer funds support these programs, which focus on reducing energy consumption. To support program planning and development, prioritization prior to and during implementation of those programs, and filings with regulators, program administrators must be able to examine estimated program benefits over the lives of the component measures, and possibly beyond (if post-program benefits can be reasonably assumed). Key benefits derived from these conservation programs are the cost associated with avoided use of electricity and natural gas. In addition, several regulatory bodies permit the inclusion of non-electric and non-gas benefits in these benefit-cost analyses.

A subgroup of the administrators[1] in the region have chosen to solicit bids from consulting firms to provide projections of avoided energy costs which will support their

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[1] The sponsors of this project include: Berkshire Gas Company, KeySpan Energy Delivery New England (Boston Gas Company, Essex Gas Company, Colonial Gas Company, and EnergyNorth Natural Gas, Inc.), Cape Light Compact, National Grid USA, New England Gas

internal program decision-making and their regulatory filings during 2008 and 2009. These project sponsors, along with non-utility parties and their consultants, constitute the 2007 Avoided-Energy-Supply-Component ("AESC") Study Group[2]. It will be the Study Group's responsibility to select the Contractor to conduct the study, interact with the Contractor, monitor progress of the study, and ensure that the results satisfy the study goals and provide the necessary factors to facilitate the cost-effectiveness analysis.

This 2007 AESC Study is intended to update prior studies conducted in 1999, 2001, 2003, and 2005, which were based on various methods including a survey of forecasts of market prices for electricity and fuels, production cost modeling, and actual experience in the energy markets. The 2005 AESC Study revisited the estimation of marginal supply costs avoided by conservation savings, based on projected demand, available sources, and fuel prices for marginal supply sources, while also including the impacts of expected locational pricing. Also in 2005, the Study Group expanded the study scope to include estimates of price effects resulting from demand reduction and to establish consistency in loss estimation and marginal transmission and distribution cost development.

The Scope for 2007 is intended to maintain continuity with prior studies and ensure consistent application of study results despite the varied nature of program offerings. At the same time, we expect it will reflect the latest developments in the ISO-New England wholesale power market, in particular, the emerging Forward Capacity Market (FCM).

This Scope includes a proposed schedule for the project (page 21). The Study Group intends for the Contractor to begin work on the project in March 2007 and to complete the final report by August 1, 2007, with a key interim deliverable by May 15, 2007. Keeping these dates in mind, the Study Group will look to the Contractor to

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Company, NSTAR Electric & Gas Company, New Hampshire Electric Co-op, Bay State Gas and Northern Utilities, 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 and Unitil Energy Systems, Inc.), United Illuminating, Southern Connecticut Gas and Connecticut Natural Gas, the State of Maine, and the State of Vermont.

[2] The following agencies or organizations are represented in the Study Group: Connecticut Energy Conservation Management Board, Massachusetts Department of Telecommunications and Energy, Massachusetts Division of Energy Resources, 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.

furnish it with a detailed timeline, consisting of dates for study milestones and deliverables.

The Study Group strongly emphasizes that the intent of this process is to determine energy supply components that will be applied only for the purposes of DSM planning, evaluation, and implementation and not be regarded as proxies for the market prices of any commodity.

SCOPE OF SERVICES

The Study Group's objective is to update the 2005 AESC Study (see http://www.nationalgridus.com/2005avoidedcoststudy to view the study) avoided costs for current conditions and current cost projections, beginning with a base year of 2007 and going out 30 years through 2037. The tasks below identify the information that is to be developed in the 2007 AESC Study, including additional requested information.

The tasks below identify up to eleven intermediate deliverables, as well as the final report deliverable. The Contractor should expect that each intermediate deliverable will be reviewed by the Study Group, which may lead to revisions. Alternatively, through meetings with Study Group members during the analysis and preparation of deliverables, consensus on various assumptions, etc., may be reached, minimizing the necessity of revision. The Contractor will note that some deliverables are dependent on others, and the prior deliverables must be completed and reviewed before doing dependent tasks.

Deliverables should be labeled as "Deliverable #," followed by a descriptive name. Intermediate deliverables should be delivered as text and/or spreadsheet, as appropriate, which will allow for review by the Study Group. The full final report should be provided both in printed form and electronic form. Final avoided cost tables must be provided in Microsoft Excel spreadsheets, suitable for manipulation and use by the users. The Study Group will work with the Contractor to develop an acceptable format for the tables.

All assumptions in the avoided cost forecasts should be explicitly stated and documented (e.g., fuel price escalation rates, unit heat rates, including a detailed explanation of how future regional resources are matched with future regional loads, etc.). The output should cover projections beginning with a base year of 2007 and ending in 2022. All forecasts should be presented in real 2007$. The Contractor will provide a single (for all of New England) real escalation rate for each primary component (electric energy, electric capacity, natural gas, oil, and other fuels) to apply to all final 2022 forecast values through 2037. The Contractor will also provide an inflation rate to convert from real dollars to nominal dollars. The Contractor will provide instructions to ensure avoided costs are used consistently and appropriately.

The selected Contractor will meet with the Study Group at a Kickoff Meeting, preferably in person, or via conference call if necessary, to reach final agreement on the scope of work, costs, deliverables, and the expected study output.

STUDY MANAGEMENT

One member of the Study Group will serve as Study Manager. He or she will organize and facilitate meetings, handle all intra-Study Group communication, be the primary liaison with the Contractor, and monitor the project budget. All teleconferences and meetings will end with a schedule update and summary of action items. The Study Manager will send out the same information electronically at the conclusion of each meeting.

In addition to the tasks outlined below, the Contractor will be responsible for timely communication with the Study Group and for managing the schedule of the project. Time is of the essence in the completion of this project as its results feed into regulatory filings that will be prepared beginning in summer 2007. Contractor must also establish adequate internal quality control procedures for reviewing numeric results prior to sending them to the Study Group.

The Study Group as a whole anticipates taking an active role in the execution of the study, including understanding the workings of any models used for the analyses. We expect there will be a number of meetings or teleconferences to discuss the preparation of or review of forecast components and deliverables. The Contractor should be aware that achieving consensus is an important element in the widespread acceptance of the forecast, and account for group interaction and consensus building in the schedule. Work that is beyond that described in this Scope of Work should be approved by the Study Group.

TASKS

1) **At the outset of the project, the Contractor will establish an electronic communication protocol for the Study**. The Study Group anticipates that this will

involve an electronic project site, though other forms will be considered. The objective of this site is to facilitate review of project documents. The project site should meet the following criteria:

a) Contractor and Study Group members would be subscribers or members.

b) Documents could be posted on the site for download, review, and upload.

c) E-mail notification would be generated every time there was a new posting.

When the project site is established, the Contractor will distribute instructions for use to the Study Group. ***DELIVERABLE #1: "ELECTRONIC PROJECT SITE AND INSTRUCTIONS FOR USE."***

2) Develop forecast of New England regional natural gas prices for the forecast horizon for 2007 through 2022.

a) Develop regional wholesale natural gas commodity price projections in $/MMBtu for the following three geographic areas: Northern and Central New England (Massachusetts, New Hampshire, and Maine); Southern New England (Connecticut and Rhode Island); Vermont.

i) ***DELIVERABLE #2: "GAS FORECAST BACKGROUND."*** Provide a written summary memo to the Study Group. The memo should contain:

(a) The wholesale natural gas commodity price projections for the region as a whole and for each of the three subregions;

- Documentation of sources of commodity, basis, and supporting assumptions (e.g., underlying inflation, market demand, fuel prices, and aggregate economic activity, including as much time differentiation that is available);

- Assumptions on new supply that may be avoided by energy efficiency and the incorporation of this new supply in the forecast.

- Methods used for the gas commodity forecast for each geographical division, as appropriate, including an explicit discussion of how the forecast method addresses the issue of volatility and/or uncertainty of gas prices;

- Explain how price spikes are handled

- A comparison of the commodity price projections with projections from the 2005 AESC study through 2010, with some explanation of differences and key drivers.
- A comparison of the commodity price projection with the most recent EIA forecast, a forecast as represented by the NYMEX futures market, and other external forecasts that the Contractor may identify.
- A comparison of the baseline commodity price forecast to optimistic and pessimistic forecast scenarios that capture the uncertain and volatile nature of natural gas prices
- Identification of the strengths and weaknesses of all alternative forecasts, including external forecasts (if possible).
- Identification of key variables that, if modified by some reasonable percentage, would have a noticeable impact on the final output, along with an estimate of the impact of each on the output (e.g., if X% more LNG storage is added, the natural gas forecast will change by Y%).

(b) Wholesale demand/capacity cost projections for the region as a whole and for each of the three subregions;

- Wellhead, transportation, storage, and peak-shaving costs and characteristics for natural gas available to the region.
- Assumptions about the timing and cost of new transportation, storage, and peak shaving projects that will be available to serve the region in the future;
- Explain how long term capacity additions are handled.

b) Develop sector specific natural gas prices. Based on Tasks (1a) and (1b), estimate end use marginal natural gas commodity costs in $/MMBtu for electric generation, commercial, and industrial, and residential end uses.

i) Determine supply sources likely to serve as marginal resources in the New England region during appropriate seasonal and peak day costing periods for the period 2008 through 2022, based on:

- Current and projected wellhead, transportation, storage, and peak-shaving characteristics for natural gas available to the region. Explain how firm vs. interruptible supply is handled for generation.
- Expected regional sales volumes and demand levels;
- Costing periods specified as peak day, 3-month, 5-month, 6-month, and 7-month winter periods and 5-month, 6-month, 7-month and 9-month summer periods, to capture programs that save baseloads, existing building heating load, new building heating loads, and domestic hot water loads, respectively; and
- A reasonable, clearly stated, and transparent method of matching anticipated resources and loads for determining marginal supply sources (which need not involve through-put simulation).

ii) Present projected gas wellhead prices and transportation tariffs to the city gate for each identified geographical division applicable to marginal sources (using secondary sources if desired).

iii) Combine the results of subtasks (i) and (ii) to compute estimates of future natural gas costs <u>avoided by energy efficiency program savings</u> stated in \$/MMBtu with all assumptions explicitly stated and documented (e.g., conversion of peak day sendout prices, loss factors, fuel price escalation rates, contract provisions, etc.) at the city gate, inclusive of stated transportation/compression losses, for the costing periods, and end use profiles specified as:

(a) Electric generation

(b) Commercial and industrial non-heating,

(c) Commercial and industrial heating,

(d) Existing residential heating,

(e) New residential heating,

(f) Residential domestic hot water,

(g) All commercial and industrial,

(h) All residential,

(i) All retail end uses.

iv) Sponsoring gas utilities will provide to the Contractor distribution charges applicable from the city gate(s) to the burner tip(s) in the defined regions. The Contractor will add these to each of the sector costs in (iii) to develop avoided end-use marginal gas costs for each end use sector.

v) Combine the results of subtasks (i) and (ii) to compute estimates of future natural gas costs faced by electric generators in $/MMBtu with all assumptions explicitly stated and documented (e.g., conversion of peak day sendout prices, loss factors, fuel price escalation rates, contract provisions, etc.) at the city gate, or at any reasonable destination of the Contractor's choice, inclusive of stated transportation/compression losses. If necessary, differentiate by season or zone. If by zone, the zones should match the zones for the electric market defined below in Task 4.

vi) ***DELIVERABLE #3 "SECTOR SPECIFIC NATURAL GAS FORECAST":*** Prepare a memo documenting the forecast for each sector and end use developed in subtasks (iv) and (v). Forecast results will be presented for 2007 through 2022 in a format acceptable to Sponsors. The Study Group will work with the Contractor to develop an acceptable format for the tables. The forecast will include a levelized cost for the stream of avoided costs, including the assumptions used to levelize the stream. Present the forecast values in printed form and in a Microsoft Excel spreadsheet.

3) **Develop forecast of New England regional oil prices for the forecast horizon**.

a) Develop forecasts for 2007 through 2022 of oil prices, in $MMBtu, used by electrical generators and in residential, commercial and industrial applications.

i) Apply sector specific characteristics, such as typical contract provisions, transportation charges, to develop end use prices for the following categories. The prices for the C&I and residential sectors should be those that would be avoided by the installation of oil-saving energy efficiency measures.

(a) By grade: #2, #4, #6, B5 and B20 (biofuel blends)

(b) By sector: generation, commercial and industrial applications, residential heating applications. and applicable residential end-use emissions standards

ii) Compare the price projection by grade with the most recent EIA forecast, a forecast as represented by the NYMEX futures market, and other external forecasts that the Contractor may identify. Identify the strengths and weakness of these forecasts, if possible.

b) ***DELIVERABLE #4 "SECTOR-SPECIFIC OIL FORECAST":*** Document forecasts in memo to study group. The memo should include the penetration assumptions used to weight grade specific fuel oil costs into sector specific costs. The memo should explicitly address (1) how the forecast method addresses the issue of volatility and/or uncertainty of oil prices; (2) other key drivers to the forecast; (3) how the forecast compares to the alternative forecasts and (4) relative consistency of oil forecast with the natural gas forecast because of fuel substitution effects. Forecast results will be presented for 2007 through 2022 in a format acceptable to Sponsors. The forecast will include a levelized cost for the stream of avoided costs, including the assumptions used to levelize the stream. The Study Group will work with the Contractor to develop an acceptable format for the tables.

4) **Develop forecast of regional electric energy supply prices avoided by energy efficiency and demand response programs for the forecast horizon.** The forecast should be developed for the New England region as a whole and for the following component zones. Zonal boundaries are to be consistent with ISO-New England definitions:

- Maine
- Vermont
- New Hampshire
- Connecticut (Statewide)
- Massachusetts (Statewide)
- Rhode Island
- SEMA (Southeast Massachusetts)
- WCMA (West-Central Massachusetts)
- NEMA (Northeast Massachusetts)

- ☞ Rest of Massachusetts (Massachusetts excluding NEMA)
- ☞ Norwalk/Stamford
- ☞ Southwest Connecticut, including Norwalk/Stamford
- ☞ Southwest Connecticut, excluding Norwalk/Stamford
- ☞ Rest of Connecticut (Connecticut excluding all of Southwest Connecticut)

a) Identify the methodology proposed for use to estimate avoided electric costs. The methodology must account for the following:

   i) Current and expected ISO-NE and Federal Energy Regulatory Commission ("FERC") rules and procedures governing the structure and operation of the electricity market in New England.

   ii) Most recent ISO-NE load forecast, transmission system projects, and capacity additions and retirement assumptions reflected in the 2007 Capacity, Energy, Loads and Transmission ("CELT") report and 2006 Regional System Plan ("RSP")

   iii) The cost of compliance with current or expected federal, regional, and state emissions control requirements for NOx, SOx, carbon/CO_2, and mercury

   iv) Renewable portfolio standards. The New England states of Connecticut, Massachusetts, Maine, Rhode Island and Vermont all have some form of renewable portfolio standard, and standards may be adopted in New Hampshire. This should be accounted for in the resource mix for generation, also assuming some level of non-compliance with the standards.

   v) Current and projected values of market-based locational marginal prices, zonal capacity prices, congestion charges, and operating reserves

   vi) Current and projected values of any avoidable costs not internalized in the market prices going forward (such as the cost of reliability must run generating plants and renewable energy credit purchases avoided by generators[3]).

[3] The cost of compliance with renewable portfolio standards should be included in the cost of generation (item iv). In addition, energy efficiency reduces the need for generation; therefore

vii) Locational disaggregation of avoided electric costs in order to reflect potential differences among the sponsors' service territories and/or zones as defined by ISO-New England.

viii) Demand reduction induced price effects. This refers to the price effects seen by customers as a result of demand savings.

b) Develop and identify assumptions for any and all variables to support the chosen methodology to estimate avoided energy supply costs. Such assumptions should include, but not be limited to,

i) Market fuel prices applicable to marginal sources. These values should be consistent with generation-related gas and fuel oil price projections provided under Tasks (1) and (2) above;

ii) Fixed and variable O&M costs (excluding fuel) of marginal units;

iii) Heat rate, marginal fuel mix, and capital cost of new generation additions;

iv) Load growth by regions or zones;

v) Major transmission projects that are currently planned to be in service during the planning period. Certain projects may have major implications not only for avoided T&D costs, but also for locational marginal prices, zonal capacity prices, congestion charges, operating reserves, superpeak, and other costs.

c) ***DELIVERABLE #5 "ELECTRIC FORECAST ASSUMPTIONS DOCUMENT":*** <u>Before</u> developing the estimates of avoided costs, the Contractor will present the Study Group with a memo documenting the chosen methodology, all input assumptions, and the actual values of those assumptions which it intends to use. The memo will also identify key variables that, if modified by some reasonable percentage, would have a noticeable impact on the final output, along with an estimate of the impact of each on the output (e.g., if the natural gas forecast changes by X%, the electricity price will change by Y %).

d) Use agreed upon methodology and assumptions to estimate energy and capacity marginal resource market prices for the New England electrical system and its

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generators may avoid purchase of some RECs. Both effects of RPS should be included in the avoided costs.

component zones out through the projected period. ***DELIVERABLE #6: "INTERIM ELECTRICITY AVOIDED COST FORECASTS".*** Submit a memo to the Study Group. The memo should contain:

i) Single forecast (all capacity and energy value rolled into one number) of avoided $/MWh for 2007 through 2022 for the New England region and each component zones. The forecast will include a levelized cost for the stream of avoided costs, including the assumption used to levelize the stream;

ii) A comparison of the new New England regional market price forecast to the prior AESC forecast through 2022 (2005 Study, Exhibit 3-11, page 106). This will provide continuity with prior AESC studies;

iii) A comparison of the wholesale price projection with the most recent EIA forecast, a forecast as represented by the NYMEX futures market, and other external forecasts that the Contractor may identify, if possible.

iv) A high level discussion of reasons for differences identified in the comparisons between (i), (ii) and (iii); and

v) Explanation of any apparent price spikes and key variables that affect the outcome, as well as identification of potential scenarios worthy of investigation.

e) The Contractor will conduct the analyses defined in subtask (f) using the following definitions of seasons and costing periods.

i) Energy Costing Periods.

(a) For all zones, Summer On-peak is as defined by ISO-NE, June-September, weekdays 6 am to 10 pm; Off-peak is 10 pm to 6 am weekdays, plus weekends, and holidays. Winter period is the remaining 8 months with the same diurnal time divisions.

ii) Capacity Value. Capacity value should be defined in 3 different ways[4] consistent with definitions being used in ISO-New England's Forward

[4] At the time this Scope of Work was developed, the final structure and rules for ISO-NE's new Forward Capacity Market (FCM) in New England is still being developed and the names and definitions of capacity costing periods are not completely settled.

Capacity Market and the Transition Period to the FCM. Contractor must review and confirm these definitions before determining capacity values.

(a) Performance Hours/On-Peak hours. For summer, these are in June, July, and August, non-holiday weekdays, from 1 pm to 5 pm. For winter, these are December and January non-holiday weekdays from 5 pm to 7 pm.

(b) Critical Peak Hours/Shortage hours. These are the hours when the ISO begins to allow the depletion of 30-minute reserve (which at the present time is Action Steps 6 or higher of Operating Procedure Number 4) in the Load Zone where the Demand Resource is located. Identification of these hours will require Contractor to do an analysis of historic shortage hour occurrences as a predictor of the timing and frequency of these events.

(c) Seasonal Peak Hours. These are those hours in which the projected hourly load as shown in the ISO's most recent next day Forecast System Load, as published daily by ISO's website by 1100 EPT, for Monday through Friday on non-holidays, during the months of June, July, August, December and January is equal to or greater than 95% of the most recent 50/50 System Peak Load Forecast, as determined by the ISO, for the applicable summer or winter season. Identification of these hours will require Contractor to do an analysis of historic seasonal peak hour occurrences as a predictor of the timing and frequency of these events.

f) Estimate regional marginal electric energy and capacity costs avoided by energy efficiency savings. Combine the foregoing subtasks to compute estimates for the New England region as a whole for 2007 through 2022 in real dollars (2007$) of future electric supply costs avoided by energy-efficiency and demand response program savings at the delivery point to the transmission system, including generation energy and capacity losses. The forecast will include a levelized cost for the stream of avoided costs, including the assumptions used to levelize the stream. Transmission energy and/or capacity losses may be included if conducive to the Contractor's forecast method. Contractor must inform sponsors whether and which Transmission losses are included in the results (see Task 5(b) below). Local distribution energy and capacity losses should not be included.

i) summer on peak energy in $/MWh

ii) summer off-peak energy in $/MWh

iii) winter on-peak energy, in $/MWh

iv) winter off-peak energy in $/MWh

v) summer generation capacity in $/kW[5] and $/MWh

vi) winter generation capacity in $/kW[5] and $/MWh

g) ***DELIVERABLE #6a: "INTERIM ZONAL ELECTRICITY AVOIDED COST FORECASTS BY COSTING PERIOD"*** Develop different marginal price projections (factoring in applicable locational differences such as fuel costs, emissions requirements, and congestion) for each defined geographic zone in New England for each of the above six costing period categories for 2007 through 2022 and submit them to the Study Group[6]. Zonal transmission energy and/or capacity losses may be included if conducive to the Contractor's forecast method. Distribution energy and capacity losses should not be included.

h) Demand reduction induced price effects (DRIPE). The Contractor will estimate the effect on wholesale market energy and capacity prices resulting from reductions in energy demand on the ISO-NE system due to energy-efficiency savings for 2007 through 2022[7].

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[5] Notwithstanding any analysis performed for this study, the value of summer and winter capacity through May 2010 has been stipulated by parties, including many Sponsors, as part of the agreements regarding the Transition Period in the FCM Settlement. The following stipulated values should be used in the forecast. To determine values for a forecast year, Contractor should employ a weighted average of the values, and document the weighting method used.

Dec 1, 2006 – May 31, 2007	$3.05 / kW-month
Jun 1, 2007 – May 31, 2008	$3.05 / kW-month
Jun 1, 2008 – May 31, 2009	$3.75 / kW-month
Jun 1, 2009 – May 31, 2010	$4.10 / kW-month

[6] This may support the development of plans that will be necessary to be submitted to ISO-New England as part of demand resources qualification packages in the forward capacity market. The deadline for submission of qualification packages is June 15, 2007. Therefore, the date for Deliverable 6a is set at May 15, 2007. Contractor should be prepared to give regular status reports on progress toward this deliverable date.

[7] Because transition period capacity value is fixed, there is no DRIPE capacity value through 2009.

i) The Contractor will discuss its proposed methodology with the Study Group prior to conducting this analysis, including its recommendation about in which markets the effects exist and its confidence in its ability to model the market effects. The market applicability recommendation should explicitly address whether DRIPE are present in the energy market and in the capacity market, and the duration of those effects. It should further address, in the energy market, whether DRIPE shall be calculated for the total energy requirements of New England ("Full DRIPE") or only for the energy requirements transacted in the spot market ("Spot DRIPE").

ii) The Contractor will conduct their analysis of price effects following the Study Group's consideration of the methodological proposal. The analysis should be consistent with the costing periods as defined above in 4(e)[8]. The results will reflect the total dollar value of the estimated market price reduction divided by the energy or capacity saved during the relevant period(s). The total dollar value of the estimated price reduction shall be calculated as the estimated price effect multiplied by the energy or capacity requirements. The Contractor will express results of this analysis in $/kW and $/kWh. The forecast will include a levelized cost for the stream of avoided costs, including the assumptions used to levelize the stream.

i) ***DELIVERABLE #7:*** *"AVOIDED ENERGY SUPPLY COMPONENTS"* Submit a memo containing the New England regional and applicable zonal prices for each of the above six costing period categories, along with separate presentation of DRIPE, to the Study Group. The forecast will include a levelized cost for the stream of avoided costs, including the assumptions used to levelize the stream. Forecast results will be presented for 2007 through 2022 in a format acceptable to Sponsors. The Study Group will work with the Contractor to develop an acceptable format for the tables. The avoided costs should also be submitted in a Microsoft Excel workbook with one spreadsheet for each zone.

5) Miscellaneous Tasks to Support Proper Use of Avoided Cost Forecasts

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[8] It may not be necessary to look at price effects in all costing periods. The Study Group does not currently have the information to make this determination and will look to the Contractor to provide sufficient information to make a determination about which costing periods should be analyzed.

a) Economic Assumptions. Contractor should develop the following economic assumptions to allow for full presentation of all avoided cost forecasts. A single value for each of the following should be developed for application to all avoided costs:

   i) Real escalation rate for post forecast period (2023 through 2037).

   ii) Inflation rate to convert real $ to nominal $.

   iii) Discount rate used for levelizing.

b) Transmission Losses. If Transmission energy or capacity losses are included in the forecasts prepared in Task (4), the Contractor should prepare a summary of the embedded loss factors by costing period by zone. Sponsors will compare these values to their own utility-specific loss factors for reasonableness.

c) Reserve Margin Multiplier. Energy efficiency MW create value by reducing reserve requirements. The reserve margin multiplier is the number by which generation capacity value should be multiplied to incorporate the reserve margin benefit. ISO-NE capacity market transition period rules currently specify a reserve margin multiplier of 14%, but it could change based on forecasts of capacity demand. The Contractor should research the current value, consider factors that may influence it over the forecast horizon, and make a recommendation for a single reserve margin multiplier for application over the entire forecast horizon.

d) Work with Sponsors to collect necessary data and recommend a percent of transmission and distribution capital expenditures that are avoidable by energy efficiency programs.

e) Develop a set of application instructions to which Sponsors and others may refer to ensure proper use of avoided cost tables (similar to Appendix 2 of the 2005 AESC Study). Instructions should include, but not be limited to,

   i) guidance on the estimation of savings by costing period and season to match avoided costs;

   ii) illustrative equations on the calculation of value, e.g., savings x avoided cost x loss factor x reserve margin; and

   iii) what savings may or may not be eligible for certain components of value

f) ***DELIVERABLE #8: "MISCELLANEOUS TASKS"*** Submit a memo to the study group. The memo will contain the recommendations and findings from (a) through (e) above.

6) **Develop a regional avoided cost for other fuels used in residential heating applications for 2007 through 2022.** Determine what sources for a price projection are available, develop, and implement a methodology for projecting a regional price of

   a) Wood; in $/MMBtu.

   b) Kerosene; in $/MMBtu

   c) Propane; in $/MMBtu.

   d) ***DELIVERABLE #9, "OTHER FUELS FORECAST":*** Present the results of the forgoing analysis in a memo to the Study Group. The forecast will include a levelized cost for the stream of avoided costs in $/MMBtu, including the assumptions used to levelize the stream. Forecast results will be presented for 2007 through 2022 in a format acceptable to Sponsors. The Study Group will work with the Contractor to develop an acceptable format for the tables.

7) **Environmental Effects. Quantify the environmental effects of energy efficiency as follows:**

   a) Using the same assumptions as those used to develop the avoided electricity costs, identify heat rates, fuel sources, and emissions of NOx, SOx, CO_2, and mercury in the 2007 base year during each of the energy and capacity costing periods as defined in Task 4(e).

   b) Determine if, and quantify how much, environmental benefits correspond to energy efficiency and demand reductions, in lbs/MWh and lbs/kW, respectively, during each costing period.

   c) Monetized Emission Values. Currently the Sponsors screen DSM measures based on a variety of cost effectiveness tests, many of which include a monetized value for emissions avoided as a result of reduced electricity consumption.

      i) The Contractor will critically examine this available data, determine which is based on sound and current science, and make a recommendation to the Study Group regarding an appropriate dollar value to use for avoided emissions (damage costs or control costs) when screening DSM programs. The values should be developed for NOx, SOx, CO_2, and mercury, in $/kW or $/kWh (a range of values would be acceptable). This examination should not only include a critical examination of the available data, but also a sound theoretical explanation of the values recommended, using data from existing studies, or other information developed by the contractor. Identify the portions of the value that are already embedded in the avoided costs and what portion is not embedded. If possible, quantify other significant impacts of electricity generation as well, such as water quality and land use, and whether they, too, are embedded in the avoided costs.

ii) Additionally, some air emissions are currently regulated through a cap and trade program and the region is on the verge of implementing such a program for CO2. The Contractor will advise the group on how the various cap and trade programs affect avoided emissions and how such cap and trade programs may influence the value of avoided emissions used in measure screening.

d) ***DELIVERABLE #10, "ENVIRONMENTAL EFFECTS"***. Submit a memorandum containing a description of the analysis and its findings.

8) Presentation and Follow-Up

a) ***DELIVERABLE #11.*** Submit a draft final report to all study group members in an electronic format suitable for reviewing. The draft final report will include:

i) An executive summary and a section for each of the six major tasks outlined above. Each section should contain a complete and detailed description of methodology and assumptions supporting the final results, as well as the results themselves. To make the final report a standalone document, the sections should contain relevant information that had been previously presented and documented in interim deliverables and follow-up memoranda.

ii) Include in the Executive Summary a table comparing the overall New England regional results for natural gas and electricity from the 2005 AESC study with the present study.

iii) Include the results of any follow-up analysis.

iv) Include appendices with the developed avoided energy supply costs by zone for easy application by Program Administrators

v) All avoided energy supply costs presented in the draft final report shall be in real 2007 dollars, covering the period 2007 through 2037. Levelized values should be included for a 16 year period (2007-2022) as well as the full 31 year period, using the previously identified real discount rate.

b) An appropriate interval after delivery of the draft final report, there will be a meeting at which presentation and discussion of the results of Tasks (2) through (6) will occur.

i) Following the oral presentation, the Study Group will submit outstanding written comments on the draft final report to the Study Manager, who will compile them for delivery to the Contractor.[9] The Contractor will revise and resubmit per the oral discussion and written study group comments. The report will be declared final upon a consensus finding by the Study Group. ***FINAL DELIVERABLE.*** The final report will be delivered via hard copy in a three ring binder and electronically in Word and PDF format to all members of the Study Group. Final avoided cost tables will be submitted in the specified formats in Excel and PDF format as well. All avoided energy supply costs presented in the final report shall be in real 2007 dollars, covering the period 2007 through 2037. Levelized values should be included for a 16 year period (2007-2022) as well as the full 31 year period, using the previously identified real discount rate. A second set of tables should be included showing the same information in nominal dollars, using the previously identified inflation rate.

c) Following delivery of the final report, The Contractor will work with the Study Manager (along with any other interested Study Group member) to

i) Review and revise this scope of work for possible use in the anticipated 2007 update of the AESC study

ii) Identify potential process improvements for future updates of the AESC Study

The Study Manager will disseminate a summary of this process to the Study Group

[9] The format of the transmission of the final set of comments may change depending on the experience with the electronic project site.

d) The contactor may be called upon to do follow-up Program Administrator-specific analyses for individual Study Group members for a period of up to two years following completion of the study. Hours for this follow-up work should not be included in the proposal, but a billing rate should be provided, as noted below in “Proposal Requirements.” If revisions are created, a revised electronic version of the followup work should be sent to all members of the Study Group, with an accompanying memo highlighting the changes and identifying the affected pages of the final report.

PROPOSAL REQUIREMENTS

Refer to Article 5.0 Required Format of Proposals of the RFP Information and Instructions for Bidders for complete details on proposal requirements. Bidder’s responses must include:

1) Methodology

   a) A description of the bidder’s proposed electronic communication protocol, per Task 1.

   b) A brief description of the data sources, methodology(ies), and work plan that the bidder proposes to use to prepare direct estimates of future gas, oil, marginal electricity supply, transmission and distribution capacity, and other fuel costs avoided by energy-efficiency programs (as described in Task 2 through Task 7). Any models expected to be used should be described in detail and include reporting on their past experience in approximating actual prices, costs, or other modeled factors;

2) Project Management

   a) A proposed schedule, including a date for each of the 11 intermediate deliverables as well as the final report;

   b) Written assurance that the proposed work will be provided by the due date specified below;

   c) A description of the bidder’s proposed internal quality control procedures;

3) Experience and Qualifications

   a) Descriptions of projects that demonstrate relevant corporate experience;

b) Names of the principal personnel that will be responsible for performing the work and preparing the deliverables, plus a brief statement of their qualifications including their participation in the projects cited as relevant experience;

Bidder's responses may further include:

1) Any questions, concerns or issues, comments or relevant suggestions on the study as described in the Scope of Work for discussions at the initial meeting with the Study Group;

2) Any number of alternative scenarios for the performance of the work. If so, scenarios should be clearly identified and separate personnel assignments and bid estimates must accompany each scenario.

Proposals should be limited to 25 pages. Additional pages will be accepted for alternative scenarios. Appendices of any reasonable length are acceptable for providing individual qualifications, including further explanation of relevant experience.

PROPOSED SCHEDULE

RFP Issued	February 1, 2007
Written Questions by	February 12, 2007
Proposals due	February 20, 2007
Contractor selection	March 2, 2007 (est.)
Kickoff Meeting, Northborough, MA	March 16, 2007 (est.)
Deliverable 6a	May 15, 2007
Final Deliverable	June 29, 2007
Report Presentation	July 12, 2007
Final report	July 31, 2007