Avoided Energy Supply Costs in New England: 2015 Report

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

March 27, 2015

Revised April 3, 2015

AUTHORS

Rick Hornby
Alex Rudkevich, PhD
Ben Schlesinger, PhD
Scott Englander
John Neri, PhD
John Goldis
Kofi Amoako-Gyan
Hua He
Adan Rivas
Richard Tabors, PhD

Table of Contents

Chapter 1: Executive Summary

This 2015 Avoided-Energy-Supply-Component Study ("AESC 2015," 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 2015 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 2015 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 2015 provides projections of avoided costs of electricity 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 2016 onward. The Base Case 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 without new energy efficiency measures 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 energy in the long term. The actual market prices of energy 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 2015 provides a fresh assessment of avoided electricity and natural gas costs from a new team using a model that simulates the operation of the New England wholesale energy and capacity markets in an iterative, integrated manner. On a 15 year levelized basis AESC 2015 estimates direct avoided retail electric costs on the order of 11 cents/kWh and direct avoided gas costs at utility city-gates in the order of $6.00 to $8.00/MMBtu depending on location and gas end-use.

The AESC 2015 estimates of direct avoided electricity and gas costs are similar to the corresponding AESC 2013 estimates. Certain AESC 2015 projections differ from those in AESC 2013 due to differences in market conditions that have occurred since AESC 2013 was completed, differences in certain assumptions regarding future market conditions and differences in analytical approaches. Key changes are:

- Increases in the quantity of shale gas production available at low marginal production costs, resulting in somewhat lower projections of avoided gas supply costs and lower avoided costs for electric energy;
- Assumed addition of a total of 1 Bcf/day of new pipeline capacity through November 2018;
- Earlier retirement of Brayton Point (2017 versus 2020) and higher costs for new fossil fueled generating capacity additions, leading to higher estimates of avoided costs for electric capacity;
- Higher Renewable Energy Credit (REC) prices due to the lower projection of wholesale energy market prices;
- Lower estimates of electricity demand reduction induced price effects ("DRIPE") from reductions in electricity use due to lower estimates of the size of those DRIPE effects and to shorter projections of the duration of those effects; and
- Lower estimates of natural gas and cross-fuel DRIPE from reductions in natural gas consumption due to lower estimates of gas supply elasticity and differences in analytical approach

The Study provides detailed projections of avoided costs by year for an initial 15-year period, 2016 through 2030, and extrapolates values for another 15 years, from 2031 through 2045.[1] All values are reported in 2015 dollars ("2015$") unless noted otherwise. For ease of reporting and comparison with AESC 2013, many results are expressed as levelized values over 15 years.[2] The AESC 2013 levelized results are calculated using the real discount rate of 2.43 percent, solely for illustrative purposes.[3]

1.1 Background to Study

AESC 2015 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 2015 Study Group to oversee the design and execution of the report.

The Study sponsors include: Cape Light Compact, Liberty Utilities, National Grid USA, New Hampshire Electric Co-op, Columbia Gas of Massachusetts, Eversource Energy (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,

---

[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 2014-2028 for AESC 2013 and 2016 to 2030 for AESC 2015. AESC 2013 used a real discount rate of 1.36 percent.

[3] The AESC 2015 real discount rate is a projection of the rate for a ten-year U.S. Treasury Bond developed from *An Update to the Budget and Economic Outlook: 2014 to 2024*, Congressional Budget Office, August 2014 and the Energy Information Administration (EIA) Annual Energy Outlook 2014 (AEO 2014), as detailed in Appendix E.

Inc., and Northern Utilities), United Illuminating Holding (United Illuminating, Berkshire Gas Company, 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 Department of Energy and Environmental Protection, Connecticut Energy Efficiency Board, Massachusetts Energy Efficiency Advisory Council, , Massachusetts Department of Public Utilities, Massachusetts Department of Energy Resources, Massachusetts Attorney General, Massachusetts Low-Income Energy Affordability Network (LEAN), Acadia Center, New Hampshire Public Utilities Commission, Rhode Island Division of Public Utilities and Carriers and Rhode Island Energy Efficiency and Resource Management Council.

The AESC 2015 Study Group specified the scope of services, selected the Tabors Caramanis Rudkevich ("TCR") project team, and monitored progress of the study. As instructed by the Study Group, the TCR team developed seven distinct forecast components which, are reported in Chapters 2 through 7 of this report (See Exhibit 1-1).

For each component, the TCR project team presented its methodologies, assumptions, and analytical results in draft deliverables for each of the subtasks specified by the Study Group. The TCR 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 Electricity Costs	3, 4	2C, 3C , 2D, 3D
Chapter 6 – Sensitivity Analyses	N/A	4B
Chapter 7 – Demand Reduction Induced Price Effects	7	2G, 3G
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 TCR. Rick Hornby managed the project. Dr. Benjamin Schlesinger and Dr. John Neri of Benjamin Schlesinger and Associates ("BSA") led the development of forecasts of natural gas and fuel oil supply costs as well as of gas demand reduction induced price suppression (gas DRIPE). Dr. Alex Rudkevich developed the forecasts of wholesale electric energy and capacity costs as well as of electricity DRIPE effects. Scott Englander of Longwood Energy Group led the analysis of Renewable Portfolio Standard ("RPS") requirements and compliance costs as well as of environmental costs avoided by reductions in energy use. Dr. Richard Tabors served as senior advisor.

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 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 2015 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 2015 surveyed participating sponsors for recent values.
- Reductions in the quantities of capacity and energy that have to be acquired from wholesale energy and capacity markets may cause prices in those markets to decline relative to Base Case levels for a period of time. AESC 2015 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 retail electricity use will cause a reduction in gas consumption for electric generation, which is expected to have a price suppression effect on gas production and basis prices, which we refer to as electric own-fuel and cross-fuel DRIPE. (Reductions in annual retail gas use also have a price suppression effect on gas production and basis prices, which we refer to as gas fuel and cross-fuel DRIPE).

AESC 2015 developed estimates of the following major components of avoided electricity costs:

- **Avoided retail capacity.** Avoided retail capacity costs for the AESC 2015 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. Projected annual FCM prices are higher than in AESC 2013, for example 15 year levelized costs are approximately 77% higher. This

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

increase is primarily due to earlier retirements of existing capacity (e.g. Brayton Point) and higher costs of new capacity.

- **Avoided retail energy.** This is the largest component of avoided electricity costs. It consists of the wholesale electric energy price increased by an assumed risk premium of 9%. Levelized annual avoided energy costs under the AESC 2015 Base Case are approximately 13% lower than those in AESC 2013, depending on the pricing zone. The levelized annual wholesale electric energy costs are lower primarily due to projections of lower natural gas prices and somewhat lower projected costs for compliance with anticipated federal regulations of carbon emissions.
- **Avoided RPS compliance costs.** Energy efficiency reduces the load subject to RPS obligations, avoiding the associated cost of compliance. The cost of RPS compliance is driven by the prices of renewable energy certificates (RECs), which are the principle means of compliance. AESC 2015 REC prices are approximately 40% higher than AESC 2013 because of the lower 2015 projections of wholesale energy prices.
- **Avoided non-embedded CO_2 costs.** This is the cost of controlling CO_2 emissions, to the extent that cost is not reflected in electricity market prices. The AESC 2015 projections are approximately the same as AESC 2013.
- **Electricity DRIPE.** This is the value of the reduction in capacity and energy market prices expected from reductions in electric energy use. AESC 2015 is projecting no electric capacity DRIPE and a smaller amount of electric energy DRIPE. The lower estimates are due to differences in projections of market conditions and differences in analytical approach. These are summarized in Section 1.4 and discussed in detail in Sections 6.10 and 7.2.

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 2015 vs. AESC 2013 (WCMA Zone, Summer On-Peak, 15-Year Levelized Results, 2015$)

Illustration of Avoided Electricity Cost Components, AESC 2015 BASE vs. AESC 2013 (WCMA Zone, Summer On-Peak, 15 Year Levelized Results, 2015$)	AESC 2013 in 2013$	AESC 2013 in 2015$ [1]	AESC 2015 BASE	AESC 2015 BASE Relative to AESC 2013	
	cents/kWh	cents/kWh	cents/kWh	cents/kWh	% Difference
Avoided Retail Capacity Costs [2,3,4]	2.01	2.08	2.91	0.83	40%
Avoided Retail Energy Cost [5, 6, 7]	6.98	7.22	6.29	-0.93	-13%
Avoided Renewable Energy Credit [5, 6, 8]	0.66	0.69	0.96	0.27	39%
Capacity and Energy Subtotal	**9.65**	**9.99**	**10.15**	**0.17**	**2%**
CO_2 Non-Embedded	4.33	4.48	4.48	0.00	0%
Capacity DRIPE	0.69	0.71	0.00	-0.71	-100%
Intrastate Energy, Own Fuel and Cross-Fuel DRIPE	2.84	2.94	1.08	-1.86	-63%
DRIPE Subtotal	**3.53**	**3.65**	**1.08**	-2.57	-70%
Total	**17.51**	**18.12**	**15.71**	-2.41	-13%

Notes

1. AESC 2013 values levelized (2014-2028); escalated to 2015$ at		**1.035**
2. Assumes load factor of		**55%**
3. Avoided Cost of Capacity purchases ($/kW-year)	AESC 2013 (2013)	**$ 96.55**
	AESC 2015 (2015)	**$ 140.10**
4. Adjusted for 8% distribution losses and 17% reserve margin		
5. Retail Adjustment = Avoided Wholesale Cost * (1 + risk premium)		
6. Risk premium		**9%**
7. Avoided Energy Cost 2015$/MWh		**$ 57.68**
8. AESC 2015 REC (cents/kWh) pre-adjustment		**$ 0.88**

For this costing location and period, AESC 2015 is projecting total avoided costs from direct reductions in energy and capacity of 10 cents per kWh. This amount is approximately 2 percent higher than the corresponding AESC 2013 total.

The total of all components—i.e., the avoided cost of energy and capacity reductions (10 cents per kWh), plus energy and capacity DRIPE, plus non-embedded CO_2 costs—is 16 cents per kWh. This total is 13 percent lower than the corresponding AESC 2013 total.

1.2.1 Avoided Electric Capacity Costs

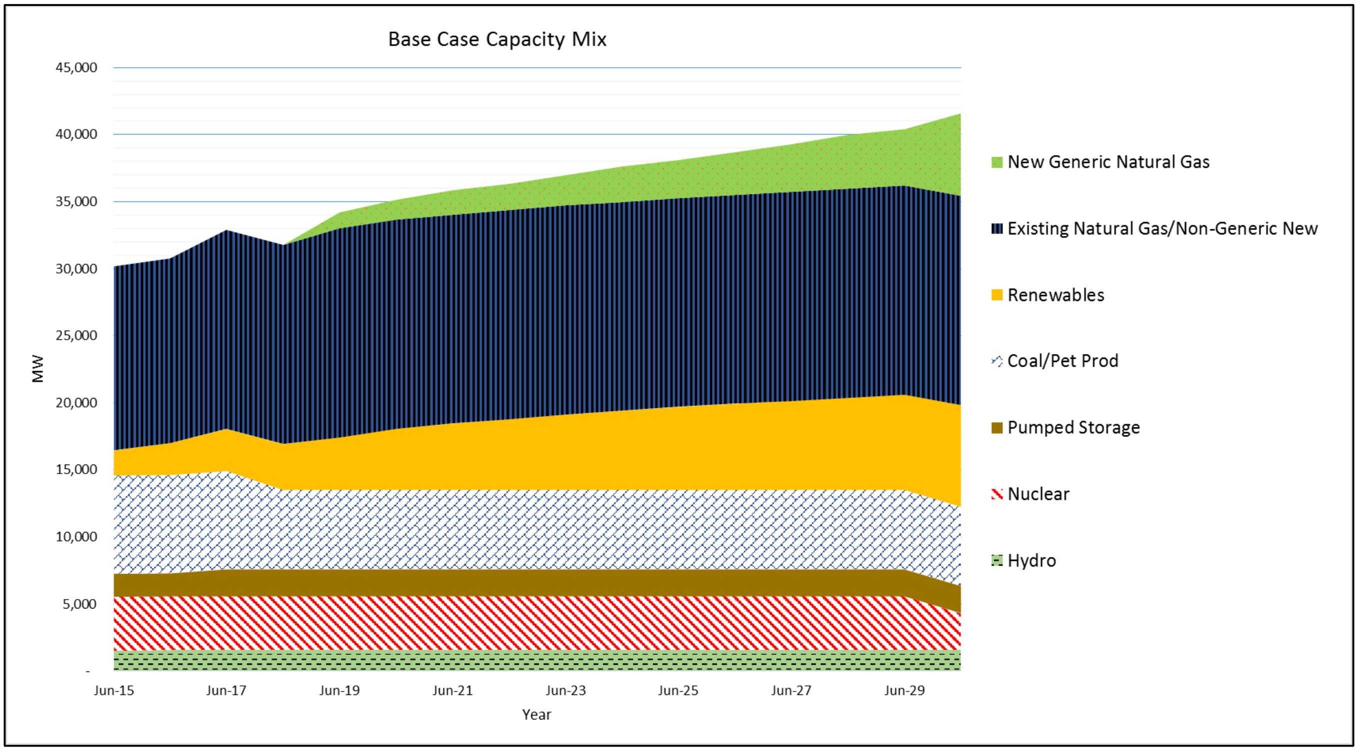
Avoided electric capacity costs are an estimate of the value of a load reduction by retail customers during hours of system peak demand.[5] The major input to this calculation is the wholesale forward capacity price to load (in dollars per kilowatt-month), which is set for a capacity year (June–May) roughly three years before the start of the capacity year. To develop an avoided cost at the meter, the wholesale 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 the 2018/2019 power year (The ISO-NE power year is June through May). This change is driven primarily by earlier projected retirements of certain existing fossil units.

[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.

Exhibit 1-3. AESC 2015 Capacity Requirements vs. Resources (Base Case), MW



The AESC 2015 Base Case estimate of levelized capacity prices is approximately 40 percent higher than the estimate from AESC 2013 on a 15-year levelized basis... The higher values are primarily due to earlier retirements of existing generating units and more expensive capacity additions.

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. PAs have to submit those bids when the FCA is held, However, the FCA for a given power year is held 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]

[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.

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.

The AESC 2015 Base Case is projecting generation from natural gas to be the dominant source of electric energy over the study period. Renewable generation is projected to increase over time in compliance with RPS requirements. Generation from nuclear is projected to remain flat until year 2029 and then decline based on the assumption of Seabrook retiring in March 2030. Coal generation is projected to decline substantially by 2020 as unit retire.

Exhibit 1-4. AESC 2015 Base case Generation Mix (GWh)

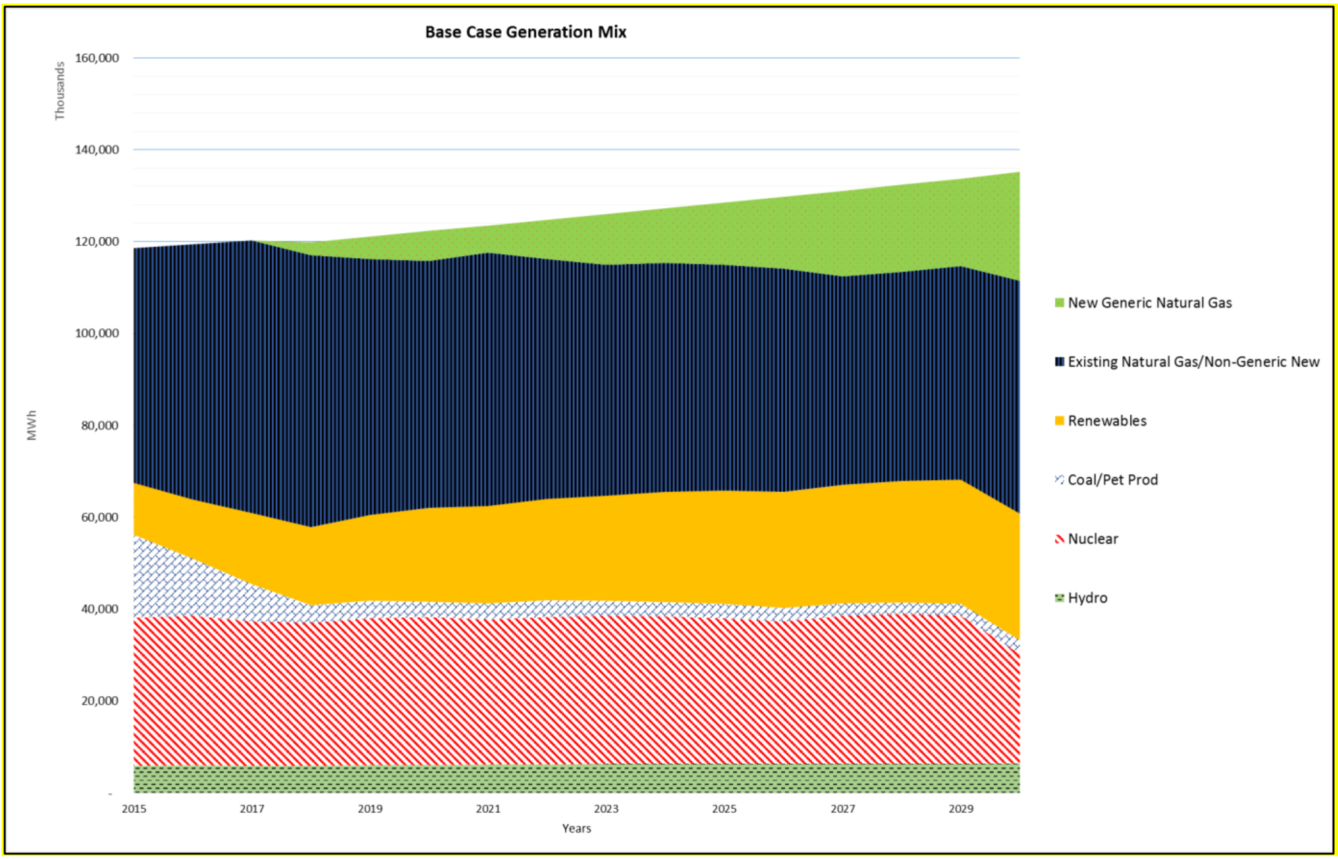


Exhibit 1-5 presents the AESC 2015 electric energy prices for the West Central Massachusetts zone for all hours compared to energy prices from AESC 2013. This WCMA price also represents the ISO-NE Control Area price, which is within this zone. On a 15 year levelized basis (2016-2030), the AESC 2015 annual all-hours price is \$56.58/MWH (2015\$), compared to the equivalent value of \$61.95/MWh from AESC 2013, representing a reduction of 8.7 percent. The lower estimate for AESC 2015 is primarily due to a lower estimate of wholesale natural gas prices in New England and of CO_2 emission compliance costs.

Exhibit 1-5. AESC 2015 vs. AESC 2013 – All-Hours Prices for West-Central Massachusetts (2015$/kWh)

	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual All-Hours Energy
AESC 2015 (2016-2030)	$62.10	$56.82	$57.68	$45.04	$56.58
AESC 2013 (2014 - 2028)	$66.64	$58.78	$66.03	$53.33	$61.95
% Difference	-6.8%	-3.3%	-12.6%	-15.6%	-8.7%

Notes:
All prices expressed in 2015$ per MWh.
Discount Rate 1.36% for AESC 2013, 2.43% for AESC 2015

Exhibit 1-6 presents the resulting 15-year levelized avoided electric energy costs for AESC 2015 by zone, after adding in the relevant REC costs and wholesale risk premiums. This exhibit also provides the corresponding estimates from AESC 2013 by zone.

Exhibit 1-6. Avoided Electric Energy Costs, AESC 2015 vs. AESC 2013 (15-year levelized, 2015$)

Avoided Electric Energy Costs, AESC 2015 versus AESC 2013 (15 year levelized 2015$)
Avoided Electric Energy Costs AESC 2015 and AESC 2013

		Winter On Peak Energy	Winter Off-Peak Energy	Summer On Peak Energy	Summer Off-Peak Energy
	AESC 2015	**$/kWh**	**$/kWh**	**$/kWh**	**$/kWh**
1	Connecticut (statewide)	0.078	0.072	0.073	0.059
2	Massachusetts (statewide)	0.077	0.072	0.073	0.059
3	Maine (ME)	0.067	0.061	0.062	0.049
4	New Hampshire (NH)	0.076	0.071	0.071	0.058
5	Rhode Island (RI)	0.073	0.068	0.068	0.054
6	Vermont (VT)	0.067	0.062	0.063	0.049
	AESC 2013	**$/kWh**	**$/kWh**	**$/kWh**	**$/kWh**
1	Connecticut (statewide)	0.079	0.070	0.078	0.064
2	Massachusetts (statewide)	0.079	0.070	0.078	0.064
3	Maine (ME)	0.066	0.060	0.064	0.054
4	New Hampshire (NH)	0.075	0.068	0.074	0.062
5	Rhode Island (RI)	0.066	0.060	0.064	0.053
6	Vermont (VT)	0.074	0.065	0.073	0.059

Exhibit 1-7 shows the change between AESC 2015 and AESC 2013 values, expressed as a percentage and in terms of 2015$ per kWh.

Exhibit 1-7. Avoided Electric Energy Costs for 2015: Change from AESC 2013 (expressed in 2015$/kWh and percentage values)

Avoided Electric Energy Costs, AESC 2015 versus AESC 2013 (15 year levelized 2015$) Avoided Electric Energy Costs : AESC 2015 Change from AESC 2013					
		Winter On Peak Energy	Winter Off-Peak Energy	Summer On Peak Energy	Summer Off-Peak Energy
	Change from AESC 2013 ($/kWh)	**$/kWh**	**$/kWh**	**$/kWh**	**$/kWh**
1	Connecticut (statewide)	(0.001)	0.002	(0.005)	(0.005)
2	Massachusetts (statewide)	(0.001)	0.001	(0.005)	(0.005)
3	Maine (ME)	0.001	0.002	(0.002)	(0.005)
4	New Hampshire (NH)	0.001	0.002	(0.003)	(0.004)
5	Rhode Island (RI)	0.007	0.008	0.004	0.002
6	Vermont (VT)	(0.007)	(0.003)	(0.011)	(0.010)
	Change from AESC 2013 (%)	**%**	**%**	**%**	**%**
1	Connecticut (statewide)	-1.4%	3.0%	-7.0%	-7.1%
2	Massachusetts (statewide)	-1.5%	1.6%	-6.8%	-8.4%
3	Maine (ME)	1.6%	3.0%	-3.2%	-9.6%
4	New Hampshire (NH)	1.1%	3.6%	-3.8%	-7.2%
5	Rhode Island (RI)	10.5%	12.5%	6.3%	3.2%
6	Vermont (VT)	-9.0%	-5.3%	-14.6%	-16.9%

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 pCA model used to generate wholesale energy prices for AESC 2015.

For AESC 2015, 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 continues to be reasonable to use the AESC 2013 CO_2 marginal abatement cost of $100 per short ton.

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

AESC 2015 assumes that the Marcellus/Utica shale will be the primary source of gas supply to New England. However, because a dominant liquid hub has yet to develop for that production area the forecast of wholesale natural gas commodity prices in New England is derived from projected gas prices at the Henry Hub. There are far more forecast and trading data available for Henry Hub than for the Marcellus/Utica area, a situation we expect will change over time.

The AESC 2015 Base Case estimate of Henry Hub prices is $ 5.18/MMBtu (2015$) on a 15-year levelized basis for the period 2016 to 2030. This is approximately 7 percent lower than the 15-year levelized price from the AESC 2013 Base Case for a similar time period.[7]

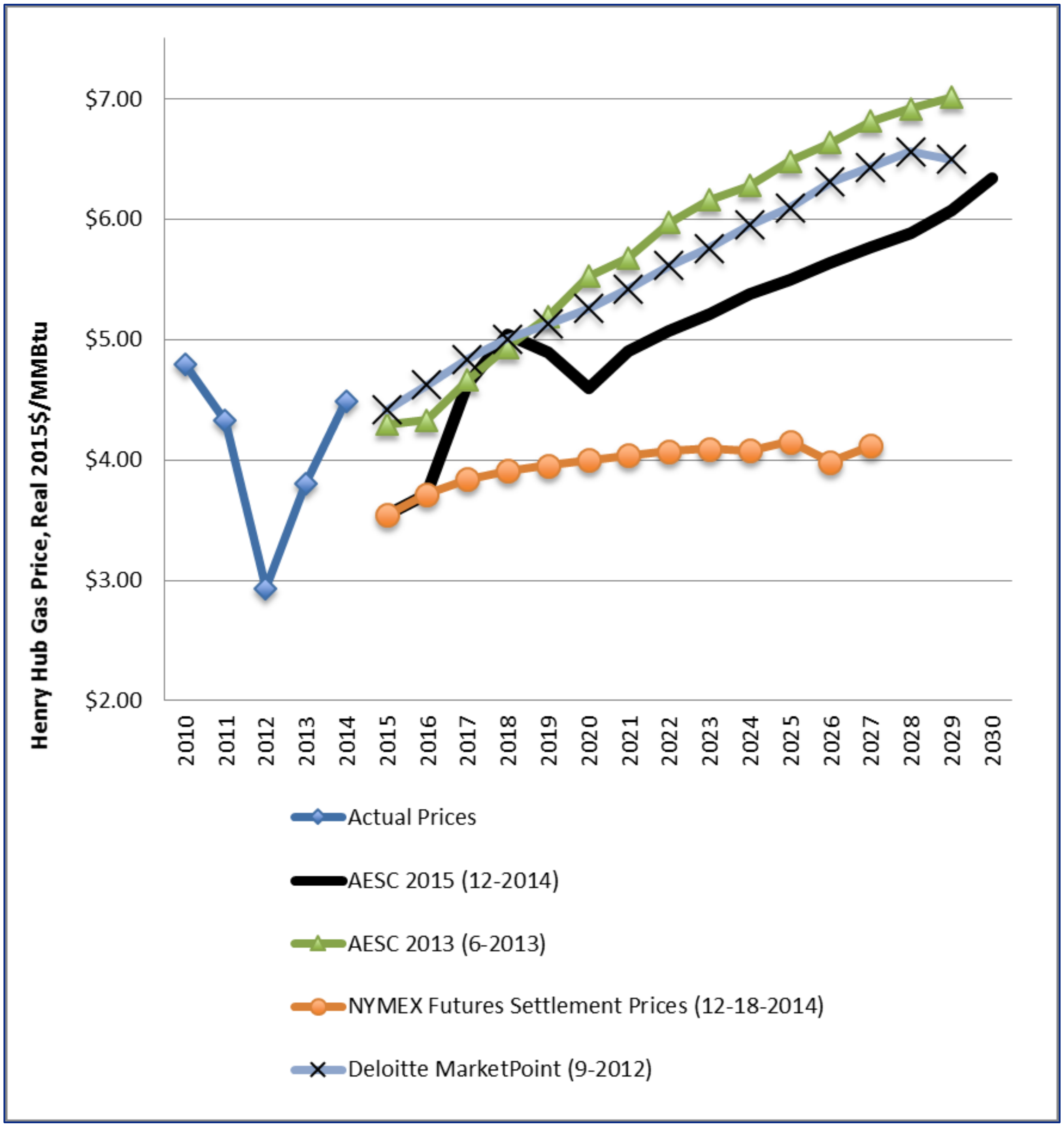
The AESC 2015 Base Case Henry Hub estimate is composed of NYMEX futures prices (as of December 18, 2014) through December 2016, and on a forecast derived from the Reference Case forecast from the Energy Information Administration's ("EIA's") Annual Energy Outlook ("AEO") 2014 for 2017 through 2030. The 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 it captures the market fundamentals that will drive those prices (i.e., demand, supply, competition among fuels) and because its underlying inputs and model algorithms are public.

Exhibit 1-8. Actual and Projected Henry Hub Prices (2015$/MMBtu) illustrates the difference between the AESC 2015 and AESC 2013 Henry Hub prices.

[7] The 15-year levelized (2014-2028) AESC 2013 Base Case in 2015$ is $5.56/ MMBtu, i.e.., 5.37/MMBtu (2013$) * 1.035).

[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.

Exhibit 1-8. Actual and Projected Henry Hub Prices (2015$/MMBtu)



This Exhibit indicates the downward trend in long-term forecasts of Henry Hub gas price forecasts since AESC 2013 was completed. Long-term gas price forecasts have been declining for several reasons. Actual gas prices have remained low. Expectations that gas supply will decline due to severe shale gas production decline rates have not materialized, nor have fears of significant production cost increases associated with the need to comply with tighter environmental regulations. Finally, and perhaps most importantly, drilling productivity has increased beyond expectations and drilling programs have become far more efficient, and time- and cost-effective.

1.3.2 Avoided Wholesale Gas Costs in New England

AESC 2015 developed a forecast of the avoided wholesale cost of gas in New England based on an analysis of the market fundamentals expected to drive that cost over the study period, using much the same general approach as the AESC 2013 Study. Specifically, the forecast of the avoided cost of gas supply begins with primary sources serving New England, and then forecasts avoided cost of gas delivery from primary sources to gas users in New England. The difference between the wholesale market price of gas at one delivery point and another delivery point is referred to as a gas price basis differential, or simply "basis." AESC 2015 developed the avoided wholesale cost of gas in New England as the avoided cost at the Henry Hub plus the basis between the Henry Hub and New England.

In addition to developing a projection of the cost of gas from the Henry Hub and the Marcellus/Utica shale, the TCR team examined other key market fundamentals that will affect the avoided cost of gas in New England including projected demand for gas for electric generation and for retail end-uses, the projected quantity of imports of gas from Atlantic Canada and of LNG, and the projected level of pipeline capacity to deliver gas from the Marcellus/Utica shales into New England. (The projected demand for gas in New England for electric generation will be driven by numerous factors, including the long run projected price of fuel oil relative to the price of natural gas, and the level of financial penalties ISO-NE may impose on generating units which fail to meet their capacity performance obligations).

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 local distribution company ("LDC"), and (2) the avoided cost of delivering gas on the LDC system (the "retail margin"). AESC 2015 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 LDC.

The AESC 2015 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 2013. Vermont requested AESC 2015 to provide avoided costs for a different set of costing periods.

Exhibit 1-9. Comparison of Avoided Gas Costs by End-Use Assuming No Avoidable Retail Margin, AESC 2015 vs. AESC 2013 (15-year levelized, 2015$/MMBtu except where indicated as 2013$/MMBtu)

	RESIDENTIAL				COMMERCIAL & INDUSTRIAL			ALL RETAIL END USES
	Non Heating	Hot Water	Heating	All	Non Heating	Heating	All	
Southern New England (CT, MA, RI)								
AESC 2013 (2013$)	6.08	6.57	6.73	6.60	6.26	6.58	6.44	6.53
AESC 2013 (b)	6.29	6.80	6.97	6.83	6.48	6.81	6.66	6.76
AESC 2015	6.00	6.53	6.70	6.56	6.20	6.54	6.39	6.48
2013 to 2015 change	-5%	-4%	-4%	-4%	-4%	-4%	-4%	-4%
Northern New England (ME, NH)								
AESC 2013 (2013$)	6.03	7.53	8.02	7.62	6.58	7.54	7.12	7.39
AESC 2013 (b)	6.24	7.80	8.30	7.89	6.82	7.81	7.37	7.65
AESC 2015	6.00	7.69	8.25	7.80	6.63	7.71	7.24	7.54
2013 to 2015 change	-4%	-1%	-1%	-1%	-3%	-1%	-2%	-1%

	Design day	**Peak Days**	**Remaining winter**	**Shoulder / summer**
Vermont				
AESC 2013 (2013$)	$ 389.03	$ 20.68	$ 8.68	$ 6.32
AESC 2013 (b)	$ 402.76	$ 21.41	$ 8.98	$ 6.54
AESC 2015	$ 523.08	$ 21.83	$ 7.51	$ 6.19
2013 to 2015 change	30%	2%	-16%	-5%

Factor to convert 2013$ to 2015$ 1.0353

Note: AESC 2013 levelized costs for 15 years 2014 - 2028 at a discount rate of 1.36%.
AESC 2015 levelized costs for 15 years 2016 - 2030 at a discount rate of 2.43%.

This set of AESC 2015 avoided natural gas cost estimates for Southern and Northern New England are generally lower than the AESC 2013 estimates, primarily due to the difference between the AESC 2015 projection of gas prices at Henry Hub and the AESC 2013 projection. The estimates for VT are also generally lower, except for the design day costs, which are higher due to a higher projection of Vermont Gas System (VGS) marginal transmission costs.

Exhibit 1-10. Comparison of Avoided Gas Costs by End-Use Assuming Some Avoidable Retail Margin, AESC 2015 vs. AESC 2013 (15-year levelized, 2015$/MMBtu except where indicated as 2013$/MMBtu)

	RESIDENTIAL				COMMERCIAL & INDUSTRIAL			ALL RETAIL END USES
	Non Heating	Hot Water	Heating	All	Non Heating	Heating	All	
Southern New England (CT, MA, RI)								
AESC 2013 (2013$)	6.67	7.17	8.30	8.12	6.88	7.74	7.44	7.80
AESC 2013 (b)	6.91	7.42	8.59	8.41	7.13	8.01	7.70	8.07
AESC 2015	6.62	7.89	8.32	8.13	6.81	7.68	7.37	7.35
2013 to 2015 change	-4%	6%	-3%	-3%	-4%	-4%	-4%	-9%
Northern New England (ME, NH)								
AESC 2013 (2013$)	6.53	8.04	9.35	8.91	7.04	8.40	7.86	8.17
AESC 2013 (b)	6.76	8.32	9.68	9.23	7.29	8.70	8.14	8.46
AESC 2015	6.52	8.86	9.64	9.15	7.11	8.61	8.01	6.88
2013 to 2015 change	-4%	6%	0%	-1%	-3%	-1%	-2%	-19%

Factor to convert 2013$ to 2015$ 1.0353

Note: AESC 2013 levelized costs for 15 years 2014 - 2028 at a discount rate of 1.36%.
AESC 2015 levelized costs for 15 years 2016 - 2030 at a discount rate of 2.43%.

This set of avoided natural gas cost estimates are also generally lower than the AESC 2013 estimates, again principally due to the lower projected gas price at Henry Hub. The exception is residential water heating, whose avoided margin was underestimated in AESC 2013.

1.4 Demand Reduction Induced Price Effects (DRIPE)

DRIPE refers to the reduction in wholesale market prices for energy and/or capacity expected from reductions in the quantities of energy and/or capacity required from those markets during a given period due to the impact of efficiency and/or demand response programs. Thus, DRIPE is a measure of the value of efficiency received by all retail customers during a given period in the form of expected reductions in wholesale prices.

DRIPE effects are typically very small when expressed in terms of their impact on wholesale market prices, i.e., reductions of a fraction of a percent. However, DRIPE effects may be material when expressed in absolute dollar terms, e.g., a small reduction in wholesale electric energy price multiplied by the quantity of electric energy purchased for all consumers at the wholesale market price, or at prices / rates tied to the wholesale price.

The value of DRIPE is a function of (i) the projected size of the impact on market prices, (ii) the projected duration of that price effect, and (iii) the quantity of energy purchased at prices tied to the wholesale market price during the duration of the price effect.

AESC 2015 estimated three broad categories of DRIPE:

- **Electric efficiency direct DRIPE:** The value of reductions in retail electricity use resulting from reductions in wholesale electric energy and capacity prices from the operation of those wholesale markets.

- **Natural gas efficiency direct and cross-fuel DRIPE:** The value of reductions in retail gas use from reductions in wholesale gas supply prices and reductions in basis to New England. Gas efficiency cross-fuel DRIPE is the value of the reductions in those prices in terms of reducing the fuel cost of gas-fired electric generating units, and through them wholesale electric energy prices.

- **Electric efficiency fuel-related and cross-fuel DRIPE:** The value of reductions in retail electricity use from reductions in wholesale gas supply prices and reductions in basis to New England. The reductions in those prices reduces the fuel cost of gas-fired electric generating units, and through them wholesale electric energy prices. Electric efficiency cross-fuel DRIPE is the value of the reductions in the wholesale gas supply price to retail gas users.

Exhibit 1-11 provides a high level overview of the AESC 2015 estimates of electricity and natural gas DRIPE.

Exhibit 1-11. DRIPE Overview

Reduction in Retail Load	Cost Component Affected	DRIPE Category
Electricity	Electric Energy Prices	Own-price (energy DRIPE)
Natural Gas	Gas Production Cost	Own-price (gas Supply DRIPE)
	Gas Production Cost	Cross-fuel (gas to electric)
	Basis to New England	Cross-fuel (gas to electric)
Electricity	Gas Production Cost	Own-price (gas Supply DRIPE)
	Basis to New England	Own- price (basis DRIPE)
	Gas Production Cost	Cross - fuel (electric to gas)

The AESC 2015 electric efficiency direct DRIPE results are lower than the corresponding AESC 2013 DRIPE results because AESC 2015 is projecting electricity DRIPE to be smaller in size and shorter in duration. The differences between the two studies are due to differences in analytical approach and in projected market conditions.

The AESC 2015 natural gas efficiency direct and cross-fuel DRIPE results, and electric efficiency fuel-related and cross-fuel DRIPE results are lower than the corresponding AESC 2013 DRIPE results primarily because of a lower estimate of basis due to a different analytical approach.

1.4.1 Analytical Approach to Estimate Electricity DRIPE

AESC 2015 estimated the size and duration of electricity DRIPE in New England, both capacity and energy, using a differential approach based on direct simulations of projected market conditions and resulting projected market prices under several different cases. AESC 2015 used a BAU Case, described in Chapter 6, as the reference point against which it measured the size and duration of DRIPE effects under each of the other cases. The other cases are the BASE Case, described in Chapter 5, and state-specific DRIPE Cases for each New England state, described in Chapter 7. The different approach is the analytical approach most commonly used to estimate DRIPE. AESC 2013 estimated the size of DRIPE using regression analyses and estimated the duration of DRIPE based on qualitative estimates.

1.4.2 Size of Electricity DRIPE.

AESC 2015 is projecting a capacity price DRIPE effect of zero. In the short term ISO New England (ISO-NE) has already set capacity prices through the 2018 power year. In the long term, as discussed in Section 6.10, AESC 2015 models future ISO-NE auctions to avoid acquiring surplus capacity and presumes that the cost characteristics of the new gas CT and CC units that will be setting the capacity market price are essentially the same.

AESC 2015 is projecting smaller energy DRIPE effects than AESC 2013 over the period January 2015 through May 2018. AESC 2015 projects the energy market prices under the BAU case and each state-specific DRIPE case by simulating the formation of energy prices based on the energy supply curve and the ISO-NE unit commitment process. The formation of energy prices under those cases, and hence the size of the resulting energy DRIPE is largely driven by the AESC 2015 assumptions' regarding the supply curve and unit commitment process.

The supply curve dampens energy DRIPE because the section of the curve that sets energy prices on most days is essentially flat, as described in Section 6.10. The unit commitment process dampens energy DRIPE because ISO-NE makes its decisions regarding which units to commit to serving load based on its projection of load for 24 hours, not for just one hour, as described in Chapter 5. Because of those two factors, AESC 2015 did not find a simple linear relationship between the energy load in a given hour and the load in that hour. Instead, AESC 2015 has demonstrated that the relationship between energy prices and loads in a given hour, is affected by load throughout the day, fuel prices on the day and unit availability on the day.

There will be days on which actual conditions will differ from the ISO NE forecast conditions due to unanticipated market conditions, e.g., an unexpected outage, oversupply or unexpectedly high or low demand. It is not clear that energy DRIPE effects would occur under those types of unexpected market conditions, i.e., when the market did not operate exactly as planned ("perfect markets" or according to perfect foresight). Many factors can cause unexpected market conditions, and one would have to identify and analyze those factors in order to determine if load reductions from energy efficiency would have any effect on prices under those conditions. In other words, to estimate the energy DRIPE effect of efficiency reductions on a day when actual conditions are materially different from forecast conditions, one must know the specific cause of the difference. It is also important to note that energy efficiency is a long-term, passive demand resource. As such, its load reduction profile is very different from that of Active Demand Resources, which provide reductions only at the time of and only in response to unexpected market conditions.

1.4.3 Duration of Electricity DRIPE

AESC 2015 is projecting electricity DRIPE effects to be shorter in duration than AESC 2013, ending after two and a half years (June 2018) rather than eight years. The differences in estimates of duration are due to differences in projection of market conditions and in analytical approach. AESC 2015 projects that ISO-NE will begin adding gas-fired capacity in all zones starting in the 2018/19 power year, approximately three years earlier than ASESC 2013. Also, AESC 2015 developed its projections of capacity and energy DRIPE from 2018 onward directly using simulation modeling of the energy market.

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 1-12 summarizes the prices projected by AESC 2015 and AESC 2013 for fuel oil and other fuels.

Exhibit 1-12. Comparison of AESC 2015 and AESC 2013 Fuel Oil and Other Fuel Prices (15-year levelized, 2015$)

Sector	Residential						Commercial	
Fuel	No. 2 Distillate	Propane	Kerosene	BioFuel	Cord Wood	Wood Pellets	No. 2 Distillate	No. 6 Residual (low sulfur)
AESC 2015 Levelized Values (2015$/MMBtu); 2016-2030	$ 19.20	$ 18.35	$ 20.94	$ 18.68	$ 6.80	$ 7.74	$18.70	$16.47
AESC 2013 Levelized Values (2015$/MMBtu); 2014-2028	$ 28.89	$ 29.16	$ 31.73	$ 30.35	$ 10.47	$ 17.45	$ 27.78	$ 16.80
AESC 2015 vs AESC 2013, % higher (lower)	-33.5%	-37.1%	-34.0%	-38.5%	-35.0%	-55.6%	-32.7%	-1.9%

The projected AESC 2013 prices for these fuels are generally lower than those from AESC 2013, primarily due to a fundamentally lower forecast of underlying crude oil prices. On a 15-year levelized basis, the AESC 2015 values range from 32 percent to 55 percent lower than the AESC 2013 projections, except for residual.