AESC 2018

Presentation of Results and User Interface

April 11, 2018

Synapse Energy Economics

Agenda

1. AESC Background and Study Group Process
2. Main findings
   a) Overall Findings
   b) Natural Gas
   c) Fuel Oil and Other Fuels
3. Input Assumptions
   a) Inflation
   b) Discount Rate
   c) Wholesale Risk Premium
4. New Elements
   a) Oil DRIPE
   b) Avoided T&D
   c) Value of Reliability
5. Sensitivities
6. User Interface

1. Project Sponsors and Study Group

- Sponsoring Entities
  - Berkshire Gas Company
  - Cape Light Compact
  - Liberty Utilities (NH, MA)
  - National Grid USA
  - Eversource (CL&P, NSTAR, PSNH, WMECO, Yankee Gas)
  - New Hampshire Electric Co-op
  - Columbia Gas
  - Unitil (FGELC, UES, NU)
  - United Illuminating
  - SCG & CNG
  - Efficiency Maine
  - State of Vermont

- Study Group Members
  - CT DEEP
  - CT EEB
  - MA AG
  - MA DPU
  - MA DOER
  - MA LEAN
  - Environment Northeast
  - Conservation Law Foundation
  - NH PUC
  - RI DPUC
  - RI EERMC
  - VT DPS

1. AESC 2018 Work Process

- **Study Group process encourages collaboration and consensus**
- **Weekly calls with Study Group**
- **Scheduled deliverables (input memos, draft sections)**

Event / Task / Deliverable / Holiday	Version/Action	Date
2017		
Contract Award		Week of Sep 25
1. Electronic communication protocol and usage instructions	Draft	Friday, Oct 6
1. Proposed schedule of deliverables and meetings		
1. Kick-off meeting and presentation	Discussion	Friday, Oct 6
Weekly check-in call	Discussion	Thursday, Oct 12
Weekly check-in call	Discussion	Thursday, Oct 19
2A. Gas forecast assumptions	Draft	Thursday, Oct 26
2D. Electric capacity value assumptions		
2C. Electric commodity forecast assumptions		
2G. DRIPE (electric, capacity, natural gas, fuel oil, and cross fuel price effects) methodology assumptions		
2H. Transmission and distribution		
2I. Reliability		
Weekly check-in call	Discussion	Thursday, Oct 26
Discussion of 2A, 2D, 2C, 2G, 2H, 2I	Discussion	Thursday, Nov 2
Weekly check-in call	Discussion	Thursday, Nov 9
Veteran's Day		Fri Nov 11 to Mon Nov 13
Revised memo of 2A, 2D, 2C, 2G, 2H, 2I	Revision	Tuesday, Nov 14
Weekly check-in call	Discussion	Thursday, Nov 16
2B. Fuel oil forecast assumptions	Draft	Tuesday, Nov 21
2E. Other fuels forecast assumptions		
2F. Value of compliance with GHG regulations		
Thanksgiving Day		Thursday, Nov 23
Discussion of 2B, 2E, 2F	Discussion	Thursday, Nov 30
Revised memo of 2B, 2E, 2F	Revision	Thursday, Dec 7
Weekly check-in call	Discussion	Thursday, Dec 7
Weekly check-in call	Discussion	Thursday, Dec 14
3C. Avoided electric commodity costs	Draft	Thursday, Dec 21
3D. Avoided electric capacity value		
Weekly check-in call	Discussion	Thursday, Dec 21
Christmas Day		Monday, Dec 25
2018		
New Year's Day		Monday, Jan 1
Discussion of 3C, 3D	Discussion	Thursday, Jan 4
Revised memo of 3C, 3D	Revision	Thursday, Jan 11
Weekly check-in call	Discussion	Thursday, Jan 11
Martin Luther King Jr. Day		Monday, Jan 15
3A. Avoided natural gas	Draft	Thursday, Jan 18
3B. Fuel oil forecast		
3E. Other fuels forecast		
3F. Value of compliance with GHG regulations		
3G. DRIPE (electric, capacity, natural gas, fuel oil, and cross fuel price effects)		
3H. Transmission and distribution		
3I. Reliability		
Weekly check-in call	Discussion	Thursday, Jan 18
Mid-study update meeting & discussion of 3A, 3B, 3E, 3F, 3G	Discussion	Thursday, Jan 25

1. Project Team and responsibilities

The Synapse Team

North Side Energy

- Avoided natural gas

Sustainable Energy Advantage

- Renewable energy buildouts
- REC/CEC prices
- Avoided cost of RPS and CES compliance

Synapse Energy Economics

Project Manager

Pat Knight

- Lead contractor
- Project Management
- Project QC
- Electricity dispatch and capacity-expansion modeling

Resource Insight

- Avoided capacity
- DRIPE
- Assisting on long-term natural gas price forecasting, reliability, oil DRIPE

Les Deman Consulting

- Long-term natural gas price forecast development

Principal Advisor and Internal Quality Control:
Synapse Energy Economics, Principal Associate Max Chang

2. Main findings

- Generally similar costs when compared to AESC 2015 Update
  - Main drivers are lower costs for natural gas & RGGI; new or revised methodologies for capacity, DRIPE
- New chapters on avoided T&D and value of reliability
- Calculated prices and loads at 8760-hour level

Illustration of avoided electricity cost components, AESC 2018 versus AESC 2015 Update

	AESC 2015 Update	AESC 2015 Update	AESC 2018	AESC 2018, relative to AESC 2015 Update		Notes
	2017 cents/kWh	2018 cents/kWh	2018 cents/kWh	2018 cents/kWh	% Difference	
Avoided Retail Capacity Costs	2.64	2.69	1.72	-0.97	-36%	3,4,5,6,7
Avoided Retail Energy Costs	5.64	5.75	4.63	-1.12	-19%	8,9,11
Avoided Renewable Energy Credit	0.99	1.01	0.39	-0.62	-61%	8,10,11
Subtotal: Capacity and Energy	9.27	9.46	6.75	-2.71	-29%	
CO_2 non-embedded	5.02	5.13	4.36	-0.76	-15%	5
Transmission & Distribution	-	-	2.11	2.11	-	3,5,12
Value of Reliability	-	-	0.01	0.01	-	3,5,7,13
Capacity DRIPE	-	-	0.91	0.91	-	5,7
Energy DRIPE	1.21	1.23	1.91	0.67	54%	8,14
Subtotal: DRIPE	1.21	1.23	2.81	1.58	128%	-
Total	15.50	15.81	16.05	0.23	1%	-

2. Natural gas

- AESC 2018 Henry Hub is 19 percent lower than the AESC 2015 base case on a levelized basis; AESC 2018 Henry Hub is 5 percent lower than the AESC 2015 update
- Drivers of wholesale price changes in Henry Hub:
  - Higher gas production
  - Downward adjustment in breakeven drilling and operating costs in the major shale and tight gas producing regions

Summary of 15-year levelized Henry Hub, Algonquin Citygate, and basis differentials

	Units	Henry Hub	Algonquin Citygates	Basis
AESC 2015 (2016–2030)	2018 $/MMBtu	$5.44	$6.23	$0.80
AESC 2015 Update (2017–2031)	2018 $/MMBtu	$4.62	$5.55	$0.93
AESC 2018 (2018–2032)	2018 $/MMBtu	$4.38	$5.39	$1.01
Change from AESC 2015 to AESC 2018	%	-19.4%	-13.6%	-
Change from AESC 2015 Update to AESC 2018	%	-5.2%	-2.9%	-

Notes: All values are in 2018 $/MMBtu. AESC 2015 levelized costs are for 15 years (2016–2030) at a discount rate of 2.43 percent. AESC 2015 Update levelized costs are for 15 years (2017–2031) at a discount rate of 1.43 percent. AESC 2018 levelized costs are for 15 years (2018–2032) at a discount rate of 1.34 percent

2. Natural gas (cont.)

- Drivers of price change at retail:
  - Avoidable pipeline capacity costs
  - High peak-period prices in the New England market
- LDC Margin- avoidable distribution related costs

All Retail End Users, No Avoidable Margin (levelized, 2018 $/MMBtu)

	Units	Southern New England	Northern New England
AESC 2015	2018 $/MMBtu	$6.80	$7.91
AESC 2015 Update	2018 $/MMBtu	$5.96	$7.18
AESC 2018	2018 $/MMBtu	$7.40	7.18
Change from AESC 2015 to AESC 2018	%	*9%*	*-9%*
Change from AESC 2015 Update to AESC 2018	%	*24%*	*0%*

All Retail End Users, Some Avoidable Margin (levelized, 2018 $/MMBtu)

	Units	Southern New England	Northern New England
AESC 2015	2018 $/MMBtu	$7.71	$8.76
AESC 2015 Update	2018 $/MMBtu	$7.26	$8.00
AESC 2018	2018 $/MMBtu	$8.17	$7.65
Change from AESC 2015 to AESC 2018	%	*6%*	*-13%*
Change from AESC 2015 Update to AESC 2018	%	*12%*	*-4%*

2. Fuel oil and other fuels

- We find that avoided levelized costs for residential fuel oil and other fuels are generally higher than was estimated in AESC 2015, while levelized costs for commercial fuel oil is slightly lower than was estimated in AESC 2015.
- The primary source of this difference is a change in data sources from the previous AESC study.

Comparison of avoided costs of retail fuels (15-year levelized, 2018 $/MMBtu)

	Residential						Commercial	
	No. 2 Distillate	Propane	Kerosene	BioFuel	Cord Wood	Wood Pellets	No. 2 Distillate	No. 6 Residual (low sulfur)
AESC 2015 (2016–2030)	$20.15	$19.26	$21.98	$19.61	$7.14	$8.12	$19.63	$17.29
AESC 2015 Update (2017–2031)	$21.22	$19.79	$23.14	$19.61	$7.14	$8.12	$19.87	$17.46
AESC 2018 (2018–2032)	$22.17	$31.11	$19.88	$22.83	$13.40	$21.60	$18.47	$16.26
Change from AESC 2015 to AESC 2018	10.0%	61.5%	-9.6%	16.4%	87.8%	165.9%	-5.9%	-5.9%
Change from AESC 2015 Update to AESC 2018	4.4%	57.2%	-14.1%	16.4%	87.8%	165.9%	-7.0%	-6.9%

3. Input Assumptions

- **Inflation Rate**

  2 percent (consistent with previous AESC studies and Congressional Budget Office estimates)

- **Discount Rate**

  Used for the purposes of levelization

Comparison of Financial Parameter Assumptions

	AESC 2015	AESC 2018	Treasury Bill Method	Congressional Budget Office	
			Feb 2018	Jan 2015	Jun 2017
Long-term nominal rate	4.36%	**3.37%**	3.04%	4.60%	3.70%
Source	Composite CBO thru 2024, AEO 2014 thru 2030	Composite of 10 and 30-year Treasury rates	30-year T-Bills over last six years	Forecast - 10 yr Treasury notes 2020–2025	Forecast - 10 yr Treasury notes 2021–2027
Inflation Rate	1.88%	**2.00%**	2.00%	2.00%	2.00%
Source	Composite CBO thru 2024, AEO 2014 thru 2030	Above historical average of 1.88%, but below AEO 2017 projection of 2.1%. Same as CBO forecast	Above historical average, but below AEO 2017 projection of 2.1%.	Consistent with GDP price index 2020–2025 forecast	Core PCE Price Index 2021–2027
Resulting long-term real rate	2.43%	**1.34%**	1.02%	2.55%	1.67%

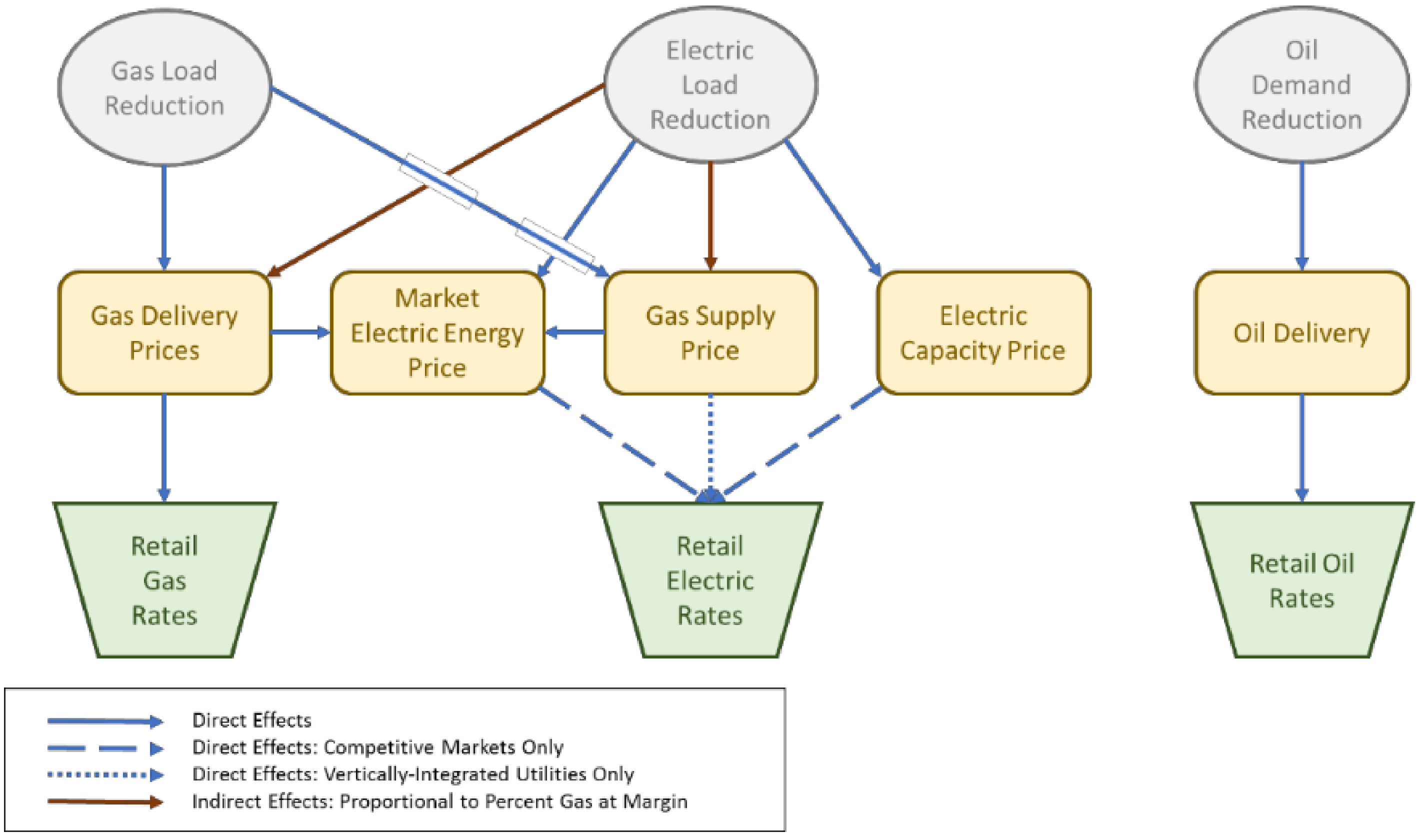
3. Wholesale Risk Premium

- Adder to energy and capacity price elements
  - Represents observed difference between retail electricity supplier prices and wholesale prices
  - Based on review of confidential supplier bids from MA, CT, and MD
- AESC 2018 uses assumption of 8%
- Municipal utilities should use less than 8%
- Individual states may mandate different risk premium
  - Vermont uses 11.1%

4. DRIPE

- 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 AESC 2018 which result 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
- AESC 2018 models DRIPE benefits induced by reduced demand on electricity (energy and capacity), natural gas (supply and transportation), and oil markets
- DRIPE results in AESC 2018 differ from those in AESC 2015 because of differences in analytical approach, assumptions about hedging and decay, new commodity and capacity forecasts, and changes in market conditions.
- We find higher energy DRIPE values, lower natural gas supply DRIPE values, and lower natural gas transportation DRIPE values

4. DRIPE Schematic



4. Generalized DRIPE Methodology

1. Estimate gross DRIPE based on relationship of loads and prices.
   - *Develop DRIPE coefficients*
2. Adjust gross DRIPE
   - *Loads exposed to market prices (long-term contracts)*
   - *Phase-in of DRIPE impacts*
     - Depends on resources bid into capacity market or not
     - 2018 for capacity already bid into market, 2021 for capacity not bid into market
   - *Decay effects*
     - DRIPE impacts will decay as customers and/or generators respond to lower prices (increased energy usage, retirement of generation resources, delay or withdrawal of new resources)
3. AESC 2018 presents methodology for cleared and uncleared capacity DRIPE
   - *Uncleared capacity has an effect on ISO forecast of capacity (five year lag)*
   - *There is a phase-in and decay effect to uncleared capacity*

4. Oil DRIPE

- Value of reduced demand for petroleum products on petroleum prices
- Harder to quantify since petroleum is a global market
- Modest size of New England oil demand in comparison to the entire global market (about 0.7 percent of worldwide consumption), the overall value of DRIPE remains modest

Oil DRIPE by state, 2018–2028 ($/MMBtu per MMBtu reduced)

	Zone-on-Zone DRIPE							Zone on Rest-of-Region DRIPE						
Year	NE	CT	MA	ME	NH	RI	VT	NE	CT	MA	ME	NH	RI	VT
2018	0.07	0.02	0.02	0.01	0.01	0.01	0.00	0.00	0.05	0.04	0.06	0.06	0.06	0.06
2019	0.07	0.02	0.03	0.01	0.01	0.01	0.00	0.00	0.06	0.05	0.06	0.07	0.07	0.07
2020	0.08	0.02	0.03	0.01	0.01	0.01	0.00	0.00	0.06	0.05	0.07	0.07	0.07	0.07
2021	0.08	0.02	0.03	0.01	0.01	0.01	0.00	0.00	0.06	0.05	0.07	0.07	0.07	0.08
2022	0.08	0.02	0.03	0.01	0.01	0.01	0.01	0.00	0.06	0.05	0.07	0.07	0.08	0.08
2023	0.08	0.02	0.03	0.01	0.01	0.01	0.01	0.00	0.06	0.05	0.07	0.07	0.08	0.08
2024	0.08	0.02	0.03	0.01	0.01	0.01	0.01	0.00	0.06	0.05	0.07	0.07	0.08	0.08
2025	0.09	0.02	0.03	0.01	0.01	0.01	0.01	0.00	0.07	0.05	0.07	0.08	0.08	0.08
2026	0.09	0.02	0.03	0.01	0.01	0.01	0.01	0.00	0.07	0.05	0.07	0.08	0.08	0.08
2027	0.09	0.02	0.03	0.01	0.01	0.01	0.01	0.00	0.07	0.05	0.07	0.08	0.08	0.08
2028	0.09	0.02	0.03	0.01	0.01	0.01	0.01	0.00	0.07	0.05	0.07	0.08	0.08	0.08
2029	0.08	0.02	0.03	0.01	0.01	0.01	0.01	0.00	0.07	0.05	0.07	0.08	0.08	0.08
2030+	0.09	0.02	0.03	0.01	0.01	0.01	0.01	0.00	0.07	0.05	0.07	0.08	0.08	0.08
levelized (2018–2030)	0.08	0.02	0.03	0.01	0.01	0.01	0.00	0.00	0.06	0.05	0.07	0.07	0.07	0.08

4. Avoided T&D costs

- Not addressed in AESC 2015, or previous studies. Avoided PTF cost is a new issue in AESC 2018
- Developed a standardized approach to estimating generic avoidable T&D costs
- Also identified the portion of the pooled transmission facility (PTF) that would be allocated to Local Networks, thus calculating an avoided cost of $94/kW-year. In addition, the various utilities may have some avoidable local transmission cost.
- For non-PTF transmission, and for distribution, we discuss methods for estimating avoided T&D costs in the absence of recent or forecast load growth.
- We also review the methods in use by the utilities and program administrators, and we identify areas in which the methods could be refined to better match the criteria

4. Value of improved reliability

- New issue in AESC 2018
- Reducing electric loads can improve reliability in several ways, which differ among generation, transmission, and distribution.
- Our analysis addresses the effect of increased reserve margins on generation reliability.
- The average benefit of reducing unserved energy through higher generation reserves, including offsets for reductions in capacity cleared
- AESC 2018 calculates values for cleared and uncleared resources.

Value of Reliability from Cleared Resources (2018$/kW-year)

Summer	Reliability Value of Cleared EE ($/kW-year)		
	2018	2019	2020
2018	$5.32		
2019	$2.15	$2.59	
2020	$0.94	$1.16	$1.40
2021	$0.27	$0.36	$0.44
2022	$0.18	$0.27	$0.36
2023	$0.10	$0.19	$0.29
2024		$0.10	$0.19
2025			$1.30
2026			
15-year levelized (2018-2032)	$0.65	$0.33	$0.27

5. Sensitivities

- In addition to the main AESC case, we ran 4 sensitivities:
  - High gas price
  - Low gas price
  - High load (with increased impacts from EVs and heat pumps)
  - With EE (to be used to estimate the costs for non-programmatic EE)
- Main focus of these sensitivities was on impacts to energy price (and capacity price, REC costs, and DRIPE)
- Energy price and DRIPE results:
  - Levelized energy price and DRIPE changes for high/low gas price cases are largely commensurate with changes to natural gas trajectory
  - Levelized energy prices and DRIPE values for high load/with EE cases are largely similar to main case (+/-2 percent), mainly because natural gas trajectory is <u>not</u> changing
- Capacity and RPS
  - Different prices are due to different equilibriums in demand and supply

General questions

?

6. User Interface

- Excel workbook containing hourly load and price data for 2018-2035 for each region
- Also dynamically calculates DRIPE values
- Users can view avoided costs according to the traditional AESC costing periods (summer onpeak, etc.), or set up their own costing periods where they focus on peak prices or peak loads
- Updates are ongoing

Contacts

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Background Slides

1. Main findings

- Generally lower avoided costs when comparing with AESC 2015
  - Main drivers are lower costs for natural gas & RGGI; new or revised methodologies for capacity, DRIPE
- New chapters on avoided T&D and value of reliability
- Calculated prices and loads at 8760-hour level

Illustration of avoided electricity cost components, AESC 2018 versus AESC 2015 (WCMA)

	AESC 2015	AESC 2015	AESC 2018	AESC 2018, relative to AESC 2015		*Notes*
	2015 cents/kWh	*2018 cents/kWh*	*2018 cents/kWh*	*2018 cents/kWh*	*% Difference*	
Avoided Retail Capacity Costs	2.91	3.05	1.72	-1.33	-44%	3,4,5,6,7
Avoided Retail Energy Costs	6.29	6.60	4.63	-1.97	-30%	8,9,11
Avoided Renewable Energy Credit	0.96	1.01	0.39	-0.62	-61%	8,10,11
Subtotal: Capacity and Energy	**10.16**	**10.66**	**6.75**	**-3.92**	**-37%**	
CO_2 non-embedded	**4.88**	**5.13**	**4.36**	**-0.76**	**-15%**	5
Transmission & Distribution	**-**	**-**	**2.11**	**2.11**	**-**	3,5,12
Value of Reliability	**-**	**-**	**0.01**	**0.01**	**-**	3,5,7,13
Capacity DRIPE	-	-	0.91	0.91	-	5,7
Energy DRIPE	1.18	1.24	1.91	0.67	54%	8,14
Subtotal: DRIPE	**1.18**	**1.24**	**2.81**	**1.58**	**128%**	-
Total	**16.22**	**17.02**	**16.05**	**-0.98**	**-6%**	-

2c. Common electric assumptions (i.e., modeling inputs)

- Various pieces of our modeling use the same assumptions for the electric sector
- Demand
  - Assume no EE added in 2018 or later years
  - Annual load trajectory based on ISO New England's 2017 CELT forecast
  - Regional, hourly load shapes based on 2002
- Supply
  - Assume that MA 83C and 83D are in effect
  - Assume that MA DEP policies (CES and CO2 cap) are in effect
  - Assume no change to renewable portfolio standard (RPS) policies, except an extension to CT RPS of 1% through 2030
  - Assume units with FCM commitments are built; model builds other CCs/GTs dynamically
- Prices
  - Natural gas: Based on blend of near-term NYMEX futures with long-term prices from AEO 2017
  - RGGI: Based on most recent modeling by RGGI Inc (conducted by ICF)

2d. Avoided capacity costs

- Avoided capacity costs are driven by actual and forecast clearing prices in ISO New England's Forward Capacity Market (FCM).
- Forecasted capacity prices are based on the experience in recent auctions and expected changes in demand, supply, and market rules.

AESC 2018 capacity prices (2018 $ / kW-month)

Commitment Period (June to May)	FCA	AESC 2018	AESC 2015
2018/2019	9	$9.81	$13.60
2019/2020	10	$7.28	$11.85
2020/2021	11	$5.35	$11.89
2021/2022	12	$4.74	$12.29
2022/2023	13	$4.84	$12.20
2023/2024	14	$4.94	$11.93
2024/2025	15	$5.22	$12.55
2025/2026	16	$5.65	$12.55
2026/2027	17	$6.13	$12.64
2027/2028	18	$6.60	$12.37
2028/2029	19	$7.07	$13.08
2029/2030	20	$7.54	$13.42
2030/2031	21	$6.60	-
2031/2032	22	$7.07	-
2032/2033	23	$7.54	-
2033/2034	24	$6.60	-
2034/2035	25	$7.07	-
2035/2036	26	$7.54	-
15-year levelized		$6.52	$12.32
Percent Difference		-47%	-

Notes: All prices are in 2018 $ per month. Levelization periods are 2015/2016 to 2029/2030 for AESC 2015 and 2018/2019 to 2032/2033 for AESC 2018. Real discount rate is 2.43 percent for AESC 2015 and 1.34 percent for AESC 2018.
Source: AESC 2015 Exhibit 5-32.

2e. Avoided energy costs

- Key drivers of these lower prices include lower overall demand for electricity (even in a future with no incremental energy efficiency), lower Henry Hub natural gas prices, lower RGGI prices, more renewables (caused by changes to the RPS in states like Connecticut and Rhode Island), and the addition of a new transmission line from Canada.
- This decrease is similar to the change in avoided energy costs observed between the 2013 AESC study and the 2015 AESC study

15-year levelized cost comparison for WCMA region (2018 $ / MWh)

	Annual All hours	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak
AESC 2015	$59.38	$65.18	$59.64	$60.54	$47.27
AESC 2015 Update	$49.95	$56.58	$49.02	$48.74	$37.20
AESC 2018	$48.56	$55.67	$51.41	$42.91	$36.72
AESC 2015 Pcnt Diff	-18%	-15%	-14%	-29%	-22%
AESC 2015 Update Pcnt Diff	-3%	-2%	5%	-12%	-1%

Notes: All prices have been converted to 2018 $ per MWh. Levelization periods are 2016–2030 for AESC 2015, 2017–2031 for AESC 2015 Update, and 2018–2032 for AESC 2018. The real discount rate is 2.43 percent for AESC 2015, 1.43 percent for AESC 2015 Update, and 1.34 percent for AESC 2018. Source: AESC 2015 Exhibit 1-5, TCR workbook.

2f. Avoided cost of RPS compliance

- Relative to AESC 2015, AESC 2018 sees generally lower prices for meeting RPS compliance.
- In the near term, a supply boom stimulated mainly by distributed generation policies has surpassed demand, creating a market surplus.
- This surplus is sustained in the long term as substantial supply driven by large-scale renewable procurement policies in Connecticut, Massachusetts, and Rhode Island are expected to become operational without matching growth on the demand side.

Avoided cost of RPS compliance, aggregated by new and existing, by state, 2018$/MWh

	CT	ME	MA	NH	RI	VT
Class 1/New	$2.82	$0.21	$1.72	$1.51	$2.39	$0.53
MA CES	NA	NA	$0.45	NA	NA	NA
All Other Classes	$0.94	$0.31	$1.44	$3.43	$0.03	$1.46
Total	$3.76	$0.51	$3.61	$4.94	$2.42	$1.99

2g. Non-embedded GHG costs

Carbon dioxide

- Two possible approaches: one based on global avoided cost of CO_2, and one based on a New England-centric value
  - Global cost is based on avoided cost of CCS, about $100/short ton
  - New England-centric value based on estimated current cost of offshore wind, about $318/short ton. This results in a non-embedded value of $174/short ton
  - We have performed our initial calculations using the $100/short ton value, but have left it up to the PA's to determine which value should be used in their calculations

Nitrogen oxides

- Based on review of the literature—reasonably large range of values that are typically in the range of $13,000 to $60,000 per ton of N
- Heavily driven by assumed value of statistical life
- Not applied in Appendix B

2I. Appendices

- Appendix A: Usage instructions
- Appendix B: Summary of energy avoided costs
  - Contains text describing how to use these
  - Two pages for each state/zone with annual and levelized values for energy prices, capacity prices, DRIPE, REC costs, non-embedded costs, etc.
  - Also available as an Excel workbook
- Appendix C: Summary of natural gas avoided costs
- Appendix D: Summary of fuel oil and other fuel avoided costs
- Appendix E: Financial parameters
- Appendix F: Description of User Interface
- Appendix G: MA GWSA Compliance costs
- Appendix H: DRIPE derivation
- Appendix I: Matrix of Resources for Value of Reliability