Avoided Energy Supply Costs in New England: 2013 Report

Prepared for the Avoided-Energy-Supply-Component (AESC) Study Group

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List of Abbreviations

AEO	Annual Energy Outlook
AGT	Algonquin Gas Transmission
AIM	Algonquin Incremental Market
API	American Petroleum Institute
BACT	Best Available Control Technology
BART	Best Available Retrofit Technology
BDAT	Best Demonstrated Available Technology
CAGR	Compound Annual Growth Rate
Bcfd	Billion Cubic Feet per Day
CCP	Central Connecticut Project
CCR	Coal Combustion Residuals
CCS	Carbon Capture and Storage
CECP	Clean Energy Climate Plan (Massachusetts)
CSAPR	Cross State Air Pollution Rule
DOE	Department of Energy
DOER	Massachusetts Department of Energy Resources
DRIPE	Demand Reduction Induced Price Effects
EEFWG	ISO-New England Energy-Efficiency Forecast Working Group
EIA	Energy Information Administration
EMF	Energy Modeling Forum
EUR	Expected Ultimate Recovery
FCAs	Forward Capacity Auctions
FCM	Forward Capacity Market
FTA	Free Trade Agreement
FT	Firm Transportation
FTR	Financial Transmission Rights
GAO	Government Accountability Office
GSRP	Greater Springfield Reliability Project
GWSA	Massachusetts Global Warming Solutions Act
HDD	Heating Degree Day
IEA	International Energy Agency

IGCC	Integrated Gasification Combined-Cycle
IGTS	Iroquois Gas Transmission System
IPCC	Intergovernmental Panel on Climate Change
IRP	Interstate Reliability Project
LAER	Lowest Achievable Emissions Reductions
LDCs	Local Distribution Companies
LNG	Liquefied Natural Gas
LSEs	Load-Serving Entities
M&N	Maritimes & Northeast Pipeline
MACT	Maximum Achievable Control Technology
MMcf	Million Cubic Feet
MPRP	Maine Power Reliability Plan
NAAQS	National Ambient Air Quality Standards
NEEWS	New England East-West Solution
NGLs	Natural Gas Liquids
NGPA	Natural Gas Policy Act
NRC	Nuclear Regulatory Commission
PDR	Passive Demand Resources
PNGTS	Portland Natural Gas Transmission System
RACT	Reasonably Available Control Technology
REC	Renewable Energy Certificate
RGGI	Regional Greenhouse Gas Initiative
RIRP	Rhode Island Reliability Project
RPS	Renewable Portfolio Standard
SEDS	State Energy Data System
TCPL	TransCanada PipeLines
TETCO	Texas Eastern Transmission
TGP	Tennessee Gas Pipeline
TPH	Tudor Pickering Holt
VOM	Variable Operating and Maintenance Costs
WTI	West Texas Intermediate

Chapter 1: Executive Summary

This 2013 Avoided-Energy-Supply-Component Study ("AESC 2013," or "the Study") provides projections of marginal energy supply costs that will be avoided due to reductions in the use of electricity, natural gas, and other fuels resulting from energy efficiency programs offered to customers throughout New England. All reductions in use referred to in the Study are measured at the customer meter, unless noted otherwise.

AESC 2013 provides estimates of avoided costs for program administrators throughout New England to support their internal decision-making and regulatory filings for energy efficiency program cost-effectiveness analyses. The AESC 2013 project team understands that, ultimately, the relevant regulatory agencies in each state specify the categories of avoided costs that program administrators in their states are expected to use in their regulatory filings, and approve the values used for each category of avoided cost.

In order to determine the value of efficiency programs, AESC 2013 provides projections of avoided costs of electricity and natural gas in each New England state for a hypothetical future, the "Base Case," in which **no new** energy efficiency programs are implemented in New England from 2014 onward. AESC 2013 avoided costs should **not** be interpreted as projections of, or proxies for, the market prices of natural gas, electricity, or other fuels in New England at any future point in time, for the following two reasons. First, the projections are for a hypothetical future and thus do not reflect the actual market conditions and prices likely to prevail in New England in an actual future with significant amounts of new efficiency measures. Second, the Study is providing projections of the avoided costs of these fuels in the long term. The actual market prices of those fuels at any future point in time will vary above and below their long-run avoided costs due to the various factors that affect short-term market prices.

AESC 2013 updates the 2011 AESC study ("AESC 2011") to reflect changes in observed facts and in expectations regarding future market conditions and future costs. Specific changes in expectations that contribute to changes from the AESC 2011 avoided costs are:

- Increases in the quantity of shale gas production available at marginal production costs less than $5/MMBtu, resulting in lower projections of avoided gas supply costs;
- Constraints on pipeline capacity into New England through 2016, resulting in wholesale market costs of gas in New England higher than the rest of the Northeast during that period, particularly in winter months;
- Retirements of existing generating units with a total capacity of 7,400 MW, leading to higher estimates of avoided costs for electric capacity;

- Higher RGGI allowance prices, and a delay in the start of federal regulation of carbon emissions from 2018 to 2020; and
- Estimates of demand reduction induced price effects (“DRIPE”) for reductions in gas consumption resulting from gas efficiency programs and from electric efficiency programs.

The Study provides detailed projections of avoided costs by year for an initial 15-year period, 2014 through 2028, and extrapolates values for another 15 years, from 2029 through 2043.[1] All values are reported in 2013 dollars (“2013$”) unless noted otherwise. For ease of reporting and comparison with AESC 2011, many results are expressed as levelized values over 15 years.[2] The AESC 2013 levelized results are calculated using the real discount rate of 1.36 percent, solely for illustrative purposes.[3]

1.1 Background to Study

AESC 2013 was sponsored by a group of electric utilities, gas utilities, and other efficiency program administrators (collectively, “program administrators” or “PAs”). The sponsors, along with non-utility parties and their consultants, formed an AESC 2013 Study Group to oversee the design and execution of the report.

The Study sponsors include: Berkshire Gas Company; Cape Light Compact; Liberty Utilities; National Grid USA; New England Gas Company; New Hampshire Electric Co-Op; Columbia Gas of Massachusetts; Northeast Utilities (Connecticut Light and Power, NSTAR Electric & Gas Company, Western Massachusetts Electric Company, Public Service Company of New Hampshire, and Yankee Gas); Unitil (Fitchburg Gas and Electric Light Company, Unitil Energy Systems, Inc., and Northern Utilities); United Illuminating; Southern Connecticut Gas and Connecticut Natural Gas; Efficiency Maine; and the State of Vermont. The non-sponsoring parties represented in the Study Group include: Connecticut Energy Conservation Management Board; Conservation Law Foundation; Massachusetts Department of Public Utilities; Massachusetts Department of Energy Resources; Massachusetts Department of Environmental Protection; Massachusetts Attorney General; Massachusetts Low-Income Energy Affordability Network (“LEAN”); Massachusetts Energy Efficiency Advisory Council; New Hampshire Public Utilities Commission; Vermont Gas Systems, Inc.; and Rhode Island Division of Public Utilities and Carriers.

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[1] Escalation rates for extrapolation are based on compound annual growth rates specific to the value stream and are noted throughout the report.

[2] 15-year levelization periods of 2012-2026 for AESC 2011 and 2014-2028 for AESC 2013. AESC 2011 used a real discount rate of 2.46 percent.

[3] The AESC 2013 real discount rate reflects 30-year United States Treasury yields as of February 2013. Thirty-year U.S. Treasury yields are much lower for AESC 2013 compared to AESC 2011, which explains the difference in the levelization rate, as detailed in Appendix E.

The AESC 2013 Study Group specified the scope of services, selected the Synapse Energy Economics ("Synapse") project team, and monitored progress of the study. As instructed by the Study Group, the Synapse team developed seven distinct forecast components, which correspond to Chapters 2 through 7 of this report (See Exhibit 1-1). Two of the components—avoided fuel oil costs and avoided costs of other fuels—were combined into one chapter.

For each component, the Synapse project team presented its methodologies, assumptions, and analytical results in draft deliverables for each of the subtasks specified by the Study Group. The Synapse team reviewed each draft deliverable with the Study Group in conference calls. The relationships between the sections of this report, the forecast components, and the subtask deliverables are presented in Exhibit 1-1.

Exhibit 1-1. Relationship of chapters to forecast components and subtasks

Chapter/Appendix	Forecast Component	Subtasks
Chapter 2 – Avoided Natural Gas Costs	1	2A, 3A
Chapter 3 – Avoided Costs of Fuel Oil and Other Fuels	2, 5	2B, 3B, 2E, 3E
Chapter 4 – Embedded and Non-Embedded Environmental Costs	6	2F, 3F
Chapter 5 – Avoided Electric Capacity Costs	4	2D, 3D
Chapter 6 – Avoided Electric Energy Costs	3	2C, 3C
Chapter 7 – Demand Reduction Induced Price Effects	7	2G, 3G
Chapter 8 – Sensitivity Analyses	N/A	4B
Appendix A – Usage Instructions	N/A	4C
Appendix G – Survey of Transmission and Distribution Capacity Values	N/A	4A
Appendix E – Common Financial Parameters	N/A	1

This report was prepared by a project team assembled and led by Synapse. Synapse's Rick Hornby and Max Chang managed the project. Ron Denhardt of Strategic Energy and Economic Research, John Rosenkranz of North Side Energy, and Dr. Thomas Vitolo of Synapse developed the avoided natural gas cost projections. Dr. David White and Patrick Luckow of Synapse developed projections of avoided costs of fuel oil and other fuels. Dr. Elizabeth A. Stanton of Synapse led the analysis of non-embedded environmental costs avoided due to reductions in electricity and fuel use. Paul Chernick of Resource Insight led the analysis of wholesale electric capacity costs and demand reduction induced price effects, with assistance from Ben Griffiths. Dr. David White and Patrick Luckow of Synapse developed the projections of wholesale electric energy prices. Bob Grace and Jason Gifford of Sustainable Energy Advantage ("SEA") provided estimates of renewable energy credit ("REC") demand, supply, and price.

1.2 Avoided Costs of Electricity

Initiatives that enable retail customers to reduce their peak electricity use ("demand") and/or their annual electricity use ("energy") have a number of key monetary and environmental benefits. Major categories of benefits include:

- Avoided costs due to reductions in quantities of resources required to meet electric demand and annual energy. *Electric capacity costs* are avoided due to a reduction in the annual quantity of electric capacity that load serving entities ("LSEs") will have to acquire from the Forward Capacity Market ("FCM") to ensure an adequate quantity of generation during hours of peak demand. *Electric energy costs* are avoided due to a reduction in the annual quantity of electric energy that LSEs will have to acquire. These avoided costs include a reduction in the cost of renewable energy incurred to comply with the applicable Renewable Portfolio Standards ("RPS").[4] Non-embedded environmental costs are avoided due to a reduction in the quantity of electric energy generated. (A non-embedded environmental cost is the cost of an environmental impact associated with the use of a product or service, such as electricity, that is not reflected in the price of that product.) AESC 2013 uses the long-term abatement cost of carbon dioxide emissions as a proxy for this value.
- Local transmission and distribution ("T&D") infrastructure costs are avoided due to delays in the timing and/or reductions in the size of new projects that have to be built, resulting from the reduction in electric energy that has to be delivered. AESC 2013 surveys participating sponsors for recent values.
- Avoided costs due to reductions in wholesale market prices of capacity and energy occur as the lower requirements for electric demand and annual energy are met by lower-cost marginal resources. Reductions in the quantities of capacity and energy being acquired from those markets will cause prices in those markets to decline relative to Base Case levels for a certain period of time, after which responses by market participants will lead to a shift in the supply curve and cause prices to rise back toward the Base Case levels. AESC 2013 refers to the reduction or mitigation of market prices due to reductions in demand for electric capacity and electric energy as "capacity DRIPE" and "energy DRIPE," respectively. In addition, reductions in annual electricity use will cause a reduction in gas consumption for electric generation, which will have a price suppression effect on gas supply prices, which we refer to as electric cross-fuel DRIPE.

AESC 2013 develops estimates of each category of avoided costs, and (as noted above) surveys Study Group members for avoided T&D costs, which are utility-specific. The forecast components that feed into the AESC 2013 projections of avoided electricity costs consist of the following:

- **Avoided capacity.** Avoided capacity costs for the AESC 2013 Base Case consist of revenue from demand reductions bid into the FCM and the value of generating capacity avoided by demand reductions that are not bid into the FCM. Levelized annual FCM prices are approximately 61 percent higher than in AESC 2011. This increase is primarily due changes in the Forward Capacity

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

Auction ("FCA") market rules post-FCA 8, and earlier need for new capacity additions due to the increased quantity of existing capacity projected to retire.

- **Avoided energy.** This is the largest component. It consists of the wholesale electric energy price, the REC cost, and a wholesale risk premium. Levelized annual avoided energy costs under the AESC 2013 Base Case range between 4 and 9 percent lower than those in AESC 2011, depending on the pricing zone. The levelized annual wholesale electric energy costs are lower primarily due to projections of lower natural gas prices and a delay in the anticipated implementation of federal regulation of carbon emissions. The decline in this component is offset somewhat in winter periods by New England natural gas pipeline constraints through 2016, which affect the winter basis prices, and higher RGGI allowance prices from 2014 through 2019.
- **Capacity DRIPE.** This is the value of the reduction in capacity market prices due to reductions in demand. The AESC 2013 15-year levelized annual capacity DRIPE value is approximately 45 percent lower on average than AESC 2011 due to the extension of the FCA floor price, projection of new generation in 2020, and a shorter dissipation period.
- **Energy DRIPE.** This is the value of the reduction in energy market prices due to reductions in electric energy use. Levelized annual intrastate energy DRIPE values are approximately 19 percent lower on an annual load-weighted average than AESC 2011, primarily due to changes in our assumptions of dissipation of DRIPE effects, lower wholesale energy prices compared to AESC 2011, and our AESC 2013 assumptions regarding the need for new generation capacity.
- **Electricity cross-fuel DRIPE.** This value represents the impact of the reduction in natural gas used for electric generation upon natural gas prices. This value is new for AESC 2013.
- **Avoided non-embedded CO_2 costs.** This is the cost of controlling CO_2 emissions not reflected in wholesale energy market prices. The AESC 2013 15-year levelized annual value is approximately 14 percent higher than AESC 2011 due to our projection of a higher long-term marginal abatement cost of carbon.

The relative magnitude of each component for the **Summer On-Peak** costing period is illustrated in Exhibit 1-2 for an efficiency measure with a 55-percent load factor implemented in the West Central Massachusetts zone ("WCMA").

Exhibit 1-2. Illustration of Avoided Electricity Cost Components, AESC 2013 vs. AESC 2011 (WCMA Zone, Summer On-Peak, 15-Year Levelized Results, 2013$)

	AESC 2011	AESC 2013	Difference Relative to AESC 2011	
	cents/kWh	cents/kWh	cents/kWh	% Difference
Avoided Capacity Costs[1,2]	1.11	2.01	0.90	80.7%
Avoided Energy Costs	9.36	7.64	-1.73	-18.4%
Capacity and Energy Subtotal	**10.47**	**9.65**	**-0.83**	**-7.9%**
DRIPE				
Capacity[2]	1.27	0.69	-0.57	-45.2%
Intrastate Energy[3]	3.29	2.74	-0.54	-16.5%
DRIPE Subtotal	**4.55**	**3.44**	**-1.11**	**-24.5%**
Subtotal: Avoided Capacity and Energy + Intrastate DRIPE	**15.03**	**13.09**	**-1.94**	**-12.9%**
CO_2 Non-Embedded[4]	3.52	4.33	0.81	23.0%
Total	**18.55**	**17.42**	-1.13	-6.1%

Notes
-Values may not sum due to rounding
-Avoided energy costs for Summer On-Peak incorporate avoided REC costs
-AESC 2011 values levelized (2012-2026) escalated to 2013$
1) Avoided capacity costs assumes 100% ***selling*** into Forward Capacity Markets
2) Assuming a 55% load factor
3) Values are for Intrastate *energy* DRIPE
4) For AESC 2013, 2013 CO_2 prices and physical emission rates

For this costing location and period, AESC 2013 is projecting total avoided costs from direct reductions in energy and capacity of 9.65 cents per kWh. This amount is approximately 7.9 percent lower than the corresponding AESC 2011 total.

The total of all components—i.e., the avoided cost of energy and capacity reductions (9.65 cents per kWh), plus energy and capacity DRIPE, plus non-embedded CO_2 costs—is 17.42 cents per kWh. This total is 6.1 percent lower than the corresponding AESC 2011 total. Note this illustrative avoided cost component does not include the electricity cross-fuel DRIPE effect described in detail in Chapter 7.

1.2.1 Avoided Electric Capacity Costs

Avoided electric capacity costs are an estimate of the value of a load reduction by retail customers during hours of system peak demand.[5] The major input to this calculation is the wholesale forward capacity price to load (in dollars per kilowatt-month), which is set for a capacity year (June–May) roughly three years before the start of the capacity year. To develop an avoided cost at the meter, the wholesale

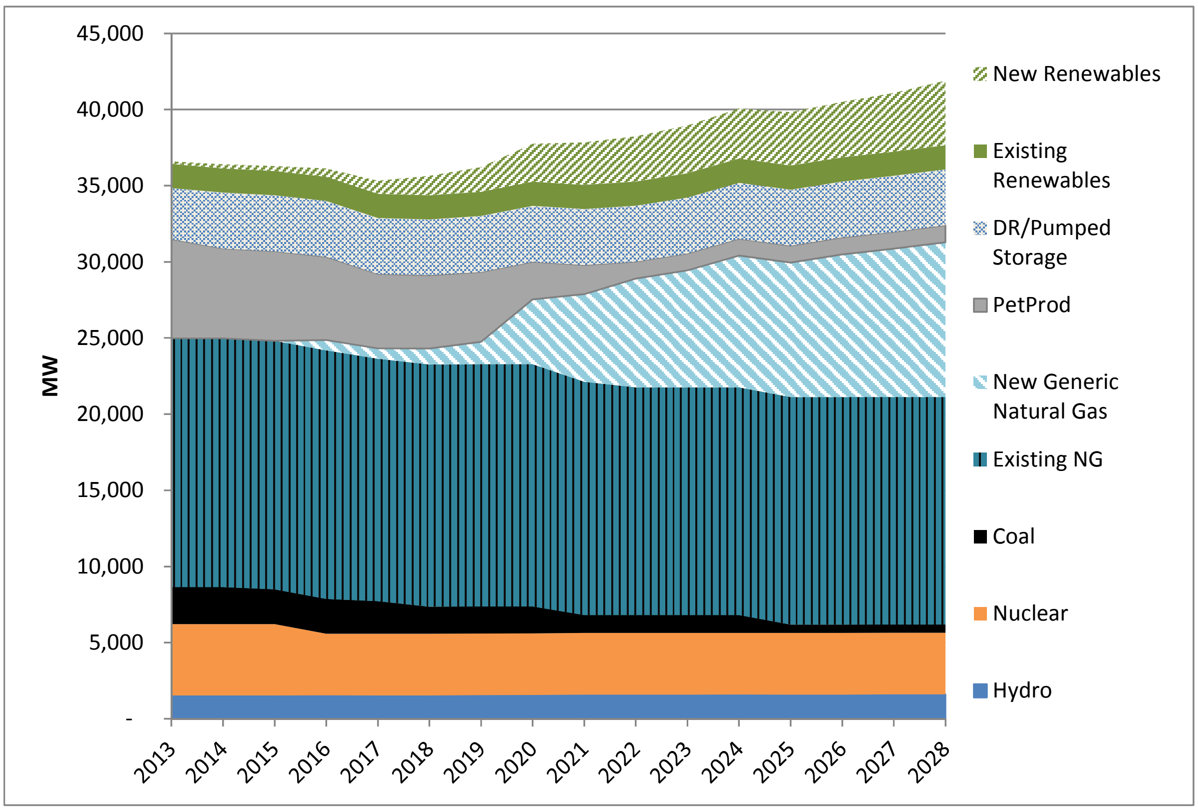
[5] The benefit arises from two sources: the reduction of load at the system annual peak hour, and the capacity credit attributed to energy-efficiency programs (called "passive demand response" in the ISO-NE forward capacity mechanism), measured as the average load reduction of the on-peak hours in high-load months or the hours with loads over 95 percent of forecast peak.

electric capacity price is first increased by the reserve margin requirements forecasted for the year, then increased by eight percent to reflect ISO-New England's (ISO-NE's) estimate of distribution losses.

The major drivers of the avoided wholesale capacity price are system peak demand, capacity resources, and the detailed ISO-NE rules governing the auction. ISO-NE rules specify which resources are allowed to bid in the auction, how the resources' capacity values are computed, and what range of prices each resource category is allowed to bid. The load-resource balance is determined by load growth, retirements of existing capacity, addition of new capacity from resources to comply with RPS requirements, imports, exports, and new, non-RPS capacity additions.

As indicated in Exhibit 1-3, AESC 2013 projects that new capacity, other than RPS-related renewable resources, will have to be added starting in 2020. This change, which results largely from the projected retirements of existing fossil units, is somewhat reduced by the lower CELT load forecast.

Exhibit 1-3. AESC 2013 Capacity Requirements vs. Resources (Base Case), MW



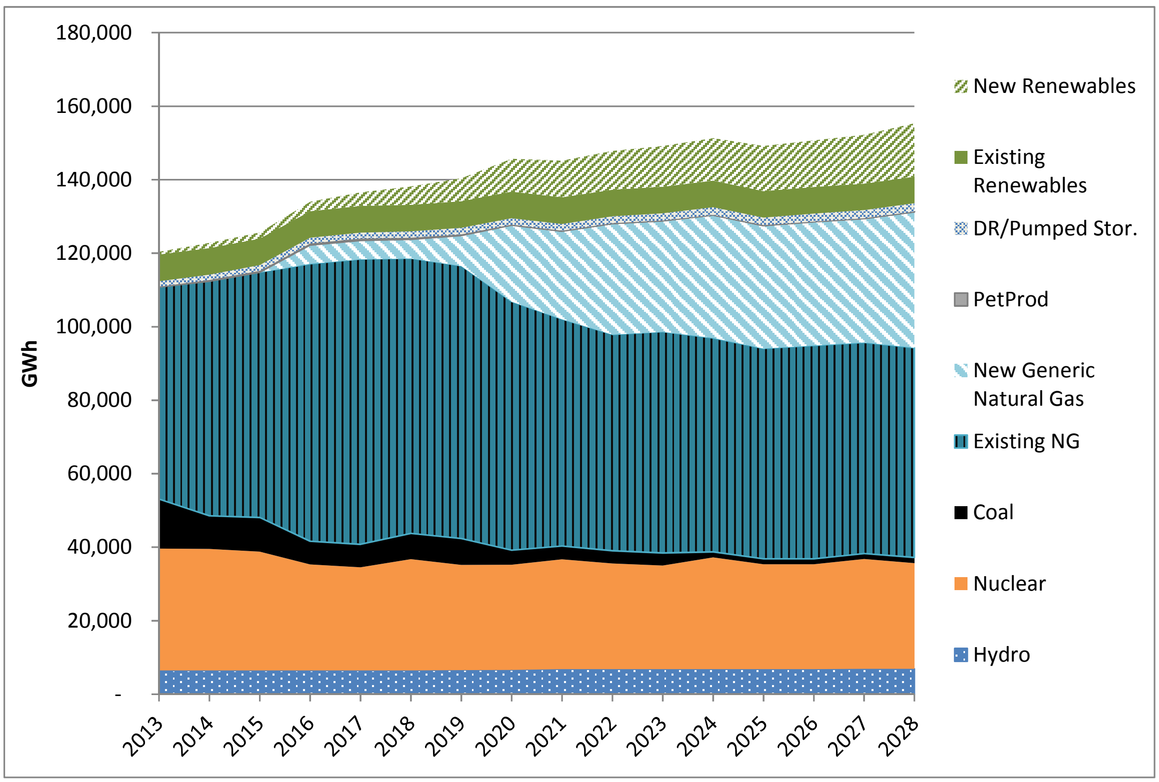
The AESC 2013 Base Case estimate of levelized capacity prices is approximately 61 percent higher than the estimate from AESC 2011. The 15-year levelized projection of capacity prices from AESC 2011 was $49.67/kW-year in each pricing zone (in 2013 dollars), while the corresponding levelized value from AESC 2013 is $79.89/kW-year. The higher values are primarily due to the projected cost of new capacity additions to replace the existing capacity that AESC 2013 projects will retire due to the cost of complying with tighter environmental requirements and to changes in the FCM.

The actual amount of wholesale avoided electric capacity costs that a reduction in demand will avoid depends on the approach that the program administrator (PA) responsible for that reduction takes towards bidding it into the FCM. PAs will achieve the maximum avoided cost by bidding the entire anticipated kW reduction from measures in a given year into the FCA for that power year. However, PAs have to submit those bids when the FCA is held, which is approximately three years in advance of the applicable power year. Some expected load reductions may not be bid into the first FCA for which the reduction would be effective, due to uncertainty about future program funding and energy savings.[6]

1.2.2 Avoided Electric Energy Costs

Avoided electric energy costs at the customer meter consist of the wholesale electric energy price plus the REC cost plus a wholesale risk premium. Exhibit 1-4 presents the projected mix of generation underlying our projection of electric energy prices.

Exhibit 1-4. New England Generation Mix from AESC 2013 (GWh)



[6] PAs also avoid capacity costs from kW reductions that are not bid into FCAs, since those kW reductions lower actual demand, and ISO-NE eventually reflects those lower demands when setting the maximum demand to be met in future FCAs and the allocation of capacity requirements to load. However, the total amount of avoided capacity costs is lower because of the time lag—up to four years—between the year in which the kW reduction first causes a lower actual peak demand and the year in which ISO-NE translates that kW reduction into a reduction in the total demand for which capacity has to be acquired in an FCA. Since the load reduction in one year will affect the allocation of capacity responsibility in the next year, the PA's customers experience a one-year delay in realized savings that are not bid into the auctions at all.

Exhibit 1-5 presents the AESC 2013 electric energy prices for the West Central Massachusetts zone for all hours compared to energy prices from AESC 2011. This WCMA price also represents the ISO-NE Control Area price, which is within this zone. On a levelized basis, the AESC 2013 annual all-hours price for the period 2014 through 2028 is $59.86/MWh, compared to the equivalent value of $64.68/MWh from AESC 2011, representing a reduction of 7.4 percent. The lower estimate for AESC 2013 is primarily due to a lower estimate of wholesale natural gas prices in New England, and delayed introduction of federal CO_2 prices.

Exhibit 1-5. AESC 2013 vs. AESC 2011 – All-Hours Prices for West-Central Massachusetts (2013$/kWh)

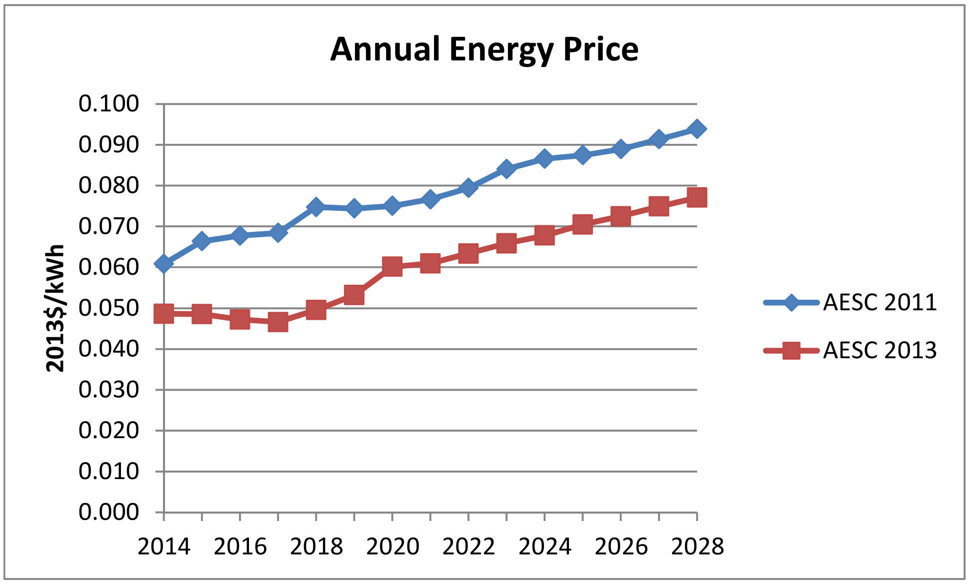


Exhibit 1-6 presents the resulting 15-year levelized avoided electric energy costs for AESC 2013 by zone, after adding in the relevant REC costs and wholesale risk premiums. This exhibit also provides the corresponding estimates from AESC 2011 by zone.

Exhibit 1-6. Avoided Electric Energy Costs, AESC 2013 vs. AESC 2011 (15-year levelized, 2013$)

		Winter On Peak Energy	Winter Off-Peak Energy	Summer On Peak Energy	Summer Off-Peak Energy	Annual Weighted Average
	AESC 2013	**$/kWh**	**$/kWh**	**$/kWh**	**$/kWh**	**$/kWh**
1	Maine (ME)	0.064	0.058	0.062	0.052	0.059
2	Vermont (VT)	0.072	0.063	0.071	0.057	0.066
3	New Hampshire (NH)	0.073	0.066	0.071	0.060	0.068
4	Connecticut (statewide)	0.076	0.067	0.075	0.062	0.070
5	Massachusetts (statewide)	0.076	0.068	0.075	0.062	0.071
6	Rhode Island (RI)	0.064	0.058	0.062	0.051	0.059
7	SEMA	0.074	0.067	0.074	0.061	0.069
8	Central & Western Massachusetts (WCMA)	0.077	0.069	0.076	0.063	0.072
9	NEMA	0.075	0.068	0.075	0.062	0.070
10	Rest of Massachusetts (non-NEMA)	0.076	0.068	0.075	0.062	0.071
11	Norwalk / Stamford (NS)	0.077	0.068	0.076	0.062	0.071
12	Southwest Connecticut (SWCT) including Norwalk/Stamford	0.077	0.068	0.076	0.062	0.071
13	Southwest Connecticut (SWCT) excluding Norwalk/Stamford	0.077	0.068	0.076	0.062	0.071
14	Rest of Connecticut (non-SWCT)	0.075	0.067	0.075	0.061	0.070
	AESC 2011	**$/kWh**	**$/kWh**	**$/kWh**	**$/kWh**	**$/kWh**
1	Maine (ME)	0.069	0.061	0.074	0.060	0.066
2	Vermont (VT)	0.076	0.066	0.090	0.065	0.073
3	New Hampshire (NH)	0.075	0.066	0.081	0.064	0.071
4	Connecticut (statewide)	0.077	0.067	0.092	0.066	0.074
5	Massachusetts (statewide)	0.079	0.070	0.093	0.068	0.076
6	Rhode Island (RI)	0.067	0.057	0.079	0.057	0.064
7	SEMA	0.079	0.070	0.092	0.068	0.076
8	Central & Western Massachusetts (WCMA)	0.080	0.070	0.094	0.069	0.077
9	NEMA	0.079	0.069	0.093	0.067	0.075
10	Rest of Massachusetts (non-NEMA)	0.079	0.070	0.094	0.068	0.076
11	Norwalk / Stamford (NS)	0.078	0.068	0.093	0.067	0.075
12	Southwest Connecticut (SWCT) including Norwalk/Stamford	0.078	0.068	0.093	0.067	0.075
13	Southwest Connecticut (SWCT) excluding Norwalk/Stamford	0.078	0.068	0.092	0.067	0.075
14	Rest of Connecticut (non-SWCT)	0.076	0.067	0.091	0.065	0.073

Exhibit 1-7 shows the change between AESC 2013 and AESC 2011 values, expressed as a percentage and in terms of 2013$ per kWh.

Exhibit 1-7. Avoided Electric Energy Costs for 2013: Change from AESC 2011 (expressed in 2013$/kWh and percentage values)

		Winter On Peak Energy	Winter Off-Peak Energy	Summer On Peak Energy	Summer Off-Peak Energy	Annual Weighted Average
	Change from AESC 2011	**$/kWh**	**$/kWh**	**$/kWh**	**$/kWh**	**$/kWh**
1	Maine (ME)	(0.006)	(0.004)	(0.012)	(0.008)	(0.006)
2	Vermont (VT)	(0.004)	(0.003)	(0.019)	(0.007)	(0.007)
3	New Hampshire (NH)	(0.002)	0.000	(0.010)	(0.004)	(0.003)
4	Connecticut (statewide)	(0.001)	0.000	(0.016)	(0.004)	(0.004)
5	Massachusetts (statewide)	(0.003)	(0.002)	(0.018)	(0.006)	(0.006)
6	Rhode Island (RI)	(0.003)	0.001	(0.017)	(0.006)	(0.004)
7	SEMA	(0.004)	(0.003)	(0.019)	(0.007)	(0.007)
8	Central & Western Massachusetts (WCMA)	(0.003)	(0.001)	(0.017)	(0.006)	(0.005)
9	Boston (NEMA)	(0.003)	(0.001)	(0.018)	(0.006)	(0.005)
10	Rest of Massachusetts (non-NEMA)	(0.003)	(0.002)	(0.018)	(0.007)	(0.006)
11	Norwalk / Stamford (NS)	(0.001)	0.000	(0.016)	(0.004)	(0.004)
12	Southwest Connecticut (SWCT) including Norwalk/Stamford	(0.001)	0.000	(0.016)	(0.004)	(0.004)
13	Southwest Connecticut (SWCT) excluding Norwalk/Stamford	(0.001)	0.000	(0.016)	(0.004)	(0.004)
14	Rest of Connecticut (non-SWCT)	(0.001)	0.000	(0.016)	(0.004)	(0.004)
	% Change from AESC 2011	**%**	**%**	**%**	**%**	**%**
1	Maine (ME)	-8.2%	-5.9%	-16.2%	-12.8%	-9.6%
2	Vermont (VT)	-5.9%	-4.4%	-21.4%	-11.6%	-9.4%
3	New Hampshire (NH)	-2.7%	0.5%	-11.8%	-6.3%	-3.9%
4	Connecticut (statewide)	-1.5%	0.3%	-17.7%	-6.6%	-4.9%
5	Massachusetts (statewide)	-4.2%	-2.5%	-19.4%	-9.5%	-7.4%
6	Rhode Island (RI)	-4.3%	1.9%	-21.4%	-9.8%	-6.6%
7	SEMA	-5.3%	-3.9%	-20.4%	-10.9%	-8.7%
8	Central & Western Massachusetts (WCMA)	-3.3%	-1.6%	-18.4%	-8.2%	-6.5%
9	Boston (NEMA)	-3.9%	-1.9%	-19.3%	-8.6%	-7.0%
10	Rest of Massachusetts (non-NEMA)	-4.2%	-2.5%	-19.4%	-9.6%	-7.5%
11	Norwalk / Stamford (NS)	-1.6%	0.3%	-17.7%	-6.7%	-4.9%
12	Southwest Connecticut (SWCT) including Norwalk/Stamford	-1.6%	0.3%	-17.7%	-6.7%	-4.9%
13	Southwest Connecticut (SWCT) excluding Norwalk/Stamford	-1.6%	0.3%	-17.7%	-6.7%	-4.9%
14	Rest of Connecticut (non-SWCT)	-1.5%	0.4%	-17.7%	-6.6%	-4.9%

1.2.3 Embedded and Non-Embedded Environmental Costs

Some environmental costs associated with electricity use are “embedded” in our estimates of avoided energy costs, and others are not. The costs that are embedded are incorporated in the Market Analytics model used to generate wholesale energy prices for AESC 2013.

For AESC 2013, we anticipate that the “non-embedded carbon costs” will continue to be the dominant non-embedded environmental cost associated with marginal electricity generation in New England.

Based on our review of the most current research on marginal abatement and carbon capture and sequestration (“CCS”) costs, and our experience and judgment on the topic, we believe that it is reasonable to use a CO_2 marginal abatement cost of $100 per short ton in 2013 dollars. The AESC 2013 CO_2 marginal abatement cost of $100/ton is 20 percent higher than the AESC 2011 value of $83/ton (2013 dollars). This change results from three major factors:

1) AESC 2013 incorporates new studies with different estimates than two years ago.

2) AESC 2011 used values from multiple vintages of the same studies, whereas AESC 2013 only uses values from the most up-to-date versions of studies.

3) AESC 2013 incorporates an analysis of CCS technologies that are expected to be the marginal technology.

Massachusetts Global Warming Solutions Act (GWSA)

The AESC 2013 scope of work required the Synapse project team to determine if there was some component of compliance with state-specific climate plans that would directly impact generators and that the project team could quantify and credibly support. GWSA was the only state-specific climate plan to be reviewed. The key findings from that review are as follows:

- The current *Massachusetts Greenhouse Gas Emissions Inventory* method does not provide an accurate accounting of electricity sector emission reductions for GWSA compliance. Synapse presents an example alternate inventory method that would provide an accurate accounting.

- The Massachusetts Clean Energy Climate Plan (CECP) assumes the electricity sector will achieve significant reductions in emissions by 2020 under its Business as Usual Forecast. The CECP then identifies six policy measures the electricity sector could use to comply with GWSA targets in 2020 and beyond, as well the quantity of reductions and cost per ton of reduction from each. The AESC 2013 Base Case reflects the compliance measures that are currently enforced for the Massachusetts electricity sector except for energy efficiency, which are RPS, RGGI, and EPA Power Plant Rules. The remaining compliance measures are all cost-effective energy efficiency, the Clean Energy Import Strategy (CEI) and a Clean Energy Performance Standard (CEPS).

- The Massachusetts electricity sector will require reductions from a CEPS or other additional component in order to comply with the GWSA at some point from 2020 onward. However, there are unresolved policy questions regarding the CECP targets for the electricity sector beyond 2020 and the inventory method for accounting for reductions in that sector. As a result, the project team could not determine the size of reductions that would be required in the electricity sector each year and therefore could not quantify and credibly support an estimate of the cost of the marginal resource required to achieve those reductions.

- In the absence of detailed modeling, the project team identified additional renewable generation, incremental to RPS quantities, as the marginal resource for electric-sector compliance with the GWSA. If the quantity of additional renewable generation required for GWSA compliance in a given year is comparable to the AESC 2013 projected quantity of renewable generation added to meet RPS requirements in that year, it is reasonable to expect the cost of that additional renewable generation in that year to be comparable to the REC prices estimated for Massachusetts for that year (e.g., $18.40/MWh in 2020, per Exhibit 6-30) plus the AESC 2013 estimate of electric energy costs for Massachusetts in that year. If the quantity of additional renewables required for GWSA compliance is significantly larger than those added to meet RPS requirements, the cost of the marginal resource required to achieve those larger reductions would have to be determined through new modeling.

1.3 Avoided Natural Gas Costs

Initiatives that enable retail customers to reduce their natural gas use also have a number of benefits. The benefits from those reductions include some or all of the following avoided costs:

- Avoided gas supply costs due to a reduction in the annual quantity of gas that has to be produced;
- Avoided pipeline costs due to a reduction in the quantity of gas that has to be delivered; and
- Avoided local distribution infrastructure costs due to delays in the timing and/or reductions in the size of new projects that have to be built resulting from the reduction in gas that has to be delivered.

Detailed results of our analysis are presented in Appendix C, Avoided Natural Gas Cost Results. A summary of results is presented below.

1.3.1 Wholesale Natural Gas Supply Costs

The forecast of wholesale natural gas commodity prices in New England begins with a forecast of the price of gas at the Henry Hub, Louisiana. Henry Hub is used because: 1) it is a major trading point whose prices serve as a reference point against which prices at other locations are indexed, 2) most comparative forecasts provide prices for this location, and 3) the Gulf Coast is a major source of U.S. supply.

The AESC 2013 Base Case estimate of Henry Hub prices is $5.37/MMBtu (2013$) on a 15-year levelized basis for the period 2014 to 2028. This is approximately 17 percent lower than the 15-year levelized price from the AESC 2011 Base Case for the same time period.[7]

The AESC 2013 Base Case Henry Hub estimate is composed of NYMEX futures prices (as of March 15, 2013) through March 2016, and on a forecast derived from the Reference Case forecast from the Energy Information Administration's ("EIA's") Annual Energy Outlook ("AEO") 2012 from April 2016 through 2035. The near-term forecast is based on NYMEX futures because they are an indication of the market's estimate of prices for the future months for which trading volumes are significant.[8] For the remaining period, the forecast is based on an AEO long-term forecast because a long-term forecast captures the

[7] The 15-year levelized (2014-2028) AESC 2011 Base Case in 2013$ is $6.47/ MMBtu.

[8] The NYMEX futures used to prepare prior AESC studies have proven to be higher than actual Henry Hub prices, indicating that price expectations of the gas industry are not always accurate.

market fundamentals that will drive those prices (i.e., demand, supply, competition between fuels) and because the inputs and model algorithms underlying AEO forecasts are public. The difficulty the project team faced was to select an appropriate AEO forecast as a starting point and then determine what, if any, adjustments to make to that AEO forecast.

The Synapse project team chose the AEO 2012 Reference Case as its starting point, and made three adjustments to that forecast, based primarily upon its review of physical and economic data on the country's major shale gas plays. This review included an assessment of the time it would take before production from dry gas plays would begin setting the market price, i.e., the point in time when growth in gas production associated with oil plays and gas plays rich in natural gas liquids ("NGL") would no longer be sufficient to offset the decline in production from dry gas plays and the growth in natural gas demand. The project team also reviewed the potential for exports in the form of liquefied natural gas ("LNG") to increase Henry Hub prices above those forecast in the AEO 2012 Reference Case. Each of those assessments is subject to some degree of uncertainty, and different analysts have different views regarding those trends. The Synapse project team did consider the AEO 2013 Reference Case forecast but found it to be well below forward market prices in the near term, well below estimates of the marginal cost of production from the marginal dry gas plays needed to balance demand and supply in 2020 and beyond, and below a range of public forecasts of other entities presented in AEO 2012.

The Synapse project team derived its Base Case forecast for 2016 onward from the AEO 2012 Reference Case by making the following three adjustments:

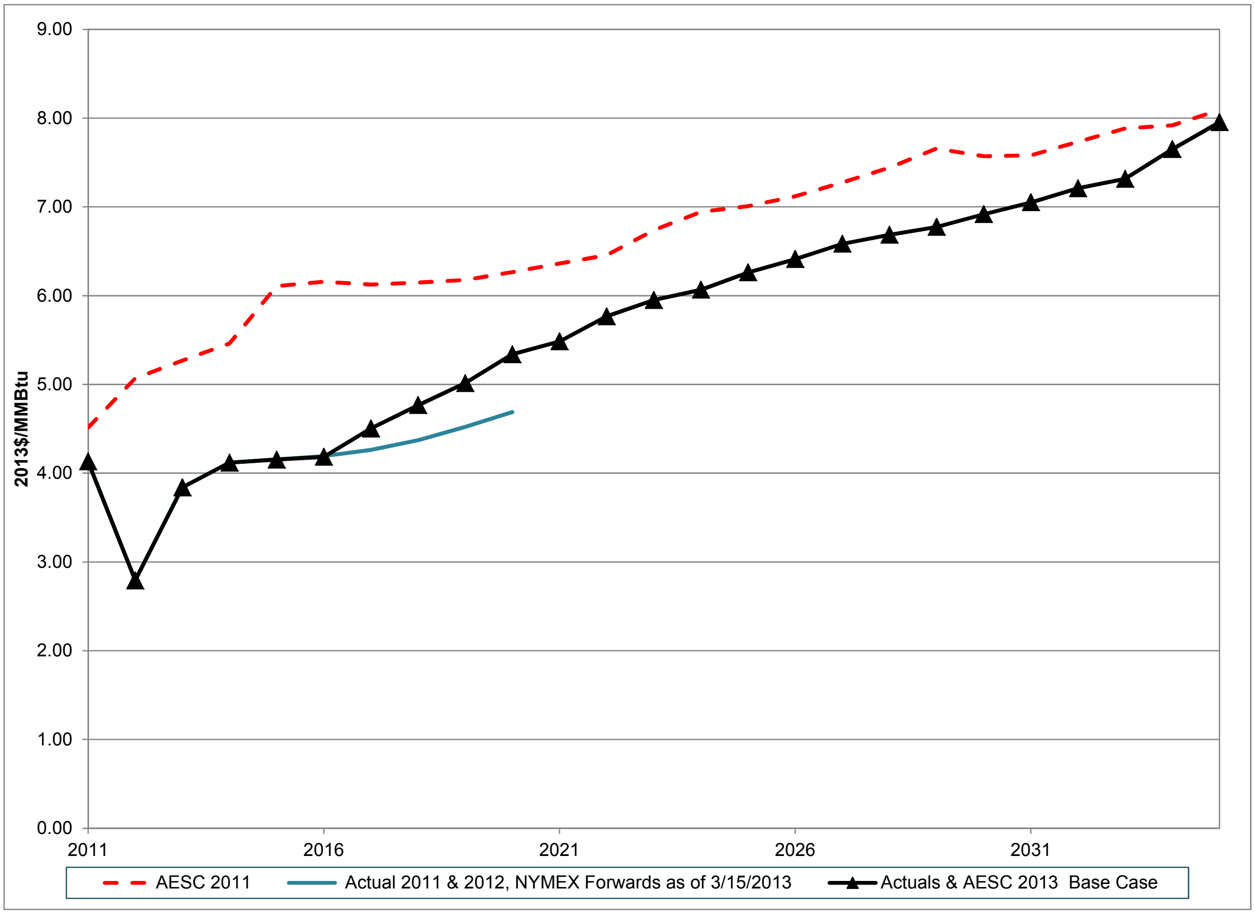
- **EIA Henry Hub methodology downward adjustment:** The EIA has made a major change in the methodology it uses to calculate Henry Hub prices. We incorporate that change in our estimate, which represents a downward adjustment of approximately $0.50 per MMBtu (2013$) over the study horizon.

- **Marginal well economics upward adjustment:** AESC 2013 makes an upward adjustment of $0.33 per MMBtu that phases in beginning in 2016 and reaches full value in 2020. We make this adjustment based on our analysis of the economics of marginal gas plays in 2020.

- **Fracturing best practices upward adjustment:** We make an upward adjustment starting in 2017 that reaches $0.54 per MMBtu by 2021 based upon our assessment that producers are likely to incur costs to reduce the adverse impacts of fracturing through some combination of industry self-enforcement of best practices and further regulations on fracturing.

The following exhibit illustrates the difference between the AESC 2013 and AESC 2011 Henry Hub prices.

Exhibit 1-8. Actual and Projected Henry Hub Prices (2013$/MMBtu)



1.3.2 Avoided Wholesale Gas Costs in New England

AESC 2013 addresses several important developments that have occurred since the release of AESC 2011, and which have changed the historical relationship between wholesale natural gas prices in New England and the Henry Hub, as described in section 2.3. These developments include the following:

- Rapid growth in Marcellus shale gas production in the Appalachian[9] producing area has reduced gas prices in the Northeast relative to Henry Hub. This trend is expected to continue as Appalachian gas production expands.
- Lower gas imports from Canada and fewer LNG shipments to New England import terminals have reduced east-to-west gas flows into the New England market.
- The reduction in east-side gas receipts has caused the pipelines delivering gas into New England from the west to operate at or near capacity much more frequently.

[9] The principal gas-producing states in the Appalachian area are Pennsylvania and West Virginia.

These gas transmission constraints have caused New England gas prices to diverge from prices in other Northeast markets. Significant expansion of natural gas pipeline capacity into New England is not expected to occur before 2016.

The wholesale price forecast methodology for AESC 2013 accounts for the above changes affecting the relationship between wholesale prices in New England and Henry Hub prices in three major ways. First, supply from the Appalachian area is expected to replace supply from the Gulf Coast as the primary driver of Northeast-region gas prices. Second, Appalachian prices are expected to decline relative to Henry Hub prices. Third, the expected constraints on gas transmission capacity into New England through at least 2016 are expected to cause New England prices to diverge from prices elsewhere in the Northeast.

1.3.3 Avoided Natural Gas Costs by End Use

The avoided cost of gas at a retail customer's meter has two components: (1) the avoided cost of gas delivered to the LDC; and (2) the avoided cost of delivering gas on the LDC system (the "retail margin"). AESC 2013 presents these avoided gas costs without an avoided retail margin and with an avoided retail margin, as the ability to avoid the retail margin varies by distribution company.

The AESC 2013 avoided cost estimates are summarized in Exhibit 1-9 and Exhibit 1-10. These exhibits also compare the AESC 2013 results to the corresponding values from AESC 2011.

Exhibit 1-9. Comparison of Avoided Gas Costs by End Use Assuming No Avoidable Retail Margin, AESC 2013 vs. AESC 2011 (15 year-levelized, 2013$/MMBtu except where indicated as 2011$/MMBtu)

	RESIDENTIAL				COMMERCIAL & INDUSTRIAL			ALL RETAIL END USES
	Non Heating	Hot Water	Heating	All	Non Heating	Heating	All	
Southern New England (a)								
AESC 2011 (2011$/MMBtu)	7.04	7.04	7.81	7.57	7.04	7.81	7.57	7.57
AESC 2011 (b)	7.27	7.27	8.06	7.83	7.27	8.06	7.83	7.83
AESC 2013	6.08	6.57	6.73	6.60	6.26	6.58	6.44	6.53
2011 to 2013 change	-16.41%	-9.61%	-16.54%	-15.66%	-13.88%	-18.46%	-17.74%	-16.61%
Northern New England (a)								
AESC 2011 (2011$/MMBtu)	6.94	6.94	7.58	7.39	6.94	7.58	7.39	7.39
AESC 2011 (b)	7.17	7.17	7.83	7.63	7.17	7.83	7.63	7.63
AESC 2013	6.03	7.53	8.02	7.62	6.58	7.54	7.12	7.39
2011 to 2013 change	-15.98%	5.01%	2.41%	-0.15%	-8.18%	-3.67%	-6.68%	-3.17%
Vermont								
AESC 2011 (2011$/MMBtu)	7.06	7.06	8.63	8.16	7.06	8.63	8.16	8.16
AESC 2011 (b)	7.29	7.29	8.91	8.43	7.29	8.91	8.43	8.43
AESC 2013	6.32	6.91	7.11	6.95	6.54	6.92	6.75	6.86
2011 to 2013 change	-13.39%	-5.22%	-20.28%	-17.54%	-10.36%	-22.41%	-19.91%	-18.63%

(a) Massachusetts was included with Northern New England in AESC 2011, but is included with Southern New England in AESC 2013.
(b) Factor to convert 2011$ to 2013$ 1.0331

Note: AESC 2011 levelized costs for 15 years 2012 - 2026 at a discount rate of 2.465%.
AESC 2013 levelized costs for 15 years 2014 - 2028 at a discount rate of 1.36%.

Exhibit 1-10. Comparison of Avoided Gas Costs by End Use Assuming Some Avoidable Retail Margin, AESC 2013 vs. AESC 2011 (15-year levelized, 2013$/MMBtu except where indicated as 2011$/MMBtu)

	RESIDENTIAL				COMMERCIAL & INDUSTRIAL			ALL RETAIL END USES
	Non Heating	Hot Water	Heating	All	Non Heating	Heating	All	
Southern New England (a)								
AESC 2011 (2011$/MMBtu)	7.64	7.64	9.39	9.11	7.58	8.82	8.44	8.75
AESC 2011 (b)	7.89	7.89	9.70	9.41	7.83	9.11	8.72	9.04
AESC 2013	6.67	7.17	8.30	8.12	6.88	7.74	7.44	7.80
2011 to 2013 change	-15.43%	-9.17%	-14.43%	-13.70%	-12.06%	-15.02%	-14.74%	-13.77%
Northern New England (a)								
AESC 2011 (2011$/MMBtu)	7.47	7.47	8.96	8.73	7.59	8.79	8.43	8.58
AESC 2011 (b)	7.71	7.71	9.26	9.02	7.84	9.08	8.71	8.86
AESC 2013	6.53	8.04	9.35	8.91	7.04	7.43	7.17	7.31
2011 to 2013 change	-15.34%	4.17%	0.97%	-1.19%	-10.21%	-18.21%	-17.67%	-17.56%
Vermont								
AESC 2011 (2011$/MMBtu)	7.54	7.54	9.88	9.37	7.30	9.08	8.54	8.86
AESC 2011 (b)	7.79	7.79	10.21	9.68	7.54	9.38	8.82	9.15
AESC 2013	6.94	7.53	8.74	8.54	6.68	7.19	6.98	7.61
2011 to 2013 change	-10.88%	-3.22%	-14.37%	-11.85%	-11.37%	-23.33%	-20.86%	-16.83%

(a) Massachusetts was included with Northern New England in AESC 2011, but is included with Southern New England in AESC 2013.
(b) Factor to convert 2011$ to 2013$ 1.0331

Note: AESC 2011 levelized costs for 15 years 2012 - 2026 at a discount rate of 2.465%.
AESC 2013 levelized costs for 15 years 2014 - 2028 at a discount rate of 1.36%.

The avoided natural gas cost estimates for AESC 2013 are generally lower than the AESC 2011 estimates. The main reason for this is the lower projected gas price at Henry Hub. The AESC 2013 avoided natural gas cost estimates are also lower than the AESC 2011 estimates because LDCs in Southern New England and Northern New England are expected to purchase more gas in the Appalachian region, at market prices that are projected to be below the Henry Hub benchmark price.

The difference between avoidable natural gas costs for heating and non-heating loads in the Northern New England region is greater than for AESC 2011. This is mainly the result of the change in region definitions. Since Massachusetts is now included in Southern New England, the Northern New England region is composed solely of Maine and New Hampshire. These markets have less access to the Gulf Coast and Appalachian supply areas, and are more dependent on higher-cost supply, transportation, and storage services from Canada. The cost of delivering this gas to Northern New England is greater because of higher transportation costs on TransCanada PipeLines (“TCPL”) and the additional cost of pipeline transportation service from the Canadian border to the LDC citygate. Because Northern New England (Maine and New Hampshire) takes a lot of gas supply from Canada, and the Canadian transportation services have high fixed costs (and little or no variable cost), the cost of supplying low-load-factor customers is relatively high, especially after 2018 when existing long-term contracts need to be extended or replaced.

Another change from AESC 2011 to AESC 2013 is that the load shape used for residential hot water customers for AESC 2013 includes a temperature-sensitive component, while the load shape used for AESC 2011 did not.

1.4 Demand Reduction Induced Price Effects (DRIPE)

Demand reduction induced price effects refer to the changes in prices in the wholesale markets for capacity and energy, relative to the prices estimated in the Base Case, resulting from the reduction in quantities of capacity and energy required from those markets due to the impact of efficiency and/or demand response programs. Thus, DRIPE is a measure of the value of efficiency in terms of the changes in wholesale prices seen by all retail customers in a given period.

DRIPE effects are very small when expressed in terms of an impact on market prices, i.e., reductions of a fraction of a percent. However, the DRIPE impacts are significant when expressed in absolute dollar terms. Very small impacts on market prices, when applied to all energy and capacity being purchased in the market, translate into large absolute dollar amounts. AESC 2005, 2007, 2009, and 2011 each provided estimates of electricity DRIPE (energy and capacity). AESC 2013 provides an estimate of those two components of electricity DRIPE and introduces a new component which estimates the effect of reduced electric energy usage on gas supply prices paid by retail gas customers. This component is referred to as electricity cross-fuel DRIPE. In addition, AESC 2013 also introduces estimates of natural gas DRIPE. The following exhibit provides a high level overview of these estimates of electricity and natural gas DRIPE.

Exhibit 1-11. DRIPE Overview

Reduction in Retail Load	Affected Cost Categories	Affected Cost Component
Natural Gas	Own-price (retail gas prices)	Gas Supply
	Cross-fuel (electric energy prices)	Gas Supply
		Basis to New England
Electricity	Own-price (electric prices)	Electric Energy
		Electric Capacity
	Cross-fuel (natural gas supply prices)	Gas Supply

Our estimates of natural gas "own" DRIPE, natural gas cross-fuel DRIPE and electricity cross-fuel DRIPE begin with a decomposition of the wholesale cost of gas acquired to supply end-use gas consumers (the customers of LDCs) and gas-fired power plants into a gas supply component and a gas transportation component. The gas supply component reflects the cost of acquiring gas supply in producing regions, which is determined by demand and supply conditions in the North American market. The gas transportation component reflects the cost of transporting the gas supply from the point of production to New England.

A reduction in the quantity of gas used in New England, whether by retail gas customers or by gas-fired power plants, will reduce the demand for gas in producing regions and therefore reduce the market price for gas supply in those regions. In contrast, a reduction in the quantity of gas used in New England has a different impact on the transportation cost component of gas delivered to retail customers' supply than on the transportation cost component of gas delivered to gas-fired power plants. A reduction in gas use does not generally reduce retail gas customer transportation costs, because LDCs pay regulated fixed rates to hold pipeline capacity between the point of production and New England. In contrast, a reduction in gas use by retail gas customers does tend to reduce the transportation cost component of gas costs to electric generators, because gas-fired power plants tend to purchase their gas delivered to New England, and the transportation component of that delivered cost, or basis, is determined by demand and supply in the New England wholesale market.

1.4.1 Natural Gas DRIPE

Natural Gas "Own" DRIPE

A reduction in the quantity of gas used by retail gas customers reduces the demand for gas in producing regions and therefore reduces the market price for that gas supply.

Exhibit 1-12 presents the natural gas supply DRIPE for each state and the annual benefit for New England gas consumers based on our analysis of AEO 2012 demand scenarios.

Exhibit 1-12. State Supply DRIPE Benefit (2013$ per MMBtu for installation in year 2014)

	CT	MA	ME	NH	RI	VT	New England
2014	$0.039	$0.085	$0.012	$0.007	$0.012	$0.003	$0.157
2015	$0.054	$0.119	$0.016	$0.010	$0.016	$0.004	$0.220
2016+	$0.077	$0.171	$0.023	$0.015	$0.024	$0.006	$0.315

Notes:
Supply DRIPE benefit stream extends for gas efficiency measure life
Based on Exhibit 7-19
LDC gas supply hedge estimated at 50% Year 1, 30% Year 2, 0% Year 3

As discussed in detail in Chapter 7, we do not expect to see any significant decay in these natural gas supply DRIPE values. For illustration purposes, a 15-year natural gas program would have the following levelized natural gas supply benefits:

Exhibit 1-13. 15-year Levelized Natural Gas Supply DRIPE by State (2013$/MMBtu)

	CT	MA	ME	NH	RI	VT	New England
15-year levelized	$0.073	$0.161	$0.022	$0.014	$0.022	$0.005	$0.296

Notes: 15-year levelized (2014-2028) at 1.36% discount rate

Natural Gas Cross-Fuel DRIPE

A reduction in gas use by retail gas customers reduces the gas supply and gas transportation components of the wholesale gas costs incurred by electric generators, and hence the bid prices submitted by the generators into the wholesale electricity market and the resulting market prices of electric energy.

Exhibit 1-14 summarizes the own-state and ISO-wide gas cross-fuel DRIPE values for 2014 gas efficiency. These values vary based on electric usage and are benefits accrued to gas programs for reducing natural gas prices for electric generation as a result of natural gas efficiency. For illustrative purposes, we have included the 15-year levelized values in the exhibit.

Exhibit 1-14. 15-year Levelized Gas-Cross DRIPE for Heating Load 2014 Installation ($/MMBtu)

	State Winter Heating DRIPE						
	CT	MA	ME	NH	RI	VT	ISO
2014	$3.04	$5.31	$1.14	$1.13	$0.73	$0.20	$11.55
2015	$8.92	$15.58	$3.34	$3.29	$2.11	$0.75	$33.99
2016	$8.94	$15.60	$3.36	$3.30	$2.12	$0.79	$34.11
2017	$3.49	$6.13	$1.31	$1.29	$0.83	$0.31	$13.36
2018	$2.41	$4.24	$0.90	$0.89	$0.57	$0.22	$9.24
2019	$1.19	$2.10	$0.45	$0.44	$0.28	$0.11	$4.56
2020	$0.76	$1.34	$0.28	$0.28	$0.18	$0.07	$2.92
2021	$0.57	$1.01	$0.21	$0.21	$0.14	$0.05	$2.19
2022	$0.38	$0.67	$0.14	$0.14	$0.09	$0.04	$1.46
Levelized	**$2.11**	**$3.69**	**$0.79**	**$0.78**	**$0.50**	**$0.18**	**$8.06**

1.4.2 Electricity DRIPE

Capacity DRIPE

On a 15-year levelized basis, the AESC 2013 estimates of capacity DRIPE are approximately 45.3 percent lower than those from AESC 2011.[10] This decrease is primarily due to: 1) the extension of the floor price through 2016; 2) the projection of generic new generation in 2020; and 3) a change in the assumed duration of DRIPE. AESC 2013 assumes the phase-out, or dissipation, of capacity DRIPE will last up to 8 years, versus 11 years assumed in AESC 2011. The shorter projected dissipation of capacity DRIPE is based on an analysis of the various factors that tend to offset the reduction in capacity prices. Those factors include timing of new capacity additions, timing of retirements of existing capacity, elasticity of customer demand, and the portion of capacity that LSEs acquire from the FCM.

[10] AESC 2011 values for 2012 installations levelized from 2012-2026.

Energy DRIPE

The AESC 2013 estimates of intrastate energy DRIPE are approximately 19 percent lower on a levelized annual load-weighted basis than those from AESC 2011. This is primarily due to our change in assumptions regarding: 1) the dissipation of energy DRIPE effects, which is shorter than our AESC 2011 projection; and 2) lower annual wholesale energy prices than AESC 2011.

Electric Cross-Fuel DRIPE

A reduction in the quantity of gas used for electric generation reduces the demand for gas in producing regions and therefore reduces the market price for gas supply purchased by LDCs for retail gas customers.

The electric cross-DRIPE effect of electric energy efficiency on end-use gas prices is shown in Exhibit 1-15 for each state and the region.

Exhibit 1-15. Annual Gas Price Benefit per MWh Saved

	Coefficient	CT	MA	ME	NH	RI	VT	New England
Gas End Use (quads)		0.1155	0.2559	0.0347	0.0222	0.0353	0.0085	0.4722
Electric-Gas DRIPE $/MWh saved	5.103	$0.589	$1.306	$0.177	$0.113	$0.180	$0.043	$2.410

These values would continue for the life of the measure, but would change based on state natural gas usage.

The effect of electric energy efficiency on electric prices through gas supply prices is shown below in Exhibit 1-16, which adjusts by the cross-fuel DRIPE decay factors to estimate the electric-gas-electric DRIPE effect for 2014 installations.

Exhibit 1-16. Electric Cross-Fuel DRIPE ($/MWh for 2014 Installation)

	CT	MA	ME	NH	RI	VT	ISO
2014	$0.24	$0.42	$0.09	$0.09	$0.06	$0.02	$0.91
2015	$0.96	$1.68	$0.35	$0.35	$0.23	$0.08	$3.63
2016	$1.07	$1.87	$0.39	$0.39	$0.26	$0.09	$4.06
2017	$1.09	$1.92	$0.40	$0.39	$0.26	$0.09	$4.16
2018	$1.00	$1.76	$0.36	$0.36	$0.24	$0.09	$3.81
2019	$0.73	$1.29	$0.27	$0.27	$0.18	$0.06	$2.79
2020	$0.47	$0.83	$0.17	$0.17	$0.11	$0.04	$1.78
2021	$0.35	$0.62	$0.13	$0.13	$0.08	$0.03	$1.34
2022	$0.23	$0.41	$0.08	$0.08	$0.06	$0.02	$0.89
Levelized (2014-2028)	**$0.43**	**$0.75**	**$0.16**	**$0.16**	**$0.10**	**$0.04**	**$1.63**

These results start in 2014 and dissipate by 2022.

1.5 Avoided Cost of Fuel Oil and Other Fuels

Some electric and gas efficiency programs enable retail customers to reduce their use of energy sources other than electricity or natural gas. The benefits associated with reducing the use of "other fuels"—such as fuel oil, propane, kerosene, biofuel, and wood—include avoided fuel supply costs. For petroleum-related fuels, the major driver of these avoided costs are forecast crude oil prices.

The avoided costs of fuel oil and other fuels are used primarily by administrators of electric energy efficiency programs. Detailed results are presented in Appendix D, Avoided Costs of Other Fuels.

Exhibit 1-17 summarizes the prices projected by AESC 2011 and AESC 2013 for fuel oil and other fuels.

Exhibit 1-17. Comparison of AESC 2011 and AESC 2013 Fuel Oil and Other Fuel Prices (15-year levelized, 2013$)

	No. 2 Distillate	No. 2 Distillate	No. 6 Residual (low sulfur)	Propane	Kerosene	BioFuel	BioFuel	Cord Wood	Pellets
Sector	Res	Com	Com	Res	Res & Com	B5 Blend	B20 Blend	Res	Res
AESC 2013 Levelized Values (2013$/MMBtu) 2014-2028	$27.91	$26.84	$16.23	$28.17	$30.66	$28.26	$29.33	$10.11	$16.86
AESC 2011 Levelized Values (2013$/MMBtu) 2012-2026	$26.21	$24.31	$17.83	$37.19	$26.34	$26.21	$26.21	$9.78	-
Percent Difference from AESC 2011	6.5%	10.4%	-9.0%	-24.3%	16.4%	7.8%	11.9%	3.4%	-

Notes
Res = Residential Sector
Com = Commercial Sector

The projected AESC 2013 prices for these fuels are generally higher than those from AESC 2011, primarily due to a higher forecast of underlying crude oil prices. On a 15-year levelized basis, the AESC 2013 values are between 16 percent higher and 24 percent lower than 2011, depending on the fuel and sector.

As shown in Exhibit 1-17, there are two fuels whose prices are lower in AESC 2013 than in AESC 2011: propane and No. 6 residual fuel oil (low sulfur). Propane prices are down 24.3 percent due to lower costs for natural gas liquids associated with the rapid rise in shale gas production. Low-sulfur fuel oil prices are down 9.0 percent due to changes to the Energy Information Administration (EIA) Annual Energy Outlook (AEO) forecast, reflecting future regulations and production expectations.

Chapter 2: Avoided Natural Gas Costs

This chapter presents our estimate of avoided natural gas costs, the first of the seven distinct components required under the scope of work. The projections include estimates of wholesale natural gas commodity prices—starting at the Henry Hub and then moving to New England—which are major inputs to the energy model described in Chapter 6. The projections also include estimates of the marginal costs of gas supply and distribution by retail end use for various time periods within the year, which represent the avoided costs for commercial, industrial, and residential gas uses. The chapter describes the assumptions and methodology used to develop each of these projections.

2.1 Overview of New England Gas Market

In order to place the projections of avoided natural gas costs in context, we begin with an overview of demand for natural gas in New England by major consuming sector and by month, as well as the physical supply of gas to the region.

2.1.1 Demand for Wholesale Gas in New England

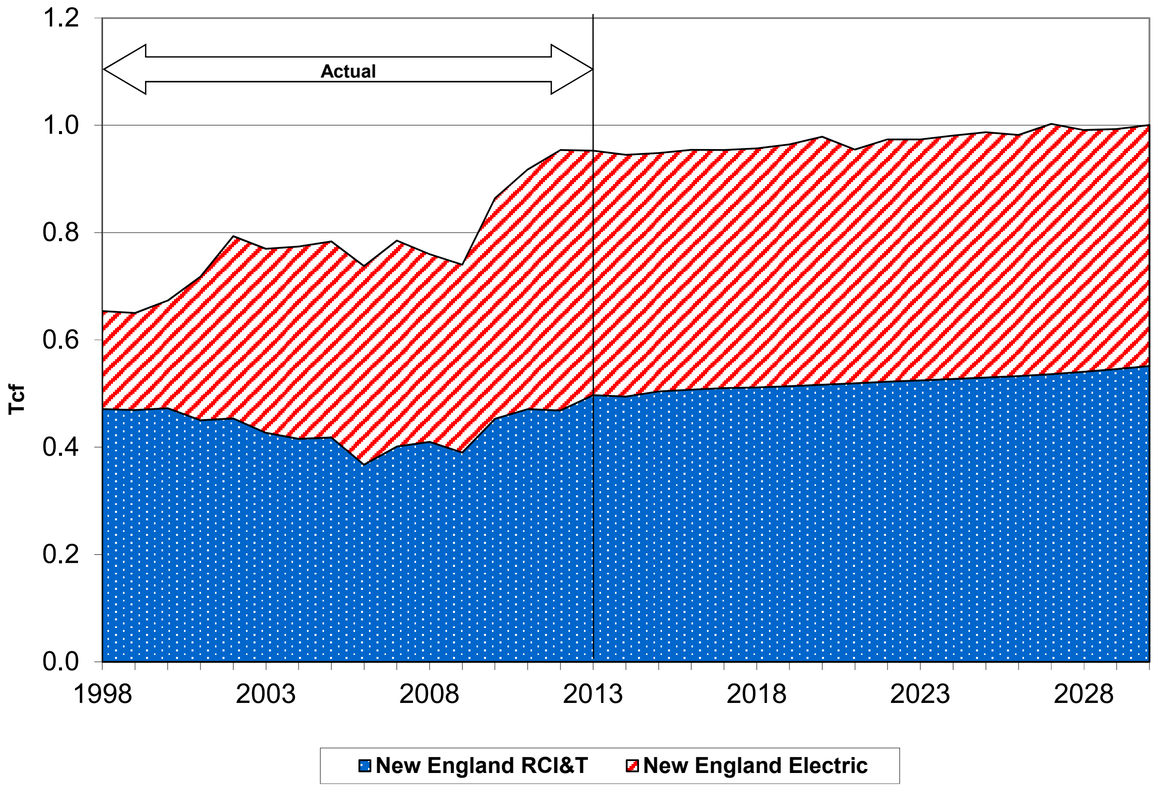
In 2011, the six New England states consumed 925,183 million cubic feet (MMcf) of natural gas, or approximately 2,500 MMcf per day. That annual gas consumption can be grouped into two broad categories. The first group is natural gas use by very large end users. These are primarily merchant power plants that generate electricity but also include large users in the industrial, commercial, and institutional sectors. The second group are retail customers in the residential, commercial, and industrial (RC&I) sectors. Currently, gas use for electric generation accounts for roughly half of the annual gas consumption in New England.

Total consumption of natural gas by all sectors in New England grew 40 percent between 1998 and 2011, as indicated in Exhibit 2-1. Increased use of gas for electric generation accounted for essentially all of that increase; there was no material cumulative increase in total gas use in the end-use sectors (i.e., residential, commercial, industrial, or "RC&I"). The increases in use of gas for electric generation occurred primarily between 1998 and 2004 and again between 2009 and 2011.

In its 2013 Annual Energy Outlook (AEO 2013) Reference Case, the Energy Information Administration (EIA) forecasts annual gas use for electric generation in New England to remain constant between 2014 and 2028. That Reference Case forecasts the annual gas use by the RC&I group to grow at about 0.5% per year between 2014 and 2028.

Actual and projected levels of annual natural gas use in these two categories are presented in Exhibit 2-1. (The projections are drawn from the AEO 2013 Reference Case.)

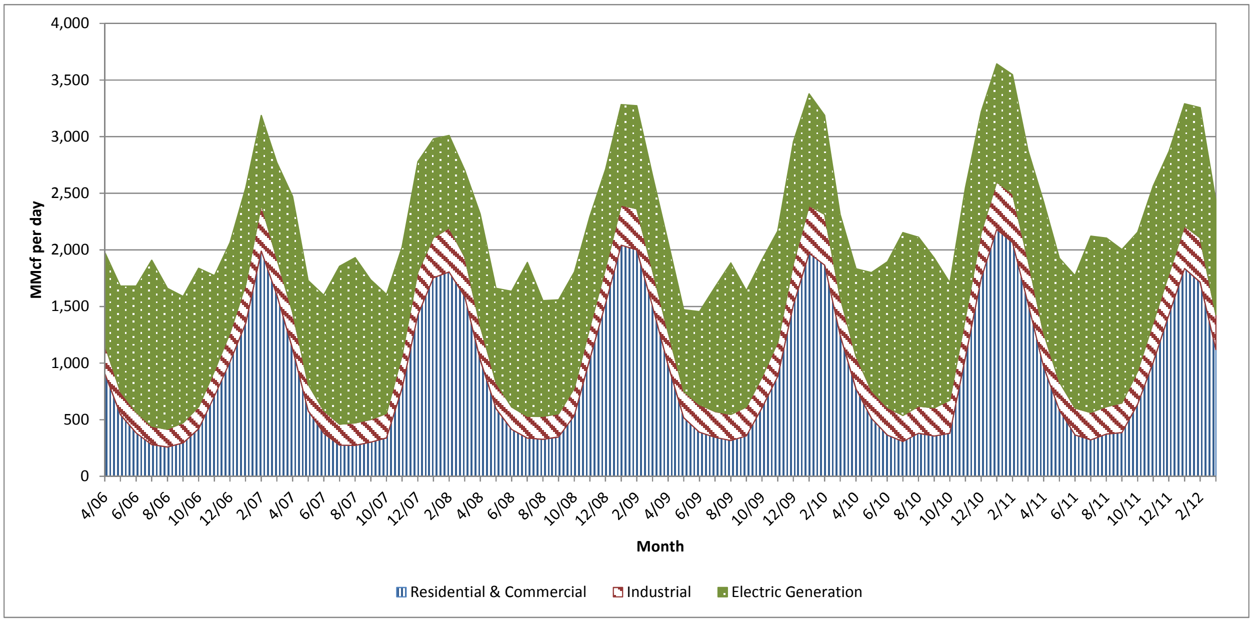
Exhibit 2-1. Annual Gas Use (Tcf) in New England, Actual and AEO 2013 Reference Case projection (Tcf)



Source: EIA data; Natural Gas Consumption by End Use. See: http://www.eia.gov/dnav/ng/ng_cons_sum_dcu_nus_a.htm. Accessed July 10, 2013.

The pattern of gas use in these two groups varies substantially by season, as well as month to month within each season. As shown in Exhibit 2-2, natural gas use by the RC&I sector is highest in December, January, and February, when heating demand is at its peak, and lowest in May and June, when heating demand is low. In contrast, gas use for electric generation is higher in the summer than in the winter.

Exhibit 2-2. New England Natural Gas Delivered Monthly to Customer by Class (MMcf/day)



Source: EIA AEO 2013

The gas procurement strategy of customers also differs between these two groups. Customers in the first group (electric generation), primarily merchant power plants, typically have a direct physical connection to a major pipeline and buy all of their supply from third-party marketers at prices tied to wholesale gas market prices in New England. In contrast, RC&I customers in the second group have direct physical connections to their local distribution company (LDCs) and either buy their supply from their LDC or from third-party marketers and have that gas delivered by the LDC.

The gas procurement strategies of New England LDCs typically consist of a portfolio drawing from three categories of gas supply resources: 1) flowing gas, 2) off-system storage, and 3) on-system peaking.

1. <u>Flowing Gas</u>

   Flowing gas is primarily natural gas that an LDC purchases in a producing area, or some other upstream location, and has transported to its citygate under long-term transportation contracts with interstate pipelines. Flowing gas also includes gas that LDCs buy from third-party marketers at prices tied to wholesale gas market prices in New England.

2. <u>Off-System Storage</u>

   LDCs acquire gas from off-system storage services to provide a flexible source of firm gas supply during the peak winter months. Most of the gas storage services purchased by New England LDCs utilize depleted gas fields located in Pennsylvania, New York, and Michigan. LDCs generally enter long-term contracts for the gas storage service as well as for firm pipeline transportation services from the storage facilities to the LDC citygate.

3. <u>On-System Peaking</u>

New England LDCs own peaking facilities which use either liquefied natural gas (LNG) or propane to supplement pipeline deliveries during periods of peak demand. These facilities, which connect directly to their gas distribution systems, have high daily delivery capability, but typically have only enough LNG and/or propane storage capacity to operate a few days per year.

2.1.2 Natural Gas Delivery Capacity into New England

New England depends entirely on pipeline deliveries of domestic and Canadian gas, and LNG imports delivered by ship. Five interstate pipeline companies, described below, deliver natural gas into the New England market. Tennessee Gas Pipeline and Algonquin Gas Transmission were the first gas pipeline companies to enter the region, and still operate the majority of the high-pressure transmission pipelines in Connecticut, Massachusetts, and Rhode Island. Three additional pipelines extending into or through New England were completed between 1992 and 2000. New England also has one active LNG import terminal and two inactive offshore LNG receiving facilities.

Pipelines

<u>Tennessee Gas Pipeline (TGP)</u>

The TGP system begins in the Gulf Coast producing areas and extends into New Hampshire. Two TGP pipelines supply New England. The 200 Line enters western Massachusetts from upstate New York and extends to the Boston area. The 300 Line enters southwestern Connecticut at Greenwich and connects to the 200 Line near Springfield, MA. In addition to the two mainlines, TGP operates lateral lines that extend into Rhode Island and New Hampshire.

<u>Algonquin Gas Transmission (AGT)</u>

AGT begins in Lambertville, NJ, where it connects Texas Eastern Transmission (TETCO) and delivers gas in Connecticut, Rhode Island, and eastern Massachusetts. In 2003, AGT built a 25-mile undersea pipeline extension (the HubLine pipeline) from Weymouth, MA to Salem, MA.

<u>Iroquois Gas Transmission System (IGTS)</u>

IGTS connects with TransCanada PipeLines (TCPL) at Waddington, NY, and crosses southwestern Connecticut before terminating in Long Island and New York City. IGTS interconnects with TGP at Wright, NY (near Albany) and with AGT at Brookfield, CT. IGTS has delivery meters to two LDCs and four gas-fired generating plants in Connecticut.

<u>Portland Natural Gas Transmission System (PNGTS)</u>

PNGTS connects with the TCPL in northern New Hampshire and delivers gas in Maine and New Hampshire before terminating at an interconnection with TGP at Dracut, MA. Completed in 1999, PNGTS replaced a smaller converted oil pipeline that had been the primary source of natural gas for Maine markets since the 1980s. PNGTS can receive up to 250 MMcf per day from TCPL at the Canadian border.

Maritimes & Northeast Pipeline (M&N)

M&N was built in 1999 to access new gas-producing fields in offshore Nova Scotia. The U.S. portion of the M&N system extends from the Maine-New Brunswick border to Northeastern Massachusetts. M&N connects with TGP at Dracut, MA and with AGT at Salem, MA. In 2009, M&N began receiving gas from the Canaport LNG import terminal in St. John, New Brunswick.

LNG Terminals

Distrigas LNG

The Distrigas LNG import terminal, located in Everett, MA, has operated since 1971. Distrigas expanded its activities in 1999, with increased vaporization capacity and new LNG supplies from Trinidad. The Distrigas terminal connects to TGP, AGT, and National Grid, and is the sole source of fuel for 1,500 MW of gas-fired generating capacity at Mystic units 8 and 9. Distrigas has sustained delivery capacity of 700 MMcf per day and supplies additional LNG to LDC peaking facilities by truck.

Northeast Gateway

Northeast Gateway is an offshore LNG receiving terminal in Massachusetts Bay. Northeast Gateway can deliver up to 800 MMcf per day into the AGT HubLine pipeline, but has not operated since 2010.

Neptune LNG

Neptune LNG is a second offshore LNG receiving terminal connected to the AGT HubLine system. Neptune LNG has a peak sendout capacity of 700 MMcf per day, but has not operated since it was completed in 2010.

2.2 Henry Hub Gas Price Forecast

2.2.1 Summary

This section begins with a summary of the AESC 2011 Base Case forecast of Henry Hub prices and its performance to date. Next it discusses the methodology and assumptions we used to develop a forecast of Henry Hub prices for AESC 2013. Finally, it presents our Base Case forecast of Henry Hub prices and discusses various issues relevant to that forecast.

AESC 2011. The AESC 2011 Base Case forecast of Henry Hub prices was based upon New York Mercantile Exchange (NYMEX) futures for 2011 through 2014 and on the EIA AEO 2010 High Shale case forecast from 2015 onward. The choice of the AEO 2010 High Shale case forecast was informed by several factors, including an estimate of the “full-cycle” costs of finding and producing shale gas over the life of a given project and uncertainty regarding projections of shale gas production costs based upon the possibility of tighter regulations on fracking and on the production characteristics of future wells. The AESC 2011 Base Case forecast of Henry Hub prices is $6.47/MMBtu (2013$) on a 15-year levelized basis.

Actual Henry Hub prices in 2011 and 2012 were well below the AESC 2011 Base Case forecast, and the NYMEX forward market prices as of March 15, 2013 were well below AESC 2011 Base Case forecasts through 2020.

The fact that actual prices in 2011 and 2012 and current NYMEX futures have proven to be lower than the AESC 2011 Base Case prices for those years simply indicates that the price expectations of the entire gas industry as of March 2011 have proven to be incorrect, since the AESC 2011 forecast prices through 2015 were based on NYMEX futures as of March 2011. One major factor which has contributed to the lower actual prices since 2011, and the lower current NYMEX prices, has been the quantity of production from plays with "rich" or "wet" gas, which has a high content of natural gas liquids (NGLs).[11] Sale of the NGLs provides those producers additional revenue to augment the revenue from sale of gas from those plays, and can often be enough to allow them to continue producing gas at very low market prices. A second contributing factor has been "hold by production agreements," under which producers must drill even when gas prices were below the level necessary to earn an adequate return.

Methodology. We developed our forecast of annual Henry Hub natural gas prices for the short term and for the mid to long term using the same basic methodology used in AESC 2007, 2009, and 2011. Under that methodology, we base the forecast on futures prices from NYMEX for the first few years of the study period, then on an appropriate long-term forecast from the EIA for the bulk of the study period, and finally on an extrapolation for the remaining years not covered by the EIA forecast. Thus, the AESC 2013 Base Case forecast is developed as follows:

- January – March 2013, Henry Hub actuals monthly prices
- April 2013 – March 2016, NYMEX futures as of March 15, 2013
- April 2016 – December 2035, forecasts of monthly prices derived from our Base Case forecast of annual Henry Hub prices
- January 2036 – December 2043 extrapolation using the average compound annual growth rate (CAGR) from the prior ten years (2026 to 2035).

Our forecast is based on NYMEX futures in the near term because they provide the market's estimate of prices for the future months for which trading volumes are significant. Our forecast is based on an AEO long-term forecast for the remaining period because a long-term forecast captures the market fundamentals that will drive those prices (i.e., demand, supply, competition between fuels) and because the inputs and model algorithms underlying AEO forecasts are public.

Assumptions. The major difficulty in developing a Base Case forecast has been, and continues to be, the selection of an appropriate AEO forecast as a starting point and then determining what, if any, adjustments to make to that AEO forecast.

[11] Natural gas liquids are propane, butane, iso-butane, and natural gasoline.

We developed the AESC 2013 Base Case forecast by starting from the AEO 2012 Reference Case forecast and making three adjustments to it. The three adjustments are a downward adjustment to incorporate a change in EIA's methodology for forecasting Henry Hub prices ("EIA HH methodology"), an upward adjustment to reflect the economics of developing marginal wells ("marginal well economics"), and an upward adjustment to reflect the costs of reducing the adverse environmental impacts of fracturing ("fracturing best practices"). Our basis for this approach is summarized below and discussed in detail in each sub-section.

- **Analysis of Gas Market Fundamentals:** We began our analysis by reviewing the economics of United States gas production, which included an analysis of physical and economic data on the country's major shale gas plays. This analysis is more comprehensive than the AESC 2011 estimate of full-cycle costs of producing shale gas in that it estimates the marginal production cost by play as well as which plays will set the market price in which time period. This review included an assessment of the time it would take before production from dry gas plays would begin setting the market price, i.e. the point in time when natural gas production associated with oil plays and gas plays rich in natural gas liquids (NGL) would no longer be sufficient to offset the decline in production from dry gas plays and the growth in natural gas demand. Our review also evaluated the potential for exports of U.S. gas in the form of LNG to increase Henry Hub prices above those forecast in the AEO 2012 Reference Case. We concluded that potential was small because LNG export quantities are not likely to be materially greater than those assumed in the AEO 2012 Reference Case.
- **AEO 2012 Reference Case forecast:** Our forecast starts from the AEO 2012 Reference Case because it compares well with NYMEX forwards as of March 2013 and with the published forecasts from Energy Ventures Analysis, Deloitte, the International Energy Agency and IHS Global Insight as of 2012. In contrast, the AEO 2013 ER prices are well below March 2013 NYMEX[12] prices and the average prices from the forecasts we reviewed.
- **EIA HH methodology downward adjustment:** The AEO 2013 ER Reference Case Henry Hub forecast reflects a major change in the methodology that EIA uses to calculate Henry Hub prices. The AESC 2013 Base Case forecast incorporates that change in methodology, which represents a downward adjustment of approximately $0.50 per MMBtu (2013$) to the AEO 2012 Reference case forecast over the study horizon.
- **Marginal well economics upward adjustment**: Our analysis of the economics of marginal wells indicates that by 2020 marginal plays would need market prices $0.33 per MMBtu higher than the AEO 2012 Reference Case projection. The AESC 2013 Base Case forecast phases this adjustment in gradually beginning in 2016 and reaches the full level in 2020.

[12] The volume of trading on NYMEX is very low after three years. Consequently, we do not view prices beyond that period as a meaningful guide to natural gas price. In June 2008, NYMEX prices were trading at $12 to $13 per MMBtu through 2025.

- **Fracturing best practices upward adjustment:** The EIA is prohibited from reflecting the impacts of potential new or tighter federal and/or state regulation in its AEO forecasts, thus the AEO 2012 Reference Case forecast reflects no increases in costs due to tighter regulations on fracturing or voluntary adoption of best practices. The AESC 2013 Base Case forecast includes such an adjustment based on our assessment that producers are likely to incur costs to reduce the adverse impacts of fracturing through some combination of industry self-enforcement of best practices and further regulations on fracturing. Although we have not found rigorous estimates of these costs, we consider an upward adjustment of approximately $0.54 per MMBtu by 2021 to be a reasonable order of magnitude estimate. The AESC 2013 Base Case Forecast phases this adjustment in gradually beginning in 2017 and reaches the full level in 2021.

The AESC 2013 Base Case forecast of Henry Hub prices that results from this methodology and set of assumptions is $5.37/MMBtu (2013$) on a 15-year levelized basis. The AESC 2013 Base Case forecast of Henry Hub prices is approximately 17 percent lower than the corresponding 15-year levelized AESC 2011 Base Case (2013$) forecast. The prices under this AESC 2013 Base Forecast compare well to NYMEX in 2015 and 2016 and the average of other published forecasts in 2025 and 2035.

2.2.2 Henry Hub as a Starting Point

The forecast of wholesale natural gas commodity prices in New England begins with a forecast of the price of gas at the Henry Hub, Louisiana. Henry Hub is used because 1) it is a major trading point whose prices serves as a reference point against which prices at other locations are indexed, 2) most comparative forecasts provide prices for this location, and 3) the Gulf Coast is a major source of U.S. supply. In 2011, the Gulf Coast accounted for approximately 31 percent of U.S. supply and 37 percent of lower 48 U.S. production.

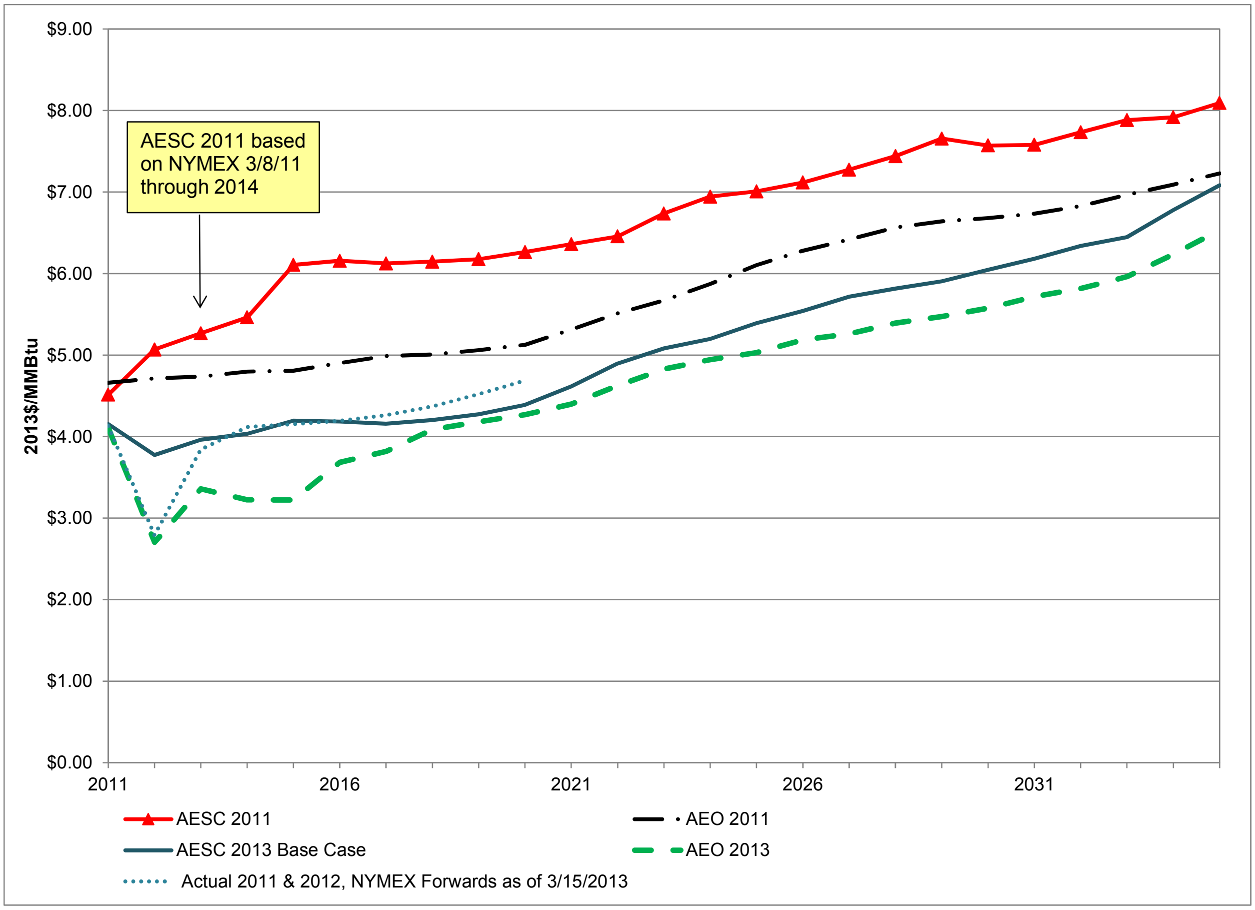
As a result of the growing U.S. natural gas production from shale, the sources of U.S. supply are changing significantly. Strong growth in the Appalachian region (primarily Marcellus shale) and the Utica in Ohio will displace gas flowing to New England from the Gulf Coast and Canada. Our forecast of wholesale gas prices in New England will reflect the impact of these changes in supply dynamics.

2.2.3 Review of AESC 2011 Projections

The AESC 2011 Base Case forecast is drawn directly from the AEO 2010 High Shale case forecast from 2015 onward. The choice of that forecast was informed by several factors, including an estimate of the "full-cycle" costs of finding and producing shale gas over the life of a given project developed from 2010 financial data filed by gas producers, and uncertainty regarding projections of shale gas production costs based upon the possibility of tighter regulations on fracturing and on the production characteristics of future wells.

As indicated in Exhibit 2-3, the AESC 2011 Base Case forecast has proven to be high relative to actual prices to date and to more recent AEO forecasts. However, the fact that actual prices in 2011 and 2012, and current NYMEX futures for 2013 and 2014, were lower than the AESC 2011 prices for those years simply indicates that the price expectations of the entire gas industry as of March 2011 have proven to be incorrect, since the AESC 2011 forecast prices through 2015 were based on NYMEX futures as of March 2011.

Exhibit 2-3. Henry Hub Prices - Actual and Projected (2013 $/MMBtu)



Source: EIA AEO 2011, 2012, AESC 2011, NYMEX

Exhibit 2-3 also shows that the AESC 2011 Base Case forecast is substantially higher than the Reference Case forecasts from AEO 2013 and what we have labeled as AESC 2013 Base Case. Those two AEO forecasts reflect a major change in the method the EIA uses to calculate the Henry Hub price (discussed below) plus EIA's estimate of the impacts of improvements in gas production technology and, in the near term, of production from NGL rich shale resources.

EIA HH Methodology Downward Adjustment

AEO 2013 reflects a significant change in the method EIA uses to forecast Henry Hub prices. The EIA made this change because it will no longer collect data on wellhead prices, which have been a key input to its forecasting method until now. Before AEO 2013, the EIA regressed actual Henry Hub prices against actual wellhead prices and used the regression results to forecast Henry Hub prices as a function of its forecast of the average national wellhead price. Under its new method, EIA forecasts Henry Hub prices by adding an estimated gathering charge to its forecast of the average Gulf Coast wellhead price. The EIA's new method results in substantially lower Henry Hub prices than its previous method. This result implies that AEO forecasts prior to AEO 2013 have probably overstated the Henry Hub price.

Our review of gas wellhead price data indicates that the new EIA methodology is appropriate. As discussed later, the AESC 2013 Base Case forecast incorporates an EIA HH methodology adjustment as a downward adjustment of approximately $0.50 per MMBtu (2013$) to the AEO 2012 Reference Case forecast over the forecast horizon.

The EIA provided us with an adjusted AEO 2012 forecast of Henry Hub prices that reflect this methodology adjustment. In the balance of this section we refer to that adjusted AEO 2012 forecasts as "AEO 2012 Adj." Our remaining analyses start from AEO 2012 Adj.

2.2.4 U.S. Natural Gas Price Dynamics

The following brief review of U.S. natural gas price dynamics is intended to provide an understanding of the inherent uncertainty in the natural gas industry, why analysts have misread the data, and the current state of the market.

Like many capital intensive industries the natural gas industry has had periods of boom and bust. These boom and bust periods often lead to misperceptions of the full-cycle cost of production and to poor forecasts of future prices. With few exceptions, industry analysts have gone through periods of projecting low prices for a long time periods (approximately 1985 to 1999), projecting high prices and the need for a high level of imports (approximately 2000 to 2009) and projecting low prices and exports of natural gas (today). The industry is now going through a period in which low prices for natural gas have caused drilling to drop off sharply. Given the track record of past forecasts of gas prices, it is understandable that there is substantial disagreement about the current outlook for natural gas prices.

A brief review of gas price dynamics over the past few decades provides some insight into the inherent uncertainty in natural gas price projections and the factors that have biased forecasts. This understanding is useful in assessing how recent dynamics might bias the outlook for future natural gas prices.

Exhibit 2-4 below shows the variation in annual average natural gas wellhead prices over time under various regulatory frameworks and market conditions, with prices expressed in 2013$ per MMcf.[13] Regulatory decisions have had a major impact on the natural gas industry.

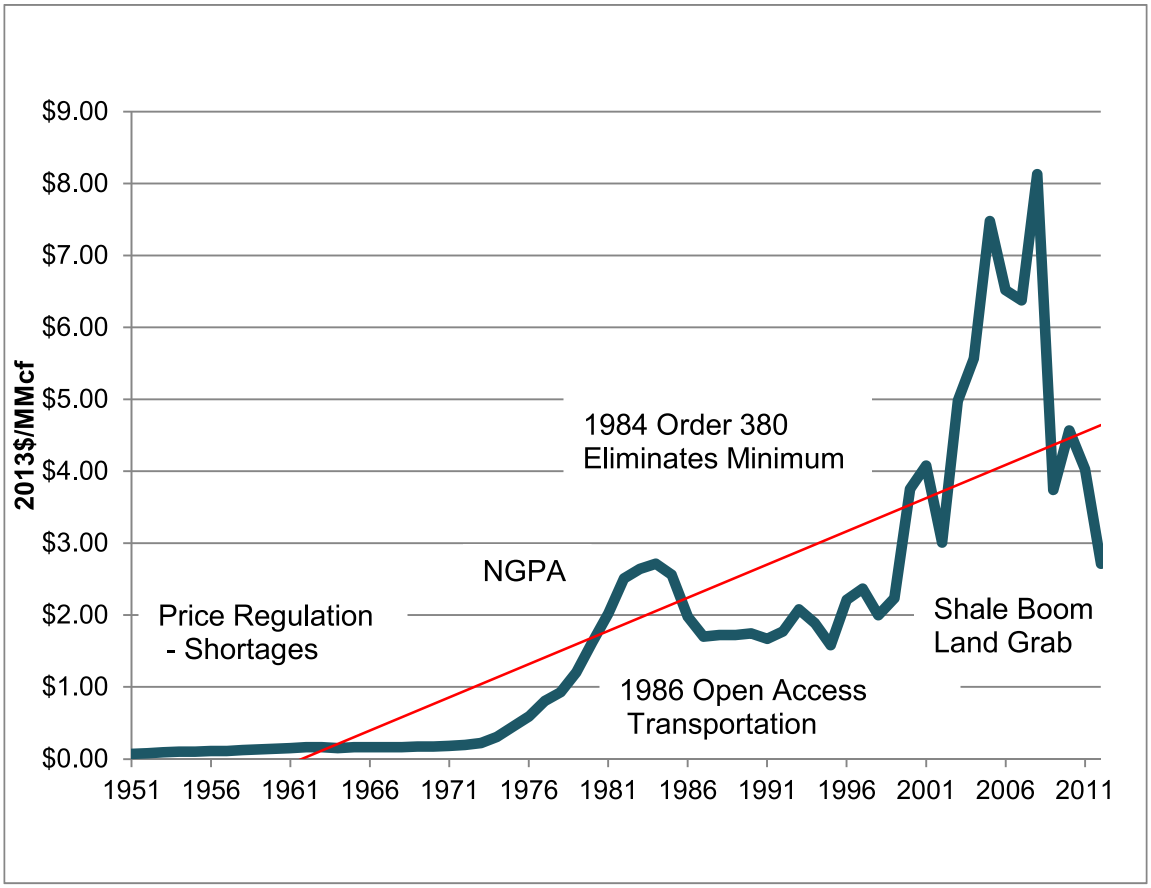
- 1951 to 1978. In 1951, the Phillips Act regulated natural gas prices on the interstate market. These regulations caused natural gas shortages on the interstate market after the Arab oil embargo in 1973.

[13] One MMcf is one million cubic feet.

- 1978 to 1984. In 1978, the Natural Gas Policy Act (NGPA) created a complex classification of natural gas production. Old gas prices were regulated at low prices and "new gas" had a high price ceiling. This price structure along with pipelines' concern about meeting requirements to serve customers created an incentive to increase natural gas productive capacity and proved reserves. During this period, interstate natural gas pipelines bundled the sale of transportation and gas supply. In part because they were obligated to serve, pipelines contracted for supplies at prices higher than would clear the market. Take-or-pay obligations in the form of a minimum bill forced gas distribution companies to buy gas prices above the level that would clear the market.

- 1984 to 1999. In 1984, FERC Order 380 outlawed including fixed costs in the minimum bill to LDCs. This change allowed LDCs to buy gas from the lowest cost pipeline. This put downward pressure on gas prices and caused financial problems for pipelines that had contracted to take gas at prices that were not competitive. In 1986, FERC Order 436 required all pipelines to provide open access transportation. This allowed interstate buyers to negotiate directly with producers and transport their own gas. As a result, natural gas prices dropped sharply and some pipelines had to file for bankruptcy because they had taken-or-pay contracts with producers. Because prices had been well above the level necessary to clear the market for many years, excess productive capacity and reserves were developed. In 1986, wells were operating at about 75 percent of capacity and producers didn't have to develop new reserves. Producers could drill existing proved reserves and production grew by simply using excess productive capacity. Companies laid off geologists and crews and this lowered short run costs. Also, the cost of rigs was low because fewer rigs were needed to grow production. As analysts looked at the price levels needed to grow production, they concluded that the cost of developing natural gas supply was very low and projected low natural gas prices for decades, but they were not taking into account factors that kept costs below the level necessary to sustain supply over the long term.

Exhibit 2-4. Natural Gas Wellhead Prices (2013$/MMcf)



Source: EIA

- 2000 to 2008. By the year 2000, productive capacity was being used at a 96 percent level. As a result of high capacity utilization, wellhead prices increased 68 percent from 1999 to 2000. Because exploration efforts had been at a low level and there was a shortage of crews and geologists, production grew very slowly. By 2008, wellhead prices averaged $8.13/MMcf in 2008 a 264 percent increase from 1999. In June 2008, Henry Hub prices exceeded $12 per MMBtu and forward prices out to 2025 were trading close to that level. Most analysts concluded that prices would stay at high level for the foreseeable future and that the U.S. would have import large amounts of liquefied natural gas.

- 2009 to present. However, in 2008 natural gas production from shale was ramping up. Most analysts did not recognize the impact this production was going to have on the market until late in the summer. Henry Hub prices declined from $12.59 per MMBtu in June 2008 to $5.82 in December 2008 and only averaged $3.89 in 2009. The high prices in 2008 and the attractive economics of shale caused a great land grab. Producers wanted to lock in land with attractive shale plays. The lease provisions between the producers and land owners contained "hold by production" clauses which required producers to develop wells or lose their lease. Consequently, despite prices that were below the level necessary to earn an adequate return, producers continued to bring on new wells. Production increased 19 percent (a 4.5 percent annual rate) from 2008 to 2012 and by 2012 Henry Hub prices averaged $2.77 per MMBtu.

As a result of low prices, the natural gas rig count has declined from 1,215 in January 2009 to 425 as of February 2013, as shown in Exhibit 2-5. Despite the decline in the gas rig count, estimated production growth in 2012 increased 4.5 percent. Production growth has remained strong despite a low rig count because uncompleted wells are still being connected, rigs are much more productive, and some supply additions are coming from gas associated with drilling for oil in shale plays. Also, doubts have been raised about the accuracy of the rig count. Natural gas production is not economic, so producers have been claiming they are drilling for oil.

Exhibit 2-5. Henry Hub and Gas Rig Count

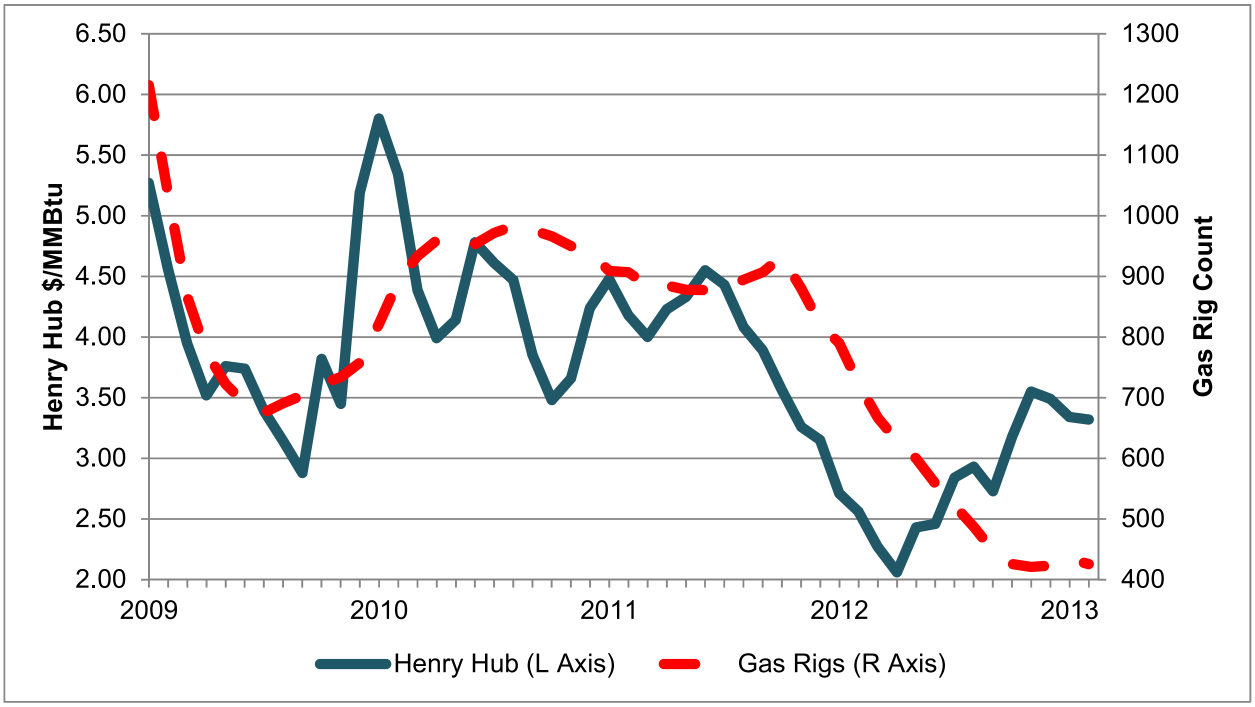
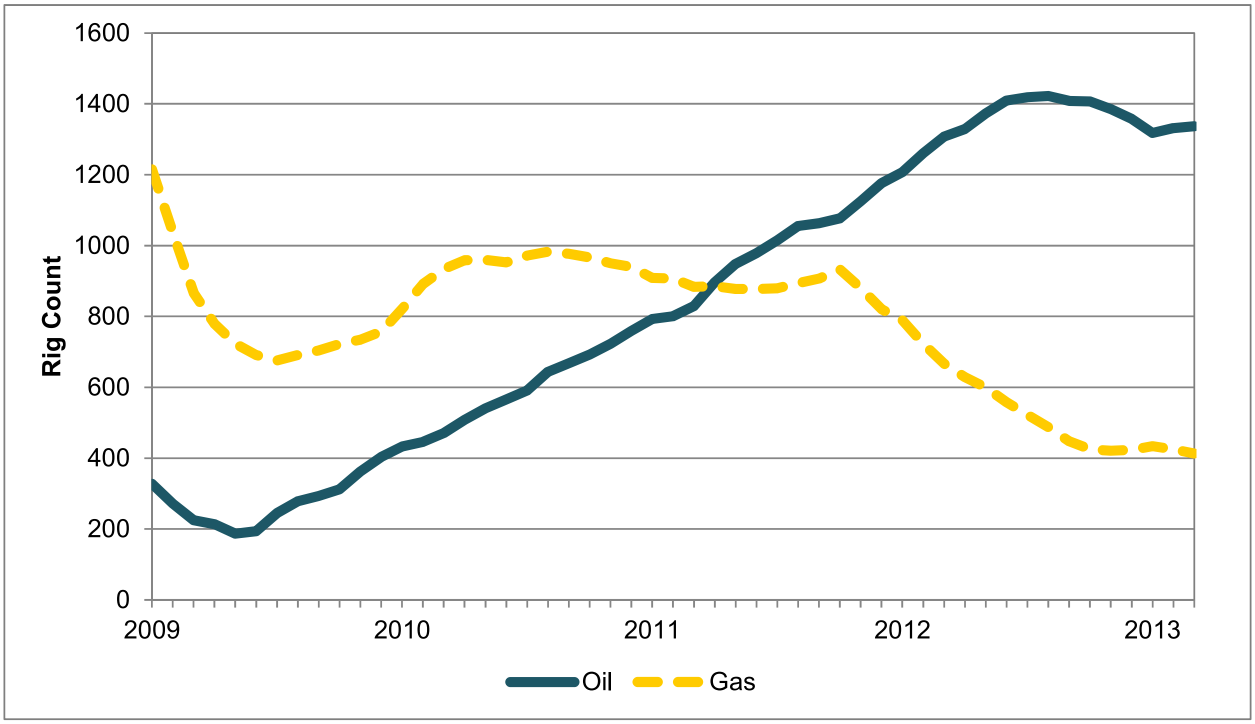


Exhibit 2-6 shows the sharp shift that has occurred since 2009 between the number of rigs drilling for gas and the number drilling for oil. A major question is whether this shift will result in a slowdown or decline in natural gas production. In a report entitled *U.S. Natural Gas Production2013-2014 Outlook: Believe the Shale Boom,* Bentek estimated associated gas[14] will add 5.7 Bcf per day of production between 2012 and 2014. This is equal to 8.6 percent of estimated 2012 production. However, there is

[14] Bentek defines associated gas that comes from plays that are rich in NGLs or oil plays.

very little data on the amount of associated gas because these plays are nascent and the content varies greatly within a play. Production of "rich" or "wet" gas is economic at relatively low natural gas prices.[15]

Exhibit 2-6. Oil and Gas Rig Count



Source: Baker Hughes North America Rotary Rig Count

This review of natural gas price dynamics suggests the following:

- Forecasting gas supply prices based upon analyses of current finding and development costs are often inaccurate because the costs of inputs to current production costs are often either overpriced, or underpriced compared to the long run equilibrium production cost. During the 1985 to 1999 period, long run prices were underestimated. From 2000 to 2008, prices were overestimated. The errors in forecasts were so large that the outlook for natural gas supply changed dramatically over these periods.
- There is a similar risk in projecting prices based on what is happening in the current gas market. The land grab in 2008 resulted in land costs that are probably greater than would have been paid had shale production grown at a more gradual price. The rapid growth in shale production has caused a sharp rise in the cost of rigs and crews.

[15] Rich or wet natural gas contains large amounts of NGLs and or Condensate.

> The “hold by production” requirements have resulted in the development of many areas at prices that are below the level for a producer to earn an adequate return on investment. However, much of the cost is sunk. Consequently, for a substantial time period it could be economic for producers to produce at lower prices than would earn them an adequate return on all of their costs.

2.2.5 AESC 2013 Henry Hub Forecast Methodology

Consistent with the approach used to develop the gas price forecast in AESC 2011, the AESC 2013 Henry Hub natural gas price forecast is based upon data from two sources: 1) futures prices from NYMEX through 2015 and 2) a forecast from an appropriate AEO forecast for the long term. Using this methodology, we developed a Base Case forecast of Henry Hub gas prices that is a “blend” of NYMEX and AEO projections. This methodology is used by many forecasters, including various electric utility IRPs, and is consistent with reports by the National Regulatory Research Institute and Lawrence Berkeley National Laboratory. It reflects the fact that futures prices are generally considered to provide the most accurate forecast of near-term Henry Hub natural gas prices while forecasts from a model that simulates market fundamentals of physical demand, physical supply and long-run marginal costs of supply provide a better estimate of long-term prices.

For the long term, we rely upon forecasts from an appropriate AEO case because the inputs and model algorithms underlying the AEO projections are public, transparent, and incorporate the long-term feedback mechanisms of energy prices upon supply, demand, and competition among fuels. Our selection of which specific AEO forecast to rely upon was informed by our analysis of the full cycle cost of finding, developing and producing shale gas, adjustments for sunk costs, publically available forecasts from credible sources, and the NYMEX forward market prices. We focused upon shale gas because, consistent with most analysts, we expect shale gas to be the dominant marginal source of supply, and market price setter, in the long-term.

We considered Reference Cases from two AEO forecasts as possible starting points for AESC 2013, i.e., AEO 2012 and AEO 2013 ER. We chose the AEO 2012 Reference Case because its forecast compared well with NYMEX forwards as of March 2013 and with independent forecasts as of 2012 from Energy Ventures Analysis, Deloitte, the International Energy Agency and IHS Global Insights. In contrast, the AEO 2013 ER forecast prices were well below March 2013 NYMEX prices as well as the independent forecasts we reviewed.

We made three adjustments to the AEO 2012 Reference Case forecast in order to develop the AESC 2013 Base Case forecast. The first is the EIA HH methodology adjustment discussed earlier. This is a downward adjustment to reflect the change in EIA methodology for forecasting Henry Hub prices. The second and third are upward adjustments, which are discussed below. These two adjustments reflect the economics of developing marginal wells (“marginal well economics”), and the costs of reducing the adverse environmental impacts of fracturing (“fracturing best practices”).

In the process of determining which adjustments to make, and the size of those adjustments, we considered various factors that might affect the AESC 2013 Base Case forecast of Henry Hub prices.

Members of the Study Group expressed concern about the potential impact of two specific factors, gas production from NGL rich plays and exports of gas in the form of LNG. We address those two factors before describing our marginal well economics adjustment and our fracturing best practices adjustment.

2.2.6 Impact of Gas Production from Plays Rich in NGL

As noted earlier, gas prices in 2011 and 2012 proved to be much lower than industry expectations as of March 2011, yet gas production levels remained high. One of the major factors driving those market conditions was the ability of producers to maximize the quantity of gas they obtained from gas shale plays with a high content of NGLs and from natural gas associated with oil shale plays. In this discussion we refer to that gas supply as "associated gas." Those producers were able to augment the revenue from their sale of associated gas with revenue from the sale of the NGLs or oil. In some plays it was economic for the producers to produce associated gas solely for the revenues from NGLs or oil.

The question we faced when developing the AESC 2013 Base Case forecast was to estimate the time period over which the growth in associated gas, would no longer offset the decline in production for dry gas plays and the growth in natural gas demand. Our analyses indicated that NGL prices would be weak through 2016 but would rebound and increase in the mid- to long-term due to increases in demand for NGLs as feedstocks and fuels in both U.S. and export markets.[16,17] Our review of the costs of plays with rich gas production indicates that most rich and gas production associated with oil shale plays will be economic within the likely range of future prices for oil and natural gas liquids. As a result, the primary factors that will limit the production of rich gas will not be oil and NGL prices but instead will be the pace of field development, permitting, processing plant construction, and pipeline capacity. Before the gas and oil industry will make the capital expenditures required for new processing plants and pipeline capacity, there needs to be assurance that there will be sufficient reserves to support these facilities over their economic life. Thus, rich gas production is more likely to be limited by processing and pipeline capacity limitations than by low oil or NGL prices.

The rapid growth in production of rich gas and associated gas has been a major factor influencing natural gas prices. In the short run it has made much of the dry gas production uneconomic. In the longer term, the level of that rich production will influence the timing of when additional dry gas production will be economic. In the short term (over a few years) changes in rich gas production could have a major impact on prices, however our review of long term supply elasticities (see below), indicates

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[16] Lyondell Basell, a global petrochemical company, sees U.S. ethane production exceeding demand through 2016. Available at: http://www.lyondellbasell.com/NR/rdonlyres/257B0667-D5FC-4D57-9924-FD8ECD9A41F1/0/GoldmanMay2013Slides05142013FINALNOLinks.pdf (slide 10)

[17] Recent reports from the EIA and Platts have reported that the cracking capacity to process associated gas liquid may increase significantly by 2020. Platts and the EIA both report an estimated 10.1 million tons of cracking capacity is being planned through 2020, which would represent approximately 35 percent of the current U.S. cracking capacity. Available at: http://www.platts.com/IM.Platts.Content/InsightAnalysis/IndustrySolutionPapers/SR_Ethylene_AFPM_2013.pdf and http://www.eia.gov/forecasts/aeo/pdf/0383(2013).pdf (page 50)

that changes in rich gas production are unlikely to have a major impact on Henry Hub prices in the long term.

It would take an extremely large change in annual production of rich and associated gas to have a significant impact on Henry Hub prices in the long term.

- **Henry Hub Price elasticity.** Our analysis of the long run supply curve indicates that a 10 percent change in 2020 gas production (6.9 Bcfd) would cause Henry Hub prices to change about $0.20 per MMBtu or 4.4 percent. This relatively small price impact is consistent with an analysis by Deloitte that estimated the impact of additional gas demand of 6 Bcfd of LNG exports would increase their relative projections of Henry Hub prices by $0.15/MMBtu (2012$), approximately 2.5 percent between 2016 and 2030.[18]

- **Associated gas portion of total annual gas production.** The AEO 2012 projects that shale gas production in 2020 will represent 38 percent of total natural gas production. We estimate that approximately 20 percent of total production would come from associated gas from shale plays. A 10 percent change in that associated gas production would represent a less than 1 percent change in total gas production and thus would change Henry Hub prices by less than about 0.44 percent or $0.02 per MMBtu.

2.2.7 Potential Impact of LNG Exports

The AEO 2012 and AEO 2013 Reference Cases each project LNG exports of 0.7 Bcfd by 2020. Given the currently low prices, there is a reasonable chance that LNG exports will exceed those forecast quantities and drive natural gas prices above the corresponding Reference Case forecast prices. However, there is considerable uncertainty regarding the potential incremental quantities of LNG exports. For example, a recent study by Wood Mackenzie indicated that U.S. exports of LNG will face strong price competition after 2018. There is also uncertainty regarding the potential impact of incremental LNG exports on Henry Hub prices.

First, the EIA does not have a rigorous model of LNG trade. The AEO 2012 forecasts were based on exogenous assumptions about LNG and the AEO 2013 forecasts of LNG exports are based on EIA projections of international natural gas prices.

Second, the Department of Energy (DOE) must evaluate applications to export LNG. The Natural Gas Act (NGA) requires DOE to grant a permit unless it finds that such action is not consistent with the public interest. As a practical matter, the need for DOE to make a public interest judgment is only relevant for applications to export LNG to countries that have not entered into a free trade agreement (FTA) with the United States.(The NGA provides that applications involving imports from or exports to an FTA country are deemed to be in the public interest and shall be granted without modification or delay.) However, with the exception of South Korea, very few countries that would potentially import LNG from

[18] Deloitte's World Gas Model average Henry Hub in 2016 is approximately $6.09/MMBtu (2012$) from *Made in America: The economic impact of LNG exports from the United States.*

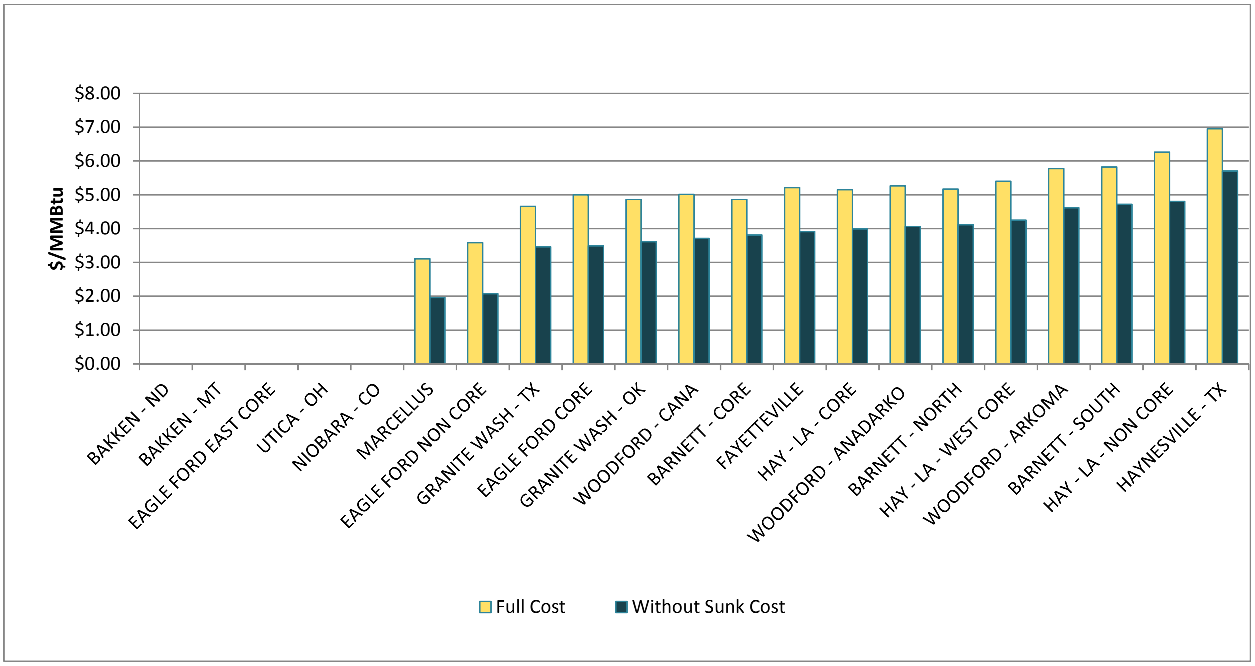
the United States have FTAs. In April 2013, President Obama made a statement of support for LNG exports, which some parties believe could result in faster approval of LNG exports by the DOE. However, the AEO 2012 and AEO 2013 export cases do not cite the need for export approval as a factor that will slow LNG exports. To date, only the Sabine Pass and Freeport LNG terminals have received LNG export approval. The Sabine Pass terminal still needs approval from FERC. If approved, the planned in-service date for the terminal in the fourth quarter of 2015. The Sabine Pass terminal will have an initial capacity of approximately 1 Bcfd with expansion to 2 Bcfd. In May 2013, the DOE issued an approval for the Freeport LNG terminal to export to non-FTA nations. It is targeted for in-service date of 2017 with capacity of 2 Bcfd.

Third, estimates of the impact of incremental LNG exports on Henry Hub prices vary widely. The EIA has estimated that incremental LNG exports of 3.3 Bcfd, i.e., to a total of 4 Bcfd by 2020, could cause prices to increase by an average of about $0.42 per MMBtu over the 2016 to 2020 period. However, the EIA prepared that estimate using their AEO 2011 model, which had a less optimistic gas supply outlook, and used a Henry Hub methodology that overstates the impact of a change in wellhead prices on Henry Hub prices. In 2013, Deloitte estimated the impact of increased LNG exports upon Henry Hub prices using their World Gas Model. Their analysis found that an annual export of 6 Bcfd of LNG caused an $0.15/MMBtu increase in their projections of Henry Hub prices from 2016 through 2030. Another recent report issued by the Bipartisan Policy Center also found that LNG exports had a modest impact on natural gas prices in the future.

2.2.8 Marginal Well Economic Adjustment

We developed estimates of natural gas production costs for shale plays from our review of state data, 10-K filings, producer presentations, and analyses of well production data from Lippman Consulting Incorporated. Exhibit 2-7 and Exhibit 2-8 show the prices that various shale plays require to earn a 10 percent internal rate of return (“IRR”). These exhibits present the prices required to earn a 10 percent IRR with “sunk” costs and without sunk costs. (Sunk costs include land, gathering costs, and overhead.) The 10 percent IRR is calculated after taxes, and is sometimes referred to as an after-tax rate of return (“ATROR”).

Exhibit 2-7. Breakeven 10% IRR Henry Hub Prices (2013$/MMBtu)



In order to estimate the market price necessary to balance the market and provide producers an adequate return requires one to estimate the marginal supply source. The marginal supply source changes over time, as higher cost plays replace lower cost plays as the marginal source due to a combination of declines in production from the lower cost plays and increases in annual gas consumption. Exhibit 2-7 and Exhibit 2-8 provide an indication of the production costs of the plays that are likely to be adequate to balance the market through 2020 and possibly longer. As production from a given play increases, its production could increase because of increased labor and rig costs, regulations that increase costs or it could decrease because of advances in technology and decreases in factors such as land costs, rigs, and labor. Thus the estimates presented in Exhibit 2-7 and Exhibit 2-8 provide an indication of the marginal pricing of each play assuming the factors that could drive production costs up are fully offset by the factors that could them down.

Exhibit 2-8. Costs of Selected Plays in 2020 (2013$/MMBtu)

Shale Gas Play	Required Henry Hub price with Sunk Costs (Breakeven 10%)	Adjustments for Sunk Costs			Henry Hub without Sunk Costs
		Land	Gathering and Processing Cost	Overhead	
	2013$/MMBtu				
BAKKEN - ND					
BAKKEN - MT					
EAGLE FORD EAST CORE					
UTICA - OH					
NIOBARA - CO					
MARCELLUS	$3.11	$0.20	$0.50	$0.45	$1.96
EAGLE FORD NON CORE	$3.58	$0.55	$0.50	$0.45	$2.08
GRANITE WASH - TX	$4.66	$0.25	$0.50	$0.45	$3.46
EAGLE FORD CORE	$5.00	$0.55	$0.50	$0.45	$3.49
GRANITE WASH - OK	$4.86	$0.30	$0.50	$0.45	$3.61
WOODFORD - CANA	$5.01	$0.35	$0.50	$0.45	$3.71
BARNETT - CORE	$4.86	$0.35	$0.25	$0.45	$3.81
FAYETTEVILLE	$5.22	$0.35	$0.50	$0.45	$3.91
HAY - LA - CORE	$5.15	$0.20	$0.50	$0.45	$4.00
WOODFORD - ANADARKO	$5.27	$0.25	$0.50	$0.45	$4.06
BARNETT - NORTH	$5.17	$0.35	$0.25	$0.45	$4.11
HAY - LA - WEST CORE	$5.40	$0.20	$0.50	$0.45	$4.25
WOODFORD - ARKOMA	$5.77	$0.20	$0.50	$0.45	$4.62
BARNETT - SOUTH	$5.82	$0.40	$0.25	$0.45	$4.72
HAY - LA - NON CORE	$6.26	$0.50	$0.50	$0.45	$4.80
HAYNESVILLE - TX	$6.95	$0.30	$0.50	$0.45	$5.70

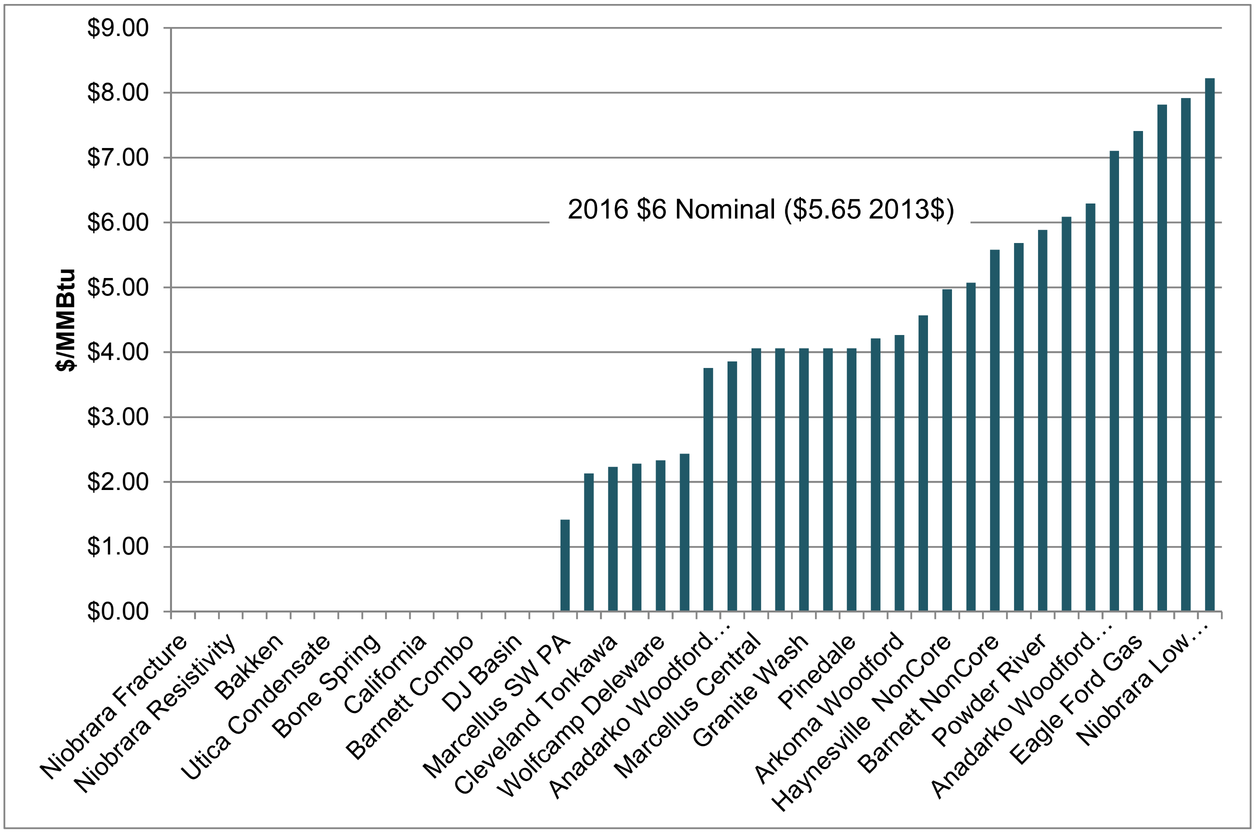
Our review of forecast annual gas consumption and production from these plays indicates that by 2020 the marginal sources of production will be plays with a cost structure as high as Barnett-South and possibly Hayesville, Louisiana, Non-Core. Considering the full cost of production this would require a market price between $5.82 and $6.26 per MMBtu. However, the model the EIA uses to develop its AEO price forecasts does not include sunk costs in the economic analysis. If one excludes sunk costs, the variable cost of gas from those marginal plays ranges from $4.72 to $4.80 per MMBtu. Those marginal production costs are higher than the AEO 2012 Adj. forecast price of $4.39 in 2020.

The AESC 2013 Base Case forecast includes a “marginal well economic adjustment” to reflect the difference between our estimate of the marginal cost of gas in 2020 and the AEO 2012 Adj. forecast price for that year. That marginal well economic adjustment is $0.33[19] per MMBtu added to the AEO 2012 Adj. forecast price in 2020. The AESC 2013 Base Case forecast prices reflect a phase-in of the $0.33 per MMBtu from 2016 to 2020 using a compound annual growth rate of 2.4 percent.

We consider this marginal well economic adjustment to be conservative. For example, a study by Tudor, Pickering, & Holt & Co. ("TPH") estimated that the market price in 2016 required for producers to break even was $5.65 per MMBtu (2013$). That market price is slightly below our estimate of the full production cost of Barnett South of $5.82 per MMBtu in 2020. We are assuming prices will stay lower than the full cycle cost estimate because producers have built gathering systems and purchased land, and those costs are fixed or sunk. Also, much of the overhead cost is probably fixed. However, one could argue that the marginal well economic adjustment should be higher, at $143 per MMBtu, which is the full marginal cost of $5.82 less the AEO 2012 Adj. price of $4.39, rather than $0.33 per MMBtu. However, the $0.33 per MMBtu adjustment produces forecast prices that are consistent with the forward market and that we consider to be conservative.

[19] The $0.33 estimate rather than the $0.41 because our estimate of the marginal supply source does not allow for natural gas production associated with oil shale development. This development is likely to lower the marginal source of supply.

Exhibit 2-9. Breakeven Prices 10% ATROR ($/MMBtu)



Source: Tudor, Pickering, & Holt & Co.

2.2.9 Fracturing Best Practices Adjustment

Hydraulic fracturing is a technique used in "unconventional" gas production. "Unconventional" reservoirs can cost-effectively produce gas only by using a special stimulation technique, like hydraulic fracturing, or other special recovery process and technology. This is often because the gas is highly dispersed in the rock, rather than occurring in a concentrated underground location. Hydraulic fracturing produces fractures in the rock formation that stimulate the flow of natural gas or oil, increasing the volumes that can be recovered. Wells may be drilled vertically hundreds to thousands of feet below the land surface and may include horizontal or directional sections extending thousands of feet.

Horizontal drilling and multi-stage fracturing can be disruptive to communities, and accidents have increased as drilling has increased. New regulations and better enforcement will be required to assure public safety and acceptance of natural gas production from shale. These regulations will come both at a state and federal level. In 2011, EPA began research under its *Plan to Study the Potential Impacts of*

Hydraulic Fracturing on Drinking Water Resources[20]. The study will not be completed until at least 2014 and it is likely that it will be several years before new regulations are implemented.

However, numerous states are considering tighter regulation of fracturing. According to a report by the National Conference of State Legislatures[21]:

- At least 119 bills in 19 states have been introduced this session that address hydraulic fracturing. At least nine states—Indiana, Maryland, New Jersey, North Carolina, Pennsylvania, South Dakota, Tennessee, Utah, and Vermont—have enacted legislation.
- At least 11 states have proposed legislation to impose new or amend existing severance taxes.
- At least nine states have proposed chemical disclosure requirements.
- At least eight states have proposed casing, well spacing, setback, water withdrawal, flow back, waste regulation requirements, or other measures to protect water resources.
- At least 11 states have proposed legislation to impose new or amend existing severance taxes.
- Legislators in at least eight states have proposed hydraulic fracturing suspensions, moratoria, or studies to investigate fracking impacts.
- At least seven states have proposed resolutions addressing hydraulic fracturing.
- At least 13 bills have been introduced in Pennsylvania with a range of proposed rates and structures. S.B. 352, for example, would impose a natural gas severance tax of 5 percent on the gross value of gas extracted at the wellhead, plus 4.6 cents per 1,000 cubic feet of natural gas extracted. H.B. 1705 would impose a natural gas severance tax of 1.5 percent of the gross value of gas severed at the wellhead for the first 60 months of production and 5 percent thereafter. This is shown in Exhibit 2-10.

States also have the ability to impose impact fees on fracturing operations. For example, Pennsylvania enacted H.B. 1950 (February 2012) to implement an impact fee based on the average price of natural gas in the preceding year. It is capped at $355,000 per well during a 15-year period. The new law aims to benefit local communities that are affected by drilling.

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[20] See http://epa.gov/hfstudy/. Accessed June 8, 2013.

[21] Natural Gas Development and Hydraulic Fracturing, A Policy Makers' Guide, Revised June 2012, Jacquelyn Press, National Council of State Legislatures.

Our review of literature in the public domain has identified only three studies that attempt to quantify regulations that might impact of the production of natural gas. A study done by Advanced Resources International[22] evaluated proposals that had been suggested without regard to whether they are likely to be implemented. This study concluded that 22 percent of natural gas production from shale would be lost at prices of $6 per MMcf (2007$) and 10 percent at prices of $9 per MMcf. However, it is our view that it is unlikely that regulations as stringent as in this study would be implemented.

A study was done on the impact of New Source Performance Standards[23] regulating volatile compounds. The study concluded that if wellhead prices were above $3.95 per MMcf (2013$) in 2015 there would be no impact on the cost of natural gas. This is because capturing the volatile compounds has value. Our forecast wellhead price in 2015 is approximately $4.03 per MMcf.

The Government Accountability Office (GAO)[24] found that shale oil and gas development is likely to pose threats to public health and the environment, but it's unclear how significant those risks will be in the long run because of gaps in knowledge. There were no cost estimates in the study.

Also, based on a study of TPH, we estimate that regulations fracturing and voluntary producer adjustments would add about $0.54 per MMBtu to the Haynesville, Louisiana non-core play (See the following section for the analysis.) This is our fracturing best practices adjustment. Since this play probably won't be economic until about 2021, we phased the additional cost in from 2016 using a compound annual growth rate.

In 2010, TPH estimated the potential impact of fracturing regulations and voluntary changes by producers on the cost of production per well. The size and costs of wells vary substantially. We estimated the required increase in gas prices by running an economic well model of Haynesville non-core production in Louisiana and Marcellus shale. The results for Haynesville analysis are shown below. Since the average Haynesville well will not be economic until about 2021, we phased in the cost of development beginning in 2016. The required price increase for Marcellus was only about $0.20 per MMBtu.

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[22] Potential Economic And Energy Supply Impacts Of Proposals To Modify Federal Environmental Laws Applicable To The U.S. Oil And Gas Exploration And Production Industry, Prepared for U.S. Department of Energy Office of Fossil Energy, Advanced Resources International, 2007.

[23] Regulatory Impact Analysis, Final New Source Performance Standards and Amendments to the National Emissions Standards for Hazardous Air Pollutants for the Oil and Natural Gas Industry, U.S. Environmental Protection Agency, Office of Air and Radiation, Office of Air Quality Planning and Standards, April 2012.

[24] Unconventional Oil And Gas Development, Key Environmental and Public Health Requirements Report to Congressional Requesters, September 2012, Government Accountability Office and Information on Shale Resources, Development, and Environmental and Public Health Risks, GAO-12-732, Sep 5, 2012.

Exhibit 2-10. Potential Impact of Fracturing Regulation on the Breakeven Price of Natural Gas (2013$)

	2013$		
	Low	High	Average
Added cost per well without federal regulation	$211,025	$527,564	$369,294
Potential EPA cost compliance	$131,891	$263,782	$197,836
Total	$342,916	$791,345	$567,131
Cost per MMBtu Haynesville Non-Core			
Added cost per well without federal regulation	$0.21	$0.49	$0.35
Potential EPA cost compliance	$0.12	$0.26	$0.19
Total	$0.33	$0.75	$0.54

Source: Frac Attack, Tudor, Pickering, & Holt & Co. 2010

Some may argue that these estimates are not sufficiently rigorous to use in this study. There are two possible responses to that position, ignore the costs because we don't know what the regulations will be or make the best estimate possible of the likely impact. While the estimated cost of fracturing is based on limited information, all natural gas forecasts make projections with limited data. In some cases there is only six months of data on production in a play. One choice would be to ignore the play and the other is to do the best one can with it. The EIA forecast is full of these assumptions that are based on very limited data. A few examples are how much liquids are in a play, how much associated gas will come from oil shale plays, technology advances, etc.

Another question is the extent to which improvements in fracturing practices and/or tighter regulations will increase gas production costs or decrease those costs. Our analyses indicate the impact is most likely to be a modest increase in production costs. It is clear that various potential changes in regulations and state taxes could increase the cost of natural gas production. For example, with a $4.00 per MMcf wellhead price, the proposed Pennsylvania severance tax of 4.6 cents per MMcf plus 5 percent of the gross value would equal 24.6 cents per MMcf ($0.24 per MMBtu). The impact fees of $355,000 per well would be equal to about 12.5 cent per MMBtu. The total of these costs would be 36.5 cents per MMBtu. This compares to our estimated fracturing cost of about $0.20 per MMBtu in Pennsylvania and $0.54 per MMBtu for the marginal well. The 36.5 cent cost would be in addition to the fracturing costs. Also, it is highly likely that states will prohibit production in certain areas. New York is a prime example of this. This will add to production cost as well. Since AEO Reference Case forecasts are prohibited by law from reflecting any potential changes in regulations, such as changes in fracturing regulations, those forecasts will probably understate future natural gas prices, other things being equal.

Earlier we suggested that an argument could be made that the economic adjustment should be $1.43 per MMBtu versus the $0.33 per MMBtu adjustment actually used (marginal well economics adjustment). Our total adjustment for marginal well economics and fracturing operations improvements of $0.87 per MMBtu is a compromise with arguments about these issues. Looking at the entire picture, we believe it is reasonable. This is supported by the fact that the resulting forecast is close to the average of other publically available forecasts.

2.2.10 Comparison to other Forecasts of Annual Henry Hub Prices

Exhibit 2-11 presents the AEO 2012 Reference Case, the AEO 2012 with the EIA HH methodology adjustment, and the AESC 2013 Base Case. The table compares those three forecasts with Henry Hub prices, average prices, and average prices less IHSGI. The comparison shows the following:

- AEO 2013 prices are well below the NYMEX[25] prices as of March 15, 2013 and the average of public forecasts as of 2012. The AEO 2013 ER projected prices in 2016 prices are $0.86 per MMBtu below the NYMEX prices in 2015 and $0.47 per MMBtu (2013$) below the NYMEX in 2016. The large discrepancy between AEO 2013 forecast prices and the near term forward market raises questions about the economic assumptions in AEO 2013. In addition, the comparison of AEO 2013 with other forecasts and our analysis of the economics of production suggest that the AEO 2013 prices are likely too low.
- AEO 2012 projections with the EIA HH methodology adjustment are also well below the average of other forecasts in 2025.
- AESC 2013 Base Case prices are close to NYMEX in 2015 and 2016 and the average of all forecasts in 2025. Also, after taking out the IHSGI forecast, the AESC 2013 Base Case is close to the average of forecasts in 2035.

In addition to the above considerations, the full documentation of AEO 2013 was not available at the time the gas forecasts were being prepared. For these reasons, we chose to use AEO 2012 as our starting point.

[25] The volume of trading on NYMEX is very low after three years. Consequently, we do not view prices beyond that period as a meaningful guide to natural gas price. In June 2008, NYMEX prices were trading at $12 to $13 per MMBtu through 2025.

Exhibit 2-11.[26] Comparison of Price Projectons (2013$/MMBtu)

		Henry Hub 2013$/MMBtu		
		2015	**2025**	**2035**
NYMEX	NYMEX	4.15	5.59	NA
Non-AEO Forecasts	IHSGI	5.01	5.09	5.41
	EVA	4.29	6.83	7.66
	Deloitte	4.48	6.12	7.00
	SEER	4.52	6.64	8.12
	IEA 2012	4.75	6.61	8.26
	Average Non-AEO Forecast	*4.61*	*6.26*	*7.29*
AEO Forecasts	AEO 2013	3.22	5.03	6.53
	AEO 2012	4.53	5.94	7.77
	AEO 2012 EIA HH Meth.	4.20	5.39	7.08
AESC 2013	AESC 2013 Base Case	4.15	6.26	7.95
NYMEX Delta	AEO 2013	-0.93	-0.56	
	AEO 2012 EIA HH Meth.	0.04	-0.20	
	AESC 2013 Base Case	0.00	0.67	
NON-AEO Forecast Delta	AEO 2013 less Average	-1.39	-1.22	-0.76
	AEO 2012 EIA HH Meth.	-0.42	-0.86	-0.21
	AESC 2013 Base Case	-0.46	0.01	0.66
	AESC 2013 Base Case (1)	-0.36	-0.29	0.19
	(1) Excludes IHSGI from average			

Exhibit 2-12 below shows estimates of total natural gas consumption and supply in the United States in 2012, and AEO 2012 projections for 2020. Projected national consumption is expected to be about the same in 2020 as in 2012. The 2012 data is strongly influenced by weather. Heating Degree Days were 15 percent below normal in 2012. Much of the projected growth in the Residential and Commercial sectors is because the forecast assumes normal weather. Also, Cooling Degree Days were almost 15 percent above normal, this caused high electricity and natural gas demand for power generation. In addition,

[26] AEO 2013 Early Release Table 13 (http://www.eia.gov/forecasts/aeo/er/tables_ref.cfm). NYMEX prices are closing prices 2/27/2012 deflated using AEO 2013 inflation assumptions. The source of AEO 2012 is http://www.eia.gov/forecasts/aeo/pdf/0383 (2012).pdf page 113. AEO 2012 (Reference case): AEO 2012 National Energy Modeling System, run AEO 2012.REF2012.D020112C. IHSGI: IHS Global Insight, 30-year U.S. and Regional Economic Forecast (Lexington, MA, November 2011), website www.ihs.com/products/global-insight/index.aspx (subscription site). EVA: Energy Ventures Analysis, Inc., e-mail from Anthony Petruzzo (January 26, 2012). Deloitte: Deloitte LLP, e-mail from Tom Choi (January 26, 2012). SEER: Strategic Energy and Economic Research, Inc., e-mail from Ron Denhardt (February 21, 2012). IEA (International Energy Agency) World Energy Outlook 2012.

because of low natural gas prices, on a national basis natural gas displaced a significant amount of coal generation. As natural gas prices increase, gas is expected to lose market share back to coal throughout the United States. Despite essentially flat natural gas consumption, U.S. production is expected to increase to offset declines in Canadian production and for the export of LNG. Shale production will grow, while other sources of supply are expected to decline.

Exhibit 2-12. United States Gas Consumption and Supply: 2012 vs. AEO 2012 Projections for 2020 (Tcf/year)

	2012		2020
	(a)		(b)
Consumption of Natural Gas			
Residential and Commercial	7.06		8.26
Industrial and Transportation	7.11		7.16
Electric Power Generation	9.11		7.87
Pipeline and Lease & Plant Fuel	2.10		2.17
Total	**25.39**		**25.47**
Supply of Natural Gas			
Shale Gas Production (b)	8.13		9.69
Other	15.85		15.40
Total Production	23.98		25.09
Pipeline Net Imports	1.34		1.01
LNG Net Imports	0.18		-0.66
Total Net Imports	1.51		0.35
Total Supply	**25.53**		**25.5**

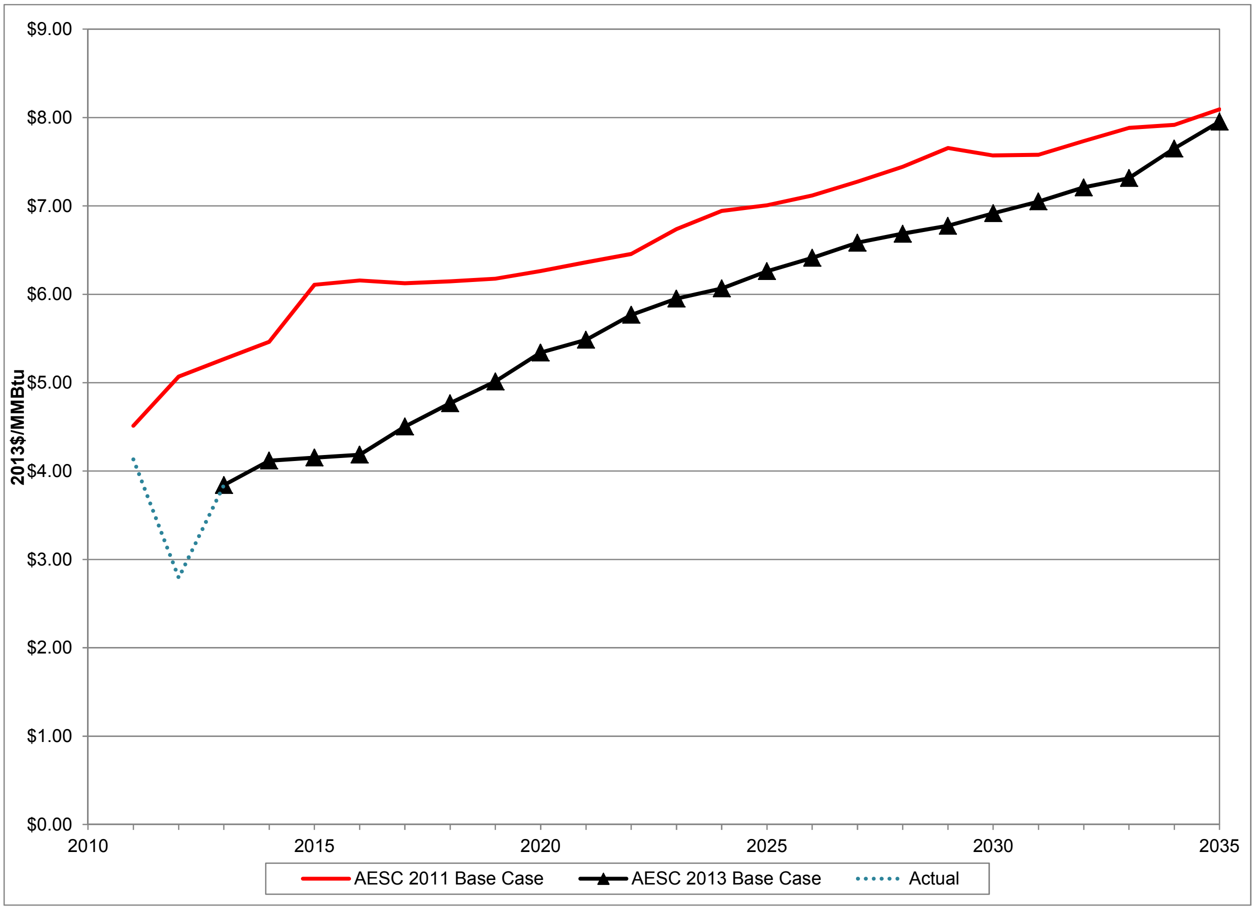
Source: (a) Actual 2012 is estimated based on EIA Short Term Energy Outlook, April 9th 2013. Supply does not add to total because of inventory change.. (b) Data from AEO 2012, Table A14 Oil and Gas Supply. Available at http://www.eia.gov/forecasts/aeo/pdf/0383(2012).pdf

The AESC 2013 Base Case forecast of Henry Hub prices that results from this methodology and set of assumptions is $5.37/MMBtu (2013$) on a 15-year levelized basis. This AESC 2013 Base Case forecast of Henry Hub prices would be approximately 17 percent less than the AESC 2011 Base Case forecast over that period.

Comparison to AESC 2011 Base Case

Exhibit 2-13 compares the AESC 2013 Base Case forecast with the AESC 2011 Base Case forecast. This comparison shows the AESC 2013 Base Case annual Henry Hub natural gas price forecast and the actual Henry Hub gas prices since 2011 through 2012.

Exhibit 2-13. Comparison of Henry Hub Natural Gas Price Forecasts (2013$/MMBtu)

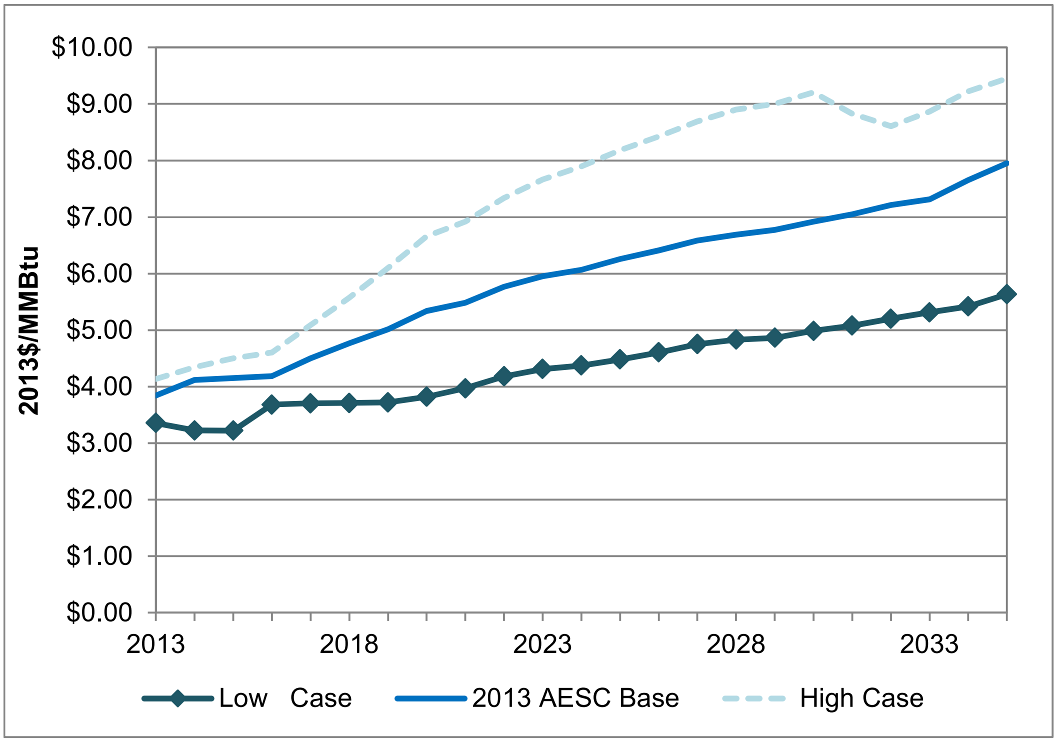


2.2.11 High and Low Case Forecasts of Henry Hub Prices

As discussed earlier in this chapter, there is a great deal of uncertainty about the natural gas price outlook. Among the factors driving these uncertainties are the size of the resource base, the expected ultimate recovery (EUR) of these resources, proposed LNG exports, technology changes, fracturing regulations, state taxes, oil prices, potential for increased use in the residential, commercial and industrial sectors, carbon regulations, and economic growth. To reflect this uncertainty, we have developed high and low gas price forecasts. These forecasts reflect high and low trends and do not account for short term variability caused by factors such as weather or supply disruptions. The high and low price forecasts are intended to reflect plausible outcomes rather than extreme possible values. The AESC 2013 Base Case forecast could be viewed as an expected value of the possible outcomes.

The forecasts of the AESC 2013 Base Case, High Price Case, and Low Price Case are shown in Exhibit 2-14. The average percentage deviations from the Base Case are approximately 23 percent for both the High Price and Low Price Cases. In the High Price Case, the Alaska gas pipeline comes online in 2031 because of the high prices. This causes prices to fall for a few years.

Exhibit 2-14. Forecasts of AESC 2013 Henry Hub Natural Gas Prices: Base, High and Low (2013$/MMBtu)



Both the high and low price cases are based on alternative assumptions about the EUR from the AESC 2013 Base Case. Disagreement about the EUR is one of the most contentious areas of the natural gas outlook. Since many plays are nascent, the data is very limited. The High Price case assumes the EUR is 50 percent lower than the EUR in the AESC 2013 Base Case and the Low Price case assumes the EUR is 50 percent higher. In addition, the Low Price projections do not include any adjustments for the economics of fracturing regulations. Also, AEO 2013 prices were used through 2016 because they were lower than the High EUR case. The High Price forecast adds an economic adjustment of $0.88 per MMBtu versus $0.33 per MMBtu in the AESC 2012 Base Case to the low EUR price. The higher economic adjustment is based on the assumption that a return is earned on some of the sunk costs.

Any estimate of the probability of these cases is highly subjective. Our estimate is that there is a 20 percent probability that the levelized value exceeds the high value and a 20 percent probability of it exceeding the low value; alternatively, there is a 60 percent probability of the levelized prices being within the range of the high and low price scenarios. The Base Case is the expected value.

2.2.12 Uncertainty Regarding Shale Gas Production

There is considerable uncertainty regarding projections of shale gas production quantities and costs, as described in previous sections and below. Given the uncertainty associated with projections of shale gas resource availability, production quantities, regulations, and costs, there is certainly a possibility that material changes in the long-term outlook for shale gas production and cost may occur after the completion of AESC 2013 and before the initiation of AESC 2015. Those material changes might be driven by public developments such as significant revisions to public geological analyses; a legislative body, policy agency, or regulatory agency identifying specific changes in the regulation of hydraulic fracturing; published estimates of the costs associated with regulatory changes; or changes in natural gas market prices. In the event of such public developments, members of the Study Group may choose to determine if the AESC 2013 Base Case and High Gas Price Case projections of natural gas prices are still suitable for use in energy efficiency cost-effectiveness analyses. If they determine that neither of those projections is within a range of reasonableness in light of the public developments, the members of the Study Group should consider revising the natural gas price forecast and the avoided costs.

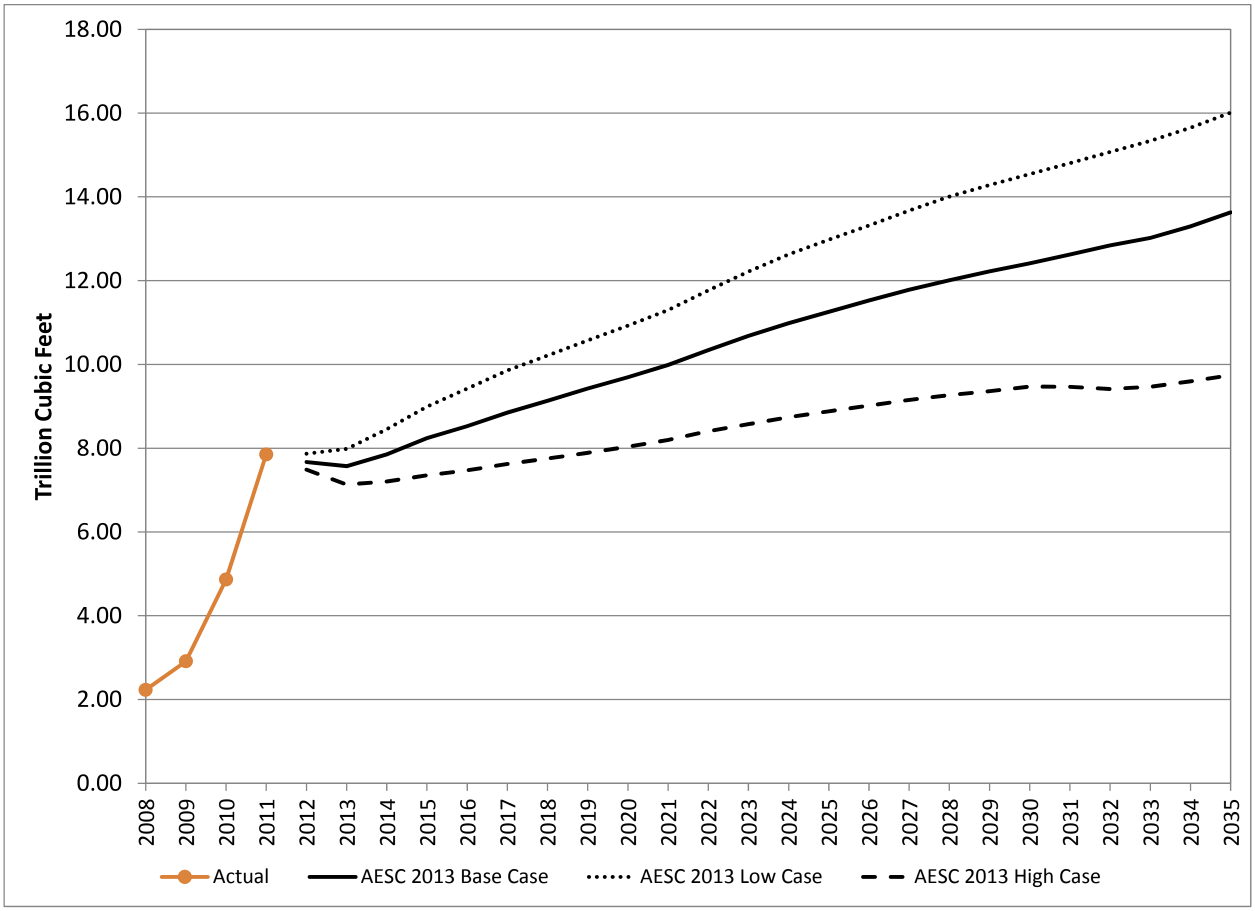
Technical Uncertainty

The first area of uncertainty relates to the estimates of technically recoverable quantities of shale gas and the costs of recovering those volumes. AEO 2013 acknowledges this uncertainty and identifies several factors that could tend to result in less production or higher costs under some scenarios, or more production and lower costs under other scenarios.[27] These factors include limited reliable data on long-term production profiles and ultimate gas recovery rates, use of production rates from portions of certain formations to infer the productive potential of the entire formation, and the possibility that technical advances could reduce drilling and completion costs.

Exhibit 2-15 presents actual levels of annual shale gas production from 2008 through 2011 as well as the projected production underlying the various cases we examined.

[27] AEO 2013 report page 77.

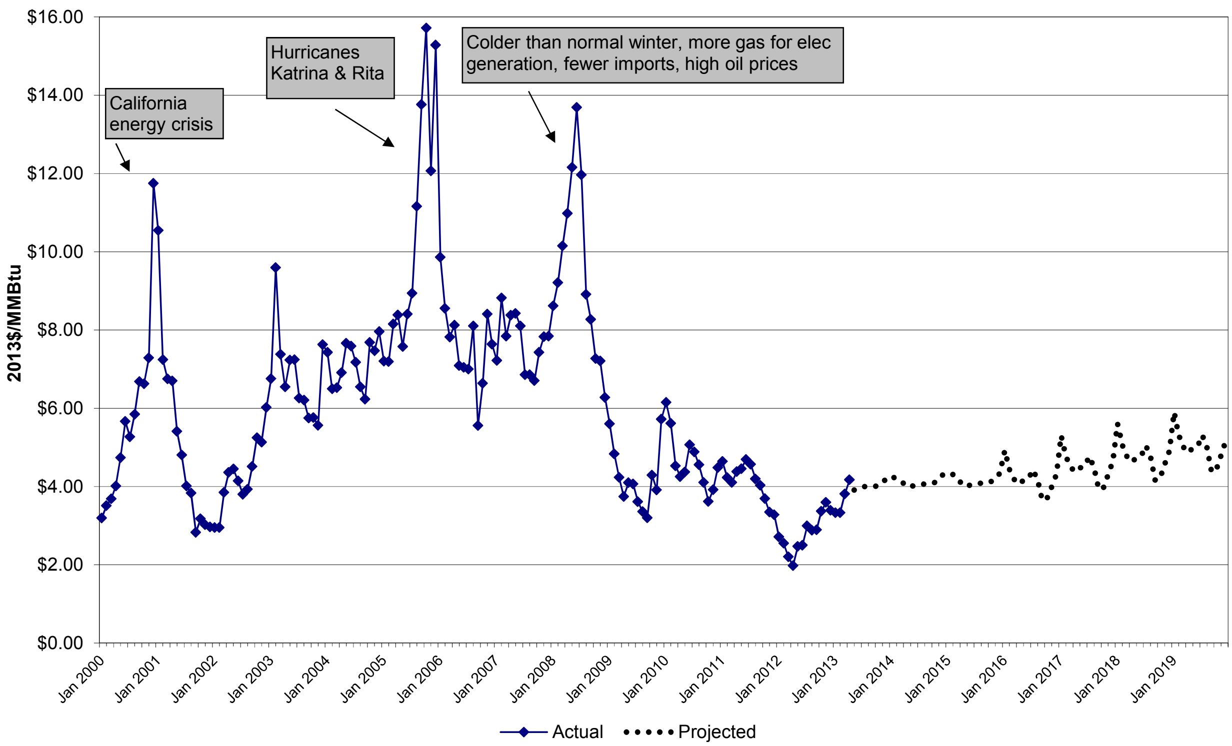
Exhibit 2-15. Dry Shale Gas Production: Actual and Projected (Tcf/year)



2.2.13 Volatility in Henry Hub Prices

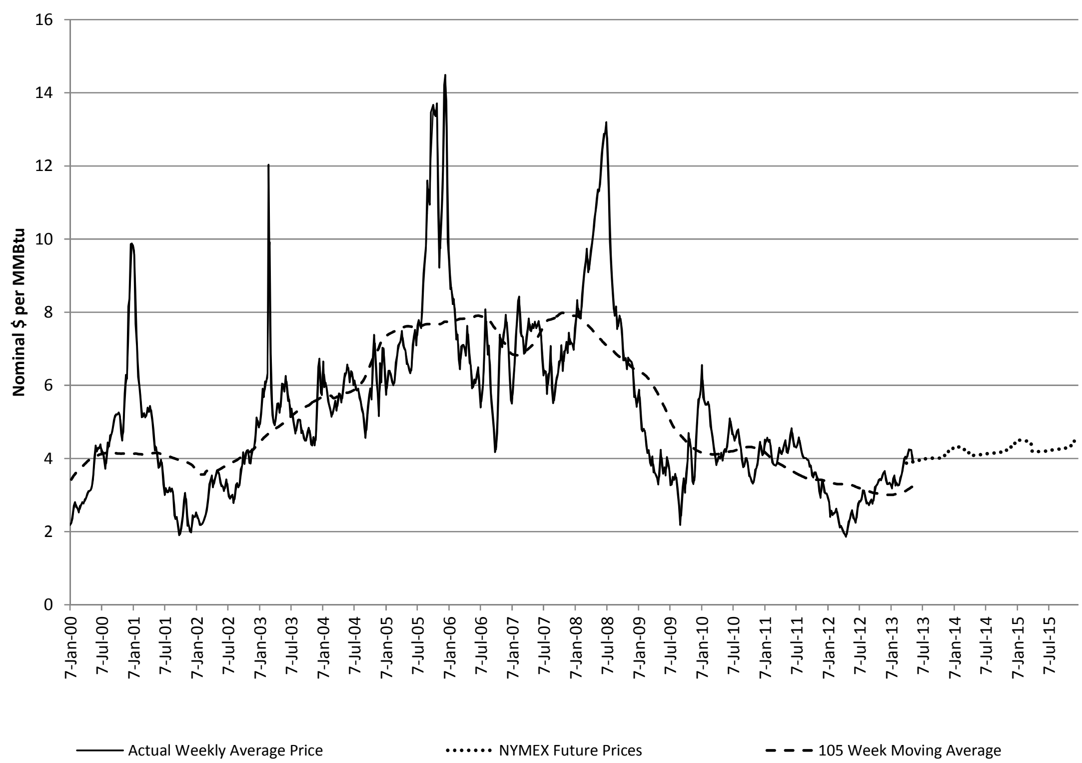
Volatility is a measure of the randomness of variations in prices over time as affected by short-term factors such as extreme temperatures, hurricanes, supply systems disruptions, etc. It is not a measure of the underlying trend in the price over the long-term. Our forecasts of Henry Hub prices under the Base, high, and low cases provide projections of expected average natural-gas price in any year. Actual gas prices are volatile and in any future month, week, or day will vary around the expected annual average prices forecast in each of those three cases. We have not attempted to forecast the actual monthly or weekly prices that would reflect historical price volatility primarily because we are forecasting prices used to evaluate avoided costs in the long term. Our analyses indicate that the levelized price of gas over the long term would not be materially different if one estimated increases from an occasional one-to-three-day price spike during a cold snap or even the type of several month gas price increases following Hurricane Katrina in the fall of 2005. For example, monthly Henry Hub prices were very volatile from 2000 through 2010, ranging from less than $4.00/MMBtu to over $14.00/MMBtu. See Exhibit 2-16. However, the levelized average annual cost over that period was $5.80/MMBtu. If one substitutes annual average prices for certain months with very high prices, such as the four months affected by Hurricanes Katrina and Rita, and the three month price spike in mid-2008, the levelized price over the entire eleven year period remains very similar at $5.65/MMBtu.

Exhibit 2-16. Monthly Henry Hub Prices, Historical (EIA) and Projected (2013 Dollars per MMBtu)



The range of volatility in weekly Henry Hub gas prices is even higher. Exhibit 2-17 shows the weekly average of the daily spot price of natural gas at the Henry Hub from 2000 through May of 2013 and then monthly NYMEX gas futures prices through December 2013. These prices are in nominal dollars; they have not been adjusted for inflation because this discussion of volatility does not require prices in real terms.

Exhibit 2-17. Henry Hub Average Weekly Natural-Gas Prices, Actual and Futures, Jan 2000 – Dec 2015



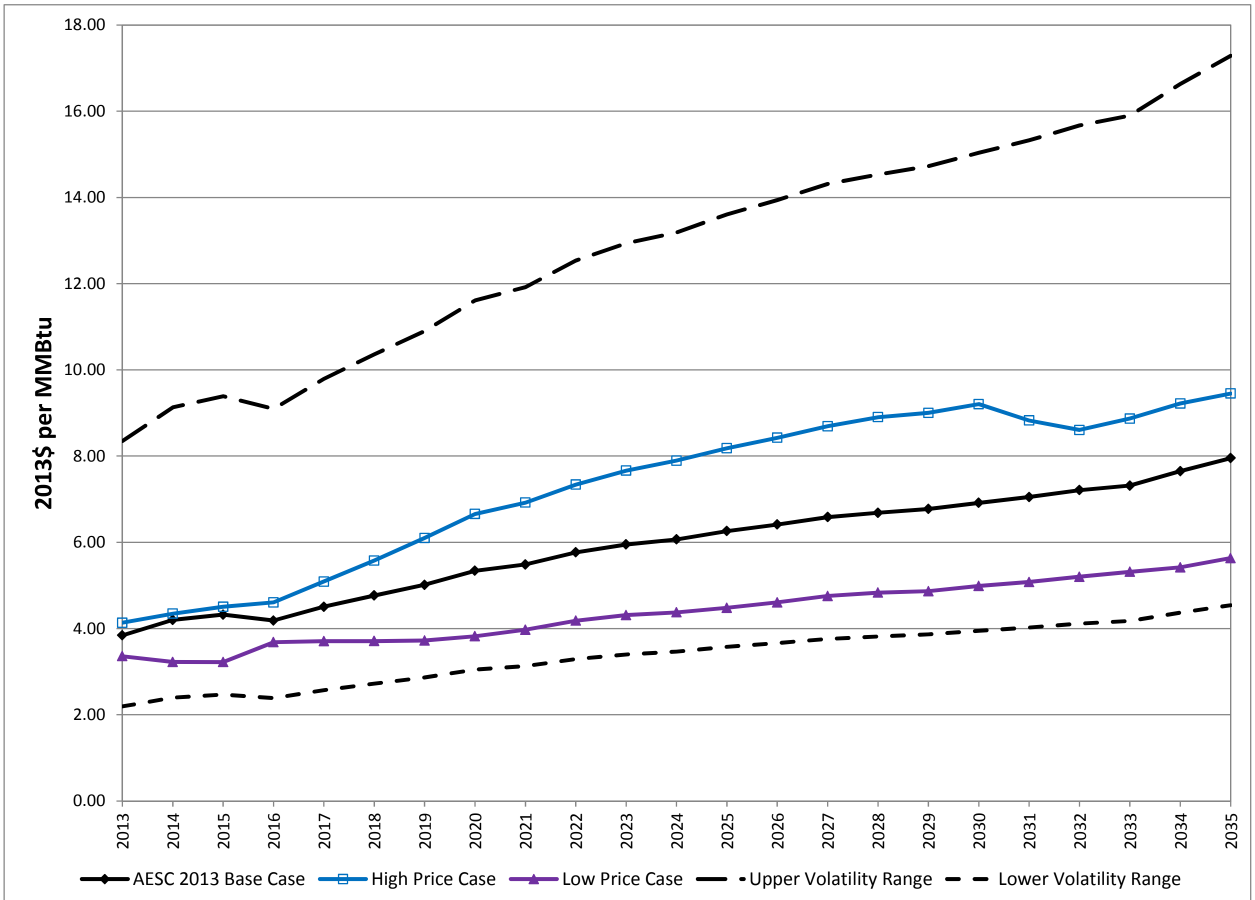
Price spikes and dips show price volatility. In New England and in other gas consuming areas, there have been daily price spikes during very cold weather, including recent price spikes in November 2012 and February 2013 in New England. In addition, natural-gas prices have increased for longer periods. The recent example of Hurricane Katrina in 2005 is illustrative, as follows.

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

In this example, a shock that removed 5 billion cubic feet per day of natural-gas supply produced a strong increase in prices. However, prices quickly reversed to more-typical levels and in less than a year gas futures price fell (temporarily) to a level less than one-third of the peak of December 2005. We expect such shocks and gas price volatility to continue periodically in the future. Nonetheless, the AESC 2013 Base Case gas price provides a reasonable estimate of average or expected Henry Hub gas prices for the purposes of this study.

We quantify Henry Hub–price volatility as follows. First, we find a 105-week moving average of the weekly prices centered on the current week. This 105-week moving average is the average of the 52 previous weeks of prices, the price of the instant week, and the prices from the 52 weeks following. Then, for each week we calculate the ratio of the current price to the 105 week average price. There have been four peak prices during this period of 2000 to March 2011 and the average ratio of the peak price to the 105-week moving average price as of that week is 2.17. Similarly, there were four downside bottoms in price and the average ratio of the four bottom prices is 0.56 of the 105-week moving average price. These results indicate that the actual average of daily prices in any week could range between 0.59 and 2.17 of the long-term average of Henry Hub daily prices. Exhibit 2-18 depicts this range. The range of price volatility is large, especially compared with the upper and lower range of forecast average prices.

Exhibit 2-18. Range of Potential Weekly Price Volatility versus the Forecast Base Case Annual Average Henry Hub Natural Gas Price (2013$/MMBtu)



2.3 Wholesale Natural Gas Prices in New England

The wholesale natural gas price in New England is the market price paid by merchant power plants, large direct use customers, and the LDCs for gas purchased at interstate pipeline delivery points in New England. The wholesale natural gas price in New England is our estimate of the avoided costs for electric generation.

For the New England market, the principal measures of wholesale gas prices are the Algonquin Citygates price index and the Tennessee Zone 6 price index. These are published indices of prices for monthly sales and daily spot sales for gas delivered from the two largest transporters of natural gas into the New England market. These price indices are also used as reference prices for long-term, firm sales transactions.

2.3.1 Changes in Gas Industry Affecting Wholesale Prices in New England

The following summarizes the difference between the AESC 2011 and AESC 2013 methodology.

AESC 2011

AESC 2011 developed its forecast of New England wholesale gas prices directly from its forecast of the Henry Hub prices. It began by calculating the historical average ratio of the New England wholesale market prices to Henry Hub prices for each calendar month. It then applied that ratio to the monthly Henry Hub forecast to develop the monthly New England wholesale market price forecast. AESC 2011 calculated separate ratios for the Tennessee Zone 6 price index—which was used to develop the wholesale price forecast for Massachusetts, New Hampshire, and Maine—and for the Algonquin Citygates price index—which was used to develop the wholesale price forecast for Connecticut and Rhode Island. AESC 2011 also developed a combined forecast for the New England region (excluding Vermont) using an average of the two ratios.

AESC 2013

Several important developments have occurred since the release of AESC 2011 which have changed the historical relationship between wholesale natural gas prices in New England and natural gas prices at the Henry Hub:

- Rapid growth in Marcellus shale gas production in the Appalachian[28] producing area has reduced gas prices in the Northeast relative to Henry Hub. This trend is expected to continue as Appalachian gas production expands.
- Lower gas imports from Canada and fewer LNG shipments to New England import terminals have reduced east-to-west gas flows into the New England market. Between 2011 and 2012, Maritimes & Northeast Pipeline's average receipts at the New Brunswick border declined from just over 400 MMcf per day (approximately 15 percent of total New England natural gas consumption) to less than 190 MMcf per day. Receipts at the Distrigas LNG terminal in Everett, Massachusetts dropped from 371 MMcf per day in 2011 to 236 MMcf per day in 2012.
- The reduction in east-side gas receipts has caused the pipelines delivering gas into New England from the west to operate at, or near, capacity much more frequently. These gas transmission constraints have caused New England gas prices to diverge from prices in other Northeast markets. Significant expansion of natural gas pipeline capacity into New England is not expected to occur before 2016.

The wholesale price forecast methodology for AESC 2013 accounts for the above changes affecting the relationship between wholesale prices in New England and Henry Hub prices. First, supply from the Appalachian area is expected to replace supply from the Gulf Coast as the primary driver of Northeast region gas prices. Second, Appalachian prices are expected to decline relative to Henry Hub prices. Third, the expected constraints on gas transmission capacity into New England through 2016 are

[28] The principal gas-producing states in the Appalachian area are Pennsylvania and West Virginia.

expected to cause New England prices to diverge from prices elsewhere in the Northeast. Based upon those factors, we develop the AESC 2013 New England wholesale gas price forecast in two steps.

The first step is to create a price forecast for Appalachian area gas supplies from the forecast of Henry Hub prices. We do this by applying the ratio of forecast Northeast region wellhead prices to forecast Henry Hub prices from the AEO 2012 Reference Case to the Henry Hub price. This ratio reflects the EIA's projected reduction in annual Appalachian gas prices relative to annual Henry Hub prices over the forecast period. The EIA projects that the Appalachian supply area price, which has historically been higher than the Henry Hub price, will be 5 percent below Henry Hub in 2015, and 9 percent below Henry Hub in 2035. We add an adjustment of $0.10 per MMBtu (2013$) to the resulting Appalachian supply area wellhead price forecast to arrive at a forecast Appalachian "into-pipeline" price.

The second step is to develop the New England wholesale price forecast. We develop separate forecasts for two time periods: (1) January 2013 through March 2016, and (2) April 2016 onward. For the period January 2013 through March 2016 we calculate the wholesale market gas price by adding the exchange-traded basis futures prices for the Algonquin Citygates price index to our forecast Henry Hub price.[29] This is consistent with the methodology for the AESC 2013 Henry Hub gas price forecast, which also uses NYMEX natural gas futures prices for the first three years of the forecast period.

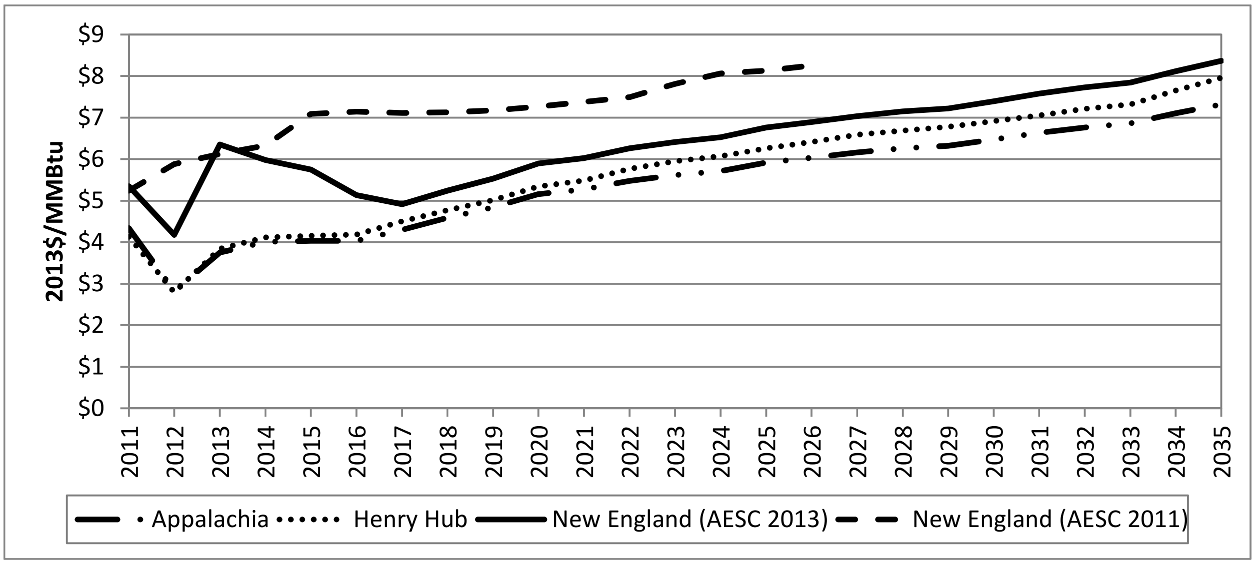
From April 2016 onward, the New England wholesale price forecast is based on the Appalachian "into-pipeline" price forecast described above. We assume the relationship between the New England wholesale market gas price and the Appalachian supply area price will return to the conditions that existed before gas transmission constraints began to cause extreme, localized price spikes in the New England market, i.e. prior to 2012. The methodology used here is similar to methodology used to forecast New England wholesale prices for AESC 2011, in that the wholesale price is calculated by applying historical ratios of monthly New England prices to monthly Appalachian area prices to the Appalachian area price forecast. The historical New England market prices used are the average of the Tennessee Zone 6 index price and the Algonquin Citygates index price. The Appalachian area price is measured by the Dominion South Point index price. The historical ratios for each calendar month are calculated by the averaging the individual-year ratios for the years 2007 through 2011.

The graph below compares the AESC 2013 New England wholesale natural gas price forecast to the AESC 2013 Henry Hub and Appalachian price forecasts and the New England price forecast from AESC 2011. After the first three years, when the New England price forecast is based on future prices, the ratio between the New England price and the Appalachian price remains constant. Because the Appalachian price is expected to decline relative to the Henry Hub price, the difference between the New England price and the Henry Hub price narrows over time. Except for 2013, the AESC 2013 New England gas price forecast is substantially lower than the AESC 2011 forecast.

[29] The basis price futures product is the CME ClearPort "Algonquin Citygates Natural Gas (Platts IFERC) Basis Futures." We use the settlement prices for the March 15, 2013 trading day.

The New England price forecast for the years 2013 through 2016 reflects the supply reductions and gas transmission constraints that are currently affecting gas deliveries into the New England market. We assume that these extreme supply conditions will phase out by 2017, and that the relationships between New England natural gas prices and prices in other Northeast markets will return to the relationships that existed prior to 2012. This assumption is largely supported by the fact that several significant projects to expand pipeline capacity into New England have been proposed that could be completed by 2016. In addition, other near-term developments are expected to narrow the gap between New England prices and prices in other markets. One of these is the start-up of production from the Deep Panuke field in offshore Nova Scotia. A second is the construction of new pipeline capacity to deliver Marcellus shale gas into New York City and Long Island, which should allow some of the existing Canadian and domestic gas supplies flowing on IGTS to be diverted to New England markets. This suggests that the New England gas price basis will gradually decline between now and 2017, even if one or more of the proposed New England pipeline expansion projects is delayed.

Exhibit 2-19. AESC 2013 New England Wholesale Gas Price Forecast (2013$/MMBtu)



Natural Gas Price Forecasts for Other Market Hubs

As noted above, AESC 2013 estimates the avoided cost of gas supply to LDCs based upon an analysis of their various gas supply resources. These estimates require price forecasts for two supply areas other than Appalachia: the Mid-Atlantic region (defined as Eastern Pennsylvania, New Jersey, and portions of downstate New York), and the Dawn Hub in southeastern Ontario. Natural gas prices in the Mid-Atlantic market region are represented by the index price for gas delivered to points within the Texas Eastern Transmission market zone 3 (TETCO M3).

The TETCO M3 price forecast for AESC 2013 is developed by applying historical monthly price ratios for the years 2008 to 2012 to the Appalachian price forecast. The Dawn price forecast is developed by adding the average monthly basis over the 2008 to 2012 period, in 2013$, to the Henry Hub forecast. Forecasts for years 2013 through 2028 can be found in Exhibit 2-20.

Exhibit 2-20. Natural Gas Wholesale Price Forecasts, 2013$/MMBtu

Year	Henry Hub	Appalachia	TETCO M3	Dawn	New England
2013	3.84	3.75	4.13	4.19	6.35
2014	4.12	4.01	4.42	4.47	5.98
2015	4.15	4.03	4.44	4.50	5.75
2016	4.18	4.03	4.44	4.53	5.14
2017	4.50	4.30	4.74	4.85	4.91
2018	4.77	4.59	5.05	5.11	5.24
2019	5.01	4.84	5.33	5.36	5.53
2020	5.34	5.16	5.68	5.69	5.90
2021	5.48	5.27	5.80	5.83	6.02
2022	5.77	5.48	6.03	6.11	6.26
2023	5.95	5.61	6.18	6.30	6.41
2024	6.07	5.71	6.29	6.41	6.52
2025	6.26	5.92	6.52	6.61	6.76
2026	6.41	6.03	6.64	6.76	6.89
2027	6.58	6.16	6.78	6.93	7.04
2028	6.69	6.26	6.89	7.03	7.15

2.3.2 Natural Gas Price Forecast by State

AESC 2011 developed separate New England wholesale natural gas price forecasts by region. For the states of Massachusetts, New Hampshire, and Maine, the wholesale price was based on the historical relationship between Henry Hub and the Tennessee Zone 6 price index. For Connecticut and Rhode Island, the wholesale was based on the historical relationship between Henry Hub and the Algonquin Citygates price index. AESC 2011 did not include a wholesale natural gas price forecast for Vermont because there is not a liquid spot market for gas delivered to locations within the state.

In preparing the New England wholesale natural gas price forecast for AESC 2013, we examined the relationship between the Tennessee Zone 6 and Algonquin Citygates price indexes using daily data for the years 2009 through 2012. The results, which are summarized in Exhibit 2-21, show little or no difference between the two indexes when day-to-day differences are averaged over the course of a year. In addition, the three Southern New England states receive gas from both major pipelines. For forecast purposes, therefore, we use a single natural gas price to represent the wholesale market in the five states included in the Southern New England and Northern New England regions. This price represents an average of the Algonquin Citygates price and the Tennessee Zone 6 price.

Exhibit 2-21. Comparison of Algonquin Citygate and Tennessee Zone 6 Indexes ($/MMBtu)

	2009	2010	2011	2012
AGT Citygates	$4.80	$5.29	$4.99	$3.94
TGP Zone 6 (200 Leg)	$4.80	$5.23	$5.00	$3.92
Difference	$0.00	$0.06	-$0.01	$0.02

Source: IntercontinentalExchange

2.4 Avoided Natural Gas Costs by End Use

2.4.1 Introduction and Summary

The avoided cost of gas at a retail customer's meter has two components: (1) the avoided cost of gas delivered to the LDC; and (2) the avoided cost of delivering gas on the LDC system (the "retail margin"). Natural gas avoided costs are presented with and without the retail margin.

Avoided natural gas cost estimates are developed for three regions: Southern New England (Connecticut, Rhode Island, and Massachusetts), Northern New England (New Hampshire and Maine), and Vermont. These region definitions are different from AESC 2011, which grouped Massachusetts with New Hampshire and Maine. New Hampshire and Maine are separated from Southern New England because these markets are much more dependent on gas deliveries from the Maritimes & Northeast Pipeline and the Portland Natural Gas Transmission System than the other New England states. Avoided gas costs for Vermont, which receives natural gas directly from TransCanada PipeLines and has no connections to the rest of the New England gas market, are estimated independently.

The AESC 2013 avoided cost estimates are summarized in Exhibit 2-22 and Exhibit 2-23. These exhibits also compare the AESC 2013 results to the corresponding values from AESC 2011.

Exhibit 2-22. Comparison of Avoided Gas Costs by End Use Assuming No Avoidable Retail Margin, AESC 2013 vs. AESC 2011 (15-year levelized, 2013$/MMBtu except where indicated as 2011$/MMBtu)

	RESIDENTIAL				COMMERCIAL & INDUSTRIAL			ALL RETAIL END USES
	Non Heating	Hot Water	Heating	All	Non Heating	Heating	All	
Southern New England (a)								
AESC 2011 (2011$/MMBtu)	7.04	7.04	7.81	7.57	7.04	7.81	7.57	7.57
AESC 2011 (b)	7.27	7.27	8.06	7.83	7.27	8.06	7.83	7.83
AESC 2013	6.08	6.57	6.73	6.60	6.26	6.58	6.44	6.53
2011 to 2013 change	-16.41%	-9.61%	-16.54%	-15.66%	-13.88%	-18.46%	-17.74%	-16.61%
Northern New England (a)								
AESC 2011 (2011$/MMBtu)	6.94	6.94	7.58	7.39	6.94	7.58	7.39	7.39
AESC 2011 (b)	7.17	7.17	7.83	7.63	7.17	7.83	7.63	7.63
AESC 2013	6.03	7.53	8.02	7.62	6.58	7.54	7.12	7.39
2011 to 2013 change	-15.98%	5.01%	2.41%	-0.15%	-8.18%	-3.67%	-6.68%	-3.17%
Vermont								
AESC 2011 (2011$/MMBtu)	7.06	7.06	8.63	8.16	7.06	8.63	8.16	8.16
AESC 2011 (b)	7.29	7.29	8.91	8.43	7.29	8.91	8.43	8.43
AESC 2013	6.32	6.91	7.11	6.95	6.54	6.92	6.75	6.86
2011 to 2013 change	-13.39%	-5.22%	-20.28%	-17.54%	-10.36%	-22.41%	-19.91%	-18.63%

(a) Massachusetts was included with Northern New England in AESC 2011, but is included with Southern New England in AESC 2013.
(b) Factor to convert 2011$ to 2013$ 1.0331

Note: AESC 2011 levelized costs for 15 years 2012 - 2026 at a discount rate of 2.465%.
AESC 2013 levelized costs for 15 years 2014 - 2028 at a discount rate of 1.36%.

Exhibit 2-23. Comparison of Avoided Gas Costs by End Use Assuming Some Avoidable Retail Margin, AESC 2013 vs. AESC 2011 (15-year levelized, 2013$/MMBtu except where indicated as 2011$/MMBtu)

	RESIDENTIAL				COMMERCIAL & INDUSTRIAL			ALL RETAIL END USES
	Non Heating	Hot Water	Heating	All	Non Heating	Heating	All	
Southern New England (a)								
AESC 2011 (2011$/MMBtu)	7.64	7.64	9.39	9.11	7.58	8.82	8.44	8.75
AESC 2011 (b)	7.89	7.89	9.70	9.41	7.83	9.11	8.72	9.04
AESC 2013	6.67	7.17	8.30	8.12	6.88	7.74	7.44	7.80
2011 to 2013 change	-15.43%	-9.17%	-14.43%	-13.70%	-12.06%	-15.02%	-14.74%	-13.77%
Northern New England (a)								
AESC 2011 (2011$/MMBtu)	7.47	7.47	8.96	8.73	7.59	8.79	8.43	8.58
AESC 2011 (b)	7.71	7.71	9.26	9.02	7.84	9.08	8.71	8.86
AESC 2013	6.53	8.04	9.35	8.91	7.04	7.43	7.17	7.31
2011 to 2013 change	-15.34%	4.17%	0.97%	-1.19%	-10.21%	-18.21%	-17.67%	-17.56%
Vermont								
AESC 2011 (2011$/MMBtu)	7.54	7.54	9.88	9.37	7.30	9.08	8.54	8.86
AESC 2011 (b)	7.79	7.79	10.21	9.68	7.54	9.38	8.82	9.15
AESC 2013	6.94	7.53	8.74	8.54	6.68	7.19	6.98	7.61
2011 to 2013 change	-10.88%	-3.22%	-14.37%	-11.85%	-11.37%	-23.33%	-20.86%	-16.83%

(a) Massachusetts was included with Northern New England in AESC 2011, but is included with Southern New England in AESC 2013.
(b) Factor to convert 2011$ to 2013$ 1.0331

Note: AESC 2011 levelized costs for 15 years 2012 - 2026 at a discount rate of 2.465%.
AESC 2013 levelized costs for 15 years 2014 - 2028 at a discount rate of 1.36%.

The avoided natural gas cost estimates for AESC 2013 are generally lower than the AESC 2011 estimates. The main reason for this is the lower projected gas price at Henry Hub. The AESC 2013 avoided natural gas cost estimates are also lower than the AESC 2011 estimates because LDCs in Southern New England and Northern New England are expected to purchase more gas in the Appalachian region, at market prices that are projected to be below the Henry Hub benchmark price.

The difference between avoidable natural gas costs for heating and non-heating loads in the Northern New England region is greater than for AESC 2011. This is mainly the result of the change in region definitions. Since Massachusetts is now included in Southern New England, the Northern New England region is composed solely of Maine and New Hampshire. These markets have less access to the Gulf Coast and Appalachian supply areas, and are more dependent on higher-cost supply, transportation, and storage services from Canada. While the Vermont market is even more dependent on Canadian resources than Northern New England, the cost of delivering this gas to Northern New England is greater because of higher transportation costs on TCPL and the additional cost of pipeline transportation service from the Canadian border to the LDC citygate. Because Northern New England (Maine and New Hampshire) takes a lot of gas supply from Canada, and the Canadian transportation services have high fixed costs (and little or no variable cost), the cost of supplying low-load-factor customers is therefore relatively high, especially after 2018 when existing long term contracts will need to be extended or replaced.

Another change from AESC 2011 to AESC 2013 is that the load shape used for residential hot water customers for AESC 2013 includes a temperature-sensitive component, while the load shape used for AESC 2011 did not.

2.4.2 Retail Customer Load Shapes

In broad terms, the shape of the retail gas load has a major impact on the cost of natural gas supplied and thus the avoided natural gas costs. End uses of natural gas at the retail level are distinguished by three types of end use: heating (low load factor), non-heating (high load factor), and all. The costs associated with these end uses also vary by the type of customer or sector, i.e., residential, commercial, and industrial.[30]

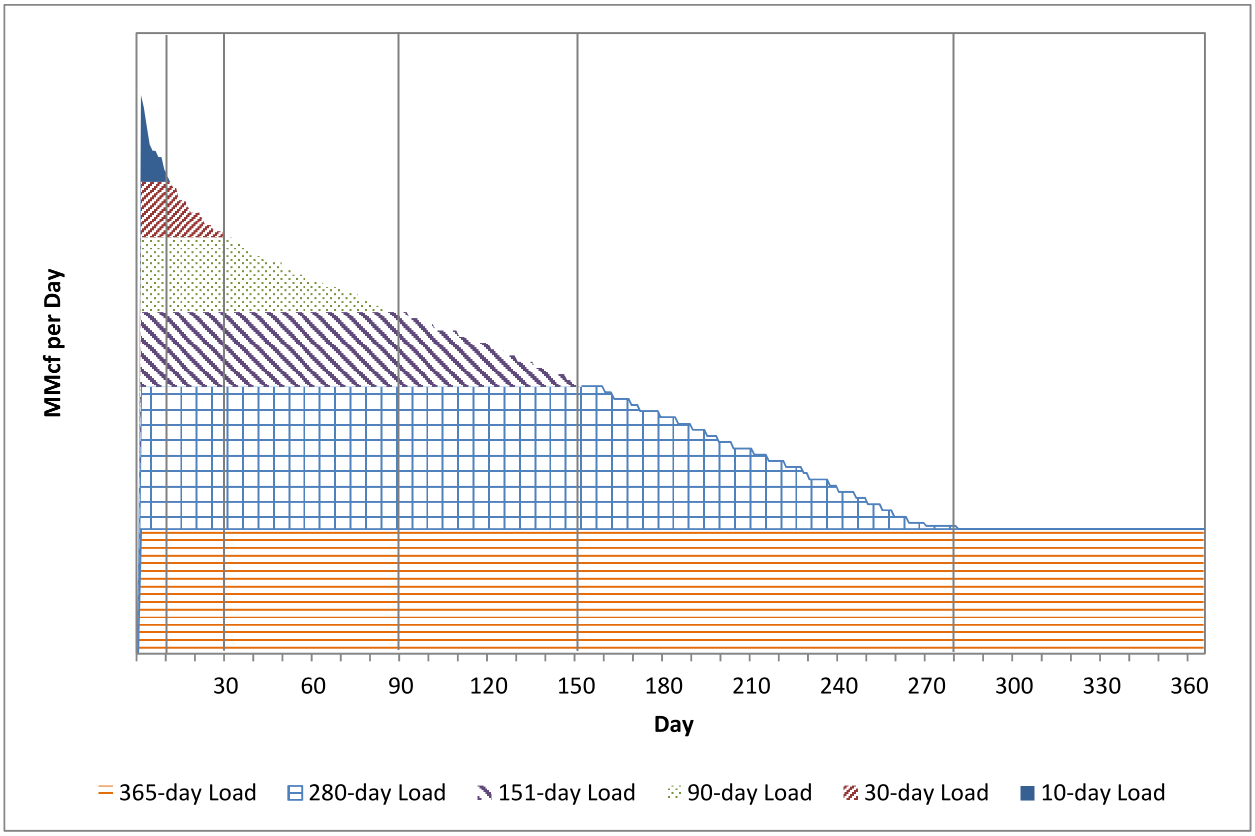
Seasonal variations in natural gas use have a large impact on delivered gas costs. LDCs typically contract for firm pipeline transportation services from supply areas to the citygate to meet their average daily requirement over the year. Off-system storage services and on-system peaking resources are used to meet the higher winter season requirements of temperature-sensitive customers.

The variation in daily gas requirements over the course of a year can be described by a load duration curve. For this study, we represent the load shape of each retail customer type by dividing the annual gas requirement into six load segments, as represented by the Representative Segmented Load Duration Curve in Exhibit 2-24. These are:

(1) Annual base load (365 days per year)
(2) Winter/shoulder load (280 days per year)
(3) Winter base load (151 days per year)
(4) 90-day load
(5) 30-day load
(6) 10-day load

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

Exhibit 2-24. Representative Segmented Load Duration Curve (MMcf/day)



Moving up the load curve, each load segment represents the incremental daily gas requirement compared with the previous segment. These load segments were chosen because they provide a reasonable representation of the shape of the load duration curve. These segment definitions also correspond to the types of gas supply resources that New England LDCs use to meet retail customer requirement. Non-heating load is the base load responsible for the lowest tier in the load duration curve, and is constant year round. Heating load, which varies as a function of the heating degree day (HDD), generally occurs October through May with a peak in January. The heating load represents the largest end use and determines the shape of the other tiers within the load duration curve.

On the supply side, long-haul pipeline capacity is generally used to meet annual baseload and a portion of the additional requirement in the winter and shoulder months. Off-system storage is used to meet winter baseload, 90-day, and 30-day requirements. On-system peaking resources are typically reserved to meet the incremental requirements on the few coldest days each year.

The distribution of the annual gas demand for each of the five types of end use is shown in Exhibit 2-25. These numbers are derived from base use per day and use per heating degree day (HDD) estimates provided by National Grid (MA). The shape of the HDD distribution is based on information provided by Northeast Utilities. These retail end use load shapes were considered representative for all three New England regions and were used for our analyses of each region.

Exhibit 2-25. Distribution of Gas Use by Load Segment

	Residential			Commercial & Industrial	
Load Segment	Non-Heating	Water Heating	Heating	Non-Heating	Heating
Annual Baseload	100.00%	24.46%	0%	71.95%	23.80%
Winter/Shoulder	0%	49.67%	65.75%	18.44%	50.10%
Winter Baseload	0%	14.72%	19.49%	5.47%	14.85%
90-Day	0%	9.33%	12.35%	3.47%	9.41%
30-Day	0%	1.68%	2.23%	0.62%	1.70%
10-Day	0%	0.14%	0.18%	0.05%	0.14%
Total	100.00%	100.00%	100.00%	100.00%	100.00%

Source: Synapse calculations and LDC survey results

2.4.3 Avoidable Gas Supply Resources

Each LDC develops a portfolio of gas supply resources to meet the requirements of its firm retail customers. As a regulated utility company, the LDC is obligated to provide a reliable supply of natural gas at the lowest reasonable cost.

The gas supply costs that are avoided by reducing retail customer gas consumption will depend on which gas supply resources are on the margin. The marginal gas supply resources are determined by the characteristics of an LDC's existing gas supply portfolio, and the opportunities to add or eliminate resources in response to changes in projected requirements. Since LDCs practice least-cost planning, the marginal gas supply resource will generally be the resource with the highest delivered cost for serving a given type of load.

While all gas supply resources are avoidable over the long run, in the near term LDCs often hold multi-year contracts that commit the LDC to pay for a firm pipeline transportation service or off-system storage service for a minimum period of time. In these situations, the fixed cost of the resource cannot be avoided until the end of the contract term, when the LDC typically has an option to renew or terminate the service. Until the "renew or terminate" decision is faced, however, the avoided cost of the resource is the variable cost of utilizing the resource to supply end use customers. Similarly, we assume that LDCs will continue to operate and maintain the on-system peaking facilities that are currently in service. The avoided cost for an LNG peaking facility is therefore assumed to be the cost of purchased gas, and the fuel used for liquefaction and vaporization.[31] For a propane-based peaking facility, the avoided cost is assumed to be the delivered cost of propane.

[31] Because many New England LDCs depend on winter refill of LNG storage, the commodity price is the peak-month New England wholesale price. The LNG fuel use factors are 17 percent for liquefaction and 3 percent for vaporization. These fuel use factors are the same as those used for AESC 2011.

To identify the fixed and variable costs associated with the gas supply resources currently held by New England LDCs, we reviewed the most recent integrated resource plans of thirteen LDCs. While these LDCs have a variety of gas supply arrangements of different types and vintages, we were able to classify all of the existing gas supply resources of the New England LDCs into nine basic resource categories based on the source of the gas and the transportation infrastructure used to deliver it to New England.

1. Flowing Gas Supply

   a. Supply via Gulf Coast Transportation

This category consists of natural gas purchased in Texas and Louisiana and transported to Southern New England and Northern New England on long-haul pipeline capacity. Most of this gas is transported using firm transportation (FT) services that LDCs acquired when interstate pipelines unbundled sales services from transportation services in the 1980s. These "legacy" FT services are priced at standard tariff rates that reflect the costs of older, depreciated pipeline assets. For Southern New England the transportation cost is an average of (a) the TGP Zone 1 to Zone 6 tariff rates, and (b) the TETCO and AGT rates for FT service from TETCO WLA to New England citygates. For Northern New England, the transportation cost is the TGP Zone 1 to Zone 6 rates. We also assume that LDCs can use long-haul Gulf Coast capacity to deliver Appalachian area purchases when it is economic to do so.

   b. Supply via Dawn/Niagara Transportation

This category consists of natural gas that is either purchased at the Dawn, Ontario (ON) storage and transportation hub, or purchased at points upstream of Dawn—such as Michigan or Chicago—and delivered through Dawn. For LDCs in Southern New England, the transportation path includes Union Gas and TCPL services in Canada, and IGTS capacity in the U.S. LDCs that cannot receive gas directly from IGTS hold additional FT service on TGP or AGT. For LDCs in Northern New England and Vermont, the transportation path also includes Union Gas and TCPL. Vermont Gas takes gas directly from TCPL at Phillipsburg, while LDCs in Northern New England transport gas from the Canadian border on PNGTS. This category also includes gas transported from the Niagara import point to Southern New England and Northern New England on TGP, because of the close similarity between gas prices at Niagara and Dawn.

   c. Supply via Appalachia Transportation

This category consists of natural gas delivered via short-haul transportation capacity from points in western Pennsylvania and Southeastern Ohio to Southern New England. Although most of the transportation that LDCs hold on this path is used to deliver gas from storage, LDCs also hold stand-alone capacity from the Appalachian region.

   d. Supply via Wright, NY Transportation

This category consists of natural gas delivered from the interconnection between IGTS and TGP at Wright, NY to Southern New England. Wright, NY is expected to become more significant as a natural gas market center as Appalachian production increases, and more pipeline capacity is built to move gas to New England markets. A prime example is the proposed Constitution Pipeline, which would deliver 650 MMcf per day from gas producing areas in Pennsylvania to Wright beginning November 1, 2015.[32]

e. Supply via Mid-Atlantic Transportation

This category consists of gas delivered on AGT from interconnections with TETCO and other interstate pipelines in New Jersey to Southern New England.

f. New England Wholesale Purchases

This category is natural gas purchased at locations within the New England market area or firm gas sales at LDC citygates. The principal locations for local purchases are major pipeline interconnection points such as Dracut, MA (M&N, PNGTS and TGP); Beverly/Salem, MA (M&N and AGT); and Mendon, MA (AGT and TGP).

2. Off-System Storage

a. Supply from New York/Pennsylvania Storage

This category is natural gas delivered from legacy pipeline storage services and some storage services with independent storage operators in the Appalachian region.

b. Supply from Michigan/Dawn Storage

This category is natural gas storage services at the Union Gas storage and transmission hub at Dawn, ON, and services from Michigan storage fields located just west of Dawn. These storage services are newer than the NY/PA storage services, and generally priced at higher market rates.

c. On-System Peaking

This category is LNG and propane-based peaking facilities connected to the LDC distribution systems.

Exhibit 2-26 shows, on a consolidated basis, the gas supply resources that were available to the LDCs in each region to meet firm peak day requirements during the 2012-13 planning year.

[32] Federal Energy Regulatory Commission Docket CP13-499.

Exhibit 2-26. New England LDC Gas Supply Capability for the 2012-13 Planning Year, MMcf/day

Resource Type	Resource	Southern New England	Northern New England	Vermont
Flowing Gas	Gulf Coast	936.2	34.7	0
	Dawn/Niagara	169.4	15.9	39.5
	Appalachia	89.2	0	0
	Wright, NY	41.5	0	0
	Mid-Atlantic	78.7	0	0
	Local Purchases	318.8	99.7	0
	Sub-Total Flowing Gas	**1,633.8**	**150.3**	**39.5**
Off-System Storage	NY/PA Storage	662.3	30.8	0
	MI/Dawn Storage	127.3	32.9	19.1
	Sub-Total Off-System Storage	**789.6**	**63.7**	**19.1**
On-System Peaking	**Sub-Total On-System Peaking**	**1,334.2**	**57.2**	**7.7**
All Resource Types	**Total (Flowing, Storage, Peaking)**	**3,757.6**	**271.2**	**66.3**

Source: LDC resource plans

2.4.4 New Transportation Resources

Several projects are currently in development that would increase gas transportation capacity into the New England market.

Algonquin Incremental Market (AIM) Expansion

AGT proposes to expand its existing system to provide up to 450 MMcf per day of additional transportation service from interconnects with upstream pipelines near the NJ/NY border to delivery points in CT, RI, and MA. This service would be priced at an incremental rate tied to the size of the expansion and the actual cost of facilities. The planned in-service date is November 1, 2016. AGT held an open season for the AIM project in late 2012.

TGP Connecticut Expansion

TGP is offering 72 MMcf per day additional firm transportation service from its interconnection with IGTS at Wright, NY to delivery points in CT. The planned in-service date is November 1, 2016. TGP estimates the cost of the Connecticut Expansion Project to be $81.2 million.[33]

TGP Northeast Expansion

In addition to the Connecticut Expansion Project, TGP proposes to expand its system from Wright, NY to other points in CT and MA by constructing a new pipeline across northern Massachusetts. The Northeast

[33] Kinder Morgan Investor Presentation dated January 30, 2013.

Expansion Project could range from 500 to 1,200 MMcf per day. Service would be available in November 2017, or later.[34]

PNGTS Continent to Coast

PNGTS is offering additional firm transportation service from the Canadian border to its interconnection with M&N at Westbrook, ME. Service would be available as soon as November 1, 2016, but would require an upstream expansion by TCPL.

TCPL 2013 Eastern Market Expansion

TCPL has received National Energy Board approval for a project that would expand capacity on the Dawn-to-New England transportation path. This project will allow TCPL to provide 3.3 MMcf per day of additional firm transportation service for Vermont Gas starting November 1, 2013. Further expansions of the Union Gas and TCPL systems to increase gas deliveries of Dawn and Niagara are planned for 2015.

The cost of building new, incrementally priced gas transmission capacity into the New England market has been factored into the AESC 2013 avoided cost analysis by including three new gas supply resources in the list of options available to LDCs. The first new resource corresponds to the TGP Connecticut Expansion Project, and provides for up to 72 MMcf per day of firm transportation service beginning in 2016. Based on TGP's capital cost estimate of $18.2 million, we assume that this capacity has a fixed cost of $0.52 per MMBtu (2013$). This cost is approximately 60 percent higher than TGP's standard tariff rate for transportation service from New York to New England.

The second new resource represents capacity on either the AGT AIM Project or the TGP Northeast Expansion to delivery points in the Southern New England. The fixed cost of this capacity is assumed to be $1.00 per MMBtu (2013$) for service starting 2016 or later. This cost is based on the estimated cost of a generic short-haul expansion on TGP or AGT that was developed by the three Connecticut LDCs and filed with the Public Utilities Regulatory Authority with the LDCs' most recent five-year supply-demand forecasts.[35]

The third new resource represents a TGP expansion that would increase gas deliveries into Northern New England sometime after 2016. The fixed cost for this resource is assumed to be the same as the cost of a generic short-haul expansion into Southern New England.

2.4.5 Avoided Gas Supply Cost by Load Segment

We calculate the cost of using each resource to supply each of the six load segments defined earlier in section 2.4.2. The gas commodity cost is calculated for each load segment to match the corresponding time period during the year. For example, the price of gas for the 90-day load segment is assumed to be

[34] TGP Presentation at Northeast Gas Association's Regional Market Trends Forum, April 30, 2013.

[35] See Southern Connecticut Gas, "Forecast of Natural Gas Demand and Supply, 2013-2017", Docket No. 12-10-06, October 1, 2012, Exhibit S-8.

the average price for the months of December through February. The gas price for the 30-day load segment is the highest monthly price for the same three-month period. The transportation fixed costs will also vary depending on the number of days per year that the capacity is utilized. For example, if the fixed cost of using a transportation service for annual baseload deliveries (100 percent load factor) is $1.00 per MMBtu, the cost of using that transportation capacity to supply incremental requirements during the 151-day winter baseload period is $2.42 per MMBtu ($1.00 per MMBtu x 365 days / 151 days).

Exhibit 2-27 shows the total LDC firm requirements by load segment for the 2013 base year. These requirements are assumed to escalate by 0.5 percent per year for the Southern New England Region, and by 1.4 percent per year for the Northern New England and Vermont regions. These growth rates are weighted averages of the individual base case load growth forecasts from the LDC resource plans.

Exhibit 2-27. New England LDC Firm Requirements by Load Segment for 2013, MMcf/day

Load Segment	Southern New England	Northern New England	Vermont
Annual Baseload	225.1	12.3	3.0
Winter/Shoulder	463.1	36.4	8.8
Winter Baseload	447.1	36.5	9.0
90-Day	547.0	42.2	10.4
30-Day	443.6	34.0	8.4
10-Day	333.8	25.6	6.3
Total	2,489.7	186.0	45.9

Our analysis considers each of the nine existing supply categories plus the three new resource options to represent the new delivery capacity that could be constructed in the three New England regions identified in section 2.5.5. The gas supply resources included in the avoided cost analysis are listed in Exhibit 2-28.

Exhibit 2-28. Gas Supply Resources Included in Avoided Cost Analysis

Supply Resource	Type of Facilities	Gas Price Forecast	Regions
Gulf Coast Production	Existing	Henry Hub	SNE, NNE
Appalachia Purchases	Existing	Appalachia	SNE
Purchases at Wright, NY	Existing	TETCO M3	SNE
Purchases at Wright, NY New	*New*	TETCO M3	SNE,NNE
Dawn Purchases	Existing	Dawn	SNE, NNE, VT
Dawn Purchases New	*New*	Dawn	NNE, VT
Mid-Atlantic Purchases	Existing	TETCO M3	SNE
Mid-Atlantic Purchases New	*New*	TETCO M3	SNE
New York/Pennsylvania Storage	Existing	Appalachia	SNE, NNE
Michigan/Dawn Storage	Existing	Dawn	SNE, NNE, VT
Local Purchases	Not Applicable	New England	SNE, NNE
On-System LNG or LPG	Existing	New England	SNE, NNE, VT

SNE = Southern New England, NNE = Northern New England, VT = Vermont

For each gas supply resource we identify the costs of acquiring the resource and the cost of delivering that resource to the LDC.

- For flowing gas resources, the cost components are: (a) gas purchase costs, (b) the FT service demand rate, and (c) the variable transportation cost. The variable transportation cost includes the variable transportation commodity rate charged by the pipeline, and the cost of gas retained by the pipeline for compressor fuel use and “lost and unaccounted for” gas.

- For off-system storage resources, which include firm transportation service from the storage to the LDC, the cost components are: (a) the cost of gas purchased for injection, (b) the fixed storage and transportation service charges, and (c) the variable storage and transportation service charges, which includes the storage and transportation fuel costs.

- For on-system peaking resources, we assume there is only a variable cost component. In the case of LNG peaking, which is the predominant type of on-system peaking for LDCs in Southern New England and Northern New England, the variable cost is the purchased gas cost and the cost of gas consumed for liquefaction and vaporization. For propane-based peaking, which is the only type of on-system peaking in Vermont, the variable cost is assumed to be the propane price.

The marginal gas supply resource for each load segment is determined by matching the available gas supply resources to the LDC firm requirements to minimize the total avoidable gas supply cost. This optimization is done by year for each of the three regions through 2020 using a linear programming spreadsheet model developed for this purpose. Since the gas supply resources included in the avoided cost analysis do not change after 2019, the marginal supply resources are assumed to be the same over remaining years of the forecast.

To illustrate, Exhibit 2-29 shows the delivered cost of the marginal gas supply resources identified for each load segment for the Southern New England region for the year 2016. Using the Residential Heating load category as an example, Exhibit 2-30 shows how the avoided cost for each end use is calculated as a weighted average of these costs, using the weighting factors presented in Exhibit 2-25. The resulting avoided cost of $5.64 per MMBtu for Residential Heating for 2016 appears in Exhibit 2-35.

Exhibit 2-29. Marginal Resource Costs for Southern New England Region, 2016

Load Segment	Marginal Gas Supply Resource	Delivered Cost (2013$/MMBtu)
Annual Baseload	Gulf Coast Transportation	$5.01
Winter/Shoulder	Gulf Coast Transportation	$5.18
Winter Baseload	Gulf Coast Transportation	$6.23
90-Day	New York/Pennsylvania Storage	$6.57
30-Day	New York/Pennsylvania Storage	$8.60
10-Day	On-System Peaking	$8.62

Exhibit 2-30. Sample Calculation of 2016 Residential Heating for Southern New England Region

Load Segment	Marginal Gas Supply Resource	Delivered Cost (2013$/MMBtu)	Load Shape	Cost times Shape
Annual Baseload	Gulf Coast Transportation	$5.01	0%	$0.00
Winter/Shoulder	Gulf Coast Transportation	$5.18	65.75%	$3.41
Winter Baseload	Gulf Coast Transportation	$6.23	19.49%	$1.21
90-Day	New York/Pennsylvania Storage	$6.57	12.35%	$0.81
30-Day	New York/Pennsylvania Storage	$8.60	2.23%	$0.19
10-Day	On-System Peaking	$8.62	0.18%	$0.02
Avoided Cost of Gas Assuming No Retail Margin is Avoidable				**$5.64**

2.4.6 Avoided Distribution Cost by Sector

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

Estimates of the portion or amount of distribution cost that is avoidable due to reductions in gas use from efficiency measures vary by LDC. Some LDCs have estimated this amount as their incremental or marginal cost of distribution; that is, the change in cost of distribution incurred as demand for gas increases or decreases. The conclusion was that the incremental cost of distribution depends upon the load type and the customer sector. For low load factor or heating loads, more of the embedded cost for each sector is incremental or avoidable than for high load factor or non-heating loads. The incremental or avoidable cost is measured as a percent of the embedded costs. For AESC 2013, we measure the embedded cost 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 - industrial, and all retail customers.[36] The embedded distribution cost for each of the two regions, Southern New England and Northern New England, were the weighted average distribution costs among the relevant states where the weighting is the volume of gas delivered to each sector in each state.

Exhibit 2-31 shows the estimated avoidable LDC margin percentage and avoidable costs, measured as 2013 dollars per MMBtu, by each of the end-use types and customer sectors for each region in New England.

[36] The citygate gas prices and the prices charged to each retail customer sector are reported by the EIA for each state each year. In AESC 2013 the cost used is the average for the five years 2007-2011, which is the most recent data available.

Exhibit 2-31. Estimated Avoidable LDC Margins (2013$/MMBtu)

Type of End Use	Total LDC Retail Margin & CG Price (a) (2013$/MMBtu)	Avoidable LDC Margin (a) (2013$/MMBtu) Non-heating (High Load Factor)	Heating (Low Load Factor)	All
Avoidable Margin (percent) (b)				
Residential		8.0%	21.0%	20.4%
Commercial & Industrial		15.0%	28.0%	24.0%
All Retail				22.0%
Southern New England (c)				
Average City Gate Price	8.706			
Residential	7.466	0.60	1.57	1.52
Commercial & Industrial (e)	4.164	0.62	1.17	1.00
All Retail (f)	5.775			1.27
Northern New England (d)				
Average City Gate Price	9.977			
Residential	6.324	0.51	1.33	1.29
Commercial & Industrial (e)	3.051	0.46	0.85	0.73
All Retail (f)	3.549			0.78
Vermont				
Average City Gate Price	9.616			
Residential	7.782	0.62	1.63	1.59
Commercial & Industrial (e)	0.970	0.15	0.27	0.23
All Retail (f)	3.427			0.75

(a) Average of Margins among states for 2007 - 2011 weighted by the delivered volumes in each state.
(b) Based on LDC marginal cost studies from National Grid (MA).
(c) Southern New England is Massachusetts, Connecticut, and Rhode Island.
(d) Northern New England is New Hampshire and Maine.
(e) An average of the margins weighted by the commercial and industrial use delivered volumes.
(f) An average of residential, commercial and industrial margins weighted by associated volumes.

Source: EIA website data sources

Some LDCs assume they will not avoid any distribution costs due to reductions in gas use from efficiency measures. The avoided cost of gas by end use for an LDC with no avoided distribution cost is their avoided cost of gas delivered to their citygate.

2.4.7 Total Avoided Gas Costs by End Use

Exhibit 2-32 through Exhibit 2-37 show the total avoided costs per year per MMBtu for the retail end uses categorized by the end-use type and customer sector for Southern New England, Northern New England, and Vermont. The avoided cost of the gas sent out by the LDCs by load type is the weighted sum of the avoided cost per MMBtu across all six portions of the load duration curve delivered to the citygate, multiplied by the percent used each load duration curve portion for each load type (heating, non-heating, or all) plus the avoided retail margin for each retail customer sector. The levelized avoided cost is the cost for which the present value at the real rate of return of 1.36 percent has the same present value as the estimated avoided costs for the 15-year period 2014 through 2028 at the same rate of return.

Exhibit 2-32, Exhibit 2-33, and Exhibit 2-34 provide projections of avoidable cost by end use for utilities in Southern New England, Northern New England, and Vermont, for which some LDC retail margin is avoidable.

Exhibit 2-32. Avoided Cost of Gas Delivered to an End-Use Load, Assuming Some Retail Margin is Avoidable; Southern New England (2013$/MMBtu)

	RESIDENTIAL				COMMERCIAL & INDUSTRIAL			ALL RETAIL END USES
Year	Non Heating	Hot Water	Heating	All	Non Heating	Heating	All	
2013	5.32	5.78	6.90	6.73	5.51	6.35	6.05	6.41
2014	5.53	5.98	7.10	6.93	5.72	6.56	6.26	6.61
2015	5.54	5.98	7.09	6.93	5.72	6.56	6.26	6.61
2016	5.61	6.08	7.21	7.03	5.81	6.66	6.36	6.71
2017	5.71	6.34	7.51	7.30	5.96	6.91	6.57	6.95
2018	6.02	6.62	7.79	7.58	6.26	7.20	6.86	7.24
2019	6.46	6.95	8.08	7.90	6.66	7.53	7.22	7.58
2020	6.73	7.20	8.33	8.15	6.93	7.78	7.48	7.83
2021	6.87	7.36	8.48	8.30	7.07	7.93	7.62	7.98
2022	7.07	7.55	8.67	8.50	7.27	8.12	7.82	8.18
2023	7.20	7.67	8.80	8.62	7.40	8.25	7.95	8.30
2024	7.33	7.82	8.95	8.77	7.53	8.39	8.08	8.44
2025	7.52	7.99	9.12	8.94	7.72	8.57	8.27	8.62
2026	7.64	8.13	9.25	9.07	7.84	8.70	8.39	8.75
2027	7.76	8.25	9.37	9.19	7.96	8.82	8.51	8.87
2028	7.86	8.34	9.46	9.29	8.06	8.91	8.61	8.97
Levelized (a)	6.67	7.17	8.30	8.12	6.88	7.74	7.44	7.80
Simple Average	6.72	7.21	8.35	8.17	6.93	7.79	7.48	7.84

(a) Years 2014-2028 (15 years); Real (constant $) riskless annual rate of return: 1.360%

Exhibit 2-33. Avoided Cost of Gas Delivered to an End-Use Load, Assuming Some Retail Margin is Avoidable; Northern New England (2013$/MMBtu)

Year	RESIDENTIAL Non Heating	RESIDENTIAL Hot Water	RESIDENTIAL Heating	RESIDENTIAL All	COMMERCIAL & INDUSTRIAL Non Heating	COMMERCIAL & INDUSTRIAL Heating	COMMERCIAL & INDUSTRIAL All	ALL RETAIL END USES
2013	5.21	5.81	6.83	6.63	5.38	6.03	5.78	5.92
2014	5.07	5.79	6.84	6.61	5.29	6.24	5.99	6.12
2015	5.14	6.49	7.75	7.35	5.59	6.24	5.99	6.12
2016	5.50	6.12	7.15	6.94	5.68	6.34	6.09	6.22
2017	5.94	6.38	7.34	7.19	6.05	6.59	6.30	6.46
2018	6.07	6.81	7.87	7.64	6.30	6.88	6.59	6.75
2019	6.34	8.19	9.61	9.08	6.98	7.21	6.95	7.09
2020	6.60	8.44	9.86	9.33	7.23	7.46	7.21	7.34
2021	6.73	8.61	10.04	9.50	7.38	7.61	7.35	7.49
2022	6.94	8.83	10.26	9.72	7.59	7.80	7.55	7.69
2023	7.06	8.96	10.39	9.85	7.71	7.93	7.68	7.81
2024	7.19	9.12	10.57	10.02	7.86	8.07	7.81	7.95
2025	7.37	9.31	10.75	10.20	8.04	8.25	8.00	8.13
2026	7.49	9.44	10.90	10.34	8.16	8.38	8.12	8.26
2027	7.62	9.58	11.03	10.48	8.30	8.50	8.24	8.38
2028	7.71	9.67	11.13	10.57	8.39	8.59	8.34	8.48
Levelized (a)	6.53	8.04	9.35	8.91	7.04	7.43	7.17	7.31
Simple Average	6.58	8.11	9.43	8.99	7.10	7.48	7.22	7.35

(a) Years 2014-2028 (15 years); Real (constant $) riskless annual rate of return: 1.360%

Exhibit 2-34. Avoided Cost of Gas Delivered to an End-Use Load, Assuming Some Retail Margin is Avoidable; Vermont (2013$/MMBtu)

Year	RESIDENTIAL Non Heating	RESIDENTIAL Hot Water	RESIDENTIAL Heating	RESIDENTIAL All	COMMERCIAL & INDUSTRIAL Non Heating	COMMERCIAL & INDUSTRIAL Heating	COMMERCIAL & INDUSTRIAL All	ALL RETAIL END USES
2013	5.59	6.10	7.28	7.10	5.31	5.76	5.58	6.19
2014	5.68	6.19	7.36	7.19	5.40	5.84	5.66	6.27
2015	5.75	6.34	7.55	7.35	5.50	6.00	5.79	6.42
2016	5.81	6.41	7.62	7.42	5.56	6.07	5.86	6.49
2017	6.11	6.71	7.92	7.72	5.86	6.37	6.16	6.79
2018	5.85	6.39	7.58	7.40	5.58	6.05	5.86	6.48
2019	6.65	7.27	8.48	8.28	6.41	6.92	6.71	7.34
2020	6.93	7.53	8.73	8.53	6.68	7.18	6.97	7.60
2021	7.11	7.73	8.95	8.74	6.87	7.39	7.18	7.81
2022	7.37	7.98	9.19	8.99	7.13	7.63	7.42	8.05
2023	7.54	8.14	9.34	9.14	7.29	7.79	7.58	8.21
2024	7.68	8.30	9.51	9.31	7.44	7.95	7.74	8.37
2025	7.86	8.48	9.68	9.48	7.62	8.13	7.92	8.55
2026	8.03	8.64	9.85	9.65	7.79	8.30	8.09	8.72
2027	8.18	8.79	10.00	9.80	7.94	8.44	8.23	8.86
2028	8.28	8.89	10.09	9.89	8.03	8.54	8.33	8.96
Levelized (a)	6.94	7.53	8.74	8.54	6.68	7.19	6.98	7.61
Simple Average	6.99	7.59	8.79	8.59	6.74	7.24	7.04	7.67

(a) Years 2014-2028 (15 years); Real (constant $) riskless annual rate of return in %: 1.360%

Exhibit 2-35, Exhibit 2-36, and Exhibit 2-37 demonstrate the avoided cost by end use for utilities at which it is assumed that no LDC retail margin is avoidable.

Exhibit 2-35. Avoided Cost of Gas Delivered to LDCs by End-Use Load Type Assuming No Avoidable Retail Margin, Southern New England (2013$/MMBtu)

	RESIDENTIAL				COMMERCIAL & INDUSTRIAL			ALL RETAIL END USES
Year	Non Heating	Hot Water	Heating	All	Non Heating	Heating	All	
2013	4.72	5.18	5.33	5.21	4.89	5.18	5.05	5.14
2014	4.93	5.38	5.53	5.41	5.10	5.39	5.26	5.34
2015	4.94	5.38	5.52	5.41	5.10	5.39	5.26	5.34
2016	5.01	5.48	5.64	5.51	5.19	5.49	5.36	5.44
2017	5.11	5.74	5.94	5.78	5.34	5.74	5.57	5.68
2018	5.42	6.02	6.22	6.06	5.64	6.03	5.86	5.97
2019	5.86	6.35	6.51	6.38	6.04	6.36	6.22	6.31
2020	6.13	6.60	6.76	6.63	6.31	6.61	6.48	6.56
2021	6.27	6.76	6.91	6.78	6.45	6.76	6.62	6.71
2022	6.47	6.95	7.10	6.98	6.65	6.95	6.82	6.91
2023	6.60	7.07	7.23	7.10	6.78	7.08	6.95	7.03
2024	6.73	7.22	7.38	7.25	6.91	7.22	7.08	7.17
2025	6.92	7.39	7.55	7.42	7.10	7.40	7.27	7.35
2026	7.04	7.53	7.68	7.55	7.22	7.53	7.39	7.48
2027	7.16	7.65	7.80	7.67	7.34	7.65	7.51	7.60
2028	7.26	7.74	7.89	7.77	7.44	7.74	7.61	7.70
Levelized (a)	6.08	6.57	6.73	6.60	6.26	6.58	6.44	6.53
Simple Average	6.12	6.62	6.78	6.65	6.31	6.62	6.48	6.57

(a) Years 2014-2028 (15 years); Real (constant $) riskless annual rate of return: 1.360%

Exhibit 2-36. Avoided Cost of Gas Delivered to LDCs by End-Use Load Type Assuming No Retail Margin, Northern New England (2013$/MMBtu)

Year	RESIDENTIAL Non Heating	RESIDENTIAL Hot Water	RESIDENTIAL Heating	RESIDENTIAL All	COMMERCIAL & INDUSTRIAL Non Heating	COMMERCIAL & INDUSTRIAL Heating	COMMERCIAL & INDUSTRIAL All	ALL RETAIL END USES
2013	4.70	5.30	5.50	5.34	4.92	5.31	5.14	5.25
2014	4.56	5.28	5.51	5.32	4.83	5.28	5.08	5.21
2015	4.63	5.98	6.42	6.06	5.13	5.99	5.61	5.85
2016	4.99	5.61	5.82	5.65	5.22	5.62	5.45	5.56
2017	5.43	5.87	6.01	5.90	5.59	5.87	5.75	5.83
2018	5.56	6.30	6.54	6.35	5.84	6.31	6.10	6.23
2019	5.83	7.68	8.28	7.79	6.52	7.70	7.18	7.51
2020	6.09	7.93	8.53	8.04	6.77	7.95	7.43	7.76
2021	6.22	8.10	8.71	8.21	6.92	8.12	7.60	7.93
2022	6.43	8.32	8.93	8.43	7.13	8.33	7.81	8.14
2023	6.55	8.45	9.06	8.56	7.25	8.46	7.93	8.27
2024	6.68	8.61	9.24	8.73	7.40	8.63	8.09	8.43
2025	6.86	8.80	9.42	8.91	7.58	8.81	8.27	8.61
2026	6.98	8.93	9.57	9.05	7.70	8.95	8.40	8.75
2027	7.11	9.07	9.70	9.19	7.84	9.08	8.54	8.89
2028	7.20	9.16	9.80	9.28	7.93	9.18	8.63	8.98
Levelized (a)	6.03	7.53	8.02	7.62	6.58	7.54	7.12	7.39
Simple Average	6.07	7.61	8.10	7.70	6.64	7.62	7.19	7.46

(a) Years 2014-2028 (15 years); Real (constant $) riskless annual rate of return: 1.360%

Exhibit 2-37. Avoided Cost of Gas Delivered to LDCs by End-Use Load Type Assuming No Retail Margin, Vermont (2013$/MMBtu)

Year	RESIDENTIAL Non Heating	RESIDENTIAL Hot Water	RESIDENTIAL Heating	RESIDENTIAL All	COMMERCIAL & INDUSTRIAL Non Heating	COMMERCIAL & INDUSTRIAL Heating	COMMERCIAL & INDUSTRIAL All	ALL RETAIL END USES
2013	4.97	5.48	5.65	5.51	5.16	5.49	5.35	5.44
2014	5.06	5.57	5.73	5.60	5.25	5.57	5.43	5.52
2015	5.13	5.72	5.92	5.76	5.35	5.73	5.56	5.67
2016	5.19	5.79	5.99	5.83	5.41	5.80	5.63	5.74
2017	5.49	6.09	6.29	6.13	5.71	6.10	5.93	6.04
2018	5.23	5.77	5.95	5.81	5.43	5.78	5.63	5.73
2019	6.03	6.65	6.85	6.69	6.26	6.65	6.48	6.59
2020	6.31	6.91	7.10	6.94	6.53	6.91	6.74	6.85
2021	6.49	7.11	7.32	7.15	6.72	7.12	6.95	7.06
2022	6.75	7.36	7.56	7.40	6.98	7.36	7.19	7.30
2023	6.92	7.52	7.71	7.55	7.14	7.52	7.35	7.46
2024	7.06	7.68	7.88	7.72	7.29	7.68	7.51	7.62
2025	7.24	7.86	8.05	7.89	7.47	7.86	7.69	7.80
2026	7.41	8.02	8.22	8.06	7.64	8.03	7.86	7.97
2027	7.56	8.17	8.37	8.21	7.79	8.17	8.00	8.11
2028	7.66	8.27	8.46	8.30	7.88	8.27	8.10	8.21
Levelized (a)	6.32	6.91	7.11	6.95	6.54	6.92	6.75	6.86
Simple Average	6.37	6.97	7.16	7.00	6.59	6.97	6.80	6.91

(a) Years 2014-2028 (15 years); Real (constant $) riskless annual rate of return in %: 1.360%

2.4.8 Comparison of Avoided Retail Gas Costs with AESC 2011

Exhibit 2-38 and Exhibit 2-39 show the end use avoided costs of gas use in AESC 2013 as compared to AESC 2011. Care must be taken when comparing the two study results for both Southern New England and Northern New England, because while Massachusetts was included in Northern New England in AESC 2011 (referred to as Northern and Central New England), the AESC 2013 report includes Massachusetts with Southern New England. Furthermore, the avoided cost of gas delivered to residential customers for non-heating and hot water loads are no longer coupled in the model.

The end use avoided costs of gas use in AESC 2013 are generally less than estimated in AESC 2011 for all three regions in New England.[37] As a result of the two fundamental modeling changes detailed above, the avoided cost of gas reductions aren't distributed evenly, and in fact there are a few slight *increases* for end uses in Northern New England. Southern New England saw significant decreases, because the decline in the costs of gas delivered to the citygate outpaced slight increases in the avoidable LDC margin. The changes for Northern New England's levelized avoided costs from AESC 2011 to AESC 2013 are mixed. The avoidable LDC margin declined considerably due in part to Massachusetts being shifted to Southern New England in the model, with the bulk of that decline on the commercial - industrial side. Much of Maine and New Hampshire's natural gas is supplied by Canada, and has a high fixed-cost transportation, resulting in especially high cost in servicing low load factor customers. Similarly, without Massachusetts's lower citygate prices, the average citygate price of gas was nearly unchanged for residential customers in Northern New England, with some decline for commercial and industrial customers. As a result, residential customers in Northern New England have very similar levelized avoided costs of gas delivered in AESC 2013 as in AESC 2011, whereas commercial and industrial customers saw a reduction in AESC 2013 as compared to AESC 2011. Finally, Vermont saw double digit percentage declines in the levelized avoided costs of gas delivered to retail customers in nearly all end uses. The only end use that saw a decline less than 10 percent was residential hot water, the result of a methodological change. Exhibit 2-38 shows the end use avoided costs of gas use if one assumes some retail margin is avoidable in AESC 2013.

[37] Exhibit 2-38 is the same as Exhibit 2-22, and Exhibit 2-39 is the same as Exhibit 2-23.

Exhibit 2-38. Comparison of AESC 2013 and AESC 2011 Avoided Cost of Gas Delivered to Retail Customers by End Use Assuming Some Retail Margin Avoidable (2013$/MMBtu, unless noted)

	RESIDENTIAL				COMMERCIAL & INDUSTRIAL			ALL RETAIL END USES
	Non Heating	Hot Water	Heating	All	Non Heating	Heating	All	
Southern New England (a)								
AESC 2011 (2011$/MMBtu)	7.64	7.64	9.39	9.11	7.58	8.82	8.44	8.75
AESC 2011 (b)	7.89	7.89	9.70	9.41	7.83	9.11	8.72	9.04
AESC 2013	6.67	7.17	8.30	8.12	6.88	7.74	7.44	7.80
2011 to 2013 change	-15.43%	-9.17%	-14.43%	-13.70%	-12.06%	-15.02%	-14.74%	-13.77%
Northern New England (a)								
AESC 2011 (2011$/MMBtu)	7.47	7.47	8.96	8.73	7.59	8.79	8.43	8.58
AESC 2011 (b)	7.71	7.71	9.26	9.02	7.84	9.08	8.71	8.86
AESC 2013	6.53	8.04	9.35	8.91	7.04	7.43	7.17	7.31
2011 to 2013 change	-15.34%	4.17%	0.97%	-1.19%	-10.21%	-18.21%	-17.67%	-17.56%
Vermont								
AESC 2011 (2011$/MMBtu)	7.54	7.54	9.88	9.37	7.30	9.08	8.54	8.86
AESC 2011 (b)	7.79	7.79	10.21	9.68	7.54	9.38	8.82	9.15
AESC 2013	6.94	7.53	8.74	8.54	6.68	7.19	6.98	7.61
2011 to 2013 change	-10.88%	-3.22%	-14.37%	-11.85%	-11.37%	-23.33%	-20.86%	-16.83%

(a) Massachusetts was included with Northern New England in AESC 2011, but is included with Southern New England in AESC 2013.
(b) Factor to convert 2011$ to 2013$ 1.0331

Note: AESC 2011 levelized costs for 15 years 2012 - 2026 at a discount rate of 2.465%.
AESC 2013 levelized costs for 15 years 2014 - 2028 at a discount rate of 1.36%.

Exhibit 2-39 shows the end use avoided costs of gas use if one assumes that no retail margin is avoidable in AESC 2013.

Exhibit 2-39. Comparison of AESC 2013 and AESC 2011 Avoided Cost of Gas Delivered to Retail Customers by End Use Assuming No Retail Margin Avoidable (2013$/MMBtu, unless noted)

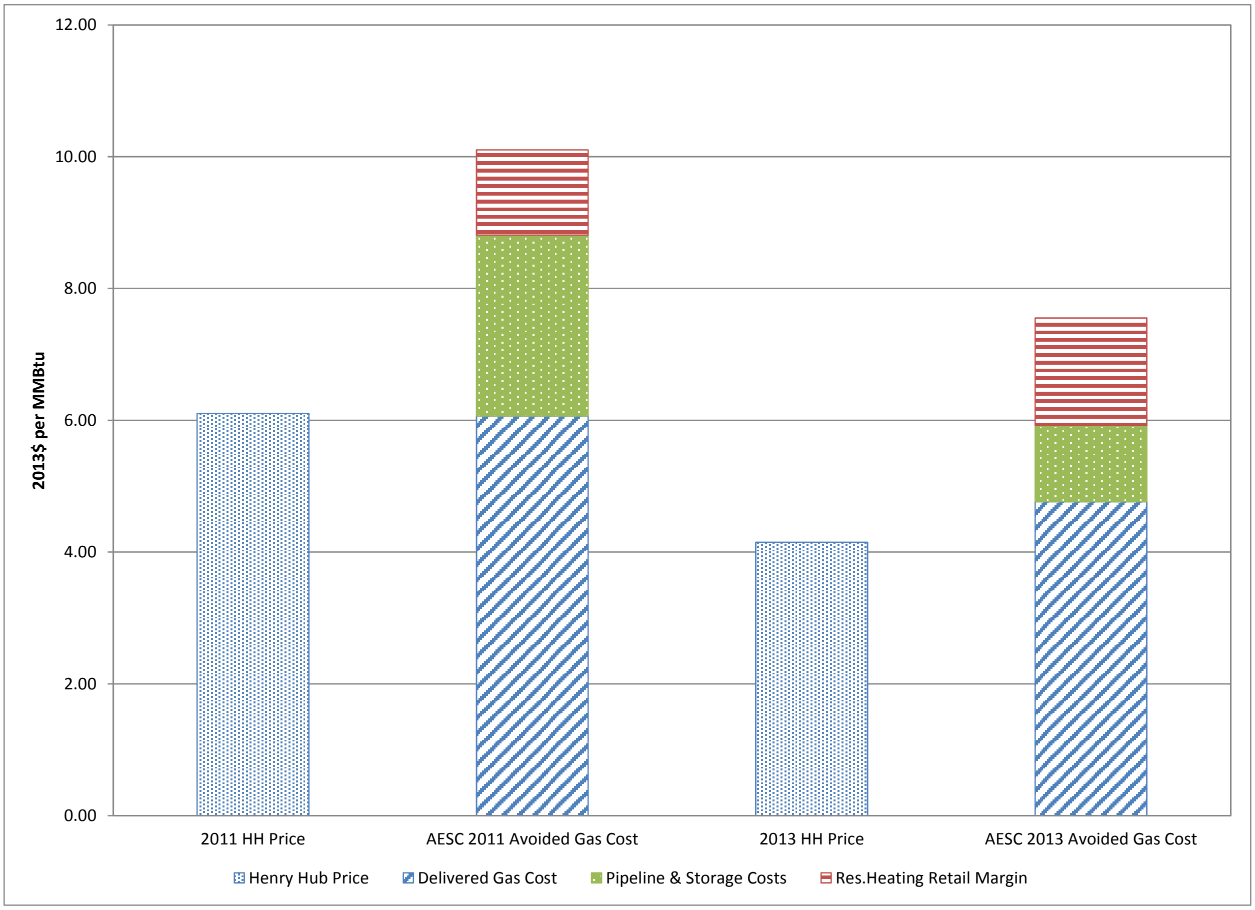
	RESIDENTIAL				COMMERCIAL & INDUSTRIAL			ALL RETAIL END USES
	Non Heating	Hot Water	Heating	All	Non Heating	Heating	All	
Southern New England (a)								
AESC 2011 (2011$/MMBtu)	7.04	7.04	7.81	7.57	7.04	7.81	7.57	7.57
AESC 2011 (b)	7.27	7.27	8.06	7.83	7.27	8.06	7.83	7.83
AESC 2013	6.08	6.57	6.73	6.60	6.26	6.58	6.44	6.53
2011 to 2013 change	-16.41%	-9.61%	-16.54%	-15.66%	-13.88%	-18.46%	-17.74%	-16.61%
Northern New England (a)								
AESC 2011 (2011$/MMBtu)	6.94	6.94	7.58	7.39	6.94	7.58	7.39	7.39
AESC 2011 (b)	7.17	7.17	7.83	7.63	7.17	7.83	7.63	7.63
AESC 2013	6.03	7.53	8.02	7.62	6.58	7.54	7.12	7.39
2011 to 2013 change	-15.98%	5.01%	2.41%	-0.15%	-8.18%	-3.67%	-6.68%	-3.17%
Vermont								
AESC 2011 (2011$/MMBtu)	7.06	7.06	8.63	8.16	7.06	8.63	8.16	8.16
AESC 2011 (b)	7.29	7.29	8.91	8.43	7.29	8.91	8.43	8.43
AESC 2013	6.32	6.91	7.11	6.95	6.54	6.92	6.75	6.86
2011 to 2013 change	-13.39%	-5.22%	-20.28%	-17.54%	-10.36%	-22.41%	-19.91%	-18.63%

(a) Massachusetts was included with Northern New England in AESC 2011, but is included with Southern New England in AESC 2013.
(b) Factor to convert 2011$ to 2013$ 1.0331

Note: AESC 2011 levelized costs for 15 years 2012 - 2026 at a discount rate of 2.465%.
AESC 2013 levelized costs for 15 years 2014 - 2028 at a discount rate of 1.36%.

Exhibit 2-40 shows the contribution to overall avoided cost to a heating customer by each of the components: cost of gas delivered to VGS; commodity cost of storing, delivering, and transporting the gas; and the avoidable retail margin. This picture shows more clearly the substantially lower cost of both delivered gas and pipeline and storage costs in AESC 2013 as compared to AESC 2011, offset slightly by an increased residential heating retail margin.

Exhibit 2-40. Comparison between AESC 2011 and AESC 2013 of the Components of the Avoided Cost to a Residential Heating Customer on Vermont Gas Systems in 2015 (2013$/MMBtu)



Chapter 3: Avoided Fuel Oil Costs and Avoided Costs of Other Fuels by Sector

3.1 Introduction

This chapter details the development of a forecast of prices for petroleum products used in electric generation as well as in the residential, commercial, and industrial sectors in New England. For AESC 2013, we develop forecast prices for three fuel oil grades (No. 2, No. 4, and No. 6), two biofuel blends (B5 and B20), and coal prices for the electric sector. In addition, we develop a forecast of unit fuel oil costs that would be avoided by the installation of oil-saving energy efficiency measures in the commercial, industrial, and residential sectors.

This chapter also details the development of avoided costs by state, if supported by research, for other fuels used in residential heating applications. For AESC 2013, these other fuels are wood, wood chips or pellets, kerosene, and propane.

Our AESC 2013 forecasts for crude oil and fuels by sector and region are presented in detail in Appendix D.

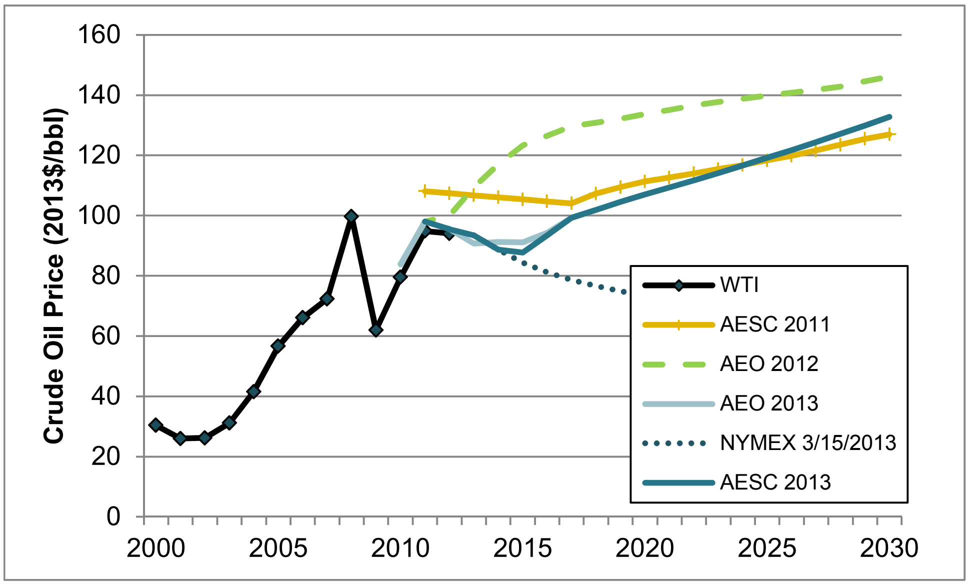
3.2 Forecast of Crude Oil Prices

Our general approach to developing the forecasts of crude-oil prices and of Henry Hub natural-gas prices is to use a set of relevant NYMEX futures prices in the near term, e.g. the first three years, and the relevant EIA AEO forecast in the long term. Similar to the approach for natural gas described in Chapter 2, this approach is based upon our view that futures market prices are the most accurate estimates in the near term, while projections from a forecasting model that reflects long-term demand and supply fundamentals, such as the EIA's National Energy Modeling System, are the most accurate estimates in the long term. As in AESC 2009 and AESC 2011, we developed our forecast of petroleum product prices based on NYMEX futures for West Texas Intermediate (WTI) in the near term, and EIA's Reference Case forecast prices in the following years. Our analyses use prices of WTI for this comparison because it is actively traded and its price in the past has been very close to that of the low-sulfur light crude used in EIA's Reference Case. We note, however, that there is considerable uncertainty regarding the future price of crude oil.

Based on this general approach, our first step in developing a forecast of crude oil prices was to review the EIA's AEO 2013 Reference Case forecast. We then compared the AEO 2013 Reference Case forecasts of WTI prices through 2017 with NYMEX futures prices for WTI as of March 15, 2013.[38]

This comparison revealed a significant difference between NYMEX futures for WTI in the medium to long term, and the AEO 2013 Reference Case forecast prices. That disparity is presented in Exhibit 3-1, which plots, in 2013 dollars per bbl, (1) actual oil prices since 2000, (2) WTI futures through 2021, and (3) AEO 2013 Reference Case forecast prices through 2030. For comparison, it also plots the AEO 2012 forecast.

Exhibit 3-1. Low-Sulfur-Crude Prices, EIA vs. NYMEX as of March 15, 2013 (2013$ per bbl)



The exhibit shows that the AEO 2012 projections of crude oil prices differ dramatically from NYMEX futures from March 15, 2013. Unlike our analysis of market dynamics affecting natural gas prices, we do not conduct such detailed market analysis of the crude oil market. As such, we rely on a relevant EIA analysis, which for AESC 2013 is the AEO 2013 Reference Case for crude oil.

For AESC 2013, we use a combination of NYMEX prices in the first five years, transitioning to AEO 2013 values for the remainder of the forecast. This forecast projects a slight dip in prices in 2013 through 2015 followed by a gradual rise.

3.3 Forecast of Electric-Generation Fuel Prices in New England

AEO 2013 provides forecasts of regional prices for distillate, residual, and coal for electricity generation in New England. This section discusses how those prices are used in AESC 2013.

[38] AESC 2013 projections using NYMEX all use NYMEX prices as of March 15, 2013.

3.3.1 Forecast Prices of Distillate and Residual

We compared historical state ratios of crude oil to distillate prices to develop our forecast of distillate prices. Our analysis did not identify material differences by state in the historical prices for these fuels in the electric sector. Therefore, we developed a forecast of these prices by multiplying the corresponding AEO 2013 forecast price by the average ratio of crude oil prices to delivered distillate prices.

3.3.2 Forecast Prices of Coal

The AEO 2013 (Table 78) Reference Case forecasts slightly rising prices for coal in New England. We consider this reasonable. The U.S. has substantial coal resources and coal prices have been relatively stable over a long time period without the volatility seen in oil and natural gas prices. While coal at the mine mouth is relatively cheap on an energy basis, it is expensive to transport and to burn. Coal is more expensive in New England because of the transportation costs, and represents a smaller fraction of annual electric generation in New England than most other parts of the U.S.

Coal demand is also unlikely to increase significantly because of the age of existing coal-fired generation plants and various environmental concerns; in AESC 2013, we assume the retirement of most of the coal-fired generation in New England over the study period. We use the AEO 2013 coal prices for AESC 2013. For the modeling, we also make appropriate adjustments based on the source of coal used by the specific generating plants in New England.

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

AEO 2013 provides forecasts of regional prices for distillate and residual fuel oil in the residential, commercial, and industrial sectors in New England. The retail price of each fuel in each sector of a given state can be separated into two major components. The first component is the price of the underlying resource, crude oil. The second component is a margin, or the difference between the price of each fuel at the retail level and the crude oil price. The margin represents the aggregate unit costs of the refining process, distribution, and taxes attributed to the particular fuel by sector and state. We developed our forecast of prices for fuels in each sector in the following three steps:

- First, we calculated the price margin implicit in the AEO 2013 forecast of the New England regional price for each fuel, expressed as a ratio to the crude oil price, and compared it to the historical price margin, calculated from historical price data. We developed a modified New England price margin for any fuel with an AEO 2013 forecast margin that we found unreasonable based on historical patterns.

- Second, we derived regional forecasts of New England prices for each fuel by multiplying our forecast of the crude oil price by the above product price ratios.

- Finally, we developed our forecast of prices for each fuel by New England state from the regional forecast to the extent that historical prices for that fuel have differed materially by state.

These steps are detailed in the following sections (3.4.1, 3.4.2, and 3.4.3).

Our analysis found material differences by state in the historical prices for some fuels in these sectors. Therefore, we adjusted the corresponding AEO 2013 regional forecasts to reflect those differences. We then developed a forecast of prices for each fuel type by New England state from the regional forecast.

3.4.1 New England Regional Prices by Sector

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

We derived forecasts of regional petroleum product prices by adjusting the corresponding AEO 2013 forecasts of petroleum product prices in proportion to the ratio of our crude oil forecast to the AEO 2013 crude oil forecast. This approach is based on our conclusion that crude oil is the dominant component of petroleum product prices, and that preparing a forecast of future absolute margins by product based upon historical absolute margins is beyond the scope of this project.

In summary, our AESC 2013 forecast of regional prices of petroleum and related products by sector is based on the following approaches:

- **No. 2 and 6 Fuel Oil:** The AEO 2013 forecast of the regional product prices were adjusted by the ratio of AESC 2013 crude oil forecast to AEO 2013 crude oil forecast.
- **No. 4 Oil:** No projection. No. 4 is a blend of distillate and residual and we had no data on the relative proportions of that blend.
- **B5 and B20:** The AEO 2013 forecast of corresponding petroleum products was adjusted for recent price premium, assuming the phase-out of the current $1.00 per gallon tax credit by 2016.

A forecast for B100 (100 percent biodiesel) based on recent premiums over petroleum diesel was developed for use in forecasts of biofuel blends. This included the phase-out of the $1/gallon Biodiesel Excise Tax Credit by 2016. Per ASTM D396, fuel oils for home heating and boiler applications may be blended with up to 5 percent biodiesel below the rack.[39,40] Marketers are not required to disclose information on biodiesel content below these levels. While the AEO forecast for fuel oil does not reflect any inherent biodiesel content, the price premium for biodiesel peaks at $1.20 per gallon. At a 5 percent blend, the maximum blending ratio without requiring additional reporting, this represents a premium of 6 cents per gallon. We did not attempt to include any below-the-rack blending in our forecast.

AEO 2013 does not provide a forecast of New England regional prices for biofuels B5 and B20, as these blends continue to represent a small portion of the New England market. Our research indicated that B5

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[39] ASTM International. "ASTM Sets the Standard for Biodiesel." Jan 2009. Available at: http://www.astm.org/SNEWS/JF_2009/nelson_jf09.html

[40] "Below the rack" refers to blending at the refinery, before fuel is sold to wholesalers.

and B20 are each a mix of a petroleum product, such as distillate oil or diesel, and an oil-like product derived from an agricultural source (e.g., soy beans). The number in their name is the percent of agricultural-derived component. Thus “B5” and “B20” represent products with a 5 percent and a 20 percent agricultural-derived component, respectively. They are both similar to No. 2 fuel oil and are used primarily for heating. Each of these fuels has advantages and disadvantages relative to No. 2 fuel oil. Their advantages include lower greenhouse-gas emissions per MMBtu of fuel consumed, more efficient operation of furnaces, and less reliance on imported crude oil. Their disadvantages include somewhat lower heat contents and concerns about the long-term supply of agricultural source feedstocks. Forecasts for B5 and B20 were developed by combining the B100 and petroleum diesel forecasts.

Since oil prices did not show meaningful variations by month or season, we did not develop monthly or seasonal price variations for petroleum products. Storage for petroleum products is relatively inexpensive and this also tends to smooth out variations in costs relative to market prices. For these reasons, and those presented in the Chapter 2 discussion of volatility in natural gas prices, our forecast does not address volatility in the prices of these fuels.

3.4.2 Weighted Average Avoided Costs by Sector Based on Regional Prices

We developed weighted average costs of avoided petroleum-related fuels by sector by multiplying our projected regional prices for each fuel and sector by the relative quantities of each petroleum-related fuel that AEO 2013 projects will be used in that sector. The relative quantity of each petroleum-related fuel that AEO 2013 projects for each sector, expressed as percentages, are presented in Appendix D. The resulting weighted average costs of avoided petroleum-related fuels by sector are also presented in Appendix D.

We estimate that the crude oil price component of these projected prices is the portion that can be avoided.

3.4.3 Prices by State by Sector

To determine if there were material differences by state in the historical prices for any of these fuels in these sectors, we analyzed the actual prices by sector in each state from 1999 through 2011 using data from the EIA State Energy Data System (SEDS). This is the most complete and consistent source of state-level energy prices.

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

3.5 Avoided Costs of Other Residential Fuels

For wood and kerosene, we determined the historical average ratio between the price of each fuel and the price of distillate in the residential sector from EIA SEDS data. These resulting ratios were 0.36 for wood and 1.1 for kerosene.[41] Then we derived the forecast of regional prices for each of those fuels by multiplying our AESC 2013 forecast price of distillate in the residential sector each year by the historical ratio. Although wood is not based on oil, they compete in the fuel market and thus such a price relationship seems reasonable.

The wood values are for both cordwood and pellets. EIA data shows a national average ratio of the price of pellets to cordwood of 1.7.[42,43] Vermont[44], Maine[45], and New Hampshire[46] are the only New England states to publish prices for both cordwood and pellets; other New England states do not, relying instead upon prices reported by EIA. Based on these factors, we used the EIA SEDS data to develop prices for cordwood in New England. Discussions with representatives in Vermont and New Hampshire indicated that local wood prices can vary widely within New England.

For propane, we drew on the AEO 2013 forecast of New England regional prices. The AESC 2013 forecast was derived from the AEO 2013 regional forecast using the AESC 2013 crude oil forecast.

Our detailed forecasts of prices for each fuel are presented in Appendix D. All prices are reported in constant 2013 dollars per MMBtu except where noted.

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[41] EIA State Energy Data System, http://www.eia.gov/state/seds/ (accessed 4/1/2013).

[42] EIA National Average for Heat Cost Calculator, March 13 http://www.eia.gov/tools/faqs/faq.cfm?id=8&t=7 (accessed 4/1/2013)

[43] Residential customers can purchase either cord wood or wood pellets. We use EIA national average values for pellet price premiums, due to the small sample size in New England, although recent data has shown pellet premiums ranging from 15 percent to 41 percent for Vermont, Maine, and New Hampshire.

[44] The Vermont Department of Public Service publishes prices for cordwood and wood pellets collected by the Vermont Department of Forests through an informal survey each month. http://publicservice.vermont.gov/pub/vt-fuel-price-report.html

[45] Maine Current Heating Fuel Prices, April 3, 2013. Available at: http://maine.gov/energy/fuel_prices/index.shtml

[46] New Hampshire Office of Energy and Planning Fuel price data. April 2, 2013. Available at: http://www.nh.gov/oep/programs/energy/fuelprices.htm

Chapter 4: Embedded and Non-Embedded Environmental Costs

4.1 Introduction

This chapter discusses the value associated with mitigating the most significant airborne pollutants created by: 1) the combustion of natural gas, fuel oil, coal, and biomass for the purpose of electricity generation; and 2) the combustion of natural gas, fuel oil, wood, and kerosene for use in commercial, industrial, and residential sectors.

Some of the environmental costs associated with the combustion of fuels have been "embedded" in electricity market prices 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.[47] These costs are embedded in our analysis for AESC 2013 in the form of pollutant allowance prices. The remainder of the environmental costs associated with the combustion of fuels, which are not reflected in the price of that good or service, are "non-embedded" costs.[48]

This chapter discusses both embedded and non-embedded environmental costs, and includes the following major sections:

- **Environmental Regulations: Embedded Costs:** This section identifies avoided costs associated with expected and existing NO_x, SO_x, and CO_2 regulations. These costs are embedded in the assumptions used by our electric market simulation model (Market Analytics) to calculate avoided electric energy costs for AESC 2013.
- **Non-Embedded Environmental Costs:** Non-embedded costs are above and beyond the costs imposed by NO_x, SO_x, and CO_2 regulations. For AESC 2013, we anticipate that the "non-embedded CO_2 cost" will continue to be the dominant non-embedded environmental cost associated with marginal electricity generation in New England. This

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[47] For example, the Clean Air Transport Rule, while currently in draft form, is expected to adjust the SO_2 and NO_x emissions caps downward with an ultimate effect of reducing SO_2 emissions approximately 73 percent from 2003 levels. Under the draft rule, annual emissions of SO_2 are required to decline from 4.7 million tons in 2009 to 3.9 million tons by 2012, and then to 2.5 million tons by 2014, for a cumulative reduction of 47 percent over the five-year compliance period. Annual NO_x emissions are capped at 1.4 million tons. As a result, while there will be some "external costs" associated with the residual SO_2 and NO_x pollution, these externalities are now relatively small. The EPA's proposed Air Toxics Rule governing electric utilities under section 112(d) of the Clean Air Act would do the same for emissions of mercury and other air toxics, while the proposed rule under section 316(b) of the Clean Water Act would minimize the externalities associated with the impingement and entrainment of aquatic organisms from power plant cooling water intake systems.

[48] In economics, a non-embedded impact can be positive (a non-embedded benefit) or negative (a non-embedded cost); in this discussion we are focusing on negative costs.

cost is not included in AESC 2013 avoided cost calculations for electric energy or other fuels. We provide recommendations for PAs to apply avoided non-embedded CO_2 costs in their evaluations of EE programs.

- **Value of Mitigating Significant Pollutants:** This section identifies and describes the most significant pollutants associated with electricity generation, end-use natural gas, and end-use fuel oil and other fuels. The section then provides the value associated with mitigating those pollutants for end-use natural gas, fuel oil, and other fuels based on AESC 2013 NO_x, SO_2, and CO_2 emissions allowance prices per short ton (embedded costs), and the AESC 2013 recommended CO_2 abatement cost (non-embedded cost). For end-use natural gas, fuel oil, and other fuels, the value of mitigating significant pollutants is not-embedded.
- **Discussion of Non-Embedded NO_x Costs:** This section addresses non-embedded NO_x costs, at the request of the Study Group, in order to increase awareness. Please note that we are **not** recommending that PAs use an additional non-embedded NO_x value beyond the embedded allowance prices discussed in this chapter. Instead, we recommend a methodology consistent with AESC 2011.
- **Emissions from Hydraulic Fracturing:** Although calculating upstream avoided externalities associated with fracking is outside the scope of work for AESC 2013, discussion of "front end" emissions for gas fracking is important and is included here because of the large amount of greenhouse gas emissions associated with this fuel extraction process.
- **Compliance with State-Specific Climate Plans:** The AESC scope of work required the Synapse project team to determine if there was some component of compliance with state-specific regulations or climate plans that would directly impact generators, and that the project team could credibly support in its estimate of avoided electric energy costs. This section describes the methodology and policy questions raised by our analysis.

4.2 Environmental Regulations: Embedded Costs

For all fuels, we estimate the value associated with the mitigation of NO_x, SO_x, and CO_2 based on the allowance prices per short ton of emissions described and presented in this section. In addition, future environmental regulations will impact generator expenses, outages, and retirement decisions that are inputs into our simulation model.

4.2.1 Cost of Complying with Existing and Expected SO_2, NO_x, and CO_2 Regulations

For AESC 2013, we used Market Analytics to model and apply the unit costs of complying with regulations governing the emissions of SO_2, NO_x and CO_2. Market Analytics includes the unit costs associated with each of these emissions when calculating bid prices, and when making commitment and dispatch decisions.[49] In this way, AESC 2013 projects market prices which reflect, or "embed," the unit-compliance costs for each type of emission, excluding mercury. The unit compliance costs assumed for each pollutant are presented in Exhibit 4-1.

The NO_x and SO_2 allowance prices are based on the Market Analytics default assumptions.[50] Since there is still considerable uncertainty about the longer term, we have kept NO_x and SO_2 prices level at constant 2013 dollar (2013$) values. For mercury, we assume no trading, and hence no allowance price. The Ventyx Database Release Notes of February 2013 explains the Market Analytics NO_x and SO_2 emission price forecasts as follows:[51]

> In August 2012, the DC Circuit Court vacated EPA's Cross State Air Pollution Rule (CSAPR), sending the rule back to EPA for revision and re-instating the Clean Air Interstate Rule (CAIR). The court stated that CSAPR required states to make emissions reductions beyond what was mandated by the law. EPA has appealed that ruling, but in the meantime states are required to comply with CAIR. CAIR's requirements are much less stringent than those of CSAPR, and the clearing prices of the emissions markets indicate that those requirements have effectively been met: the value of an SO_2 and NO_x allowances are much lower than had been projected—$0/ton for SO_2 and around $27/ton for NO_x.

We note that even though allowance prices are low, these emission standards require investment in new emission control equipment that may cause the retirement of some older plants, as discussed in detail in Chapter 5, Electric Capacity.

Embedded CO_2 allowance prices are based on Regional Greenhouse Gas Initiative (RGGI) allowance prices through 2019. In 2020 and beyond, our estimate of embedded CO_2 costs is based on allowance prices estimated by the *2012 Carbon Dioxide Price Forecast* (Wilson et al. 2012) for our Base Case, in which a national cap-and-trade program for GHG is enacted.[52]

As requested by the Study Group, we have also estimated CO_2 allowance prices for a special case that assumes no new federal regulatory framework and thus continuation of RGGI indefinitely (RGGI-only). Under the RGGI-only scenario, as required by the state of Rhode Island, we assume that RGGI prices will

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[49] These are the carbon allowance prices that are embedded in the cost of electricity. For a discussion of the overall cost of carbon, including its non-embedded/climate plan compliance cost and overall value, see the remaining sections of this chapter.

[50] NO_x allowance prices in AESC 2011 fell considerably since the previous AESC report in 2009, and have fallen considerably once again in 2013. AESC 2011 NO_x prices started at $230 and fell to $132 per ton, compared to approximately $27 per ton in 2013. At $0 per ton, the 2013 SO_2 prices are also lower than AESC 2011 prices, which started at $3.75 and fell to $1.62 per ton. Compared to AESC 2011, 2013 CO_2 prices are only slightly lower in most years, resulting from the 2012 Synapse CO_2 Price Forecast's policy start date of 2020, compared to 2018 in AESC 2011.

[51] Further discussion of EPA regulations is provided in Chapter 4, Environmental Regulations.

[52] Wilson et al., "2012 Carbon Dioxide Price Forecast," October 2012. http://www.synapse-energy.com/Downloads/SynapseReport.2012-10.0.2012-CO2-Forecast.A0035.pdf

remain relatively stable due to electricity imports. Thus, we assume allowance prices in that RGGI-only case will rise at the rate of inflation. This scenario is shown in the last column of Exhibit 4-1.

When RGGI was established in 2007, the expectation was that the CO_2 cap would generate allowance price revenues for consumer benefit programs such as energy efficiency, renewable energy and clean energy technologies.[53] While RGGI has provided revenues for consumer benefit, its allowance prices have generally remained near the floor. External influences, including changes to fuel prices, caused a shift from coal and oil to natural gas generation. Compared to those external factors, the effect of the RGGI cap requirements were relatively minor in meeting the goals of reducing carbon dioxide emissions in the power sector.

In 2012 and 2013, the RGGI states evaluated a number of plans for tighter emissions caps that would result in higher allowance prices. In February of 2012, the RGGI states agreed to lower the CO_2 cap from 165 million to 91 million tons by 2020. Their analysis indicated that this would result in the allowance price rising to about $4 per short ton (2010$) in 2014 and increasing to about $10 per ton (2010$) in 2020.[54]

Exhibit 4-1. Emission Allowance Prices per Short Ton (Constant 2013$ and Nominal Dollars)

	NOx		SO_2		CO_2 (Synapse)		CO_2 (RGGI)	
Year	2013$	Nominal	2013$	Nominal	2013$	Nominal	2013$	Nominal
2013	27.41	27.41	0.00	0.00	2.80	2.80	2.80	2.80
2014	27.41	27.95	0.00	0.00	4.22	4.30	4.22	4.30
2015	27.41	28.51	0.00	0.00	5.28	5.49	5.28	5.49
2016	27.41	29.08	0.00	0.00	6.33	6.72	6.33	6.72
2017	27.41	29.66	0.00	0.00	7.39	7.99	7.39	7.99
2018	27.41	30.26	0.00	0.00	8.44	9.32	8.44	9.32
2019	27.41	30.86	0.00	0.00	9.50	10.69	9.50	10.69
2020	27.41	31.48	0.00	0.00	20.30	23.32	10.55	12.12
2021	27.41	32.11	0.00	0.00	22.58	26.46	10.55	12.36
2022	27.41	32.75	0.00	0.00	24.87	29.72	10.55	12.61
2023	27.41	33.41	0.00	0.00	27.15	33.10	10.55	12.86
2024	27.41	34.07	0.00	0.00	29.44	36.60	10.55	13.12
2025	27.41	34.76	0.00	0.00	31.72	40.23	10.55	13.38
2026	27.41	35.45	0.00	0.00	34.00	43.99	10.55	13.65
2027	27.41	36.16	0.00	0.00	36.29	47.88	10.55	13.92
2028	27.41	36.88	0.00	0.00	38.57	51.91	10.55	14.20
2029	27.41	37.62	0.00	0.00	40.85	56.08	10.55	14.48
2030	27.41	38.37	0.00	0.00	43.14	60.40	10.55	14.77

NOx & SO_2 from Ventyx assumptions. CO_2 (RGGI) from Auction 19 and RGGI Updated Model Rule Modeling, CO_2 (Synapse) starting in 2020 from Synapse report of October 2012.

53 http://www.rggi.org/

54 RGGI Press Release 2/7/13 http://www.rggi.org/docs/PressReleases/PR130207_ModelRule.pdf

The 15-year levelized value of the embedded avoided cost of carbon compliance for AESC 2013 is 21.6 percent higher than AESC 2011 (2013$) ($19.72/ton versus $16.21/ton), primarily due to upward pressure from RGGI Model Rule allowance prices, which was moderated somewhat by a delay in federal GHG regulation.

The following sections summarize the existing and expected environmental regulations that are incorporated into AESC 2013, and which are reflected in Exhibit 4-1, above.

4.2.2 Existing Regulations

Regional Greenhouse Gas Initiative

The Regional Greenhouse Gas Initiative (RGGI) is a cap and trade greenhouse gas program for power plants in the northeastern United States. Current participant states include Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont. Pennsylvania, Québec, New Brunswick, and Ontario are official "observers" in the RGGI process. To date, 19 rounds of RGGI auctions have occurred.

RGGI is designed to:

- Limit CO_2 emissions from power plants to 2009 levels for the period 2009 – 2013, followed by a 42 percent reduction below those levels by 2020.
- Allocate a minimum of 25 percent 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.
- Include certain offset provisions that increase flexibility to include opportunities outside the capped electricity generation sector.[55]

AESC 2013 assumes RGGI allowance prices as reported in Exhibit 4-1 based upon the proposed RGGI Model Rule update expected to be in place starting in 2014.

4.2.3 Expected Regulations

In AESC 2013, our assumptions incorporate the impact of future environmental regulations on the existing electric generation fleet. When considered individually, these rules will require generator retrofits and associated outages, and may result in retirements and/or the repowering of existing electric generating units across the United States. Taken together, these rules will have a significant effect on the generating fleet and influence our assumptions regarding unit retirements. The following is a short description of the rules anticipated to have the most economically consequential impacts on the power sector.

[55] Regional Greenhouse Gas Initiative website, http://www.rggi.org/design/program_review

Expected EPA Regulations

<u>National Ambient Air Quality Standards</u>

National Ambient Air Quality Standards (NAAQS) set maximum air quality limitations that must be met at all locations across the nation. Compliance with the NAAQS can be determined through air quality monitoring stations, which are stationed in various cities throughout the United States, or through air quality dispersion modeling. States with areas found to be in “nonattainment” of a particular NAAQS are required to set enforceable requirements to reduce emissions from sources contributing to nonattainment such that the NAAQS are achieved and maintained. The U.S. Environmental Protection Agency (EPA) has established NAAQS for six pollutants: sulfur dioxide (SO_2), nitrogen dioxides (NO_2), carbon monoxide (CO), ozone, particulate matter—measured as particulate matter less than or equal to 10 micrometers in diameter (PM10) and particulate matter less than or equal to 2.5 micrometers in diameter (PM2.5)—and lead.

In nonattainment areas, pollutant sources must comply with emission reduction requirements known as “Reasonably Available Control Technology” (RACT) to bring the areas into attainment of the NAAQS. New major sources, including major modifications at existing sources, must comply with very strict emissions reductions consistent with “lowest achievable emissions reductions” (LAER) and obtain emission offsets.

EPA is currently in the process of drafting new, more stringent NAAQS for SO_2, PM2.5, and ozone.

- On June 22, 2010, EPA revised[56] the standard for SO_2 by establishing a new 1-hour standard at a level of 75 parts per billion (ppb) in place of the existing annual and 24-hour standards for SO_2. EPA plans to make area designations for the new SO_2 standard by June 3, 2013, and compliance would be required in 2017.
- On December 14, 2012, EPA strengthened the annual PM2.5 standard from 15 µg/m3 to 12 µg/m3, and retained the current 24-hour standard at 35 µg/m3. EPA will make final area designations for the new standard by December 2014. Once designations are made, states with non-attainment areas will have to develop a State Implementation Plan within three years outlining how they will reduce pollution to meet the standard by 2020.
- In March 2008, EPA strengthened the 8-hour ozone standard from 84 ppb to 75 ppb. On September 16, 2009, EPA announced that because the 2008 standard was not as protective as recommended by EPA’s panel of science advisors, it would reconsider the 75 ppb standard. In 2010, EPA proposed lowering the 8-hour ozone standard from 75 ppb to between 60 and 70 ppb, and on September 2, 2011, the Administration announced that EPA would not finalize its proposed reconsideration

[56] 75 Fed. Reg. 35520 (June 22, 2010)

of the 75 ppb standard ahead of the regular 5-year NAAQS review cycle. The next 5-year review for 8-hour ozone is expected in 2013. Compliance with the upcoming standard would likely be required in the 2019-2020 timeframe.

Cross State Air Pollution Rule

The Cross State Air Pollution Rule (CSAPR) was finalized in 2011, establishing the obligations of each affected state to reduce emissions of NO_x and SO_2 that significantly contribute to another state's PM2.5 and ozone non-attainment problems. The rule targets electric generating units, and uses a cap and-trade approach to limit each state to emissions below a level that significantly contributes to non-attainment in downwind states.

On August 21, 2012, CSAPR was vacated by the U.S. Court of Appeals for the District of Columbia. EPA has filed a petition for *en banc* rehearing of that decision; however, even if EPA fails to salvage CSAPR through the courts, the Agency must still promulgate a replacement rule to implement Clean Air Act requirements to address the transport of air pollution across state boundaries. In the meantime, the court left the requirements of the 2005 Clean Air Interstate Rule in place.

Regional Haze Rules

One of the national goals set out in the Clean Air Act is reducing existing visibility impairment from human-made air pollution in all "Class I" areas (e.g., most national parks and wilderness areas).[57] EPA's Regional Haze Rule—issued in 1999, and revised in 2005—requires states to create plans to significantly improve visibility conditions in Class I areas with the goal of achieving natural background visibility conditions by 2064. These requirements are implemented through state plans with enforceable reductions in haze-causing pollution from individual sources and with other measures to meet "reasonable further progress" milestones.[58] The first progress milestone is 2018.

A key component of this program is the imposition of air pollution controls on existing facilities that impact visibility in Class I areas. Specifically, the rules require installation of "best available retrofit technology" (BART) that is developed for such facilities on a case-by-case basis. In addition, EPA's BART determinations specify particular emission limits for each BART-eligible facility. EPA evaluates BART for the air pollutants that impact visibility in our national parks and wilderness areas—namely SO_2, PM, and NO_x. Under the Clean Air Act, states develop Regional Haze requirements, but EPA approves state plans for compliance. If EPA finds the plans are not consistent with the Clean Air Act, it adopts a federal plan with BART and reasonable progress requirements. Affected facilities must comply with the BART

[57] 42 U.S.C. § 7491(a)(1)

[58] 40 C.F.R. §51.308-309

determinations as expeditiously as practicable but no later than five years from the date EPA approves the state plan or adopts a federal plan.[59]

Mercury and Air Toxics Standards (MATS)

In 2000, EPA determined it was appropriate and necessary to regulate toxic air emissions (or hazardous air pollutants) from steam electric generating units. As a result, EPA adopted strict emission limitations for hazardous air pollutants that are based on the emissions of the cleanest existing sources.[60] These emission limitations are known as Maximum Achievable Control Technology (MACT). The final MATS rule, approved in December 2011, sets strict stack emissions limits for mercury, other metal toxins, other organic and inorganic hazardous air pollutants, as well as acid gasses. Compliance with MATS is required by 2015, with a potential extension to 2016.

Coal Combustion Residuals Disposal Rule

Coal-fired power plants generate a tremendous amount of ash and other residual wastes, which are commonly placed in dry landfills or slurry impoundments. The risk associated with wet storage of coal combustion residuals (CCR) was dramatically revealed in the catastrophic failure of the ash slurry containment at the Kingston coal plant in Roane County, Tennessee in December 2008, releasing over a billion gallons of slurry and sending toxic sludge into tributaries of the Tennessee River.

On June 21, 2010, EPA proposed to regulate CCR for the first time either as a Subtitle C hazardous waste or Subtitle D solid waste under the Resource Conservation and Recovery Act. The current rulemaking is 30 years overdue. If the EPA classifies CCR as hazardous waste, a cradle-to-grave regulatory system would apply to CCR, requiring regulation of the entities that create, transport, and dispose of the waste. Under a Subtitle C designation, the EPA would regulate siting, liners, run-on and run-off controls, groundwater monitoring, fugitive dust controls, and any corrective actions required; in addition, the EPA would implement minimum requirements for dam safety at impoundments. Under a solid waste Subtitle D designation, the EPA would require minimum siting and construction standards for new coal ash ponds, compel existing unlined impoundments to install liners, and require standards for long-term stability and closure care.

[59] EPA's regulations allow certain states in the "Grand Canyon Visibility Transport Region" to participate in an SO_2 trading program in lieu of adopting source-specific SO_2 BART requirements, if the trading program will result in greater reasonable progress toward attaining the national visibility goal than source-specific BART. Although nine states were originally eligible to participate, today only three states are opting to participate in this program – New Mexico, Utah, and Wyoming. These states agreed to a gradually declining cap on SO_2 emissions from all emission sources. If the declining caps are exceeded in any year, then even greater SO_2 emission reductions have to be achieved—although the reductions can be met through emissions trading, rather than imposition of specific emission limitations on any one facility. This program is called the Backstop Trading Program. As of the date of this testimony, EPA has not yet approved the Backstop Trading Program to meet Regional Haze requirements in any of the three states' Regional Haze plans, so the trading program is not yet federally enforceable.

[60] Clean Air Act §112(d)

The EPA is currently evaluating which regulatory pathway will be most effective in protecting human health and the environment. In 1999, EPA released a series of technical papers to Congress documenting cases in which damages are known to have occurred from leakages and spills from coal ash impoundments.[61] In the current proposed rule, the EPA recognizes a substantial increase in the types and quantities of potentially toxic CCR caused by air pollution control equipment.

Use of more advanced air pollution control technology reduces air emissions of metals and other pollutants in the flue gas of a coal-fired power plant by capturing and transferring the pollutants to the fly ash and other air pollution control residues. The impact of changes in air pollution control on the characteristics of CCRs and the leaching potential of metals is the focus of ongoing research by EPA's Office of Research and Development.[62]

Steam Electric Effluent Limitation Guidelines

Following a multi-year study of steam-generating units across the country, EPA found that coal-fired power plants are currently discharging a higher-than-expected level of toxic-weighted pollutants into waterways. Current effluent regulations were last updated in 1982 and do not reflect the changes that have occurred in the electric power industry over the last thirty years, and do not adequately manage the pollutants being discharged from coal-fired generating units. Coal ash ponds and flue gas desulfurization systems used by such power plants are the source of a large portion of these pollutants, and are likely to result in an increase in toxic effluents in the future as environmental regulations are promulgated and pollution controls are installed. No new rule has yet been proposed, but EPA is under a court order to issue the proposed regulation by April 19, 2013 and a final rule in May 22, 2014.[63] New requirements will be implemented in 2014 to 2019 through the five-year National Pollutant Discharge Elimination System permit cycle.[64]

Clean Water Act Cooling Water Intake Structure Rule

On March 28, 2011, the EPA proposed a long-expected rule implementing the requirements of Section 316(b) of the Clean Water Act at existing power plants.[65] Section 316(b) requires "that the location, design, construction, and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impact." Under this new rule, EPA set new standards

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[61] EPA. March 15, 1999. Technical Background Document for the Report to Congress on Remaining Wastes from Fossil Fuel Combustion: Potential Damage Cases. http://www.epa.gov/osw/nonhaz/industrial/special/fossil/ffc2_397.pdf

[62] 75 Fed. Reg. 35139 (June 21, 2010).

[63] *See* U.S. Environmental Protection Agency website. Accessed February 21, 2013. Available at: http://water.epa.gov/scitech/wastetech/guide/steam-electric/amendment.cfm

[64] *See* U.S. Environmental Protection Agency. *Steam Electric ELG Rulemaking*. UMRA and Federalism Implications: Consultation Meeting. October 11, 2011. http://water.epa.gov/scitech/wastetech/guide/upload/Steam-Electric-ELG-Rulemaking-UMRA-and-Federalism-Implications-Consultation-Meeting-Presentation.pdf

[65] 33 U.S.C. § 1326.

reducing the impingement and entrainment of aquatic organisms from cooling water intake structures at new and existing electric generating facilities.

The rule provides that:

- Existing facilities that withdraw more than two million gallons per day are subject to an upper limit on fish mortality from impingement, and must implement technology to either reduce impingement or slow water intake velocities.
- Existing facilities that withdraw at least 125 million gallons per day are required to conduct an entrainment characterization study to establish a "best technology available" for the specific site.

Greenhouse Gas Tailoring Rule

Under EPA's Greenhouse Gas Tailoring Rule, large sources of greenhouse gas emissions are subject to permitting requirements. For purposes of determining whether New Source Review applies, a "large source" is a new facility with emissions of at least 100,000 tons per year of carbon dioxide equivalent (CO_2e) or an existing facility that emits at least 100,000 tons per year CO_2e and is making modifications that would increase greenhouse gas emissions by at least 75,000 tons per year CO_2e. These sources are required to obtain permits under the New Source Review Prevention of Significant Deterioration program and therefore must install Best Available Control Technology (BACT) for greenhouse gases. In the case of a modification, to a facility that does not emit at least 100,000 tons per year CO_2e but will increase greenhouse gas emissions by 75,000 tons per year CO_2e, the BACT requirement only applies for GHG if the project triggers new source review for another criteria pollutant. Any new or existing source with emissions of 100,000 tons per year CO_2e or more must obtain a Title V operating permit.

New Source Performance Standards

Under Section 111 of the Clean Air Act, EPA sets technology-based standards for new sources on a category-by-category basis. These standards are set based on the best demonstrated available technology (BDAT) and apply to all new sources built or modified following promulgation of the standard.

On March 27, 2012, EPA proposed[66] New Source Performance Standards for greenhouse gas emissions from new electric generating units. The standard was set at 1,000 lbs CO_2e/MWh, which is equivalent to the emission rate that a combined-cycle natural gas unit can achieve. The rule also allows a unit's emissions to be averaged over 30 years to achieve an annual average emission rate of 1,000 lbs CO_2e/MWh. This option allows the phase-in of CCS within the first 10 years of operation.

While New Source Performance Standards apply only to new facilities, Section 111(d) of the Clean Air Act requires states to develop plans for *existing* sources of any non-criteria pollutants (i.e., a pollutant

[66] 77 Fed. Reg. 22392 (April 13, 2012)

for which there is no NAAQS) and non-hazardous air pollutant whenever EPA promulgates a standard for a new source. These plans are subject to EPA review and approval, similar to state implementation plans under the NAAQS program.

Federal Carbon Regulation

The AESC 2013 Base Case assumes federal cap-and-trade carbon regulation will take effect in 2020, consistent with the *2012 Carbon Dioxide Price Forecast* developed by Synapse in October 2012, as described in section 4.2.1.

As previously noted, embedded CO_2 costs for the AESC 2013 Base Case are based on RGGI allowances prices (as reported in Exhibit 4-1) in the near term, and prices estimated in Synapse's *2012 Carbon Dioxide Price Forecast* for years 2020 and beyond.

4.2.4 Impact of Energy Efficiency Programs on CO_2 Emissions under a Cap and Trade Regulatory Framework

With CO_2 emissions regulated under a cap and trade system, as assumed in this market price analysis, it is conceivable that a load reduction from an energy efficiency program will not lead to a reduction in the amount of total system CO_2 emissions. The annual total system emissions for the affected facilities in the relevant region are, after all, capped. In the analysis documented in this report, the relevant cap and trade regulation is the RGGI for the period 2013 to 2019, and an assumed national cap and trade system thereafter. There are, however, a number of reasons why an energy efficiency program could nonetheless result in CO_2 emission reductions. Specifically:

- A reduction in load that reduces the cost (marginal or total cost) of achieving an emissions cap can result in a decision to tighten 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 reasonably may 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 U.S. carbon regulatory system.

- It is also possible that energy efficiency 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).

- To the extent that the cap and trade system "leaks" outside of its geographic boundaries, one would expect the benefits of a carbon emissions reduction resulting from an energy efficiency program to similarly "leak." That is, a load reduction in New York could cause reductions in generation (and emissions) at power plants in New York, Pennsylvania, and elsewhere. Because New York is in the RGGI cap and trade system, the emissions reductions realized at New York generating units may accrue as a result of increased sales of allowances from New York to other RGGI states. Since Pennsylvania is not in the RGGI system, however, the emissions reductions at

Pennsylvania generating units would be true reductions attributable to the energy efficiency program.

The first three of these points, above, would also apply to a national CO_2 cap and trade program. The fourth point, regarding leakage and boundaries, would apply as well, but to a lesser extent.

4.3 Non-Embedded Environmental Costs

Non-embedded costs are impacts from the production of a good or service that are not reflected in price of that good or service, and are not considered in the decision to provide that good or service.[67] Air pollution generated in the production of electricity is a classic example of a non-embedded cost: pollutants released from a power plant impose health impacts on a population, cause damage to the environment, or both. In this example, health impacts and ecosystem damages not reflected in the price of electricity and not considered in the power plant owner's decision of how much electricity to provide are "non-embedded," whereas adverse impacts that are reflected in the market price of electricity (e.g., through regulation) and are considered in decisions regarding production are "embedded."

For AESC 2013, we anticipate that the "non-embedded carbon costs" will continue to be the dominant non-embedded environmental cost associated with marginal electricity generation in New England. This is the case for two main reasons. First, regulations to address the greenhouse gas emissions responsible for global climate change have yet to be implemented with sufficient stringency to reduce carbon emissions, particularly in the United States.[68] The damages from the EPA's criteria air pollutants are relatively bounded, and to a great extent "embedded," 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, as well as relatively low NO_x emissions.

4.3.1 History of Non-Embedded Environmental Cost Policies in New England

In the 1980s and 1990s, several New England states had proceedings dealing with non-embedded costs that influence current utility planning and decision-making.[69] In Massachusetts, dockets DPU 89-239 and

[67] In economics, a non-embedded impact can be positive (a non-embedded benefit) or negative (a non-embedded cost); in this discussion we are focusing on negative impacts (non-embedded costs).

[68] On April 17, 2009; EPA issued a proposed finding that concluded that greenhouse gases posed an endangerment to public health and welfare under the Clean Air Act ("Proposed Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act" 74 Fed. Register 78: 18886–18910). This proposed finding initiates the process of potentially regulating greenhouse gases as an air pollutant. http://epa.gov/climatechange/endangerment.html

[69] A more detailed description of the history of electricity generation environmental externalities and policies in New England may be found in AESC 2007 (p. 7-6–7-8).

91-131 served as models for other states. Docket DPU 89-239 was opened to develop "Rules to Implement Integrated Resource Planning" and included the determination and application of non-embedded environmental cost values. This docket adopted a set of dollar values for air emissions, including a CO_2 value of $37 per ton of CO_2 (in 2013 dollars) (Exhibit DOER-3, Exhibit. BB-2, p. 26).[70] Docket DPU 91-131 examined environmental costs to develop recommendations of various approaches for quantifying the non-embedded CO_2 value. The Department's Order in Docket DPU 91-131 was noteworthy for its foresight regarding climate change, albeit optimistic about the timing of the adoption of climate change regulations in the U.S.[71] Based on information in the record, the Department reaffirmed the CO_2 value it had adopted in the previous case, $37 per ton (in 2013 dollars).

4.3.2 Estimating Non-Embedded CO_2 Costs

Setting a Threshold for Global CO_2 Emissions

The level of global CO_2 emissions thought to be consistent with avoiding the most serious forms of climate damage is essentially unchanged since AESC 2011.[72] Sustainability targets for CO_2 equivalent concentrations in the atmosphere are roughly 350 to 450 ppm[73], consistent with an approximately 50 percent chance of limiting the change in the average global temperature to 2°C above pre-industrial levels.[74] The Copenhagen Agreement, drafted at the 15th session of the Conference of the Parties to the United Nations Framework Convention on Climate Change in 2009, recognizes the scientific view that in order to prevent the more drastic effects of climate change, the increase in global temperature should be limited to no more than 2°C.[75]

The Intergovernmental Panel on Climate Change (IPCC 2007, Table SPM5) indicates that reaching concentrations of 450 to 490 ppm CO_2 equivalent will require a reduction in 2050 global CO_2 emissions of 50 to 85 percent below 2000 emissions levels. Stern (2007, xi) states that global emissions would have to be 70 percent below current levels by 2050 for stabilization at 450 ppm CO_2 equivalent. To accomplish such stabilization, the U.S. and other industrialized countries would have to reduce greenhouse gas emissions on the order of 80 to 90 percent below 1990 levels, and developing countries would have to achieve reductions from the baseline increase in emissions caused by improvements in the standard of living as soon as possible (den Elzen and Meinshausen, 2006).

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[70] $22 in 1989 dollars.

[71] AESC 2009 provides more detail about the Massachusetts DPU Order in Docket DPU 91-131.

[72] AESC 2011 Section 6.6.4.1 page 6-97.

[73] We are unaware of specific abatement cost estimate studies for the 350 ppm target; thus the information and analysis presented here focuses on the 450 ppm target.

[74] Ackerman and Stanton (2013) *Climate Economics: The State of the Art*. Routledge: NY.

[75] IPCC, 2007: Summary for Policymakers. In: *Climate Change 2007: Mitigation. Contribution of Working Group III to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change* [B. Metz, O.R. Davidson, P.R. Bosch, R. Dave, L.A. Meyer (eds)], Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA.

In the U.S., several states have adopted state greenhouse gas abatement targets of 50 percent or more reduction from a baseline of 1990 levels or then-current levels by 2050 (Arizona, California, Connecticut, Florida, Illinois, Maine, Massachusetts, Minnesota, New Hampshire, New Jersey, New Mexico, Oregon, Vermont, and Washington).[76] In Massachusetts, the Global Warming Solutions Act (GWSA), signed into law by Governor Deval Patrick in August 2008, calls for initial reductions in greenhouse gas emissions of between 10 percent and 25 percent below 1990 levels by 2020.[77] The *Massachusetts Clean Energy and Climate Plan for 2020*, released on December 29, 2010 by the Massachusetts Executive Office of Energy and Environmental Affairs, sets out policies, with associated emissions reductions, necessary to meet the 2020 target of 25 percent below 1990 levels.[78]

Methods to Monetize Non-Embedded CO_2

Several different methods are available to monetize environmental costs. These include "damage cost" approaches that seek to assign a value to damages associated with a particular pollutant, and "control cost" approaches that seek to quantify the marginal cost of controlling a particular pollutant. For the reasons outlined below, AESC 2013 recommends using the control cost approach to estimate non-embedded CO_2 costs for the study period.

Damage Cost Approach: The Social Cost of Carbon

Damage cost methods generally rely on travel costs, hedonic pricing, or contingent valuation to assign values in the absence—by definition—of market prices for non-embedded impacts. These are forms of "implied valuation," asking complex and hypothetical survey questions, or extrapolating from observed behavior, to impute a price to something that is never bought or sold in a market. For example, data on how much people will spend on travel, subsistence, and equipment on fishing can be used to measure the value of those fish, and the value of *not* killing fish with waterborne pollution. Even human lives sometimes have been valued based on wage differentials for jobs that expose workers to different risks of mortality. Comparing the difference in wages between 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 a life-threatening risk and, by analogy, as a controversial estimate of the value of life itself.

Valuation of the societal damages caused by the emission of an additional ton of CO_2—a measure often called the "social cost of carbon"—typically combines cost estimates, using a variety of implied valuation techniques, for numerous damages from climate change that are expected around the world. In 2010, the U.S. government began to include a social cost of carbon in the valuation of federal rulemakings with the goal of accounting for the damages resulting from climate change, defined as "an estimate of

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[76] Center for Climate and Energy Solutions, "A Look at Emissions Targets," http://www.c2es.org/what_s_being_done/targets

[77] Massachusetts G.L. c. 21N

[78] http://www.mass.gov/eea/docs/eea/energy/2020-clean-energy-plan.pdf

the monetized damages associated with an incremental increase in carbon emissions in a given year."[79] A range of four social cost of carbon values was initially calculated by the Interagency Working Group on the Social Cost of Carbon (the "Working Group"), a group composed of members of the Department of Agriculture, Department of Commerce, Department of Energy, Environmental Protection Agency, and Department of Transportation, among others.

The Working Group's estimates, presented in Exhibit 4-2, seek to represent the range of social cost of carbon values for three discount rates as well as the high-cost tail-end of the uncertain distribution of impacts in 2013 dollars per short ton (t) CO_2.[80] It is important to note that social cost of carbon values represent the damages associated with an incremental increase in CO_2 emissions *in a given year*; for this reason, they are time-dependent and are expected to increase in future years as atmospheric concentrations of CO_2 increase. As of May 2012, these estimates had been used in more than 20 federal government rulemakings, for policies including fuel economy standards, industrial equipment efficiency, lighting standards, and air quality rules.[81] In May 2013, the Working Group released a technical update that revised its estimate of the Social Cost of Carbon.[82]

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[79] Interagency Working Group on the Social Cost of Carbon, U. S. G. (2010). Appendix 15a. Social cost of carbon for regulatory impact analysis under Executive Order 12866. In Final Rule Technical Support Document (TSD): Energy Efficiency Program for Commercial and Industrial Equipment: Small Electric Motors. U.S. Department of Energy. URL http://go.usa.gov/3fH.

[80] The Working Group's 2010 social cost of carbon values are commonly reported in 2007 dollars of $5, $21, $35, and $65 per metric tonne CO_2. In Exhibit 4-2, these values are converted to 2013 dollars and short tons.

[81] Robert E. Kopp and Bryan K. Mignone (2012). The U.S. Government's Social Cost of Carbon Estimates after Their First Two Years: Pathways for Improvement. Economics: The Open-Access, Open-Assessment E-Journal, Vol. 6, 2012-15. http://dx.doi.org/10.5018/economics-ejournal.ja.2012-15

[82] Interagency Working Group on the Social Cost of Carbon, U. S. G. (2013). Technical Support Document:- Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis- Under Executive Order 12866. URL http://www.whitehouse.gov/sites/default/files/omb/inforeg/social_cost_of_carbon_for_ria_2013_update.pdf

Exhibit 4-2. U.S. Interagency Working Group Social Cost of Carbon (2013 dollars per short ton CO_2)

Climate Sensitivity	Median	Median	Median	95th Percentile
Discount Rate	**5%**	**3%**	**2.5%**	**3%**
2010	$5	$21	$35	$65
2015	$6	$24	$38	$73
2020	$7	$26	$42	$81
2025	$8	$30	$46	$90
2030	$10	$33	$50	$100
2035	$11	$36	$54	$110
2040	$13	$39	$58	$119
2045	$14	$42	$62	$128
2050	$16	$45	$65	$136

Source: U.S. EPA (2012) "The Social Cost of Carbon" http://www.epa.gov/climatechange/EPAactivities/economics/scc.html

These social cost of carbon values are the result of the Working Group's reanalysis using the DICE, PAGE, and FUND integrated assessment models, which simplify the relationships among complex climate and economic systems with the goal of providing information useful in making climate policy decisions.[83] The social cost of carbon values are calculated as the net present value of the discounted path of hundreds of years of future damages computed by each of the three models resulting from the addition of a ton of CO_2 emissions in a given year.

The Working Group based its common sets of assumptions regarding emissions, population, and gross domestic product (GDP), used for all three models, on four business-as-usual scenarios from an Energy Modeling Forum (EMF) model comparison exercise and an average of 550 ppm CO_2e scenarios from the same four EMF models.[84] The process-based integrated assessment models used in the EMF survey contain substantially more detailed representations of the climate and energy systems than the DICE, PAGE, and FUND models, but only provide results out to 2100. The Working Group analysis extrapolates these trends out to 2300 based upon assumptions regarding changes in fertility rates, GDP per capita, and carbon intensities.

DICE, PAGE, and FUND all employ simplified climate modules to convert emissions into atmospheric concentrations, and then use a climate sensitivity parameter to convert concentrations into temperature increases. To address the substantial uncertainty in this climate sensitivity parameter, the

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[83] The DICE model was further simplified by the Working Group for use in its analysis, see Interagency Working Group 2010.

[84] Clarke, L. (2009). Overview of EMF 22 international scenarios http://emf.stanford.edu/events/emf_briefing_on_climate_policy_scenarios_us_domestic_and_international_policy_architectures/.

Working Group conducted a "Monte Carlo" analysis that averages results from a distribution of likely sensitivities. Three of the four social cost of carbon values are based on the median of this distribution, with the fourth based on the high-cost tail-end 95th percentile.

The DICE, PAGE, and FUND integrated assessment models rely on implied valuations of future climate damages to calibrate their "damage functions," which translate temperature changes into changes in GDP. Climate damage valuation is hampered by significant uncertainty in the climate system itself, long time intervals separating cause and effect, and practical difficulties in assigning monetary values to projected damages that fall outside of the range of past experience. A common practice used in these and other climate-economics models is to set a point estimate for the expected cost of near-term, low-level climate damages and then to extrapolate the costs as rising with the square of temperature change.[85] The climate damage values used in the Working Group analysis represent the most likely level of damage given these estimation techniques, ignoring any uncertainty in the range of damages expected to occur from a given rise in temperature.

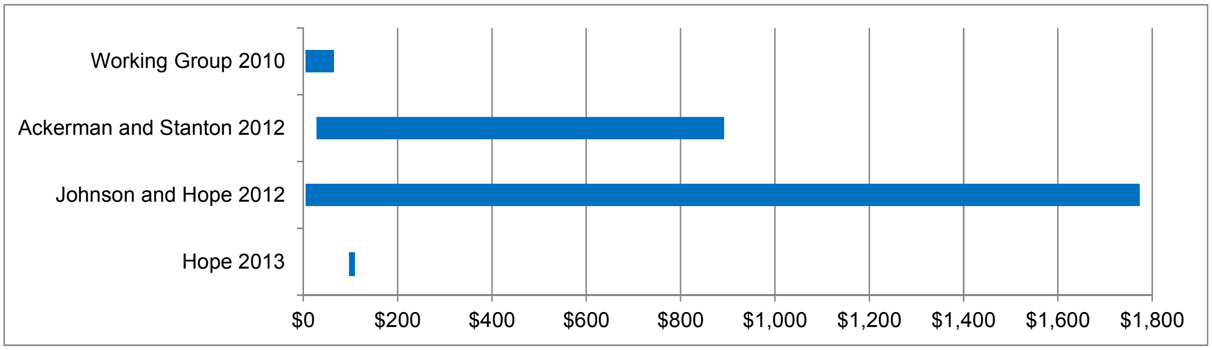
In a 2012 paper, Ackerman and Stanton critiqued and modified several of the assumptions in the Working Group's DICE model analysis—climate sensitivity, the expected level of damages at low and high greenhouse gas concentrations, and the discount rate—and found 2010 social cost of carbon values ranging from the Working Group's level up to more than an order of magnitude greater, up to $892 per short ton (in 2013 dollars) compared to the median $28/t value from DICE (see Exhibit 4-3).[86] Johnson and Hope also explored changes in the discount rate, equity weighting to differentiate damages based on regional income levels, and the full range of climate sensitivity uncertainty in the Working Group's social cost of carbon. This analysis resulted in 2010 social cost of carbon values ranging up to $1,774 per short ton (in 2013 dollars).[87]

[85] Stanton, Ackerman and Kartha (2009) "Inside the Integrated Assessment Models: Four Issues in Climate Economics." Climate and Development 1:2(166-184). DOI 10.3763/cdev.2009.0015

[86] Ackerman and Stanton (2012) "Climate Risks and Carbon Prices: Revising the Social Cost of Carbon." Economics: The Open-Access, Open-Assessment E-Journal, Vol. 6, 2012-10. http://dx.doi.org/10.5018/economics-ejournal.ja.2012-10

[87] Johnson, L. and Hope, C. (2012). "The social cost of carbon in US regulatory impact analysis: an introduction and critique." J Environ Stud Sci. DOI 10.1007/s13412-012-0087-7

Exhibit 4-3. Alternate Estimates of the Working Group's Social Cost of Carbon (2013 dollars per short ton CO_2)



Source: See text.

Using an updated version of PAGE, the model's developer (Hope) also conducted an independent analysis of the social cost of carbon based on new socioeconomic scenarios, new discount rate ranges, updated climate sensitivity, and reduced climate-damage adaptation from the earlier version of the model. The mean estimate of $106/t (in 2013 dollars) for the average social cost of carbon was substantially larger than $30/t for the median PAGE model run at the 3 percent discount rate.[88]

Only the Working Group's median, 3-percent-discount-rate social cost of carbon—for 2010, $21 per short ton in 2013 dollars—is used in federal impact analysis. While the Working Group's central case is now employed in environmental impact analysis of many federal regulations, we find that both the overall social cost of carbon methodology and the Working Group's application of it include serious flaws that should not be overlooked. The social cost of carbon methodology relies on the estimation of damage costs for far future impacts that are expected to be outside of the range of past experience. This type of valuation is, at best, highly speculative. The Working Group's social cost of carbon calculations ignore critical uncertainties in damage estimation. To the extent that the Working Group examines a limited set of discount rates and a broader set of climate sensitivities, the distribution of results is essentially thrown out.

As noted previously, in May 2013, the Working Group released a technical update to its Social Cost of Carbon that used the same methodology as 2010, but used updated versions of the DICE, FUND, and PAGE models. The revised modeling exercise resulted in change in the working Group's **median**, 3-percent-discount-rate social cost of carbon—for 2010, $21 to $33 per short ton in 2013 dollars.

For the purposes of AESC 2013, the Working Group's revised $33/t may be viewed as an extreme lower bound to possible non-embedded CO_2 values in 2010.[89]

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[88] Hope, C. (2013). "Critical issues for the calculation of the social cost of CO_2: why the estimates from PAGE09 are higher than those from PAGE2002". Climatic Change. Vol 117. 2013-04. DOI: 10.1007/s10584-012-0633-z

[89] We note that in May 2013, the DOE's microwave appliance standard used a SCC value of $33/ton as noted previously.

Control Cost Approach

The Marginal Cost of Stabilizing CO_2 Emissions

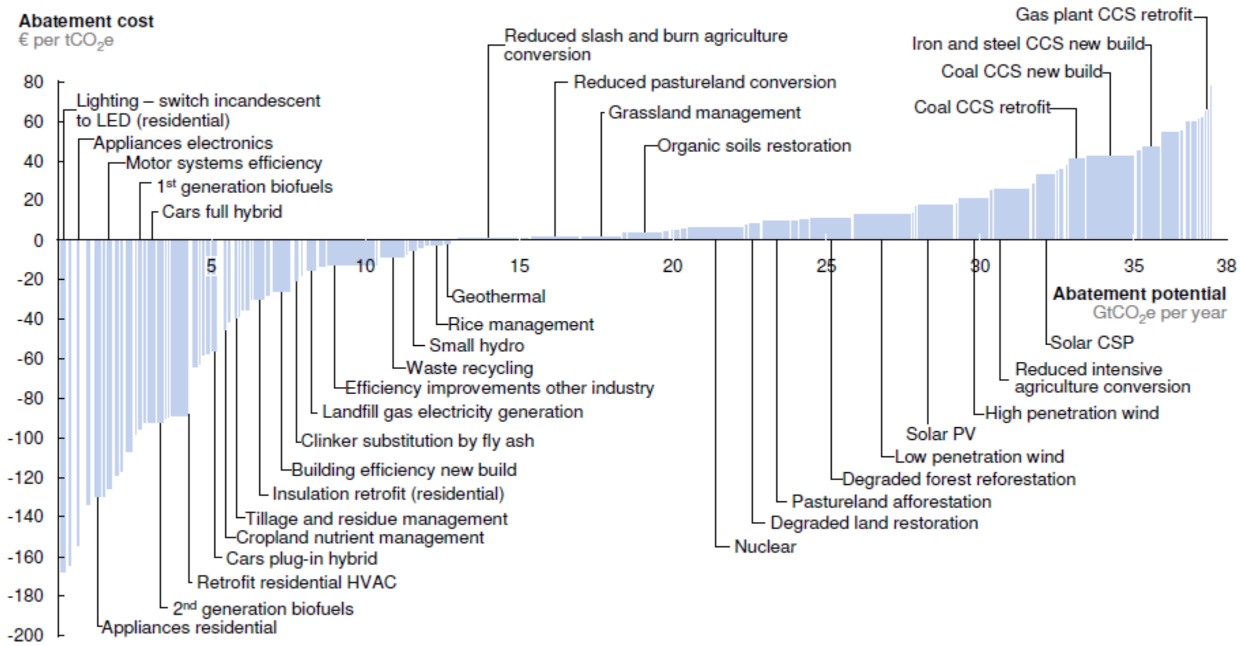
Control cost methods generally look at the marginal cost of abating CO_2 emissions—that is, the last (or most expensive) unit of emissions reduction required to comply with regulations. The cost of control approach is often based on regulators' revealed preferences. For example, if air quality regulators require a particular technology that costs $X for each ton of emissions that it achieves, then this can be taken as an indication that regulators value emission reductions at or above $X/t. For CO_2 emissions, however, regulators' preferences are not as yet fully revealed.

A marginal cost of abatement can also be based on a sustainability target of staying at or below the highest level of damage or risk that is considered to be acceptable. In this case, the marginal cost of abatement is the cost per ton of the most expensive technology needed to achieve the sustainability target. A sustainability target for CO_2 emissions relies on the assumption—well established in documents related to international climate policy negotiations—that there is a threshold beyond which the nations of the world deem climatic changes and their associated damages to be unacceptable.

A wealth of well documented, compelling research exists both on setting an acceptable threshold for CO_2 emissions and on current and projected costs of CO_2 emissions abatement technologies. Here, we review several recent analyses of strategies and technologies that would contribute to emission reductions consistent with an increase in average temperature of no more than 2°C above preindustrial levels or atmospheric concentrations no greater than 450 ppm CO_2 equivalent. The information and analysis presented here focuses on the 450 ppm target, entirely because the available studies used the 450 ppm level in their analyses. The 350 ppm target has been identified and is viewed as a more current target to maintain the global temperature increase above pre-industrial levels at no more than 2°C. While there is a lack of abatement cost estimates associated with a 350 ppm target, given the factors described in the following text it is reasonable to conclude that such an abatement cost would be equal or more than the abatement cost associated with a 450 ppm target, and could potentially be considerably higher.

McKinsey & Company examined these technologies in a 2010 report entitled *Impact of the Financial Crisis on Carbon Economics: Version 2.1 of the Global Greenhouse Gas Abatement Cost Curve*. The CO_2 mitigation options identified by McKinsey and the costs of those options are reproduced in Exhibit 4-4. The figure represents a marginal abatement cost curve, where the per ton cost of abatement is shown on the vertical axis and cumulative metric tons of CO_2 equivalent reductions are shown on the horizontal axis. Global CO_2 mitigation technologies are ordered from least to most expensive with the width of each bar representing each technology's expected total emission reduction. If technologies are assumed to be implemented in order of their costs, beginning with the cheapest abatement options, the marginal cost of maintaining the sustainability threshold is the cost per ton of the most expensive technology needed to provide the appropriate reduction (here, 38 metric gigatonne CO_2 equivalent in 2030).

Exhibit 4-4. Marginal Abatement Technologies and Associated Costs for the Year 2030



Note: The curve presents an estimate of the maximum potential of all technical GHG abatement measures below €80 per tCO_2e if each lever was pursued aggressively. It is not a forecast of what role different abatement measures and technologies will play.
Source: Global GHG Abatement Cost Curve v2.1

Source: McKinsey & Company. Impact of the Financial Crisis on Carbon Economics: Version 2.1 of the Global Greenhouse Gas Abatement Cost Curve. 2010. Page 8.

As shown in Exhibit 4-4, the marginal technology is a gas plant carbon capture and storage (CCS) retrofit costing $106 per short ton in 2013 dollars.[90] This figure also shows a variety of technologies for carbon mitigation that are available to the electric sector, including those related to energy efficiency, nuclear power, renewable energy, and CCS for fossil-fired generating resources.

In *World Energy Outlook 2012*, the IEA has modeled the implications of a 450 Scenario, which stabilizes CO_2 levels at 450 ppm with a goal of limiting temperature increase to 2°C.[91] IEA projects regionally specific 2035 marginal cost of abatements for OECD+ countries ($115 per short ton in 2013 dollars) and other major economies ($91/t) for its 450 Scenario.[92]

In *Energy Technology Perspectives 2012*, the IEA examines another 450 ppm CO_2 scenario, referred to as the "2DS" with broad deployment of CCS for coal, gas, and biomass, utility-scale PV, offshore wind, and

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[90] 2005 Euro to Dollar conversion factor, 1.25, [http://www.oanda.com/convert/fxhistory accessed 4/28/09](http://www.oanda.com/convert/fxhistory)

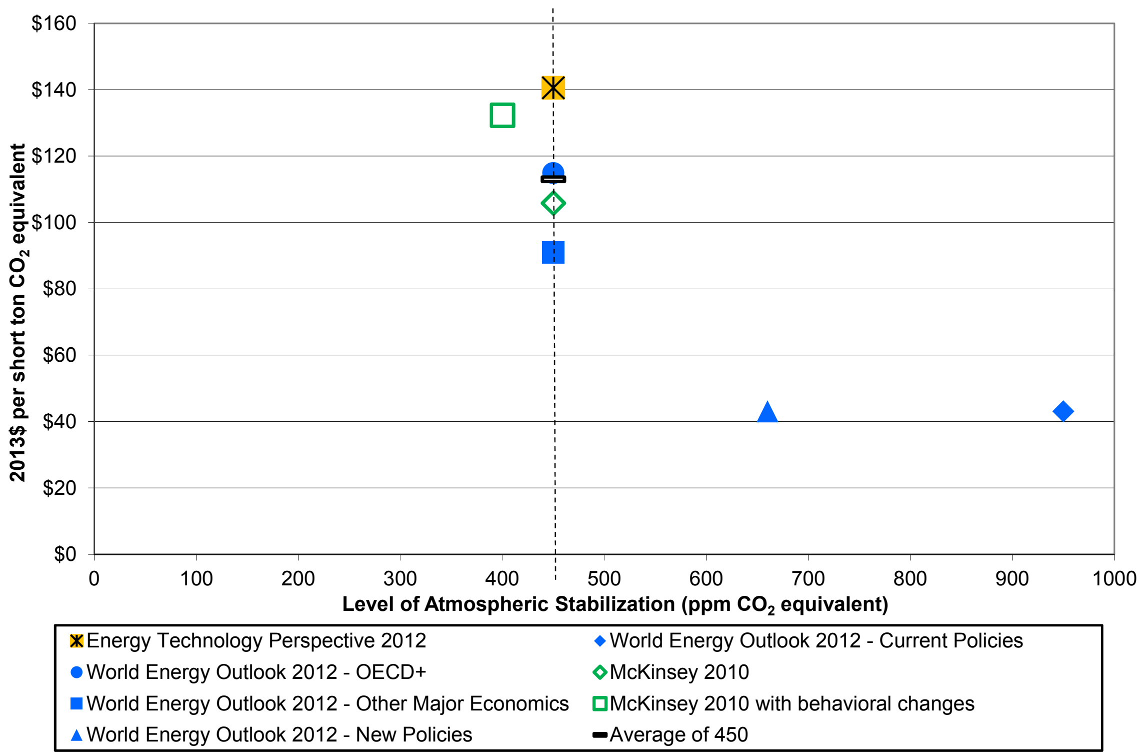
[91] IEA (2012). World Energy Outlook 2012. Available at: http://www.worldenergyoutlook.org/publications/weo-2012/

[92] OECD+ countries include all OECD countries, as well as non-OECD countries in the European Union. Other Major Economies includes Brazil, China, the Middle East, Russia, and South Africa.

geothermal. The marginal cost of abatement for this scenario reaches $141 per short ton in 2013 dollars in 2050. This represents a decrease in abatement costs on the order of $20/t from the *Energy Technology Perspectives 2010*, primarily as a result of higher projected prices for fossil fuels and more optimistic forecasts for low-carbon technologies.

The results of these studies are summarized below in Exhibit 4-5. The dotted line is drawn at the value of atmospheric stabilization of 450 ppm CO_2 equivalent, which corresponds to a good chance of limiting global temperature increase to 2°C above pre-industrial levels. The average of the 450 ppm marginal cost of abatement estimates shown here is $113 per short ton of CO_2 equivalent in 2013 dollars. Based on this analysis—as well as the CCS costs presented in the section below, and our own judgment and experience—we recommended an AESC 2013 abatement cost of $100 per short ton (in 2013 dollars).

Exhibit 4-5. Summary Chart of Marginal Abatement Cost Studies



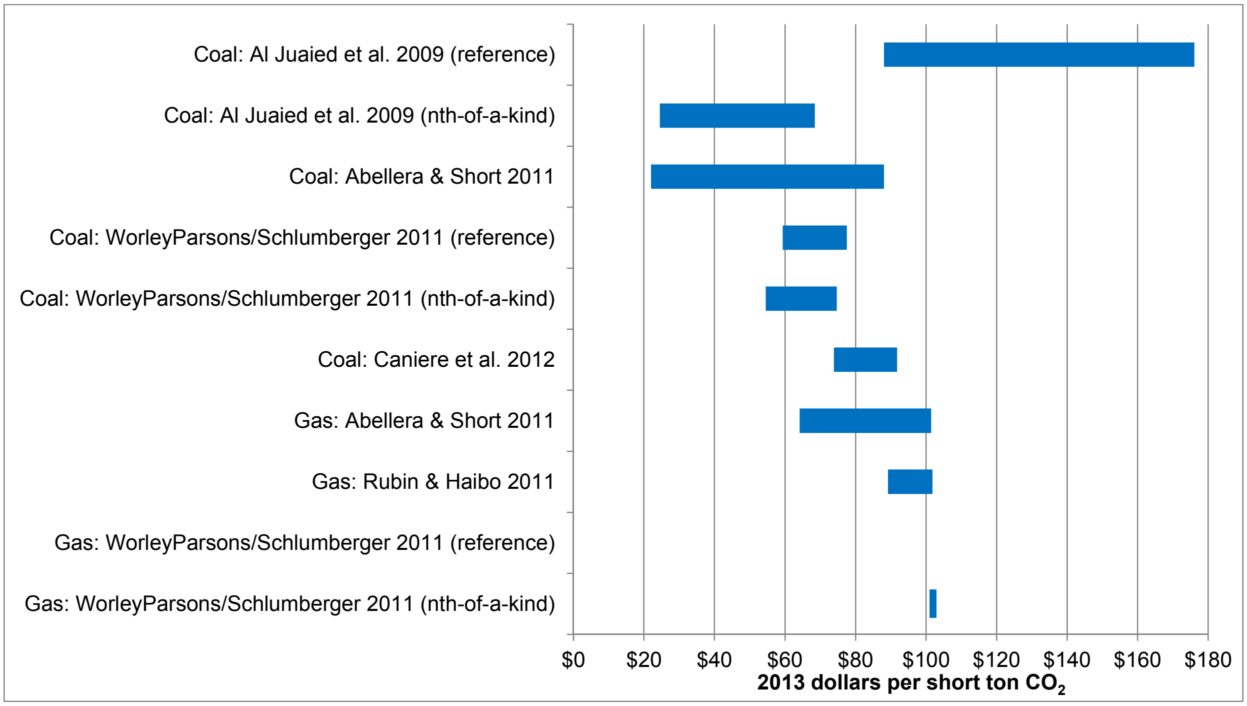
Source: See text.

CCS Technology Costs

CCS for electricity generation is often at or near the margin for targets of limiting temperature rise to 2°C above pre-industrial levels. For this reason, we expect that CCS costs may be viewed as providing an alternate, first-order approximation of the marginal cost of abating CO_2 emissions. Projected technology costs vary widely, with gas CCS typically more expensive than coal on a per ton of avoided emissions basis. For mature (nth-of-a-kind) CCS deployment, estimates are commonly in the range of $60 to $100 per short ton of CO_2 avoided in 2013 dollars (see Exhibit 4-6). The exceptionally high values from Al

Juaied et al. reflect first-of-a-kind technologies, as if they were built today, with commodity costs from 2008.

Exhibit 4-6. Projected Costs of CCS (in 2013 dollars per short ton of CO_2 avoided)



Source: Al-Juaied, Mohammed and Adam Whitmore. Realistic Costs of Carbon Capture. Belfer Center Discussion Paper 2009-08. Harvard Kennedy School. July 2009; Abellera, Chester and Christopher Short. The costs of CCS and Other Low-Carbon Technologies. Global CCS Institute. Issues Brief 2011, No. 2; Worley, Parsons and Schlumberger. Economic Assessment of Carbon Capture and Storage Technologies. 2011 Update. Supported by the Global CCS Institute. 2011; Caniere, H. et al. Marginal abatement cost curves for coal-fired power plants in Europe: CO2 reduction potential for 2020. Climate Change and Environmental Services - Energy Efficiency Centre. 2012. Antwerp, Belgium; and Rubin, Edward and Haibo Zhai. The Cost of CCS for Natural Gas-Fired Power Plants. Presentation to the 10th Annual Conference on Carbon Capture and Storage. Pittsburgh, PA. May 3, 2011.

Existing deployment of CCS in electricity generation is limited to a few small-scale demonstration projects. The AEP Mountaineer plant in West Virginia operated CCS facilities for 2 percent of its 1,300 MW plant for nearly two years, but canceled planned scale-up activities due to the uncertainty of climate policy.[93] Many similar examples exist across the United States. The Texas Clean Energy project, an integrated gasification combined-cycle (IGCC) coal plant with CCS, and perhaps one of the most advanced U.S. commercial projects, is not scheduled for completion until at least 2015. At $2.8 billion,

[93] MIT (2013). "AEP Mountaineer Fact Sheet" Available at: http://sequestration.mit.edu/tools/projects/aep_alstom_mountaineer.html

the 400 MW plant is expected to cost \$7,000/kW in comparison to the cost of a new natural gas combined-cycle plant (\$1,000/kW) or a new IGCC without CCS (\$3,200/kW).[94]

Substantial uncertainty still exists in the long-term costs of CCS deployment. CCS costs can provide an important cross-check of long-term forecasts of mitigation costs, but should be coupled with other metrics such as complete marginal cost of abatement curves constructed from energy system modeling results.

CO_2 Abatement Cost in AESC 2013

Based on our review of the most current research on marginal abatement and CCS costs, and our experience and judgment on the topic, we believe that it is reasonable to use a CO_2 marginal abatement cost of \$100 per short ton in 2013 dollars. We contend that \$100/short ton is also a practical and reasonable measure of the total societal cost of carbon dioxide emissions. This CO_2 marginal abatement cost can be applied to the emissions reductions that result from lower electricity generation as a result of energy efficiency, in order to quantify these reductions' full value to society. A portion of this CO_2 marginal abatement cost will be reflected in the allowance price for emissions, and thus embedded in the avoided costs; the balance may be referred to as a non-embedded cost.

States that have established targets for climate mitigation comparable to the targets discussed in section 4.3.1, or that are contemplating such action, could view the \$100/t CO_2 marginal abatement cost as a reasonable estimate of the societal cost of carbon emissions, and hence as the long-term value of the cost of reductions in carbon emissions required to achieve those targets.

Like any long-run projections, this estimate of the marginal abatement cost includes important uncertainties in underlying assumptions regarding the extent of technological innovation, the selected emission reduction targets, the technical potential of key technologies, and the evolution of international and national policy initiatives, along with a variety of other influencing factors. It will be necessary to review available information and reassess what value is reasonable given the best state of knowledge at the time of future reviews.

Estimating Non-Embedded CO_2 Costs for New England

The non-embedded value for New England's CO_2 emissions in each year was calculated as the estimated marginal abatement cost of \$100 per short ton in 2013 dollars less the annual allowance values embedded in the projected electric energy market prices. These values are summarized in Exhibit 4-7.

[94] Platts (2012). "Summit signs key contracts for planned coal-gasification plant in Texas". Feb 2012. Available at: http://www.platts.com/RSSFeedDetailedNews/RSSFeed/Coal/6958831. For comparison costs see: EIA. 2013. Assumptions to the Annual Energy Outlook 2012. Table 8.2. http://www.eia.gov/forecasts/aeo/assumptions/pdf/electricity.pdf

Exhibit 4-7. AESC 2013 Non-Embedded CO_2 Costs (2013 dollars per short ton CO_2)

	Marginal abatement cost	Reference Allowance Price	Reference Externality	RGGI-Only Scenario Allowance Price	RGGI-Only Scenario Externality
	a	b	c = a - b	d	e = a - d
2013	$100	$2.80	***$97.20***	$2.80	***$97.20***
2014	$100	$4.22	***$95.78***	$4.22	***$95.78***
2015	$100	$5.28	***$94.72***	$5.28	***$94.72***
2016	$100	$6.33	***$93.67***	$6.33	***$93.67***
2017	$100	$7.39	***$92.61***	$7.39	***$92.61***
2018	$100	$8.44	***$91.56***	$8.44	***$91.56***
2019	$100	$9.50	***$90.50***	$9.50	***$90.50***
2020	$100	$20.30	***$79.70***	$10.55	***$89.45***
2021	$100	$22.58	***$77.42***	$10.55	***$89.45***
2022	$100	$24.87	***$75.13***	$10.55	***$89.45***
2023	$100	$27.15	***$72.85***	$10.55	***$89.45***
2024	$100	$29.44	***$70.57***	$10.55	***$89.45***
2025	$100	$31.72	***$68.28***	$10.55	***$89.45***
2026	$100	$34.00	***$66.00***	$10.55	***$89.45***
2027	$100	$36.29	***$63.71***	$10.55	***$89.45***
2028	$100	$38.57	***$61.43***	$10.55	***$89.45***

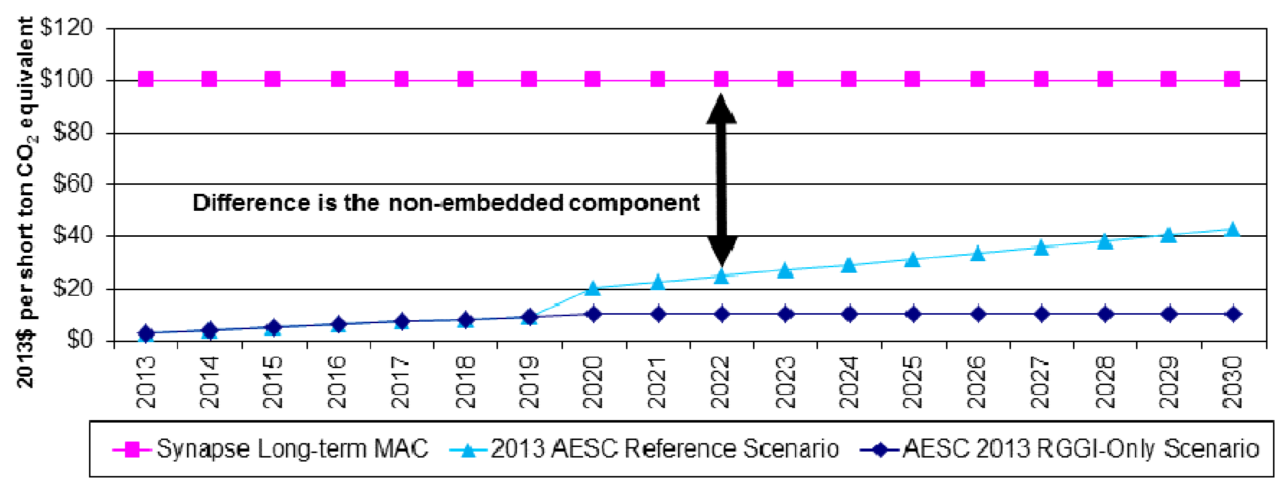
The annual allowance values embedded in the projected electric energy market prices are shown in column b of Exhibit 4-7. These carbon prices were included in the generators' bids in the dispatch model runs and therefore are embedded in the AESC 2013 avoided electricity costs. The non-embedded value in each year is the difference between the marginal abatement cost ($100/t) and the value of the embedded carbon trading price shown in column c of Exhibit 4-7. Exhibit 4-8 illustrates how the non-embedded CO_2 cost was calculated.

Comparison to AESC 2011

The AESC 2013 value for the CO_2 marginal abatement cost of $100/ton is 20 percent higher than the AESC 2011 value of $83/ton (2013 dollars). The change in the assessment results from three major factors:

1) AESC 2013 incorporates new studies with different estimates than two years ago.
2) AESC 2011 used values from multiple vintages of the same studies, whereas AESC 2013 only uses values from the most up-to-date version of studies.
3) AESC 2013 incorporates an analysis of CCS technologies that are expected to be the marginal technology.

Exhibit 4-8. Determination of the Additional Cost of CO_2 Emissions (2013$/short ton of CO_2 equivalent)



Applying Non-Embedded CO_2 Costs in Evaluating Energy Efficiency Programs

The non-embedded values from Exhibit 4-7 are incorporated as a separate value in the avoided electricity cost workbooks and expressed as dollars per kWh based upon our analysis of the CO_2 emissions of the marginal generating units summarized below. We recommend that program administrators include these values in their analyses of energy efficiency programs unless specifically prohibited from doing so by state or local regulations. At a minimum, program administrators should calculate the costs and benefits of energy efficiency programs with and without these values in order to assess their incremental impact on the cost-effectiveness of programs.

4.4 Value of Mitigating Significant Pollutants

4.4.1 Electricity Generation

Pollutants and Their Significance

Impacts associated with electricity production and uses include a wide variety of air pollutants, water pollutants, and land use impacts. These include the following:

- Air emissions (including SO_2, NO_x and ozone, particulates, mercury, lead, other toxins, and greenhouse gases) and the associated health and ecological damages;
- Fuel cycle impacts associated with "front end" activities such as mining and transportation, and waste disposal;
- Water use and pollution;
- Land use;
- Aesthetic impacts of power plants and related facilities;

- Radiological exposures related to nuclear power plant fuel supply and operation (routine and accident scenarios); and

- Other non-embedded impacts, such as economic impacts (generally focused on employment), energy security, and others.

Over time, regulations limiting emission levels have forced suppliers and buyers to consider at least a portion of these costs in their production and use decisions, thereby "embedding" a portion of these costs. As noted in section 4.3 (below), we anticipate that the "non-embedded carbon cost" will continue to be the dominant non-embedded environmental cost associated with marginal electricity generation in New England.

For AESC 2013, our approach to quantifying the reduction in physical emissions due to energy efficiency is as follows:

- Identify the marginal unit in each hour in each transmission area from our energy model;

- Draw the heat rates, fuel sources, and emission rates for NO_x and CO_2, of those marginal units from the database of input assumptions used in our Market Analytics simulation; and

- Calculate the physical environmental benefits from energy efficiency and demand reductions by calculating the emissions of each of those marginal units in terms of lbs/MWh. We do this by multiplying the quantity of fuel burned by each marginal unit 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:

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

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.

Value of Mitigating Significant Pollutants

The scope of work for AESC 2013 asks for the heat rates, fuel sources, and emissions of NO_x, and CO_2 of the marginal units during each of the energy and capacity costing periods in the 2013 base year. It also asks for the quantity of environmental benefits that would correspond to energy efficiency and demand reductions, in pounds per MWh, respectively, during each costing period.

Exhibit 4-9 summarizes the marginal heat rate and marginal fuel characteristics from the model results. The results are based on the marginal unit in each hour in each transmission area, as reported by the model. Once the marginal units are identified, we extracted the heat rates, fuel sources, and emission rates for the key pollutants from the database of input assumptions used in our Market Analytics simulation of the New England wholesale electricity market.

Exhibit 4-9. 2013 New England Marginal Heat Rate by Pricing Period (Btu per kWh)

	Season and Period				
	Summer		**Winter**		**Grand Total**
	Off Peak	On Peak	Off Peak	On Peak	
Average Heat Rate (BTU/kWh)	8,085	9,061	7,918	8,348	**8,254**

Exhibit 4-10. 2013 New England Marginal Fuel by Percentage

	Season and Period				
	Summer		Winter		
Fuel Type	Off	On	Off	On	**Grand Total**
Natural gas	91%	96%	89%	95%	92%
Oil	0%	0%	0%	0%	0%
Coal	8%	4%	8%	3%	6%
Nuclear	0%	0%	0%	0%	0%
Biomass	1%	0%	1%	1%	1%
Other	0%	1%	2%	1%	1%
Renewable	0%	0%	0%	0%	0%
Grand Total	**100%**	**100%**	**100%**	**100%**	**100%**

The avoided emissions values shown in the exhibits below represent the averages for each pollutant over each costing period for all of New England in pounds per MWh. The emission rates are presented by modeling zone; however, differences between zones tend to be relatively minor.

Exhibit 4-11. 2013 New England Avoided CO_2 Emissions by Modeling Zone and Pricing Period (lbs/MWh)

	Season and Period				
	Winter		Summer		Grand Total
	On Peak	Off Peak	On Peak	Off Peak	
NE - BHE	969	1,033	1,103	1,043	1,026
NE - Boston	960	1,023	1,060	1,023	1,009
NE - CT NE Central	973	1,009	1,077	1,025	1,011
NE - CT Norwalk	974	1,009	1,078	1,030	1,013
NE - ME	968	1,033	1,103	1,043	1,026
NE - NEMA	963	1,019	1,061	1,020	1,009
NE - New Hampshire	968	1,028	1,099	1,046	1,024
NE - Rhode Island	960	1,019	1,058	1,026	1,008
NE - SEMA	958	1,018	1,057	1,017	1,006
NE - SME	968	1,031	1,103	1,047	1,026
NE - SWCT	974	1,009	1,078	1,030	1,013
NE - Vermont	967	1,010	1,081	1,032	1,012
NE - WCMA	965	1,011	1,073	1,028	1,009
Average	**967**	**1,019**	**1,079**	**1,032**	**1,015**

Exhibit 4-12. 2013 New England Avoided NOx Emissions by Modeling Zone and Pricing Period (lbs/MWh)

	Season and Period				
	Winter		Summer		Grand Total
	On Peak	Off Peak	On Peak	Off Peak	
NE - BHE	0.390	0.550	0.510	0.395	0.467
NE - Boston	0.385	0.507	0.467	0.327	0.431
NE - CT NE Central	0.383	0.475	0.481	0.331	0.422
NE - CT Norwalk	0.383	0.475	0.484	0.334	0.423
NE - ME	0.389	0.550	0.510	0.395	0.466
NE - NEMA	0.391	0.508	0.471	0.338	0.436
NE - New Hampshire	0.388	0.527	0.495	0.372	0.452
NE - Rhode Island	0.370	0.501	0.458	0.343	0.426
NE - SEMA	0.366	0.497	0.451	0.338	0.421
NE - SME	0.389	0.539	0.509	0.395	0.462
NE - SWCT	0.383	0.475	0.484	0.336	0.423
NE - Vermont	0.398	0.478	0.479	0.337	0.428
NE - WCMA	0.396	0.478	0.473	0.330	0.425
Average	**0.385**	**0.505**	**0.482**	**0.352**	**0.437**

Our recommended dollar values to use for relevant "embedded" avoided pollutant emissions are summarized in Exhibit 4-1. Our recommended dollar value to use for non-embedded carbon costs is provided in Exhibit 4-7.

4.4.2 End-Use Natural Gas

We estimate the environmental benefit from reduced combustion of end-use natural gas due to energy efficiency programs with the following analyses:

- Identifying the various pollutants created by the combustion, and assessing which of them are significant and how, if at all, the impact of those pollutants is currently embedded in the cost of natural gas.
- Finding the value associated with mitigation of each significant pollutant and the portion that should be treated as a non-embedded cost.

Natural gas consists of methane (generally above 85 percent) and varying amounts of ethane, propane, butane, and inert gases (typically nitrogen, carbon dioxide, and helium) (EPA 1999).

In general, the combustion in boilers and furnaces generate the following pollutants (EPA 1999, 1.4-2–5):

- oxides of nitrogen (NO_x),
- sulfur oxides (SO_x) (trace levels)[95],
- CO_2 and other greenhouse gases,
- particulates (trace levels),
- volatile organic compounds, and
- carbon monoxide.

Pollutants and their Significance

To estimate the absolute quantities of each pollutant from the combustion of natural gas relative to the absolute quantity of each from all sources, we began by estimating the quantity of each that is emitted per MMBtu of fuel consumed. Exhibit 4-13 provides emissions factors for NO_x and CO_2 for three generalized boiler type categories.

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

Exhibit 4-13. Emission Rates of Significant Pollutants

Boiler Type	NO_x (lbs/MMBtu)	CO_2 (lbs/MMBtu)
Residential boiler	0.092	118
Commercial boiler	0.098	118
Industrial boilers	0.137	118

Notes
NO_x emissions from industrial boilers without low NO_x burners would be 0.274 lb/MMBtu. We assumed these boilers were controlled in order to be conservative.
NOx and CO_2 emissions factors for all boilers utilized conversion rate of 1,020 btu/scf.
Sources
Environmental Protection Agency, AP-42, Volume I, Fifth Edition, January 1995, Chapter 1, External
Combustion Sources. http://www.epa.gov/ttnchie1/ap42/

We apply these pollutant emission rates to the quantity of natural gas consumed, by sector, in New England in 2013. The estimated annual quantity of each of the two pollutants from natural gas combustion, and from other sources, is presented in Exhibit 4-14.

Exhibit 4-14. Pollutant Emissions in New England from Natural Gas

Sector	NO_x (tons)	CO_2 (tons)
Residential	9,325	11,904,588
Commercial	7,584	9,100,294
Industrial	7,829	6,710,412
R, C & I Total	***24,738***	***27,715,294***
Electric Gen	3,904	27,380,362

Notes
All figures are from 2011.
Source
Energy Information Administration
http://tonto.eia.doe.gov/dnav/ng/ng_cons_sum_a_EPG0_vrs_mmcf_a.htm
Environmental Protection Agency AMPD Database
http://ampd.epa.gov/ampd/?bookmark=5342

Exhibit 4-14 illustrates that combustion of natural gas is a source of both NO_x and CO_2 emissions. Moreover, these emissions are not currently subject to regulation, as explained below.

- *CO_2.* RGGI applies to electric generating units larger than 25 MW. New England CO_2 emissions for 2011 were 27.4 million tons. The total CO_2 emissions from the end-use sectors above would represent about 50 percent of the total CO_2 emissions, if such emissions were included.
- *NO_x.* The Clean Air Interstate Rule applies only to Massachusetts and Connecticut during the ozone season. New England NO_x emissions for 2011 were approximately 3,900 tons for just the

electric generating sector[96]. The total NO_x emissions from the end use sectors above would represent about 86 percent of the total NO_x budget if such emissions were included.

Value of Mitigating Significant Pollutants

We estimate the value associated with mitigation of NO_x and CO_2 based on the 2013 emissions allowance prices per short ton presented in Exhibit 4-1.[97] As noted previously, natural-gas combustion is not a significant source of SO_2 emissions. Consequently, we have not included an emission value for SO_2.

In addition, for states with aggressive carbon mitigation targets, we provide a value of reducing CO_2 based upon the $100/ton long-term marginal abatement cost of carbon dioxide reduction.

The annual pollutant-emission values by end-use sector are summarized below in Exhibit 4-15. They equal the pollutant allowance prices multiplied by the pollutant emission rates.

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[96] A few large sources in the industrial sector are included in CAIR. These include municipal waste combustors, steel and cement plants, and large industrial boilers (such as those located at Pfizer in New London, CT and General Electric in Lynn, MA). However, the number of NO_x allowances used, sold, and traded for the industrial sector is very small. A few allowances in each state are allocated to non-electric generating units compared to thousands of allowances used, sold and traded for electric generating units.

[97] The full non-embedded value associated with NO_x emissions is probably not captured in the allowance price from electricity generation; however, determining that non-embedded value is beyond the scope of this project.

Exhibit 4-15. Annual Pollutant Emission Values (2013$/MMBtu)

Pollutant Emission Values by Sector and by Year in 2013$/MMBtu									
	Residential			Commercial			Industrial		
	NOx	CO2	CO_2 at $100/ton	NOx	CO_2	CO_2 at $100/ton	NOx	CO_2	CO_2 at $100/ton
2013	$0.001	$0.16	$5.88	$0.001	$0.16	$5.88	$0.002	$0.16	$5.88
2014	$0.001	$0.25	$5.88	$0.001	$0.25	$5.88	$0.002	$0.25	$5.88
2015	$0.001	$0.32	$5.88	$0.001	$0.32	$5.88	$0.002	$0.32	$5.88
2016	$0.001	$0.40	$5.88	$0.001	$0.40	$5.88	$0.002	$0.40	$5.88
2017	$0.001	$0.47	$5.88	$0.001	$0.47	$5.88	$0.002	$0.47	$5.88
2018	$0.001	$0.55	$5.88	$0.001	$0.55	$5.88	$0.002	$0.55	$5.88
2019	$0.001	$0.63	$5.88	$0.002	$0.63	$5.88	$0.002	$0.63	$5.88
2020	$0.001	$1.37	$5.88	$0.002	$1.37	$5.88	$0.002	$1.37	$5.88
2021	$0.001	$1.56	$5.88	$0.002	$1.56	$5.88	$0.002	$1.56	$5.88
2022	$0.002	$1.75	$5.88	$0.002	$1.75	$5.88	$0.002	$1.75	$5.88
2023	$0.002	$1.95	$5.88	$0.002	$1.95	$5.88	$0.002	$1.95	$5.88
2024	$0.002	$2.15	$5.88	$0.002	$2.15	$5.88	$0.002	$2.15	$5.88
2025	$0.002	$2.37	$5.88	$0.002	$2.37	$5.88	$0.002	$2.37	$5.88
2026	$0.002	$2.59	$5.88	$0.002	$2.59	$5.88	$0.002	$2.59	$5.88
2027	$0.002	$2.82	$5.88	$0.002	$2.82	$5.88	$0.002	$2.82	$5.88
2028	$0.002	$3.05	$5.88	$0.002	$3.05	$5.88	$0.003	$3.05	$5.88
Levelized (2013$/MMBtu)									
5 year (2014-18)	$0.001	$0.40	$5.88	$0.001	$0.40	$5.88	$0.002	$0.40	$5.88
10 year (2014-23)	$0.001	$0.90	$5.88	$0.001	$0.90	$5.88	$0.002	$0.90	$5.88
15 year (2014-28)	$0.001	$1.43	$5.88	$0.002	$1.43	$5.88	$0.002	$1.43	$5.88
Notes									
Based on Emission Rates of Significant Pollutants for Natural Gas in Exhibit 4-13.									
Pollutant values based on emission allowance prices detailed in Exhibit 4-1 and $100/short ton long-term marginal abatement cost for CO2.									

The entire amount of each value is a non-embedded cost. With the exception of those industrial sources subject to the EPA NO_x budget program, which represent a small fraction of the total emissions, none of these emissions are currently subject to environmental requirements. Therefore, none of these values are embedded in their market prices.

4.4.3 End-Use Fuel Oil and Other Fuels

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

- Identifying the various pollutants created by the combustion, and assessing which of them are significant and how, if at all, the impact of those pollutants is currently embedded in the cost of the studied fuels.

- Finding the value associated with mitigation of each significant pollutant and the portion that should be treated as a non-embedded cost.

The pollutant emissions associated with the combustion of fuel oil are dependent on the fuel grade and composition, boiler characteristics and size, combustion process and sequence, and equipment maintenance (EPA 1999 1.3-2). [98]

In general, the combustion in boilers and furnaces generate the following pollutants (EPA 1999, 1.4-2–5):

- Oxides of nitrogen (NO_x)
- Sulfur oxides (SO_x)
- CO_2 and other greenhouse gases
- Particulates
- Volatile organic compounds
- Carbon monoxide
- Trace elements
- Organic compounds

Pollutants and Their Significance

Like the combustion of natural gas, NO_x, SO_x, and CO_2 are potentially the most significant pollutants.[99] NO_x is a precursor to the unhealthy concentrations of ozone that areas in New England continue to experience. The region is also required to reduce NO_x and SO_x emissions by EPA programs, implement state low sulfur fuel requirements, and participate in the RGGI program to reduce CO_2 from the power sector.[100]

For the electric generation sector, the forecast of emissions allowance prices value of mitigating emissions of from the combustion of NO_x, SO_x, and CO_2 is shown in Exhibit 4-1.

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[98] EPA, 1999. "Stationary Point and Area Sources" v. 1 of Compilation of Air Pollutant Emission Factors 5th Ed. AP-42. Triangle Partk, N.C.: U.S. Environmental Protection Agency. (Section 1.3-2)

[99] Wood combustion may contribute to an accumulation of unhealthy concentrations of fine particulate matter ($PM_{2.5}$). This is especially true in many valleys, where pollutants accumulate during stagnant meteorological conditions. The regulation of $PM_{2.5}$ from wood combustion is a state by state process. No comparable regionally consistent or market-based program of allowances have been established for $PM_{2.5}$, like those described above for SO_x, NO_x, and CO_2.

[100] SO_2 and NO_X emissions are regulated by the EPA under the acid rain program and the regional NOX budget trading program, as well as the new Clean Air Interstate Rule. CO_2 emissions from electrical generation sources are regulated under the Regional Greenhouse Gas Initiative (RGGI).

In order to estimate the absolute quantities of each pollutant from the combustion of fuels by sector, we began by estimating the quantity of each pollutant that is emitted per MMBtu of fuel consumed.[101] The pollutant emissions associated with the combustion of wood are dependent on the species of wood, moisture content, appliance used for its combustion, combustion process, and sequence and equipment maintenance. The pollutant emissions associated with the combustion of kerosene are similar to those associated with the combustion of distillate oil, and depend upon boiler characteristics and size, combustion process and sequence, and equipment maintenance (EPA 1999, 1.3-2).

Exhibit 4-16 provides emissions factors for each fuel based on three generalized boiler-type categories.

Exhibit 4-16. Emission Rates of Significant Pollutants from Fuel Oil

Boiler type, and fuel combusted	SO_x (lbs/MMBtu)	NO_x (lbs/MMBtu)	CO_2 (lbs/MMBtu)
#2 Fuel Oil			
Residential boiler, combusting #2 oil	0.002	0.129	173
Commercial boiler, combusting #2 oil	0.002	0.171	164
Industrial boilers, combusting #2 oil	0.002	0.171	161
Kerosene—Residential heating	0.152	0.129	173
Wood—Residential heating	0.468	2.59	N/A

Notes:
For fuel oil, assumed sulfur content of 15ppm
Kerosene same as AESC 2011

Sources:
1) Energy Information Administration, Electric Power Annual with data for 2011. Table A3 http://www.eia.gov/electricity/annual/html/epa_a_03.html (for CO_2 for industrial boilers)
2) Environmental Protection Agency, AP-42, Volume I, Fifth Edition, January 1995, Chapter 1, External Combustion Sources. *http://www.epa.gov/ttnchie1/ap42/* (for SO_x and NO_x emissions factors for all boilers)
3) Environmental Benefits of DSM in New York: Long Island Case Study; Bruce Biewald and Stephen Bernow, Tellus Institute. Proceedings from Demand-Side Management and the Global Environment, Arlington, Virginia, April 22-23, 1991. (for CO_2 emissions factors for residential and commercial boilers)
4) James Houck and Brian Eagle, OMNI Environmental Services, Inc., Control Analysis and Document for Residential Wood Combustion in the MANU-VU Region, December 19, 2006. (for wood)

[101] Number-6 fuel oil has about the same rate of SO_2 emissions as distillate, about twice the rate of NO_x emissions and about seven percent higher rate of CO_2 emissions.

AESC 2013 reduces emissions values for fuel oil based on standards mandating the use of low sulfur heating oil.[102] Values for kerosene were based on AESC 2011 values and updated with EIA data. The values for emissions from wood remain unchanged from the AESC 2011 values.

Next, we applied those pollutant emission rates to the quantity of each fuel consumed by sector in New England in 2011.[103]

Exhibit 4-17. Distillate Consumption, 2011 (Trillion BTU)

Residential	Commercial	Industrial
217	60	24
Notes: Data from EIA 2011		

Combustion of No. 2 fuel oil is a major source of each of these pollutants, but kerosene and wood are not, as shown in Exhibit 4-18 below.

[102] EIA 2013 "Heating oil futures contract now uses ultra-low sulfur diesel fuel." May 10th, 2013. Available at: http://www.eia.gov/todayinenergy/detail.cfm?id=11211

[103] Distillate fuel oil consumption figures for 2011 come from the Energy Information Administration (http://www.eia.gov/state/seds/data.cfm?incfile=/state/seds/sep_fuel/html/fuel_use_df.html&sid=US). Our research did not find updated kerosene or wood consumption data , therefore we continue to use the same values as in the AESC 2011 report.

Exhibit 4-18. Pollutant Emissions in New England by Major Source

	Sector	SO_2 (tons)	NO_x (tons)	CO_2 (tons)
Emissions from Electric Generation				
A		**63,560**	**40,311**	**41,467,433**
Combustion of #2 Fuel Oil in R, C & I				
I	Residential	16,477	13,924	18,735,900
Ii	Commercial	4,595	5,177	4,952,800
Iii	Industrial	3,606	2,031	1,907,850
B = i + ii +iii	**R, C & I Total**	**24,678**	**21,133**	**25,596,550**
C	**Combustion of kerosene in Residential heating**	**302**	**255**	**343,146**
D	**Combustion of wood in Residential heating**	**556**	**3,081**	**N/A**
E = A + B + C + D		**89,096**	**64,779**	**67,407,138**
Non-electric as percent of total (B+C+D)/E		**29%**	**38%**	**38%**
Notes				
All figures are for 2011 Residential, commercial, and industrial SO_2 emissions for 2011 are based on higher levels of fuel SO_2 content than shown in Exhibit 4-15 of 0.152 lbs/MMBtu compared to 0.002 lbs/MMBTU for low sulfur heating oil				

Value of Mitigating Significant Pollutants

Emissions of NO_x, SO_x, and CO_2 from the combustion of these fuels are not currently subject to regulation, as explained below.

All of these values are non-embedded values.

- SO_2 & CO_2: The acid rain program and RGGI apply to electric generating units larger than 25 MW. New England SO_x emissions from electric generating units for 2011 were approximately 63,560 tons. The total SO_x emissions from the end-use sectors above would represent approximately 29 percent of the total SO_x emissions, if such emissions were included.[104] New England electric generation CO_2 emissions for 2011 were approximately 41.5 million tons. The calculated CO_2 emissions from the end-use sectors above would represent approximately 38 percent of the total electric generation CO_2 emissions, if such emissions were included.

- NO_x: The Ozone Transport Commission–EPA NO_x budget program applies to electric generating units larger than 15 MW and to industrial boilers with a heat input larger than 100 MMBtu per hour. New England NO_x emissions for 2011 were approximately 40,000 tons for just the electric generating sector[105]. The total NO_x emissions from the end use sectors above would represent approximately 38 percent of the total NO_x budget, if such emissions were included.

We base the value associated with mitigation of NO_x, SO_x, and CO_2 on the 2013 emissions allowance prices per short ton in Exhibit 4-1 and the non-embedded value of CO_2 shown in Exhibit 4-7. Using the allowance prices associated with electricity generation for NO_x, SO_x, and CO_2 represents applying what AESC 2013 has internalized in its forecast consistently across fuels as noted in this chapter. For CO_2, we have also provided the value of pollutant emissions associated with the long term marginal abatement cost of $100/short ton.

The pollutant-emission values for 2013 based upon these allowance prices and the pollutant emission rates, as presented in Exhibit 4-1, are presented below.

Exhibit 4-19. Value of Pollutant Emissions from Fuel Oil in 2013

Generalized Boiler Type by Sector	SO_2 ($/MMBtu)	NO_x ($/MMBtu)	CO_2 ($/MMBtu)
Residential boiler	0	0.0018	0.2422
Commercial boiler	0	0.0023	0.2296
Industrial boiler	0	0.0023	0.2254

The emission values in Exhibit 4-19 are non-embedded.[106] With the exception of those industrial sources subject to the EPA NO_x budget program, which represent a small fraction of the total emissions, none of

[104] The use of ultra-low sulfur fuel (15 ppm) will be required in four of the five New England states by mid-2018.

[105] A few large sources in the industrial sector are included in the NO_x budget program. These include municipal waste combustors, steel and cement plants and large industrial boilers (such as those located at Pfizer in New London, Connecticut, and General Electric in Lynn, Massachusetts). However, the number of NO_x allowances used, sold and traded for the industrial sector is very small. A few allowances in each state are allocated to non-electric generating units compared to thousands of allowances used, sold, and traded for electric generating units.

[106] The full externality value associated with SO_x and NO_x emissions is probably not captured in the allowance price from electricity generation associated with these two pollutants; however, determining that externality value is beyond the scope of this project.

the emissions shown in Exhibit 4-18 are currently subject to environmental requirements.[107] None of these values, therefore, are internalized in the relevant fuel's market prices.

The values by year for fuel oil over the study period are presented in Appendix E.

4.5 Discussion of Non-Embedded NO_x Costs

This section addresses the request in the AESC 2013 scope of work to provide a discussion of non-embedded NO_x costs. Please note that we are **not** recommending an additional non-embedded NO_x value beyond the embedded allowance prices based on the analysis discussed in this section. Instead, we recommend a methodology consistent with AESC 2011, and detailed below.

4.5.1 Health Impacts and Damages

NO_x emitted from the combustion of coal and natural gas reacts with compounds in the air ("precursors") to produce ozone, particulate matter ("PM2.5"), and acid rain. Both PM2.5 and ozone are EPA criteria pollutants that have been shown to have harmful effects on human health, and are regulated under the Clean Air Act. Quantifying the value associated with damages from NO_x emissions is a particularly complicated process. Most studies look at incidence rates of premature death and chronic bronchitis in order to evaluate health impacts. The reaction of NO_x with precursors to form PM2.5 and ozone is highly dependent on atmospheric conditions and local emissions of other precursors. Fowlie and Muller use a stochastic model to estimate damages and quantify health impacts, and found impacts on human health to be valued at $1,518/ton NO_x with a standard deviation of $1,823/ton resulting from air quality modeling uncertainty.[108] Mauzerall et al. found a similar level of uncertainty in an earlier study, citing one location where the health impact of emissions nearly doubled within a short span of time as the temperature changed. [109] EPA has used the BenMAP tool to calculate benefits of NO_x reduction based on reduced mortality from particulate matter, and calculates national benefits of $19,286/ton for electricity generation and $12,479/ton for non-electricity sources, respectively.[110]

The analyses above do not include valuation of the impacts of environmental effects resulting from nitrogen deposition, or visibility impairment from increased haze.

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[107] EPA. Factsheet: EPA's Final Air Toxics Standard Major and Area Source Boilers and Certain Incinerators Overview of Rules and Impacts. Available at http://www.epa.gov/airquality/combustion/docs/overviewfsfinal.pdf. Accessed June 20, 2011.

108 Fowlie, M. N. Muller (2013) "Market-Based Emissions Regulation When Damages Vary Across Sources: What Are the Gains from Differentiation?" National Bureau of Economic Research. NBER Working Paper No. 18801.

[109] Mauzerall, D.L., B. Sultan, N. Kim, and D.F. Bradford. 2005. "NOx emissions from large point sources: Variability in ozone production, resulting health damages and economic costs." Atmos. Environ. 39(16):2851-2866

[110] EPA (2012). "RSM-based Benefit Per Ton Estimates." Dec 2012. Available at: http://www.epa.gov/oaqps001/benmap/bpt.html

4.5.2 Abatement Costs

Market prices for NO_x emissions fall far below the estimated costs of health impacts. Values for costs of NO_x mitigation have fallen substantially from those cited in AESC 2011.[111] An analysis by the EIA published in early 2012 showed a drop in allowance prices from $870/ton in 2008 to $17/ton in 2011.[112] Another report from September 2012, after the Cross-State Air Pollution Rule (CASPR) was vacated, estimated a price of $36/ton (the CSAPR vacature in August 2012 caused a brief price spike to $46/ton).[113] Given uncertainty in how EPA NO_x policies will ultimately play out, it is difficult to predict how these prices will change in the future.

In New England, significant progress on NO_x abatement has already been made, marked by rapid reductions over the past decade (see Exhibit 4-20). While Connecticut and Massachusetts are subject to Clean Air Interstate Rule (CAIR) requirements, their prior reductions already surpass CSAPR standards. As a result, in the recent Connecticut 2012 Integrated Resource Plan, annual allowance prices were assumed to be zero.[114]

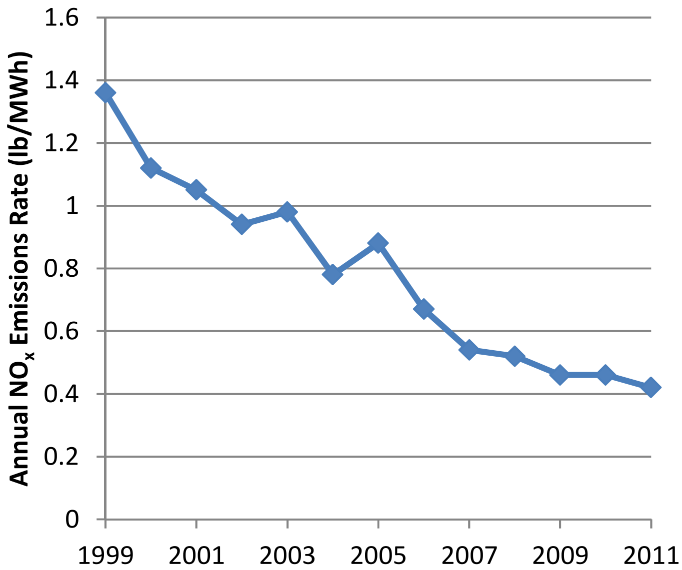
[111] NOx allowances prices began at $238/ton and fell to $136/ton (in 2013 dollars)

[112] EIA (2012). "Emissions allowance prices for SO2 and NOx remained low in 2011." Feb. 2, 2012. Available at: http://www.eia.gov/todayinenergy/detail.cfm?id=4830

[113] Argus Air Daily (2012). US Emissions Market Prices. Sept 2012. Vol. 19, Issue 173. Available at: http://www.argusmedia.com/Coal/~/~/media/Files/PDFs/Samples/Argus-Air-Daily.ashx

[114] CT DEEP (2012). "2012 Integrated Resource Plan". Connecticut Department of Energy and Environmental Protection. Available at: http://www.ct.gov/deep/cwp/view.asp?a=4405&q=486946&deepNav_GID=2121%20

Exhibit 4-20. Annual NO_x Emissions Rate in New England (lb/MWh)



Source: 2011 ISO New England Electric Generator Air Emissions Report. February 2013. http://www.iso-ne.com/genrtion_resrcs/reports/emission/2011_emissions_report.pdf

Given the uncertainty described above, a methodology consistent with AESC 2011 is recommended. Assumptions for NO_x allowance prices will be based on revised Market Analytics default data. The embedded value of annual NO_x prices in the model are \$38/ton, although most New England generators only see seasonal prices of \$27/ton.

4.6 Emissions from Hydraulic Fracking

The AESC 2013 scope of work requested a discussion of greenhouse gas emissions from hydraulic fracturing. These are air emissions that occur when extracting natural gas from the ground, and may be avoided as a result of energy efficiency programs reducing demand for natural gas. Although calculating upstream avoided externalities associated with fracking is outside the scope of work for AESC (our calculations associated with natural gas include only those externalized emission costs avoided due to reduced combustion of gas at electricity-generating facilities, or at end-user boilers and furnaces), discussion of "front end" emissions for gas fracking is important and is included here because of the large amount of greenhouse gas emissions associated with this fuel extraction process.

Electricity generation from natural gas is widely recognized as the second largest source (after coal generation) of CO_2 emissions in the U.S. electric sector. Conventional production, processing, and distribution of natural gas have also long been sources of greenhouse gas emissions into the atmosphere. These emissions are largely made up of methane (CH_4) but can also include CO_2. Natural gas wells must be drilled in order to access underground formations of raw gas, and a portion of that gas is often emitted into the atmosphere through energy-consumption-related combustion (flaring), equipment leaks, and venting during the drilling process and completion of the wells. Emissions occur through these same mechanisms (flaring, equipment links, venting, etc.) as raw natural gas is processed into "pipeline quality" gas. Finally, natural gas is also released through pipeline and service line leakage as it is transported and distributed to end users.

Recent technological innovations have expanded the use of unconventional natural gas drilling techniques and enabled access to large volumes of new natural gas resources contained in shale, tight sands, or coal bed methane formations. These drilling techniques include the combined use of horizontal drilling and hydraulic fracturing ("fracking").[115] Approximately 90 percent of oil and gas wells in the United States now require the use of hydraulic fracturing, and the use of fracking techniques in shale gas deposits has changed the trajectory of natural gas supply across the country from one of declining gas production to one of rising production.[116]

Fracking involves the drilling of conventional wells below the surface, and then using horizontal drilling techniques to add lateral sections that run parallel to the rock layer containing the natural gas that will be extracted. These lateral sections can extend several thousand feet. A mixture of water, sand, and chemical additives ("frack fluid") is then injected at high pressure into the rock formation, creating and reopening fractures and releasing trapped gas. The frack fluid is then drawn back out, during a period known as "flowback," in order to prepare the well for production.

There are many potential environmental issues associated with fracked natural gas wells. The most prominent is that of groundwater contamination, with the concern being that fracking chemicals will accidentally be injected near or into aquifers, or that chemicals will remain underground and leach into aquifers over time. Spills of chemicals and wastewater can also occur above ground, resulting in surface contamination. Water use is also of concern, as millions of gallons may be used in the drilling and fracking process. Much of the water may remain underground after wells have been fracked, rather than being returned to its source, and drillers have been criticized for depleting smaller water sources.[117] The equipment and chemicals used to frack natural gas wells must be trucked in from off-site, and any resulting waste or wastewater must be trucked away for disposal. This truck transit can take a heavy toll on local roads, creating traffic congestion near drilling sites and leading to increased vehicular air emissions. Finally, a significant amount of methane is brought up during the flowback period leading to additional gas venting or flaring, and thus greater methane or CO_2 emissions than at conventional wells.[118] As a result, lifecycle estimates of greenhouse gases emitted from fracked natural gas, which

[115] A Litovitz, et. al. Estimation of regional air-quality damages from Marcellus Shale natural gas extraction in Pennsylvania. RAND Corporation. Environmental Research Letters: 8(2013). January 31, 2013. Available at: http://iopscience.iop.org/1748-9326/8/1/014017/pdf/1748-9326_8_1_014017.pdf

[116] A Davis Vaughan and David Pursell. Frac Attack: Risks, Hype, and Financial Reality of Hydraulic Fracturing in the Shale Plays. Reservoir Research Partners and Tudor Pickering Holt & Co. July 8, 2010.

[117] A Davis Vaughan and David Pursell (2010).

[118] U.S. EPA. Greenhouse Gas Emissions Reporting from the Petroleum and Natural Gas Industry: Background Technic al Support Document. 2010. Available at: http://www.epa.gov/ghgreporting/documents/pdf/2010/Subpart-W_TSD.pdf

include significant flowback emissions, are thought to be larger than estimates of emissions from conventional natural gas.[119] The focus of this section is on the emissions leakage associated with the flowback period.

The average emissions rate of natural gas-fired electricity generation in the United States is 1,135 pounds per MWh of CO_2, compared to an average emissions rate for coal-fired generation of 2,249 pounds per MWh of CO_2. The average emissions rate for oil-fired generation falls in between the two at 1,672 pounds per MWh of CO_2.[120] In a 2011 study by Hultman et al., the authors conclude that when production is taken into account, electricity generated from natural gas from fracked wells produces 11 percent more greenhouse gas emissions (in CO_2 equivalents) than electricity from conventional gas. Using this estimate, the emissions from electricity generation powered by natural gas from fracked wells are still less in CO_2 equivalent terms than the emissions from coal-fired electricity generation.[121] While natural gas, which is mostly methane, releases fewer CO_2 emissions than other fossil fuels, when uncombusted methane leaks into the atmosphere it acts as a powerful, short-term greenhouse gas. Over a 20-year period, each pound of methane is 72 times more powerful at increasing the retention of heat in the atmosphere than a pound of CO_2.[122]

The EPA estimates that 11,400 new natural gas wells are fractured each year, and that another 1,400 existing wells are re-fractured in order to increase production or to extract natural gas from a different production zone.[123] Given this large number of wells, and increasing volume of natural gas production, the rate of methane leakage associated with fracking becomes of particular importance. Research to date has been inconclusive, and rates of methane leakage will often vary by drilling site or field, equipment used, and level of care taken by the natural gas producers. Exhibit 4-21, below, shows nine recent estimates of methane leakage as a percentage of lifetime production of natural gas. The Hultman et al. estimate, cited above, falls in the middle of this range of estimates.

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[119] A Litovitz, et. al. Estimation of regional air-quality damages from Marcellus Shale natural gas extraction in Pennsylvania. RAND Corporation. Environmental Research Letters: 8(2013). January 31, 2013. Available at: http://iopscience.iop.org/1748-9326/8/1/014017/pdf/1748-9326_8_1_014017.pdf

[120] U.S. Environmental Protection Agency, "Air Emissions," accessed on March 19, 2013, available at: http://www.epa.gov/cleanenergy/energy-and-you/affect/air-emissions.html.

[121] N Hultman et al. (2011). The greenhouse impact of unconventional gas for electricity generation. Environ. Res. Lett. doi:10.1088/1748-9326/6/4/044008

[122] Steven Hamburg, Environmental Defense Fund, "Measuring Fugitive Methane Emissions from Fracking," Eco Watch, January 4, 2013.

[123] U.S. EPA. Overview of Final Amendments to Air Regulations for the Oil and Natural Gas Industry: Fact Sheet. April 17, 2012. Available at: http://www.epa.gov/airquality/oilandgas/pdfs/20120417fs.pdf

Exhibit 4-21. Estimates of Methane Losses, Shown as a Percent of Lifetime Production.

Author	Affiliation	Study Date	Estimate of Losses (Does not include T&D)
Stephenson et al.[A]	Shell Oil	December 2011	0.6%
Cathles et al.[B]	Cornell University	October 2011	0.9%
Burnham et al.[C]	Argonne National Laboratory	December 2011	1.3%
Jiang et al.[D]	Carnegie Mellon University	August 2011	2.0%
Hultman et al.[E]	University of Maryland	October 2011	2.8%
EPA[F]		April 2011	3.0%
Howarth et al.[G]	Cornell University	April 2011	3.3% (mean; range = 2.2% to 4.3%)
Petron et al.[H]	NOAA, University of Colorado at Boulder	February 2012	4.0% ("best estimate;" range = 2.3% to 7.7%
Petron et al.[I]	NOAA, University of Colorado at Boulder	January 2013	9.0% (preliminary results)

Source:

A. T Stephenson et al. (2011). Modeling the Relative GHG Emissions of Conventional and Shale Gas Production. Environ. Sci. Tech. 45: 10757–10764.
B. LM Cathles et al. (2012). A commentary on "The greenhouse-gas footprint of natural gas in shale formations" by R.W. Howarth, R. Santoro, and Anthony Ingraffea. Climatic Change, doi: 10.1007/s10584-011-0333-0.
C. A Burnham et al. (2011). Life-cycle greenhouse gas emissions of shale gas, natural gas, coal, and petroleum. Environ. Sci. Technol., doi:10.1021/es201942m
D. M Jiang et al. (2011). Life cycle greenhouse gas emissions of Marcellus shale gas. Environ. Res. Lett., doi:10.1088/1748-9326/6/3/034014
E. N Hultman et al. (2011). The greenhouse impact of unconventional gas for electricity generation. Environ. Res. Lett. doi:10.1088/1748-9326/6/4/044008
F. US EPA (2011). Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2009. April 15, 2011. Available at: http://epa.gov/climatechange/emissions/usinventoryreport.html
G. Howarth et al. (2011). Methane and the greenhouse gas footprint of natural gas from shale formations. Climatic Change Letters, doi: 10.1007/s10584-011-0061-5
H. G Petron et al. (2012). Hydrocarbon Emissions Characterization in the Colorado Front Range – A Pilot Study. Journal of Geophysical Research. doi:10.1029/2011JD016360.
I. J Tollefson. (2013). Methane leaks erode green credentials of natural gas. Nature 493:12. January 2, 2013. Available at: http://www.nature.com/news/methane-leaks-erode-green-credentials-of-natural-gas-1.12123

Only two of the nine studies listed above—both led by National Oceanic and Atmospheric Administration (NOAA) scientist Gabrielle Petron—attempt to measure actual leakage rates in basins where methane is being extracted. The first NOAA study examined leakage rates in the Denver-Julesburg Basin in Colorado, and relied on measurements taken in 2008 on the ground and from a nearby tower. The team calculated leakage rates based on chemical analysis of the pollutants it measured—a methodology that remains in dispute—and resulting figures were twice as high as official figures. Michael Levi, an energy analyst at the Council on Foreign Relations in New York, has questioned the findings and presented an alternative interpretation of the data in a peer-reviewed comment that brings the study's leakage rates in line with official estimates.[124]

The second study led by Petron examined methane leakage in the Uinta Basin in Utah and suggested leakage rates of nine percent of total production. The team used ground-based equipment and an aircraft to take measurements of various pollutants, and used atmospheric modeling to calculate the

[124] J Tollefson. Methane leaks erode green credentials of natural gas. Nature 493:12. January 2, 2013. Available at: http://www.nature.com/news/methane-leaks-erode-green-credentials-of-natural-gas-1.12123

level of methane emissions required to reach those concentrations. The resulting leakage rates were compared with industry data on gas production to obtain the percentage of methane that was escaping into the atmosphere through venting and leakage.

In order to give these numbers additional context, a study published by scientists at Princeton University and the Environmental Defense Fund suggests that a shift from coal-fired power plants to those fueled by natural gas has a climate benefit as long as the methane leakage rate—distinct from the total CO_2 equivalent emissions rate cited from Hultman et al. above—from natural gas production is less than 3.2 percent.[125] These calculations assume an average leaking rate for the entire U.S. natural gas supply, and the authors emphasize that much work needs to be done to determine actual emissions on a site-specific basis with any degree of accuracy.

Efforts to measure methane leakage rates in the natural gas industry are ongoing. NOAA scientists are participating in a series of studies with the University of Texas at Austin, the Environmental Defense Fund, and various industry partners to analyze emissions from all aspects of the natural gas industry: production, gathering, processing, long-distance transmission, and local distribution of gas. Researchers are reviewing industry data and collecting field measurements at various sites across the United States. The results of these studies are expected to be submitted for publication in 2013.[126]

4.6.1 Abatement Options for Emissions from Flowback

Emissions resulting from the flowback that occurs during natural gas production can be reduced through a process called "reduced-emissions completion," or "green completion." During green completion, special equipment separates gas and liquid hydrocarbons from the flowback. The gas and hydrocarbons can then be treated and used, or can be sold, thereby avoiding venting or flaring into the atmosphere.[127] The states of Wyoming and Colorado and the cities of Fort Worth and Southlake (both in Texas) already require green completion. In April 2012, the EPA adopted new rules requiring that operators of natural gas wells use green completion to capture fugitive emissions and make them available for use or sale. These requirements will take effect in 2015. In its cost-benefit analysis of the requirements, the EPA estimates that green completion will reduce methane emission leakage during the well completion process by 95 percent, and that revenues from the sales of captured gas will result in a cost savings of $11 to $19 million on an industry-wide basis.[128] This analysis assumes a natural gas price in 2015 of $4.22 per million cubic feet, as forecast by the EIA. A break-even analysis conducted by the EPA suggests

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[125] R Alvarez, et al. Greater focus needed on methane leakage from natural gas infrastructure. Proceedings of the National Academy of Sciences of the United States of America: 109(17). February 13, 2012.

[126] J Tollefson. Methane leaks erode green credentials of natural gas. Nature 493:12. January 2, 2013. Available at: http://www.nature.com/news/methane-leaks-erode-green-credentials-of-natural-gas-1.12123

[127] U.S. EPA. Overview of Final Amendments to Air Regulations for the Oil and Natural Gas Industry: Fact Sheet. April 17, 2012. Available at: http://www.epa.gov/airquality/oilandgas/pdfs/20120417fs.pdf

[128] Id.

that natural gas prices of $3.66 per million cubic feet or greater in 2015 result in revenue from the recovery of natural gas that had previously been vented or flared that exceeds the annualized costs of the required green completion.[129]

On a per well basis, a report commissioned by the Natural Resource Defense Council estimates that the investment cost for green completions ranges from $8,700 to $33,000. Methane capture per well is estimated to be 7,000 to 23,000 million cubic feet, resulting in a profit of $28,000 to $90,000, exceeding expected costs. The payback period for investing in green completion equipment is projected to be less than one year.[130]

Some natural gas developers, including Southwestern Energy Co. and Devon Energy Corp., already use green completion systems to capture fugitive methane. Mark Boling, president of the V+ Development Division at Southwestern Energy Co., said in an interview that "what we do today with reduced emissions completions in our wells doesn't cost us any more than just venting the gas into the atmosphere," and noted that Southwestern has cut the cost of emissions capture from $20,000 per well to $0. The Company estimates that it captures an average of 16 million cubic feet of natural gas that would have been vented or flared. [131]

At the other end of the range, the American Petroleum Institute (API) estimates that the cost of leasing the equipment needed for a green completion is approximately $180,000 per well, plus $30,000 to transport the equipment from one well to the next. As a result, industry expenses would increase by $783 million over four years.[132] According to the API, these costs, combined with an insufficient supply of equipment needed to comply with the regulations, would lead to a 52 percent reduction in drilling, causing gas output to fall by nine to eleven percent.[133]

It should be noted that the number of permit applications for drilling in Colorado did not decline after green completion standards were implemented, but instead more than doubled. Permit applications

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[129] U.S. EPA. Regulatory Impact Analysis: Final New Source Performance Standards and Amendments to the National Emissions Standards for Hazardous Air Pollutants for the Oil and Natural Gas Industry. April 2012.

[130] S Harvey, et. al. Leaking Profits: The US Oil and Gas Industry Can Reduce Pollution, Conserve Resources, and Make Money by Preventing Methane Waste. Natural Resources Defense Council. March 2012. Available at: http://www.nrdc.org/energy/files/Leaking-Profits-Report.pdf

[131] Efstathiou, Jim. Drillers Say Costs Manageable from Pending Gas Emissions Rule. Bloomberg. April 17, 2012. Available at: http://www.bloomberg.com/news/2012-04-17/drillers-say-costs-manageable-from-pending-gas-emissions-rule.html

[132] Comment submitted by Howard J. Feldman, Director, Regulatory and Scientific Affairs, American Petroleum Institute, on Proposed Rule: Oil and Natural Gas Sector, New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews. Docket ID: EPA-HQ-OAR-2010-0505.

[133] Efstathiou, Jim. Drillers Say Costs Manageable from Pending Gas Emissions Rule. Bloomberg. April 17, 2012. Available at: http://www.bloomberg.com/news/2012-04-17/drillers-say-costs-manageable-from-pending-gas-emissions-rule.html

have also not fallen in Wyoming. Rather, in both states the supply of green completion equipment and installation has expanded to meet demand.[134]

4.7 Compliance with State-Specific Climate Plans

The AESC 2013 scope of work required the Synapse project team to determine if there was some component of compliance with state-specific regulations or climate plans that would directly impact generators and that the project team could quantify and credibly support. The scope of work further required the project team, if it made such a determination, to include their estimate of that compliance cost in one of the three categories of costs related to emissions control reflected in the AESC 2013 avoided energy cost forecast. (Those three categories of emissions control costs are "currently enforced," "enacted, but not yet in effect," and "reasonably expected to be enacted.") This is because, due to the nature of the regional market, the costs of complying with one state's law may also affect avoided costs in other states in the New England market. The scope notes that AESC 2013 was not to determine the value of full compliance with these plans, laws, or regulations or the impact of energy efficiency on other sectors that may also be covered by them, such as transportation or industry, in achieving the overall objectives of the plan, law or regulation.

The AESC 2013 scope of work identified the GWSA of 2008 and Connecticut's generator tax as examples of state-specific regulations or climate plans. The Synapse project team ultimately limited its analysis to the GWSA.[135] [136] As required under the GWSA, the Secretary of Energy and Environmental Affairs established a statewide limit for Massachusetts greenhouse gas (GHG) emissions for 2020, and a plan to achieve the 2020 target, in the Massachusetts Clean Energy Climate Plan (CECP). [137] Our analysis of the components required to comply with the GWSA relative to the AESC 2013 Base Case finds the following:

1. The current *Massachusetts Greenhouse Gas Emissions Inventory* method does not provide an accurate accounting of electricity sector emission reductions for GWSA compliance. Synapse presents an example alternate inventory method that would provide an accurate accounting.

2. The Massachusetts Clean Energy Climate Plan (CECP) assumes the electricity sector will achieve significant reductions in emissions by 2020 under its Business as Usual Forecast. The CECP then identifies six policy measures the electricity sector could use to comply with GWSA targets in 2020 and beyond, as well the quantity of reductions and cost per

[134] Id.

[135] The Connecticut Generator Tax is scheduled to sunset on June 30, 2013. However, a final decision on the fate of the tax has not been made. For AESC 2013, we have assumed that the generator tax sunsets.

[136] On April 12, 2013, Synapse polled the Study Group to determine the likelihood of similar regulations in the other New England states.

[137] Massachusetts Executive Office of Energy and Environmental Affairs, December 29, 2010, http://www.mass.gov/eea/docs/eea/energy/2020-clean-energy-plan.pdf

ton of reduction from each. The AESC 2013 Base Case reflects the GWSA compliance components that are currently enforced for the Massachusetts electricity, (i.e., RPS, RGGI, and EPA Power Plant Rules). The remaining compliance measures are all cost-effective energy efficiency, the Clean Energy Import Strategy (CEI) and a Clean Energy Performance Standard (CEPS).

3. The Massachusetts electricity sector will require reductions from a CEPS or other additional component in order to comply with the GWSA at some point from 2020 onward. However, there are unresolved policy questions regarding the CECP targets for the electricity sector beyond 2020 and the inventory method for accounting for reductions in that sector. As a result, the project team could not determine the size of reductions that would be required in the electricity sector each year and therefore could not quantify and credibly support an estimate of the cost of the marginal resource required to achieve those reductions.

4. In the absence of detailed modeling, the project team identified additional renewable generation, incremental to RPS quantities, as the marginal resource for electric-sector compliance with the GWSA. If the quantity of additional renewable generation required for GWSA compliance in a given year is comparable to the AESC 2013 projected quantity of renewable generation added to meet RPS requirements in that year, it is reasonable to expect the cost of that additional renewable generation in that year to be comparable to the REC prices estimated for Massachusetts for that year (e.g. $18.40/MWh in 2020 per Exhibit 6-30) plus the AESC 2013 estimate of electric energy costs for Massachusetts in that year. If the quantity of additional renewables required for GWSA compliance is significantly larger than those added to meet RPS requirements, the cost of the marginal resource required to achieve those larger reductions would have to be determined through new modeling.

4.7.1 Electricity Sector Compliance with GWSA: Current Regulatory Background

In accordance with the requirement of the 2008 Green Communities Act[138] to implement all cost-effective energy efficiency resources, Massachusetts Department of Public Utilities (MassDPU) clarified its policies with regard to the avoided costs of energy efficiency programs, including policies regulating the types of costs and benefits that can be included in cost-effectiveness screening in Massachusetts. In 2009, MassDPU affirmed the use of the Total Resource Cost test, and detailed how environmental benefits could be used in evaluating cost-effectiveness. MassDPU cited a Supreme Judicial Court (SJC) case that addressed the circumstances under which the Department may require Program Administrators (PAs) to account for environmental impacts in evaluating energy resources. The SJC found that MassDPU could not require PAs to consider environmental externalities in evaluating energy resources, as it did not have the statutory authority to do so.[139]

[138] *An Act Relative to Green Communities*, Acts of 2008, Chapter 169, July 2, 2008.

[139] Investigation by the Department of Public Utilities on its Own Motion into Updating its Energy Efficiency Guidelines Consistent with an Act Relative to Green Communities, Order, DPU 08-50-A, March 16, 2009, pages 14 and 15.

The SJC, however, has asserted that MassDPU does have the authority to require PAs to include the costs of compliance with current and reasonably foreseeable future environmental regulations, as these compliance costs would be incorporated in electricity prices over which the Commonwealth has clear jurisdiction. MassDPU identified the GWSA and federal measures to control greenhouse gas emissions as examples of existing and reasonably anticipated future environmental regulations, stating that "the Department expects Program Administrators to include estimates of such compliance costs in the calculation of future avoided energy costs."[140]

In the case of GWSA, these compliance costs may be developed in a broader stakeholder process per MassDPU Docket 11-120, which states that:

> In light of the required GHG emissions reductions set forth in the GWSA and the [Clean Energy and Climate Plan (CECP)] 2020 Plan, the Department will investigate the extent to which the current approach of calculating the benefits associated with reduced CO_2 emissions (i.e., the internalized cost approach included in the 2011 AESC Study) may undervalue the actual benefits. If the Department concludes that the current method understates actual benefits, we seek to identify whether and, if so, how the reasonably anticipated costs of complying with the GWSA and the 2020 Climate Plan can be incorporated into the cost-effectiveness analyses for both electric and gas energy efficiency programs.[141]

After receiving extensive public comments—many of which urged MassDPU to adopt a proxy value based on Massachusetts Renewable Energy Portfolio REC market prices or alternative compliance mechanism prices until a complete analysis of supply curves for the GWSA can be completed[142]—MassDPU issued the following finding:

> At this point in our investigation, we have not developed record evidence as is required by G.L. 30A, § 14(7) (e), and the case law discussed above, that would support the use of an interim proxy value for CO_2 emissions. Accordingly, we decline to adopt an interim proxy value for CO_2 to be used in the cost-effectiveness determination of energy efficiency programs. Our investigation into environmental compliance costs is ongoing and will not conclude until after our review of the 2013-2015 three-year energy efficiency plans is complete. To the extent that the Department determines that it is appropriate to update environmental compliance cost values, the Department will

[140] Ibid, page 17.

[141] MassDPU 11-120. November 29, 2011. "Investigation by the Department of Public Utilities on its own Motion into Updating its Energy Efficiency Guidelines."

[142] See for example, MassDPU 11-120. January 11, 2010. Massachusetts Department of Energy Resources Initial Comments.

consider how best to incorporate any updated values into the three-year energy efficiency plans mid-term.[143]

4.7.2 Electricity Sector Compliance with GWSA: Emission Reduction

The GWSA calls for a 25 percent reduction from Massachusetts' 1990 greenhouse gas emissions by 2020, and an 80 percent reduction from 1990 by 2050. The GWSA does not establish specific targets for each sector of the Massachusetts economy.

The CECP establishes target reductions for various sectors of the Massachusetts economy including the electricity sector. The CECP begins with a Business-as-Usual (BAU) forecast that assumes the electricity sector will emit 4.4 million short tons less CO_2 in 2020 than in 1990. The CECP then identifies a further total emission reduction target for 2020 of 13.3 million short tons based on the following measures:[144]

- **All Cost-Effective Energy Efficiency:** 5.2 million short tons CO_2 (CECP, p.18, and ERG, April 2010, "Initial Estimates of Emission Reductions from Existing Policies Related to Reducing Greenhouse Gas Emissions," p.4, http://www.mass.gov/dep/air/climate/gwsa_docs.htm#erg)
- **Renewable Portfolio Standard:** 1.2 million short tons CO_2 (CECP, p.40)
- **Regional Greenhouse Gas Initiative:** 0 short tons CO_2 (CECP, p.42)
- **More Stringent EPA Power Plant Rules:** 1.3 million short tons CO_2 (CECP, p.44)
- **Clean Energy Imports:** imports of low-carbon energy from Canada via a new transmission line, 5.6 million short tons CO_2 (CECP, p.45)[145]
- **Clean Energy Performance Standard:** 0 short tons CO_2 (CECP, p.47)

For years after 2020, the CECP describes two possible "Scenarios for a Clean Energy Future": the Electrification Scenario, in which there is a significant conversion to electric vehicles and 100 percent of electricity consumed in Massachusetts comes from "near zero carbon" sources, and the Efficiency Scenario, in which there are far stronger energy efficiency standards and only 80 percent of electricity comes from near zero carbon sources.[146] CECP Figure 13 reports 2050 electricity sector emissions for both scenarios: 0.6 million short tons CO_2 for the Electrification Scenario and 5.5 million short tons for Efficiency Scenario. Expected 2050 emission reductions from 1990 electricity sector emissions are 98 and 82 percent, respectively. Required emission reductions for 2030 and 2040 are linearly interpolated using expected CECP 2020 and 2050 reductions.

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[143] MassDPU 11-120-A. August 10, 2012. "Investigation by the Department of Public Utilities on its own Motion into Updating its Energy Efficiency Guidelines."

[144] The CECEP reports its targets in metric tons; we have prepared our analysis in short tons.

[145] The CECP assumptions regarding the quantity of GHG reductions from the CEI and its average cost per ton of reduction are not uniformly accepted by all parties. In addition the GWSA method for estimating GHG emissions does account for life-cycle emissions of GHG associated with the development of a resource to provide generation.

[146] CECP, p.95-102.

Exhibit 4-22 reports the GWSA's required electricity-sector emission reductions for the modeled years. The 44-percent emission reduction target for 2020 is the sum of electricity-sector emission reductions designated in the CECP (13.3 million short tons divided by Massachusetts' 1990 electricity-sector emissions (30.6 million short tons CO_2).[147]

Exhibit 4-22. GWSA Required Electricity-Sector Emission Reductions

	2020	2030	2040	2050
Emission reduction from 1990 (million short tons CO_2)				
CECP Electrification Scenario: Electricity-Sector Target	13.3	18.9	24.5	30.1
CECP Efficiency Scenario: Electricity-Sector Target	13.3	17.3	21.2	25.1
Emission reductions as share of 1990 electricity sector emissions				
CECP Electrification Scenario: Electricity-Sector Target	44%	62%	80%	98%
CECP Efficiency Scenario: Electricity-Sector Target	44%	56%	69%	82%

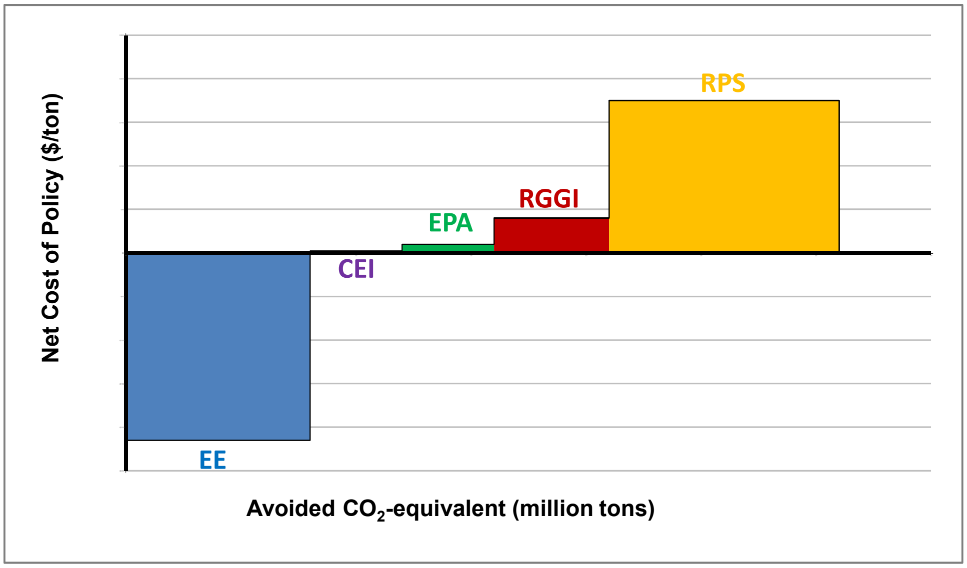
4.7.3 Electricity Sector Compliance with GWSA: Synapse Methodology

The project team estimated the projected costs and CO_2 emissions savings of the specific GWSA electric-sector policies set out in the CECP for 2013, 2020, 2030, 2040, and 2050. The project team prepared this analysis using a "supply curve" methodology.[148] The supply curve for a given year compares estimated costs per short ton and CO_2 emissions reductions in short tons of the specific electric-sector policies set out in the CECP. Elements of each supply curve depict GWSA policies as blocks or columns with a width representing policy-specific emission reductions and a height representing the average cost of that policy's implementation per ton of emission reductions (see Exhibit 4-23).

[147] *Statewide Greenhouse Gas Emissions Level: 1990 Baseline & 2020 Business As Usual Projection,* and *Appendix 1: Statewide Greenhouse Gas Emissions Level: Final 1990 Baseline & 2020 Business As Usual Projection.* Available from the MassDEP.

[148] For illustrative purposes, we estimate cost and emissions savings for 2040 and 2050 to represent the full extent of GWSA compliance through its 2050 target and to inform future AESC calculations.

Exhibit 4-23. Illustrative supply curve of CECP policies



Note: EE is energy efficiency; CEI is the Clean Energy Import Strategy; EPA is more stringent EPA regulation of power plants; RGGI is the Regional Greenhouse Gas Initiative; and RPS is Massachusetts' Renewable Portfolio Standard.

The supply curve for a given year presents the compliance policies in order of their cost per ton of emission reductions, from least to most expensive. The avoided cost of GWSA compliance is the cost per ton of the last policy needed to achieve GWSA required electricity-sector emission reductions, where policies are assumed to be adopted in order of their costs, starting with the least expensive measures.

Because the AESC 2013 Base Case includes three of the CECP policies (i.e., Massachusetts' Renewable Portfolio Standard, the RGGI, and more stringent EPA rules for power plants), the effective supply curve of policy measures for the purpose of modeling GWSA compliance is limited to (1) all cost effective energy efficiency, (2) the CEI and (3) a CEPS which might include a portfolio of compliance measures. Of these three, the CECP provides estimates of the size of reductions, and cost per ton of reductions, for the first two of those policy measures.

Before the project team could estimate the incremental cost of electricity sector compliance with the GWSA, it had to first identify the marginal compliance policy in each year, and the reductions that would be required from that marginal compliance policy. The project team included the CECP policy measure of reductions from energy efficiency in order to determine whether the electricity sector would require marginal compliance policy measures over and above energy efficiency and CEI, and if so, what quantity of additional reductions would be required in each year. That approach is different from the approach used to estimate avoided costs in the AESC 2013 Base Case, which is to estimate the costs of meeting future sales in each year while complying with the quantitative policy and regulatory goals, such as specific RPS percentages, applicable in each year assuming no reductions from new energy efficiency. The difference in approach arose because the project team was attempting to determine the specific goal and quantity of reductions the electricity sector would require in order to comply with the GWSA each year. The results and implications of this approach for the calculation of the marginal cost of compliance are presented in section 4.7.7.

The project team determined whether the Massachusetts electricity sector would require a CEPS or some other additional component in order to comply with the GWSA and, if so, the size of reductions that component would have to achieve using an "inventory" model, i.e., a spreadsheet which accounts for the reductions in GHG emissions from each compliance policy measure. The team used this model to estimate CO_2 emissions associated with Massachusetts electricity consumption under several scenarios, and comparing those emissions to Massachusetts 1990 electricity-sector emissions.

The major components of the project team analysis are:

- **Two sets of CECP emission reduction targets and futures:**
    - The CECP electricity sector targets for the Efficiency Scenario are 44 percent less than 1990 emissions by 2020 and 82 percent less than 1990 emissions by 2050. In this scenario, there are stronger energy efficiency requirements, less conversion to electric vehicles, and slower adoption of zero-carbon generation resources.
    - The CECP electricity sector targets for the Electrification Scenario are 44 percent less than 1990 emissions by 2020 and 98 percent less than 1990 emissions by 2050. In this scenario, reductions from energy efficiency measures are offset by significant conversion to electric vehicles; and
- **Three emission reduction policy cases:**
    - AESC 2013 Base Case (which includes several CECP policies: Massachusetts' Renewable Portfolio Standard, the RGGI, and more stringent EPA rules for power plants);
    - The AESC 2013 Base Case with the all-cost effective energy efficiency measures described in the CECP; and
    - The AESC 2013 Base Case with additional energy efficiency measures and Clean Energy Import Strategy from the CECP.
- **Two inventory methods:**
    - The current *Massachusetts Greenhouse Gas Emission Inventory* method; and
    - An example of an alternate inventory method (described below).

4.7.4 Electricity Sector Compliance with GWSA: Carbon Emission Inventory Methods

Current Massachusetts Method

The current methodology used for the *Massachusetts Greenhouse Gas Emission Inventory* follows a hierarchy illustrated in Exhibit 4-24.

Exhibit 4-24. Illustration of Current Massachusetts Inventory Method

Current MA Inventory Method (numbers are illustrative)	GWh	10^6 short tons CO_2-e
MA Retail Electricity Sales	**60,000**	
less MA Generation (C)	**35,000**	**13.7**
Residual: MA Sales less MA Generation	25,000	
less MA share of Intra-NE Imports (D)	**14,000**	**5.2**
Residual: MA Sales less NE Generation	11,000	
less MA share of Extra-NE Imports (E)	**11,000**	**0.6**
MA Emissions from Electricity Consumption (C+D+E)		**19.4**

First, the method assumes that Massachusetts retail electricity sales are satisfied by Massachusetts generation to the greatest extent possible.

Next, residual sales (Massachusetts total retail sales less Massachusetts generation) are then satisfied to the greatest extent possible by electricity exports from other New England states. Massachusetts is awarded a share of each state's exports equal to the Massachusetts share of all New England electricity imports (from other New England states and from outside of New England combined).

Residual sales (Massachusetts total retail sales less Massachusetts generation and the Massachusetts share of exports from other New England states) are then satisfied in their entirety by electricity imported from outside of New England. Massachusetts is awarded a share of each region's exports into New England equal to the Massachusetts share of all New England electricity imports (from other New England states and from outside of New England combined).[149]

We note that this current method: (1) does not account for REC certificates for zero-carbon resources purchased by Massachusetts LSEs in compliance with RPS and APS regulations; (2) would only award Massachusetts a share of the emission reductions expected from additional transmission of Canadian relatively low-carbon energy in the Clean Energy Import Strategy; and, (3) depending on the design of the standard, might not account for emission reductions from a Clean Energy Performance Standard. We found that it is not possible to determine the marginal policy for GWSA compliance using this inventory method.

[149] Note that in our GWSA compliance calculations we abstract from the official inventory's state-specific allocations of imports and exports, and instead model the imports and exports of an "other New England" (excluding Massachusetts) five-state group.

Synapse alternative example method

The spreadsheet model used to estimate the emissions associated with GWSA compliance includes an example alternative inventory method labeled as the "Synapse alternative example" method for clarity and illustrated in Exhibit 4-25.

Exhibit 4-25. Illustration of "Synapse alternative example" Inventory Method

New Synapse Inventory Method (numbers are illustrative)	**GWh**	**10^6 short tons CO_2-e**
MA Retail Electricity Sales	**60,000**	
less MA RPS/APS REC purchases (A)	**6,000**	**0.0**
Residual: MA Sales less MA RPS	54,000	
less MA Clean Energy Import Strategy (B)	**4,000**	**0.0**
Residual: MA Sales less MA RPS and CEIP	50,000	
less MA Generation (C)	**35,000**	**13.7**
Residual: MA Sales less MA Generation	15,000	
less MA share of Intra-NE Imports (D)	**14,000**	**5.2**
Residual: MA Sales less NE Generation	1,000	
less MA share of Extra-NE Imports (E)	**1,000**	**0.1**
MA Emissions from Electricity Consumption (A+B+C+D+E)		**18.9**

In this method, Massachusetts retail electricity sales are first satisfied to the greatest extent possible by RPS and APS REC purchases.

Next, residual sales (Massachusetts total retail sales less Massachusetts LSEs' RPS and APS REC purchases) are next satisfied to the maximum extent possible by imports from the Clean Energy Import Strategy.

Residual sales (Massachusetts total retail sales less REC purchases and Clean Energy Import Strategy imports) are then satisfied by Massachusetts generation to the greatest extent possible.

Residual sales (Massachusetts total retail sales less REC purchases, Clean Energy Import Strategy imports, and Massachusetts generation) are then satisfied to the greatest extent possible by electricity exports from other New England states, after accounting for these states' own REC requirements. Massachusetts is awarded a share of each state's exports equal to the Massachusetts share of all New

England electricity imports (from other New England states and from outside of New England combined).[150]

Residual sales (Massachusetts total retail sales less REC purchases, Clean Energy Import Strategy imports, Massachusetts generation, and the Massachusetts share of exports from other New England states) are then satisfied in their entirety by electricity imported from outside of New England. Massachusetts is awarded a share of each region's exports into New England equal to the Massachusetts share of all New England electricity imports (from other New England states and from outside of New England combined).

In this alternative method, the emission reductions of all CECP policies are accounted for in the inventory, making it possible to determine the marginal policy for GWSA compliance. The spreadsheet model designed for estimating the emission reductions associated with GWSA compliance replicates both inventory methodologies; the model allows the user to choose to display results either from the current Massachusetts inventory method or the alternative inventory method.

4.7.5 Electricity Sector Compliance with GWSA: Policy Measure Assumptions

Our analysis begins by determining if the Massachusetts electricity sector will require reductions from a CEPS or other additional component in order to comply with the GWSA at some point from 2020 onward. We do this by modeling the annual CO_2 emissions of the Massachusetts electricity sector for three policy cases –the AESC 2013 Base Case, the AESC 2013 Base Case plus the CECP estimate of all-cost-effective energy and the AESC 2013 Base Case plus the CECP estimate of all-cost-effective energy and the CEI.

GHG Emission Rates

Our estimates of CO_2 emissions per MWh of generation from each resource are drawn from the AESC 2013 Base Case, with three exceptions where the project team uses CECP emission rate assumptions. These exceptions are:

- All RECs purchased by Massachusetts load serving entities (LSEs) are zero carbon, except for RECs for waste-to-energy and combined heat and power.
- Waste-to-energy generation has one-half the emission rate implied by AESC 2013 Base Case emissions to generation ratio in order to account only for non-biogenic emissions.[151]
- Electricity imports from outside of New England have the 2006 electricity generation greenhouse gas intensity for Quebec.[152]

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[150] Note that in our GWSA compliance calculations we abstract from the official inventory's state-specific allocations of imports and exports, and instead model the imports and exports of an "other New England" (excluding Massachusetts) five-state group.

[151] See Massachusetts Department of Environmental Protection, http://www.mass.gov/eea/docs/dep/air/climate/rse11cal.xls

Policy Case Measures

Our modeling assumptions for the policy case measures are as follows:

All Cost-Effective Energy Efficiency: Our analysis uses the CECP assumption that the average cost per ton of energy efficiency measures in the electricity sector is negative.[153] Our analysis models the quantity of reductions from this measure as the difference between the AESC 2013 Base Case forecast of Massachusetts retail sales and the CECP forecast of retail sales under each of the CECP scenarios (see Exhibit 4-26).[154]

Exhibit 4-26. Projected Massachusetts Retail Sales (GWh)

	2013	2020	2030	2040	2050
AESC 2013 Base Case	61,368	67,189	76,011	85,968	97,230
CECP Electrification Scenario	61,368	62,026	62,684	63,342	64,000
CECP Efficiency Scenario	61,368	55,226	49,084	42,942	36,800

Clean Energy Import Strategy: Our analysis uses the CECP assumption that the average cost per ton of clean energy imports is zero or negative. [155] Our analysis models the CEI Strategy using the CECP assumption of 1,200 MW of new clean energy import capacity by 2020.[156] However, our analysis assumes the CEI will provide 4,730 GWh based upon an assumed 45 capacity factor, which is consistent with the AESC 2013 Base Case assumptions but lower than the capacity factor assumed in the CECP projections.[157]

4.7.6 Electricity Sector Compliance with GWSA: Marginal Compliance Measure Reductions

The results of our estimates of Massachusetts electricity sector emissions under the CECP Efficiency Scenario and Electrification scenarios are summarized in Exhibit 4-27. These results indicate that, at some point in time, the Massachusetts electricity sector will require some level of reductions from a CEPS or other additional component in order to comply with the GWSA.

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[152] See Environment Canada, http://www.ec.gc.ca/pdb/ghg/inventory_report/2006_report/a9_eng.cfm#ta9_6

[153] CECP, p.18 fn.25.

[154] CECP, Figure 12.

[155] CECP, p.45-46.

[156] CECP, p.45-46.

[157] Hydro-Quebec Annual Report 2012, http://www.hydroquebec.com/publications/en/annual_report/pdf/annual-report-2012.pdf

Exhibit 4-27. GWSA Compliance Emissions Results

Efficiency Scenario		Inventory Method: Current MA					Inventory Method: Synapse Example Alternative				
		2013	**2020**	**2030**	**2040**	**2050**	**2013**	**2020**	**2030**	**2040**	**2050**
Reduction from 1990 Electricity-Section Emissions											
Target: CECP Efficiency Electricity-Sector			44%	56%	69%	82%		44%	56%	69%	82%
AESC 2013											
Base Case	Emissions (10^6 Short Tons CO_2-e)	19.2	23.3	24.9	26.1	30.0	19.3	23.0	23.3	23.8	23.6
	Emission Reduction (10^6 Short Tons CO_2-e)	11.4	7.3	5.7	4.5	0.6	11.3	7.6	7.3	6.8	7.0
	Percent Reduction from 1990 Emissions	*37%*	*24%*	*19%*	*15%*	*2%*	*37%*	*25%*	*24%*	*22%*	*23%*
AESC 2013 Efficiency Scenario											
EE	Emissions (10^6 Short Tons CO_2-e)	19.2	19.3	17.3	15.3	13.3	19.3	17.2	13.5	10.1	7.1
	Emission Reduction (10^6 Short Tons CO_2-e)	11.4	11.3	13.3	15.3	17.3	11.3	13.4	17.1	20.5	23.5
	Percent Reduction from 1990 Emissions	*37%*	*37%*	*43%*	*50%*	*57%*	*37%*	*44%*	*56%*	*67%*	*77%*
EE + CEI	Emissions (10^6 Short Tons CO_2-e)	19.2	19.3	17.3	15.3	13.3	19.3	17.2	13.5	10.1	7.1
	Emission Reduction (10^6 Short Tons CO_2-e)	11.4	11.3	13.3	15.3	17.3	11.3	13.4	17.1	20.5	23.5
	Percent Reduction from 1990 Emissions	*37%*	*37%*	*43%*	*50%*	*57%*	*37%*	*44%*	*56%*	*67%*	*77%*

Electrification Scenario		Inventory Method: Current MA					Inventory Method: Synapse Example Alternative				
		2013	**2020**	**2030**	**2040**	**2050**	**2013**	**2020**	**2030**	**2040**	**2050**
Reduction from 1990 Electricity-Section Emissions											
Target: CECP Electrification Electricity-Sector			44%	62%	80%	98%		44%	62%	80%	98%
AESC 2013											
Base Case	Emissions (10^6 Short Tons CO_2-e)	19.2	23.3	24.9	26.1	30.0	19.3	23.0	23.3	23.8	23.6
	Emission Reduction (10^6 Short Tons CO_2-e)	11.4	7.3	5.7	4.5	0.6	11.3	7.6	7.3	6.8	7.0
	Percent Reduction from 1990 Emissions	*37%*	*24%*	*19%*	*15%*	*2%*	*37%*	*25%*	*24%*	*22%*	*23%*
AESC 2013 Electrification Scenario											
EE	Emissions (10^6 Short Tons CO_2-e)	19.2	21.6	21.0	22.5	23.0	19.3	21.2	19.5	17.5	15.5
	Emission Reduction (10^6 Short Tons CO_2-e)	11.4	9.0	9.6	8.1	7.6	11.3	9.4	11.1	13.1	15.1
	Percent Reduction from 1990 Emissions	*37%*	*30%*	*31%*	*26%*	*25%*	*37%*	*31%*	*36%*	*43%*	*49%*
EE + CEI	Emissions (10^6 Short Tons CO_2-e)	19.2	21.6	21.0	22.5	23.0	19.3	19.4	17.6	15.6	13.6
	Emission Reduction (10^6 Short Tons CO_2-e)	11.4	9.0	9.6	8.1	7.6	11.3	11.2	13.0	15.0	17.0
	Percent Reduction from 1990 Emissions	*37%*	*30%*	*31%*	*26%*	*25%*	*37%*	*37%*	*42%*	*49%*	*55%*

The project team prepared these estimates using the current Massachusetts Greenhouse Gas Emissions Inventory method as well as an example alternate inventory method because, as noted earlier, the current method does not provide an accurate accounting of emission reductions for GWSA compliance.

The top half of Exhibit 4-27 provides results for the Efficiency Scenario. Under that scenario, the Massachusetts electricity sector would not require reductions from a CEPS or other new compliance measure until after 2030, if all of the underlying modeling assumptions prove correct. However, the Massachusetts electricity sector could require reductions from CEPS as early as 2020 if the state does not achieve a 4.4 million short ton reduction by 2020 through BAU improvements and/or if actual reductions from energy efficiency and the CEI prove to be less than assumed.

The bottom half of Exhibit 4-27 provides results for the Electrification Scenario. Under that scenario, the Massachusetts electricity sector would require some level of reduction as early as 2020.

Our estimates of the reductions in GHG emissions in 2020 from all cost-effective energy efficiency and the CEI are lower than the CECP target reductions for those two compliance measures. In particular, our analysis estimates that the CEI would reduce emissions by 1.8 million short tons in 2020 as compared to the CECP target of 5.6 million short tons. The difference between these two estimates is due to differences in two key assumptions. First, our analysis assumes approximately 50 percent less generation from the CEI, based upon it operating at a 45 capacity factor rather than a 90 percent capacity factor. Second, our analysis assumes generation from the CEI will displace conventional fossil generation with an emissions rate of 0.38 million short tons CO_2 per MWh, based on average emissions of generation located outside of Massachusetts under the AESC 2013 Base case. The rate of displaced emissions is approximately 30 percent less than the 0.54 short tons CO_2 per MWh underlying the CECP estimates of the reductions from the CEI. (This difference in assumptions regarding emissions per MWh of displaced generation is the primary reason our estimate of reductions in emissions from energy efficiency in 2020 is lower than the CECP target.)

4.7.7 Electricity Sector Compliance with GWSA: Cost of Marginal Compliance Measure

Our results indicate that, at some point in time, the Massachusetts electricity sector will require some level of reductions from a CEPS or other additional component in order to comply with the GWSA. However, our results also indicate that there are unresolved policy questions regarding the CECP targets beyond 2020 and the inventory method for accounting for reductions in that sector. As a result, the project team could not determine the size of reductions that would be required in the electricity sector each year and therefore could not estimate the cost of the marginal resource required to achieve those reductions.

The marginal cost of GWSA compliance is determined by several modeling assumptions for which there are no obvious or well-supported choices at present:

1) **What greenhouse gas inventory method for the electricity sector should be used to compare GWSA emission savings to GWSA target emission reductions?** The current method used for the *Massachusetts Greenhouse Gas Emission Inventory*[158] does not account for emission reductions from some of the policies described in the CECP. The project team developed an example alternative inventory method that accounts for these policies’ effect on emissions.
2) **To what emission reduction targets for the electricity sector should emissions savings from GWSA policies after 2020 be compared?** The CECP electricity-sector target is 44 percent less than 1990 emissions by 2020. After 2020, the CECP targets are higher in the Electrification Scenario than in the Efficiency Scenario. By 2050, the target reductions are either 98 or 82 percent less than 1990 emissions—depending on the scenario.
3) **If emission reduction targets for the electricity sector are not met by policies with specific costs and emissions savings described in the CECP, what quantity of additional reductions are required for compliance and what marginal cost can be assigned to GWSA compliance?** The

[158] Massachusetts Department of Environmental Protection, July 2012, *Final 2006-2008 Massachusetts Greenhouse Gas Emissions Inventory*, http://www.mass.gov/dep/air/climate/ghg08inf.pdf

> CECP provides for a "Clean Energy Performance Standard" that could provide additional emissions savings, but provides no details on exactly how it would be designed and implemented, the quantity of reductions it might provide, or its costs. The GWSA *2012 Annual Report* notes that "an analysis of the risks and opportunities of a Clean Energy Performance Standard will be performed by summer 2013."[159] For AESC 2013, treat the Clean Energy Performance Standard's costs and emission reductions as unknown.

As a result, the project team could not determine the size of reductions that would be required in the electricity sector each year and therefore could not quantify and credibly support an estimate of the cost of reductions from a CEPS or other additional component the Massachusetts electricity sector would require in order to comply with the GWSA over the planning horizon. In the absence of detailed modeling the project team identified additional renewable generation, incremental to RPS quantities, as the marginal resource for electric-sector compliance with the GWSA. It is reasonable to expect the cost of that marginal compliance resource, and its impact on wholesale electric energy prices, will vary according to its size and timing.

If the quantity of additional renewable generation the Massachusetts electricity sector requires for GWSA compliance in a given year is comparable to the AESC 2013 projected quantity of renewable generation added to meet RPS requirements in that year, the avoided cost of that additional renewable generation in that year would be comparable to the REC prices estimated for Massachusetts in that year and would not have a material impact on the marginal cost of energy in the New England market. For example, the cost of adding a limited quantity of renewable resources in 2020 would be comparable to the incremental REC premium for Massachusetts in 2020 (e.g. $18.40/MWh per Exhibit 6-30) plus the AESC 2013 estimate of wholesale electric energy and capacity costs for Massachusetts in that year.

In contrast, it is possible that the quantity of additional renewables the Massachusetts electricity sector will require for GWSA compliance in 2020 or beyond will be significantly larger than the quantity added to meet RPS requirements in the AESC 2013 Base Case. For example, an updated BAU forecast may indicate that the Massachusetts electricity sector is not on track to emit 4.4 million short tons less CO_2 in 2020 than in 1990. Similarly, updated estimates may project a smaller emission reduction from current energy efficiency programs than the CECP had anticipated. Such analyses may indicate that the Massachusetts electricity sector will require reductions much greater than the renewable generation additions for RPS compliance modeled in AESC 2013. If so, the cost of the marginal resource required to achieve those larger reductions would have to be determined through new modeling. The addition of such a significant quantity of renewable generation could have a material impact on the marginal cost of energy in the New England market, and hence could affect the AESC 2013 estimates of avoided wholesale energy costs for each state. For this reason, the impact of a significant additional quantity of

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[159] Massachusetts Executive Office of Energy and Environmental Affairs, April 2013, http://www.mass.gov/eea/docs/eea/gwsa/2012-annual-report.pdf, p.19.

renewable energy should be estimated through additional modeling that is not within the scope of the current analysis.

Value of energy efficiency as a GWSA compliance measure

The value of reductions from energy efficiency in Massachusetts that would enable the electricity sector to avoid the cost of adding renewable generation to comply with the GWSA will vary according to the size and cost of the marginal compliance resource.

The incremental value of energy efficiency in Massachusetts that would avoid a limited addition of renewable generation can be estimated using the Massachusetts avoided Class I REC price shown in Exhibit F-1 (in Appendix F) adjusted for ISO-NE line losses per Exhibit F-1 and for the retail risk premium per the Massachusetts Statewide “inputs to avoided costs” table on page B-14 of Appendix B. Program administrators in Massachusetts could add this incremental value to the avoided costs applicable to their efficiency programs.

Following is an example calculation of the incremental value of energy efficiency based on avoiding the cost of a limited addition of renewable generation in 2020 to comply with the GWSA. Multiply the 2020 Class I REC price for Massachusetts of $18.40/MWh from Exhibit F-1 by 1.08 to reflect the ISO-NE line losses of 8 percent in Exhibit F-1. This results in an avoided cost of $19.47/MWh at the customer meter. Multiply that $19.47 by 1.09 to reflect the wholesale risk premium of 9 percent from the Massachusetts Statewide “inputs to avoided costs” table on page B-14 of Appendix B. This results in an avoided electric energy value of $21.66/MWh or $0.022/kWh for electric sector GWSA compliance in 2020.

The value of energy efficiency in Massachusetts that would avoid the need for additional renewable generation significantly larger than the RPS additions modeled in the AESC 2013 Base Case would need to be calculated through new modeling.

If another New England state had to achieve reductions in emissions from its electricity sector to meet its state climate goal, it could follow the approach described in this section to estimate the value of energy efficiency as a compliance measure. To use this approach the state would first have to determine if incremental renewables were the marginal compliance resource and, if so, whether the quantities were comparable to the quantities added for RPS compliance in the AESC Base Case. If so, the state would also have to use the AESC 2013 REC value for its state.

Chapter 5: Avoided Electric Capacity Costs

5.1 Introduction

Avoided electric capacity costs are an estimate of the value of a load reduction by retail customers during hours of system peak demand.[160] The major input to this calculation is the wholesale forward capacity price to load (in dollars per kilowatt-month), which is set for a capacity year (June–May) roughly three years before the start of the capacity year. To develop an avoided cost at the meter, the wholesale electric capacity price is first increased by the reserve margin requirements forecasted for the year, then increased by eight percent to reflect ISO-NE's estimate of distribution losses.

The major drivers of the avoided wholesale capacity price are: 1) system peak demand, 2) capacity resources, and 3) the detailed ISO-NE rules governing the auction. ISO-NE rules indicate which resources are allowed to bid in the auction, how the resources' capacity values are computed, and what range of prices each resource category is allowed to bid. The load-resource balance is determined by load growth, retirements of existing capacity, addition of new capacity from resources to comply with RPS requirements, imports, exports, and new non-RPS capacity additions. AESC 2013, which is based on the counter factual assumption of no new energy efficiency, projects that new capacity, other than RPS-related renewable resources, will have to be added starting in 2020.

The 15-year levelized projection of capacity prices from AESC 2011 was $49.69/kW-year in each pricing zone (in 2013 dollars), while the corresponding levelized value from AESC 2013 is $79.88/kW-year. The AESC 2013 estimate of levelized capacity prices is approximately 61 percent higher than the estimate from AESC 2011. The higher values are primarily due to the AESC 2013 forecast of expected retirement of larger quantities of capacity due to environmental requirements and changes in the Forward Capacity Market (FCM).

The actual amount of wholesale electric capacity costs avoided by kW reductions from energy efficiency measures will vary according to the approach that the PA responsible for those measures takes towards the FCM. PAs achieve the maximum avoided cost by bidding the entire anticipated kW reduction from measures in a given year into the Forward Capacity Auction (FCA) for that power year. However, PAs have to submit those bids when the FCA is held, which is approximately three years in advance of the applicable power year. Some expected load reductions may not be bid into the first FCA for which the reduction would be effective, due to

[160] The benefit arises from two sources: the reduction of load at the system annual peak hour and the capacity credit attributed to energy-efficiency programs (called "passive demand response" in the ISO-NE forward capacity mechanism), measured as the average load reduction of the on-peak hours in high-load months or the hours with loads over 95 percent of forecast peak.

uncertainty about future program funding and savings.[161] Information provided by various PAs indicates that the majority of expected savings will be bid into the first applicable auction (75 percent to 100 percent, depending on PA), with the remainder bid in over the next two years.

This chapter is organized as follows:

- Section 5.2 describes the basic assumptions and methodologies underlying our projections of avoided electric capacity costs and avoided electric energy costs. This includes components such as the load forecast, transmission assumptions, generating unit retirements, and resource additions.
- Section 5.3 describes additional assumptions that are specific to our projection of elements influencing avoided electric capacity costs, such as results of FCAs, reserve margin requirements, and reliability contracts.
- Section 5.4 describes the wholesale capacity market in New England and expected changes to that market during the study period.
- Section 5.5 describes the spreadsheet model used in AESC 2013 to estimate electric capacity market prices by simulating future FCAs in the FCM.
- Section 5.6 provides our projections of avoided capacity costs for each year of the study period.

5.2 Basic Assumptions and Methodologies Shared with Electric Energy Forecast

5.2.1 Load Forecast

In order to forecast electric energy and capacity prices that would occur in the absence of new energy efficiency (EE) programs, the project team developed a forecast of peak demand and energy requirements in the absence of such new EE programs.[162]

The forecasts of annual energy and peak load used to calculate avoided costs in AESC 2013 are derived from ISO-NE's 2012–2021 Forecast Report of Capacity, Energy, Loads and Transmission (CELT 2012), as

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[161] PAs also avoid capacity costs from kW reductions that are not bid into FCAs, since those kW reductions lower actual demand, and ISO-NE eventually reflects those lower demands when setting the maximum demand to be met in future FCAs and the allocation of capacity requirements to load. However, the total amount of avoided capacity costs is lower because of the time lag, up to four years, between the year in which the kW reduction first causes a lower actual peak demand and the year in which ISO-NE translates that kW reduction into a reduction in the total demand for which capacity has to be acquired in a FCA. Since the load reduction in one year will affect the allocation of capacity responsibility in the next year, the PA's customers experience a one-year delay in realized savings that are not bid into the auctions at all.

[162] The purpose of the overall study is to develop avoided costs for program administrators to use in their economic evaluations of measures for inclusion in EE program budgets for calendar years 2014 and beyond. The program administrators will submit those proposed budgets in regulatory filings from mid-2013 onward. If the program budgets are approved, the measures would be installed after January 1, 2014, causing savings from that point onward.

discussed below.[163] Beyond 2021, we extrapolate using the last five years' (2017–2021) Compound Annual Growth Rate (CAGR) reflected in that report.

Load Forecast for 2013 through 2021 (CELT 2012)

ISO-NE developed the CELT 2012 forecast of peak demand and energy requirements through 2021 based upon econometric models.[164]

ISO-NE forecasts of annual energy for New England as a whole and for each individual state and load zone is based on previous usage along with real electricity price, real personal income, gross state product, and heating and cooling degree days.[165] ISO-NE developed the model and its coefficients by analyzing the historical relationships between energy requirements and those independent variables since 1984. Therefore, the forecast implicitly contains some level of reductions from efficiency programs because the programs in effect during the historical period would have influenced the actual levels of energy used, and would be reflected in the derived model coefficients, most likely for the personal income and electricity price variables. Since 2008, the econometric models have sought to compensate for those effects by explicitly accounting for energy efficiency in the load by representing them as passive demand resources (PDR). Thus to a large degree the effects of energy efficiency programs are excluded from the econometric forecasts. However, the econometric forecast results are adjusted for the expected effects of federal energy efficiency standards.

ISO-NE then produces an adjusted forecast representing actual system loads based on its expectations of EE program effects. These EE effects are represented by ISO-NE as PDR, and their levels are based on what has cleared in the future capacity markets and future expectations. While this may not capture all EE effects, it is a fairly complete and well-documented value that we will use to adjust the load forecast in the absence of new programs.

For its forecast of peak load, ISO-NE develops peak-load models for each calendar month, for New England as a whole, and for each state using daily historical data. The models are based on the annual energy load, a temperature humidity index, and several dummy variables for weekends and holidays. The historical and forecast loads are then explicitly modified by PDRs based on EE programs that qualified in the capacity market. These resources are called passive because they cannot be dispatched, but do have identified effects on loads and qualify as capacity resources.

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163 We are using CELT 2012 for this study, as that report has been completed, and a full set of supporting documentation is currently available. CELT 2013 was released on May 1, 2013, too late to be incorporated in a timely manner for this study.

164 Further information about the CELT forecasting process can be found at ISO-NE's web page, http://www.iso-ne.com/trans/celt/fsct_detail/2012/index.html.

165 The CELT 2012 econometric models vary by state, as shown in the "prelim_ne_ene_model.xls" document on the above website.

CELT 2012 includes explicit calculations of PDR effects to develop its estimates of system net peak and energy loads. CELT 2012 estimates that PDRs would lower the New England summer peak (relative to the econometric forecast) by 978 MW in 2012, 1,136 MW in 2013, and 1,398 MW in 2014. To represent the 2013 year-end value for existing EE programs, we use the average of the 2013 and 2014 values, which is 1,267 MW. Then, going forward we project that those savings from the existing programs would decline over a 20-year period.

The forecast of annual energy load for AESC 2013 applies the same methodology as for the AESC peak load forecast.

The capacity requirements forecast excludes the PDR reductions, since those resources can now participate in the capacity market.

Load Forecast Post 2021

Beyond 2021, we extrapolate using the CAGR from the last five years reflected in the CELT 2012 forecast. This represents a period of sustained economic growth in the drivers used to develop the econometric forecast. For context, the summer peak growth (2012 – 2021) without the PDR effects is 1.46 percent, but when PDRs are included that rate comes down to 0.79 percent.

The following two exhibits show historical and projected summer peak loads as well as the adjusted peak load used for the AESC project excluding the effects of future EE programs. Note that the historical values prior to about 2008 are actuals and represent the embedded effects of EE.

Exhibit 5-1. ISO-NE Summer Peak Load

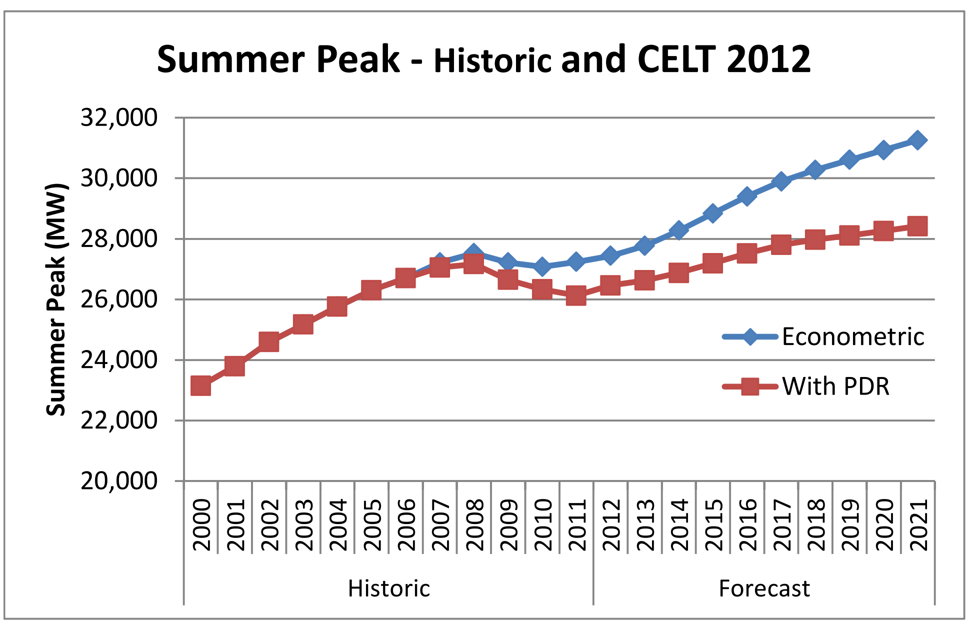
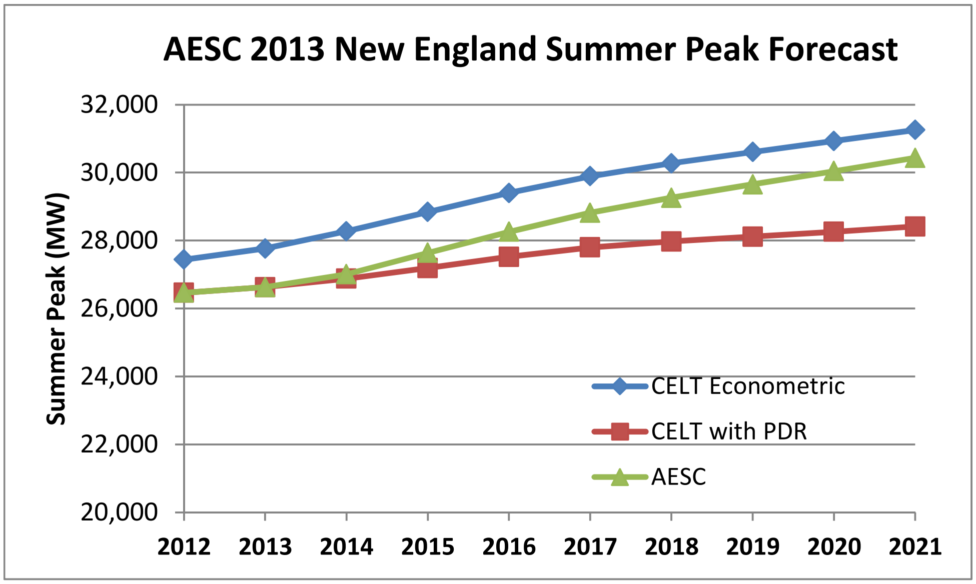


Exhibit 5-2. AESC 2013 New England Summer Peak Forecast



Energy- Efficiency Forecast Working Group

In 2012, ISO-NE formed an Energy-Efficiency Forecast Working Group (EEFWG) that produced an EE forecast for 2015-2021.[166] The EEFWG identified EE savings beyond that incorporated in the CELT report. To illustrate, the additional summer peak load reduction in 2021 was projected to be 1,444 MW above the 2,841 MW PDR value used in CELT 2012.[167] An updated version of that report released in February 2013 for 2016-2022 forecasts an additional summer peak load reduction of 1,353 MW by 2022.

The EEFWG methodology is based on taking expected future expenditures in EE programs and then projecting the energy savings based on actual previous and anticipated future program performance. While these projections are useful for the purpose of forecasting future EE savings, it is not relevant for the AESC 2013 forecast, which is based on loads without future EE program savings.

5.2.2 Transmission Assumptions

The interface limits used in the simulations reflect the existing system, ongoing transmission upgrades including those discussed in the ISO-NE 2012 Regional System Plan,[168] related transmission planning documents, and the reference Market Analytics database.

Transmission-path assumptions are based on those developed by Market Analytics for the Base Case version 9.5. We have modified those assumptions based on ISO data and proposed projects to represent

166 EEFWG documents are available at: http://www.isone.com/committees/comm_wkgrps/othr/enrgy_effncy_frcst/index.html

167 Slide 32, "Final Energy-Efficiency Forecast 2015-2021," April 12, 2012.

168 ISO-New England. November 2, 2012. *2012 Regional System Plan*. Available at: http://www.iso-ne.com/trans/rsp/

future additions. These transmission assumptions, like our other resource assumptions, are not intended to represent specific forecasts or projections, but a reasonable allowance for likely additions.

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, and
- Wheeling charges.

Exhibit 5-3 shows the AESC 2013 assumptions for transmission capabilities of each path between New England zones and between New England and external areas as indicated in the Market Analytics database, reconciled to the interface limits reported in recent ISO reports and transmission planning documents.

Exhibit 5-3. Existing Transmission Paths and Future Upgrades

Path Type	Name	"From" Zone	"To" Zone	Capacity "From-To" (MW)	Notes	Capacity Back (MW)	Notes
Transmission Paths within New England	BHE-ME	BHE	ME	1200		1050	
	CMA-BOSTON	CMA-NEMA	BOST	3200		3000	
	CMA-NH	CMA-NEMA	NH	912		925	
	CMA-WMA	CMA-NEMA	WEMA	1360		2000	
	CT-RI	CT-CNE	RI	720		720	(a) Part of CT import
				1170	As of 1/1/2016	1170	(b) As of 1/1/2016
	CTSW-CT	CT-SW	CT-CNE	2000		3550	
	CTSW-NOR	CT-SW	CT-NOR	1650		1650	
	MPS-BHE	MPS	BHE	10		10	
	NH-BOSTON	NH	BOST	900		912	
	NH-SME	NH	SME	1400		1525	As of 1/1/2013
				1400	As of 1/1/2015	1500	As of 1/1/2015
				2400	As of 1/1/2016	2500	(c) As of 1/1/2016
	NH-VERMONT	NH	VT	720		715	
	RI-BOSTON	RI	BOST	400		400	
	RI-CMA	RI	CMA-NEMA	1480		600	
	RI-SEMA	RI	SEMA			3000	
				1000		3300	(d) As of 1/1/2017
	SEMA-BOSTON	SEMA	BOST	400		400	
	SME-ME	SME	ME	1250		1250	
	VERMONT-WMA	VT	WEMA	875		875	
	WEMA-CT	WEMA	CT-CNE	2880	As of 1/1/2013	710	(a) Part of CT import
Transmission Paths between New England and External Control Areas	BHE-NBPC	BHE	NBPC	728		1000	
	CMA-HYQB (Phase II)	CMA-NEMA	HYQB	1467		1600	
	EMEC-NBPC	EMEC	NBPC	20		20	
	HYQB-VT (Highgate)	HYQB	VT	214		170	
	MPS-NBPC	MPS	NBPC	100		90	
	NOR-NYZK	CT-NOR	NYZK	300		300	
	NYZD-VERMONT	NYZD	VT	150		150	(e) part of NY-NENG
	NYZF-WEMA	NYZF	WEMA	575		650	(e) part of NY-NENG
	NYZG-CT	NYZG	CT-CNE	700		300	(e) part of NY-NENG
	NYZK-CT (CSC)	NYZK	CT-CNE	346		330	

Notes

(a) Connecticut import total of 2,500 MW distributed among several paths.

(b) Interstate Reliability Project (IRP) or equivalent increase CT-RI ties by 450 MW by 2016.

(c) Increased Maine interconnection associated with the Maine Power Reliability Project (MPRP) of 1000 MW in 2016.

(d) Per ISO-NE projections on SEMA exports, based on NEEWS in-service dates.

(e) Based on NY - New England import limit.

A discussion of our major transmission assumptions is provided below.

The New England East-West Solutions (NEEWS) transmission program consists of four major components:

1) The Rhode Island Reliability Project (RIRP),

2) The Greater Springfield Reliability Project (GSRP),

3) The Interstate Reliability Project (IRP), and

4) The Central Connecticut Project (CCP).

These components, when in service, will enhance several transmission interface limits, but most importantly, the Connecticut import capability.

- In the AESC 2013 Base Case, the interface limit between Western Massachusetts and Central Connecticut is increased to 2,880 MW, reflecting the effect of the GSRP.
- In 2016, we add an additional 450 MW between Connecticut and Rhode Island for the IRP project. The GSRP required approval in two states; the IRP will apparently require siting review in three states (Massachusetts, Rhode Island, and Connecticut). Hence, 2016 appears to be a realistic in-service date for the next phase of NEEWS for our modeling purposes. The IRP project was recently approved by regulators in Connecticut; studies are underway to evaluate the CCP project.

Most of the additional transfer capability into Connecticut (and on the East-West and SE Massachusetts-Rhode Island export interfaces, as well) results from the IRP and CCP. These two projects were justified primarily by the objective of meeting Connecticut's load with combined generation and transmission outages at times of extraordinary (once in ten years) high-load conditions, even if more than 1,200 MW of Connecticut generation is retired. Since the original analyses, Connecticut has contracted for over 1,500 MW of additional capacity, load forecasts have fallen, and the GSRP is expected to increase import capacity, greatly reducing the prospect of shortfalls in the Connecticut transmission-security analysis.

AESC 2013 leaves the interface limits between Central Massachusetts and Hydro Quebec intact and does not include the effects of the proposed Northern Pass project at this time. The Northern Pass project is still in the preliminary phases of development, and there are uncertainties regarding the project schedule and in-service dates.

AESC 2013 assumes a 1,000 MW increase in the transmission capacity between Maine and the rest of New England, effective 2016. This assumption is based in part on estimates of the transfer effects in the Maine Power Reliability Plan (MPRP). Additional transmission is also necessary to allow new renewable resources access to load. Our preliminary modeling results indicate that if new capacity is not added, then energy prices in Maine fall substantially below the rest of New England, which provides a strong economic argument for increased interties.

5.2.3 Generating Unit Retirements

In general, AESC 2013 assumes that plants that have been operating since the implementation of restructured markets will continue to operate in the absence of any major changes in market and regulatory conditions. AESC 2013 assumes that retirements of existing plants will be driven by the following factors:

- Requirements for environmental retrofits due to regulatory changes. A discussion of changing environmental and economic conditions that will drive retirements is presented in Chapter 4, Embedded and Non-Embedded Environmental Costs.
- Failure of major components in old and marginally cost-effective units. In these situations, restoring the plant to service may not be cost-effective. Component failure is inherently unpredictable. Our assumptions about the retirement of older capacity reflect anticipated effects of equipment failure.
- The expiration of nuclear, hydro, or other licenses for plants that cannot economically meet requirements for license extension. We describe the relicensing of New England nuclear units in Chapter 6, Avoided Electric Energy Costs. Relicensing of hydroelectric plants has resulted in reduced capacity or retirement of a few small units; we do not anticipate any significant effects on hydro capacity in the future.
- Construction of new capacity at the site of existing capacity, requiring retirement due to lack of space, transmission capacity, or emission compliance. No pending capacity additions are expected to drive retirements of existing units. When new generic units are added, some existing units on those sites may retire. We assume that such additions will occur primarily at sites with units that would be close to retirement for other reasons, so this factor will have little or no effect on market prices.

The specific units that we assume will be retired are presented in Exhibit 5-4, representing 7,400 MW of fossil generation capacity. The basis for these assumptions is presented in the sections below. AESC 2013 treats retirements as occurring on January 1 of the relevant year. AESC 2013 retires about 10 MW of old gas turbines annually.

While most of the remaining steam-electric units in New England have cleared in the FCAs through FCA 7, this does not imply that they are committed to remaining in service until May 2017.

Exhibit 5-4. Fossil Unit Retirements for Energy Modeling

	MW	In-service date	Fuel	Retirement	Age at retirement
Salem Harbor 3	150	Aug-58	Coal	2014	56
Salem Harbor 4	437	Aug-72	Oil	2014	42
Norwalk Harbor 1	162	Jan-60	Oil	2016	56
Norwalk Harbor 2	168	Jan-63	Oil	2016	53
Mt. Tom	143	Jun-60	Coal	2016	56
Middletown 4	400	Jun-73	Oil	2017	44
Montville 6	407	Jul-71	Oil	2017	46
Wyman 1	52	Jan-57	Oil	2017	60
Wyman 2	51	Jan-58	Oil	2017	59
Bridgeport Harbor 3	383	Aug-68	Coal	2017	49
Montville 5	81	Jan-54	O/G	2020	66
Brayton 4	435	Dec-74	O/G	2020	46
Canal 1	573	Jul-68	Oil	2020	52
Canal 2	545	Feb-76	Oil	2020	44
Wyman 3	116	Jul-65	Oil	2020	55
Brayton 1	243	Aug-63	Coal	2020	57
Brayton 2	244	Jul-64	Coal	2020	56
Schiller 4	48	Apr-52	Coal	2020	68
Schiller 6	48	Jul-57	Coal	2020	63
New Haven Harbor	448	Aug-75	O/G	2021	46
Mystic 7	578	Jun-75	O/G	2021	46
Middletown 2	117	Jan-58	O/G	2022	64
Middletown 3	236	Jan-64	O/G	2022	58
Cleary 8	26	Jan-66	Oil	2022	56
West Springfield 3	94	Jan-57	O/G	2022	65
Wyman 4	603	Dec-78	Oil	2022	44
Brayton 3	612	Jul-69	Coal	2024	55
Merrimack 1	113	Dec-60	Coal	Not Retired	
Merrimack 2	320	Apr-68	Coal	Not Retired	
Newington	400	Jun-74	O/G	Not Retired	

Vermont Yankee Retirement

The AESC 2013 Base Case assumes Vermont Yankee retires in 2015.

The Nuclear Regulatory Commission has granted Vermont Yankee a 20-year license extension, but the plant also requires state certification to operate beyond March 2012. According to Vermont law (30 V.S.A. § 248), the Vermont general assembly must vote affirmatively to allow the Public Service Board to issue such certification; however, in February 2010 the state senate voted 26–4 against such issuance. The plant owner, Entergy Nuclear Vermont Yankee, has sued to force the state to allow it to continue operating the plant on the grounds that the state's actions are preempted by federal authority over nuclear safety issues. The plant currently operates under federal court order pending resolution of this suit and, if Entergy is successful, certification by the Public Service Board. While we cannot predict with certainty the outcome of these proceedings, we assume a 2015 retirement as a reasonable proxy for when the owner would have to come into compliance with Vermont law.

Retirements of Coal Plants

Six coal plants (consisting of ten units) are operating in New England. Four additional units have been retired in recent years:

- **Somerset 6** (100 MW, Massachusetts) did not clear in any of the FCAs and was not even qualified in FCA 7.
- **AES Thames** (182 MW, Connecticut) shut down in 2011 in a contract dispute with its steam host, entered bankruptcy, and was sold for dismantlement.
- **Salem Harbor 1 and 2** (158 MW, Massachusetts) delisted in the third and fourth FCA and retired permanently in June 2012.

Exhibit 5-5 summarizes recent operating characteristics of most of the coal fired units in New England.[169]

Exhibit 5-5. Recent Performance by New England Coal-Fired Plants

	MW	In Service	Controls				Capacity Factor			2012 Heat Rate	Typical Energy Bid $/MWh
			FGD	NOx	PM	Cooling Tower	2012	2011	2010		
Brayton 1	243	8/63	Y	SCR	FF	Y	29%	41%	78%	10.5	$35
Brayton 2	244	7/64	Y	SCR	FF	Y	18%	31%	79%	10.5	$35
Brayton 3	612	7/69	Y	SCR	FF	Y	18%	38%	61%	9.8	$45
Bridgeport Harbor 3	383	8/68			ESP		3%	14%	37%	11.4	$52
Mt. Tom	143	6/60			ESP		10%	9%	42%	12.1	$100
Merrimack 1	113	12/60	Y	SCR	ESP	P	35%	59%	68%	11.5	$46
Merrimack 2	320	4/68	Y	SCR	ESP	P	30%	50%	71%	10.7	$50
Schiller 4	48	4/52		SNCR	ESP		11%	29%	54%	14.0	$50
Schiller 6	48	7/57		SNCR	ESP		11%	26%	52%	13.9	$50

Notes:

From EIA Forms 860 & 923, EPA Air Markets Program database
FGD = Flue-Gas Desulfurization (scrubber)
SCR = Selective Catalytic Reduction
SNCR = Selective Non-Catalytic Reduction
FF = Fabric Filter
ESP = Electrostatic Precipitator
Y = Yes
P = Planned

Bridgeport 2011 and 2012 and Mt. Tom 2012 energy are gross output, overstating capacity factor and understating heat rate

[169] Information was not available for Salam Harbor 3.

The AESC 2013 Base Case assumes eight of the region's remaining coal units will retire over the study period.

- **Salem Harbor 3** (150 MW, Massachusetts) submitted high bids for the third and fourth FCAs but has been required to stay online for reliability until June 2014, at which point it will retire.

- **Mt. Tom** (143 MW, Massachusetts) has installed a scrubber, SCR, and a baghouse, but is rather small and probably faces 316(b) issues with its withdrawal of cooling water from the Connecticut River. The unit did not clear in FCA7, has been bidding into the energy market at over $100/MWh, and has been operating at capacity factors at or below 10 percent. We assume this unit retires in 2016.

- **Schiller 4 and 6** (48 and 48 MW, New Hampshire) are small, old (1952 and 1957 in-service dates) units, but they are adjacent to the wood-fired Schiller 5 and the large gas- and oil-fired steam unit Newington, which may reduce these units' operating costs. They have SNCR to reduce NO_x emissions and a precipitator for particulates, but no sulfur controls. In addition, the units are owned by Public Service of New Hampshire and are rate-regulated, so they are not under the same market pressures as other plants. We assume the 2020 retirement data projected by PSNH (NHPUC Docket No. 11-215, Record Request 1, 12/19/2011).

- **Bridgeport Harbor 3** (383 MW, Connectictut) has relatively low NO_x emission rates (about 0.14 lb/MMBtu in 2010–2012) for a coal plant, and a baghouse to control particulate and mercury emissions, but does not have a scrubber or post-combustion NO_x controls. The plant burns very-low-sulfur (0.8 percent S, 9200 Btu/lb), sub-bituminous coal from Indonesia. Bridgeport 3 operated at capacity factors up to the 80 percent range a few years ago, but in only the 30 to 40 percent range in 2009 and 2010, about 15 percent in 2011, and single digits in 2012, presumably due to lower gas prices (and hence lower electric energy prices) and higher coal prices. [170] The high fuel prices have also resulted in Bridgeport 3 bidding into the ISO energy markets at about $50/MWh. Even at the high gas prices in December 2012, this unit ran at only about 9 percent capacity factor. The expected changes in the capacity markets would likely render Bridgeport 3 substantially uneconomic, leading to its retirement. We assume that retirement would occur in 2017.

- **Brayton Point 1–3** (243, 244, and 612 MW, Massachusetts) has installed SCR, scrubbers, baghouses, and cooling towers. The owner, Dominion, invested over a billion dollars in the last few years to meet emission and water-use requirements and keep the plant in operation. However, a recent analysis suggests that Brayton's cash flow is very limited (Schlissel and Sanzillo).[171] Dominion recently sold a package of

[170] In the first quarter of 2009, PSEG renegotiated its coal contract for Bridgeport Harbor with its Indonesian supplier, Adaro, resulting in a 75 percent price increase. (PSEG Outlook, May 2009, pp. 1, 6)

[171] Dominion recently sold Brayton Point (about 1,100 MW of coal, 435 MW of oil/gas capacity), the 1,158 MW Kincaid coal plant in Illinois, and 712 MW of modern combustion turbine capacity at the Elwood plant in Illinois, for a total of $472

assets including Brayton Point at a price consistent with attributing essentially zero value to Brayton; the new owner, Energy Capital Partners, is not bothering to offer Brayton Point as security for the loans supporting the purchase, again suggesting that the plant has little value. The future of this plant remains uncertain; it may retire as soon as 2017 or operate throughout the modeling period. As an intermediate case, we include retirement of Brayton 1 and 2 in 2020 and Brayton 3 in 2024.

- **Merrimack 1 and 2** (113 and 338 MW, New Hampshire) share a scrubber and SCR, and the owner, PSNH, has committed to adding a cooling tower. PSNH appears to be committed to keeping the plant online and, given rate-of-return regulation, may well succeed. We treat Merrimack as continuing to operate.

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

We have less complete information on the older steam plants fired by oil and/or gas. None of these plants are likely to be able to support the cost of major emissions controls.

The AESC 2013 Base Case assumes the following steam units, which burn only residual oil, will retire over the study period:

- **Bridgeport Harbor 2** (130 MW, Connecticut) has delisted for FCA 4 through FCA 6, and did not qualify for FCA 7. We assume it is retired in June 2013.
- **Cabot 6 and 8** (19 MW, Massachusetts), owned by the Holyoke Municipal Light Plant, delisted in FCA 4 and beyond, and appear to be out of service.
- **Salem Harbor 4** (437 MW, Massachusetts) burns only oil, and it is committed to retirement in June 2014, along with Unit 3.
- **Norwalk Harbor 1 and 2** (162 and 168 MW, Connecticut) burns only oil and has reported very high O&M costs (both under regulation and in its RMR cost claim). The plant has SNCR installed, and hence relatively low emissions but higher variable operating costs than other oil units, and operated at less than 1 percent capacity factor in 2012. These units cleared through FCA 6 (except for a play for higher RMR payments in FCA 1), but delisted for FCA 7. Considering the changes in future capacity auctions, we assumed that both units will retire in 2016.[172]

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million (Dominion 10-Q, 1Q2013, p. 17), a price consistent with attributing essentially zero value to Brayton. The new owner, Energy Capital Partners, is not bothering to offer Brayton Point as security for the loans supporting the purchase, again suggesting that the plant has little value. As a result of the bids for Brayton Point, Dominion wrote down its investment in Brayton by $1.22 billion in December 2013 and Brayton and Kincaid by another $450 million in February 2013, bringing the book value of the “long-lived assets” at these plants down to $216 M (Dominion Resources 2012 10-K Report, pp. 78, 127).

[172] After we estimated the retirement schedule, the owner of Norwalk Harbor announced that the plant would be shut down in June 2013. It has now been retired.

- **Middletown 4** and **Montville 6** (~400 MW each, Connecticut) are relatively large and modern (early 1970s), and have moderate NO_x emission rates, but burn only oil, operate at low capacity factors (0.5 percent in 2012), and have particularly high heat rates. They have cleared through FCA 7. We assume that they will be retired in 2017.

- **Cleary 8** (26 MW, Massachusetts) is very small and has the highest NO_x emission rates in New England. It has cleared through FCA 7, and is owned by a municipal utility. We assume that this unit will retire in 2022.

- **Wyman 1–4** (50, 51, 115, and 603 MW, Maine) runs on higher-sulfur, and hence less expensive, fuel than other oil plants in New England (which generally burn 0.5 percent sulfur oil in most Massachusetts plants, and 0.3 percent in Connecticut and at the Canal units). As a result, they operate more often, even though they are in Maine, the zone with the lowest market energy and capacity prices.[173] Other than a requirement to switch to 0.5 percent sulfur oil in 2018, Wyman does not appear to face any environmental challenges. Maine, like New Hampshire, has not been subject to as stringent NO_x control regulations as southern New England. The Wyman units are subject to 136(b). ISO-NE determined in May 2009 that both Units 1 and 2 are needed for reliability until completion of transmission upgrades in southern Maine. These units have not filed above-market delist bids, suggesting that their forward-going costs are less than the FCM prices through FCA 4, when the price paid to generation in Maine fell to $2.336/kW-month, or $28/kW-year.[174] The four units all operated at about one percent capacity factors in 2012. The operating costs reported by the regulated co-owners of unit 4 (PSNH and GMP) indicate that at least that unit's non-fuel O&M has been about $13/kW in 2011 and $5/kW in 2012. The completion of the Maine Power Reliability Project will apparently eliminate the reliability need for Wyman 1 & 2, and NextEra (owner of Wyman 1–3 and 84 percent of Wyman 4) is considering sale of the plant.[175] We assume the retirement of Units 1 and 2 in June 2017. We assume that the larger units will hold on somewhat longer, with Unit 3 retiring in 2020 and Unit 4 in 2022.

- **Canal 1** (547 MW, Massachusetts) has installed selective catalytic reduction (SCR) and operates with very low NO_x emissions. Canal 1 has been the most efficient of the New England oil plants, but was designed for baseload operation and does not follow load well. When oil prices were more competitive with gas prices, this unit had relatively high capacity factors, but in 2012, with low gas prices, its capacity factor was about 0.4

[173] This plant is also sometimes referred to as Yarmouth 1–4.

[174] The Wyman owner has asserted that "Units No. 1 and 2 are not expected to realize any energy revenues in the foreseeable future. Additionally, a bleak capacity revenue outlook makes it unlikely that the subject units will recover their full operations and maintenance costs, and capital expenditures. Since it is not economically feasible to maintain the units, FPL Energy is seriously contemplating retiring Units No. 1 and 2 in the near future." (Request for Determination of Need for System Reliability and Consideration of RMR Cost-of-Service Agreement for Wyman Units No. 1 and 2; December 11, 2008). Despite these warnings, Wyman 1 & 2 have continued clearing with only market capacity prices.

[175] "NextEra Weighs Maine Peaker Sale," *Power Intelligence*, March 25, 2013.

percent. We assume that the unit is retired in 2020, due to more stringent performance rules for capacity and/or stricter limits on use of cooling water.

The information we have regarding the remaining major dual-fueled steam units is summarized below:

- **New Haven Harbor** (448 MW, Connecticut) is not as flexible as some other dual-fuel units, but it has moderate NO_x emissions and capacity factors.

- **Middletown 2 and 3** (117 and 236 MW, Connecticut) have relatively low NO_x emissions, dual-fuel capability, and high capacity factors for oil/gas units (although those are still in single digits).

- **Montville 5** (81 MW, Connecticut) has very low NO_x emissions, dual-fuel capability, and relatively high capacity factors. The owner (NRG) has proposed converting the unit to fire primarily biomass (at up to 40 MW) while retaining the ability to operate at full capacity on natural gas or (if necessary) distillate oil.

- **Canal 2** (545 MW, Massachusetts) has installed selective non-catalytic reduction (SNCR) and has moderate NO_x emissions. While it can burn gas, its capacity is reduced substantially in gas-only operation. Even with low gas prices, Canal 2 has tended to run less than Canal 1. Like Canal 1, Unit 2 is subject to continuing proceedings with EPA regarding compliance with 316(b) requirements.

- **West Springfield 3** (94 MW, Massachusetts) has moderately low NO_x emissions and relatively high capacity factors and does not appear to face any specific environmental challenges. West Springfield did not clear in FCA 5 or 6, but did clear in FCA 7.

- **Brayton Point 4** (435 MW, Massachusetts) has low NO_x emissions, and shares the cooling towers with the coal plants, but has operated at low capacity factors. It was recently sold with the Brayton coal plants.

- **Newington** (400 MW, New Hampshire) has relatively high capacity factors, has been allowed to burn higher-sulfur oil than most New England plants, and does not appear to face any special environmental challenges. It is owned by PSNH, which assumes the unit will continue operating until 2039.

- **Mystic 7** (406 MW, Massachusetts) has very low NO_x emissions and moderate capacity factors, and does not appear to face any environmental challenges.

Exhibit 5-6 summarizes the capacity factors of the region's oil- and gas-fired steam plants over the last few years.

Exhibit 5-6. Recent Performance by Gas- and Oil-Fired Steam Plants

	MW	In-service date	Capacity Factor 2012	2011	2010	Dual-fuel?
Middletown 2	117	Jan-58	6.9%	3.7%	12.7%	Y
Middletown 3	236	Jan-64	4.5%	2.1%	7.3%	Y
Middletown 4	400	Jun-73	0.5%	0.6%	1.8%	
Montville 5	81	Jan-54	1.5%	1.8%	7.4%	Y
Montville 6	407	Jul-71	0.5%	0.4%	1.4%	
New Haven Harbor	448	Aug-75	3.7%	2.8%	3.5%	Y
Norwalk Harbor 1	162	Jan-60	0.7%	1.0%	2.7%	
Norwalk Harbor 2	168	Jan-63	0.7%	1.0%	3.1%	
Brayton Point 4	435	Dec-74	2.2%	0.8%	1.1%	Y
Canal 1	573	Jul-68	0.4%	0.7%	2.2%	
Canal 2	545	Feb-76	0.1%	0.0%	0.4%	Partial
Cleary 8	26	Jan-66	0.5%	1.4%	1.6%	
Mystic 7	578	Jun-75	3.3%	2.0%	4.4%	Y
Salem Harbor 4	437	Aug-72	0.1%	-0.3%	0.4%	
West Springfield 3	94	Jan-57	*6.4%*	*4.0%*	*7.7%*	Y
Wyman 1	52	Jan-57	1.1%	2.0%	2.2%	
Wyman 2	51	Jan-58	1.1%	1.3%	2.6%	
Wyman 3	116	Jul-65	1.0%	1.6%	2.4%	
Wyman 4	603	Dec-78	0.7%	1.1%	2.5%	
Newington 1	400	Jun-74	2.1%	3.6%	6.9%	Y
Notes: From EIA Forms 860 & 923 West Springfield capacity factors are based on gross output						

We assume for the purposes of this analysis that all the oil-fired steam generation and a large portion of the dual-fueled steam generation will retire in the period 2017 through 2022, as changes in the capacity markets make them less economic to operate. The specific units we model as retiring are listed in Exhibit 5-6 above.

5.2.4 Resource Additions

Over the course of the AESC 2013 study period, new generation resources will be needed in addition to the existing mix of generating capacity in order to satisfy renewable portfolio standards, meet future load growth, and respond to retirements. Since Market Analytics is not a capacity expansion model, these additions are inputs to the model. Our assumptions regarding new capacity additions are presented in the following sections.

Resource Additions to Meet Renewable Portfolio Standards

Specific renewable energy resource additions (including fuel cells in Connecticut) were based on generation in the interconnection queues and other sources in the near-term, and based on a supply curve analysis in the longer term.

The Synapse project team found the operating characteristics of renewable generation units to be reasonably consistent between the Market Analytics modeling inputs and the SEA analysis.

Renewable Portfolio Standards in New England

Each New England state has adopted some form of Renewable Portfolio Standard (RPS) or renewable energy goal. Connecticut, Maine, Massachusetts, New Hampshire, and Rhode Island each have a mandatory RPS which requires either Renewable Energy Certificate (REC) purchases or alternative compliance payments (ACPs) to demonstrate compliance. Vermont currently has a voluntary renewable energy goal, with a legislatively driven option to convert to a binding RPS requirement if the voluntary target is not met.[176] There are no alternative compliance payments if these goals are not achieved. While AESC 2011 assumed that Vermont would adopt a mandatory RPS target of 5 percent by 2017, after consulting with the Study Group, the AESC 2013 analysis assumes that Vermont does not establish a binding RPS during the study period. The region's RPS requirements and eligibility criteria are summarized, by state and by RPS sub-category, in Appendix F.

The quantity of *new* or *incremental* renewables that will be added each year during the study period is driven by the state RPS requirements. In particular, new renewable additions are driven by demand from the "premium RPS tiers," which consist of:

- The "Class I" tiers in Connecticut, Maine, Massachusetts, and New Hampshire;
- The "New" tier in Rhode Island;
- The "Class II" (solar) tier in New Hampshire;
- The MA Class I Solar Carve-Out;[177] and
- The NH Class I Useful Thermal Energy Carve-Out.[178]

Some states have also implemented additional requirements that specific percentages of energy be provided by unconventional non-renewable or efficiency resources. Two examples of such alternative requirements are the Massachusetts Alternative Portfolio Standard (which includes combined heat and power, flywheel storage, coal gasification, and efficient steam technologies) and the Connecticut Class III RPS requirement (which includes CHP, conservation and load management, and waste heat or pressure recovery).

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[176] The Vermont Public Service Board issued its first report on the "Progress Towards SPEED Goals" in January 2012 and concluded that the state is making adequate progress toward meeting the goal of 20 percent by 2017. As such, no binding RPS is yet required.

[177] The Massachusetts Solar Carve-Out is a sub-component of the MA Class 1 RPS target.

[178] The Useful Thermal Energy Carve-Out is a sub-component of NH Class 1 and is defined as renewable energy delivered from Class I sources that can be metered and for which fuel or electricity would otherwise be consumed.

It is important to note that while past experience has favored the creation of new or accelerated RPS requirements, the delay or reduction of future RPS targets is also proposed and discussed from time to time. For example, the New Hampshire legislature made a downward adjustment to the state's RPS targets during the 2012 session, and Connecticut policymakers are currently discussing the merits of adjusting their RPS targets (and associated eligibility) between now and 2020.

<u>Demonstrating Compliance with RPS Policies</u>

With the exception of Vermont, all states require the use and retirement of NEPOOL Generation Information System (GIS) certificates in order to demonstrate RPS compliance.[179] In the marketplace where this commodity is traded, NEPOOL GIS Certificates are often referred to as Renewable Energy Certificates (RECs). While the definition of a GIS Certificate is narrower than that of a REC, the two terms are used interchangeably and their reciprocal meaning is commonly understood.

For AESC 2013, we assumed full compliance with established RPS requirements via one of two possible mechanisms. First, entities subject to RPS requirements are expected to comply primarily through the acquisition and retirement of GIS Certificates/RECs. In the alternative, an obligated entity can comply with RPS requirements by making an Alternative Compliance Payment (ACP).[180] ACP levels have been set at prices above the minimum REC price level *expected* to be necessary to allow plants to be financed and built. Because the ACP exists as a valid form of compliance, actual non-compliance with RPS requirements will be extremely rare. In other words, if the market is short on supply, there is a valid alternative route to comply. Given these options, we expect load-serving entities to comply each year, particularly since regulators have the authority to impose penalties or ultimately withdraw the load-serving entity's and/or generator's right to participate in the RPS market. The rate at which the ACP is set—which is not uniform across the New England states—will, however, influence the manner in which compliance is achieved. All else equal (e.g., in the absence of bilateral contracts or asset ownership which would dictate otherwise), states with lower ACPs (CT and NH) will tend to receive more Alternative Compliance Payments than REC compliance during periods of shortage, while RECs flow to markets where the ACP and REC prices are higher.

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179 Currently, Vermont's voluntary goal allows the contracting utilities to resell the RECs associated with SPEED-qualifying facilities to other load-serving entities in satisfaction of RPS obligations in other New England states. Therefore, Vermont's policy does not lead to incremental renewable energy additions beyond what would be predicted in the presence of other states' requirements. It has been argued, however, that Vermont's policy supports financing and therefore leads to incremental renewable capacity and therefore less regional reliance on Alternative Compliance Payments.

180 The Class 1/New Renewable ACPs in Massachusetts, Rhode Island, and Maine are harmonized. For these states, the 2013 ACP is $65.27/MWh, and escalates with the Consumer Price Index (CPI) thereafter. New Hampshire recently parted company from this group and now has an ACP of $55/MWh in 2013 with annual escalation at ½ of CPI. In Connecticut, the penalty for non-compliance is set at $55/MWh, with no annual escalation. While it is called a penalty payment rather than ACP in Connecticut, its effect is the same and it is often referred to as an ACP, which has become the generic term in the industry.

Gross and Net Demand for Renewable Resources

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

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

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

Renewable resources eligible to satisfy state RPS requirements have considerable overlap, but vary by state. With the exception of Maine, AESC 2013 assumes that renewable resources eligible in one or only a few states are insufficient to completely fulfill the demand of the limited states in which they are eligible. This means that beginning in the first year of the study period (2013), we assume that all states other than Maine are competing at the margin to satisfy their requirements for new renewables, other than the solar tiers, from the same group of eligible supply resources. Maine's inclusion of refurbished biomass facilities in its Class I RPS creates the potential that the state will remain in RPS surplus until at least 2022—after taking into account the limited ability to bank state RPS compliance. In this scenario, Maine Class I REC prices would be expected to remain suppressed throughout this period and separated from REC prices in the rest of the region. As such, the Maine RPS may encourage a modest amount of retooling at existing biomass facilities, but is unlikely to spur the development of incremental renewable energy supply. Connecticut's current eligibility definitions also allow for certain biomass supply to be uniquely eligible in Connecticut, but its RPS targets have increased at a pace such that this supply is now sub-marginal. In the near term (from 2013 to 2017), we assume that the aggregate net demand for new RPS supply will be met by a mix of renewable resources consistent with: (1) RPS-eligible resources in the New England administered systems and Maine Public Service interconnection queues, plus (2) other expected RPS-eligible generation in the development pipeline, which has not entered the queue. This includes both large projects that have not yet filed for interconnection studies, and distributed wind, solar, and fuel cell projects, which—due to their size—are not required to go through the large generator interconnection process. Due to the increasing expense of entering and maintaining a position in the interconnection queue, some proposed projects must delay this stage of the process until early site evaluation and permitting progress has been sufficient to attract substantial development capital.

The Impact of Policy Uncertainty on RPS Supply

In some cases, the development and interconnection processes are also delayed by regulatory uncertainty. Examples of such uncertainty are available in each state in today's market—making the regional RPS marketplace increasingly complex and challenging for developers and investors. The critical example in today's market is Connecticut's seemingly perennial legislative discussion regarding whether or not to adjust RPS eligibility criteria, RPS demand targets, or both. Connecticut legislators and regulators both are considering these issues as this study is being drafted. In Vermont, after receiving a detailed proposal from the Public Service Board for an RPS substantiated by REC retirement, the legislature firmly defeated the RPS bill and continued to support the resale of RECs associated with SPEED program resources into other New England RPS markets. During the 2012 legislative session, New Hampshire reduced its Class I RPS targets and lowered the ACP to $55/MWh for 2013. In the 2013 session, the NH legislature has proposed to reduce the Class III RPS target and to return the ACP to its previous level (which would restore consistency with MA and RI). The Class III bill had passed the House but had not cleared the Senate when this report was drafted. As previously described, Maine has introduced the potential for a flood of RECs eligible only in Maine through its Class I refurbishment provisions. Because these RECs would come from existing facilities, Maine's role in encouraging new renewable energy supply would be greatly reduced. Finally, the MA DOER recently revised the RPS-eligibility of biomass generators and feedstock. After a lengthy stakeholder and rule promulgation process (which delayed the development of nearly all of the region's proposed biomass projects), DOER and the legislature approved new regulations which effectively foreclosed the MA RPS market to new biomass through efficiency requirements that are expected to be unattainable by all but small combined heat and power facilities.

<u>Additional Assumptions for Renewable Energy Supply</u>

All proposed generators for which information has entered the public domain are included in this analysis. This generation is derated to reflect the likelihood that not all proposed projects will ultimately be built, and may not be built on the timetable reflected in the queue. This information is grouped by load area as an input to the Market Analysis model.

For the longer term (generally after 2017), we estimate the quantity and types of renewables that will be developed using a supply-curve approach based on resource potential studies. In this approach, potentially available resources are sorted from least to greatest REC premium required to attract financing. This approach identifies the incremental resources required to meet net incremental demand in each year through 2028.

The one exception to this methodology is solar PV. We assume that resource is developed in proportion to various state policies intended to promote solar, including solar RPS tiers and other factors. In AESC 2013, we assume that the MA Solar Carve-Out (a sub-set of MA Class I) reaches its 400 MW target in 2014 and that the policy is expanded—either through a supplementary or parallel program—to require an additional 600 MW (for 1 GW total), which we assume is installed by 2019. Opt-in terms for the initial 400 MW are expected to expire in approximately 2022, and assuming that the same market design principles are applied to the next 600 MW, the opt-in terms for this supply are expected to expire in approximately 2024. Beginning in 2023, we assume that the Solar Carve-Out begins to sunset into MA Class I at the same rate as it ramped up, reaching zero carve-out shortly after the study period ends.

Planned Additions and Uprates

The non-renewable generation resources used as inputs to our simulations are drawn from the capacities in CELT 2012. So far as we have determined, the only planned non-renewable generation addition with a specific construction schedule and a high probability of completion is the Footprint Power project, a 670 MW combined-cycle facility on the site of the retiring Salem Harbor power plant. This project cleared in FCA 7 and locked in a capacity rate of $15/kW-month for the first five years, so it has high incentives to reach commercial operation by June 2016. [181]

Demand-Response Resources

Demand Response (DR) resources participate in the FCA. For simulation purposes we start with the quantities of DR that cleared in FCA 7 and project a modest decline in DR capacity in response to the changes in market structure in future FCAs. DR resources, when dispatched, affect energy prices primarily in peak hours.

Generic Non-Renewable Additions

In order to reliably serve the forecasted load in the mid- to long-term portion of the forecast period, the model adds new generic additions as needed. New generic non-renewable resources were added to meet any residual installed capacity requirements after adding planned and RPS additions. We developed our assumptions regarding the quantity, type, and timing of these generic additions in coordination with our simulation of the FCM because revenues from FCA prices help support those investments.

Based on the mix of resources in the interconnection queue, and the constraints on construction of new coal or nuclear units in New England in the foreseeable future, we assumed generic additions consisted of a 50/50 mix of capacity from gas/oil-fired 375-MW combined-cycle (CC) units and 180-MW combustion turbines (CT). No coal or nuclear units were added.

New resources were dispersed geographically based on a combination of zonal need and historical zonal capacity surplus/deficit patterns. Maine's surplus of capacity, low energy prices, and export constraints tended to suppress development of new generic capacity in that zone. The locational markets for energy and forward reserves tended to provide incentives to build new generation in import-constrained zones, principally Connecticut.

5.2.5 Environmental Regulations

Assumptions regarding environmental regulations are discussed in Chapter 4, Embedded and Non-Embedded Environmental Costs.

[181] The financing of the Footprint is not in place, and it is possible that the plant will not be built without a purchased-power agreement. The DPU rejected a PPA with the Massachusetts utilities in DPU Docket No. 12-77.

5.2.6 Wholesale Risk Premium

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

This premium over wholesale prices, or *wholesale risk premium,* is attributable to various costs that retail electricity suppliers incur in addition to the cost of acquiring wholesale energy, capacity, and ancillary-service at wholesale market prices. These additional costs include costs incurred to mitigate cost risks associated with uncertainty in charges that will be borne by the supplier but whose unit prices cannot be definitely determined or hedged in advance. These cost risks include costs of hourly energy balancing, transitional capacity, ancillary services, and uplift.

The larger component of the risk is the difference between projected and actual energy requirements under the contract, driven by unpredictable variations in weather, economic activity, and/or customer migration. For example, during hot summers and cold winters, load-serving entities (LSEs) may need to procure additional energy at shortage prices, while in mild weather they may have excess supply under contract that they need to "dump" into the wholesale market at a loss. The same pattern holds in economic boom and bust cycles. In addition, the suppliers of power for utility standard-service offers run risks related to migration of customer load from utility service to competitive supply (presumably at times of low market prices, leaving the supplier to sell surplus into a weak market at a loss) and from competitive supply to the utility service (at times of high market prices, forcing the supplier to purchase additional power in a high-cost market).

AESC 2013 applies the same wholesale risk premium to avoided wholesale energy prices and to avoided wholesale capacity prices.[182] Estimates of the appropriate premium range from less than 8 percent to around 10 percent, based on analyses of confidential supplier bids, primarily in Massachusetts, Connecticut, and Maryland, to which the project team or sponsors have been privy. Short-term procurements (for six months or a year into the future) may have smaller risk adders than longer-term procurements (upwards to about three years, which appears to be the limit of suppliers' willingness to offer fixed prices). Utilities that require suppliers to maintain higher credit levels will tend to see the resulting costs incorporated into the adders in supplier bids.

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

In the absence of robust information on the retail premium implicit in the prices being bid for retail supply in New England, we assumed a 9 percent premium as a default risk premium. The risk premium is a separate input to the avoided-cost spreadsheet. Therefore, program administrators will be able to input whatever level of risk premium they feel best reflects their specific experience, circumstances, economic and financial conditions, or regulatory direction.

The details of the risks and costs of serving load are somewhat different for Vermont, Public Service of New Hampshire (PSNH), and various municipal utilities, where vertically integrated utilities procure power from owned resources and a variety of long- and short-term contracts. For Vermont, we have included the 11.1 percent risk premium mandated by the Vermont Public Service Board. For PSNH and the municipal utilities, program administrators should use a risk premium less than the 9 percent premium default.

5.3 Additional Assumptions Specific to Electric Capacity

5.3.1 Results of Forward Capacity Auctions

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

5.3.2 Reserve Margin Requirements

The New England ISO acquires sufficient capacity to ensure reliability in each power year. In the FCM, the absolute cost of that capacity equals the required capacity, i.e., the installed capacity requirements (ICR) times the FCA auction price. The percentage by which the ICR exceeds the projected system peak is the reserve margin. Based on the average requirement for the auctions in 2011 and 2012, we have projected future reserve requirements of 17.2 percent from 2017 onward, as described in section 5.6.

5.3.3 Reliability Contracts

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

All of the RMR contracts have expired—the last of them on June 1, 2010. A few units have received special reliability contracts in connection with transmission constraints in the FCAs, the last of which appear to be Salem 3 and 4, which appear to be eligible to receive $5.005/kW-month in 2013/14. Since future FCAs will allow for different prices in each of the eight pricing zones (western, northeastern, and southeastern Massachusetts, and the five other states), future reliability contracts are unlikely, although they may be required for very local supply conditions.

Lower loads and other system changes allowed the ISO to cancel above-market payments for Norwalk Harbor 2 in FCA 1 and Vermont Yankee in FCA 4. It thus appears that some of the costs of reliability contracts have been avoidable. Additional reliability contracts may have been avoided by load reductions that have already occurred, or are reflected in the demand resources bid into the FCAs. Continuing reductions may avoid reliability contracts for other generators that may seek to delist in future years.

5.3.4 Other Wholesale-Load-Cost-Components

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

- First-Contingency Net Commitment Period Compensation (NCPC),
- Second-Contingency NCPC,
- Regulation (automatic generator control),
- Forward Reserves,
- Real-Time Reserves,
- Inadvertent Energy,
- Marginal Loss Revenue Fund,
- Auction Revenue Rights revenues,
- ISO Tariff Schedule 2 Expenses,
- ISO Tariff Schedule 3 Expenses, and
- NEPOOL Expenses.

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

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

- The NCPC costs are compensation to generators that comply with ISO instructions to warm up their boilers, ramp up to operating levels, remain available for dispatch, possibly generate some energy, and then shut down without earning enough energy- or reserve-market revenue to cover their bid costs. Older boiler plants may take many hours to reach full load and have minimum run-times and shut-down periods, requiring plants to continue running at minimum levels overnight. Smaller loads would tend to reduce the need for bringing these plants into warm reserve, thus reducing NCPC costs. On the other hand, lower energy prices would tend to increase the net compensation due to these units when they were required, since they would earn less when they actually operated. Hence, while energy efficiency may affect NCPC costs, the direction and magnitude of the effects are not clear.

- Regulation costs are associated with units that follow variations in load and supply in the range of seconds to a few minutes. Reduced load due to efficiency is likely to result in reduced variation in load (in megawatts per minute), reducing regulation costs. On the other hand, some controls may increase regulation costs, if end-use equipment responds more quickly to changing ambient conditions. Overall, energy efficiency programs will probably reduce regulation costs, but we cannot estimate the magnitude of the effect.

- Forward and real-time reserve requirements should decrease slightly with energy efficiency, for two reasons. First, lower load will tend to leave more available capacity on transmission lines, which will tend to reduce the need for local reserves. Second, a portion of real-time reserves are priced to recover forgone energy for units that remain in reserve; lower energy prices will tend to depress reserve prices. We expect that these effects would be small and difficult to measure.

- Inadvertent energy exchanges with other system operators (NY ISO, Hydro Quebec, and New Brunswick) are small and probably not affected by energy efficiency.

- The Marginal Loss Revenue Fund returns to load the difference between marginal losses included in locational energy prices and the average losses actually experienced over the pool transmission facilities. That fund is—by definition—generated by infra-marginal usage, and will not be affected by reduction of loads at the margin.

- Auction Revenue Right revenues are generated by the sale of Financial Transmission Rights (FTR), to return to load the value of transfers on the ISO transmission facilities. To the extent that efficiency programs reduce energy congestion, the value of these rights will tend to decrease.

- Expenses (ISO Tariff Schedules 2 and 3 and NEPOOL) are largely fixed for the pool as a whole, although a portion of the ISO tariffs are recovered on a per-MWh basis. Some of the ISO costs may decrease slightly as energy loads decline, if that leads to a reduction in the number of energy transactions, dispatch decisions, and other ISO actions required. Any such effect is likely to be small and slow to occur, and energy-efficiency programs add their own costs in load forecasting, resource-adequacy planning, and operation of the FCM.

5.4 Wholesale Market Prices for Electric Capacity

The capacity markets previously operated by ISO-NE were superseded in June 2010 by the FCM. The power year for the FCM, also referred to as an FCM year, is from June through May. Thus, the calendar year unit cost of capacity (expressed as dollars per kW-year) is the average of January through May from one power year, and June through December of the following power year.

Under the FCM, ISO-NE acquires sufficient capacity to satisfy the installed capacity requirement (ICR) it has set for a given power year through a Forward Capacity Auction for that power year.[183] The price for capacity in that power year is based upon the results of the FCA for that year. The FCA for each power year is conducted roughly three years in advance of the start of that year. ISO-NE has held seven FCAs to date, plus annual reconfiguration auctions (ARAs) every year or so between the FCA and the start of the power year. Exhibit 5-7 summarizes the auction megawatt requirements and supply to date. Exhibit 5-7 also provides the local supply requirement (LSR) for the import-constrained sub-regions (Connecticut and northeastern Massachusetts) that the ISO modeled and the maximum capacity limit (MCL) for export-constrained Maine.

Exhibit 5-7. Summary of ISO-NE Capacity Requirement and Supply (MW)

			Local Supply Requirement		Maximum Capacity Limit	Load Forecast		
Capability Year	ICR	Net ICR	CT	NEMA/ Boston	ME	Summer Peak Forecast	Year of Load Forecast	Filing Date
2016 FCA 7	34,023	32,968	7,603	3,209	3,709	29,400	2012	6-Nov-2012
2015 FCA 6	34,498	33,456	7,542	3,289	3,888	29,380	2011	3-Jan-2012
2015 1st ARA	33,813	32,771	7,402	3,036	3,818	28,840	2012	30-Nov-2012
2014 FCA 5	34,154	33,200	7,478	3,046	3,702	29,025	2010	8-Mar-2011
2014 2nd ARA	33,163	32,209	7,262	2,917	3,682	28,275	2012	30-Nov-2012
2013 FCA 4	33,043	32,127	7,419	2,957	3,187	28,570	2010	4-May-2010
2013 2nd ARA	33,463	32,547	7,489	3,118	3,584	28,525	2011	30-Nov-2011
2013 3rd ARA	32,550	31,552	7,310	2,799	3,632	27,765	2012	30-Nov-2012
2012 FCA 3	32,879	31,965	6,640	2,019	3,257	29,020	2009	7-Jul-2009
2012 2nd ARA	32,841	31,927	7,284	2,718	3,517	28,165	2010	1-Dec-2010
2012 3rd ARA	32,987	32,010	7,312	3,013	3,707	28,095	2011	30-Nov-2011
2011 FCA 2	33,439	32,528	6,817	2,016	3,395	29,405	2008	9-Sep-2008
2011 2nd ARA	32,652	31,741	5,666	1,956	3,140	28,575	2009	2-Feb-2010
2011 3rd ARA	32,463	31,552	7,244	2,668	3,406	27,660	2010	1-Dec-2010
2010 FCA 1	33,705	32,305	7,017	2,246	3,855	29,035	2007	11-Oct-2007
2010 2nd ARA	33,537	32,137	6,737	1,990	3,725	28,955	2008	30-Jan-2009
2010 3rd ARA	32,510	31,110	6,496	1,838	3,697	28,160	2009	15-Dec-2009

183 Some of the ICR (varying from 911 MW in the fourth FCA to 1,055 MW in the seventh FCA) was met by installed capacity credits from the Phase I/II interconnection, which are allocated to the transmission owners with entitlements in the line. The Hydro Quebec Interconnect Certificate rights are valued at the market-clearing price, and the actual auction acquires the remaining ICR, called the net ICR or NICR.

Through FCA 7, each FCA had a ceiling price and a floor price. Each of these first seven auctions concluded when the price in the principal pricing zone (Rest of Pool, or ROP) reached the floor price, although the amount of capacity offered at that price still exceeded the requirement. Existing resources have been allowed to withdraw capacity from the auction in four ways:

- In a dynamic bid during the auction, once the price falls below a preset level (typically $4 to $5/kW-month);
- In a static bid offered prior to the auction, at a price justified by the costs of continuing to operate the resource;
- In a permanent delist bid, which is similar to a static bid but, if the bid is accepted, the resource is permanently delisted; or
- In a non-price bid, which requests permission from ISO-NE to terminate the resource regardless of price.

The floor price for FCA 7 was $3.15/kW-month. Since more capacity cleared at the floor price than was required to satisfy the ICR, each cleared resource was required to choose between downward proration of the quantity of capacity that it bid or downward proration of the final auction price. For example, when the capacity clearing was roughly 6 percent above the net ICR in FCA 1, each resource chose between being paid 94 percent of the floor price (about $4.23 in FCA 1) for all its bid capacity, or the floor price for 94 percent of its bid capacity.[184] Exhibit 5-8 summarizes the market-clearing prices and the payment rates for auctions to date. The payment rate for each auction is listed for the rest of pool (ROP), the zones for which no constraints were binding. Where the payment rate differed among zones, Exhibit 5-8 includes the prices for the zones that varied from the ROP price.

Exhibit 5-8. FCA Price Results ($/kW-month)

FCA	Year	Clearing Price	Payment Rate			
			ROP	ME	CT	NEMA
4	2013 – 2014	$2.951	$2.516	$2.336		
5	2014 – 2015	$3.209	$2.855			
6	2015 – 2016	$3.434	$3.129			
7	2016 – 2017	$3.150	$2.744	$2.744	$2.883	$6.665

Suppliers of capacity whose bids are accepted in the FCA are paid an amount equal to the quantity of capacity they bid multiplied by the final prorated auction price. In each month of the capacity year, this amount is reduced by *peak energy rents* (PER), an estimate by ISO-NE of the annual wholesale energy

[184] Emergency generation and resources in Maine have been subject to additional constraints and proration in some years, and the Northeastern Massachusetts (NEMA) zone cleared with a price higher than the ROP price in FCA 7.

market revenues that a hypothetical generator with a heat rate of 22,000 Btu/kWh would earn.[185] Suppliers are also subject to penalties for any failure to meet the ISO's tests for capacity in the power year.

The buyers of capacity, i.e., load-serving entities, pay an amount approximately equal to the quantity of capacity ISO-NE requires them to support in the power year times the auction-clearing price for that power year.[186] The quantity of capacity that a particular load is required to hold in the power year is set by ISO-NE and is called the Capacity Load Obligation (ISO-NE Market Rule 1 §III.13.7.3). This obligation is based on the estimated contribution of that load to the ISO annual peak in the preceding power year. Thus, the total cost of capacity to a load-serving entity for a given power year, i.e., required kW of capacity multiplied by FCA price in dollars per kW, is mostly set in advance of that power year. The price is mostly determined over three years in advance of the power year, and each load's individual share of the cost is set to the summer preceding the power year.

5.4.1 Proposed Changes to the Forward Capacity Market

A number of important changes are pending in the Forward Capacity Market that will affect the price of capacity to consumers and the payments for capacity for generators and other resources. In the eighth FCA, the floor will no longer exist, and dynamic delist bids will only be allowed when the price falls under $1/kW-month. Any existing resource that wished to delist at a higher price would have to submit a static delist bid (or permanent delist bid, if it wished to retire) and justify the economics of the delisting prior to the FCA. Depending on the stringency of the ISO's review of the resource's economics, delisting may be difficult. Under those circumstances, if a capacity surplus persists, the capacity price could fall dramatically in FCA 8.

In addition, the ISO has proposed that, starting in June 2018 (FCA 9), resources should be penalized for not being online when the system experiences a shortfall in operating reserves, an event that might happen 25 or 30 times annually. Some of those events would be on high-load days, when all generation is operating or ready to operate (other than generation on forced outage). Any power plant (baseload, peaker, cycling steam) faces similar risks of penalties on those days, which can be mitigated by bidding in less than the full capacity of the resource, so that it earns enough rewards on days it is available to compensate for its outages.[187] But some events could occur on low-load days, and even in off-peak hours, depending on outages and other factors, which would present very serious problems for plants that are not online at those times and are not able to start quickly. The ISO has proposed (at least in its

185 Our analyses do not adjust for PER as it appears to be minimal. In 2012, PER was above zero for only one hour, 1/28/2013 HE18, for an adjustment of no more than 16¢/kW.

186 These costs are reduced by the PER and credits for supplier performance penalties, as well as by adjustments due to reconfiguration auctions (in which the ISO can buy back unnecessary capacity obligations, or purchase additional obligations). Load-serving entities can also self-supply a portion of their capacity requirements.

187 It is not clear how much flexibility the eventual rules will give the resources, but it seems likely that they would be able to derate enough to reflect their forced-outage rates.

examples) very high penalty rates for non- or under-performance (and corresponding reward for resources that operate above their capacity obligations), which would have a number of effects on the behavior of existing resources, including these three:

- Resources that are not online in most hours and cannot come online on short notice will not be able to earn any capacity revenues. This is not a problem for baseload plants (e.g., nuclear, biomass, waste-to-energy, industrial cogenerators), which are usually online; peakers (which can ramp up rapidly); hydro (which ramps quickly); or combined-cycle plants (which are generally online in most hours, and generally ramp quickly). However, it would be a serious problem for the steam-electric plants that do not operate baseload, including those fueled with residual oil, natural gas, and in recent years, coal. The loss of the capacity revenues may lead to the retirement of many of these plants.
- Even resources that could operate profitably in the performance-based system would have an incentive to understate their capacity to minimize penalties and maximize rewards. While the ISO would likely attempt to block these strategic deratings, some erosion of cleared capacity is likely.[188]
- Due to the surplus of capacity that has cleared at the floor price, and the fact that much of that capacity is then prorated, there is a substantial amount of uncommitted capacity that can participate in the reconfiguration auctions. The prices in the annual reconfiguration auctions have been far below the FCA prices, on the order of $0.50–$1/kW-month. Under these circumstances, there is little to be lost and much to gain by clearing a resource's capacity in the FCA, purchasing replacement capacity, and retiring the resource.[189] Starting in FCA 8, this strategy will no longer be effective, potentially triggering decisions to delist and retire resources.

The ISO's proposals are still largely conceptual. A large amount of negotiation, drafting and vetting of rules, and litigation would need to occur before the performance-based system comes into effect. We doubt that the proposal will be implemented in time for FCA 9 in early 2015. For the purposes of this analysis, we have assumed that some variant on the ISO proposal is phased in between 2020 and 2022, roughly FCAs 11 through 13. This reflects other delays in the evolution of the FCM, such as the extension of the price floor (originally established for only the first three FCAs) to seven FCAs. While we do not know the form of the eventual changes, we assume that the revised FCA will result in delisting of significant amounts of supply resources and demand response.

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188 It is not clear how energy-efficiency resources, which are not metered on an hourly basis, would be affected by this scheme.

189 For example, NRG's Norwalk Harbor 1 and 2 cleared in FCA 4, 5, and 6, but was retired June 1, 2013. It is likely that NRG will be able to find replacement capacity from its other prorated units and from other suppliers for much less than the prices it will be paid for clearing in the FCAs.

The ISO's External Market Monitor has also suggested that it may be appropriate for the ISO to implement an administrative "demand curve," similar to that used to artificially maintain capacity prices in PJM and the NYISO.[190] An administrative demand curve increases the amount of capacity purchased as price falls, in a manner similar to (but more moderate than) the floor price and proration used in the first seven ISO-NE FCAs. If the ISO imposes such a demand curve, the price of capacity will be increased in periods of capacity surplus. At this time, we cannot determine the probability, timing, and nature of this potential change in the FCM, but experience suggests that such a major change is unlikely to be implemented for several years.

5.4.2 Energy Efficiency Programs and the Capacity Market

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

A program administrator (PA) can choose an approach that ranges between bidding 100 percent of the anticipated demand reduction from the program into the relevant FCAs, to bidding zero percent of the anticipated reduction into any FCA.

- A PA that wishes to bid 100 percent of the anticipated demand reduction from the program into the relevant FCA has to do so when that FCA is conducted, which can be up to three years in advance of the program implementation year. For example, a PA responsible for an efficiency program that will be implemented starting January 2015 would had to have bid 100 percent of the forecast demand reduction for June 2015 onwards from that program into FCA 6, which was held in January 2012. Since a bid is a firm financial commitment, there is an associated financial risk if the PA is unable to actually deliver the full demand reduction for whatever reason. The value of this approach is the compensation paid by ISO-NE, i.e., the quantity of peak reduction each year times the FCA price for the corresponding year.
- If a PA does not bid any of the anticipated demand reduction into any FCA, the program can still avoid some capacity costs if it has a measure life longer than three years.[191] Under this approach, a PA responsible for an efficiency program starting January 2015 simply implements that program. The customers' contribution to the ISO peak load, whenever that occurs in the summer of 2015, would be lower due to the program. This PA's customers would see some benefit from a lower capacity share

[190] 2011 Assessment of the ISO New England Electricity Markets, Patton, et al., Potomac Economics, June 2012, pp. xxi, xxiv, 106, 117–121

[191] In many cases, the PA is a utility; in other cases it is a state agency or other entity. In any case, the reduction in load benefits the customers served by the PA, whether they pay for generation supply through a utility standard-offer supply, an aggregator, or a competitive supplier.

starting in June 2016 (the following year). The reduced capacity requirement will reduce the capacity acquired in future FCAs, so the entire region will benefit from the reduction of capacity purchases.

5.5 Wholesale Electric Capacity Market Simulation Model and Inputs

5.5.1 Description of Forward Capacity Market Simulation Model

AESC 2013 uses a spreadsheet model to develop FCM auction prices for power years from June 2014 onward. The major input assumptions regarding the forecasts of peak load and available capacity in each power year are coordinated with, and consistent with, the input assumptions used in the Market Analytics energy market simulation model.

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

- The FCM changes described in Section 5.4.1 above, with the elimination of the floor in FCA 8 and the imposition of performance standards in FCA 11–13.
- Installed capacity requirements (including the Hydro Quebec capacity credits), estimated from the peak loads in the 2012 CELT and the required reserve margins (ICR ÷ peak load–1) in FCA 7. Both are extrapolated through the analysis period.
- Resources generally continue to bid FCM capacity in a manner similar to their bidding in FCA 7. Most existing resources (renewables, nuclear, hydro, combined-cycle, and modern combustion turbines) continue to bid in as price-takers, at or below the $1/kW-month FCM price at which dynamic delist bids are allowed.
- Generators will submit bids high enough to cover their costs for maintenance, equipment replacement, and environmental compliance, net of their energy margins. If the FCM price falls below that level, the generators will not clear in the FCA and will be free to shut down.
- In the event of a major drop in the New England capacity price, a large amount of capacity now imported to New England from Quebec and New York (including imports from Quebec through New York and New Brunswick) could withdraw from the New England market, and instead sell capacity into the markets in New York or PJM. Some domestic New England capacity could probably also delist to sell capacity out of the region, while continuing to be available to serve energy loads in New England. The same is true in reverse; if New England prices rise, New York and Quebec resources are more likely to bid into New England. It is not clear how appealing other capacity markets will be. Capacity prices in upstate New York have been even lower than in New England, under $0.50/kW-month in 2009–2011, rising to about $2/kW-month in 2012. Prices on Long Island are somewhat higher. The clearing price for capacity imports to PJM has

been volatile, ranging from about \$0.50/kW-month for 2012/13 to about \$4/kW-month for 2015/16, and falling below \$2/kW-month in the May 2013 auction for 2016/17.[192] Both New York and PJM are likely to experience large amounts of generation retirement (mostly of coal plants) in the next several years.[193] While some of those retirements are reflected in PJM's latest forward auction, New York's prices do not reflect future retirements at all.

- FCA 7 cleared at the floor price with over 3,000 MW of excess capacity. This surplus would cause the capacity price in FCA 8 to fall substantially with the removal of the price floor, unless the factors listed above result in delisting and retirement of a large amount of capacity.
- Once the existing surplus no longer exists, due to retirements and load growth, FCM prices would be determined by the price of new peaking units under long-term contracts, net of energy profits and operating-reserve revenues. Following ISO-NE's estimate, we set this price at \$10/kW-month in 2017 dollars, or \$9.28/kW-month in 2013 dollars.[194] Capacity will be added preferentially in the areas with the lowest reserves and the highest market prices, gradually equalizing reserves across the region. Connecticut is most likely to have energy and possibly FCM prices higher than average, and Maine is the zone most likely to have energy and possibly effective FCM prices below average.
- Assumptions regarding FCM prices will be based upon the slope of the supply curve. We assume that the average slope of future supply curves will equal the slope from auction round 4 (80 percent of CONE, the highest price at which the ISO allows dynamic delisting of existing resources) to the bottom of FCA 7 supply curve, or about \$0.0014/kW-month/MW.
- While the ISO will run the auctions for all eight pricing zones (three zones for Massachusetts, plus the five other states), three factors will greatly reduce the probability of the pricing separating among zones:

    1. Existing and planned transmission additions, including the remaining components of the NEEWS project (increasing capacity into Connecticut by 1,000 MW in 2016 and 2017 and bringing the 745 MW Lake Road plant into the Connecticut capacity zone),[195] and the

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[192] Differences in the capacity markets in the three regions (New England, New York, and PJM) make precise comparisons difficult.

[193] The drop in prices in the latest PJM auction is partly the result of imports from MISO and other areas that will also experience significant retirements over the next few years.

[194] Forward Capacity Market Redesign Compliance Filing and Request for Waiver of Compliance Obligation, ISO-NE, December 3, 2012, Docket Nos. ER10-787, at 10.

[195] "the New England East-West Solution (NEEWS) transmission project, scheduled for completion in 2016, …would allow Connecticut to meet its Transmission Security Analysis requirement even if all fossil steam units in Connecticut retired" (2012 Integrated Resource Plan for Connecticut, Connecticut Department of Energy and Environmental Protection, June 14, 2012, p. 11).

Greater Boston transmission upgrades, increasing capacity into NEMA by 800–1,000 MW by 2018;[196]

2. Retirement of some of the surplus capacity in Maine; and
3. The construction of the Footprint plant, eliminating the shortfall in NEMA capacity.[197]

AESC 2013 uses these assumptions to estimate FCM prices for power years from June 2017 onward. We start with the capacity that cleared in FCA 7, adding the capacity and subtracting the retirements described in section 5.2.3, Generating Unit Retirements. We compare the resulting capacity available to bid in each power year to the future ICR.

5.5.2 Values for Input Assumptions to FCM Model

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

Our analysis is based on the ICR values established by the ISO for the FCAs and the follow-up Annual Reconfiguration Auctions (ARAs). Exhibit 5-9 shows the reserve margin (ICR ÷ peak load) for each FCA and ARA to date, with a line connecting the values for each capacity year for which an ARA has occurred.[198] There appears to be an upward trend of about 0.8 percent per year in the estimates since 2011/12, but recent estimates have flattened out.

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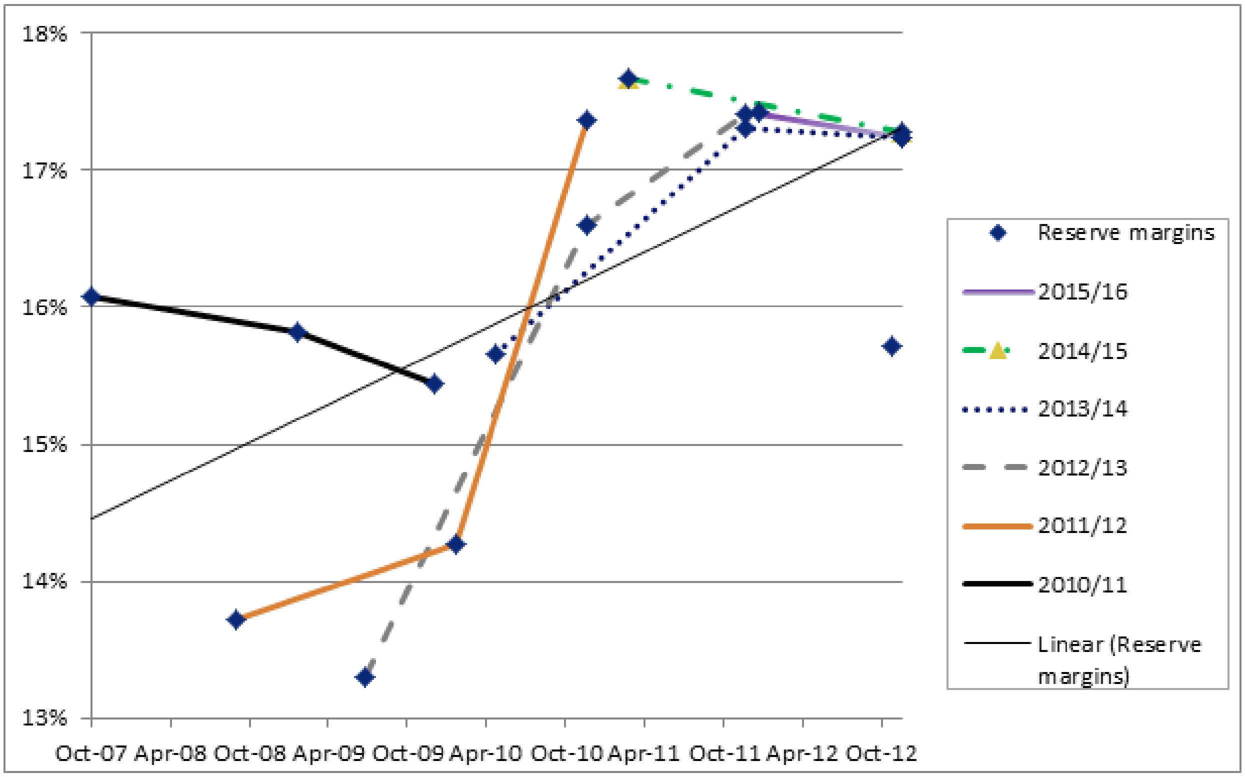
[196] Exhibit DPU-G-1, D.P.U. 12-77, November 26, 2012.

[197] Zonal capacity balances and the effect on capacity pricing are subject to even greater uncertainty than regional capacity prices, for several reasons. First, the ISO is considering the revision of its procedures for defining capacity zones, so prices may be set for zones that do not currently exist (ISO New England's Strategic Transmission Analysis, New England Electricity Restructuring Roundtable: Generation Retirement Study & 2020 Resource Options, Stephen Rourke, June 14, 2013). Second, Footprint may not be built, which could result in higher FCM prices in NEMA for some additional years. Third, while the failure of Footprint could result in high prices for NEMA in some future FCAs, planned transmission upgrades would add some 800–1,000 MW of NEMA import capacity. Fourth, some strategic bidding may be possible in some situations. For example, if regional prices were to fall very low (and neither Footprint nor transmission are built), the owner of Mystic might be able to maintain slightly higher prices in NEMA(and hence for Mystic 8 and 9) by finding an excuse to post a static delist bid for Mystic 7, depending on the ISO's mitigation decisions.

[198] "Summary of ICR, LSR & MCL for FCM and the Transition Period," ISO-NE, April 15, 2013.

Exhibit 5-9. Required Reserve Margins by Capacity Year and Filing Date



For AESC 2013, we assume that future required reserve margins will be 17.2 percent, the average of the eight ICRs set between 2011 and 2012. The value of the HQICCs has also varied from 911 MW to 1,400 MW, with an average value in 2011 through 2012 analyses of 992 MW.

The net ICR that must be acquired in each FCA is the forecast peak load plus the peak load multiplied by the reserve margin, and minus the HQICCs. Exhibit 5-10 summarizes the peak load, ICR, and Net ICR we assume for our Base Case for each power year.

Exhibit 5-10. Derivation of Net Installed Capacity Requirement (MW)

Year Starting	Peak Load	ICR	NICR
	a	b=a*1.172	c=b-992
2016	29,400	34,457	33,465
2017	29,895	35,037	34,045
2018	30,275	35,482	34,490
2019	30,605	35,869	34,877
2020	30,930	36,250	35,258
2021	31,255	36,631	35,639
2022	31,605	37,041	36,049
2023	31,958	37,455	36,463
2024	32,315	37,874	36,882
2025	32,677	38,297	37,305
2026	33,042	38,726	37,734
2027	33,412	39,159	38,167
2028	33,786	39,597	38,605
2029	34,163	40,040	39,048
2030	34,546	40,487	39,495
Notes: Load from Exhibit 5-2. Required Reserve: 17.20% HQ ICCs = 992 MW			

We assume that the capacity price for each future power year will be determined by the difference between the Net ICR and the amount of capacity available, based on the historical relationship between the price in each round of FCA 7 and the amount of capacity offered at that price. For prices lower than those observed in FCA 7, we extrapolated the slope of the FCA 7 supply curve.

Exhibit 5-11 shows the lower portions of the supply curves for FCAs 2 through 7. We do not include the supply curve for FCA 1 because it was far to the left of the other supply curves (prices were higher than for the later FCAs, at much lower supply levels), and was truncated by a $4.50/kW-year floor price. The flat section between the third and fourth points from the left of each supply curve (the relatively flat portion of the curve) represents the point at which existing resources were allowed to dynamically delist, without prior ISO-NE approval.

Exhibit 5-11. Supply Curves, FCA #2 to #7

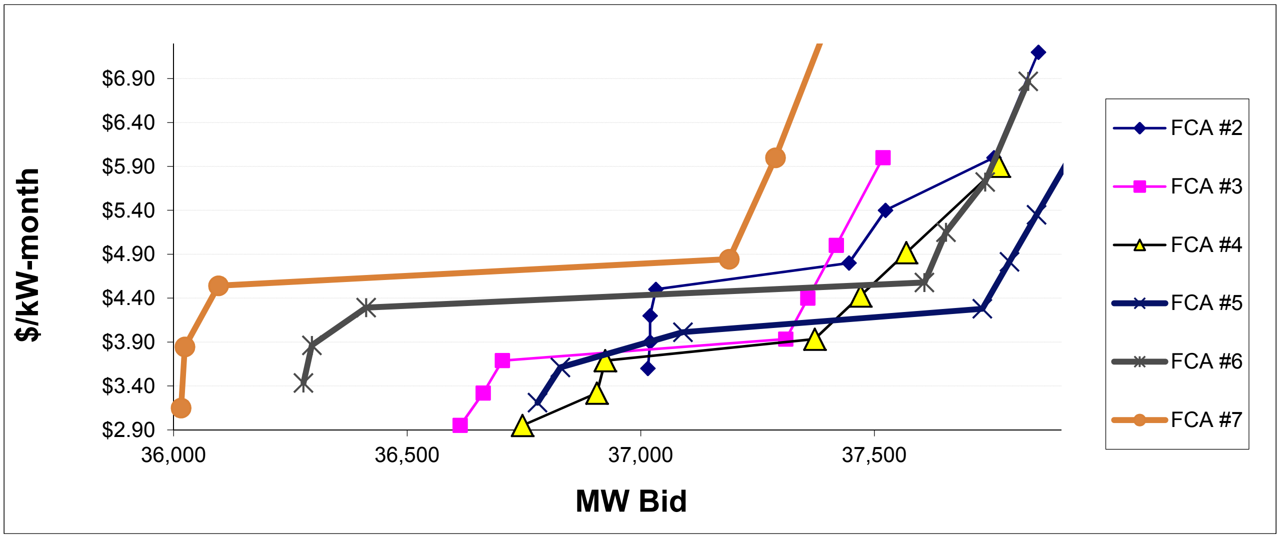


Exhibit 5-12 extrapolates the price trend of FCA 7 to zero price.

Exhibit 5-12. FCA 7 Supply Curve, Extrapolated to Zero Price

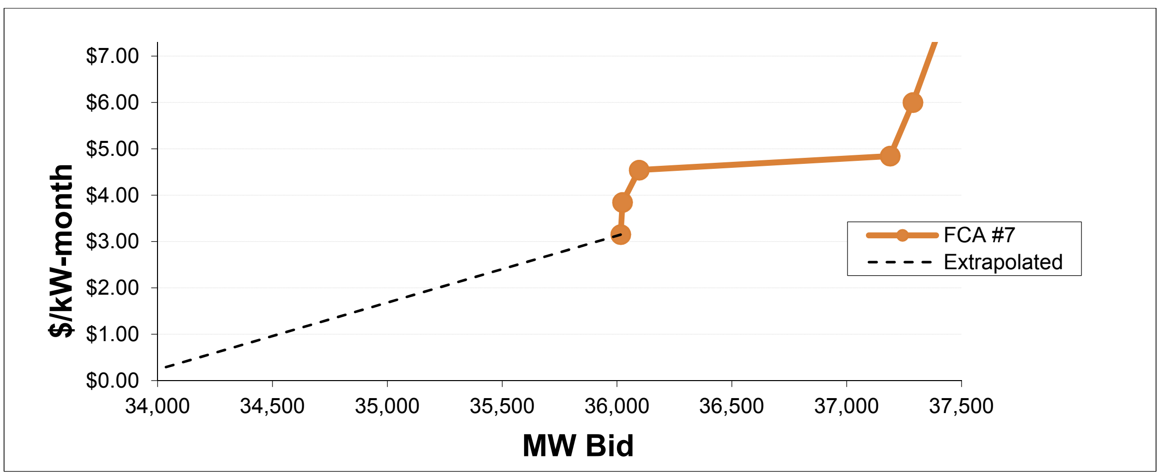


Exhibit 5-12 illustrates how extrapolating the price trend of the last four rounds of FCA 7 indicates that the market price would have to fall by about $0.144/kW-month to reduce supply by about 100 MW, below the 36,016 MW that cleared at FCA 7 floor price.

For AESC 2013, we note several factors that are different between FCA 7 and future FCAs for the purpose of our analysis:

- FCA 7 included energy-efficiency demand resources that we are eliminating from our analysis. Between FCA 3 and FCA 7, the energy-efficiency programs that cleared as on-peak and seasonal-peak resources increased from about 1,000 MW to about 1,550 MW, or a total of 550 MW.[199] A small amount of the growth in cleared energy-efficiency resources is from pre-2014 projects that were not bid into FCA 3.[200] On the other hand, some energy-efficiency resources bid into FCA 3 will have retired by FCA 7. We assume that the 210 MW of new energy-efficiency bid into FCA 3 will be completed by 2013 and another 80 MW of energy-efficiency that will be completed by 2013 will be bid into auctions from FCA 4 onward. Thus we reduce the 550 MW by 80 MW for a total of 470 MW.
- Peak load grows over time in the AESC 2013 Base Case of no new energy efficiency.
- We expect considerable retirements of generation in 2017 and beyond as detailed in section 5.2.3.
- A declining capacity price in ISO-NE would tend to result in some capacity resources that were sold into New England in FCA 7 being diverted to New York or PJM, while an increasing price would cause additional resources to bid into the New England market.
- Renewable resources above those in FCA 7 will be added to meeting RPS requirements, as discussed in section 5.2.4. Without new energy-efficiency programs, the amount of renewables would be higher than is likely in the real world.

5.6 Computation of Avoided Capacity Price

Exhibit 5-13 summarizes these adjustments to the demand-supply balances and the extrapolated FCM price. As retirements tighten the capacity market, the price of capacity would rise, attracting imports, additional demand response, and low-cost expansion of existing resources, until the capacity price reaches the cost of new peaking capacity.

It is important to note that the capacity prices in Exhibit 5-13 apply for the AESC 2013 no-new-efficiency Base Case. With planned energy-efficiency peak reductions, the FCA prices are likely to be on the order of $1/kW-month for FCA 8 through FCA 10, rising only as retirements increase around 2020 (or perhaps earlier, as lower capacity and energy prices accelerate retirements).

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[199] These numbers are approximate, since some of the resources cannot be clearly differentiated between energy-efficiency and other resources, for example load shifting and distributed generation.

[200] United Illuminating and Efficiency Vermont report bidding 100 percent of expected load reductions into the first capacity auction for which they are eligible, while National Grid and Northeast Utilities report that they bid somewhat less than 75 percent to 80 percent of their expected load reductions for 2012 into FCA3.

Exhibit 5-13. FCA Price Extrapolation

FCA	Year Starting	NICR	Increase from FCA 7	Cumulative Retirements	Renewable Additions	Net Surplus at $3.15	FCM Prices $/kW-month		
							Actual Nominal$	Extrapolated 2016$	2013$
		a	b	c	d	e	f	g	h
4	2013						$2.95		$2.95
5	2014						$3.21		$3.15
6	2015						$3.43		$3.30
7	2016	32,968					$3.15		$2.97
8	2017	34,045	1,077	1,897	101	-295		$3.57	$3.30
9	2018	34,490	1,522	1,897	235	-607		$4.02	$3.72
10	2019	34,877	1,909	1,897	325	-903		$4.45	$4.11
11	2020	35,258	2,290	4,230	422	-3,520		$8.22	$7.59
12	2021	35,639	2,671	5,256	501	-4,848		$10.13	$9.24
13	2022	36,049	3,081	6,332	536	-6,299		$12.22	$9.24
14	2023	36,463	3,495	6,332	653	-6,596		$12.65	$9.24
15	2024+								$9.24

Notes:	
a	From Exhibit 5-10
b	[1] - 32,968 MW for FCA 7
c	From Exhibit 5-4
d	Energy values from Exhibit 6-28 converted to capacity values
e	3,048 MW of FCA7 surplus – [2] –[3] + [4] – 470 MW of post-2014 efficiency bid into FCA 7
f	From Exhibit 5-8
g	$3.15 - [5] × 0.00144
h	deflated at 2%

Starting in 2021, AESC 2013 assumes that FCM prices would be determined by the price of new peaking units under long-term contracts, net of energy profits, and operating-reserve revenues. Following ISO-NE's estimate, we set this price at $9.24/kW-month in 2013 dollars.[201]

The avoided cost at the meter is equal to the avoided wholesale electric capacity price, increased by:

- The reserve margin requirement (17.2%)
- Distribution losses (which ISO-NE estimates at 8%)[202]

[201] Forward Capacity Market Redesign Compliance Filing and Request for Waiver of Compliance Obligation, ISO-NE, December 3, 2012, Docket Nos. ER10-787, at 10.

[202] Various PAs may have different estimates of marginal distribution losses at peak, which would determine the avoided costs to the PAs customers.

- Losses on the transmission system (1.5%)
- The Wholesale Risk Premium (for which we use a default value of 9%; see section 5.2.6)

As noted earlier, the actual amount of wholesale electric capacity costs avoided by kW reductions from energy efficiency measures will vary according to the approach that the PA responsible for those measures takes towards the FCM. PAs achieve the maximum avoided cost by bidding the entire anticipated kW reduction from measures in a given year into the FCA for that power year. However, PAs have to submit those bids when the FCA is held, which is approximately three years in advance of the applicable power year. Some expected load reductions may not be bid into the first FCA for which the reduction would be effective, due to uncertainty about future program funding and savings.[203] Information provided by various PAs indicates that the majority of expected savings will be bid into the first applicable auction (75 percent to 100 percent, depending on PA), with the remainder bid in over the next two years. Exhibit 5-14 summarizes the FCA price to load at wholesale, as well as the avoided capacity cost at the meter.

[203] PAs also avoid capacity costs from kW reductions that are not bid into FCAs, since those kW reductions lower actual demand, and ISO-NE eventually reflects those lower demands when setting the maximum demand to be met in future FCAs and the allocation of capacity requirements to load. However, the total amount of avoided capacity costs is lower because of the time lag, up to four years, between the year in which the kW reduction first causes a lower actual peak demand and the year in which ISO-NE translates that kW reduction into a reduction in the total demand for which capacity has to be acquired in a FCA. Since the load reduction in one year will affect the allocation of capacity responsibility in the next year, the PA's customers experience a one-year delay in realized savings that are not bid into the auctions at all.

Exhibit 5-14. FCA Price and Avoided Capacity Cost (2013 dollars)

Year Starting	FCM Price	Avoided Capacity Cost at Meter	
	$/kW-month	$/kW-month	$/kW-year
	a	b=a*(1+reserve)*(1+ISO loss)*(1+PTF)*(1+WRP)	c=b*12
2013	$2.95	$4.13	$49.59
2014	$3.15	$4.41	$52.87
2015	$3.30	$4.62	$55.47
2016	$2.97	$4.16	$49.88
2017	$3.30	$4.62	$55.50
2018	$3.72	$5.21	$62.48
2019	$4.11	$5.76	$69.10
2020	$7.59	$10.63	$127.59
2021	$9.24	$12.94	$155.25
2022	$9.24	$12.94	$155.25
2023	$9.24	$12.94	$155.25
2024	$9.24	$12.94	$155.25
2025	$9.24	$12.94	$155.25
2026	$9.24	$12.94	$155.25
2027	$9.24	$12.94	$155.25
2028	$9.24	$12.94	$155.25
2029	$9.24	$12.94	$155.25
2030	$9.24	$12.94	$155.25
17.2%	reserve margin requirement		
8%	ISO default distribution losses		
1.5%	PTF losses		
9%	default wholesale risk premium		

The cost of capacity in each month is determined by load in two ways. The total cost of capacity purchased is determined by the projected NICR for the current capacity year (which is largely driven by the peak loads in the summer at the beginning of the capacity year); the capacity-market revenues for PA efficiency savings (which benefit consumers) is determined by capacity bid into the current summer; and the allocation of those costs among power consumers is determined by their contributions to the system peak in the previous year. Hence, the total capacity charges for June 2017 through May 2018 will be determined by the loads expected for the summer of 2017, and offset by the energy-efficiency savings bid into FCA 8 for 2017/18 (which is constrained by the 2017 summer load reduction). The allocation of the capacity costs to each PA's customers will be determined by their peak loads in the summer of 2016.

While the costs *paid* in calendar 2017 will include both the capacity rates set in FCA 7 (for January to May 2017) and in FCA 8 (for June to December), the payments in the first five months will simply be delayed payments for the peak loads in summer 2016, and the peak loads in summer 2017 will determine total charges and energy-efficiency revenues for the twelve months from June 2017 through May 2018. We therefore treat the avoidable FCA8 capacity charges as being avoidable by summer 2017 load, rather than treating 2017 peak reductions as saving some mix of FCA 7 and FCA 8 capacity prices.[204] Thus, we do not make any adjustments between power year to calendar year.

5.7 Adjustment of Capacity Costs for Losses on ISO-Administered Pooled Transmission Facilities

There is a loss of electricity between the generating unit and ISO-NE's delivery points, where power is delivered from the ISO-NE administered pooled transmission facilities (PTC) to the distribution utility local transmission and distribution systems. Therefore, a kilowatt load reduction at the ISO-NE's delivery points, as a result of DSM on a given distribution network, reduces the quantity of electricity that a generator has to produce by one kilowatt plus the additional quantity that would have been required to compensate for losses.[205] The energy prices forecast by the Market Analytics model reflect these losses. However, the forecast of capacity costs from the FCM do not. Therefore, the forecast capacity costs should be adjusted for these losses.

ISO-NE does not appear to publish estimates of the losses on the ISO-administered transmission system at system peak. ISO-NE does release hourly values for System Load, which it defines as the sum of generation and net interchange, minus pumping load, and Non-PTF Demand, the term that the ISO uses for the load delivered into the networks of distribution utilities. Losses on the PTF system are thus the difference between the System Load and Non-PTF Demand. While PTF losses probably vary among zones, marginal losses by zone could not be identified using the available data.[206]

AESC 2009 estimated the marginal peak losses on the PFT system for each summer 2006 to 2008 by regressing the system losses against real-time demand for the top 100 summer hours in each year. The marginal loss ratio was 3.4 percent in 2006, 2.0 percent in 2007 and 1.8 percent in 2008. AESC 2009 used the average of the latter two values, or 1.9 percent.

For AESC 2013, we analyzed the system losses against the six days of each year with the most hours of the top 100 hours of load for 2010, 2011, and 2012. The methodology and accompanying exhibits are detailed in Appendix H.

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[204] Summer 2017 peak reductions will also affect the allocation of FCA 9 capacity charges in 2018/19; we have not attempted to reflect this complication.

[205] 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 2013 avoided costs do not include any avoided PTF investments, so marginal losses are relevant in this situation.

[206] Since losses in any zone depend both on loads in that zone and flows into and out of that zone to the rest of the region, marginal losses as a function of load in each zone would be difficult to estimate from historical data.

The results of the regression equations (with all variables in MW) were:

- 2010: PTF Losses = 1.71%
- 2011: PTF Losses = 1.60%
- 2012: PTF Losses = 1.12%

It is not clear whether there is actually a downward trend in the slopes over the years, or whether the differences are random variations in daily conditions, perhaps influenced by the unusual fuel-price relationships in 2012.

Taking into account the daily regression results and the 2010 100-hour regression, AESC 2013 uses a marginal PTF demand loss factor for capacity costs of 1.5 percent.

Chapter 6: Avoided Electric Energy Costs

6.1 Introduction

This chapter addresses avoided electric energy market prices, as well as Renewable Portfolio Standard (RPS) compliance costs that are not embedded in those energy market prices. It describes the methodology and assumptions used to develop projections of avoided energy costs and non-embedded RPS costs, and presents the results of our analyses. This chapter is organized as follows:

- Section 6.2 provides an overview of wholesale energy markets in New England.
- Section 6.3 describes the simulation model used to project avoided electric energy market prices for AESC 2013 (Market Analytics) and the assumptions used by that model.
- Section 6.4 provides an overview of our forecast of avoided electric energy market prices for AESC 2013, and compares those results to AESC 2011. Detailed results for each year of the study period, by zone, are provided in Appendix B.
- Section 6.5 describes our forecast of RPS compliance costs that are not embedded in the wholesale market prices for energy. Detailed renewable energy certificate (REC) price forecasts and avoided RPS costs by state for each year of the study period are provided in Appendix F.

6.2 Wholesale Energy Markets

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

According to the ISO-New England 2010 Annual Market Report (2011, 29–30)[207]:

> The primary objective of the electricity markets operated by ISO New England is to ensure a reliable and economic supply of electricity to the high-voltage power grid. The markets include a Day-Ahead Energy Market and a Real-Time Energy Market. In what is termed a *multi-settlement system*, each of these markets produces a separate but related financial settlement.

[207] We cite from the 2010 report because it has the most concise explanation of the NE markets.

The Day-Ahead Energy Market produces financially binding schedules for the sale and purchase of electricity one day before the operating day. However, supply or demand for the operating day can change for a variety of reasons, including generator reoffers of their supply into the market, real-time hourly *self-schedules* (i.e., generators choosing to be on line and operating at a fixed level of output regardless of the price of electric energy), self-curtailments, transmission or generation outages, and unexpected real-time system conditions. Physically, real-time operations balance instantaneous changes in supply and demand and ensure that adequate reserves are available to operate the transmission system within its limits. Financially, the Real-Time Energy Market settles the differences between the day-ahead scheduled amounts of load and generation and the actual real-time load and generation.

Participants either pay or are paid the real-time *locational marginal price* (LMP) (see below) for the amount of load or generation in megawatt-hours (MWh) that deviates from their day-ahead schedule. This section summarizes the key features of the ISO's Day-Ahead and Real Time Energy Markets, including locational marginal pricing; the factors influencing electric energy supply offers, demand bids, and LMPs; and virtual and real-time trading.

2.1.1 Locational Marginal Prices and Pricing Locations

Locational marginal pricing is a way for wholesale electric energy prices to efficiently reflect the value of electric energy at different locations, accounting for the patterns of load, generation, and the physical limits of the transmission system. In New England, wholesale electricity prices are identified at 900 pricing points (i.e., *pnodes*) on the bulk power grid. If the system were entirely unconstrained and had no losses, all LMPs would be the same, reflecting only the cost of serving the next increment of load. This incremental megawatt of load would be served by the generator with the lowest-cost energy offer available to serve that load, and electric energy from that generator would be able to flow to any node on the transmission system. LMPs differ generally among locations because transmission and reserve constraints prevent the next-cheapest megawatt (MW) of electric energy from reaching all locations of the grid. Even during periods when the cheapest megawatt can reach all locations, the marginal cost of physical losses will result in different LMPs across the system.

New England has five types of pnodes: one type is an external proxy node interface with neighboring balancing authority areas, and four types are internal to the New England system. The internal pnodes include individual generator-unit nodes, load nodes, *load zones* (i.e., aggregations of load pnodes within a specific area), and the Hub. The *Hub* is a collection of locations with a load-weighted price intended to represent an uncongested price for electric energy; facilitate trading; and enhance transparency and liquidity in the marketplace. New England is divided into the following eight load zones: Maine (ME), New Hampshire (NH), Vermont (VT), Rhode Island (RI), Connecticut (CT), Western/Central Massachusetts (WCMA), Northeast Massachusetts and Boston (NEMA), and Southeast Massachusetts (SEMA). Generators are paid the real-time LMP for electric energy at their respective nodes, and participants serving demand pay the price at their respective load zones. The load-zone price is a load-weighted average price of the load-node prices in that zone.

Import-constrained load zones are areas within New England that must use more expensive generators than the rest of the system because local, inexpensive generation or transmission-import capability is insufficient to meet both local demand and reserve requirements. *Export-constrained load zones* are areas within New England where the available resources, after serving local load, exceed the areas' transmission capability to export excess electric energy.

6.3 Wholesale Electric Energy Market Simulation Model and Inputs

6.3.1 The Energy-Market-Simulation Model

Market Analytics is a zonal locational marginal-price-forecasting model that simulates the operation of the energy and operating reserves markets. The simulation engine used is PROSYM. The modeling system and the default data is provided by the model vendor, Ventyx.

The model does not simulate the forward capacity market and, therefore, does not require assumptions regarding the capital costs of new generation capacity and the interconnection costs associated with such capacity. However, the model does require assumptions about the quantity and type of existing and new capacity over the study horizon, fuel prices, and other factors. Section 6.3.2 catalogues the input assumptions to the model.

Zonal Locational Marginal Price-Forecasting Model

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

The smallest location in Market Analytics is a Location (typically representing a utility service territory) which for modeling purposes is mapped into a Transmission Area (TA). A TA may represent one or more Locations. TAs represent sub regions of Control Areas such as ISO New England. TAs 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. PROSYM can also simulate operation in any number of control areas. Groups of contiguous control areas were modeled in order to capture regional impacts of the dynamics under scrutiny.

PROSYM uses highly detailed information on generating units. Data on specific units in the Market Analytics database are based on data drawn from various sources including the U.S. Energy Information Administration, U.S. Environmental Protection Agency, North American Electric Reliability Corporation, Federal Energy Regulatory Commission (FERC), and ISO-New England databases, as well as various trade press announcements and Ventyx's own professional assessment. Total existing capacity in the Market Analytics database was compared with that of ISO-NE CELT 2012 and found to be reasonably consistent, although we made a few adjustments to reflect retirements as detailed below.

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

Based upon hourly loads, PROSYM determines generating unit commitment and operation by transmission zone based upon economic bid-based dispatch, subject to system operating procedures and constraints. PROSYM operates using hourly load data and simulates unit dispatch in chronological order. In other words, 8,760 distinct hourly load levels are used for each TA for each study year. The model begins on January 1st and dispatches generating units to meet hourly loads. 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 TA 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 or the spot price of gas at the location closest to the plant, variable operating and maintenance costs, and opportunity cost of tradable permits for air emissions.

PROSYM does not make capacity-expansion decisions internally. Instead, the user specifies capacity additions, a practice that increases transparency and allows the system-expansion plans to be specified to reflect non-market considerations. As discussed in more detail below, 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, particularly for peak-load periods. PROSYM models generating units with a much higher level of detail, including inputs for unit specific ramp rates, minimum up/down times, and multiple capacity blocks, all of which are critical for accurately modeling hourly prices. This modeling capability enabled production of locational prices by costing period in a consistent manner at the desired level of detail.

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

6.3.2 Input Assumptions to Electric-Energy-Price Model

Our projection of avoided electric energy market prices incorporates several assumptions that are shared with other analyses in AESC 2013. Exhibit 6-1 shows the input assumptions to the Market Analytics locational-price-forecasting model that are detailed in other chapters.

Exhibit 6-1. Assumptions shared with other AESC 2013 analyses

Assumption	Chapter/Section
Forecasted annual peak demand and total energy	Chapter 5, Electric Capacity
Fuel prices	Chapter 2, Natural Gas; and Chapter 3, Fuel Oil and Other Fuels
Transmission resources	Chapter 5, Electric Capacity
Generating unit retirements	Chapter 5, Electric Capacity
Resource additions	Chapter 5, Electric Capacity
Emission allowance costs	Chapter 4, Embedded and Non-Embedded Environmental Costs
Wholesale risk premium	Chapter 5, Electric Capacity

Input assumptions to the Market Analytics model that are detailed in this chapter include: market rules and topology; hourly load profiles; generating unit characteristics for thermal, nuclear, and conventional hydro and pumped storage resources; and demand-response resources.

Market Rules and Topology

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

<u>Marginal-Cost Bidding</u>

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

<u>Installed Capacity</u>

Installed-capacity requirements for the resource-addition model include reserve requirements established by ISO-NE on an annual basis. Current estimates of the reserve-margin and installed-capacity requirement (with and without the Hydro Quebec (HQ) installed capacity credits) are described in Chapter 5, Avoided Electric Capacity Costs. Installed capacity for the energy model in each model year is consistent with the values assumed in the FCA analysis, although the values are not the same, due to imports and exports.

Ancillary Services

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

Electric Model Topology

Market Analytics represents load and generation areas at various levels of aggregation. Assets within the model, including physical or contractual resources such as generators, transmission links, loads, and transactions, are mapped to physical locations which are then mapped to TAs. Multiple TAs are linked by transmission paths to create the control area. The load and generation areas modeled for AESC 2013 are presented in Exhibit 6-2.

CELT 2012 forecasts load for 13 subareas which correspond to the locations used in the Market Analytics data. Our modeling maps those 13 load subareas into 10 TAs, which is the level of detail required to report results for the 14 reporting zones specified for AESC 2013.[208] Neighboring regions that are modeled in this study are New York, Quebec, Ontario, and the Maritime Provinces.[209]

Areas outside of New England are represented with a high level of zonal aggregation to minimize model run time.

[208] We produce results for four of the AESC zones by aggregating the results for certain of the areas we model. For example, the results for Massachusetts are the aggregate results for SEMA, WCMA, and NEMA. The results for the aggregate zones are based on the weighted averages of their constituent subzones.

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

Exhibit 6-2. Load Areas Used to Model New England

AESC Reporting Zones [210]		Load Area CELT SubArea	Market Analytics Modeling Areas	AESC Zone Mapping
1	Maine	ME + BHE + SME	BHE + ME Central + ME Southwest	Direct
2	Vermont	VT	Vermont	Direct
3	New Hampshire	NH	New Hampshire	Direct
4	Connecticut (Statewide)	CT +SWCT + NOR	=	*Aggregated*
5	Massachusetts (Statewide)	BOST + CMA/NEMA + SEMA + WMA	=	*Aggregated*
6	Rhode Island	RI	Rhode Island	Direct
7	SEMA (Southeast Massachusetts)	SEMA	MA Southeast	Direct
8	WCMA (West-Central Massachusetts)	WMA	MA Western	Direct
9	NEMA (Northeast Massachusetts)	CMA/NEMA	MA Central & Northeast	Direct
10	Rest of Massachusetts (Massachusetts excluding NEMA)	BOST + SEMA + WMA	=	*Aggregated*
11	Norwalk/Stamford	NOR	CT Norwalk	Direct
12	Southwest Connecticut, including Norwalk/Stamford	SWCT + NOR	=	*Aggregated*
13	Southwest Connecticut, excluding Norwalk/Stamford	SWCT	CT Southwest	Direct
14	Rest of Connecticut (Connecticut excluding all of Southwest Connecticut)	CT	CT Central-Northeast	Direct

This study 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 Edward Island), and Quebec. These external markets are modeled in the same manner and simultaneously with New England. The Market Analytics database is used as the primary data source for external regions. New capacity is added to meet RPS requirements, and generic gas capacity is added based on the same methodology that is used in New England. Consistent assumptions are also used for fuel prices, with the primary one being for natural gas.

The forecasts of electricity prices for each load area from the model are mapped and load-weighted into the AESC zones.

Load Forecast and Hourly Load Profiles

Forecasts of peak demand and energy by month for each of the areas modeled in Market Analytics were derived from CELT 2012, as described in Chapter 5, Avoided Electric Capacity Costs. Historical profiles for

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210 The AESC reporting zones are the six New England states and eight subareas representing various parts of Connecticut and Massachusetts.

each utility were developed by Ventyx for Market Analytics based on a set of annual historical load shapes. Hourly load profiles based on historical profiles were calculated for each load serving entity. Loads were then mapped to TAs based on location ratios. Hourly load data for future years were scaled based on forecasted peak demand and energy.

The area ISO-NE load forecasts (shown in Exhibit 6-3 and Exhibit 6-4) are used to produce the area loads required for the Market Analytics modeling.[211]

Exhibit 6-3. Summer Peak Forecast by Model Load Area

Load Area	2013 (MW)	2020 (MW)	2017-2021 CAGR	2028 (MW)
BHE	302	336	0.95%	370
ME	906	1,022	1.17%	1,148
SME	697	758	0.64%	816
NH	2,086	2,404	1.32%	2,700
VT	1,182	1,318	1.01%	1,470
BOSTON	5,482	6,174	1.13%	6,867
CMA/NEMA	1,653	1,869	1.20%	2,086
WMA	2,079	2,344	1.16%	2,613
SEMA	2,850	3,256	1.36%	3,676
RI	2,530	2,921	1.61%	3,367
CT	3,351	3,734	0.83%	4,065
SWCT	2,270	2,532	0.84%	2,758
NOR	1,240	1,376	0.77%	1,489
ISO-NE	**26,629**	**30,043**	**1.12%**	**33,405**
2028 values were developed by escalating 2021 values by the 2017-2021 Compound Annual Growth Rate.				
Loads include the effects of 2013 Passive Demand Resources.				

211 i.e., BHE, ME and SME are combined into Maine. Connecticut is represented by three load areas CT, SWCT and NOR that are aggregated in different ways

Exhibit 6-4. Energy Forecast by Model Load Area

Load Area	2013 (GWh)	2020 (GWh)	2017-2021 CAGR	2028 (GWh)
BHE	1,788	1,939	0.74%	2,106
ME	5,560	6,116	0.93%	6,737
SME	3,982	4,232	0.44%	4,491
NH	10,536	11,556	0.94%	12,639
VT	6,815	7,350	0.75%	8,058
BOSTON	27,045	29,377	0.90%	32,189
CMA/NEMA	8,096	8,791	0.89%	9,608
WMA	10,557	11,419	0.83%	12,434
SEMA	13,945	15,424	1.15%	17,176
RI	11,652	12,961	1.18%	14,492
CT	15,718	16,981	0.68%	18,374
SWCT	10,714	11,592	0.70%	12,566
NOR	5,827	6,265	0.61%	6,745
ISO-NE	**132,236**	**144,003**	**0.87%**	**157,595**
2028 values were developed by escalating 2021 values by the 2017-2021 Compound Annual Growth Rate.				
Loads include the effects of 2013 Passive Demand Resources.				

Generic Generating Unit Operating Characteristics

Thermal Units

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

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

The Market Analytics data are based on a variety of reliable public sources such as EIA reports and FERC filings, although some sources are proprietary.[212]

Exhibit 6-5. Characteristics of Market Analytics Generic Unit Additions

Characteristics	NG CC	NG CT
Typical Size	375	180
Heat Rate (Btu/kWh)	6,625	10,500
Variable O&M costs (2013 dollars per MWh)	$2.18	$3.56
Availability	85.2%	92.3%
NO_X (lb/MMBtu)	0.01	0.03
SO_2 (lb/MMBtu)	0	0
CO_2 (lb/MMBtu)	120	120
Notes: NG CC Natural Gas Combined Cycle NG CT Natural Gas Combustion Turbine		

Nuclear Units

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

Exhibit 6-6. New England Nuclear Unit Capacity and License Expirations

Nuclear Unit	Load Area	Capacity (MW)[a]	License-Expiration Year[b]
Millstone 2	CT	875	2035
Millstone 3	CT	1,225	2045
Pilgrim	SEMA	677	2032
Seabrook	NH	1,246	2030
Vermont Yankee	VT	604	2032
[a]CELT 2012 Summer capability; [b]U.S. Nuclear Regulatory Commission			

Of the five operating nuclear units in New England, the Nuclear Regulatory Commission (NRC) has relicensed the Pilgrim unit and Millstone 2 and 3, along with 60 other reactors outside New England, without denying a single extension. Based on this track record and the lack of evidence suggesting that the NRC would deny the license renewals for any of these plants, we assume that all of the nuclear

[212] Specific details about the Market Analytics Model inputs can be requested and provided under appropriate confidentiality agreements.

plants in New England will receive NRC licenses to operate for another 20 years, through the entire modeling period.

As discussed in Chapter 5, the NRC recently granted Vermont Yankee a 20-year license extension, but the plant also requires state permission to operate past March 2012. The future is somewhat uncertain for this plant, but our expectation is that it will cease operation in 2015.

Pilgrim's operating license was renewed by the NRC in March of 2012 for 20 more years. Its design and vintage is very similar to that of Vermont Yankee and Fukushima Daiichi, and it is also located on the coast. Serious earthquakes along the Massachusetts coast are very rare, but not unknown. Pilgrim is thus among the U.S. nuclear units most likely to be affected by increased safety requirements following the Fukushima disaster, either as part of an extended relicensing review or subsequently. Many such measures (hardening of spent-fuel pools and back-up power supply, transferring spent fuel to dry casks, building higher seawalls) would have little effect on Pilgrim's power output. Nor are those measures likely to result in economic retirement of the plant. On the other hand, if the NRC were to require fundamental design changes in the Mark I reactors, Pilgrim would likely retire. The NRC has rarely required such major modifications to licensed reactors. We thus assume that Pilgrim will continue operating.

Conventional Hydro and Pumped Storage Unit Characteristics

The Market Analytics database was used as the primary source for 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 over the horizon of a week, subject to hourly constraints for minimum and maximum generation, and weekly constraints for ramp rates and total energy. Although the load shape they intend to level is the overall system load, a hydro station can be scheduled against the load of a specified Transmission Area or control area.

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

Demand Resources

Demand resources were included in the model consistent with the ISO-NE 2012 Regional System Plan (RSP) and the Forward Capacity Auction results (through FCA 7). These resources were modeled as generating units that act as load reduction resources that are committed only if all other available generating resources are operating at full capacity and load is about to be lost. These resources do not set the marginal clearing price.

6.3.3 Model Calibration

Since a key objective of this study is the calculation of avoided electric energy costs, we took steps to ensure that the model is forecasting energy market prices accurately. The calibration approach we use is to compare the prices forecast by the model to electric energy historical and futures prices at the ISO-NE hub. The ability to make this comparison is complicated by the requirement for the model to forecast prices assuming no continuation of energy-efficiency activities, i.e., no “new” reductions. The complication is that the electric-energy future prices will reflect the expectations of buyers and sellers in the actual market, who are likely assuming continuation if not escalation of existing efficiency programs.

Consequently, we model the current market situation using the loads that reflect the energy efficiency resources in place through 2013. We then make appropriate model adjustments (e.g., bidding strategies, etc.) to reasonably match the electric-energy historical and futures prices at the ISO-NE hub over 2012 and 2013. Detailed results of our calibration analyses are shown in sections 6.4.1 and 6.4.2.

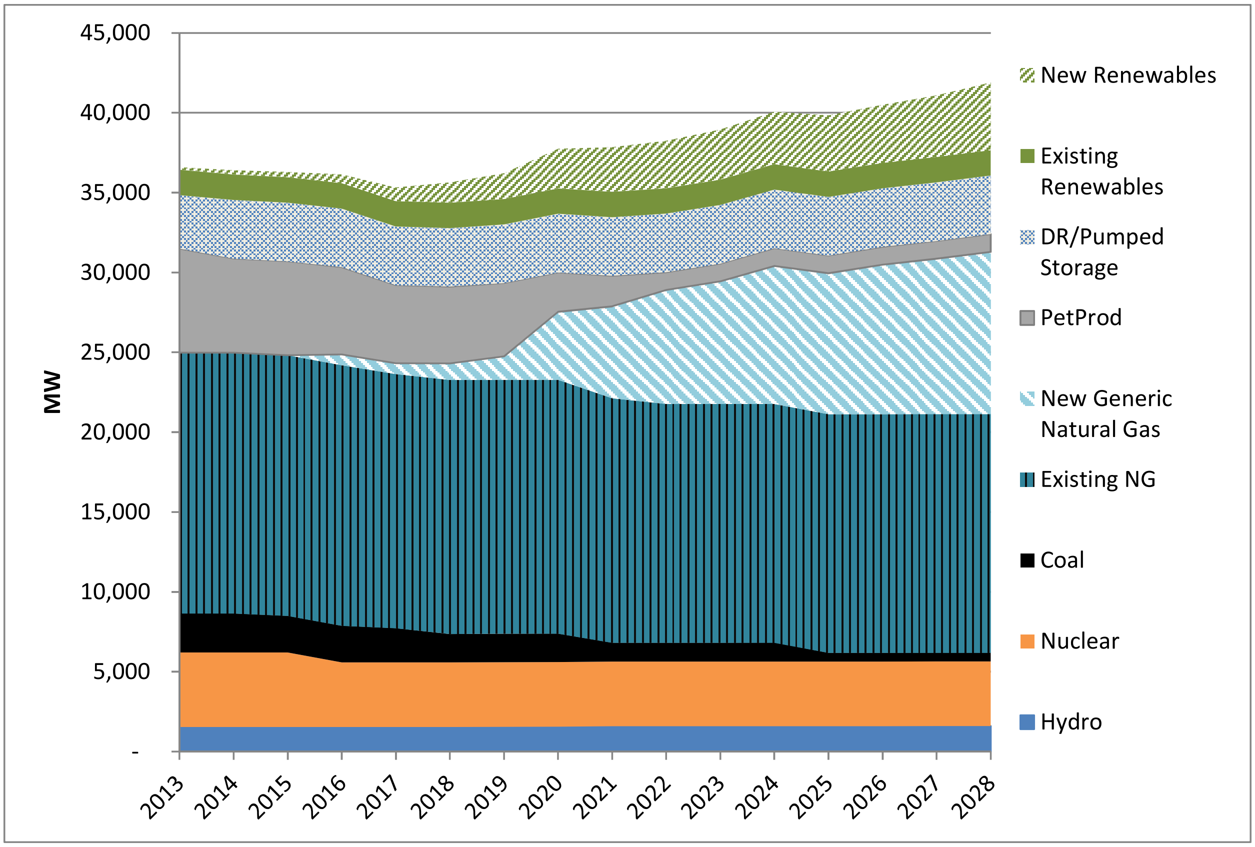
6.4 Avoided Electric Energy Costs

6.4.1 Forecast of Energy Prices Assuming No New DSM

The projected wholesale energy prices for the AESC 2013 Base Case presented below are outputs from the Market Analytics simulation model for a hypothetical future in which no new energy efficiency resources are implemented after 2013. As such, they represent the wholesale price of avoided energy in a future with no new efficiency. These prices are **NOT** meant to be used as energy price forecasts in the most likely future, i.e., one in which there will be some level of new energy efficiency measures installed each year over the planning horizon.

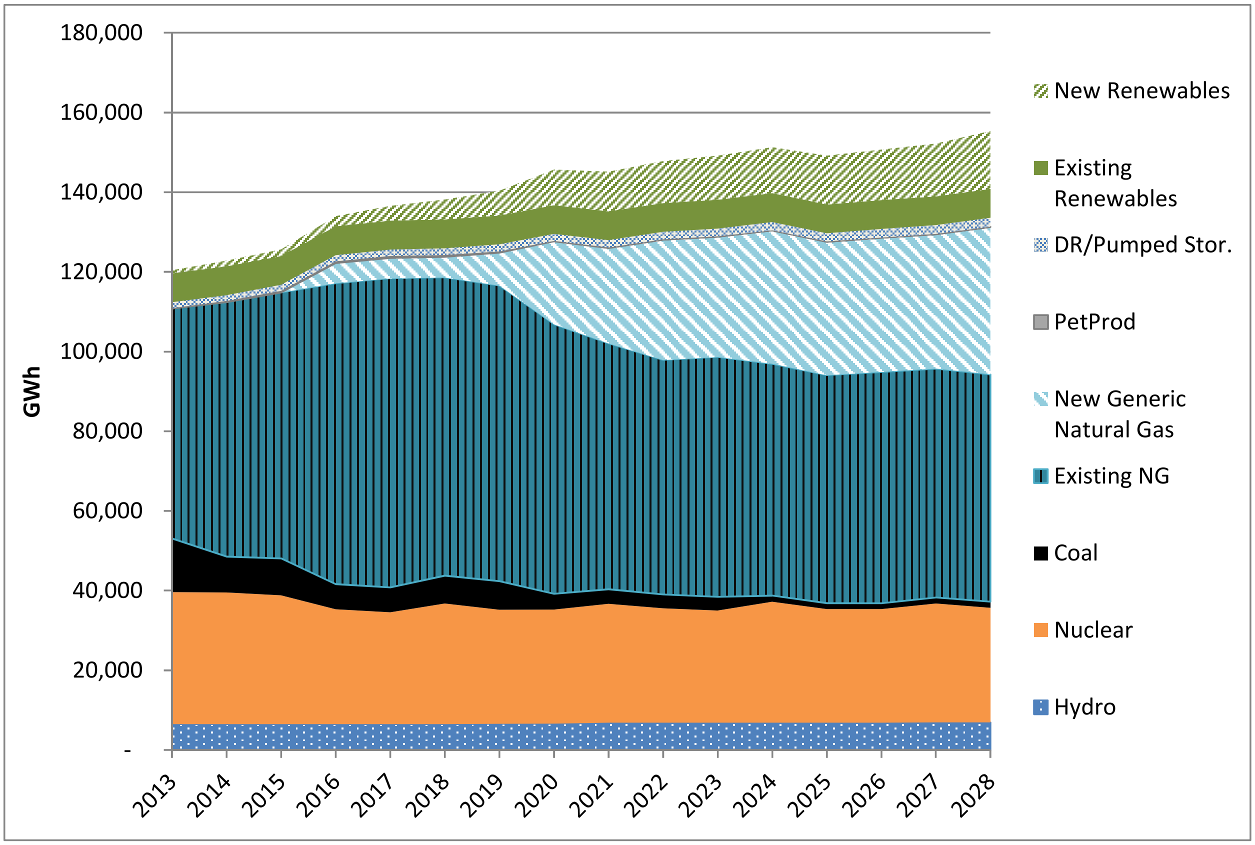
The projected level and mix of capacity in the Base Case is presented in Exhibit 6-7. New capacity additions include renewable resources to comply with RPS requirements, as well as new natural gas generators added to meet energy and reserve margin requirements. Substantial portions of the existing oil (Pet Prod) and coal capacity are forecasted to retire before 2025. Because of the relatively high price of oil compared to other fuels, these generating plants are now rarely used.

Exhibit 6-7. Base Case Capacity by Source (MW)



The projected level and mix of generation in the Base Case is presented in Exhibit 6-8. Generation from nuclear declines slightly with the closure of Vermont Yankee in 2016, and coal generation declines substantially as most units are retired. Generation from natural gas is the dominant resource, and renewable generation increases substantially in compliance with RPS requirements. The generation from oil (Pet Prod) plants is negligible on this graph.

Exhibit 6-8. Base Case Generation by Source (GWh)



Forecast of Wholesale Electric Energy Prices

For AESC 2013, we present streams of energy values for all of New England in the form of the hub price. This is separately presented for four periods—summer on-peak, summer off-peak, winter on-peak, winter off-peak.[213]

The hub price representing the ISO-NE Control Area is located in central Massachusetts, and the Central Massachusetts zone in the Market Analytics model is used as the proxy for that location. Exhibit 6-9 presents summer and winter, on-peak and off-peak energy prices as produced by the model through 2028 for Central Massachusetts.[214] The higher winter on-peak price in the initial years represents the current high winter natural gas basis prices, which moderate as more pipeline capacity is added.

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[213] Summer is defined as the four months June through September, with winter the other eight months. By combining the true winter season within Spring and Fall, the effects of high prices during the coldest months are moderated. For AESC 2013, "on-peak" hours are defined as 7 am – 11 pm, consistent with ISO-New England's definition. (See: http://www.iso-ne.com/support/training/glossary/index-p5.html.) This is a small deviation from the scope of work requested by the AESC 2013 Study Group, which defined on-peak hours as 6 am to 10 pm.

[214] Beyond 2028, AESC 2013 escalates wholesale energy prices based on the compound annual growth rate of the last five years of values from the energy model. Escalation rates are specific for each of the four costing periods.

Exhibit 6-9. Wholesale Energy Price Forecast for Central Massachusetts

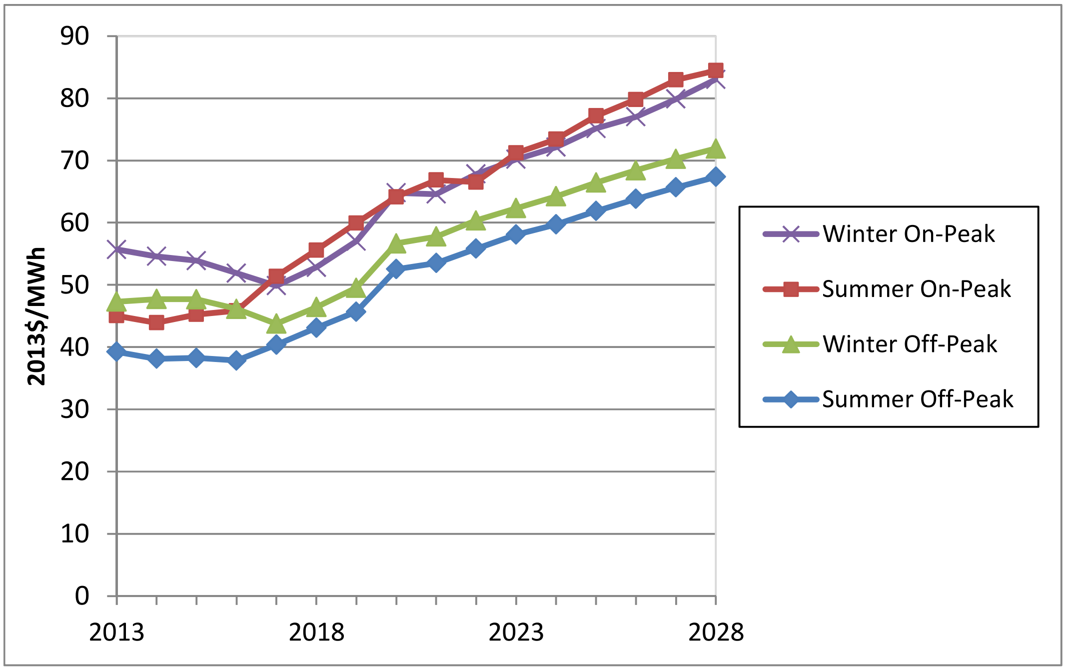


Exhibit 6-10 provides these prices in tabular form.

Exhibit 6-10. Wholesale Energy Price Forecast for Central Massachusetts (2013$/MWh)

Year	Summer Off-Peak	Summer On-Peak	Summer All-Hours	Winter Off-Peak	Winter On-Peak	Winter All-Hours
2013	39.3	45.1	42.2	47.3	55.7	51.5
2014	38.1	43.9	41.0	47.7	54.6	51.2
2015	38.3	45.3	41.8	47.7	53.9	50.8
2016	37.8	45.8	41.8	46.2	51.9	49.0
2017	40.4	51.4	45.9	43.8	49.9	46.8
2018	43.1	55.6	49.3	46.4	52.8	49.6
2019	45.7	60.0	52.8	49.5	57.0	53.3
2020	52.5	64.2	58.4	56.7	64.8	60.7
2021	53.5	66.9	60.2	57.8	64.6	61.2
2022	55.8	66.5	61.2	60.4	67.8	64.1
2023	58.1	71.2	64.7	62.3	70.2	66.3
2024	59.7	73.4	66.6	64.3	72.1	68.2
2025	61.9	77.2	69.5	66.4	75.2	70.8
2026	63.8	79.8	71.8	68.4	77.0	72.7
2027	65.7	83.0	74.3	70.3	79.9	75.1
2028	67.4	84.5	75.9	71.9	83.0	77.5
All prices expressed in 2013$ per MWh.						

6.4.2 Comparison with Other Forecasts

The AESC 2013 scope of work requested the following analyses of the AESC 2013 wholesale electric energy price forecast:

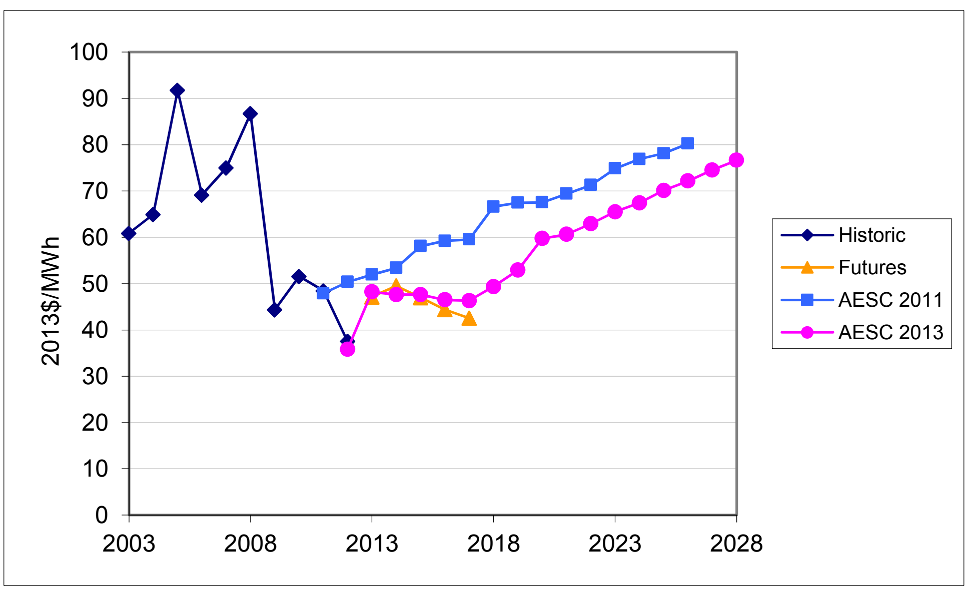
- Comparisons with other trends and forecasts, including comparisons to a trend of actual monthly prices (real time) from ISO-NE, a forecast as represented by the NYMEX futures market and the most recent EIA forecast;
- A high-level discussion of reasons for differences identified in the comparisons; and
- Explanation of any apparent price spikes and key variables that affect the outcome, as well as identification of potential scenarios worthy of investigation.

Exhibit 6-11 provides a comparison of 1) historical prices, 2) futures prices, 3) AESC 2011, and 4) AESC 2013 forecasts of the annual wholesale energy prices in the Central Massachusetts zone.

Exhibit 6-11 indicates that the AESC 2013 forecast is below AESC 2011. The lower AESC 2013 forecast reflects significant reductions in the cost of natural gas, which is generally the marginal generation fuel. It also reflects somewhat lower annual loads as well as delayed CO_2 prices.

The AESC 2013 Base Case forecast of Henry Hub natural gas prices starts in 2013 at $3.84/MMBtu, which is about $0.60/MMBtu below AESC 2011. Over time that gap narrows, but still remains. The irregularities in the annual electricity price curve primarily represent the natural gas price changes as exemplified by winter basis differences that decline through 2017, when our assumptions of additional New England pipelines remove some constraints. The 2020 increase is associated with the start of the AESC 2013 assumed federal CO_2 emission pricing.

Exhibit 6-11. Historical and Forecast Annual Wholesale Price Comparisons (2013$/MWh)

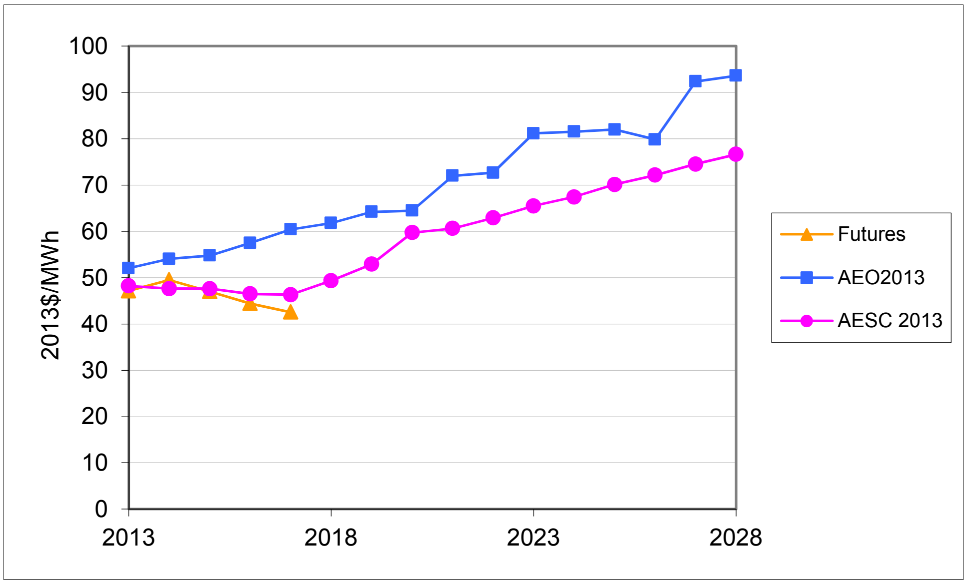


The following sections detail our comparisons of the AESC 2013 forecast with other forecasts.

Comparison with AEO 2013 Forecast

The Annual Energy Outlook is released annually by the EIA, and forecasts energy usage and price for the U.S. as a whole and for its constituent regions. Table 55.5 of the report presents generation, capacity, and prices for New England. [215] Although the AEO does not produce a wholesale market price per se, the generation service category price comes fairly close. It should also be noted that the AEO price represents a New England Average, while the AESC 2013 forecast is for the New England hub. Exhibit 6-12 compares the AEO generation price with the AESC 2013 forecast, and shows that it is moderately above the AESC price and the current futures.

Exhibit 6-12. Forecast Comparison with AEO 2013 (2013$/MWh)



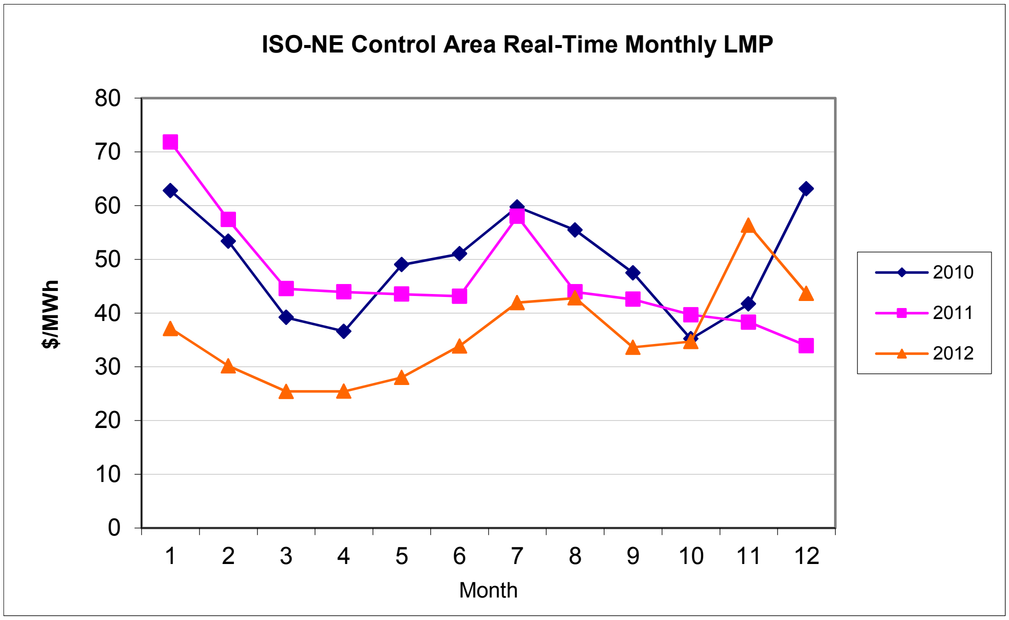
Comparison with Trends in ISO NE Prices

We examined variations in historical monthly prices in ISO-NE in 2010, 2011, and 2012 by investigating changes in monthly electricity loads and natural gas prices. Exhibit 6-13 shows the electricity monthly prices in each of the last three calendar years. The general pattern is that high loads in the summer increase prices above the spring and autumn periods because the summer marginal generation is less efficient and more expensive. And moderately higher winter loads combined with sometimes much higher spot natural gas prices can result in even higher winter electricity prices for these three years. In 2010 and 2012, years with generally lower loads, the winter prices were higher than the summer prices. In 2011, electricity prices were higher in the summer since the winter was abnormally mild. As discussed elsewhere, the primary driver of electricity prices in New England are the spot natural gas prices, which

[215] Table 55.5 “Electric Power Projections for EMM Region – Northeast Power Coordination Council / Northeast”

tend to be low in the summer but can spike considerably during cold winter periods. The AESC 2013 forecast of monthly prices is consistent with this historical trend.

Exhibit 6-13. ISO-NE Control Area Monthly Real-Time Prices ($/MWh)

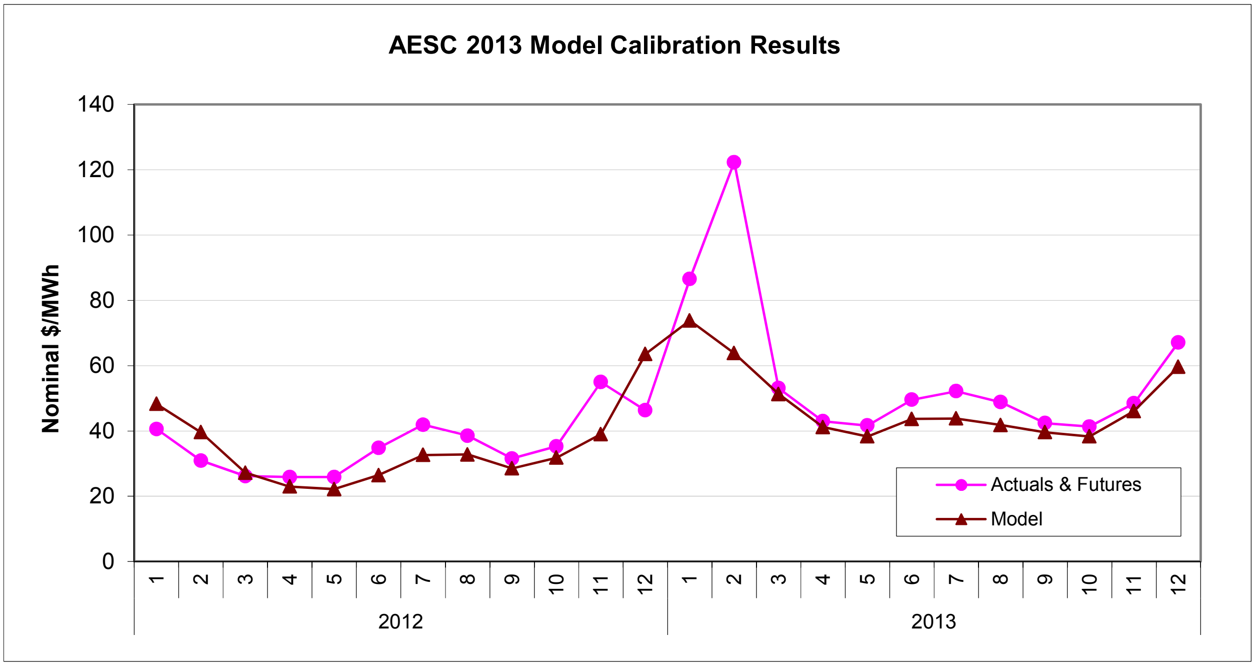


The Chicago Mercantile Exchange (CME) maintains the NYMEX futures market for electricity prices at the New England hub. There is a moderate amount of trading out about a year or two, but further out the market is quite thin. Nevertheless, these futures prices provide one source of comparison with the AESC 2013 forecast. We use futures as of March 15, 2013.

Exhibit 6-14 shows the comparisons on a monthly basis. The prices through March 2013 are historical values; those thereafter are from the NYMEX futures. Considering the volatility of the futures markets, the correspondence is close.

The price spikes in January and February 2013 represent a spike in the spot prices of natural gas as a result of pipeline constraints. The purpose of the simulation model is to generate long-term avoided costs; thus, we do not see the model as predictive of short-term price spikes.

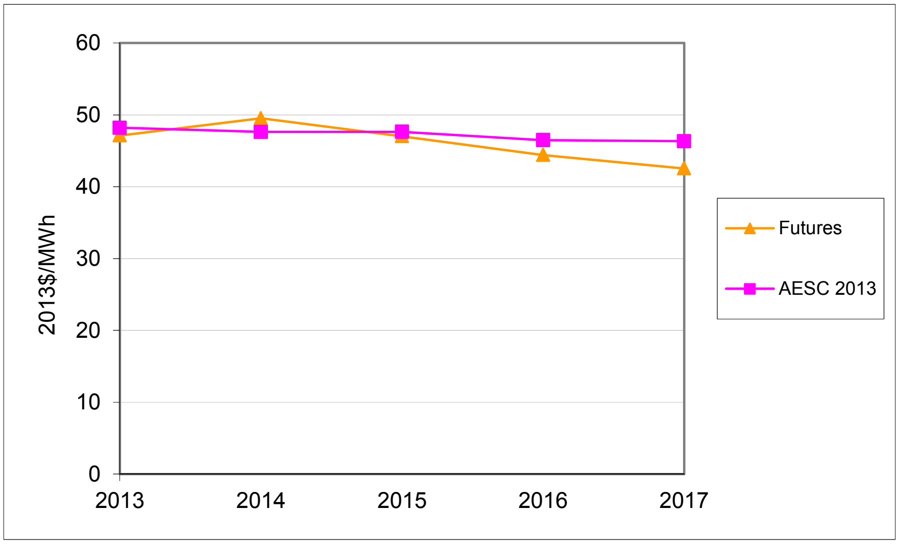
Exhibit 6-14. AESC vs. NYMEX New England Futures



The AESC 2013 Base Case prices are within 5 percent of the historical prices and the NYMEX futures (as of March 15, 2013) for ISO-NE for 2011 through 2016.

The next exhibit compares the futures and the AESC forecast energy prices on an annual average basis. The correspondence is extremely close and represents both the assumptions about natural gas prices and the AESC 2013 calibration process. Note too that the electric energy future prices may embed different assumptions about future fuel prices, and definitely represent lower load growth assumptions.

Exhibit 6-15. Comparison of Futures and Base Case Annual Prices



Comparison to AESC 2011 Forecast

The following section summarizes differences between the AESC 2013 and AESC 2011 forecasts. Exhibit 6-16 compares the two AESC forecasts on a levelized basis. Differences between the two forecasts occur in all years and periods on the order of 3.6 to 21.0 percent. The lower summer prices reflect overall lower natural gas prices. That is less apparent in the winter because of the high winter basis prices in the initial years.

Exhibit 6-16. 15-Year Levelized Cost Comparison for Central Massachusetts (2013$/MWh)

	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual All-Hours Energy
AESC 2013	$64.39	$56.79	$63.80	$51.53	$59.86
AESC 2011	$67.90	$58.93	$80.74	$57.80	$64.68
% Difference	-5.2%	-3.6%	-21.0%	-10.8%	-7.4%

Notes:
All prices expressed in 2013$ per MWh.
Levelization periods: 2014-2028 for AESC 2013, 2012-2026 or AESC 2011
Discount Rate 1.36% for AESC 2013, 2.46% for AESC 2011

On a levelized annual basis, the AESC 2013 Base Case wholesale energy prices for WCMA are approximately 7.4 percent below those of AESC 2011. The reductions are generally more for summer periods and less for winter, as shown in Exhibit 6-9.[216]

[216] Levelized values have been calculated for AESC 2013 using a discount rate of 1.36 percent, and for AESC 2011 using a discount rate of 2.46 percent.

There are two primary factors causing the current forecast to differ from that of AESC 2011:

- Natural gas price – Natural gas prices are the primary determinant of electricity prices in the New England wholesale market. The current natural gas price forecast is 13.4 percent lower on a 15-year levelized basis than the previous one.

- CO_2 price – The current forecast for a national price for CO_2 starts two years later (in 2020), but on a levelized basis (2012-2026 for AESC 2011 and 2014-2028 for AESC 2013) the AESC 2013 CO_2 price forecast is 17 percent higher than AESC 2011, due in large part to higher forecast prices through 2019 under the RGGI Model Rule Update.[217]

The impact of each of these factors is discussed in more detail below.

New England Natural Gas Price Forecast

Prices in the New England electric energy market have been historically very volatile. This volatility is very strongly linked to the price that electric generators pay for natural gas. The graph below shows these prices on a monthly average basis for the previous five years. One thing to note is that although electricity prices closely follow natural gas prices, they tend to be proportionally higher in the summer when loads are greater.[218]

[217] On levelized basis for the same period (2014-2028), AESC 2013 is 10 percent lower than AESC 2011, due the higher national CO_2 price forecast under AESC 2011.

[218] As described above, there have been some recent exceptions to this general trend.

Exhibit 6-17. Historic Monthly New England Electricity and Natural Gas Prices

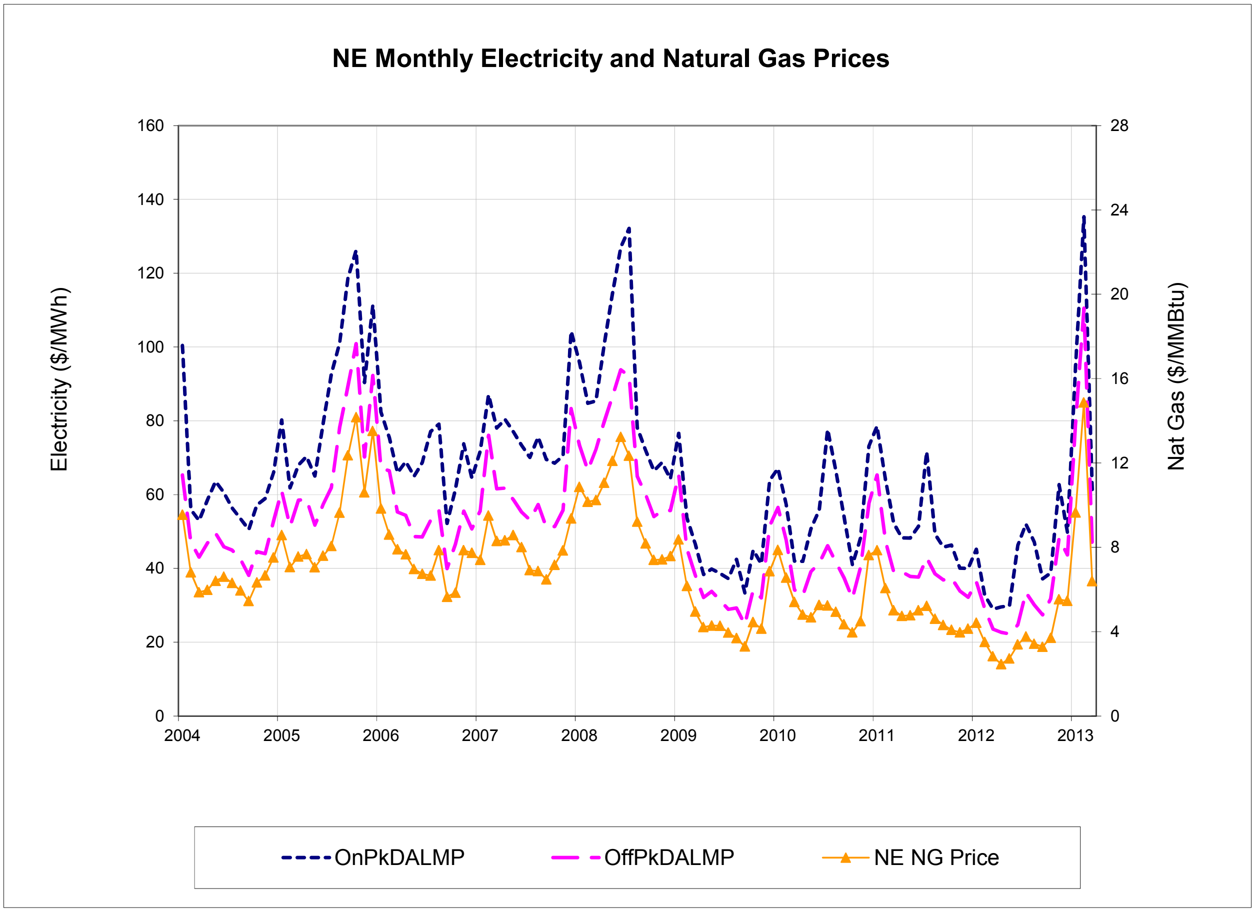
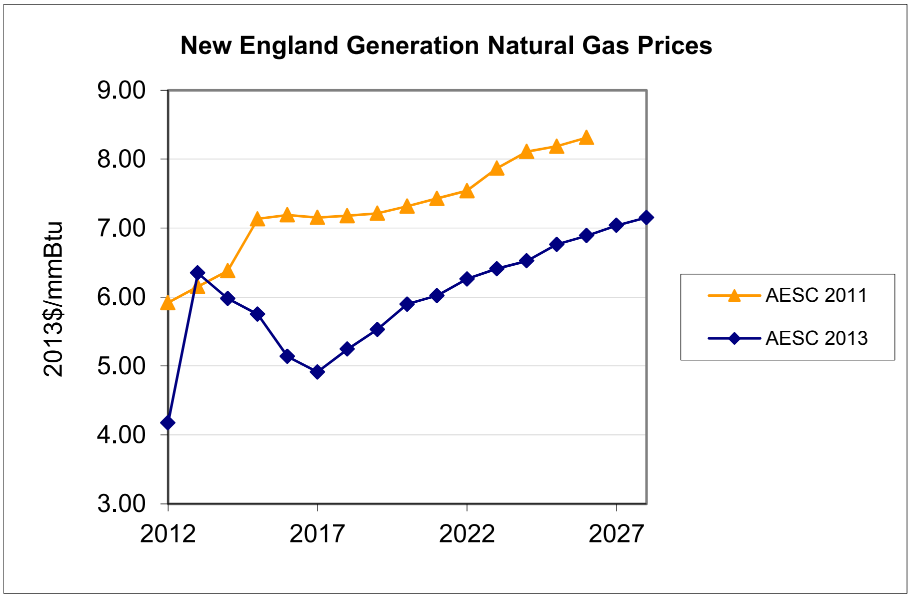


Exhibit 6-18 compares the current natural gas forecast for electric generation in New England—which reflects historical margins in the spot market—with the corresponding forecast for AESC 2011. The AESC 2013 forecast has much lower prices in all years with the exception of 2013, which reflects current constraints in New England pipeline capacity. The decline through 2017 of electric generation natural gas prices reflects the return in winter basis prices to historical patterns as the pipeline capacity is added in future years. On a levelized basis (2012-2026 for AESC 2011 and 2014-2028 for AESC 2013) the current natural gas price forecast is $0.93/MMBtu or 13.4 percent below AESC 2011.[219]

[219] For the same levelization period (2012-2026), the AESC 2013 New England natural gas forecast is $1.18/MMBtu or 16.8 percent lower than AESC 2011.

Exhibit 6-18. AESC 2013 vs. AESC 2011 Annual Gas Price Forecast Comparison

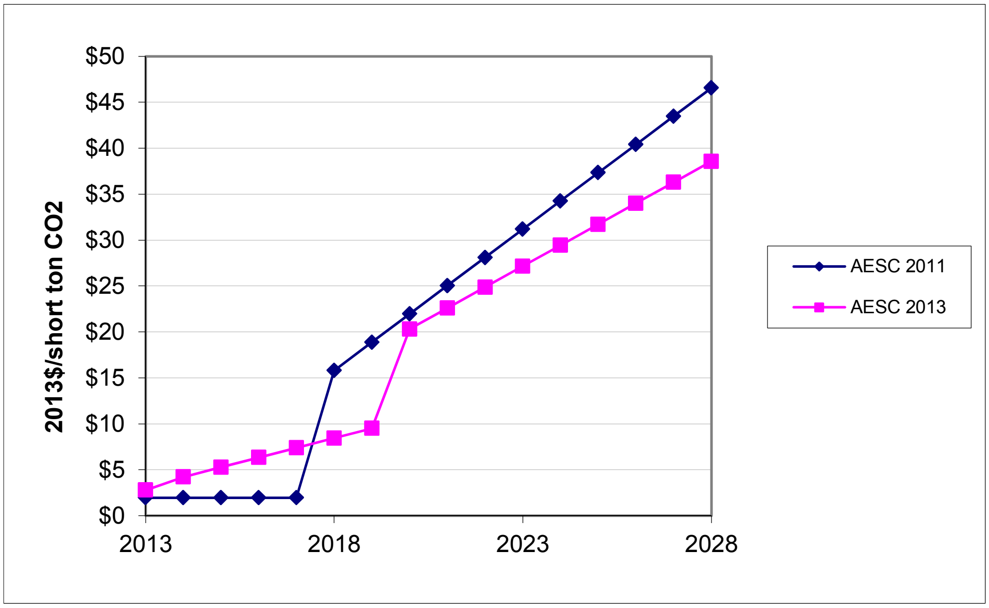


In terms of the seasonal differences, the winter (eight month) natural gas prices average 6 percent above the annual average and the summer (four month) prices average 12 percent below. This differs slightly from AESC 2011, where those seasonal differences were 3.5 percent higher for winter and 6.9 percent lower for summer.

<u>CO_2 Price Forecast</u>

The CO_2 price forecast used for AESC 2013 is different than that used in AESC 2011, reflecting expectations of higher RGGI prices, but delayed national regulation (until 2020) as shown in Exhibit 6-19. The levelized (2014-2028 for AESC 2013 and 2012-2026 for AESC 2011) cost for AESC 2013 is $19.72/ton, compared to $16.21/ton for AESC 2011, a $3.51 or 21.6 percent increase reflecting primarily an increase in RGGI prices between 2013 and 2017.

Exhibit 6-19. AESC 2013 & AESC 2011 CO_2 Price Forecasts



Load Forecast

As discussed in section 5.2.1, the CELT 2012 loads used for AESC 2013 are below those used in AESC 2011. The summer peak loads are about 1 to 2 percent less, but the annual energy differences are somewhat smaller, at 0 to 1 percent less. This overall reduction in load and energy means, for a similar amount of available capacity, marginal heat rates and energy prices tend to be lower.

Analysis of Forecast Differences

There are many factors that go into the wholesale electricity price, including fuel, environmental costs, and system operation. The following exhibit focuses on a comparative analysis of the summer peak prices for AESC 2011 and AESC 2013 on a levelized basis. As noted earlier, the AESC 2013 summer peak price on a levelized basis is 21 percent below the corresponding AESC 2011 price. Exhibit 6-20 presents an illustrative calculation of those two summer prices and the resulting differences, keeping in mind that there are numerous year-by-year variations.

The table starts by showing the levelized wholesale prices over a comparable period. That is followed by values for two of the key inputs—natural gas and CO_2 prices. The system parameters represent overall system behavior and are consistent with the behavior we see and expect from the dispatch modeling. In addition to lower gas prices, AESC 2013 includes even more retirements of old coal units than AESC 2011. Those retirements shift the generation supply curve to the left, which causes more efficient units to set the market price in summer peak periods, when loads are highest, as compared to AESC 2011. The result is a decrease in summer peak period prices in AESC 2013 relative to AESC 2011 due to lower natural gas and offset by higher CO_2 prices.

Exhibit 6-20. AESC 2013 vs. AESC 2011 Summer On-Peak Levelized Cost Comparisons

WCMA Summer On-Peak Period Price Comparison (2013$ per MWh)			
	AESC 2011	AESC 2013	% Difference
Wholesale Price from Simulation Model	$80.74	$63.80	-21.0%
Analysis			
Input Values			
Summer NG Price ($/MMBtu)	$6.70	$5.38	-19.7%
CO_2 Price ($/ton)	$16.21	$19.72	21.6%
NG CO_2 (lbs/MMBtu)	118	118	0.0%
Marginal Heat Rate (Btu/kWh)	10,150	9,061	-10.7%
Marginal CO_2 Rate (tons/MWh)	0.60	0.53	-10.7%
Price and Heat Rate Effects			
Fuel Cost ($/MWh)	$68.05	$48.79	-28%
CO_2 Cost ($/MWh)	$9.71	$10.54	9%
Other variable & bid costs ($/MWh)	$3.00	$3.00	0%
Wholesale Price Estimated from Price and Heat Rate effects + other variable costs	$80.76	$62.33	-23%

Notes

Values may not sum due to rounding
AESC 2011 levelized (2012-2026)
AESC 2013 levelized (2014-2028)
CO_2 costs are embedded portion only
Marginal heat rates are for the single years of 2011 and 2013

As indicated previously, the AESC 2013 annual wholesale energy price forecast on a levelized basis (2014-2028) is 7.4 percent below that of AESC 2011, while the summer on-peak difference is much higher. On a levelized basis, the AESC 2013 summer natural gas price for New England electric generators is 19.7 percent lower than in AESC 2011, and the CO_2 price forecast is 21.6 percent higher. Exhibit 6-21 provides the summer on-peak prices by year for AESC 2011 and AESC 2013.

Exhibit 6-21. AESC 2013 vs. AESC 2011 Summer On-Peak Prices for WCMA

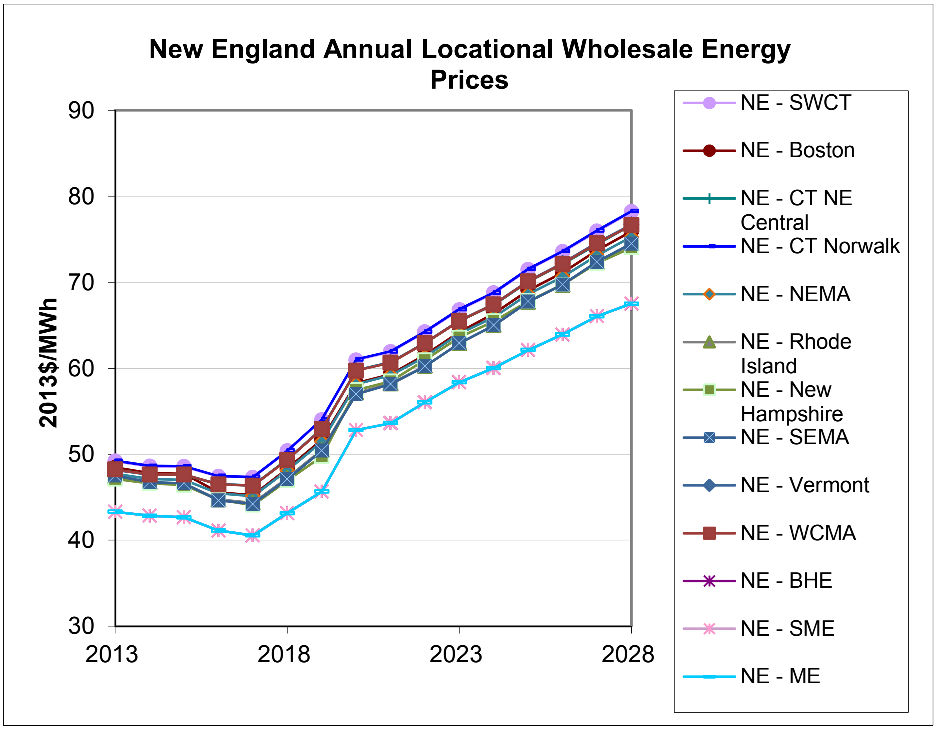
Annual Summer On-Peak Price (2013$/MWh)		
Year	AESC 2013	AESC 2011
2011		57.83
2012		63.55
2013	45.06	65.28
2014	43.93	67.74
2015	45.27	72.67
2016	45.84	78.72
2017	51.38	78.29
2018	55.60	88.19
2019	59.95	86.75
2020	64.18	82.89
2021	66.87	84.52
2022	66.53	86.13
2023	71.21	90.21
2024	73.42	91.61
2025	77.16	92.84
2026	79.82	96.91
2027	82.96	
2028	84.46	

6.4.3 Forecast of Electric Energy Prices by State

The forecast of energy values by zone by year for each period—summer on peak, summer off-peak, winter on-peak, and winter off-peak—are presented in Appendix B.

Exhibit 6-22 illustrates the zonal annual peak period prices in descending order by price. Note how some zones have nearly identical prices. The highest price zone is southwestern Connecticut and the lowest price zone is Maine. The price decline up to 2017 is associated with the decline in spot natural gas prices, as a result of increased pipeline capacity. The large increase in 2020 is associated with the implementation of a federal carbon price for electric generation. Prices in Maine are lower because of continued excess generation and transmission constraints to the rest of New England.

Exhibit 6-22. New England Annual Peak Locational Price Forecast



6.4.4 Transmission Energy Losses

Our forecast for marginal energy clearing prices includes inter-area losses for energy coming into load area 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 are presented in Exhibit 6-23 as a percentage of imports into each zone or state. These are losses only for transmission between zones and do not include losses within individual zones. Exhibit 6-24 presents the generation within each zone as a percentage of zonal load. Some zones produce energy equivalent to several times their own load, while others have nearly zero local generation.

Exhibit 6-23. AESC 2013 Modeling Zone and State Transmission Losses

Modeling Zone Losses		
Modeling Zone	**Summer**	**Winter**
NE - BHE	6.0%	6.0%
NE - ME	0.0%	0.0%
NE - NEMA	3.0%	4.1%
NE - New Hampshire	8.8%	8.6%
NE - Rhode Island	0.5%	1.1%
NE - SEMA	0.5%	0.5%
NE - SME	0.0%	0.0%
NE - SWCT	2.0%	2.0%
NE - Vermont	3.6%	4.6%
NE - WCMA	1.6%	1.4%
NE - Boston	1.0%	1.1%
NE - CT NE Central	0.6%	1.2%
NE - CT Norwalk	0.5%	0.9%
New England Average	**2.1%**	**2.4%**
State Losses		
State	**Summer**	**Winter**
CT	1.2%	1.4%
MA	1.9%	2.3%
ME	0.2%	0.7%
NH	8.8%	8.6%
RI	0.5%	1.1%
VT	3.6%	4.6%
New England Average	**2.1%**	**2.4%**

Exhibit 6-24. AESC 2013 Generation within Each Zone as a Percentage of Zonal Load

Zone	Percentage of Zonal Load
BHE	274%
NH	191%
RI	154%
CT	119%
SEMA	109%
VT	92%
WMA	91%
SWCT	83%
ME	81%
SME	80%
BOSTON	38%
CMA/NEMA	8%
NOR	0%
ISO-NE	***91%***

6.5 Avoided Cost of Compliance with RPS

6.5.1 Introduction

Our estimate of avoided costs includes the expected impact of the region's five existing Renewable Portfolio Standards. The annual quantity of renewable energy that LSEs need to acquire in order to comply with RPS requirements is directly proportional to the annual load that the LSEs supply.

To the extent that the price of renewable energy exceeds the market price of electric energy, LSEs incur a cost to meet the RPS percentage target. That incremental unit cost is the price of a Renewable Energy Certificate (REC). This annual compliance cost ($) equals the quantity of renewable energy purchased (MWh) multiplied by the REC price ($/MWh).

Energy-efficiency programs reduce the cost of compliance with RPS requirements by reducing the total load, or MWh, that must be supplied. Reduction in load due to DSM will reduce the RPS requirements of LSEs 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 percentage of retail load that a supplier must meet from renewable energy under the RPS regulations. RPS targets for Connecticut, Maine, Massachusetts, New Hampshire, and Rhode Island are a percentage of retail load as defined by state-specific legislation and regulation in effect as of April 2013. While AESC 2011 assumed that Vermont would adopt a mandatory RPS target of 5 percent by 2017, after consulting with the Study Group, the AESC 2013 analysis assumes that Vermont does not establish a binding RPS during the study period.

This section forecasts those avoided RPS costs where the key input to the calculations is a forecast of the price of renewable energy in excess of market prices each year, i.e., the forecast price of RECs. This section presents a forecast of the expected future cost of renewable energy certificates and RPS compliance. We deduct the market price of energy from the forecast cost of renewable energy in order to calculate the forecast price of RECs for each RPS subcategory, by state and by year. For all Class 1 requirements, the forecasted price of RECs for the remainder of 2013 and all of 2014 is based on historical average broker quotations regarding short-term forward transactions consummated between January and April 2013. Beginning in 2018, Class 1 REC prices reflect the forecasted cost of new entry. Class 1 prices are interpolated for 2015 through 2017 by scrutinizing the expected balance between RPS-eligible supply and RPS demand and by including the expected impact of banked compliance.[220] For Class 2 requirements, the 2013 REC prices are based on a 12-month (May 2012 to April 2013) historical average of broker quotes and/or bid-ask spreads. These REC prices are summarized in Appendix F.

The following exhibit summarizes the change in Avoided RPS costs between AESC 2011 and AESC 2013.

Exhibit 6-25. Comparison of Avoided RPS Costs

Comparison of Avoided RPS Costs 2013$/MWh of Load Levelized Price Impact 2014 - 2028 (2013 $, unless noted)						
	CT	**ME**	**MA**	**NH**	**RI**	**VT**
AESC 2011 (2011$)	$2.17	$0.92	$4.98	$2.30	$1.43	$0.50
AESC 2011 (2013$)	$2.24	$0.95	$5.14	$2.38	$1.48	$0.52
AESC 2013	**$4.62**	**$1.82**	**$6.25**	**$5.05**	**$3.45**	**$0.00**
Percent Difference	106%	91%	22%	112%	134%	-100%
Notes Conversion from 2011$ to 2013$: 1.033 AESC 2011 levelization period (2012-2026) using a 2.46 percent discount rate.						

The avoided RPS costs are generally higher for AESC 2013 than AESC 2011 due to an increase in shortage-induced near-term REC prices and delays in the renewable energy development pipeline due to a dearth of creditworthy long-term contracts in the market. The percent difference in the Massachusetts Avoided RPS costs are lower than the other states primarily due to the change in methodology to exclude the Massachusetts Solar Carve-Out that had been included in prior AESC studies.

[220] In the event that an LSE purchases RECs in excess of its current year RPS obligation, each state allows LSEs to save and count that quantity of compliance against either of the following two compliance years. This compliance flexibility mechanism is referred to as banking. LSEs may only bank compliance within a single state, and may not transfer banked compliance credit to other entities.

6.5.2 Methodology

As described in more detail in section 5.2.4, AESC 2013 assumes LSEs will comply fully with established RPS requirements each year—either by securing RECs or by making Alternative Compliance Payments. For ease of presentation, this AESC 2013 discussion generally refers to all of these requirements as RPS requirements, which must be met with RECs, even though some of the resources are not renewable.

Our estimate of avoided costs includes a forecast of the REC costs that reduction in load will enable an LSE to avoid. Reduction in load due to DSM will reduce the RPS requirement of the LSE and therefore reduce the cost they incur to comply with that requirement.

Estimating the Cost of Entry for New or Incremental Renewable Energy

As with AESC 2011, the AESC 2013 analysis assumes that in the long run, the price of renewable energy certificates (and therefore the unit cost of RPS compliance) will be determined by the cost of new entry of the marginal renewable energy unit. To estimate the new or incremental REC cost of entry, we constructed a supply curve for incremental New England renewable energy potential based on various resource potential studies that sorts the supply resources from the lowest cost of entry to the highest cost of entry.[221] The resources in the supply curve model are represented by 307 blocks of supply potential from resource studies, each with total MW capacity, capacity factor, and cost of installation and operation applicable to projects installed in each year.

The supply curve consists of land-based wind, biomass, hydro, landfill gas, offshore wind, and tidal resources. While offshore wind is the largest potential resource by MW, land-based wind is the largest source by number of blocks (modeled as 86 separate categories), varying by state, number and size of turbines in each project, wind speed, and distance from transmission.

Resources from the supply curve are modeled to meet net demand (as described earlier), which consists of the gross demand for new or incremental renewables, less:

a) Existing eligible generation already operating (including biomass co-firing in existing facilities);

b) The current level of RPS imports; and

c) Additional imports over existing ties to neighboring control areas.

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[221] These assumptions are based on technology assumptions compiled by Sustainable Energy Advantage, LLC from a range of studies and interviews with market participants. Some characteristics are adapted from those used in a New England renewable energy supply curve analysis prepared by Sustainable Energy Advantage for the New England States Committee on Electricity. Other characteristics are adapted from those used in a New England renewable energy supply curve analysis prepared by Sustainable Energy Advantage, LaCapra Associates and AWS Truewind for the Maine Governors Wind Task Force Study on behalf of the Natural Resources Council of Maine. Typical generator sizes, heat rates, availability, and emission rates are consistent with technology assumptions used by ISO-New England in its scenario planning process. The resulting supply curve is proprietary to Sustainable Energy Advantage, LLC.

For solar and fuel-cell resources, which tend not to be resource-constrained, we separately estimated the amounts that would be driven by various policy initiatives; these amounts were also netted from gross demand.

The estimated levelized cost of marginal resources is based on several key assumptions, including projections of capital costs, capital structure, debt terms, required minimum equity returns, and depreciation, which are combined and represented through a carrying charge. The estimated levelized cost of marginal resources also includes fixed and variable operations and maintenance costs, transmission and interconnection costs (as a function of voltage and distance from transmission), and wind integration[222] costs. The Federal Production Tax Credit is assumed to be phased out over a five-year period ending in 2018. Capital and operating costs were escalated over time using inflation. The levelized commodity revenue over the life of each resource was determined based on the sum of energy and capacity prices, both utilizing preliminary AESC 2013 Base Case estimates of the FCM price and all-hour zonal LMP.

Revenues for wind resources were adjusted in three ways:

- The value of wind energy was adjusted to reflect wind's variability, production profile, and historical discount of the real-time market (in which wind plants will likely sell a significant portion of their output) versus the day-ahead market.
- Energy prices were further discounted to reflect the lower prices typical in long-term contracts, especially for wind plants, with their fluctuating energy output.[223]
- Wind generators were assumed to receive FCM revenues corresponding to only 15 percent of nameplate capacity, reflecting the poor performance of most on-shore wind plants on summer afternoons. This assumption may be conservative for commercial wind farms, reflecting developer, investor, and lender risk-aversion regarding future capacity valuation.

The price for each block of the supply curve is estimated for each year. For each generator, we determined the levelized REC premium, or additional revenue the project would require in order to attract financing, for market entry by subtracting the nominal levelized value of production consistent with the AESC 2013 projection of wholesale electric energy prices from the nominal levelized cost of marginal resources:[224]

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[222] We assume that reinforcement of major transmission facilities (e.g., improved connections between Maine and the rest of New England) will be socialized.

[223] Our forecast of REC prices assumes that most renewables will be financed with long-term contracts for most of their capacity and/or RECs.

[224] SEA calculated these levelized analyses using discount rates representative of the cost of capital to a developer of renewable resource projects.

- The nominal levelized cost of marginal resources is the amount the project needs in revenue on a levelized $/MWh basis;
- The nominal levelized value of production is the amount the project would receive from selling its commodities (energy, capacity, ancillary services) into the various wholesale markets; and
- The difference between the levelized cost and the levelized value represents the REC premium.

Unless the revenue from REC prices can make up the REC premium, a project is unlikely to be developed. Resource blocks are sorted from low to high REC price, and the intersection between incremental supply and incremental demand determines the market-clearing REC price for market entry. Our projections assume that REC prices for new renewables will not fall below $2/MWh, which is the estimated transaction cost associated with selling renewable resources into the wholesale energy market. This estimate is consistent with market floor prices observed in various markets for renewable resources.

Calculating Avoided RPS Compliance per MWh Reduction

The RPS compliance costs that retail customers avoid through reductions in their energy usage is equal to the price of renewable energy in excess of market prices (e.g., the REC price) multiplied by the portion of retail load that a supplier must meet from renewable energy under the RPS. In other words,

Avoided RPS cost = REC price × RPS percentage

For example, in a year in which REC prices are $30/MWh and the RPS percentage is 10%, the avoided RPS cost to a retail customer would be $30 × 10% = $3/MWh.

We calculated the RPS compliance costs that retail customers in each state avoid through reductions in their energy usage in each year for each major applicable RPS tier as follows:

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

Where:

n = the RPS tier

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

We forecasted annual REC prices for three major RPS tiers. These are new renewables (primarily Class I), all New Hampshire Class II solar, and all other renewables. For 2013 and 2014 we relied upon recent broker quotes to estimate the market prices at which RECs are transacted. REC markets in New England continue to suffer from a lack of depth, liquidity, and price visibility. Broker quotes for RECs represent the best visibility into the market's view of current spot prices. However, since RPS compliance must be substantiated annually, and actual REC transactions occur sporadically throughout the year, the actual weighted average annual price at which RECs are transacted will not necessarily correspond to the straight average of broker quotes over time. Broker quotes for RECs may span several months with few changes and no actual transactions (being represented by offers to buy or sell), and at other times may represent a significant volume of actual transactions. As a result, care should be taken to filter such data for reasonableness. Exhibit 6-26 provides the type of REC prices we used to characterize the near-term REC market prices.[225]

Exhibit 6-26. REC and APS Prices: 2012 Annual Average and 2013 Year-to-Date (2013$/MWh)

		Annual Avg. REC Prices, 2012 (2013$/MWh)	Avg. REC Prices, Jan-Mar 2013 (2013$/MWh)
CT	Class I	$48.00	$54.00
	Class II	$0.40	$0.55
	Class III	$10.75	$10.25
MA	Class I	$58.00	$63.00
	Class II – renewable	$24.50	$26.00
	Class II – WTE	$5.75	$7.75
	APS	$19.50	$19.75
RI	New	$57.50	$62.75
	Existing	$0.65	$0.60
ME	Class I	$32.00	$22.75
	Class II	$0.40	$0.10
NH	Class I	$56.00	$54.50
	Class II – Solar	$64.00	$51.00
	Class III	$28.25	$28.75
	Class IV	$28.75	$23.50
Data from confidential REC brokers' quotations compiled by Sustainable Energy Advantage, LLC			

The AESC 2013 estimates of Class I REC prices in the longer term (after 2014) are based on analysis of the near-term supply and demand balance, banking limits and observed practices, and the cost of entry of new renewable energy resources in each applicable year. That analysis relies on SEA's renewable energy supply curve model to determine the marginal (or market-clearing) resource in each year through 2028—after which REC prices are assumed to remain stable. REC prices were estimated based on the difference between the levelized cost for the marginal renewable resource and the resource's commodity market value based on our Base Case forecast of wholesale electric-energy-market prices.

We forecasted REC prices for the remaining two tiers as follows:

[225] This table was developed from a representative sampling of REC brokers quotes, which is comprised of both consummated transactions and bid-ask spreads in periods where transactions were not reported.

- For New Hampshire Class II (solar) REC prices were estimated at the lesser of (1) the alternative compliance payment rate and (2) the difference between a levelized cost of energy estimate for solar and our production-weighted Base Case forecast of wholesale electric-energy-market prices.
- For all other RPS tiers we escalated recent broker-derived prices at inflation. The exception to this methodology was for RPS classes focused on existing supply but for which such existing supply has not been certified by the applicable RPS authority in a quantity sufficient to meet demand. Near-term REC prices for such classes were estimated based on current broker quotes and the applicable ACP. REC prices were assumed to trend toward values which reflect a market in equilibrium or modest surplus over time, as existing generators become certified and participate in the program.

6.5.3 New or Incremental Additions to RPS Supply

New or *incremental* renewable resources are those that qualify as “Class I” in CT, MA, NH, ME, and as “New” in RI. We refer to those categories in those states collectively as Class I. REC prices will be driven both by the costs of renewable resources eligible in each state and by the quantity of state-specific supply compared to state-specific demand. Because RPS eligibility criteria differ by state, REC prices are differentiated by state and reflect state-specific expectations with respect to generator certification and LSE banked compliance. A more detailed description may be found in section 5.2.4.

In AESC 2011, we assumed that the MA Solar Carve-Out (a sub-set of MA Class I) reaches its 400 MW target in 2018 and that the target remains at this level through 2022. In AESC 2013, we assumed that Governor Patrick’s April 2013 announcement targeting 1,600 MW of solar installed by 2020 increases the MA Solar Carve Out by an incremental 800 MW, for a total Solar Carve-Out obligation of 1,200 MW by 2020. Massachusetts is unique in its treatment of the solar carve-out portion of its Class 1 obligation. While the carve-out itself is not unique, Massachusetts establishes an annual MWh obligation, which is then allocated among the obligated LSEs. In aggregate, this solar target is converted into a percentage of state load and is removed from the Class 1 percentage target for that year—thereby reducing the Class 1 RPS compliance obligation, which is then avoidable through energy efficiency activities. In AESC 2011, we assumed that the MA Solar Carve Out obligation was similarly avoidable. Upon further review and discussion with LSEs, however, AESC 2013 concludes that the solar carve-out represents an LSE obligation to include a fixed quantity (MWh) of Solar RECs (SRECs) each year and is therefore not avoidable through energy efficiency measures that reduce all other RPS obligations.

While Class I RPS requirements generally spur the development of new renewable resources, Class II, III, and IV requirements are generally designed as “maintenance tiers.” These programs are intended to provide just enough financial incentive to keep the existing fleet of renewable resources in reliable operation. Due to their maintenance orientation, Class II, III and IV percentage targets are generally held constant, with annual obligations varying only based on changes in the demand forecast. CT Class II, MA Class II-WTE, ME Class II, and RI "Existing" REC markets are in surplus. Therefore, REC prices in these markets are expected to remain relatively constant at levels just above the transaction cost. The MA Class II market has overlapping eligibility with CT Class I. In addition, while there is theoretically ample supply to meet MA Class II, fewer generators than expected have undertaken the steps necessary to comply with the eligibility criteria and become certified. Therefore, the MA Class II market is currently in shortage. As a result, in 2012 the Massachusetts legislature suggested that the Department of Energy Resources (DOER) consider adjustments to the Class II (non-Waste-to-Energy) program in order to bring the market into a balance more consistent with a policy targeting existing resources. While DOER is expected to act in a manner consistent with the legislature's suggestions, such action will likely include a lengthy stakeholder process which will extend the schedule of any proposed adjustments. As a result, long-run MA Class II REC prices are assumed to be the lesser of CT Class I REC prices and 50 percent of the MA Class II Alternative Compliance Payment (ACP) rate. REC prices for MA APS are forecasted at 90 percent of the ACP rate. The CT Class III market has an administratively set REC price floor of $10. Based on the performance of this market to date, CT Class III compliance prices are expected to remain at $10 per MWh throughout the study period. Existing solar facilities across New England are eligible for NH Class II. As such, this market is expected to remain in balance, trend toward the MA Class I REC price by 2014, and settle marginally above the MA Class I REC price for the remainder of the study period. The NH Class III and NH Class IV markets[226] have overlapping eligibility with CT Class I. In the long-run, therefore, NH-III and NH-IV REC prices are assumed to be the lesser of CT Class I and 90 percent of their respective ACP rates.

Class I requirements will outpace the other classes on a GWh basis over time. This phenomenon is shown in Exhibit 6-27, which summarizes New England's total renewable energy requirements by year, based on the RPS percentage targets by state and ISO-NE's 2012 CELT forecast, as discussed in Chapter 5. Exhibit 6-27 distinguishes between the quantity of Class I renewables that are required and the *aggregate* quantity of all other classes of renewables combined.

[226] Several Class III biomass and Class IV hydroelectric facilities have been certified in both NH III or IV, respectively, and CT Class I.

Exhibit 6-27. Summary of New England RPS Demand

New England Annual RPS Demand			
Year	Class 1 (GWh)	Other Classes (GWh)	Total (GWh)
2013	9,279	10,625	19,904
2014	10,530	10,772	21,302
2015	12,083	11,082	23,165
2016	13,657	11,246	24,903
2017	15,253	11,392	26,644
2018	16,752	11,529	28,281
2019	18,276	11,662	29,938
2020	19,691	11,789	31,481
2021	20,617	11,919	32,537
2022	21,570	12,054	33,624
2023	22,542	12,189	34,731
2024	23,534	12,325	35,859
2025	24,546	12,462	37,008
2026	25,481	12,599	38,081
2027	26,434	12,738	39,172
2028	27,406	12,878	40,284
Notes: Class 1 includes voluntary demand. Based on CELT 2012 and RPS % targets as of 4/1/2013.			

The requirements for each RPS class were derived by multiplying the load of obligated entities (those retail LSEs subject to RPS requirements, often excluding public power) by the applicable annual class-specific RPS percentage target. The RPS percentage requirements by class and year are listed in Appendix F. The load by state is based on CELT 2012 as detailed in section 5.2.1.

The major sources of the renewable supply forecast used to meet the RPS requirements by year are shown in Exhibit 6-28. These sources include wind, biomass, natural gas fuel cells, and hydro. The "other" category is included to represent the aggregate contribution of solar, landfill gas, and tidal resources.

Exhibit 6-28. Cumulative Incremental Supply of Class 1 Renewable Energy Resources in New England, by Fuel Type (excludes resources already in the 2012 CELT Report)

Class 1 Renewable Energy Supply, by Fuel Type (GWh)						
Year	**Wind**	**Biomass**	**NGFC**	**Hydro**	**Other**	**Total**
	a	*c*	*d*	*e*	*f*	*g = sum a to f*
2013	709	1,035	110	105	319	**2,278**
2014	852	1,594	159	122	343	**3,070**
2015	1,727	2,114	241	131	380	**4,592**
2016	2,993	2,439	241	131	385	**6,189**
2017	4,122	2,575	241	131	385	**7,455**
2018	4,989	2,692	241	205	672	**8,800**
2019	5,907	2,702	241	327	690	**9,866**
2020	7,113	2,702	241	367	707	**11,130**
2021	7,705	2,702	241	575	725	**11,948**
2022	7,923	2,702	241	575	867	**12,308**
2023	8,341	2,702	241	575	1,047	**12,905**
2024	8,673	2,702	241	575	1,193	**13,384**
2025	9,439	2,702	241	575	1,328	**14,284**
2026	9,854	2,702	241	575	1,463	**14,835**
2027	10,421	2,702	241	659	1,598	**15,620**
2028	11,716	2,702	241	659	1,733	**17,050**

The expected distribution of Class 1 RPS supplies between ISO-NE and adjacent control areas is summarized in Exhibit 6-29. Supply is categorized as follows:

- Existing eligible generation already operating (including biomass co-firing in existing facilities)
- The quantity of (energy and) RECs currently imported from RPS-eligible facilities located outside of ISO-NE
- The assumed incremental level of (energy and) RECs imported from RPS-eligible facilities located outside of ISO-NE
- The assumed incremental renewable resources by fuel type

Exhibit 6-29. Expected Distribution of New Renewable Energy between ISO-NE and Adjacent Control Areas

Summary of Renewable Energy Supply & Demand for AESC 2013							
Class 1 RPS Supply (GWh)						**Class 1 RPS Demand (GWh)**	**New Renewable Energy Surplus/(Shortage) (GWh)**
	ISO-NE Supply		Imported Supply		Total Supply		
Year	Operating	Incremental	Current	Expected			
	a	b	c	d	e = sum a to d	f	g = e-f
2013	7,913	49	1,369	164	**9,494**	**9,279**	215
2014	7,960	794	1,431	180	**10,365**	**10,530**	(166)
2015	7,960	2,315	1,507	261	**12,043**	**12,083**	(40)
2016	7,960	3,913	1,501	536	**13,909**	**13,657**	252
2017	7,960	5,178	1,491	796	**15,425**	**15,253**	173
2018	7,960	6,523	1,482	1,089	**17,053**	**16,752**	301
2019	7,960	7,590	1,472	1,280	**18,302**	**18,276**	26
2020	7,960	8,854	1,463	1,487	**19,762**	**19,691**	71
2021	7,960	9,672	1,453	1,708	**20,793**	**20,617**	176
2022	7,960	10,032	1,444	1,947	**21,382**	**21,570**	(188)
2023	7,960	10,629	1,434	2,204	**22,227**	**22,542**	(316)
2024	7,960	11,108	1,425	2,480	**22,972**	**23,534**	(562)
2025	7,960	12,008	1,415	2,778	**24,160**	**24,546**	(386)
2026	7,960	12,558	1,406	3,258	**25,182**	**25,481**	(299)
2027	7,960	13,344	1,397	3,280	**25,980**	**26,434**	(454)
2028	7,960	14,774	1,388	3,303	**27,424**	**27,406**	18
Notes: A portion of the Operating supply (that which is not included in the CELT) was already provided to Synapse. This supply is composed of wind, solar, biomass, biogas, hydro, and natural gas fuel cell projects (which are eligible in CT), including behind-the-meter installations within ISO-NE.							

Exhibit 6-29 also compares total Class I RPS supply to total Class 1 RPS demand. The combination of operating supply, projects currently under development, imported supply and resource potential from the renewable energy supply curve analysis are expected to keep supply and demand in balance through 2028.

In addition to *new* or *incremental* renewables, several states also have minimum requirements for existing renewable energy sources, or other eligible sources. The eligibility details and target percentages are summarized in Appendix F.

6.5.4 Estimated Cost of Entry for New or Incremental Renewable Energy

Our general approach to estimating the cost of entry for new or incremental renewable supply is described in section 6.5.2.

As previously stated, 2013 and 2014 REC prices were estimated using broker quotes. Due to an increase in renewable energy imports, the price responsiveness of operating biomass supply, upcoming long-term contract solicitations in several states, and the ability to bank RPS compliance, the cost of new entry is not expected to be determined by generic supply curve supply until roughly 2018. Until then, REC prices are estimated by scrutinizing the expected balance between RPS-eligible supply and RPS demand and by including the expected impact of banked compliance. Beginning in 2018, regional REC prices are expected to converge on the cost of new entry as all states rely on new or incremental renewable resources to meet their RPS demands—with only modest price differentials between states based on eligibility, bank balances and utility-specific decisions to retire the RECs from long-term contracts in satisfaction of RPS obligations. Our projection of the cost of new entry for each state is summarized in Exhibit 6-30.

Exhibit 6-30. REC Premium for Market Entry ($/MWh)

REC Premium for Market Entry Class 1 (2013$/MWh)					
Year	CT	ME	MA	NH	RI
2018	$14.33	$8.49	$15.80	$15.00	$15.80
2019	$15.46	$9.88	$17.02	$16.23	$17.02
2020	$16.74	$11.51	$18.40	$17.62	$18.40
2021	$16.65	$13.44	$18.39	$18.08	$18.38
2022	$16.18	$15.70	$18.02	$18.18	$17.99
2023	$15.31	$18.36	$17.24	$17.86	$20.84
2024	$19.05	$21.49	$21.06	$21.24	$24.61
2025	$26.19	$24.90	$28.28	$27.56	$28.28
2026	$26.19	$24.90	$28.28	$27.56	$28.28
2027	$26.19	$24.90	$28.28	$27.56	$28.28
2028	$26.19	$24.90	$28.28	$27.56	$28.28

These results are highly dependent upon the forecast of wholesale electric energy market prices, including the underlying forecasts of natural gas and carbon allowance prices, as well as the forecast of inflation. A lower forecast of market energy prices would yield higher REC prices than shown, particularly in the long term. In all cases, project developers will need to be able to secure long-term contracts and attract financing based on the aforementioned natural gas, carbon, and resulting electricity price forecasts in order to create this expected REC market environment. This presents an important caveat to the projected REC prices, as such long-term electricity price forecasts (particularly to the extent that they are influenced by expected carbon regulation) are not easily taken to the bank.

In contrast to the long-term REC cost of entry, spot prices in the near term will be driven by supply and demand, but are also influenced by REC market dynamics and to a lesser extent to the expected cost of entry (through banking), as follows:

- Market shortage: Prices approach the cap or Alternative Compliance Payment
- Substantial market surplus, or even modest market surplus without banking: Prices crash to approximately $0.50 to $2/MWh, reflecting transaction and risk management costs

- Market surplus with banking: Prices tend towards the cost of entry, discounted by factors including the time-value of money, the amount of banking that has taken place, expectations of when the market will return to equilibrium, and other risk management factors

Detailed projections of REC prices by state for Class I renewables are presented in Appendix F.

6.5.5 Avoided RPS Compliance Cost per MWh Reduction

Our approach to calculating avoided RPS compliance costs per MWh of reduction is described in section 6.5.2. 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 percentage of retail load that a supplier must meet from renewable energy under the RPS regulation. In other words,

$$\frac{\sum_{n} \mathrm{P}_{n,i} \times R_{n,i}}{1-l}$$

Where:

i = year

n = RPS classes

$P_{n,i}$ = projected price of RECs for RPS class n in year i,

$R_{n,i}$ = RPS requirement, expressed as a percentage, for RPS class n in year i, from Exhibit 3-9 in Deliverable 3-1.

l = losses from ISO wholesale load accounts to retail meters

For example, in a year in which REC prices are $30/MWh and the RPS percentage target is 10%, the avoided RPS cost to a retail customer would be $30 × 10% = $3/MWh. Detailed results from Appendix C are incorporated into the Appendix B Avoided Cost Worksheets by costing period. The year-by-year RPS percentages for each RPS tier are shown in Appendix F. The levelized RPS price impact for the 2014 to 2028 period, in 2013$ per MWh of load, is shown below.

Exhibit 6-31. Avoided RPS Cost by Class 2013$/MWh of Load Levelized Price Impact 2014 - 2028 (2013$)

	CT	ME	MA	NH	RI	VT
Class 1	$4.23	$1.78	$4.43	$2.43	$3.44	$0.00
All Other Classes	$0.39	$0.04	$1.83	$2.62	$0.01	$0.00
Total	**$4.62**	**$1.82**	**$6.25**	**$5.05**	**$3.45**	**$0.00**

Chapter 7: Demand Reduction Induced Price Effects

7.1 Introduction

Demand Reduction Induced Price Effect (DRIPE) refers to the reduction in prices in the wholesale markets for capacity and energy, relative to the prices forecast in the Base Case, resulting from the reduction in quantities of capacity and of energy required from those markets due to the impact of efficiency and/or demand response programs. Thus, DRIPE is a measure of the value of efficiency in terms of the reductions in wholesale prices seen by all retail customers in a given period.

Price suppression, the general term including DRIPE, is not a new concept. For a review of the literature on the effect of load reductions (or alternatively, of load increases or the addition of other resources) on market prices in competitive electricity markets, see AESC 2011 pages 6-61 to 6-69.

This chapter describes our methodology and assumptions for DRIPE, and presents our estimates of capacity DRIPE and energy DRIPE in the first two sections. The remaining section of this chapter details our estimate of natural gas DRIPE, which is new to AESC 2013.

The following exhibit provides an overview of our conceptualization of electric and gas DRIPE.

Exhibit 7-1. DRIPE Overview

Reduction in Retail Load	Affected Cost Categories	Affected Cost Component
Natural Gas	Own-price (retail gas prices)	Gas Supply
	Cross-fuel (electric energy prices)	Gas Supply
		Basis to New England
Electricity	Own-price (electric prices)	Electric Energy
		Electric Capacity
	Cross-fuel (natural gas supply prices)	Gas Supply

Our estimates indicate that the DRIPE effects are very small when expressed in terms of an impact on market prices, i.e., reductions of a fraction of a percent. However, the DRIPE impacts are significant when expressed in absolute dollar terms. Very small impacts on market prices, when applied to all energy and capacity being purchased in the market, translate into large absolute dollar amounts.

On a 15-year levelized basis, the AESC 2013 estimates of capacity DRIPE are approximately 45.3 percent lower than those from AESC 2011.[227] This decrease is primarily due to: 1) the extension of the floor

[227] AESC 2011 values for 2012 Installations levelized from 2012-2026.

price; 2) the projection of generic new generation in 2020; and 3) a change in the assumed duration of DRIPE. The AESC 2013 projections assume the phase-out, or dissipation, of capacity DRIPE will last up to eight years, versus 11 years assumed in AESC 2011. The projected dissipation of capacity DRIPE is based upon an analysis of the various factors that tend to offset the reduction in capacity prices. Those factors include timing of new capacity additions, timing of retirements of existing capacity, elasticity of customer demand, and the portion of capacity that LSEs acquire from the FCM.

The AESC 2013 estimates of intrastate energy DRIPE are approximately 18 percent lower than those from AESC 2011 on a levelized annual load weighted basis. These lower estimates are primarily due to lower wholesale energy prices and shorter DRIPE dissipation.

Although uncertainty remains regarding the projections of energy DRIPE and capacity DRIPE, the consensus among the Study Group members and the Project Team is that these projections are comprehensive and reasonable based on the available information.

7.2 Electricity DRIPE

AESC 2013 provides estimates of the effect of reductions in demand and energy from energy efficiency programs on wholesale market prices for capacity and energy within the realm of the AESC 2013 construct of no new energy efficiency in New England. We estimate DRIPE in each wholesale market in three steps:

- First, we estimate the impact a reduction in load will have on the price in that wholesale market, assuming all else is held constant (gross DRIPE). We estimate this impact by analyzing the relationship between the quantity of capacity or energy required in the relevant market and the market price.
- Second, we estimate the pace at which market participants will respond to the reduction in price with actions that offset that reduction and ultimately cause the market price to eventually return to the level it would have been under the Base Case (net DRIPE). To estimate the pace of this offset or dissipation, we estimate the material differences in actions that suppliers would take each year in the DRIPE case relative to the actions they are projected to take under the Base Case. The pace of dissipation of capacity DRIPE will likely be different from the pace of energy DRIPE, because of the differences in the types of responses available to participants in those markets. Estimating the dissipation of DRIPE involves the exercise of considerable judgment, and reasonable analysts may develop different estimates.
- Third, we estimate the percentage of net DRIPE that retail customers will experience based upon the portion of their supply that is acquired from wholesale capacity and energy markets.

7.2.1 Wholesale Electric Capacity Market Effects

AESC 2013 estimates capacity DRIPE from the slope of the capacity market-clearing price in each FCA as a function of the ISO's net installed capacity requirements and available resources. (See Chapter 5, Avoided Electric Capacity Costs, for more information on capacity market assumptions.) From June 2017 onward, we assume that the FCM price will be set by the market, rather than ISO-NE setting floor prices. From that point onward, FCM prices will be determined by the prices at which generators choose to delist. (By delisting, generators in New England are able to sell into another market such as New York, or to shut down.) We use the supply curve from FCA 7, adjusted for changes in resources, above the FCA floor price of $3.15/kW-month, and extrapolate that adjusted curve below the $3.15/kW-month level. The value of capacity DRIPE will vary over time.

Capacity prices cannot be affected by future energy-efficiency measures in the years for which capacity prices have been determined by the auction floor price. Thus, we treat capacity DRIPE effects as starting in 2018.

After estimating the magnitude of capacity DRIPE, we estimate its duration. We estimate the phase-out of capacity DRIPE based upon the assumption that the effect of reductions from efficiency programs on market prices will not last indefinitely. Over time, a number of effects of lower capacity prices will tend to affect the markets in ways that will offset the price reductions. Low market prices will result in the reduction of investments in maintaining and expanding existing generation resources, resulting in less capacity being available for future auctions (or increasing the cost of reclaiming that capacity). Lower prices will also result in earlier retirement of some generation resources, which will not be available for future auctions. We develop a phase-out of DRIPE effects consistent with the AESC 2013 retirements and additions described in Chapter 5.

As shown in Chapter 5 for FCA 8 and beyond, we estimate that the slope of the capacity supply curve over a wide range in FCA 8 and beyond would average about $0.144/kW-month in 2016 dollars, or $0.136/kW-month in 2013 dollars, per 100 MW of capacity.[228]

If all capacity were procured in the market and load reductions did not affect future supply curves, the capacity DRIPE effect in a state, in dollars per MW saved, would be the product of:

- State peak load in MW,
- One plus the percentage reserve requirement,
- 12 months per year, and
- $0.00136 per kW-month per MW saved.

For Massachusetts, with a 2014 AESC forecast of 12,626 MW, in-state capacity DRIPE would be about $235/kW-year of peak savings. For the rest of the pool, a kW saved in Massachusetts would reduce capacity bills in the rest of New England by another $280/kW-year. In FCAs 4 through 7 (which have

[228] In AESC 2011, we used different DRIPE values for various parts of the supply curve. On reflection, we recognize that the anticipated (and still poorly defined) changes in the market and retirements will change the shape of the supply curve, and use only the average slope from FCA7 as a guide to future price effects.

already occurred and set the FCM price through May 2017), the auctions ended at the floor price, and would have been at the same price without any new energy-efficiency bids. As a result, capacity DRIPE is zero through FCA 7.

However, not all load is served by capacity purchased in the market, and we expect that the supply curve would change as a result of load reductions (e.g., lower current and projected capacity prices would impair the economics of capital additions to maintain or expand capacity, even at resources that are not at the margin in the short-run FCA). At some point, the market price will be set by new generic resources and the supply curve will probably flatten, further reducing DRIPE.

Exhibit 7-2 summarizes the capacity obligation in each state that is hedged (not subject to changes in market prices), including the following:

- Investor-owned utility (IOU) contracts (pre-restructuring legacy contracts, post-restructuring reliability contracts in Connecticut, renewables purchases, and utility-owned resources in Vermont);[229]
- Generation resources owned by PSNH; and
- The load of the public utilities (municipals and coops), estimated from the percentage of sales in each state that are from the public utilities, and assuming that the public utilities are hedged to the same extent as Vermont.

The capacity hedged in each state is the sum of (1) the generation entitlements and (2) the public utility hedged capacity.[230]

[229] The Vermont PSD provided a table of resources that included both owned and purchased resources for all the state's utilities, so these categories are combined here.

[230] For Vermont, we received combined entitlement data for the IOUs and public utilities.

Exhibit 7-2. Hedged Capacity Requirement by State (MW)

	IOU Contracts						Owned	Hedged Public Utilities Capacity						Capacity Hedged					
	CT	MA	ME	NH	RI	VT	PSNH	CT	MA	ME	NH	RI	VT	CT	MA	ME	NH	RI	VT
Percent sales by public utilities								4.03%	9.73%	2.69%	1.27%	0.53%							
2014	1,296	230		92	87	961	1,131	232	1,004	44	26	8		1,304	1,053	37	100	81	820
2015	1,296	230		89	87	822	1,131	199	864	37	22	7		1,276	933	32	95	80	701
2016	1,296	244		89	87	800	1,131	195	849	37	22	7		1,272	933	31	94	80	683
2017	1,296	263		88	87	777	1,131	190	828	36	21	7		1,268	931	30	93	80	663
2018	1,296	194		88	87	777	1,131	189	826	35	21	7		1,267	871	30	93	80	663
2019	1,296	194		79	87	790	1,131	193	846	36	22	7		1,270	887	31	86	80	674
2020	1,196	147		75	87	785	1,131	191	841	36	22	7		1,183	843	31	82	80	670
2021	1,196	147		75	87	754	1,035	183	808	34	21	6		1,176	815	29	82	80	643
2022	1,196	147		72	87	733	1,035	177	787	33	20	6		1,172	797	29	79	79	626
2023	1,196	147		68	87	733	1,035	177	788	33	20	6		1,171	798	29	75	79	626
2024	1,196	140		59	87	733	1,035	176	789	33	20	6		1,171	793	29	67	79	626
2025	1,136	140		59	87	733	1,035	176	790	33	20	6		1,119	794	28	67	79	626

Notes:
1. Connecticut IOU contracts from spreadsheet provided by Brian Rice (4/24/2013)
2. Massachusetts IOU contracts from AESC 2011 (NGrid) and spreadsheet provided by Brian Rice (4/24/2013) (WMECo and NStar)
3. New Hampshire IOU (PSNH) contracts from spreadsheet provided by Brian Rice (4/24/2013)
4. Rhode Island IOU contracts from AESC 2011
5. Vermont contracts from spreadsheet provided by Sean Foley, VT PSD (4/30/2013)
6. PSNH owned capacity from CELT 2013.
7. Share of load served by public utilities (municipal and cooperative) from 2011 EIA 861 data, adjusted per SEA.
8. Capacity hedged = sum of contracts, owned and public utilities.

Exhibit 7-3 shows the results from subtracting the hedged load from total load by state, to derive the load subject to the market. As noted above, DRIPE values are zero for 2014 through 2016, so the loads in those years do not matter for this analysis.

Exhibit 7-3. Load Subject to Market Capacity Prices by State (MW)

Capacity Hedged						Peak Load 2013 AESC						Peak Load Subject to FCM Price					
CT	MA	ME	NH	RI	VT	CT	MA	ME	NH	RI	VT	CT	MA	ME	NH	RI	VT
1,304	1,053	37	100	81	820	7,049	12,626	1,991	2,471	1,870	1,003	5,745	11,572	1,954	2,371	1,789	183
1,276	933	32	95	80	701	7,192	12,947	2,032	2,544	1,903	1,022	5,917	12,014	2,000	2,450	1,823	321
1,272	933	31	94	80	683	7,331	13,264	2,068	2,613	1,942	1,037	6,059	12,331	2,037	2,519	1,862	355
1,268	931	30	93	80	663	7,489	13,521	2,105	2,661	1,981	1,052	6,221	12,590	2,074	2,568	1,901	389
1,267	871	30	93	80	663	7,592	13,742	2,136	2,705	2,015	1,072	6,325	12,872	2,106	2,612	1,935	409
1,270	887	31	86	80	674	7,671	13,949	2,162	2,748	2,043	1,082	6,400	13,062	2,131	2,662	1,964	408
1,183	843	31	82	80	670	7,749	14,151	2,188	2,787	2,072	1,097	6,565	13,308	2,158	2,704	1,992	427
1,176	815	29	82	80	643	7,822	14,353	2,214	2,825	2,101	1,112	6,646	13,538	2,185	2,743	2,021	468
1,172	797	29	79	79	626	7,907	14,566	2,242	2,867	2,132	1,127	6,735	13,769	2,214	2,788	2,052	501
1,171	798	29	75	79	626	7,992	14,783	2,271	2,910	2,163	1,142	6,821	13,985	2,242	2,835	2,084	516
1,171	793	29	67	79	626	8,078	15,001	2,299	2,953	2,195	1,157	6,907	14,208	2,270	2,886	2,115	532
1,119	794	28	67	79	626	8,164	15,222	2,327	2,997	2,226	1,173	7,045	14,429	2,299	2,930	2,147	547
Load subject to market price = peak – Hedged capacity ÷ 1.172																	

The DRIPE effect for each state's capacity charges, as a result of one kilowatt of load reduction in the state, is shown in Exhibit 7-4, as the product of:

1) The load subject to market price in MW,
2) The DRIPE coefficient of $0.136/kW-month per MW,
3) One plus the 17.2 percent reserve requirement, and
4) One minus a decay factor.

The decay factor reflects the increasing probability over time that (a) lower capacity prices will result in retirement of existing units or the delay of power-plant upgrades, and (b) the FCM price will be set by the cost of new generic resources with small differences in their bid prices. This particular decay trajectory is subjective, since we have limited or no publicly available data on the underlying behavior of capacity suppliers.

Exhibit 7-4. In-State Capacity DRIPE by State (MW)

	Peak Load Subject to FCM Price						2014	$/kW-month capacity DRIPE						
	CT	MA	ME	NH	RI	VT	Decay	CT	MA	ME	NH	RI	VT	ISO
2014	5,745	11,572	1,954	2,371	1,789	183	10%	-	-	-	-	-	-	-
2015	5,917	12,014	2,000	2,450	1,823	321	20%	-	-	-	-	-	-	-
2016	6,059	12,331	2,037	2,519	1,862	355	30%	-	-	-	-	-	-	-
2017	6,221	12,590	2,074	2,568	1,901	389	40%	$5.06	$10.25	$1.69	$2.09	$1.55	$0.32	$20.96
2018	6,325	12,872	2,106	2,612	1,935	409	50%	$4.29	$8.73	$1.43	$1.77	$1.31	$0.28	$17.82
2019	6,400	13,062	2,131	2,662	1,964	408	60%	$3.47	$7.09	$1.16	$1.44	$1.07	$0.22	$14.45
2020	6,565	13,308	2,158	2,704	1,992	427	70%	$2.67	$5.42	$0.88	$1.10	$0.81	$0.17	$11.05
2021	6,646	13,538	2,185	2,743	2,021	468	80%	$1.80	$3.67	$0.59	$0.74	$0.55	$0.13	$7.49
2022	6,735	13,769	2,214	2,788	2,052	501	85%	$1.37	$2.80	$0.45	$0.57	$0.42	$0.10	$5.71
2023	6,821	13,985	2,242	2,835	2,084	516	90%	$0.93	$1.90	$0.30	$0.38	$0.28	$0.07	$3.86
2024	6,907	14,208	2,270	2,886	2,115	532	95%	$0.47	$0.96	$0.15	$0.20	$0.14	$0.04	$1.96

Exhibit 7-4 also provides similar results for the effect of load reduction in any state on capacity bills for consumers in the entire ISO.

On a levelized basis, the AESC 2013 regional capacity DRIPE value of $68.26/kW-year is about 45.3 percent lower than the AESC 2011 (2013$) value of $124.74/kW-year.

The AESC 2011 study attempted to replicate the specific shape of the FCA 4 supply curve, and assumed that the floor price would extend only to FCA 6. AESC 2013 uses the slope of the FCA 7 supply curve, but does not incorporate every twist and turn in the curve, resulting in smoother DRIPE transitions. In addition, AESC 2013 recognizes that the ISO has extended the price floor through FCA 7. Finally, since AESC 2011, we have drawn closer to the end of a capacity surplus (with the passage of time and the expected retirement of most fossil-steam generators).

7.2.2 Wholesale Electric Energy Market Effects

AESC 2013 estimates the magnitude of wholesale energy market DRIPE by year by conducting a set of regressions of historical zonal hourly market prices against zonal and regional load, similar to the process conducted in AESC 2007, 2009, and 2011. We have simplified the analysis by:

- Normalizing prices in each zone in each month in each period (on- or off-peak) to the average price in that zone/month/period (such that the average price is set to 1.0);
- Conducting a single regression on the normalized prices over several years (2009-2012), rather than conducting hundreds of separate regressions for each month and then normalizing and averaging the results; and
- Summing load and averaging prices across the three Massachusetts zones before conducting the regressions.

More specifically, we estimated regression equations for two formulations:

$$\text{normalized state LMP} = a + b \times \text{normalized state load} + c \times \text{normalized ROP load} \quad (1)$$

and

$$\text{normalized state LMP} = a + b \times \text{normalized ISO load} \quad (2)$$

The coefficients thus represent the percent change in state LMP as a function of a percent change in load. We use Equation 1 (state and rest-of-pool load) where the load coefficients are sensible (both positive and the state coefficient, adjusted for load level, exceeds the ROP coefficients) and otherwise use Equation 2. We use the regressions with only the ISO load variable for Vermont, Maine, and Connecticut on-peak energy; and the regressions with both state and ROP load for Massachusetts, New Hampshire, Rhode Island, and Connecticut off-peak energy.[231] The regression results are summarized in Exhibit 7-5. The bolded values in the exhibit are the coefficients used in subsequent calculations.

[231] The Vermont and Maine own-state coefficients are negative, which does not make sense. The Connecticut on-peak own-state coefficient is positive, but even normalized for the three-fold ratio of ROP load to Connecticut load, the own-state coefficient would imply in a smaller effect on Connecticut price from a MWh of Connecticut load than a MW of ROP load. Similar computations for New Hampshire, Rhode Island, and the Connecticut off-peak regression result in own-state effects per MWh four to seven times the ROP effects.

Exhibit 7-5. Energy DRIPE Coefficients by State

	Off Peak (18,711 hours)						On Peak (16,352 hours)					
Normalized LMP vs. Normalized (State Load, Rest-of-Pool)												
	CT	**MA**	**ME**	**NH**	**RI**	**VT**	**CT**	**MA**	**ME**	**NH**	**RI**	**VT**
Adjusted R^2	51.1%	50.2%	47.5%	50.9%	43.5%	51.1%	44.0%	42.6%	42.4%	43.8%	43.2%	47.2%
Intercept	-0.202	-0.181	-0.203	-0.099	-0.109	-0.108	-1.288	-1.253	-1.189	-1.185	-1.163	-0.913
State Load	**0.788**	**0.809**	-0.207	**0.488**	**0.245**	-0.263	0.473	**1.818**	-0.299	**0.653**	**0.713**	-0.594
Rest-of-Pool Load	**0.414**	**0.372**	1.411	**0.611**	**0.864**	1.371	1.815	**0.435**	2.489	**1.532**	**1.450**	2.507
t-stat State load	23.23	18.96	-19.10	23.22	10.78	-17.82	11.81	32.19	-18.62	22.53	23.67	-32.42
t-stat ROP load	11.3	9.7	92.1	24.8	35.4	89.8	40.2	7.9	99.7	44.1	37.4	118.0
Normalized LMP vs. Normalized ISO Load												
	CT	**MA**	**ME**	**NH**	**RI**	**VT**	**CT**	**MA**	**ME**	**NH**	**RI**	**VT**
Adjusted R2	50.6%	50.1%	45.5%	50.0%	43.3%	50.0%	44.0%	42.0%	39.5%	43.0%	42.0%	42.8%
Intercept	0.234	-0.153	-0.151	-0.143	-0.110	-0.144	-1.282	-1.235	-1.195	-1.199	-1.232	-1.191
ISO Pool Load	1.234	1.152	**1.151**	1.143	1.110	**1.144**	**2.282**	2.235	**2.195**	2.199	2.232	**2.191**
t-stat ISO load	138.6	137.2	125.0	136.9	119.6	136.7	113.4	108.7	103.4	111.0	108.9	110.7

The results are remarkably stable across states. A 1.0 percent reduction in load throughout New England results in a 1.1 to 1.2 percent reduction in off-peak price, and a 1.9 to 2.2 percent reduction in peak price.

As is true for capacity DRIPE, energy DRIPE is applicable only to energy purchased at market prices, and the effect of DRIPE decays over time. In addition, while energy DRIPE starts immediately (there is no floor price in the energy market), most energy purchased at market price for retail load is priced months or a couple years in advance of delivery, through utility contracting for standard service or a third-party contract. Hence, the magnitude of energy DRIPE is reduced in the early years following measure implementation.

Exhibit 7-6 summarizes the hedged (not subject to changes in market prices) energy obligation in each state, including the following:[232]

- IOU contracts (pre-restructuring legacy contracts, post-restructuring reliability contracts in Connecticut, renewables purchases, and utility-owned resources in Vermont);[233]

[232] These factors are the energy equivalents of the factors discussed in the Capacity DRIPE section.

[233] Based on the energy-modeling runs, we assume that the Connecticut peaker contracts would operate at a 6 percent capacity factor through 2019 and at 4 percent thereafter. The Vermont resources include a large purchase from HQ that is partially tied to market prices, with lags and fixed components. Since the pricing terms are not public, we assumed that 50 percent of the Vermont HQ contract price is tied to current market prices.

- Generation resources owned by PSNH, at the unit output from 2011; and
- The load of the public utilities (municipals and coops), estimated from the percentage of sales in each state that are from the public utilities, and assuming that the public utilities are hedged to the same extent as Vermont.

The energy hedged in each state is the sum of (1) the generation entitlements and (2) the public utility hedged energy.

Exhibit 7-6. Hedged Energy Requirement by State (GWh)

	Contracts						Owned	Public Utilities Entitlements					
	CT	MA	ME	NH	RI	VT	PSNH	CT	MA	ME	NH	RI	VT
								4.03%	9.73%	2.69%	1.27%	0.53%	included
2014	266	1,311		739	760	4,135	3,001	1,244	5,624	294	145	42	
2015	266	2,317		726	760	3,612	3,001	901	4,082	214	105	30	
2016	266	2,798		725	760	3,524	3,001	832	3,775	198	97	28	
2017	266	2,798		724	760	3,500	3,001	768	3,495	183	90	26	
2018	266	2,798		723	760	3,500	3,001	767	3,500	183	90	26	
2019	266	2,798		655	760	3,618	3,001	792	3,624	189	93	27	
2020	177	2,750		621	760	3,600	2,772	787	3,609	187	93	27	
2021	177	2,616		621	760	3,444	2,772	751	3,454	179	89	25	
2022	177	2,616		603	760	3,443	2,772	750	3,458	179	89	25	
2023	177	2,387		573	760	3,283	2,772	714	3,302	170	84	24	
2024	177	2,387		500	760	3,283	2,772	714	3,306	170	84	24	
2025	177	2,387		500	760	3,242	2,772	704	3,269	168	83	24	

Exhibit 7-7 subtracts the hedged energy from total energy by state, to derive the load subject to the market. Based on our knowledge of the procurement policies for standard service and of the length of third-party contracts, and information provided by some of the participating utilities, we estimate that 80 percent of energy is pre-contracted for the year of measure installation, 20 percent in the following year, and 10 percent in the third year.

Exhibit 7-7. Load Subject to Market Energy Prices, by State, 2014 installations, GWh

	Energy Hedged						Energy 2013 AESC						Short-term Contract	Energy Subject to LMP, 2014 EE					
	CT	MA	ME	NH	RI	VT	CT	MA	ME	NH	RI	VT		CT	MA	ME	NH	RI	VT
2014	1,510	6,935	294	3,885	802	4,135	32,966	61,791	11,695	12,248	8,405	6,091	80%	6,291	10,971	2,280	1,673	1,521	391
2015	1,167	6,399	214	3,832	790	3,612	33,428	62,776	11,901	12,458	8,526	6,166	20%	25,808	45,102	9,350	6,901	6,189	2,044
2016	1,098	6,573	198	3,823	788	3,524	33,869	63,737	12,082	12,644	8,658	6,232	10%	29,494	51,447	10,696	7,939	7,083	2,437
2017	1,034	6,293	183	3,815	786	3,500	34,261	64,642	12,233	12,804	8,780	6,297		33,227	58,350	12,051	8,990	7,994	2,797
2018	1,033	6,298	183	3,813	786	3,500	34,623	65,513	12,375	12,950	8,897	6,373		33,590	59,215	12,192	9,137	8,111	2,872
2019	1,058	6,422	189	3,748	787	3,618	34,975	66,358	12,506	13,101	9,003	6,443		33,917	59,936	12,317	9,352	8,217	2,825
2020	964	6,359	187	3,485	787	3,600	35,321	67,189	12,627	13,251	9,095	6,519		34,357	60,830	12,440	9,766	8,309	2,919
2021	929	6,070	179	3,481	785	3,444	35,673	68,004	12,758	13,402	9,182	6,594		34,744	61,934	12,579	9,921	8,397	3,151
2022	928	6,074	179	3,464	785	3,443	36,030	68,862	12,891	13,554	9,284	6,669		35,102	62,788	12,713	10,091	8,499	3,226
2023	892	5,689	170	3,430	784	3,283	36,389	69,727	13,025	13,708	9,387	6,744		35,497	64,039	12,855	10,279	8,603	3,461
2024	891	5,693	170	3,356	784	3,283	36,749	70,600	13,160	13,863	9,491	6,820		35,859	64,907	12,989	10,507	8,706	3,536
2025	881	5,656	168	3,355	784	3,242	37,112	71,479	13,295	14,020	9,595	6,895		36,231	65,823	13,127	10,664	8,811	3,653

Exhibit 7-8 provides the same computation for 2015 installations, for which the effects of the short-term contracts occur one year later than for 2014 installations.

Exhibit 7-8. Load Subject to Market Energy Prices, by State, 2015 installations

	Short-term Contracts	Energy Subject to LMP, 2015 EE					
		CT	MA	ME	NH	RI	VT
2015	80%	6,452	11,275	2,337	1,725	1,547	511
2016	20%	26,217	45,731	9,507	7,057	6,296	2,166
2017	10%	29,904	52,515	10,846	8,091	7,195	2,517
2018		33,590	59,215	12,192	9,137	8,111	2,872
2019		33,917	59,936	12,317	9,352	8,217	2,825
2020		34,357	60,830	12,440	9,766	8,309	2,919
2021		34,744	61,934	12,579	9,921	8,397	3,151
2022		35,102	62,788	12,713	10,091	8,499	3,226
2023		35,497	64,039	12,855	10,279	8,603	3,461
2024		35,859	64,907	12,989	10,507	8,706	3,536
2025		36,231	65,823	13,127	10,664	8,811	3,653

We estimate the phase-out of energy DRIPE based upon four factors:

1) Over time, customers would respond to lower energy prices by using somewhat more energy, pushing prices back up somewhat.
2) Lower loads would reduce acquisition mandates under renewable and other alternative-energy standards that specify the percentage of energy that must be provided by various categories of resources. The reduced acquisition of renewables would tend to increase prices.
3) Owners of existing generating capacity would tend to allow their energy-producing assets to become less efficient and reliable as low energy prices make continued operation of the units less attractive, leading to more outages and higher market-clearing prices.
4) The addition of new resources would tend to be delayed, and the mix of new resources would tend to be shifted toward peakers and away from baseload resources that would otherwise have reduced energy prices.

Exhibit 7-9 summarizes our estimate of the decay of energy DRIPE for 2014 installations. The demand elasticity is driven by rebound of sales as a result of price reduction, using the price elasticity estimated by ISO-NE in the 2012 CELT forecast and assuming that LMP would be 50 percent of retail revenues.[234] The RPS offset equals the load-weighted average of the new-renewable (Class 1) RPS requirement for each calendar year; each MWh of load reduction reduces the required renewable build-out by a fraction of a MWh, which pushes prices up.

The adjustments for existing and new generation are more judgmental. As prices fall, the incentive for generation owners to make investments to maintain the capacity, reliability, and heat rate for existing units declines, leading to additional retirements, de-rating, and lower availability. We assume that effect rises gradually from the time the energy-efficiency measures are implemented. We estimate in Chapter 5 that new generic capacity will be required around 2020, and recognize the uncertainty in the timing of the new capacity, in whether load reduction will delay new capacity, and whether the avoided capacity will be peaking combustion turbines (which provide little energy) or combined-cycle units (which provide large amounts of energy). We estimate total elimination of DRIPE by 2024.

Exhibit 7-9. Energy DRIPE Decay, 2014 installations

	Year	Demand Elasticity	RPS	Existing Generation	New Generation	Total
2014	1	4.0%	7.9%	2.0%		13%
2015	2	6.0%	8.9%	4.0%		18%
2016	3	6.9%	10.0%	6.0%		21%
2017	4	7.4%	11.0%	8.0%	5.0%	28%
2018	5	7.6%	11.9%	10.0%	10.0%	34%
2019	6	7.7%	12.8%	12.0%	25.0%	47%
2020	7	7.8%	13.7%	14.0%	40.0%	59%
2021	8	7.8%	14.2%	16.0%	55.0%	70%
2022	9	7.8%	14.6%	18.0%	70.0%	81%
2023	10	7.8%	15.1%	20.0%	85.0%	91%
2024	11	7.8%	15.6%	22.0%	100.0%	100%

Exhibit 7-10 shows the same computation for 2015 installations, with the price-elasticity and existing-generation effects starting one year later.

[234] This assumption somewhat overstates DRIPE decay, since the actual ratio of day-ahead LMP to retail rates averaged about 30% in 2009–2012.

Exhibit 7-10. Energy DRIPE Decay, 2015 installations

	Year	Demand Elasticity	RPS	Existing Generation	New Generation	Total
2015	1	4.0%	8.9%	2.0%		14%
2016	2	6.0%	10.0%	4.0%		19%
2017	3	6.9%	11.0%	6.0%	5.0%	26%
2018	4	7.4%	11.9%	8.0%	10.0%	32%
2019	5	7.6%	12.8%	10.0%	25.0%	46%
2020	6	7.7%	13.7%	12.0%	40.0%	58%
2021	7	7.8%	14.2%	14.0%	55.0%	69%
2022	8	7.8%	14.6%	16.0%	70.0%	80%
2023	9	7.8%	15.1%	18.0%	85.0%	90%
2024	10	7.8%	15.6%	20.0%	100.0%	100%

The energy DRIPE values for each state's energy on-peak and off peak periods, as a result of one MWh of load reduction in the state, are shown in Exhibit 7-11, Exhibit 7-12, Exhibit 7-13, and Exhibit 7-14, as the product of:

1) The load subject to market price in GWh, from Exhibit 7-7;
2) The own-state or ISO DRIPE coefficient, from Exhibit 7-5;
3) One divided by the own-state or ISO energy load, to convert from MWh to percent of load (the variable for which the coefficient was computed);
4) The regional market energy price; and
5) One minus the decay factor, from Exhibit 7-9.

Comparable data for off-peak energy DRIPE for 2014 and 2015 installations are shown for each state in the four exhibits for both intrastate and rest-of-pool energy DRIPE. The rest of pool energy DRIPE effects are generally parallel to those for own-state DRIPE, but are determined by summing across the other states: the energy subject to market energy prices, times the coefficient for the rest of pool (or ISO) regression variable, times the regional market energy price and one minus the decay factor.

Exhibit 7-11. Energy DRIPE Values for 2014 Installation On Peak Periods ($/MWh)

Winter On Peak													
	Intrastate							Rest of Pool					
	CT	MA	ME	NH	RI	VT		CT	MA	ME	NH	RI	VT
2014	5.10	15.26	1.78	4.22	6.11	0.30		7.27	16.56	9.62	10.63	10.44	10.76
2015	19.30	57.86	6.72	16.02	22.95	1.47		27.95	63.29	36.77	40.57	39.88	40.70
2016	20.06	60.00	7.00	16.77	23.87	1.59		29.17	66.03	38.32	42.25	41.55	42.33
2017	19.61	58.99	6.84	16.48	23.35	1.58		28.63	64.71	37.57	41.39	40.72	41.45
2018	18.97	57.22	6.62	16.04	22.65	1.56		27.79	62.78	36.43	40.11	39.48	40.16
2019	16.46	49.70	5.75	14.11	19.71	1.32		24.14	54.54	31.62	34.78	34.27	34.90
2020	14.50	43.81	5.05	12.81	15.44	1.18		21.38	48.25	27.97	30.65	30.29	30.82
2021	10.52	31.98	3.66	9.34	11.11	0.92		15.63	35.17	20.40	22.34	22.08	22.40
2022	7.14	21.76	2.49	6.38	7.46	0.63		10.64	23.93	13.88	15.18	15.01	15.22
2023	3.58	11.00	1.25	3.23	3.69	0.34		5.38	12.07	7.00	7.65	7.57	7.66
Summer On Peak													
	Intrastate							Rest of Pool					
	CT	MA	ME	NH	RI	VT		CT	MA	ME	NH	RI	VT
2014	4.10	12.28	1.43	3.39	4.91	0.24		5.85	13.32	7.74	8.55	8.40	8.65
2015	16.21	48.60	5.65	16.02	19.27	1.47		23.48	53.15	30.89	34.07	33.49	34.19
2016	17.72	53.00	6.18	16.77	21.08	1.59		25.76	58.32	33.85	37.32	36.70	37.39
2017	20.20	60.76	7.05	16.48	24.05	1.58		29.49	66.66	38.70	42.63	41.95	42.69
2018	19.97	60.22	6.97	16.04	23.84	1.56		29.25	66.06	38.34	42.21	41.54	42.26
2019	17.30	52.25	6.04	14.11	20.72	1.32		25.37	57.33	33.25	36.56	36.02	36.69
2020	14.36	43.38	5.00	12.81	15.03	1.18		21.17	47.78	27.70	30.35	29.99	30.52
2021	10.89	33.11	3.79	9.34	11.31	0.92		16.18	36.41	21.12	23.13	22.86	23.19
2022	7.00	21.34	2.44	6.38	7.15	0.63		10.44	23.47	13.61	14.89	14.72	14.93
2023	3.64	11.16	1.27	3.23	3.67	0.34		5.46	12.24	7.10	7.76	7.68	7.77

Exhibit 7-12. Energy DRIPE Values for 2014 Installation Off Peak Periods ($/MWh)

Winter Off Peak													
	Intrastate							Rest of Pool					
	CT	MA	ME	NH	RI	VT		CT	MA	ME	NH	RI	VT
2014	6.22	5.94	0.81	2.76	1.83	0.14		3.91	4.63	3.22	3.78	3.57	3.78
2015	23.87	22.79	3.12	10.60	6.97	0.68		15.17	18.00	12.52	14.65	13.84	14.50
2016	24.96	23.74	3.26	11.15	7.28	0.74		15.89	18.90	13.11	15.33	14.49	15.15
2017	24.11	23.03	3.15	10.81	7.03	0.73		15.39	18.29	12.71	14.84	14.03	14.66
2018	23.41	22.38	3.05	10.54	6.83	0.71		14.97	17.79	12.36	14.42	13.64	14.24
2019	20.10	19.21	2.62	9.16	5.87	0.60		12.84	15.27	10.61	12.36	11.71	12.24
2020	17.85	17.04	2.32	8.37	4.70	0.54		11.43	13.61	9.45	10.97	10.42	10.88
2021	13.27	12.73	1.72	6.25	3.43	0.43		8.55	10.17	7.07	8.20	7.79	8.10
2022	8.97	8.61	1.16	4.24	2.29	0.29		5.79	6.89	4.79	5.54	5.27	5.48
2023	4.50	4.35	0.58	2.14	1.13	0.16		2.92	3.47	2.42	2.80	2.66	2.75
Summer Off Peak													
	Intrastate							Rest of Pool					
	CT	MA	ME	NH	RI	VT		CT	MA	ME	NH	RI	VT
2014	4.97	4.74	0.65	2.20	1.46	0.11		3.12	3.70	2.58	3.02	2.85	3.02
2015	19.14	18.28	2.50	8.51	5.59	0.54		12.17	14.44	10.04	11.75	11.10	11.63
2016	20.47	19.47	2.68	9.14	5.97	0.61		13.03	15.49	10.75	12.57	11.88	12.42
2017	22.24	21.24	2.90	9.97	6.48	0.67		14.20	16.87	11.72	13.69	12.94	13.52
2018	21.72	20.77	2.83	9.78	6.34	0.66		13.89	16.51	11.47	13.38	12.66	13.21
2019	18.54	17.72	2.42	8.45	5.42	0.55		11.85	14.09	9.79	11.41	10.80	11.29
2020	16.54	15.80	2.15	7.76	4.31	0.50		10.60	12.62	8.77	10.17	9.66	10.09
2021	12.29	11.79	1.59	5.78	3.13	0.40		7.92	9.42	6.55	7.59	7.21	7.50
2022	8.30	7.97	1.07	3.93	2.08	0.27		5.35	6.37	4.43	5.13	4.88	5.07
2023	4.19	4.05	0.54	2.00	1.04	0.14		2.72	3.24	2.25	2.60	2.48	2.57

Exhibit 7-13. Energy DRIPE Values for 2015 Installations On Peak Periods ($/MWh)

Winter On Peak													
	Intrastate							Rest of Pool					
	CT	MA	ME	NH	RI	VT		CT	MA	ME	NH	RI	VT
2015	5.03	15.07	1.75	4.17	5.98	0.38		7.28	16.48	9.58	10.57	10.39	10.60
2016	18.40	55.03	6.42	15.37	21.89	1.46		26.75	60.55	35.15	38.75	38.11	38.82
2017	18.13	54.52	6.32	15.23	21.58	1.46		26.46	59.81	34.72	38.25	37.64	38.31
2018	19.45	58.64	6.79	16.44	23.21	1.60		28.48	64.33	37.33	41.11	40.46	41.16
2019	16.85	50.89	5.89	14.45	20.18	1.35		24.71	55.84	32.38	35.62	35.09	35.74
2020	14.84	44.86	5.17	13.12	15.81	1.21		21.89	49.40	28.64	31.38	31.01	31.56
2021	10.78	32.76	3.75	9.56	11.38	0.94		16.01	36.02	20.89	22.88	22.61	22.94
2022	7.32	22.29	2.55	6.54	7.64	0.65		10.90	24.52	14.22	15.55	15.38	15.60
2023	3.67	11.27	1.28	3.31	3.79	0.34		5.52	12.37	7.18	7.84	7.76	7.85
Summer On Peak													
	Intrastate							Rest of Pool					
	CT	MA	ME	NH	RI	VT		CT	MA	ME	NH	RI	VT
2015	4.22	12.66	1.47	4.17	5.02	0.38		6.12	13.84	8.04	8.88	8.72	8.90
2016	16.25	48.60	5.67	15.37	19.33	1.46		23.63	53.48	31.04	34.22	33.66	34.29
2017	18.67	56.15	6.51	15.23	22.23	1.46		27.26	61.61	35.77	39.40	38.77	39.46
2018	20.46	61.71	7.14	16.44	24.43	1.60		29.98	67.70	39.29	43.26	42.58	43.31
2019	17.72	53.50	6.19	14.45	21.22	1.35		25.98	58.71	34.04	37.44	36.89	37.57
2020	14.70	44.42	5.12	13.12	15.39	1.21		21.67	48.92	28.36	31.08	30.71	31.25
2021	11.16	33.91	3.88	9.56	11.59	0.94		16.57	37.29	21.63	23.68	23.41	23.75
2022	7.18	21.86	2.50	6.54	7.32	0.65		10.69	24.05	13.94	15.26	15.08	15.30
2023	3.73	11.44	1.30	3.31	3.76	0.34		5.60	12.55	7.28	7.96	7.87	7.96

Exhibit 7-14. Energy DRIPE Values for 2015 Installations Off Peak Periods ($/MWh)

Winter Off Peak													
	Intrastate							Rest of Pool					
	CT	MA	ME	NH	RI	VT		CT	MA	ME	NH	RI	VT
2015	6.22	5.94	0.81	2.76	1.81	0.18		3.95	4.69	3.26	3.82	3.60	3.78
2016	22.89	21.77	2.99	10.22	6.68	0.68		14.57	17.33	12.03	14.06	13.29	13.89
2017	22.28	21.28	2.91	9.99	6.50	0.67		14.22	16.90	11.75	13.72	12.97	13.55
2018	23.99	22.93	3.13	10.80	7.00	0.73		15.34	18.23	12.67	14.78	13.98	14.59
2019	20.58	19.67	2.68	9.38	6.01	0.61		13.15	15.64	10.87	12.66	11.99	12.53
2020	18.27	17.45	2.37	8.57	4.81	0.55		11.70	13.94	9.68	11.23	10.67	11.14
2021	13.59	13.04	1.76	6.40	3.52	0.44		8.75	10.42	7.24	8.39	7.98	8.30
2022	9.19	8.82	1.19	4.35	2.35	0.30		5.93	7.06	4.91	5.68	5.40	5.61
2023	4.61	4.46	0.60	2.20	1.16	0.16		2.99	3.56	2.48	2.87	2.73	2.82
Summer Off Peak													
	Intrastate							Rest of Pool					
	CT	MA	ME	NH	RI	VT		CT	MA	ME	NH	RI	VT
2015	4.99	4.76	0.65	2.22	1.46	0.14		3.17	3.76	2.62	3.06	2.89	3.03
2016	18.77	17.85	2.45	8.38	5.47	0.56		11.95	14.21	9.86	11.53	10.89	11.39
2017	20.56	19.63	2.68	9.22	5.99	0.62		13.12	15.59	10.84	12.65	11.96	12.50
2018	22.26	21.28	2.90	10.03	6.50	0.68		14.23	16.92	11.76	13.72	12.97	13.54
2019	18.99	18.15	2.47	8.66	5.55	0.56		12.13	14.43	10.02	11.68	11.06	11.56
2020	16.94	16.18	2.20	7.95	4.41	0.51		10.85	12.92	8.97	10.41	9.89	10.33
2021	12.59	12.08	1.63	5.92	3.20	0.41		8.11	9.65	6.71	7.77	7.39	7.68
2022	8.50	8.16	1.10	4.02	2.14	0.28		5.48	6.53	4.54	5.25	4.99	5.19
2023	4.30	4.15	0.56	2.05	1.06	0.15		2.79	3.32	2.31	2.67	2.54	2.63

7.3 Natural Gas DRIPE

Just as reducing electric load reduces electric energy prices, reducing gas usage reduces demand for gas in producing regions and therefore reduces the market price of that gas supply. This report refers to that gas price reduction effect as gas DRIPE.

As discussed in Chapter 2, the wholesale cost of gas for gas consumers (the customers of the local distribution companies, or LDCs) and the cost of gas for electric generation in New England can each be broken into two components:

- The supply component, determined by North American demand and supply conditions on a largely annual basis, and
- Transportation costs or basis, determined by contract prices for LDCs and by the balance of regional demand and supply (mostly from pipelines) on a daily and seasonal basis.

The following sections of this chapter consider, in turn, the effects of gas-use reductions on gas supply prices and on the market basis for delivery to New England. The final section estimates the cross-fuel DRIPE effects caused by the linkage of gas and electricity through the gas used in electric generation.

7.3.1 Wholesale gas supply market effects

Interest in the effect on natural gas prices of reduced consumption has considerable history. Exhibit 7-15 summarizes the results of a number of analyses in the period 1998 to 2004 that estimated the effect on North America natural gas prices of reducing gas use through gas or electric energy-efficiency programs and/or renewable energy.[235] Most of these studies estimated gas DRIPE based upon projections from the EIA's National Energy Modeling System (NEMS), which the EIA uses to develop its Annual Energy Outlook.[236]

Exhibit 7-15. Estimates of Gas Price Suppression from Reduced Usage for 2020

Author	Reduction in U.S. Annual Gas Consumption quads	Reduction in annual average Gas Wellhead Price $/MMBtu (2000$)	Reduction in wellhead price pre reduction in consumption $/MMBtu per quad (2000$)
EIA (1998)	1.12	$0.34	$0.30
EIA (1999)	0.41	$0.19	$0.46
EIA (2001)	1.45	$0.27	$0.19
EIA (2001)	3.89	$0.56	$0.14
EIA (2002a)	0.72	$0.12	$0.17
EIA (2002a)	1.32	$0.22	$0.17
EIA (2003)	0.48	$0.00	$0.00
UCS (2001)	10.54	$1.58	$0.15
UCS (2002a)	1.28	$0.32	$0.25
UCS (2002a)	3.21	$0.55	$0.17
UCS (2002b)	0.72	$0.05	$0.07
UCS (2003)	0.10	$0.14	$1.40
UCS (2004a)	0.49	$0.12	$0.24
UCS (2004a)	1.80	$0.07	$0.04
UCS (2004b)	0.62	$0.11	$0.18
UCS (2004b)	1.45	$0.27	$0.19
Tellus (2002)	0.13	$0.00	$0.00
Tellus (2002)	0.23	$0.01	$0.04
Tellus (2002)	0.28	$0.02	$0.07
ACEEE (2003)	1.35	$0.76	$0.56

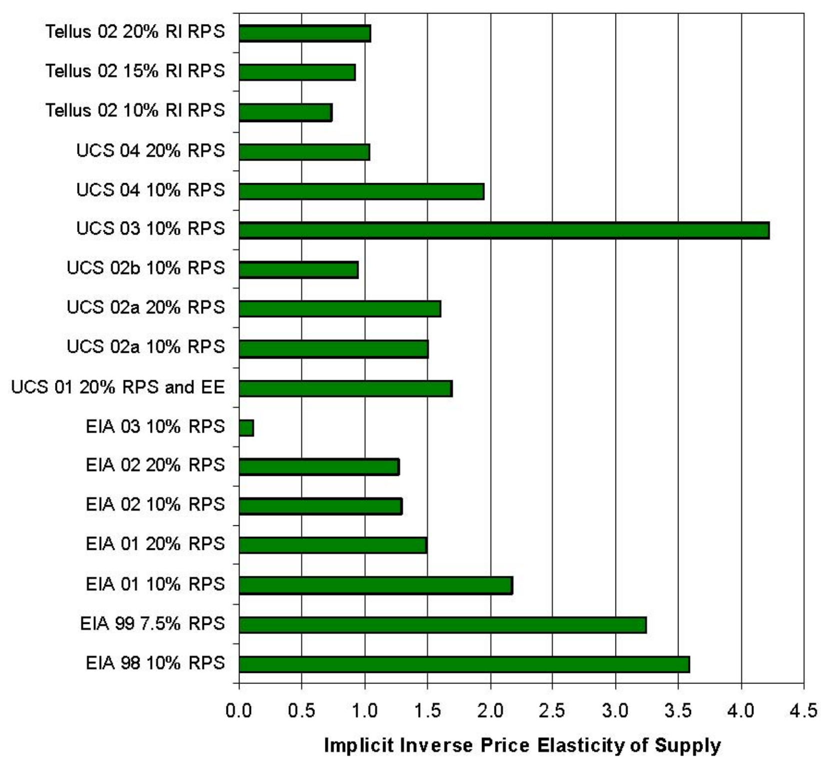
Source: Wiser (2005)

235 The city-gate wholesale price of gas varies by region throughout the United States. For any point on the pipeline system, the national average wellhead gas price is always well over half the city-gate price on an annual basis, as shown for New England in Chapter 2.

236 The ACEEE study used the proprietary model of Energy and Environmental Analysis, Inc.

Exhibit 7-16 summarizes the supply elasticities for these studies.[237] Most of these analyses estimated that a 1 percent reduction in annual U.S. gas consumption would reduce annual average gas wellhead prices by about 1 to 3 percent, with a few outliers on each side. For the roughly $4 gas supply prices AESC 2013 projects for 2014–2016, a price reduction of 1 to 3 percent would be about $0.04 to $0.12/MMBtu (2013$). For the $6/MMBtu supply price that AESC projects for 2021–2030, a 1 percent load reduction would reduce prices $0.06 to $0.18/MMBtu. Load changes in New England alone would have much smaller effects on supply prices, since annual New England gas consumption is only about 0.9 quads, or 3.5 percent of national consumption of 25 quads. Only about half of New England gas consumption is by end users, with electric generators using the other half. With the elasticity range of 1 to 3 percent, a 1 percent reduction in New England end-use gas would reduce supply prices by only about $0.001 to $0.004/MMBtu in the 2020s. That range of price reductions would reduce gas bills to New England end users by one to a few million dollars annually, enough to warrant further analysis.

Exhibit 7-16. Gas-Supply Elasticities



The structure of natural gas supply has changed considerably since these studies were performed, with the growing importance of shale gas and the transition from forecasts of large LNG imports to potential LNG exports. As a result, we have not used these older analyses to estimate gas-supply DRIPE. Instead,

[237] The elasticities cannot be directly computed from Exhibit 7-11, due to rounding and the fact that Exhibit 7-11 does not list the base consumption and price for each study.

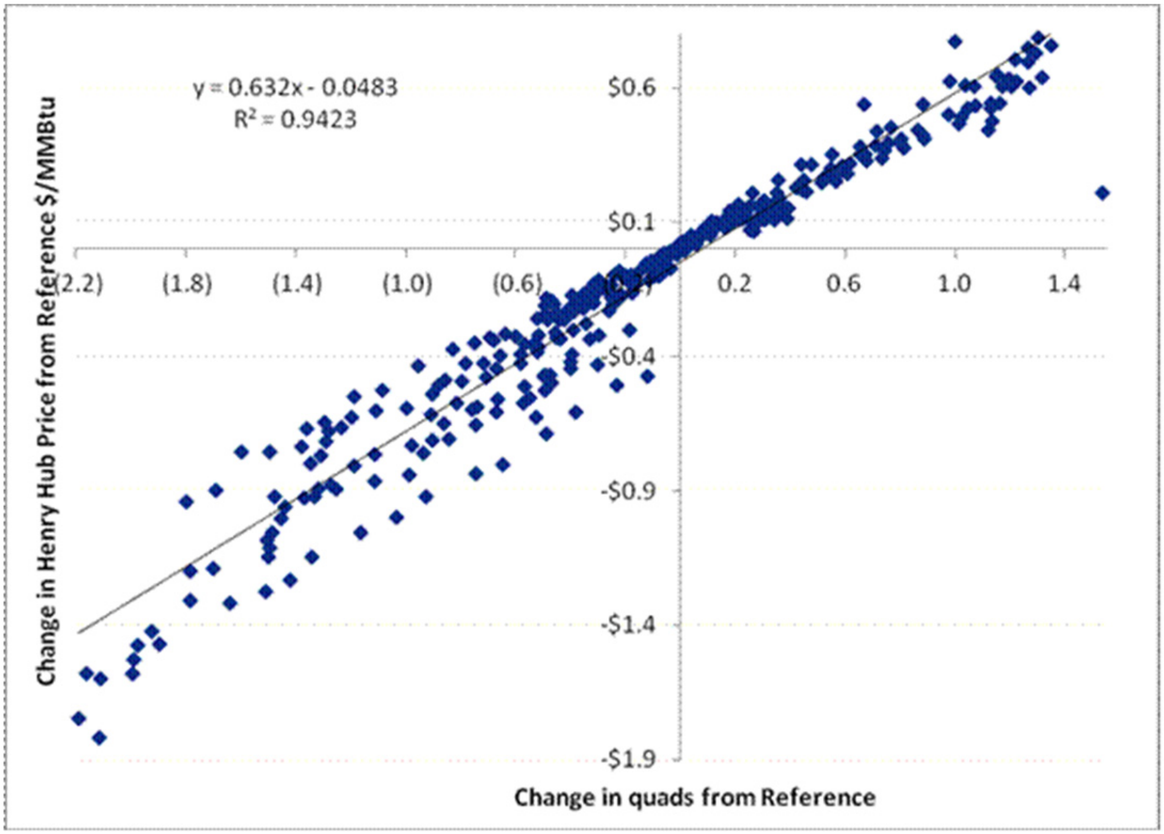
we have used EIA's most recent set of sensitivity analyses, from the 2012 AEO. Exhibit 7-17 lists the cases we identified as changing natural gas demand without affecting the gas supply curve, and identifies the differences in consumption and Henry Hub prices between the case listed and the AEO Reference Case in 2020.

Exhibit 7-17. AEO 2012 Gas-Demand Sensitivity Cases for 2020

Forecast Case	Change from 2020 Reference Case	
	Consumption (quads/year)	**Henry Hub Price (2010$/MMBtu)**
High economic growth	0.48	0.31
Low economic growth	(0.53)	(0.35)
Low nuclear uprates, lives and additions	0.07	0.05
High nuclear uprates, lives and additions	0.00	0.01
Low coal cost	(0.32)	(0.20)
High coal cost	0.45	0.26
2011 Residential and Commercial Demand Technology	0.37	0.17
High Residential and Commercial Demand Technology	(0.49)	(0.47)
Best Residential and Commercial Demand Technology	(0.74)	(0.83)
High coal retirement (Reference 05 case)	0.36	0.17
Low demand and supply technology	0.35	0.18
High demand and supply technology	(0.55)	(0.55)
Low renewable technology cost	(0.08)	(0.10)
Extended taxes and standards for efficiency and renewables	(0.15)	(0.08)
No sunset on tax policies for efficiency and renewables	(0.06)	(0.02)

Exhibit 7-18 plots those changes from the Reference Case, over all the years reported in AEO 2012. The results are remarkably linear, with the small changes in the early years clustered near the origin, and the large changes in later years closer to the ends of the trend line.

Exhibit 7-18. Gas Demand and Price Changes, AEO 2012, 2010$



The linear trend line in Exhibit 7-18 implies a $0.632/MMBtu decrease in Henry Hub gas price for every quad (quadrillion Btu or 10^9 MMBtu) decrease in annual gas consumption. As with the electric DRIPE effects, the price reduction per MMBtu saved is a miniscule portion of the price per MMBtu, but each MMBtu saved reduced prices for a very large number of MMBtus. The benefit to end-use gas consumers is a significant price change per MMBtu, for every billion MMBtus of reduced load. Since DSM avoided costs are stated in dollars per MMBtu, the price slope would be $0.632 × 10^{-9}/MMBtu per MMBtu saved, which is a very small number. On the other hand, that price decrease applies to about 450 million MMBtu of annual end-use gas in New England, of which about 260 million MMBtu are in Massachusetts. Hence, saving one MMBtu in Massachusetts (or anywhere else in North America) reduces bills to other customers by:

$$(\$0.632 \times 10^{-9}/\text{MMBtu}) \times (0.26 \times 10^{9}\ \text{MMBtu}) = \$0.162.$$

This $0.162/MMBtu would be a small, but not trivial, addition to the avoided costs of gas in Massachusetts. The gas supply DRIPE for each New England state, and the total benefit for all New England gas end-use consumers, is shown in Exhibit 7-19.

Exhibit 7-19. Supply DRIPE Benefit in Annual MMBtu Load Reduction, by State

	CT	MA	ME	NH	RI	VT	New England
Use (quads)	0.1155	0.2559	0.0347	0.0222	0.0353	0.0085	0.4722
DRIPE	$0.073	$0.162	$0.022	$0.014	$0.022	$0.005	$0.298

These benefits would continue as long as the efficiency measure continues to reduce load. While the electric energy DRIPE we observe with our regressions in intra-month price variation represents only the short-term supply curve, the AEO gas prices (at least after the first few years) reflect the full long-term costs of gas development, not just the operation of existing wells. In addition, gas supply DRIPE is measuring the effect of demand on the marginal cost of extraction for a finite resource.[238] If anything, lower gas usage in 2014 will leave more low-cost gas in the ground to meet demand in 2015, causing the DRIPE effect to accumulate over time. A program that saves 100 MMBtu annually from 2015 onward would have kept another 500 MMBtu in the ground by 2020, in addition to reducing 2020 demand by 100 MMBtu. The shape of the scatter plot in Exhibit 7-18 does not suggest strong effects of either DRIPE decay or accumulation. For each of the AEO scenarios, the later years have the largest changes from reference, since the total difference in the underlying forecasts (e.g., economic growth, nuclear capacity, coal use, installed efficiency measures) typically rises over time. DRIPE decay would produce an S curve, with the price effect slowing in the out years, at the far end of the demand range. An accumulation of price effects (due to low-cost gas staying in the ground, shifting the supply curve to the left) would result in rising effects in the out years more extreme than the trend line.[239]

In the early years following energy-efficiency implementation, the effect of DRIPE on gas consumers is reduced by the fact that utilities, marketers, and self-supplying customers typically purchase at least some of their gas under contracts ranging from under a month to more than a year into the future. Based on the information provided by the LDCs, and assuming that marketers and self-supplying customers on average hedge in a manner similar to the LDCs, we assume that gas supply is 50 percent hedged in the year of energy-efficiency implementation, 30 percent for the next year, and 0 percent thereafter.

The following exhibit shows how a natural gas program administrator could apply the gas supply DRIPE value stream to a natural gas efficiency measure.

[238] As technology changes, the size of the resource changes, but once gas is removed from the ground, it is gone forever. Less gas will be available from that play in the future, forcing the marginal supply to more expensive plays. In contrast, how much energy a power plant produces this year has little effect on its ability to produce power next year. If anything, increased energy generation at a plant in the near term may tend to justify keeping the plant online.

[239] The EIA analyses of the price effects of LNG exports (Effect of Increased Natural Gas Exports on Domestic Energy Markets, January 2012), in contrast, show large price increases in the early years, followed by smaller price increases and eventually price decreases, compared to the no-export case. The reason for the differences between the AEO cases and the LNG sensitivities is not clear.

Exhibit 7-20. State Supply DRIPE Benefit (2013$ per MMBtu for installation in year 2014)

	CT	MA	ME	NH	RI	VT	New England
2014	$0.039	$0.085	$0.012	$0.007	$0.012	$0.003	$0.157
2015	$0.054	$0.119	$0.016	$0.010	$0.016	$0.004	$0.220
2016+	$0.077	$0.171	$0.023	$0.015	$0.024	$0.006	$0.315

Notes:
Supply DRIPE benefit stream extends for gas efficiency measure life
Based on Exhibit 7-19
LDC gas supply hedge estimated at 50% Year 1, 30% Year 2, 0% Year 3

7.3.2 Wholesale Gas Transportation Market Effects

In addition to its effect on prices in the supply areas, reductions in annual gas use will reduce the basis, or price differential between the wholesale market price of gas in New England and the prices in the supply areas. The basis component of the wholesale market price of gas in New England has risen rapidly in the last year or so, as discussed in Chapter 2. The majority of that basis is attributable to constraints on gas delivery capacity into New England from the Mid-Atlantic region. As a result, our analysis focused on the basis, or price differential, between the Texas Eastern Transmission Zone M-3 (in Pennsylvania and New Jersey) and the Algonquin Gas Transmission citygates in Connecticut, Rhode Island, and eastern Massachusetts.

Price data is readily available for both of those locations because there is extensive trading in the forward and spot markets at both of these points (AGT and TETCo M-3). In addition, prices are very similar for other trading points in the same region (e.g., Transco Zone 6 non-NY prices are very similar to those for TETCo M-3, and Tennessee Gas Pipeline Zone 6 New England citygate prices are very similar to those for AGT). In particular, AGT prices are a widely accepted proxy for New England prices, since AGT prices are similar to prices on the Massachusetts, New Hampshire, and Connecticut portions of TGP, while prices in Maine, Vermont, and parts of New Hampshire are determined in large part by the price of gas at the TGP interconnection with Iroquois and at the TGP and AGT connections with PNGTS and Maritimes & Northeast Pipeline at Dracut, Beverly, and Salem, Massachusetts.

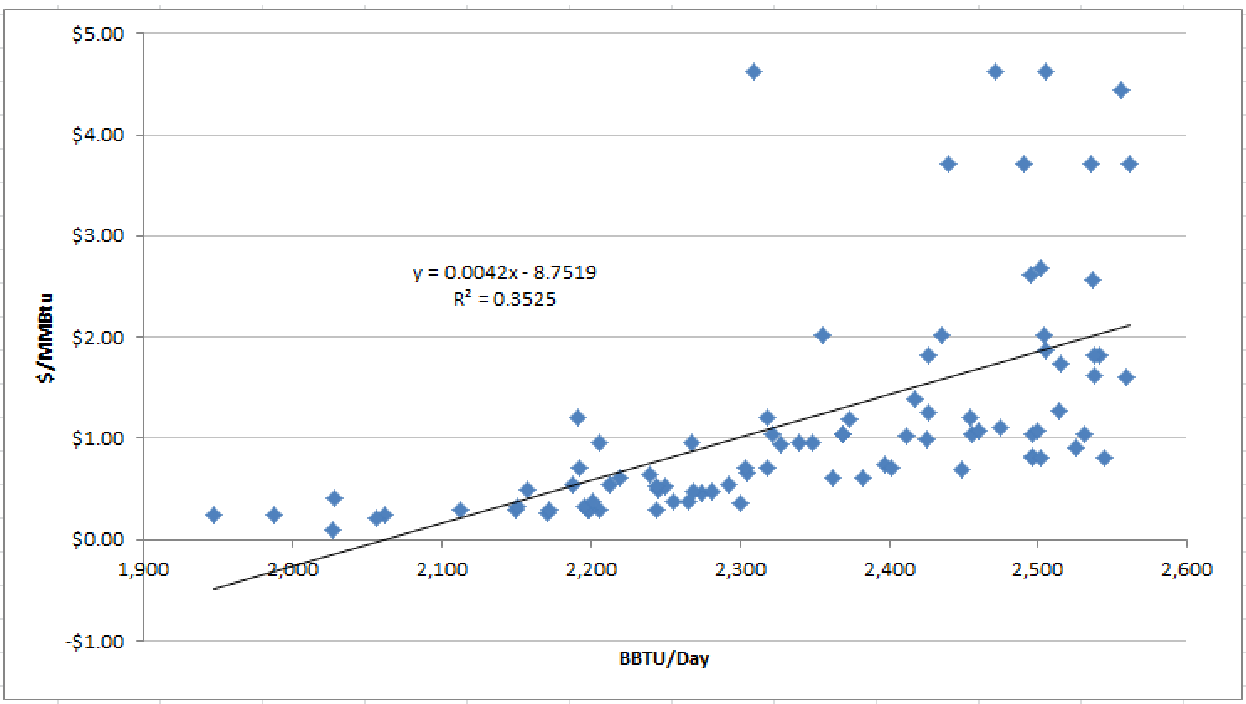
We estimated the DRIPE effect for the New England gas price basis using a method similar to the method we used for electric energy DRIPE, with some adjustments for the differences in the markets. First, gas markets are primarily daily, rather than hourly, so our analysis uses daily prices and loads. Second, no data appears to be available on daily (or even weekly) consumption by state or region, so we use as our measure of load the daily day-ahead scheduled net deliveries in New England on the AGT and

TGP pipelines, minus deliveries from the Maritimes & Northeast (MNE) and Iroquois pipeline, and from the Distrigas LNG facility at Everett.[240]

We regressed daily load against basis for the winters (December through February) of 2011/12 and 2012/13 and the summers (June to September) of 2011 and 2012.

For the winter of 2011-12 (December through February), the ICE prices show that the average basis from TETCo M-3 to Algonquin was \$1.79/MMBtu, and that the daily basis varied from about \$0.10/MMBtu to over \$4.50/MMBtu. As shown in Exhibit 7-21, the basis was under 50¢/MMBtu (typical of summer conditions) for when total loads were less than about 2,200 MMcf/day.[241] Above 2,200 MMcf/day, basis rose gradually at about \$0.004/MMBtu per MMcf/day, with three trading days in January setting prices over \$3.50/MMBtu for a total of eight days. Each of these higher prices was associated with average scheduled net load over 2,400 MMcf/day. Prices on these days may have reflected temporary supply constraints or concern about potential restrictions or cold waves, especially over weekends.

Exhibit 7-21. Basis from TETCo M-3 to Algonquin Citygates as function of net TGP and Algonquin load, Dec 2011 to Feb 2012



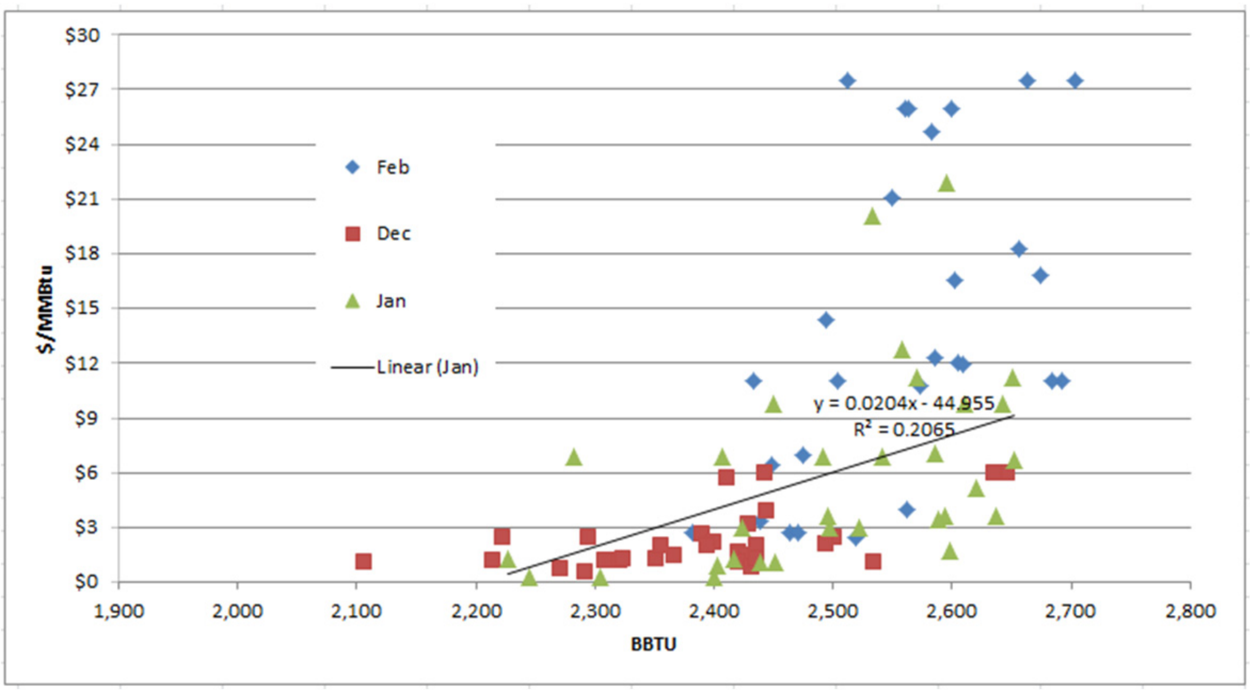
240 Our computation of basis is from ICE's day-ahead trade data, so the timing of the two data sets is roughly equivalent. Since ICE uses a single Friday trading price for Saturday, Sunday, and Monday, and the scheduling and pricing data may come from slightly different times of day, the matching is not perfect.

241 A million cubic feet (MMcf) of gas is essentially the same as a billion Btu (BBtu).

In the winter of 2012-13, colder weather, declining deliveries from the Maritimes (due to off-shore production problems and depletion), and LNG (due to high gas prices in Europe and Asia) dramatically increased New England price basis. Exhibit 7-22 shows the relationship between scheduled deliveries and basis for 2012/13, broken out by month. Note that the vertical scale in Exhibit 7-22 covers a range six times that of Exhibit 7-21, and that the top end of the range of scheduled deliveries is about 140 MMcf/day higher than in 2011/12.

Basis in December 2012 was already higher than the 2011/12 basis for similar loads, and the basis rose even higher in January 2013 and again in February 2013. The increase in basis per MMcf/day was about $0.008/MMBtu in December, $0.020/MMBtu in January, and $0.035/MMBtu in February.

Exhibit 7-22. Basis from TETCo M-3 to Algonquin Citygates as function of net TGP and Algonquin load, Dec 2012 to Feb 2013



Similar, but less dramatic, variation in delivery basis is apparent in the non-winter months.

In the future, we assume that the sensitivity of winter basis to gas load will decline to match the 2011/12 relationship by 2017. We interpolate from the slope in January 2013 ($0.020/MMBtu/MMcf-day) down to the 2011/12 slope ($0.004/MMBtu/MMcf-day), starting with a large drop in 2014 (reflecting the fall from the January 2013 basis to the difference in 2014 forward prices for AGT and TETCo M-3 basis) of about 25 percent of the difference between January 2013 and the 2011/12 average. In each year from 2015 to 2017, we assume another 10 percent convergence towards 2011 basis levels, reflecting the gradual decline in the basis forwards. Finally, we assume that major new transportation comes online around 2017, dropping the marginal basis to 2011/12 conditions in 2017, with continuing decline to 2019, at about half the supply slope of 2011/12. The resulting winter DRIPE coefficients are shown in Exhibit 7-23.

Review of the load and price data for other months suggests that the DRIPE per MMcf is about half as large in the shoulder months (November, March, and April) as in the winter, and only about \$0.0004/MMBtu per MCFd reduction in the summer months (May to October) as in the winter. The resulting shoulder and summer DRIPE coefficients are also shown in Exhibit 7-23.

Exhibit 7-23. Gas Basis DRIPE Coefficients by Year, \$/MMBtu reduction per Mcf/day saved

Year	Three-month Winter	Three-month Shoulder	Six-month Winter	Summer
2014	0.0160	0.0080	0.0120	0.0004
2015	0.0118	0.0059	0.0089	0.0004
2016	0.0106	0.0053	0.0080	0.0004
2017	0.0040	0.0020	0.0030	0.0004
2018	0.0030	0.0015	0.0023	0.0004
2019 and after	0.0020	0.0010	0.0015	0.0004

The six-month winter basis DRIPE would be appropriate to apply to gas space-heating measures.

The DRIPE coefficients in Exhibit 7-23 are stated in terms of reductions in average daily gas load in each time period in each year. For example, a one MMBtu/day of load reduction throughout the winter is a load reduction of 90 MMBtu. Therefore the DRIPE coefficient for one MMBtu reduction in total for a given time period is much lower than the coefficient for a one MMBtu/day reduction during that same time period. Exhibit 7-24 converts the gas basis price effect per MMBtu saved per day into a gas basis price effect per quad saved in each time period.

Exhibit 7-24. Gas Basis DRIPE Coefficients by Time-Period by Year, \$/MMBtu reduction per quad saved

Year	Three-month Winter	Three-month Shoulder	Six-month Winter	Summer	Annual Baseload
2014	178	88	133	2.2	33.8
2015	131	65	98	2.2	25.0
2016	118	58	88	2.2	22.5
2017	44.4	22.0	33.2	2.2	8.8
2018	33.3	16.5	24.9	2.2	6.8
2019 and after	22.2	11.0	16.6	2.2	4.7

One MMBtu reduction in gas use would reduce prices by one billionth of the coefficient in Exhibit 7-24 for the applicable year and period, but since this reduction would apply to all the gas purchased in New England at citygate prices (and thus subject to market basis cost), the effect per MMBtu saved could still be quite large. However, only a small portion of daily net deliveries to end-use gas users in New England is subject to market basis. The vast majority of the gas delivered to those end-use customers is purchased outside the region and transported under long-term cost-of-service rates, and is therefore sheltered from daily volatility in the local market. A relatively small portion of the total quantity of end-use gas appears to be purchased at market prices at New England citygates. We believe it is reasonable to ignore the DRIPE effect on that small amount of purchases.

On the other hand, we expect that all electric energy prices for gas-fired plants (including pumped storage shifting energy from and/or to hours in which gas would otherwise be marginal) would be driven by the market price of gas in New England, including basis. Even a generator with firm transportation and/or storage will price its fuel at the opportunity cost, which will generally be close to the market price. This cross-price DRIPE factor is included in the next section.

7.4 Cross-Fuel Market Price Effects

As discussed above, reduced use of natural gas, including reductions resulting from reduced operation of gas-fired power plants, will reduce natural gas prices. Thus, the value of electric energy DRIPE should include the benefit to New England gas customers from the resulting reduction in gas prices.

Similarly, reduced end-use gas consumption would reduce gas prices to electric generators. Lower gas prices would tend to reduce electricity prices by reducing the dispatch costs of electric generation. While generators are free to set their bid prices, the optimal pricing strategy for any fossil-fueled generator that may be setting the market price is likely to be affected by its fuel price.

Exhibit 7-25 summarizes the methods used for estimating the various DRIPE effects that flow through various aspects of gas prices. The effect of conserving gas on the supply price paid by gas consumers is measured in the own-DRIPE computation in Section 7.3.1. The same method is used for estimating the gas-supply price effects of electric conservation on gas consumers, gas conservation on electric generation, and electric conservation on electric generation.

Basis costs are assumed to be fully hedged for LDC customers. The effect of electric load on gas basis and hence electric price is at least partially reflected in the hourly regressions by month of market electricity prices against electric load (section 7.2.2). Since we cannot determine what portion of basis DRIPE is captured in the electric energy DRIPE, we do not include any allowance for electricity usage affecting gas basis and hence electric market prices. Finally, the effect of gas conservation on the basis prices reflected in market electric energy prices are estimated from the analysis in section 7.3.2.

Exhibit 7-25. Summary of Gas-Related DRIPE Effects

Gas Price Affected		Conservation of Energy	
		Gas	Electricity
To LDC gas consumers	Supply	Own-DRIPE	Cross-DRIPE
	Basis	Hedged	Hedged
To gas-fired electric generation	Supply	Cross-DRIPE	Cross-DRIPE
	Basis	Cross-DRIPE	Own-DRIPE (hourly regression)
Key:	Gas supply curve slope from AEO 2012		
	No effect		
	Basis supply curve analysis		

7.4.1 Effect of gas prices on market electric energy price

Natural-gas-fired generators set the market energy price in about 74 percent of the hours in 2011, and in 81 percent in 2012, and must strongly affect energy prices in the hours for which pumped storage sets the market price (roughly 13 to 14 percent in 2011 and 2012), since gas is likely to fuel most of the energy used for pumping and most of the energy that pumped-storage generation displaces.[242] The ISO-NE marginal energy price per MWh in 2012 averaged about 9.5 times the price of gas per MMBtu at the Algonquin citygates, representing an effective marginal heat rate of 9,500 Btu/kWh. The actual heat rate in the hours in which gas is at the margin may be slightly different from this value, but the ISO does not provide data in sufficient detail to determine whether the average marginal gas heat rate is higher or lower than the implied average heat rate.[243]

Gas Supply DRIPE Effect on Electric Prices

Assuming that gas sets the marginal price (directly or indirectly) in 85 percent of hours, at an average heat rate of 9,500 Btu/kWh, a $1/MMBtu change in the price of gas would change the price of electricity by about $8/MWh (= $1/MMBtu × 9.5 MMBtu/MWh × 0.85 gas-fired MWh per MWh saved). We therefore multiply the gas supply price reduction by 8 and by the projected portion of annual electric energy consumption in each state that is not subject to some form of price hedge. This indirect gas-

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[242] 2011 Annual Markets Report, May 15, 2012, p. 14; 2012 Annual Markets Report, May 15, 2013, p. 18.

[243] If the marginal energy supply when gas was not marginal were always less expensive than gas (e.g., some coal), the energy price (and hence the implicit heat rate) when gas is running would be higher than average. Conversely, if the marginal energy supply when gas was not marginal were always more expensive than gas (e.g., some coal and most oil), the energy price (and hence the implicit heat rate) when gas is running would be lower than average. It is not clear how these two factors balance out.

electric DRIPE would decay in a manner similar to the direct electric DRIPE discussed in section 7.2.2, except that gas prices have no effect on the RPS requirements.

The DRIPE effect on annual average wholesale electric energy prices in New England due to a reduction in annual average gas well-head prices from a one MMBtu reduction in annual gas use would be:

$$\$0.632 \times 10^{-9}/\text{MMBtu} \times 8\ \text{MMBtu/MWh} = \$5.1 \times 10^{-9}/\text{MWh per MMBtu saved}$$

The cross-price DRIPE effect in each state would be a function of that state's annual electric use.[244] Annual electric load in Massachusetts is about 62,000 GWh, so the gas supply DRIPE effect of that reduction on Massachusetts electric bills would be \$0.31/MMBtu saved (= \$5.06 $\times$ 10^{-9}/MWh $\times$ 0.062 $\times$ 10^{9} MWh), before any hedging or decay.

Gas Basis DRIPE Effect on Electric Prices

In 2014, one MMBtu of reduced gas use from space-heating gas conservation (at the six-month winter basis DRIPE in Exhibit 7-24) would reduce electric price by basis DRIPE of:

$$\$133/\text{MMBtu/quad saved} \div 10^{9}\ \text{quad/MMBtu} \times 8\ \text{MMBtu/MWh} = \$1.1 \times 10^{-6}/\text{MWh}$$

In Massachusetts, unhedged electric energy in 2014 totals about 5,200 GWh in the six winter months (Exhibit 7-7). If all that energy were purchased in the spot market, and there were no DRIPE decay, the basis DRIPE value per MMBtu saved would be about:

$$\$1.1 \times 10^{-6}/\text{MWh per MMBtu saved} \times 5.2 \times 10^{6}\ \text{MWh} = \$5.7/\text{MMBtu saved}$$

Gas-on-Electric Cross-Fuel DRIPE Decay

Electric energy DRIPE from reductions in annual gas use rises in 2015 as the hedged portion of energy declines. That effect then falls after 2015 as gas basis declines and electric DRIPE decays. Exhibit 7-26 summarizes the decay of cross-fuel DRIPE. It is essentially the same as Exhibit 7-9, which shows the decay estimated for electric energy DRIPE, except that:

1. There is no RPS effect.
2. The existing-generation effect is reduced by one third, reflecting the tendency for lower gas prices to improve the economics of gas-fired plants, even though the lower electric energy prices would reduce the economics of all plants.
3. The new-generation effect is increased by 50 percent, reflecting the tendency for lower gas prices to discourage investment in combined-cycle plants, rather than combustion turbines, in addition to the effect of lower electric energy prices.

[244] Since generation everywhere in ISO-NE serves load throughout New England, the cross-price effect on electric consumers in a state is not dependent on the amount of gas burned for electric generation in that state.

Exhibit 7-26. Decay of Electric DRIPE Caused by Reduction in Gas Use, 2014 Installation

	Year	Demand Elasticity	Existing Generation	New Generation	Total
2014	1	4.0%	1.3%		5%
2015	2	6.0%	2.7%		8%
2016	3	6.9%	4.0%		11%
2017	4	7.4%	5.3%	7.5%	19%
2018	5	7.6%	6.7%	15.0%	27%
2019	6	7.7%	8.0%	37.5%	47%
2020	7	7.8%	9.3%	60.0%	67%
2021	8	7.8%	10.7%	70.0%	75%
2022	9	7.8%	12.0%	80.0%	84%
2023	10	7.8%	13.3%	90.0%	92%
2024	11	7.8%	14.7%	100.0%	100%

For 2015 installations, the demand-elasticity and existing-generation components would be lagged one year.

Summary of Gas-on-Electric Cross-Fuel DRIPE

Exhibit 7-27 summarizes the gas-on-electric cross-fuel basis DRIPE, stated in dollars per TWh (million MWh) per MMBtu saved, based on the basis DRIPE coefficients in Exhibit 7-24, the supply DRIPE coefficient, and the decay factors from Exhibit 7-26.

Exhibit 7-27. Cross-fuel DRIPE ($/TWh per MMBtu Gas Saved)

	DRIPE $/TWh per MMBtu saved				
	Supply	Basis		total DRIPE	
		Heating	Baseload	Heating	Baseload
2014	0.005	1.063	0.270	1.068	0.275
2015	0.005	0.784	0.200	0.789	0.205
2016	0.005	0.704	0.180	0.709	0.185
2017	0.005	0.266	0.071	0.271	0.076
2018	0.005	0.199	0.054	0.204	0.059
2019	0.005	0.133	0.038	0.138	0.043
2020	0.005	0.133	0.038	0.138	0.043
2021	0.005	0.133	0.038	0.138	0.043
2022	0.005	0.133	0.038	0.138	0.043

Exhibit 7-28 summarizes the own-state and ISO-wide cross-fuel DRIPE values for 2014 gas efficiency installations based upon the coefficients in Exhibit 7-27, the unhedged energy in Exhibit 7-7 and an estimate that about 50 percent of electric energy usage occurs in the heating season.

Exhibit 7-28. Gas-to-Electric Cross-Fuel Heating DRIPE, $/MMBtu, 2014 gas efficiency installations

	Winter or Space Heating								Annual Baseload						
	CT	MA	ME	NH	RI	VT	ISO		CT	MA	ME	NH	RI	VT	ISO
2014	$3.0	$5.3	$1.1	$1.1	$0.7	$0.2	$11.5		$1.6	$2.9	$0.6	$0.6	$0.4	$0.1	$6.2
2015	$8.9	$15.6	$3.3	$3.3	$2.1	$0.8	$34.0		$4.9	$8.5	$1.8	$1.7	$1.2	$0.4	$18.4
2016	$8.9	$15.6	$3.4	$3.3	$2.1	$0.8	$34.1		$4.9	$8.5	$1.8	$1.8	$1.2	$0.4	$18.5
2017	$3.5	$6.1	$1.3	$1.3	$0.8	$0.3	$13.4		$2.0	$3.6	$0.7	$0.7	$0.5	$0.2	$7.8
2018	$2.4	$4.2	$0.9	$0.9	$0.6	$0.2	$9.2		$1.5	$2.6	$0.5	$0.5	$0.4	$0.1	$5.6
2019	$1.2	$2.1	$0.4	$0.4	$0.3	$0.1	$4.6		$0.8	$1.4	$0.3	$0.3	$0.2	$0.1	$2.9
2020	$0.8	$1.3	$0.3	$0.3	$0.2	$0.1	$2.9		$0.5	$0.9	$0.2	$0.2	$0.1	$0.0	$1.9
2021	$0.6	$1.0	$0.2	$0.2	$0.1	$0.1	$2.2		$0.4	$0.7	$0.1	$0.1	$0.1	$0.0	$1.4
2022	$0.4	$0.7	$0.1	$0.1	$0.1	$0.0	$1.5		$0.2	$0.4	$0.1	$0.1	$0.1	$0.0	$0.9

Exhibit 7-29 provides similar results for 2015 installations.

Exhibit 7-29. Gas-to-Electric Cross-Fuel Heating DRIPE, $/MMBtu, 2015 gas efficiency installations

	Winter or Space Heating								Annual Baseload						
	CT	MA	ME	NH	RI	VT	ISO		CT	MA	ME	NH	RI	VT	ISO
2015	$2.3	$4.0	$0.9	$0.9	$0.5	$0.2	$8.8		$1.3	$2.2	$0.5	$0.5	$0.3	$0.1	$4.8
2016	$8.1	$14.2	$3.1	$3.0	$1.9	$0.7	$31.1		$4.4	$7.8	$1.6	$1.6	$1.1	$0.4	$16.9
2017	$3.2	$5.6	$1.2	$1.2	$0.8	$0.3	$12.3		$1.9	$3.3	$0.7	$0.7	$0.5	$0.2	$7.1
2018	$2.4	$4.3	$0.9	$0.9	$0.6	$0.2	$9.4		$1.5	$2.6	$0.5	$0.5	$0.4	$0.1	$5.7
2019	$1.2	$2.1	$0.5	$0.4	$0.3	$0.1	$4.6		$0.8	$1.4	$0.3	$0.3	$0.2	$0.1	$3.0
2020	$0.8	$1.4	$0.3	$0.3	$0.2	$0.1	$3.0		$0.5	$0.9	$0.2	$0.2	$0.1	$0.0	$1.9
2021	$0.6	$1.0	$0.2	$0.2	$0.1	$0.1	$2.2		$0.4	$0.7	$0.1	$0.1	$0.1	$0.0	$1.4
2022	$0.4	$0.7	$0.1	$0.1	$0.1	$0.0	$1.5		$0.2	$0.4	$0.1	$0.1	$0.1	$0.0	$0.9

7.4.2 Effect of Electric Energy Conservation on Gas Supply Prices

From the data presented in the previous discussion, it appears that one MWh of reduction in annual electric use would reduce annual gas use for electric generation in New England by 9.5 × 85% = 8.1 MMBtu. We thus impute to each MWh reduction in electric energy a DRIPE equal to 8 times the gas supply.

($0.632 × 10^{-9}/MMBtu per MMBtu saved) × 8.1 MMBtu/MWh = $5.1 × 10^{-9}/MMBtu per MWh saved

Effect of Electric Energy Conservation on End-Use Gas Prices

Exhibit 7-30 shows the results of multiplying the estimated supply price reduction per MWh of electric conservation by the end-use gas consumption in each state and the region to estimate the electric-on-gas supply DRIPE effect.

Exhibit 7-30. Annual Gas Price benefit per MWh saved

	Coefficient	CT	MA	ME	NH	RI	VT	New England
Gas End Use (quads)		0.1155	0.2559	0.0347	0.0222	0.0353	0.0085	0.4722
Electric-Gas DRIPE $/MWh saved	5.103	$0.589	$1.306	$0.177	$0.113	$0.180	$0.043	$2.410

Effect of Electric Energy Conservation on Electric Price through Gas Supply Prices

The $\$5.1 \times 10^{-9}$/MMBtu reduction in supply gas price per MWh saved would reduce electric market prices by about

$$\$5.1 \times 10^{-9}/\text{MMBtu} \times 9.5\ \text{MMBtu/MWh} \times 0.85 = \$4.06 \times 10^{-8}/\text{MWh}.$$

Exhibit 7-31 shows the results of multiplying this supply price reduction per MWh of electric conservation by the electric consumption exposed to the market in each state and the region (from Exhibit 7-26), adjusted by the cross-fuel DRIPE estimates (in Exhibit 7-26) to estimate the electric-gas-electric DRIPE effect for 2014 installations.

Exhibit 7-31. Annual Electric-Gas-Electric Price benefit per MWh saved, 2014 installations

	CT	MA	ME	NH	RI	VT	ISO
2014	$0.24	$0.42	$0.09	$0.09	$0.06	$0.02	$0.91
2015	$0.96	$1.68	$0.35	$0.35	$0.23	$0.08	$3.63
2016	$1.07	$1.87	$0.39	$0.39	$0.26	$0.09	$4.06
2017	$1.09	$1.92	$0.40	$0.39	$0.26	$0.09	$4.16
2018	$1.00	$1.76	$0.36	$0.36	$0.24	$0.09	$3.81
2019	$0.73	$1.29	$0.27	$0.27	$0.18	$0.06	$2.79
2020	$0.47	$0.83	$0.17	$0.17	$0.11	$0.04	$1.78
2021	$0.35	$0.62	$0.13	$0.13	$0.08	$0.03	$1.34
2022	$0.23	$0.41	$0.08	$0.08	$0.06	$0.02	$0.89
Levelized (2014-2028)	$0.43	$0.75	$0.16	$0.16	$0.10	$0.04	$1.63

Exhibit 7-32 provides the results of the same computation for 2015 installations.

Exhibit 7-32. Annual Electric-Gas-Electric Price benefit per MWh saved, 2015 installations

	CT	MA	ME	NH	RI	VT	ISO
2015	$0.25	$0.43	$0.09	$0.09	$0.06	$0.02	$0.94
2016	$0.97	$1.70	$0.35	$0.35	$0.23	$0.08	$3.69
2017	$1.00	$1.76	$0.36	$0.36	$0.24	$0.08	$3.82
2018	$1.02	$1.79	$0.37	$0.37	$0.25	$0.09	$3.88
2019	$0.74	$1.31	$0.27	$0.27	$0.18	$0.06	$2.84
2020	$0.47	$0.84	$0.17	$0.17	$0.11	$0.04	$1.81
2021	$0.35	$0.63	$0.13	$0.13	$0.09	$0.03	$1.36
2022	$0.23	$0.42	$0.09	$0.09	$0.06	$0.02	$0.90
Levelized (2014-2028)	$0.35	$0.62	$0.13	$0.13	$0.09	$0.03	$1.35

Chapter 8: Sensitivity Analyses

8.1 Introduction

For the gas High Price sensitivity case, wholesale natural gas prices are 23.2 percent higher at Henry Hub through 2028 on a 15-year levelized basis than the AESC 2013 Base Case. The change in Henry Hub prices translate to an increase of 15.6 percent in the annual wholesale electric prices on a levelized basis.

For the gas Low Price sensitivity case, wholesale natural gas prices are 25.5 percent lower at Henry Hub through 2028 on a 15-year levelized basis than those used in the AESC 2013 Base Case. The change in Henry Hub prices translate to a decrease of 16.3 percent in the annual wholesale electric prices on a levelized basis.

For the RGGI Only scenario, wholesale electricity prices through 2028 on a 15-year levelized basis are 9.6 percent lower than those used in the AESC 2013 Base Case.

For the Northern Pass scenario, wholesale electricity prices through 2028 on a 15 year levelized basis are 2 percent lower in New Hampshire, but 1 percent higher at WCMA than those in the AESC 2013 Base Case.

8.1.1 Sensitivity of Wholesale Electric Energy Prices to Changes in Natural Gas Prices at Henry Hub

As documented in previous chapters, natural gas prices have a large, direct impact on avoided electric energy costs.

The AESC natural gas High and Low Price cases are described in section 2.2.11. The High and Low Price cases are based primarily on alternative assumptions about the EUR from the AESC 2013 Base Case. The High Price case assumes the EUR is 50 percent lower than the EUR in the AESC 2013 Base Case and the Low Price case assumes the EUR is 50 percent higher. In addition, the Low Price projections do not include any adjustments for the economics of fracturing regulations and the AEO 2013 prices were used through 2016. The High Price forecast adds an economic adjustment of $0.88 per MMBtu versus $0.33 per MMBtu in the AESC 2013 Base Case to the low EUR price.

The Henry Hub prices under the AESC natural gas Base, Low, and High Price case are shown in columns two and three of Exhibit 8-1 and Exhibit 8-2. The last column shows the impact on electricity prices using the gas prices sensitivities as compared to the Base Case Henry Hub natural gas.

Exhibit 8-1. Henry Hub AESC 2013 Base Case and High Gas Case Prices (2013$/MMBtu)

Year	Base NG Price	High NG Price	% Change in NG Price	% Change in Electricity Price
2014	$4.20	$4.34	3%	2%
2015	$4.32	$4.50	4%	3%
2016	$4.18	$4.61	10%	5%
2017	$4.50	$5.09	13%	9%
2018	$4.77	$5.58	17%	12%
2019	$5.01	$6.10	22%	16%
2020	$5.34	$6.66	25%	17%
2021	$5.48	$6.92	26%	17%
2022	$5.77	$7.34	27%	19%
2023	$5.95	$7.66	29%	19%
2024	$6.07	$7.89	30%	20%
2025	$6.26	$8.18	31%	20%
2026	$6.41	$8.43	31%	20%
2027	$6.58	$8.69	32%	21%
2028	$6.69	$8.90	33%	22%
Levelized	$5.39	$6.64	23.2%	15.6%

Exhibit 8-2. Henry Hub AESC 2013 Base Case and Low Gas Case Prices (2013$/MMBtu)

Year	Base NG Price	Low NG Price	% Change in NG Price	% Change in Electricity Price
2014	$4.20	$3.23	-23%	-7%
2015	$4.32	$3.22	-25%	-7%
2016	$4.18	$3.68	-12%	-7%
2017	$4.50	$3.71	-18%	-13%
2018	$4.77	$3.71	-22%	-16%
2019	$5.01	$3.72	-26%	-19%
2020	$5.34	$3.82	-28%	-20%
2021	$5.48	$3.97	-28%	-19%
2022	$5.77	$4.18	-27%	-19%
2023	$5.95	$4.31	-28%	-18%
2024	$6.07	$4.37	-28%	-19%
2025	$6.26	$4.48	-28%	-19%
2026	$6.41	$4.61	-28%	-19%
2027	$6.58	$4.75	-28%	-18%
2028	$6.69	$4.83	-28%	-18%
Levelized	$5.39	$4.01	-25.5%	-16.3%

The gas prices in the sensitivity cases do not represent variations in actual market prices of gas (e.g., weekly, monthly, or even annual). Instead, the High Price case provides a set of gas prices that reflect the range of upside uncertainty in gas prices in the long term. Our expectation is that any revised forecasts of long-term avoided Henry Hub gas costs made prior to the anticipated AESC 2015 update would fall between the Low and High Price cases.

Exhibit 8-3 shows the impacts of the High and Low Price case gas prices on New England wholesale electric energy prices by costing period. The average 23.2 percent increase in the High Price case Henry Hub natural gas price results in an average 15.6 percent increase in annual wholesale electric energy prices. The average 25.3 percent decrease in the Low Price case Henry Hub natural gas price results in an average 16.3 percent decrease in annual wholesale electric energy prices. The level of increase varies by season and time period, but not dramatically.

Exhibit 8-3. Seasonal and Time Period Impacts of Henry Hub Price Changes

Season	Time of Day	High NG Price	Low NG Price
Winter	Off-Peak	15.7%	-17.1%
	On-Peak	15.2%	-15.8%
	All-Hours	15.5%	-16.4%
Summer	Off-Peak	16.6%	-17.0%
	On-Peak	15.3%	-15.2%
	All-Hours	15.8%	-16.0%
Annual	All-Hours	15.6%	-16.3%

8.1.2 Sensitivity of Wholesale Electric-Energy Prices to Changes in Carbon-Dioxide-Allowance Prices

We tested the sensitivity of wholesale electric energy prices to a Low Case carbon forecast, shown in Exhibit 8-4 below. The RGGI carbon case provides a lower bound of CO_2 allowance prices; we draw the prices for this case from the "RGGI only" set of carbon dioxide allowance prices required under the AESC 2013 scope of work. Note that the RGGI price does not change in real terms after 2020; changes in the RGGI requirements are quite possible, but beyond the scope of AESC 2013.

Exhibit 8-4. Carbon Dioxide Reference and RGGI Case Prices

	CO_2 (2013$/short ton)	
Year	Reference	RGGI
2014	$4.22	$4.22
2015	$5.28	$5.28
2016	$6.33	$6.33
2017	$7.39	$7.39
2018	$8.44	$8.44
2019	$9.50	$9.50
2020	$20.30	$10.55
2021	$22.58	$10.55
2022	$24.87	$10.55
2023	$27.15	$10.55
2024	$29.44	$10.55
2025	$31.72	$10.55
2026	$34.00	$10.55
2027	$36.29	$10.55
2028	$38.57	$10.55
Levelized (2014-2028)	$19.72	$8.97

Exhibit 8-5 shows the annual CO_2 price differences relative to the Base Case and their impacts on the average annual wholesale energy prices. The average effect on energy prices is about $0.52/MWh on average for each $1/ton change in CO_2 prices.[245]

[245] The AESC 2013 results are quite close to the AESC 2011 calculated coefficient of $0.45/MWh on average for this effect, and the AESC 2013 result is consistent with the average marginal price being set by a natural gas plant with a heat rate slightly below 8,000 Btu/kWh.

Exhibit 8-5. Energy Price Impacts of CO_2 Price Changes (2013$)

	RGGI CO_2 Price				
Year	CO_2 Price Change ($/ton)	Energy Price Change ($/MWh)	AESC 2013 Reference Case ($/MWh)	AESC 2013 RGGI Sensitivity ($/MWh)	% Difference from Reference Case
2020	-$9.75	-$5.70	$59.95	$54.25	-9.5%
2021	-$12.03	-$6.54	$60.86	$54.32	-10.7%
2022	-$14.32	-$7.58	$63.12	$55.54	-12.0%
2023	-$16.60	-$8.74	$65.73	$57.00	-13.3%
2024	-$18.88	-$9.90	$67.66	$57.75	-14.6%
2025	-$21.17	-$10.67	$70.37	$59.70	-15.2%
2026	-$23.45	-$11.85	$72.42	$60.57	-16.4%
2027	-$25.73	-$12.86	$74.83	$61.97	-17.2%
2028	-$28.02	-$13.85	$76.95	$63.10	-18.0%
Average	**-$18.88**	**-$9.74**	**$43.49**	**$37.34**	**-14.1%**
Ratio: $/MWh vs. $/ton		0.52			

8.1.3 Sensitivity of Wholesale Electric-Energy Prices to addition of Northern Pass Project

Exhibit 8-6 shows the energy price impacts of the addition of the 1,200 MW Northern Pass project, a DC transmission link that would bring hydroelectric power directly into New Hampshire. This project is modeled with an installation date of Jan 1, 2018.

Electricity price effects are relatively modest mainly because additional transmission additions were not included as part of this sensitivity run.[246] While prices in New Hampshire decrease 2 to 4 percent, prices in the rest of New England remain flat or increase slightly, especially during summer peak periods. Our model results indicate that transmission lines from New Hampshire to Boston, Vermont, and NEMA are heavily loaded, operating at their full rated capacity 60 to 130 percent more of the time than in the Base Case. We anticipate that changes in additional transmission additions would result in more widespread electricity market price reductions than shown in this sensitivity run given the lack of additional transmission upgrades.

[246] Our research in developing transmission assumption in Chapter 5 did not identify additional transmission projects that would support additional changes resulting from the Northern Pass model run scenario.

Exhibit 8-6. Energy Price Impacts of Northern Pass (2013$/MWh)

	Reference		Northern Pass		% Change	
	NH	WCMA	NH	WCMA	NH	WCMA
2014	$46.72	$47.79	$46.71	$47.77	0%	0%
2015	$46.53	$47.79	$46.53	$47.77	0%	0%
2016	$44.84	$46.64	$44.84	$46.58	0%	0%
2017	$44.23	$46.51	$44.25	$46.44	0%	0%
2018	$47.08	$49.54	$45.42	$49.77	-4%	0%
2019	$49.89	$53.14	$48.00	$53.51	-4%	1%
2020	$57.65	$59.95	$56.09	$60.75	-3%	1%
2021	$58.66	$60.86	$57.35	$61.29	-2%	1%
2022	$61.12	$63.12	$60.14	$63.82	-2%	1%
2023	$63.80	$65.73	$62.72	$66.80	-2%	2%
2024	$65.69	$67.66	$64.18	$68.62	-2%	1%
2025	$68.05	$70.37	$66.31	$71.03	-3%	1%
2026	$69.95	$72.42	$68.26	$73.42	-2%	1%
2027	$72.47	$74.83	$70.42	$75.57	-3%	1%
2028	$74.29	$76.95	$71.88	$77.90	-3%	1%
Levelized	$57.47	$59.62	$56.32	$60.11	-2%	1%

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