Achieving 80% GHG Reduction in New England by 2050

Technical Appendix

PREPARED FOR

COALITION FOR COMMUNITY SOLAR ACCESS

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THE Brattle GROUP

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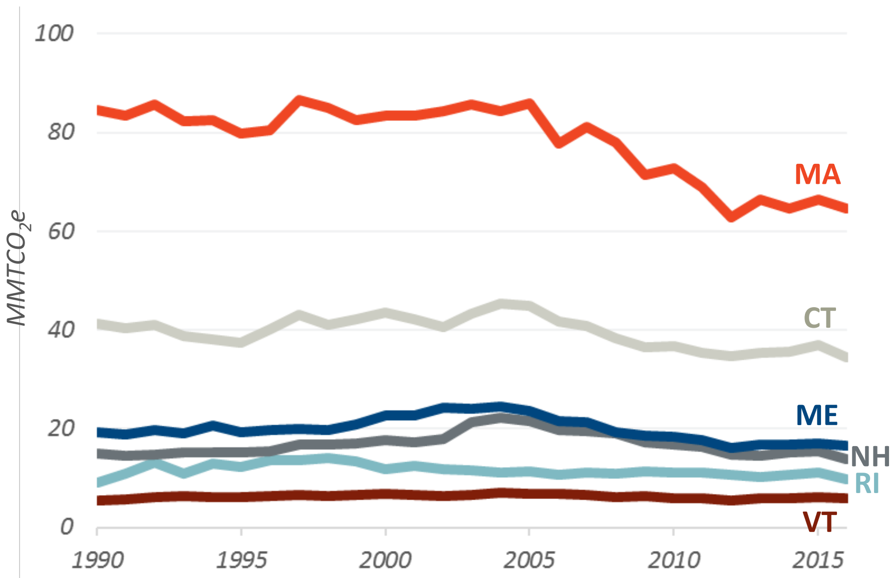
Appendix

A1: New England GHG Emissions

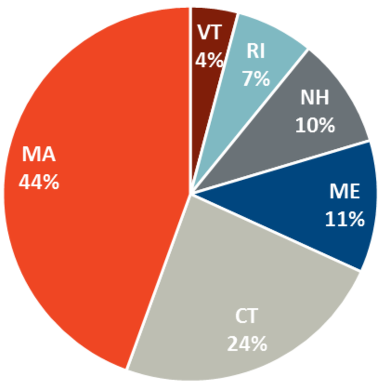
1990-2016 New England GHG emissions

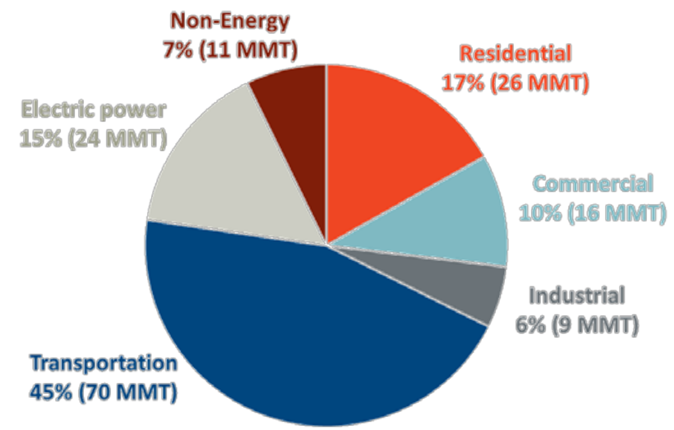
Historical Energy-Related GHG Emissions by State
1990-2016



Source: EIA.

GHG Emissions in 2016
Total: 156 $MMTCO_2e$





Source: EIA (energy-related) and state GHG inventories (non-energy).

GHG Emissions Sources Relied On

- We primarily relied on the reported GHG emissions from each state's GHG inventory and the energy-related emissions reported by the EIA
- Each state defines the scope of GHG emissions differently in terms of the non-energy sectors included and how they account for electricity imports/exports
- The EIA and state inventories align in most cases, except for electric sector emissions due to the approach to calculating imports/exports
- For our analysis, we:
  - Set the 2050 goals based on the GHG inventories
  - Used the EIA data for energy sector emissions for consistency
  - Used the state inventories for non-energy emissions

Massachusetts GHG Emissions

- Difference in total energy-related emissions between EIA and MA GHG Inventory mainly due to inclusion/ exclusion of imported electricity
  - Imported electricity generation accounts for ~20–25% of total electricity
  - EIA "assigns all emissions related to the primary energy consumed for the production of electricity to the state where that electricity was produced rather than where it was consumed"
- In addition, MA's GHG Inventory includes non-energy emissions from industrial processes, agriculture & land use, and waste

MA GHG Emissions (MMTCO$_2$e)
EIA vs State's GHG Inventory

	1990		2016	
	EIA	*State Inv.*	*EIA*	*State Inv.*
Energy	**84.6**	**90.6**	**64.2**	**69.3**
From Fossil Fuel Combustion	**84.6**	**88.2**	**64.2**	**68.5**
Residential	n.a.	15.3	11.4	11.5
Commercial	n.a.	8.4	7.0	7.0
Industrial	n.a.	5.8	3.4	3.5
Transportation	n.a.	30.5	31.7	31.7
Electric Sector	n.a.	28.2	10.7	14.7
Natural Gas Systems	n.a.	2.4	n.a.	0.8
Non-Energy	**n.a.**	**3.8**	**n.a.**	**5.0**
Industrial Processes	n.a.	0.7	n.a.	3.9
Agriculture & Land Use	n.a.	0.3	n.a.	0.2
Waste	n.a.	2.7	n.a.	0.8
Total	**n.a.**	**94.5**	**n.a.**	**74.2**

Note: Totals may not add up due to rounding. *Sources:* Massachusetts Emissions Inventory: https://www.mass.gov/lists/massdep-emissions-inventories, EIA: https://www.eia.gov/environment/emissions/state/analysis/pdf/table4.pdf.

A1: New England GHG Emissions

Connecticut GHG Emissions

- CT's GHG Inventory includes both generation- and consumption-based electric power emissions (see table below)
- CT's GHG Inventory also includes non-energy emissions from agriculture & land use and waste

Electric Power Emissions ($MMTCO_2e$)

	2001	2016
Consumption-based	12.3	9.3
Generation-based	11.4	8.6

CT GHG Emissions ($MMTCO_2e$)

EIA vs State's GHG Inventory

	2001		2016	
	EIA	*State Inv.*	*EIA*	*State Inv.*
Residential	n.a.	8.5	6.3	6.4
Commercial	n.a.	4.3	3.9	3.9
Industrial	n.a.	4.4	1.8	3.9
Transportation	n.a.	17.8	15.3	15.5
Electric Sector	n.a.	11.4*	7.0	8.6*
Agriculture & Land Use	n.a.	0.33	n.a.	0.25
Waste	n.a.	1.5	n.a.	1.9
Energy-based	**42.3**	**n.a.**	**34.3**	**n.a.**
Total	**n.a.**	**49.0**	**n.a.**	**40.4**

Notes: Totals may not add up due to rounding. *Generation-based emissions. *Sources:* Connecticut Emissions Inventory: https://www.ct.gov/deep/lib/deep/climatechange/publications/ct_2016_ghg_inventory.pdf, EIA: https://www.eia.gov/environment/emissions/state/analysis/pdf/table4.pdf.

A1: New England GHG Emissions

Maine GHG Emissions

- Maine's GHG Inventory includes non-energy emissions from industrial processes, agriculture & land use, and waste
- Maine's GHG Inventory does not state whether electric sector emissions account for electricity imports/exports
- 3% of in-state generation is exported

ME GHG Emissions (MMTCO_2e)

EIA vs State's GHG Inventory

	2003		2015/2016		
	EIA	*State Inv.*	*EIA 2016*	*EIA 2015*	*State Inv. 2015*
Energy	**24.0**	**24.2**	n.a.	n.a.	**17.2**
From Fossil Fuel Combustion	**24.0**	**23.6**	**16.5**		**16.8**
Residential	n.a.	4.8	2.9		3.0
Commercial	n.a.	2.3	1.6		1.8
Industrial	n.a.	2.4	1.5		1.7
Transportation	n.a.	9.4	8.9		8.8
Electric Sector	n.a.	4.8	1.5		1.6
Other	n.a.	0.6	n.a.	n.a.	0.4
Non-Energy	n.a.	**2.2**	n.a.	n.a.	**1.9**
Industrial Processes	n.a.	1.2	n.a.	n.a.	1.0
Agriculture & Land Use	n.a.	0.7	n.a.	n.a.	0.6
Waste	n.a.	0.5	n.a.	n.a.	0.4
Total	n.a.	**26.6**	n.a.	n.a.	**19.1**

Note: Totals may not add up due to rounding. *Sources:* Maine Emissions Inventory: http://www.maine.gov/tools/whatsnew/attach.php?id=778255&an=1, EIA: https://www.eia.gov/environment/emissions/state/analysis/pdf/table4.pdf.

New Hampshire GHG Emissions

- Limited information available on inputs to New Hampshire's GHG Inventory
- Non-energy emissions include industrial processes and other sources

NH GHG Emissions (MMTCO_2e)
EIA vs State's GHG Inventory

	1990		2015/2016	
	EIA	*State Inv.*	*EIA (2016)*	*State Inv. (2015)*
Energy	**14.9**	**14.7**	**13.8**	**15.2**
Residential	n.a.	2.5	2.5	2.7
Commercial	n.a.	1.3	1.4	1.5
Industrial	n.a.	0.8	0.8	0.7
Transportation	n.a.	5.2	6.7	7.0
Electric Sector	n.a.	4.9	2.4	3.3
Non-Energy	n.a.	1.1	n.a.	1.5
Industrial Processes	n.a.	0.1	n.a.	0.7
Other	n.a.	1.0	n.a.	0.8
Total	**n.a.**	**15.8**	**n.a.**	**16.7**

Note: Totals may not add up due to rounding. *Sources:* New Hampshire Emissions Inventory: https://www.des.nh.gov/organization/divisions/air/tsb/tps/climate/ghg-emissions.htm, EIA: https://www.eia.gov/environment/emissions/state/analysis/pdf/table4.pdf.

Rhode Island GHG Emissions

- Rhode Island's GHG Inventory assumes that all electricity used to satisfy RI's load comes from the grid average mix from New England states
- Rhode Island includes non-energy emissions from industrial processes, agriculture & land use, and waste

RI GHG Emissions ($MMTCO_2e$)
EIA vs State's GHG Inventory

	1990		2015/2016	
	EIA	*State Inv.*	*EIA (2016)*	*State Inv. (2015)*
Energy	**9.0**	**12.3**	**9.7**	**10.7**
From Fossil Fuel Combustion	**9.0**	**12.0**	**9.7**	**10.7**
Residential	n.a.	2.4	1.8	2.2
Commercial	n.a.	1.2	0.9	0.9
Industrial	n.a.	0.7	0.6	0.8
Transportation	n.a.	5.0	3.9	4.5
Electric Sector*	n.a.	2.8	2.6	2.3
Natural Gas Systems	n.a.	0.3	n.a.	n.a.
Non-Energy	n.a.	**0.15**	**n.a.**	**0.6**
Industrial Processes	n.a.	0.09	n.a.	0.3***
Agriculture & Land Use	n.a.	0.04	n.a.	0.0
Waste**	n.a.	0.02	n.a.	0.3
Total	n.a.	**12.5**	n.a.	**11.3**

Notes: *Includes Electricity Consumption Methodology adjustment in the GHG inventory. **Waste = solid waste + wastewater – LULUCF adjustment. ***Represents "Other": transmission/ distribution, wastewater, agricultural, and land use. *Sources:* Rhode Island Emissions Inventory: http://climatechange.ri.gov/documents/ec4-ghg-emissions-reduction-plan-final-draft-2016-12-29-clean.pdf, EIA: https://www.eia.gov/environment/emissions/state/analysis/pdf/table4.pdf.

A1: New England GHG Emissions

Vermont GHG Emissions

- Electric sector emissions in the Vermont GHG Inventory are consumption-based, while EIA emissions are generation based
- Vermont includes non-energy emissions from industrial processes, agriculture & land use, and waste

VT GHG Emissions ($MMTCO_2e$)

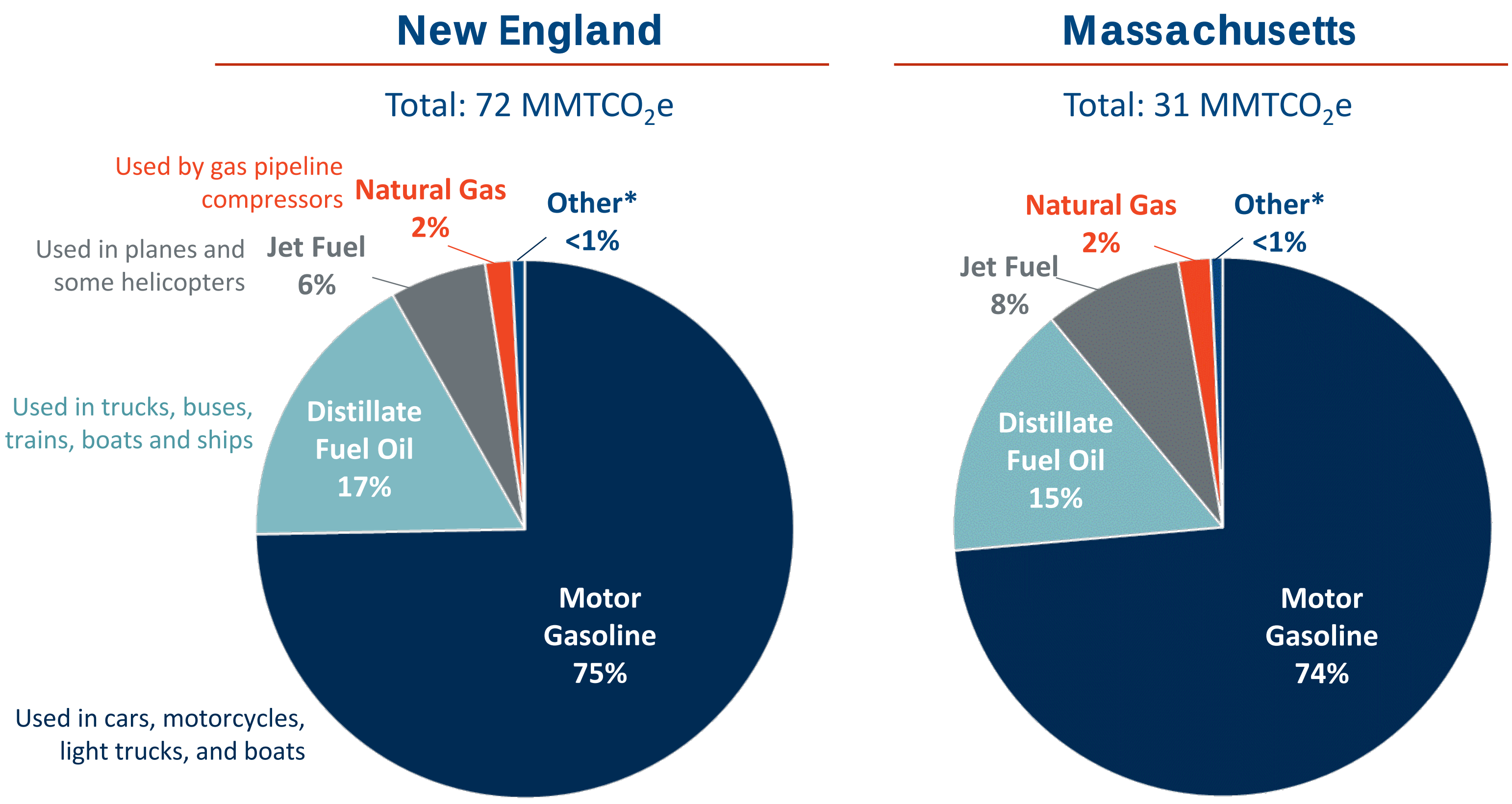
EIA vs State's GHG Inventory

	1990		2016	
	EIA	*State Inv.*	*EIA (2016)*	*State Inv. (2015)*
Energy	**5.5**	**6.9**	**6.0**	**8.1**
From Fossil Fuel Combustion	**5.5**	**6.9**	**6.0**	**8.1**
Res/Com/Ind	n.a.	2.4	2.6	2.8
Transportation	n.a.	3.4	3.4	4.3
Electric Sector	n.a.	1.1	0.0	1.0
Natural Gas Systems	n.a.	<0.1	n.a.	<0.1
Non-Energy	n.a.	**1.7**	**n.a.**	**1.9**
Industrial Processes	n.a.	0.2	n.a.	0.6
Agriculture & Land Use	n.a.	1.2	n.a.	1.1
Waste	n.a.	0.3	n.a.	0.2
Total	n.a.	**8.6**	n.a.	**10.0**

Note: Totals may not add up due to rounding. *Sources:* Vermont Emissions Inventory: https://dec.vermont.gov/sites/dec/files/aqc/climate-change/documents/_Vermont_Greenhouse_Gas_Emissions_Inventory_Update_1990-2015.pdf, EIA: https://www.eia.gov/environment/emissions/state/analysis/pdf/table4.pdf.

Transportation Emissions

Transportation Sector Emissions by Fuel Source in 2015



Note: *Other includes lubricants, residual fuel oil, and hydrocarbon gas liquids.
Source: Derived from EIA State Energy Data System (SEDS) and Documentation for estimates of state energy-related carbon dioxide emissions.

Appendix

A1: New England GHG Emissions

A2: New England Historical Energy Demand

A3: Building Assumptions

A4: Transportation Assumptions

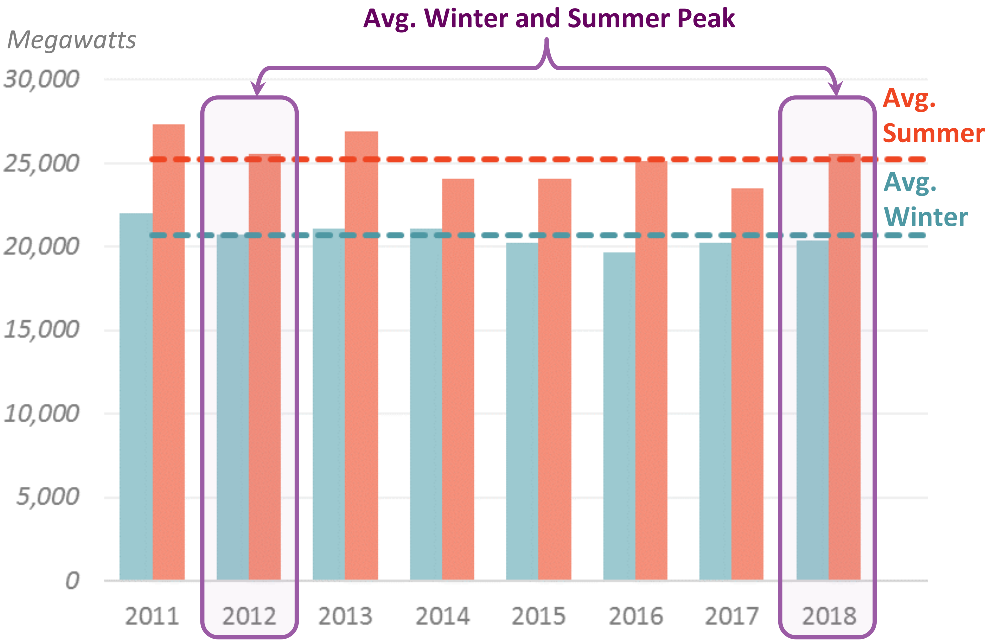
A5: Supply Resources Assumptions

A6: Additional Portfolio Results

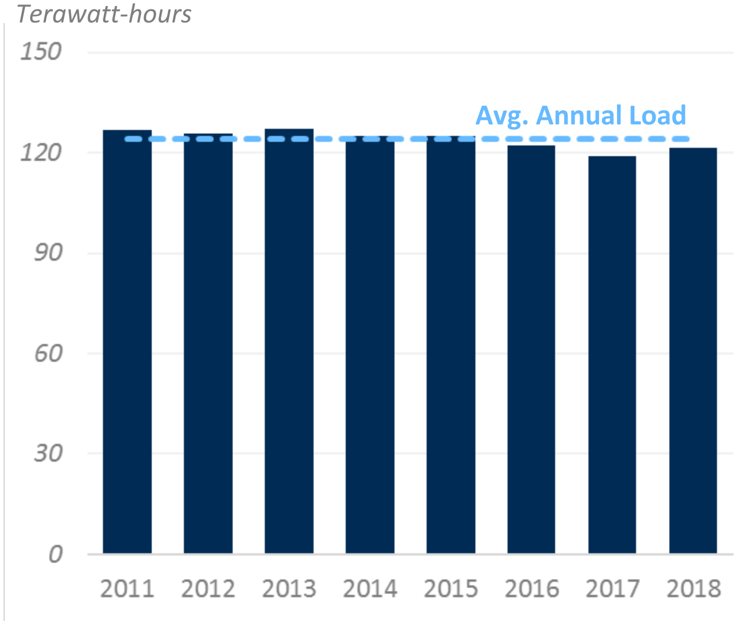
A2: New England Historical Energy Demand

Historical ISO-NE Load

Historical Winter and Summer Electric Demand Peaks in New England



Annual Load in New England



Note: Winter defined as Nov-Feb, Summer as Jun-Sep. *Source: ABB,* Velocity Suite and Brattle analysis.

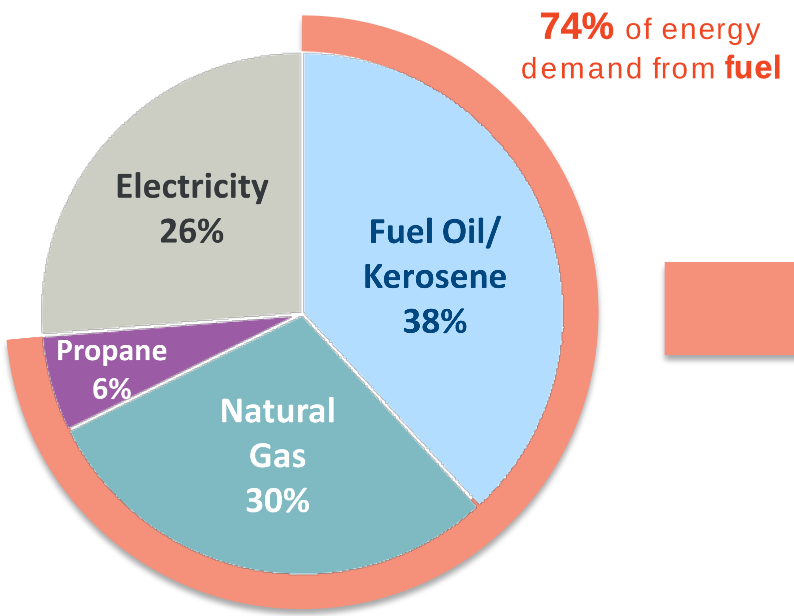
2018 represents average demand conditions in New England and was therefore the base year for the analysis.

A2: New England Historical Energy Demand

Residential Fuel Demand

Energy Demand by Source in 2015

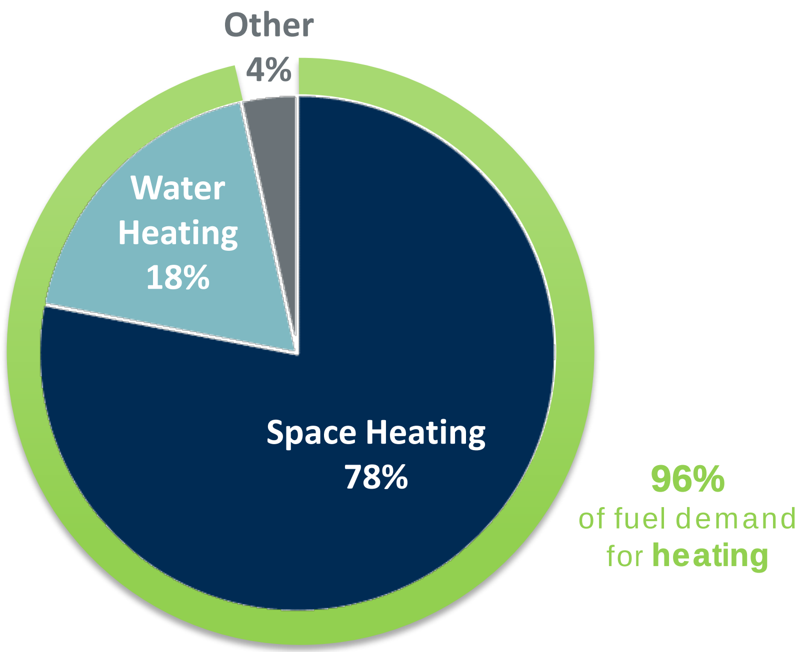
Total Energy Demand: 547 Trillion Btu



Source: EIA 2015 RECS Survey Data.

Fuel Demand by End-Use in 2015

Total Fuel Demand: 401 Trillion Btu



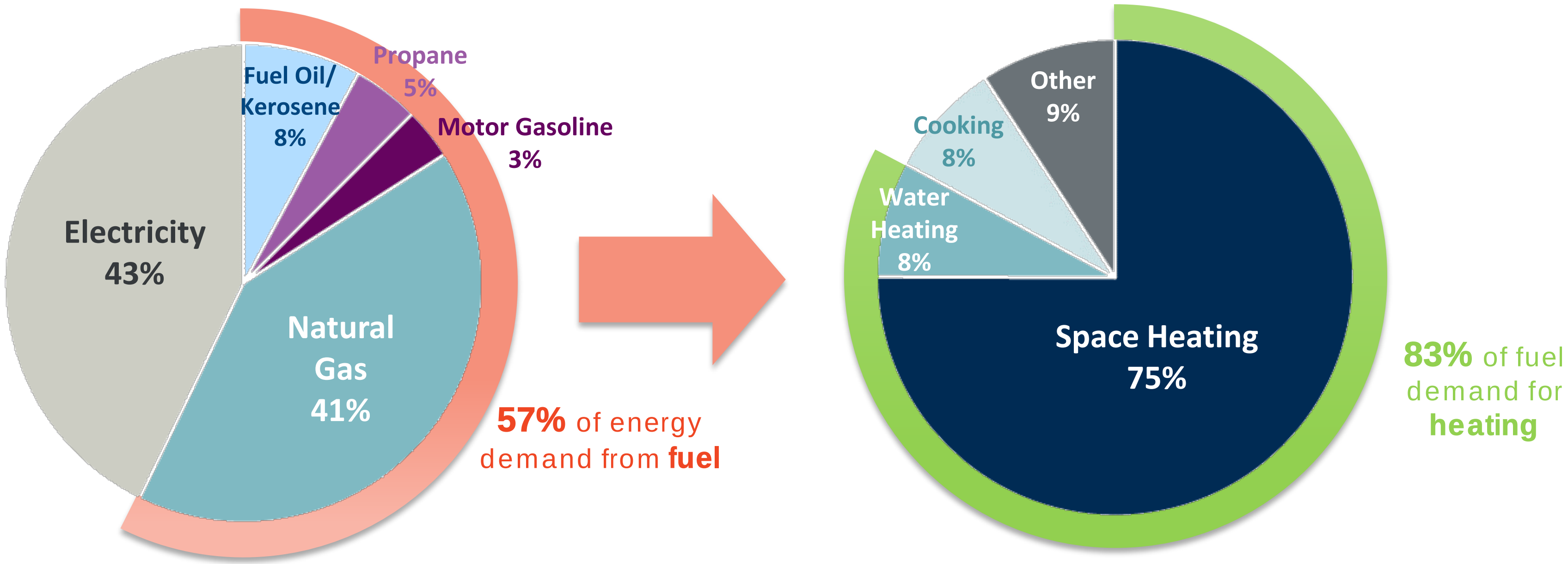
Source: EIA 2015 RECS Survey Data.
Note: "Other" includes clothes dryers, cooking, pool heaters, and hot tub heaters.

Nearly 100% of residential energy demand can be electrified.

Commercial Fuel Demand

Energy Demand by Source in 2017
Total Energy Demand: 480 Trillion Btu

Fuel Demand by End-Use in 2017
Total Fuel Demand: 274 Trillion Btu



Source: AEO 2019 and EIA 2012 CBECS Survey Data.

Source: AEO 2019 and EIA 2012 CBECS Survey Data.
Note: "Other" includes office equipment, cooling, refrigeration, manufacturing, and electricity generation.

Nearly 100% of commercial energy demand can be electrified

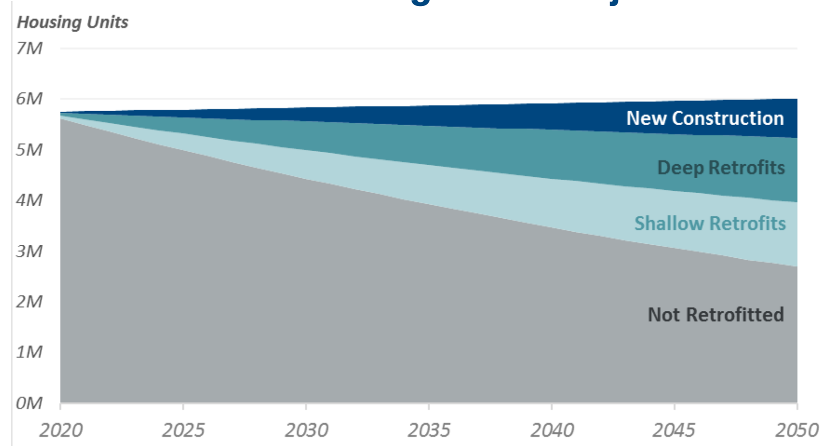
Appendix

A3: Building Assumptions

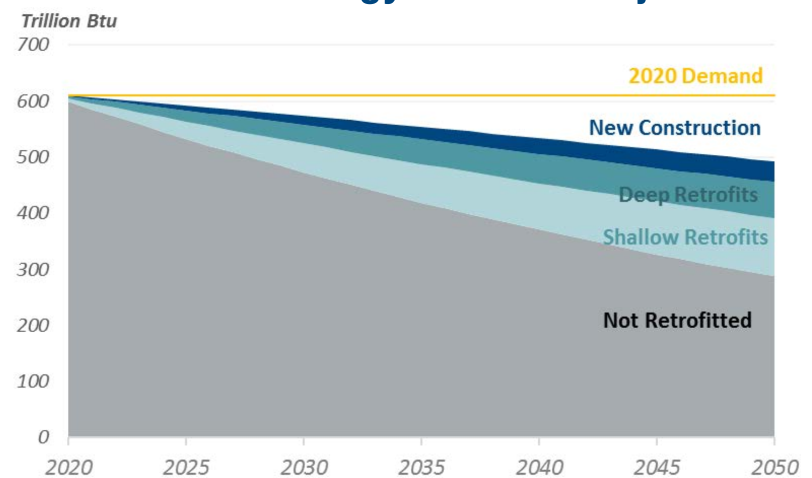
Residential and Commercial Energy Efficiency Assumptions

- Current New England EE programs target up to 2% per year of residential and commercial electricity demand reductions
  - Primarily occurring through programs to increase use of more efficient lighting
  - Several utilities and states include retrofit programs in their EE efforts
- Residential & commercial retrofit programs in MA and CT implemented retrofits at 1–2% of housing units per year
  - This rate of energy efficiency retrofits is a small fraction of total residential home improvement projects undertaken each year
- We assume 2% of housing units and commercial buildings undergo a retrofit each year with half completing a shallow retrofit (10% savings) and half a deep retrofit (40% savings); retrofit effectiveness increases by 2% per year
- Efficiency of new construction similar to deep retrofits
- Translates to 0.7% per year of energy savings

Residential Housing Stock Projections



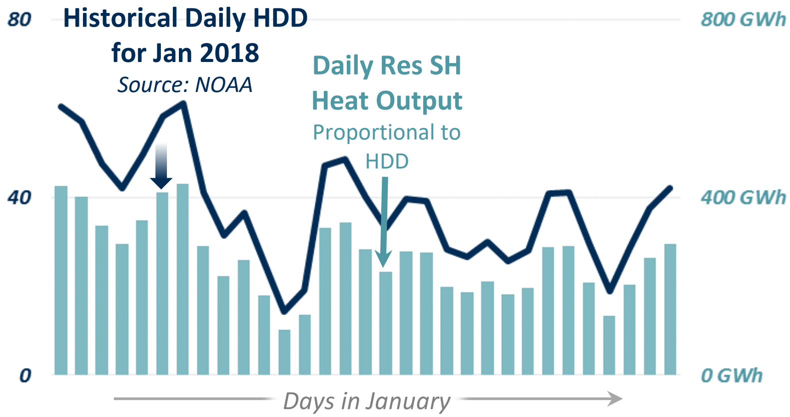
Residential Energy Demand Projections



A3: Building Assumptions

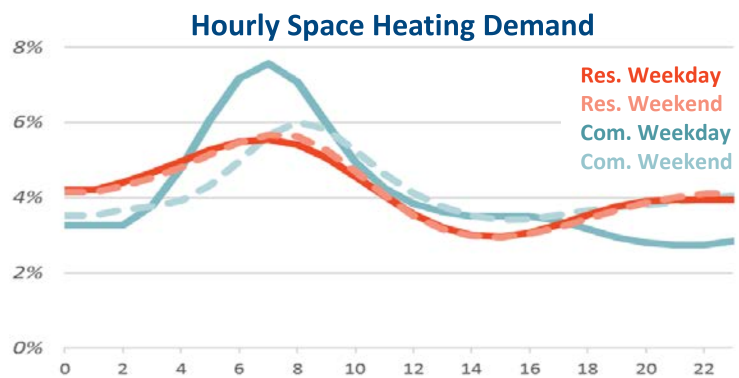
Electric Space Heating Demand

1 *Estimate daily heating demand based on annual heating demand from EIA and daily HDD*



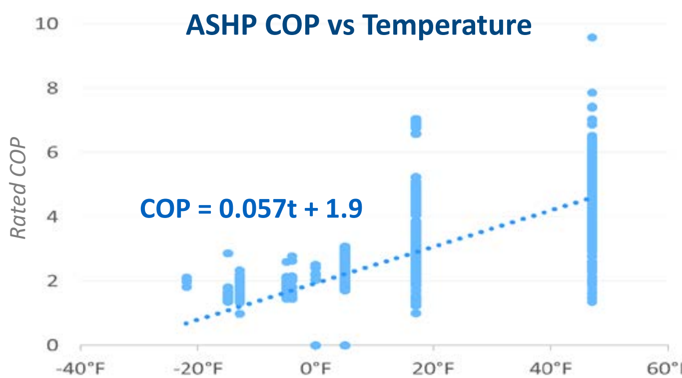
Note: Assumes conventional heating efficiency of 85%.

2 *Estimate hourly heating demand based on daily heating demand and 24-hr load shapes from EPRI*



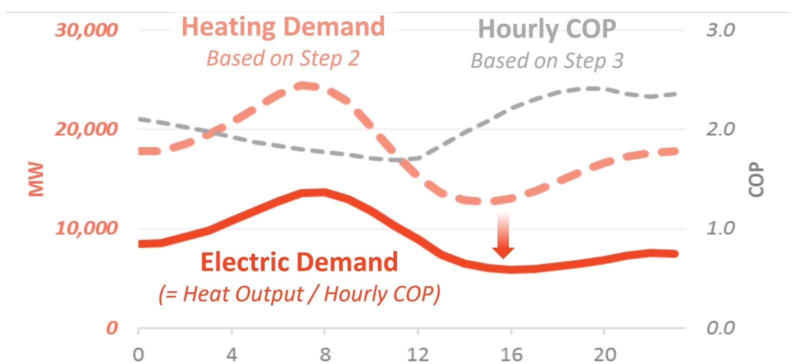
Source: EPRI.

3 *Estimate hourly COP based on hourly temperatures and relationship between COP and temperature*



Source: Brattle analysis of Northeast Energy Efficiency Partnerships data. COP adjusted to take into account differences between rated COP and actual heat pump performance. Assume constant COP for GSHP and 75% / 25% split between ASHP and GSHP.

4 *Estimate hourly electricity demand based on hourly COP and hourly heating demand*



A3: Building Assumptions

Modeling Water Heating Demand

1 *Assume daily consumption is consistent throughout the year*

Annual WH demand

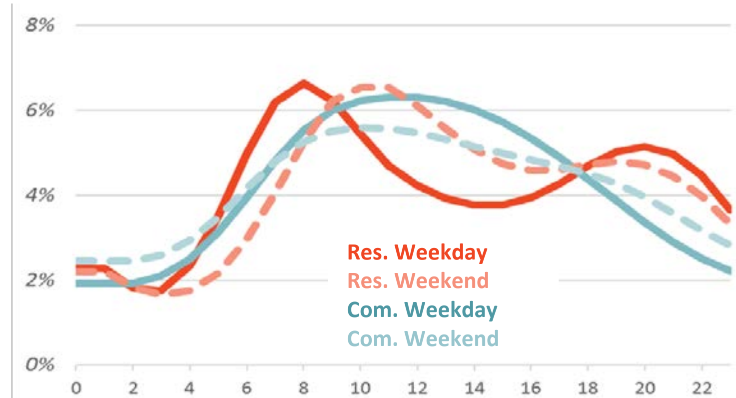
Daily Demand

Annual Demand ÷ 365 days

Potential improvements:

- *Weekend/weekday differentiation*
- *Seasonal differentiation*

2 *Estimate hourly fuel demand based on daily fuel demand and 24-hr load shapes from EPRI*



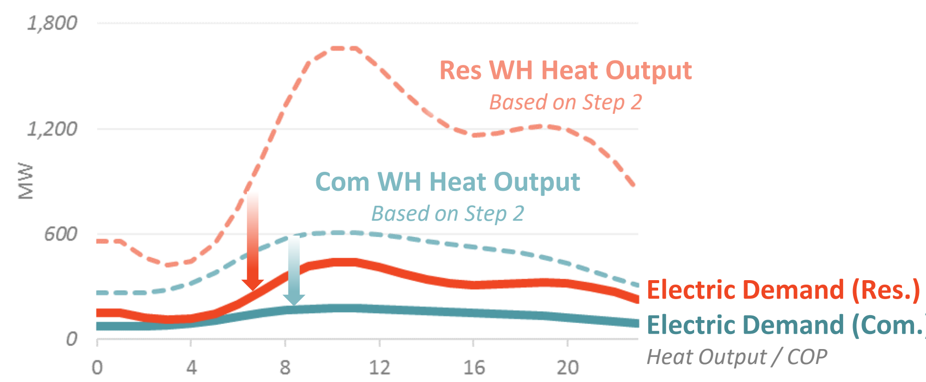
Source: EPRI.

3 *Estimate average COP for residential & commercial customers in 2050 based on NREL analysis*

Sector	COP 2015	COP 2050
Residential	2.5	**3.8**
Commercial	2.5	**3.4**

Source: NREL Electrification Futures Study.

4 *Estimate hourly electricity demand based on COP and hourly fuel demand*



Note: Figure shows data for January 7, 2050 (based on year 2018).

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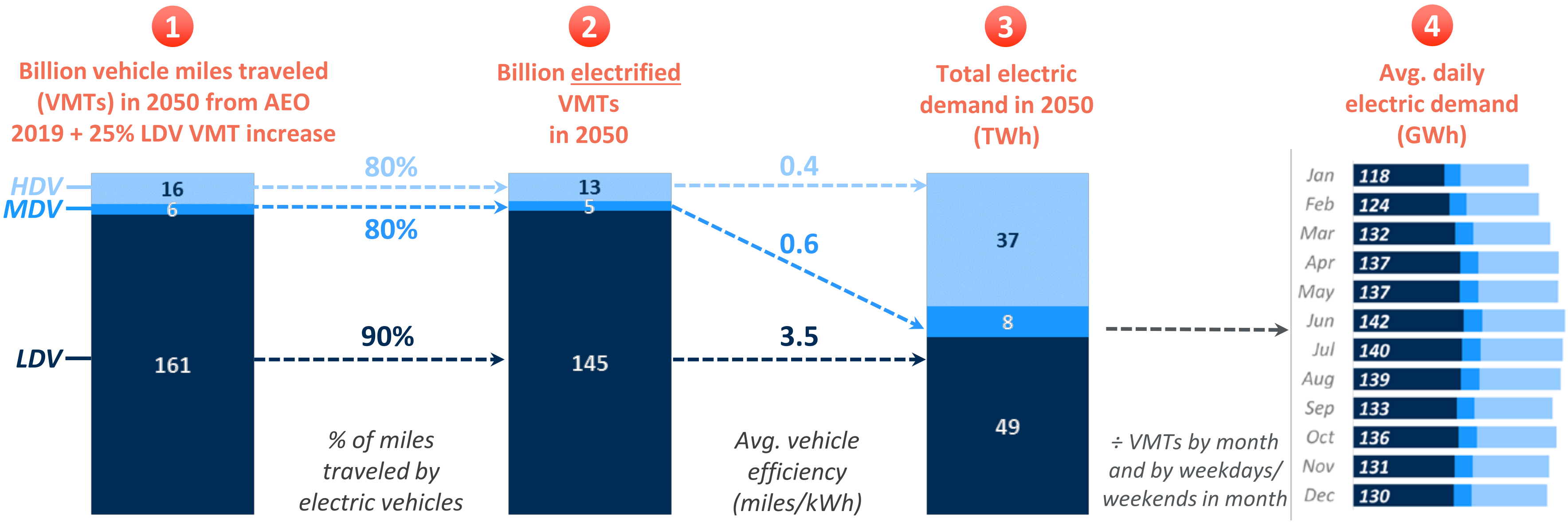
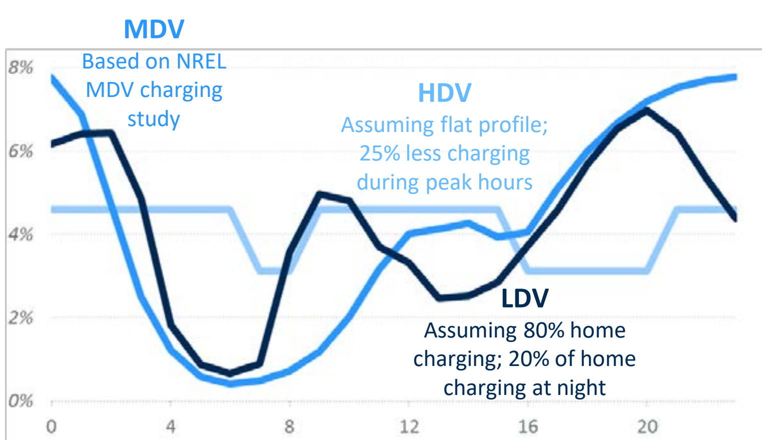
Transportation Demand Modeling



5

Determine hourly demand using load shape and temperature-dependent efficiency assumptions



Note: Off-road transportation not modeled

- *Rail (passenger and freight)*
- *Shipping (domestic and international)*
- *Recreational boats*
- *Other: air, military use, lubricants, pipeline and distribution fuel*

Off-road transp. currently represents ~20% of total energy demand for transp.

Note: LDV = Light-duty vehicle; MDV = medium-duty vehicle (commercial light trucks and bus transportation); HDV = heavy-duty vehicle (freight trucks)

Transportation Assumptions

- Accounted for monthly differences in vehicle miles traveled (VMT) based on average historical monthly VMT data from the U.S. Department of Transportation
- Accounted for differences in weekday and weekend VMTs (30% more on weekdays for LDV, 60% more for MDV/HDV)
- Increased total VMT by 25% in 2050 to account for increase in transportation due to lower per-mile operating costs of electric vehicles
- Estimated electricity demand based on average efficiency estimates by vehicle class from NREL's Electrification Futures Study
- Estimated effect of varying daily average temperatures on vehicle efficiency and charging demand based on study from Carnegie Mellon University[1]
- Assumed charger efficiency of 85% based on review of studies by the VEIC and the National Center for Sustainable Transportation[2]

Sources:

1. Tugce Yuksel and Jeremy J. Michalek, "Effects of Regional Temperature on Electric Vehicle Efficiency, Range, and Emissions in the United States," Environmental Science & Technology 2015 49 (6), 3974-3980, published February 11, 2015.
2. Vermont Energy Investment Corporation (VEIC) Transportation Efficiency Group, "An Assessment of Level 1 and Level 2 Electric Vehicle Charging Efficiency," March 20, 2013 (Revised). National Center for Sustainable Transportation, "Exploring Electric Vehicle Battery Charging Efficiency," September 2018.

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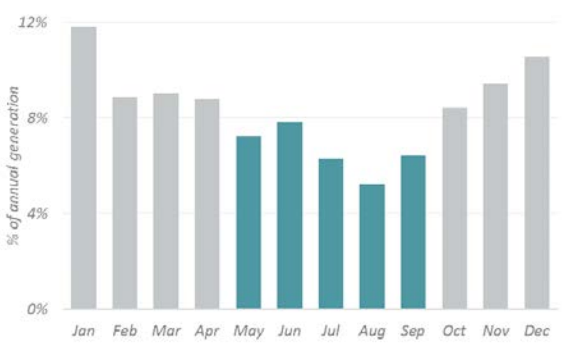
Planned State-Level Procurements

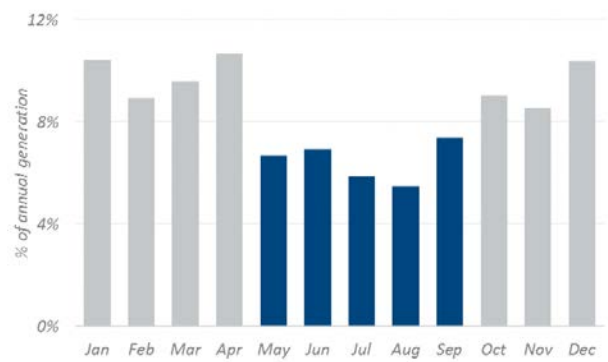
Year	State	Name	Resource Type	Capacity (MW)	Estimated Annual Energy (GWh)
2020	Rhode Island	TBD	Renewable Energy Projects (20-200 MW)	400	526
2020	Connecticut	TBD	Solar	165	236
2021	Massachusetts	Vineyard Wind 1	Offshore Wind	400	1,577
2022	Massachusetts	Vineyard Wind 2	Offshore Wind	400	1,577
2022	Massachusetts	TBD	Large Hydro	1,200	9,450
2023	Connecticut	Revolution Wind	Offshore Wind	300	1,225
2023	Rhode Island	Revolution Wind	Offshore Wind	400	1,633
2024	Maine	TBD	Distributed Renewable Generation	375	535
2025	Massachusetts	SMART Program	Solar PV	1,600	2,285
2027	Massachusetts	TBD	Offshore Wind	800	3,154
2030	Connecticut	TBD	Offshore Wind	2,000	8,164
2035	Massachusetts	TBD	Offshore Wind	1,600	6,307

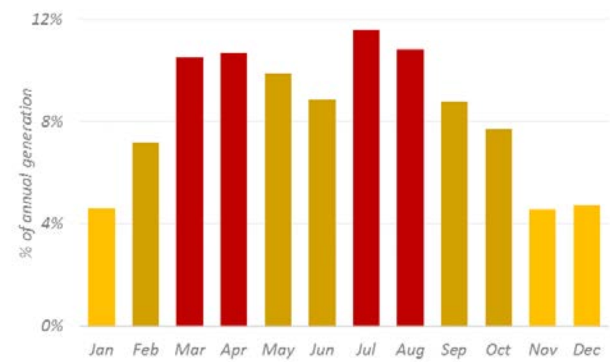
A5: Supply Resources Assumptions
Generation Profiles

Offshore Wind	Onshore Wind	Solar

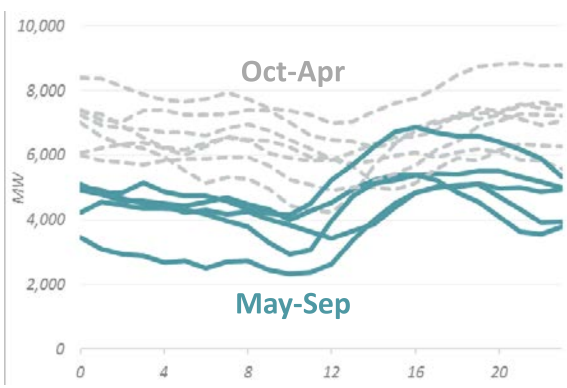
Total Monthly Generation

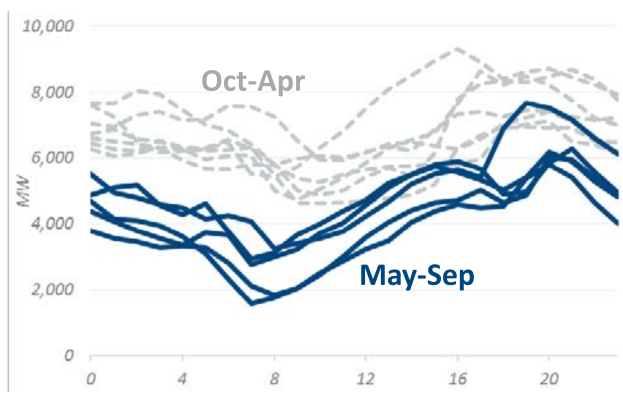


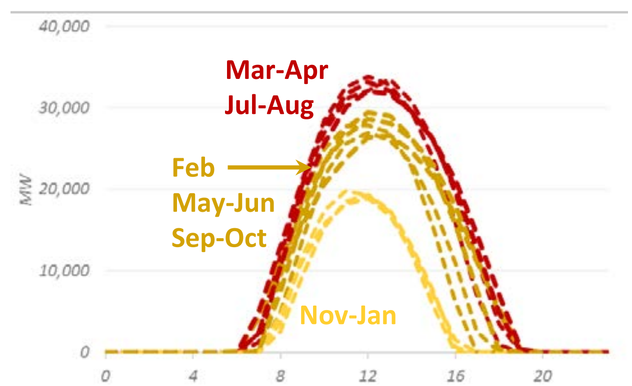




Avg. Hourly Generation by Month







Source: NREL's WIND Toolkit and NREL SAM PV dataset based on 2012 weather data for ISO-NE.

New England Offshore Wind Costs

- We estimated the costs of recent offshore wind procurements based on the levelized revenue of energy approach utilitized by NREL in analyzing the Vineyard Wind project
  - 800 MW Vineyard Wind (Massachusetts, online 2021 and 2022)[1]
  - 700 MW Revolution Wind (Connecticut and Rhode Island, online 2023)[2]
- Cost ranges are based on our analysis of the 2018 and 2019 NREL Annual Technology Baseline reports

Large-Scale Offshore Wind Project Costs ($/MWh)

All monetary units in 2018$	**Vineyard Wind Facility 1** (2021)	**Vineyard Wind Facility 2** (2022)	**Revolution Wind** (2023)
Levelized PPA Revenue (Energy + RECs)	$67	$57	$73
Levelized Value of ITC	$11	$11	$12
Levelized Capacity Revenues	$6	$6	$6
Levelized Revenue of Energy	**$84**	**$74**	**$91**

1. *Source:* https://www.nrel.gov/docs/fy19osti/72981.pdf, pp. 5-7. LROE (levelized revenue of energy) is used as a proxy for LCOE when cost data is not available. It includes revenue received from sale of energy, RECs, capacity, and tax incentive. Assumes ITC value of 18%, CapEx of $3,250/kW (2018 $), capacity revenues of $60,000/MW-year (2018 $), UCAP value of 38%, and annual capacity factor of 45%.
2. *Source:* http://www.ripuc.org/eventsactions/docket/4929-NGrid-ScheduleNG-5(REDACTED).pdf, p. 15. Uses project-specific levelized revenues for energy and RECs, assumes the same ITC rate, CapEx, capacity revenues, and UCAP value calculated for Vineyard Wind. Assumes a 46.6% annual capacity factor

Note: Assumed 2.5% inflation rate and a 7.0% nominal discount rate.

New England Onshore Wind Costs

- SEA projections in 2016 UCS study show 2020 costs of $58-91/MWh and 2030 costs of $75-99/MWh (2018 $) for the first 2,000 MW[1]
- NREL ATB projects cost decline of 0-3% (real) per year, with the mid case decreasing at 1%/year[2]
- We define a cost range of $65-$95 (2018 $) in 2020, with the upper and lower end of that range decreasing by 1% annually
- We add $15/MWh (2018 $) in all years for transmission costs to deliver generation to Massachusetts

Large-Scale Onshore Wind Project Costs ($/MWh)

All monetary units in 2018$	Number Nine Wind Farm (2016)[3]	Cassadaga Wind (2021)[4]
Levelized PPA Revenue (Energy + RECs)	$72	$73
Levelized Value of PTC	$19	$12
Levelized Capacity Revenues	$6	$6
Levelized Revenue of Energy	**$96**	**$91**

1. "An Analysis of the Potential Cost of Increasing MA RPS Targets and RE Procurements," Sustainable Energy Advantage LLC, March 2016, p. 12.
2. "NREL 2018 Annual Technology Baseline Spreadsheet," NREL, 2018, available at: https://data.nrel.gov/files/89/2018-ATB-data-interim-geo.xlsm.
3. Brattle analysis; "Power Purchase Agreement Between The Connecticut Power and Light Company and Number Nine Wind Farm LLC," September 19, 2013, Exhibit D, available at: http://www.dpuc.state.ct.us/dockhistpost2000.nsf/8e6fc37a54110e3e852576190052b64d/067ea16d118981a28525829c00734710/$FILE/Docket%20No.%2013-09-19%20Cover%20Letter%20with%20attached%20Power%20Purchase%20Agreements.pdf.
4. Brattle analysis; "RPS Class I Renewable Generation Unit Power Purchase Agreement Between Massachusetts Electric Company and Nantucket Electric Company, D/B/A National Grid As Buyer and Cassadaga Wind LLC as Seller," May 25, 2017, available at: https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/9484098.

Note: Assumes that Number Nine Wind Farm receives full PTC. Cassadaga Wind receives 80% of PTC. Assumes capacity prices of $60,000/MW-year, UCAP value of 30%, Annual capacity factor of 32%.

Large-Scale Solar Costs

- We define a cost range of $95-$111/MWh in 2020, with the lower bound decreasing at 3.0%/year and the upper bound decreasing at 1.4%/year
  - The upper bound is set equal to the LROE value for large DG solar projects in the National Grid Block 8 of the Solar Massachusetts Renewable Target (SMART) program ($111/MWh)[1]
  - The lower bound is set equal to the capacity weighted average of the LROE values of recent MA 83A solar procurements ($105/MWh)[2]
  - The cost decline rate is consistent with 2018 NREL ATB projections

Large-Scale Solar Project Costs in 2020 ($/MWh)

All monetary units in 2018$	Scituate RI Solar and Hope Farm Solar	Woods Hill Solar	Sanford Airport Solar	Chinook Solar	Farmington Solar	Quinebaug Solar	SMART large DG block 8 National Grid	SMART large DG block 8 Eversource West
Levelized PPA Revenue (Energy + RECs)	$74	$78	$62	$64	$67	$70	$84	$77
Levelized Value of ITC	$26	$26	$26	$26	$26	$26	$26	$26
Levelized Capacity Revenues	$7	$7	$7	$7	$7	$7	$0	$0
Levelized Revenue of Energy	**$107**	**$112**	**$95**	**$98**	**$100**	**$103**	**$111**	**$103**

1. *Sources:* SMART Program Base Compensation Rates, available at: https://www.mass.gov/doc/capacity-block-base-compensation-rate-and-compensation-rate-adder-guideline-1/download.
2. Brattle analysis of power purchase agreements filed in MA D.P.U. Docket No. 17-120.

Note: Assumes capacity prices of $60,000/MW-year, UCAP value and annual capacity factor of 16%, a 30% ITC for all projects, and a CapEx of $1,690/kW.

A5: Supply Resources Assumptions

Imported Hydro Costs

There is economic potential to build out at least 35 TWh of new incremental hydro in Québec that could be exported to the Northeastern U.S.[1]

Bin	Potential TWh	Levelized Cost 2018 $/MWh
1 (Existing)	144, growing to 157 by 2050[2]	Current: $20; Post-2030: $25
2 (New)	10	$70
3 (New)	10	$100
4 (New)	15+	$130

1. *Source:* Williams, J.H., Jones, R., Kwok, G., and B. Haley, (2018). Deep Decarbonization in the Northeastern United States and Expanded Coordination with Hydro-Québec. A report of the Sustainable Development Solutions Network in cooperation with Evolved Energy Research and Hydro-Québec. April 8, 2018.
2. *Note:* The existing potential grows through 2050 due to efficiency improvements and a wetter climate.

A5: Supply Resources Assumptions

Renewable Resource Constraints Sources

- ISO-NE, 2015 Economic Study: Strategic Transmission Analysis—Onshore Wind Integration, September 2, 2016, p. 37.
- BOEM, BOEM's Renewable Energy Program, May 2019.
- U.S. DOE, Wind Vision: A New Era for Wind Power in the United States, 2015.
- Pfeifenberger, et al., U.S. Offshore Wind Generation and Transmission Needs, May 23, 2018.

Appendix

A1: New England GHG Emissions

A2: New England Historical Energy Demand

A3: Building Assumptions

A4: Transportation Assumptions

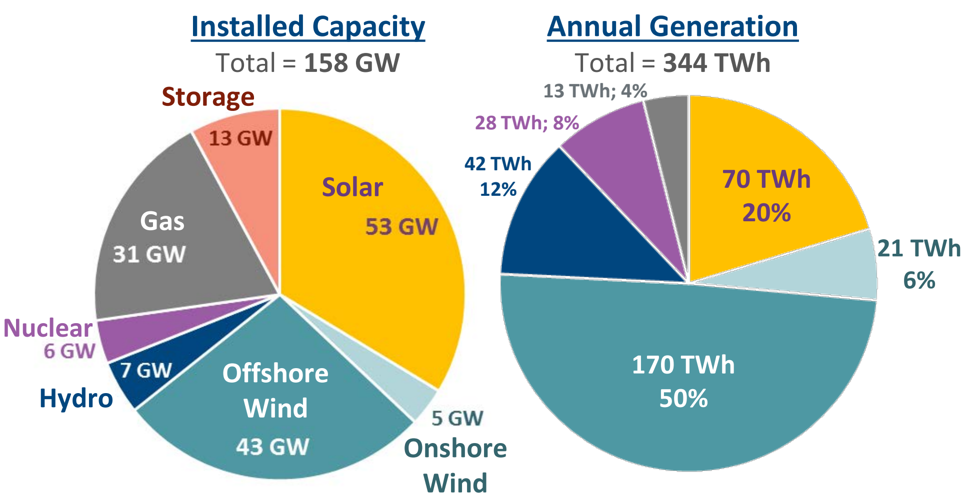
A5: Supply Resources Assumptions

A6: Additional Portfolio Results

A6: Additional Portfolio Results

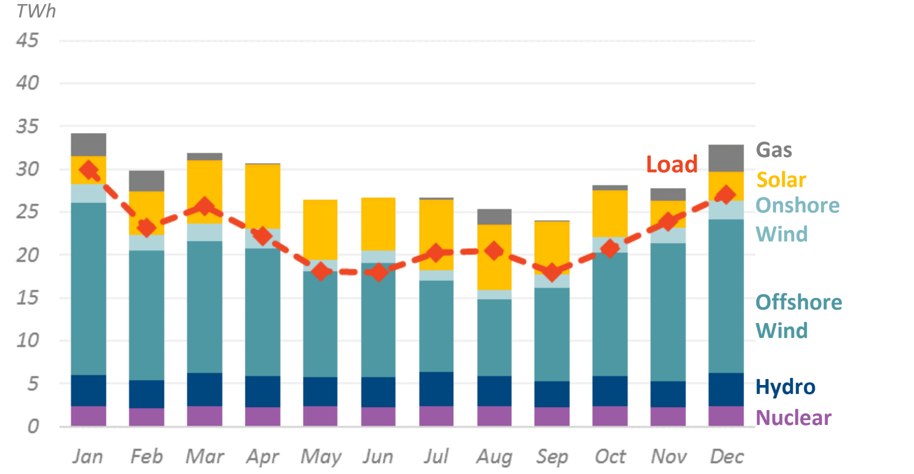
A preference for large-scale resources will limit the role of solar & storage to meeting demand

2050 New England Resource Mix
Scenario: Large-Scale Resources

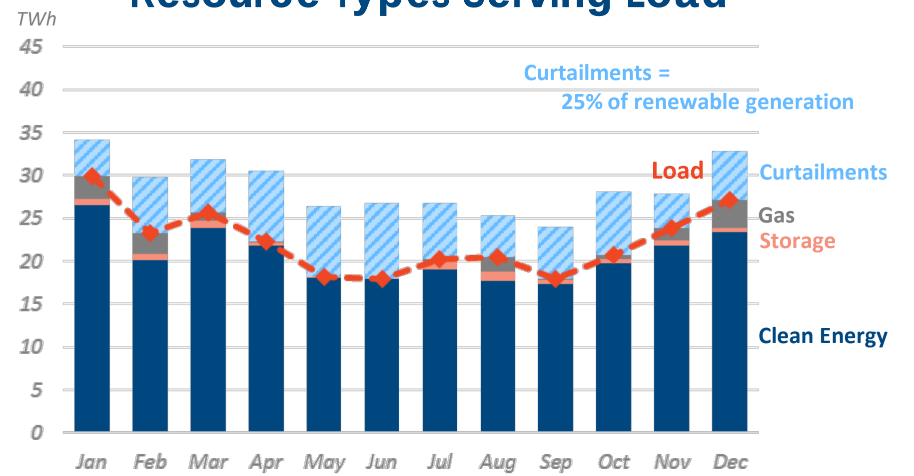


- Large-scale resources, especially offshore wind, provide majority of supply
- 53 GW of solar accounts for 20% of generation
- Limited storage capacity required (13 GW) due to hydro flexibility and low solar generation
- 25% curtailments is high compared to today, but lowest across portfolios
- This portfolio requires a large-scale transmission buildout to access remote resources

Monthly Generation by Resource



Resource Types Serving Load

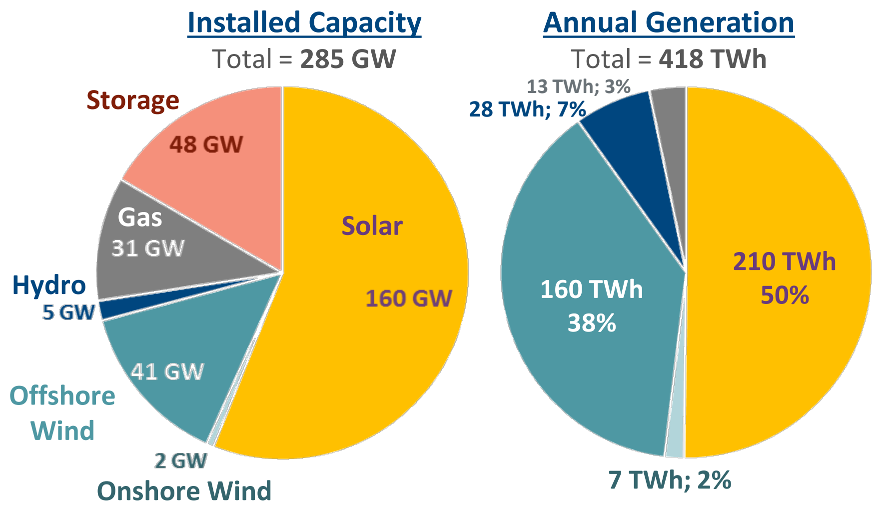


Note: Load includes T&D losses. Curtailments includes battery losses.

A6: Additional Portfolio Results

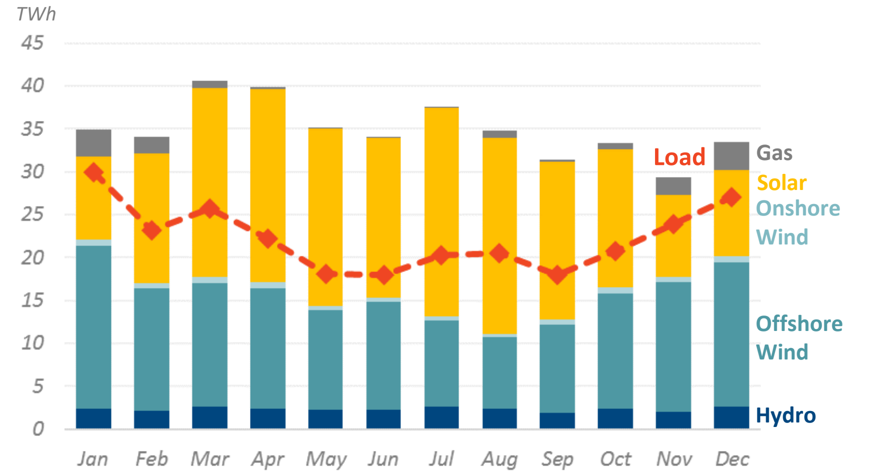
Supplying 50% of generation from solar will require nearly 50 GW of storage

2050 New England Resource Mix
Scenario: Local Solar and Storage

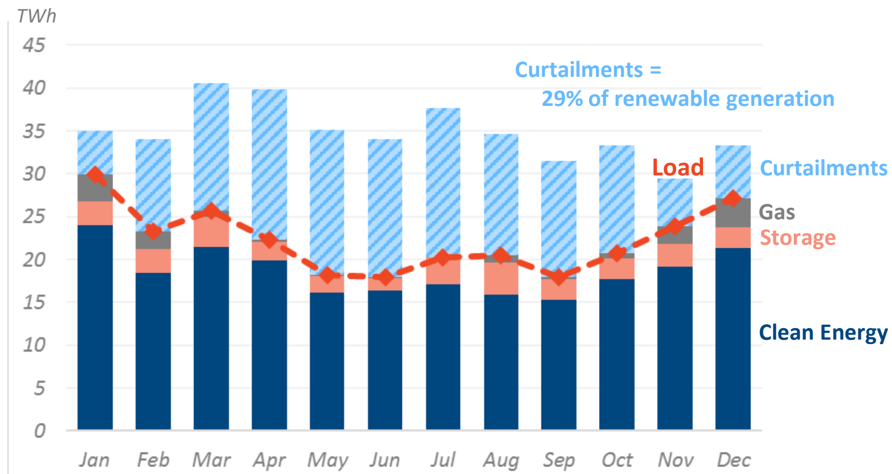


- 160 GW of solar accounts for 50% of generation
- Increased solar requires 48 GW of storage (77% of peak demand) to balance supply & demand
- Offshore wind decreases slightly but over 40 GW still required to meet high winter demand
- Curtailments rise to 29% due to excess generation in non-winter months
- Gas primarily generates in the winter months

Monthly Generation by Resource



Resource Types Serving Load



Note: Load includes T&D losses. Curtailments includes battery losses.