Synapse/MA Clean Peak Council Analysis Update

Results Review

September 15, 2025 DTP FAWG

Pat Knight and Jennifer Kallay

Study Purpose & Steps

Synapse is conducting a MA systemwide analysis to determine (a) the amount of generation likely to come from peaker power plants in a future year of interest (e.g., 2050) and (b) the quantity of resources that could reliably replace this quantity and address additional peaking needs due to electrification.

- Electrification levels in 2050 are intended to be consistent with MA state policy.
- Load to be served by winter peak resources is significantly higher with electrification and variable, based on winter temperatures. System will be winter peaking.
- Analysis will characterize resources to replace existing peakers as well as additional resources needed to serve new peak load.

Step 1: Relate peaker dispatch to Massachusetts load

Step 2: Develop hourly load forecasts

Step 3: Estimate peaker generation in a future year

Step 4: Develop replacement solutions

Forecasting Load Consistent with MA State Policy

Synapse adjusted the ISO 2024 Load Forecast* in the following ways:

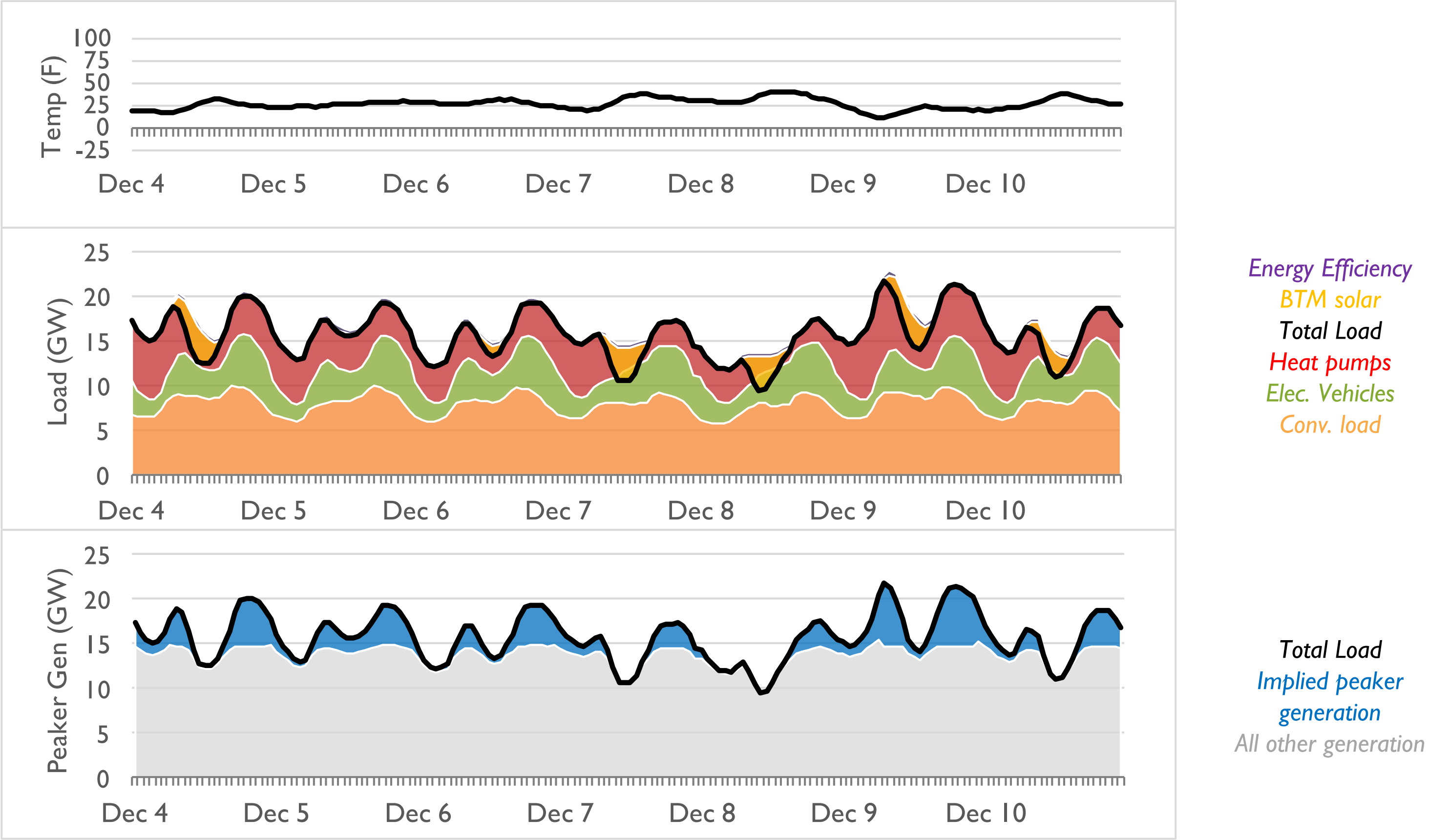
1. Building electrification – Clean Heat Standard
   - Our analysis is aligned with Clan Heat Standard draft framework from November 2023; 2.1 million households with heat pumps by 2050 (about 75 percent of all households), including 90 percent full replacements and 10 percent partial replacements (with fossil backup), and a similar penetration in the commercial sector.
2. Vehicle electrification – Modeling EVs of all types
   - Based on ISO New England's 2024 forecast: assumes that 100% of light-duty vehicles are EVs by mid-2040s.
   - Other vehicle types (e.g., buses, heavy-duty vehicles) follow slightly faster or slower adoption trajectories.
3. Energy efficiency
   - Assumes that EE measures continue to persist into the future and are installed at a slower rate as (a) EE measures become standardized as part of the conventional load forecast and (b) the MA three-year plan switches its main focus to heat pumps.
4. Behind the meter solar
   - Assumes that the SMART program continues to drive BTM solar adoption at similar rates through 2050.

In combination, all these assumptions lead to high winter peaks.

** The ISO 2025 Load Forecast was not available at the beginning of this analysis.*

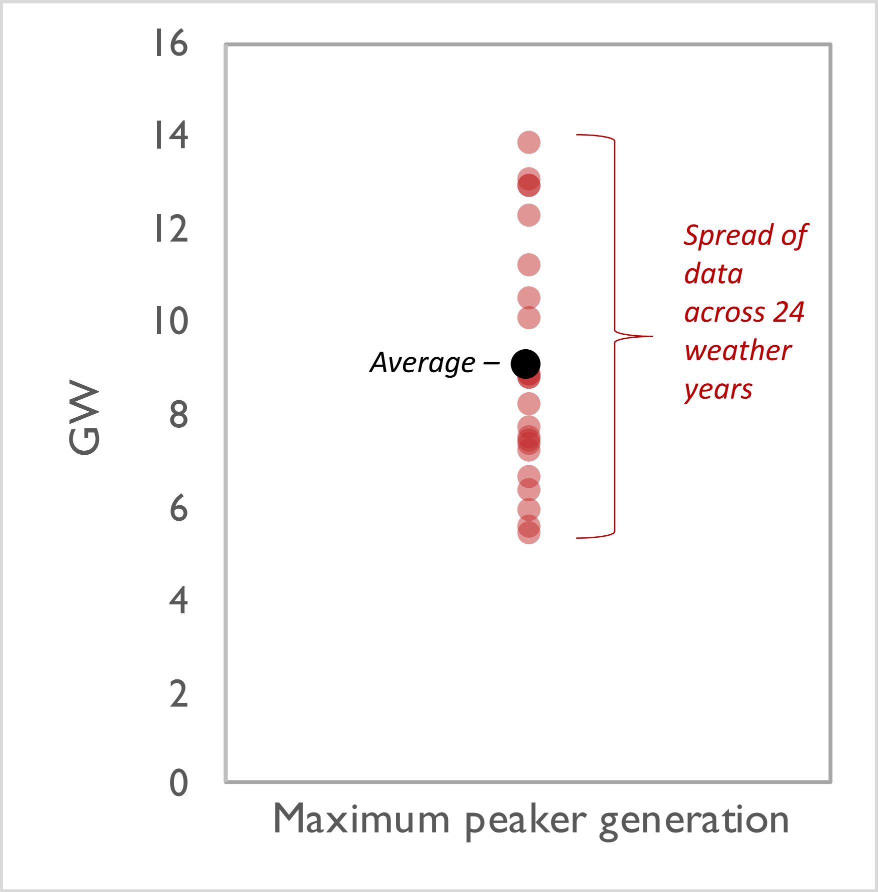
2050 Peak Demand: Winter

Extreme winter weather in MA: Implied demand and peaker generation



- In general, 2050 demand peaks in the winter due to heat pump use during periods of extreme cold weather.
- Two peaks per day: 6AM-11AM and 5PM-midnight.
- Our model assumes that peaker generation grows as demand grows.
- Example shown is for weather year 2023.

Maximum peaker generation requirements



- Across 24 weather years, the maximum amount of "peaker" generation required ranges from 5.4 GW to 13.9 GW.
- The average value across all years is 9.0 GW.
  - This is 4.4 GW more than the amount of peaker capacity currently existing in Massachusetts.
- Different requirements for peaker generation in each modeled weather year have different solution sets, and different results for costs, avoided CO_2, etc.

Characterization of demand-side portfolio

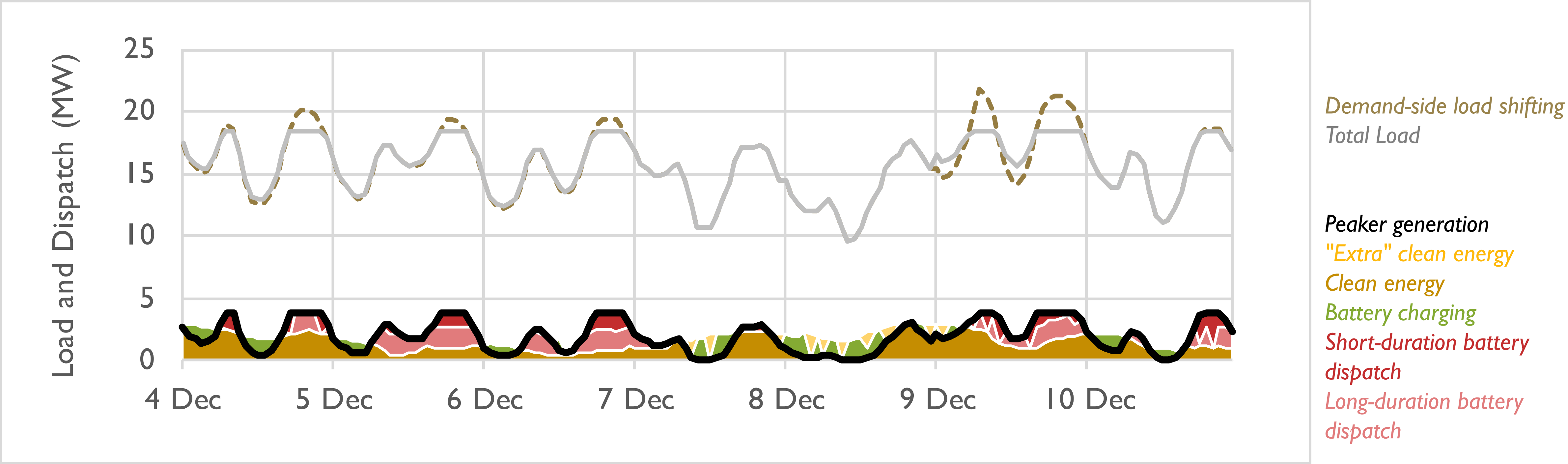
Measure Type	Measure Name	Measure Description	Peak Reduction (GW and % of total demand)	Notes
Load shifting	EV Vehicle-to-Grid (V2G) dispatch	Assumes 25% of charged electricity in EVs is dispatched during peak demand	0.87 GW (3%)	Would need to charge vehicles at other times, partially offsetting the reductions achieved in other near-peak hours
Load shifting	Reducing EV charging	Charging reduced in peak hour by 25%	0.87 GW (3%)	Would need to charge vehicles at other times, partially offsetting the reductions achieved in other near-peak hours
Load reducing	Envelope improvements	Assumes (a) 30% whole-home air leakage reduction in ACH50 and (b) R-60 attic floor insulation in 33% of residential households	0.64 GW (2%)	Envelope improvements may have compounding effects on COP improvements and temperature setbacks that are not accounted for here
Load reducing	COP improvements	Assumes heating COP (at 47F) of 3.6 for all sectors (4.7% improvement) (all sectors)	0.62 GW (2%)	COP improvements may have compounding effects on envelope improvements and temperature setbacks that are not accounted for here
Load shifting	Distributed battery dispatch	Assumes 2.3 GW of 2-hour batteries online by 2050, with 25% of capacity (0.57 GW) enrolled in demand response programming	0.57 GW (2%)	This assumes 0.3 GW existing behind-the-meter storage, with an additional 1.9 GW expected online by 2050. May not be able to sustain 0.57 GW of savings over each peak period (average peak period is 7 hours)
Load shifting	Hydronic thermal storage	Assumes 5 kWh of peak load shifting per household from heat pumps in homes with existing hydronic systems (23% of households)	0.49 GW (2%)	Would need to shift water heating to other times, partially offsetting the reductions achieved in other near-peak hours
			~4 GW (14%)	

Summary of results

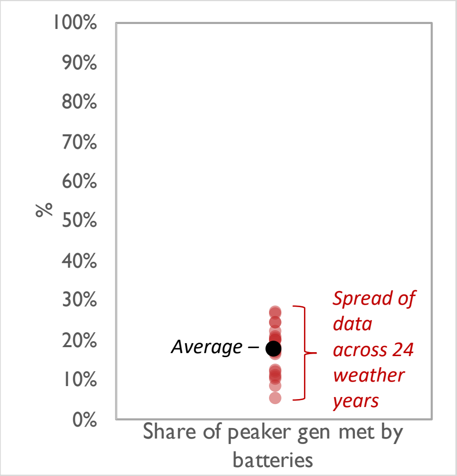
All values are estimated as averages across the 24 weather years.

		Peak demand or nameplate capacity (GW)	Capital costs (2022 $/kW)	Emissions (metric tons)
Maximum peaker generation requirements		9.0	-	-
Replacement Resources	Offshore Wind	4.4	$2,848	
	Demand-Side Measures	4.2	$734 *(see slide 24 for more)*	
	100-Hr Batteries	4.1	$2,230	
	4-Hr Batteries	2.4	$1,088	
	Onshore Wind	2.0	$1,398	-
	2-Hr Batteries	0.3	$694	-
	8-Hr Batteries	0.1	$1,877	-
	Total	17.5	-	-
	Average	-	$1,746	-
Avoided emissions	CO2	-	-	2.8 million
	NOX	-	-	885
	SO2	-	-	364

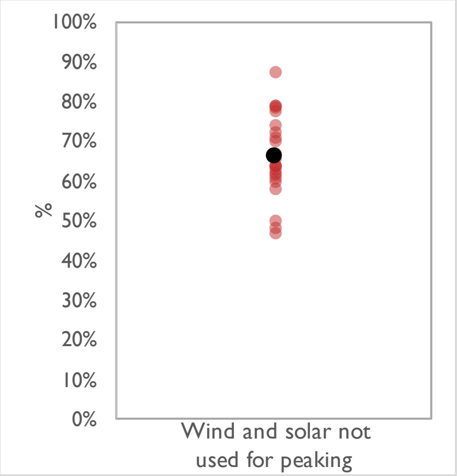
Illustrative winter week with demand-side portfolio



Wind generation during peak and non-peak times

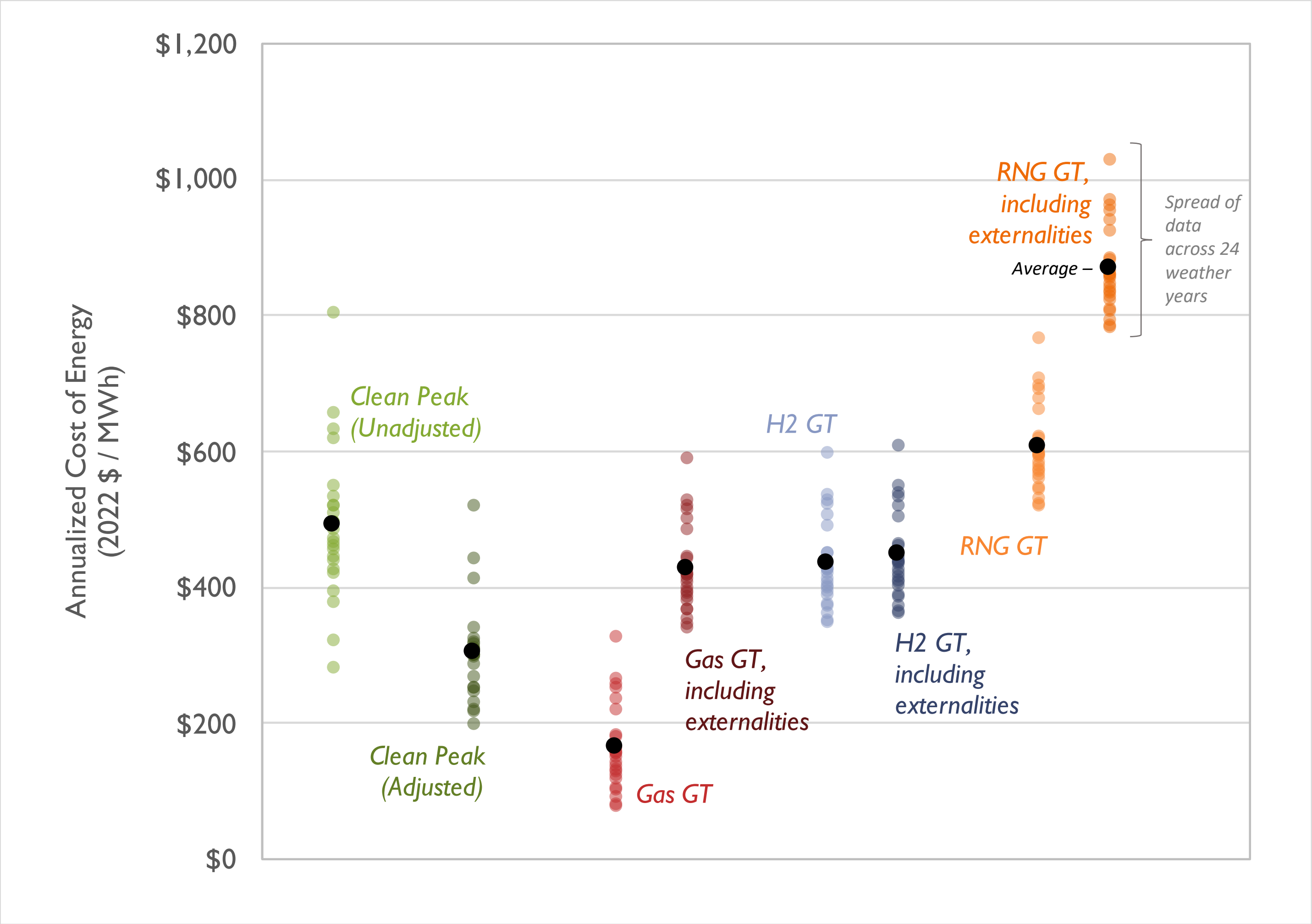


- On average, only about 18 percent of non-demand side measure “peaker” generation is met through batteries.
- The remaining 82 percent is met by wind.



- At the same time, two thirds of generation from the wind plants built to meet peaker generation needs occurs during non-peaker times.
- In other words, for every 33 GWh of wind generation that is used to meet peaker generation, there is about 67 GWh of wind generation that could be used for other, non-peaker purposes.

Annualized Costs of Clean Peak Portfolio vs. Other Resources



- The average annualized cost of clean peaking resources in 2050 is about $500/MWh.
  - This value can be adjusted to reflect the fact that many resources used for Clean Peaking purposes are also producing energy outside the hours required for peaking.
  - This adjusted average value is about $300/MWh.
  - Assumed costs do not include any tax credits.
- We compare the costs of clean peaking resources to the costs of gas-turbine (GT) alternatives.
  - These alternatives include gas-, hydrogen (H2)-, and renewable natural gas (RNG)-fired turbines (GT).
  - The primary difference among these resources is the cost of fuel. We make the same assumptions for upfront capital costs, and do not make any assumptions with respect to operating costs, or additional infrastructure costs (e.g., pipeline construction or upgrades).
  - We assume that all currently existing peaker facilties in MA (4.6 GW) are required to run on gas, H2, or RNG, depending on the scenario. We do not assume any retrofit costs.
- Alternatives are priced both with and without externalities, which include the social cost of carbon and impacts to public health.
  - Externalities increase costs for Gas- and RNG-fired GTs by about $263/MWh. This includes a 2050 social cost of CO2 of about $500 per short ton, based on research compiled by Synapse in its 2024 AESC Study.
  - H2-fired GTs, which are assumed to only produce impacts to public health, have a smaller externality cost of about $10/MWh.

2030 Bill Impacts of Clean Peak Portfolio vs. Other Resources

Table 1. Annualized costs (2022 $ billion)

	Clean Peak (Unadjusted)	Clean Peak (Adjusted)	Gas GT	Hydrogen GT	RNG GT
Average	$2.9	$1.9	$1.0	$2.7	$3.8
Min	$1.6	$1.1	$0.4	$1.9	$2.8
Max	$5.4	$2.8	$1.7	$3.6	$4.8

Table 2. Monthly Residential Bill Impacts (2022 $/month)

	Clean Peak (Unadjusted)	Clean Peak (Adjusted)	Gas GT	Hydrogen GT	RNG GT
Average	$33	$21	$11	$30	$42
Min	$18	$13	$5	$21	$32
Max	$60	$31	$19	$40	$53

- Residential bill impacts are estimated by allocating annualized costs to the residential sector and dividing by an estimate of the number of residential customers.
- Caveats:
  - We assume that historical (2023) values for percentage of residential sales and number of customers would remain constant into the future using data from EIA 861
  - We assume that all residential customers consume equal amounts of electricity and pay the same rates.

Questions?

Additional Reference Slides

Methodology Detail

Step 1

Relate peaker dispatch to Massachusetts load

- Using historical hourly data for 2021-2023, Synapse will develop a relationship between hourly demand for electricity in Massachusetts and peaker dispatch.
- Relies on data from EPA's hourly *AMP dataset* and ISO New England's *VER dataset*.
- Key assumption: The amount of demand met by peakers in future years maintains the same relationship as in the past.

Step 2

Develop hourly load forecasts

- Project load inclusive of electric vehicles, heat pumps, conventional load, energy efficiency, and distributed solar.
- Started with ISO 2024 load forecast and adjusted to be consistent with MA state policy (as described in subsequent slides)
- Use ISO New England's *VER dataset* and internal Synapse tools to develop hourly load impacts for each component, across 24 years of varying weather. This allows us to test the solution package in periods of both extreme heat and cold.
- Estimate impact from demand-side measures.

Methodology Detail (continued)

Step 3

Estimate peaker generation in a future year of interest

- Combine the results of Step 1 and Step 2 to estimate peaker generation in a future year of interest.
- Since the future year of interest is after the mid-2030s, the peak will be the winter.
- This quantity describes the amount of generation that comes from resources that have historically acted like peakers.

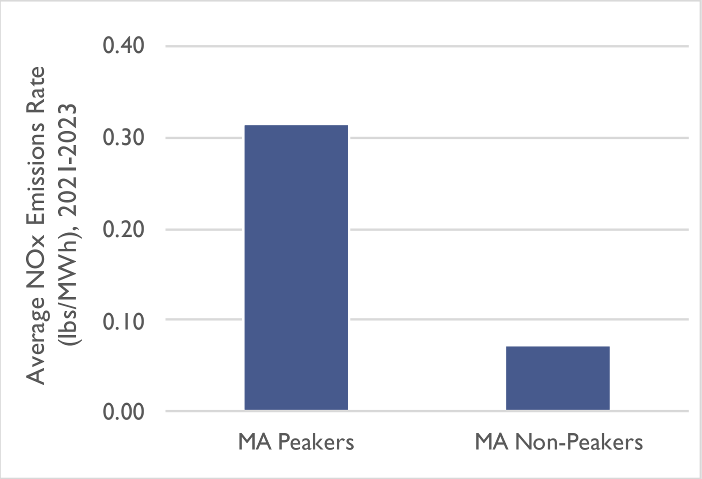
Step 4

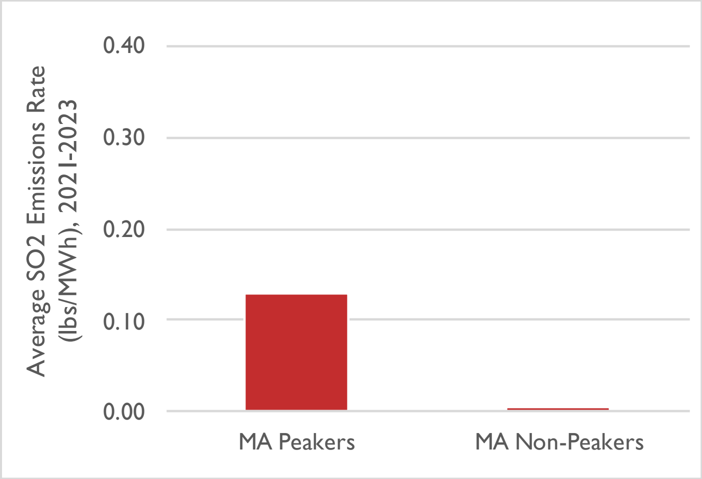
Develop replacement solutions

- Use ISO New England's VER data and to-be-determined optimization algorithm to determine how many MW of resources would be needed to replace the generation estimated to be provided by peakers.
- Report on metrics such as quantity of generation replaced for the entire year, as well as during peak periods.

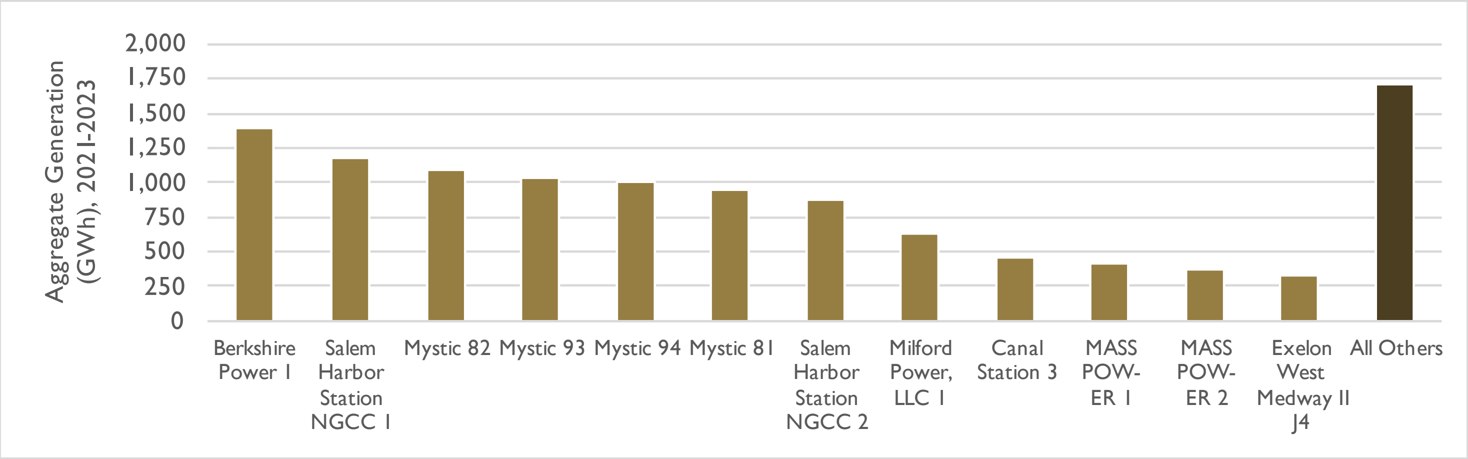
Peaker Emission Rates and Generation

NOx and SO2 emissions rates for MA peaker vs. non-peaker units





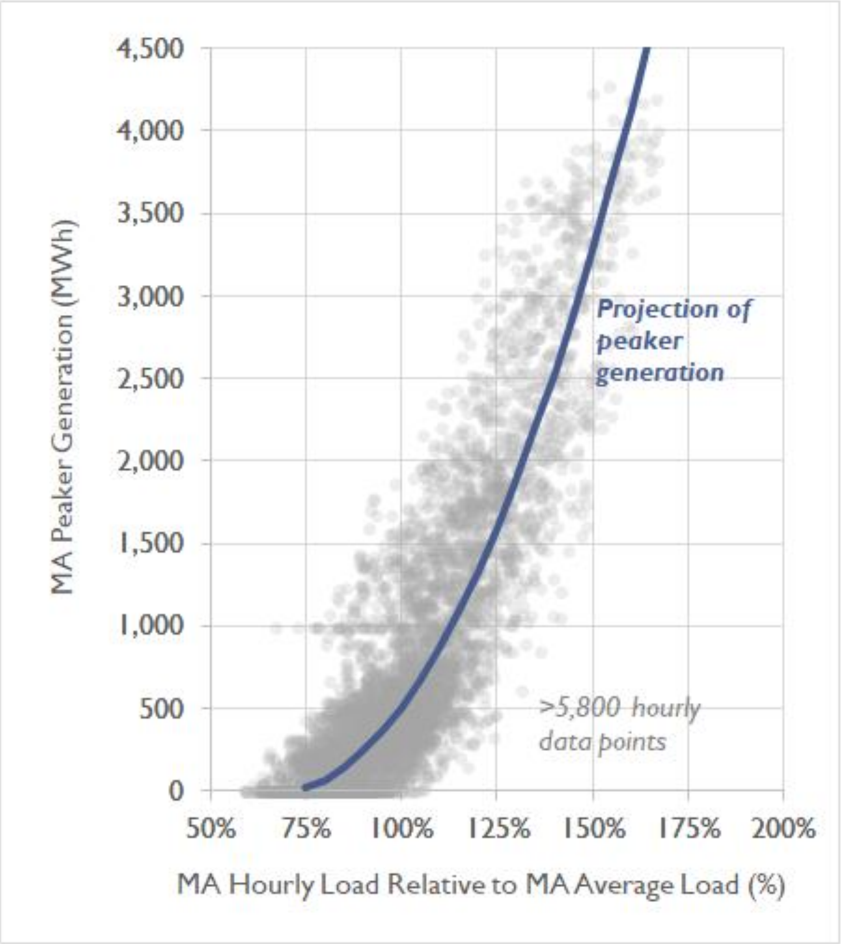
Generation from 12 largest peaker units in MA, versus all other MA peakers



- Peaker plants have much higher emission rates of criteria pollutants (and sulfur dioxide or SO_2) than other emitting power plants.
  - Emission rates of nitrogen oxides or NO_X are 4X higher, on average
  - Emission rates of sulfur dioxide or SO_2 are 25X higher, on average
- 12 peaker units at 7 power plants made up 85% of all generation from MA peakers in 2021-2023.
  - Of these units, four are already retired (Mystic). Two more (Salem Harbor) are required by DEP to eliminate GHG emissions by 2050.
  - A further 10 units (included within "All Others") make up an additional 12% of peaker generation.
  - 36 units (the rest of "All Others") make up the remaining 3% of peaker generation.
- In future versions of this analysis, we will provide unit-specific emission rates.

Determining Relationship Between Load and Peaker Generation

Massachusetts hourly electricity load vs. Massachusetts generation from peaker plants, Summer Day hours



- We divide the year into four standard periods, each of which has its own strong relationship between electricity demand and peaker operation:
  - The four periods are summer Day, Summer Night, Winter Day, and Winter Night. This is a standard division of seasons and periods, used in other studies in New England
  - Summer = June through September
  - Winter = All other months
  - Day = Hours ending in 8 through 23
  - Night = All other hours

Peaker Operation Findings

Peakers run at some level in most hours, but operation is concentrated in daytime hours.

Sum of peaker generation by month and hour, 2021-2023 (GWh)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	52	40	11	6	13	14	42	30	9	3	8	32
2	49	38	11	6	12	12	39	28	9	3	7	30
3	49	37	11	6	12	12	38	27	9	3	7	30
4	50	38	12	8	13	13	39	27	9	4	8	31
5	52	39	14	10	15	14	41	29	11	7	10	32
6	55	41	18	15	16	16	45	33	15	13	14	35
7	64	47	22	17	17	20	48	36	17	18	19	40
8	73	53	21	17	18	22	52	42	18	21	20	44
9	76	54	19	16	18	25	59	49	19	20	18	44
10	74	54	18	16	19	29	71	61	21	21	17	43
11	75	53	17	15	21	35	85	76	26	22	17	43
12	73	52	16	15	22	40	97	91	31	23	17	42
13	72	51	16	14	24	46	107	103	35	26	18	41
14	72	51	16	15	26	52	115	111	38	30	22	42
15	73	50	17	18	28	56	119	116	43	38	26	46
16	76	51	18	22	31	61	127	120	48	45	33	51
17	82	54	20	27	35	66	133	126	53	52	42	57
18	90	60	24	30	35	67	132	126	53	54	44	61
19	88	60	26	32	35	66	129	125	53	51	42	57
20	84	56	25	32	35	62	121	120	47	45	37	55
21	79	52	22	27	31	52	106	99	36	32	31	52
22	74	49	18	18	24	33	80	67	24	17	23	46
23	70	44	15	10	17	20	56	43	14	7	14	38
24	63	40	12	7	15	16	47	34	10	4	10	33

Peaker Operation Findings (continued)

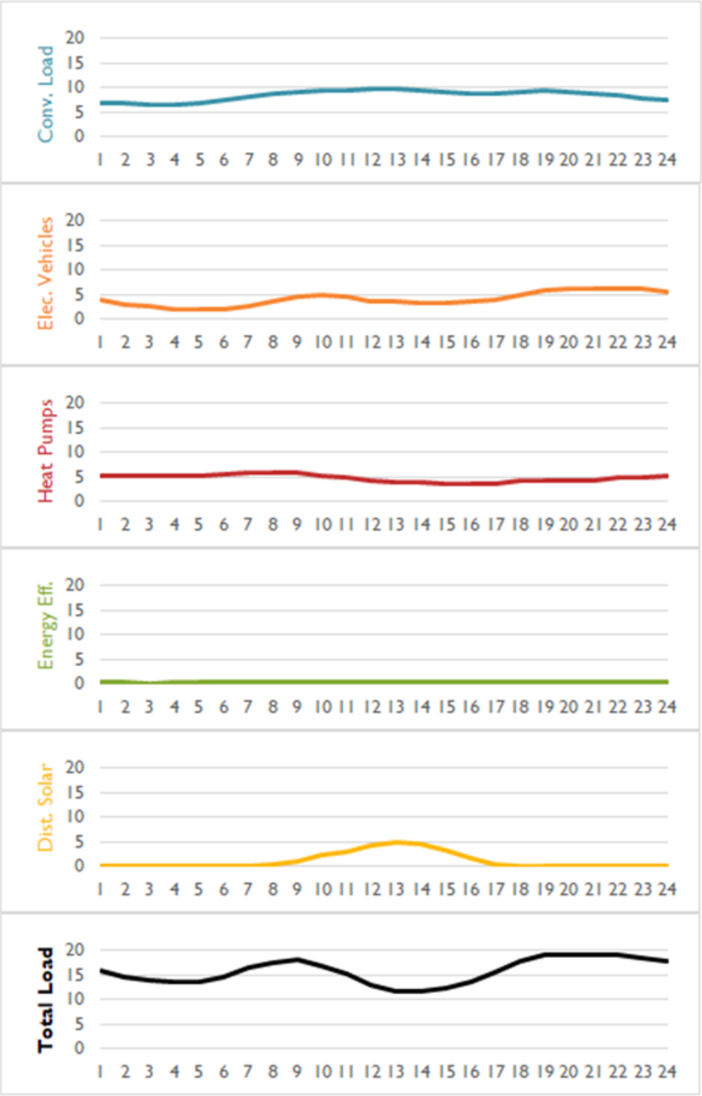
The maximum observed peaker output in any one hour was 4.3 GW in the summer and 3.3 GW in the winter. Currently about 6 GW of peaker capacity online in MA with 9 GW of winter peak demand.

Maximum aggregate peaker output by month and hour, 2021-2023 (GW)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	1.7	2.5	1.1	0.8	1.1	2.0	2.5	3.1	0.9	0.8	1.0	1.6
2	1.6	2.5	1.1	0.8	1.1	1.7	2.3	3.1	1.0	0.7	0.9	1.5
3	1.6	2.7	1.1	0.8	1.1	1.7	2.1	3.0	0.9	0.8	0.9	1.5
4	1.7	2.7	1.1	0.9	1.1	1.8	2.0	3.0	0.9	0.6	1.0	1.5
5	1.7	2.7	1.1	0.9	1.1	1.9	2.3	3.2	1.2	0.6	1.2	1.4
6	1.8	2.8	1.1	0.9	1.2	2.1	2.5	3.2	1.4	1.0	1.6	1.5
7	1.8	3.1	1.1	1.0	1.3	2.4	2.6	3.2	1.2	1.4	1.8	1.7
8	2.1	3.4	1.1	1.0	1.3	2.5	2.8	3.3	1.4	1.4	1.7	1.8
9	1.9	3.2	1.2	0.9	1.3	2.7	3.0	3.3	1.4	1.6	1.5	1.8
10	1.8	2.9	1.2	1.0	1.3	2.9	3.3	3.4	1.6	1.5	1.5	1.8
11	1.9	2.9	1.2	0.9	1.3	3.1	3.5	3.7	1.8	1.4	1.5	1.9
12	1.9	2.7	1.2	0.9	1.3	3.4	3.6	3.9	2.1	1.5	1.5	1.7
13	2.0	2.6	1.2	0.9	1.3	3.6	3.5	3.9	2.3	1.5	1.5	1.5
14	2.0	2.4	1.2	0.8	1.3	3.8	3.2	3.9	2.5	1.5	1.5	1.5
15	2.0	2.8	1.2	0.8	1.6	3.8	3.3	4.0	2.5	1.4	1.6	1.6
16	2.1	3.0	1.2	0.9	1.9	3.9	3.3	4.2	2.6	1.3	1.6	1.7
17	2.3	3.0	1.2	0.9	2.0	4.1	3.5	4.2	2.6	1.5	1.6	2.2
18	2.4	3.3	1.2	1.0	2.1	4.2	3.5	4.2	2.5	1.6	1.6	2.5
19	2.4	3.0	1.2	1.0	2.0	4.1	3.4	4.3	2.5	1.6	1.3	2.5
20	2.4	3.1	1.2	1.0	1.7	3.9	3.4	4.2	2.4	1.5	1.2	2.3
21	2.3	3.1	1.2	0.8	1.6	3.6	3.5	3.7	2.3	1.4	0.9	2.3
22	2.2	2.8	1.1	0.8	1.2	2.9	3.2	3.2	1.9	1.3	0.9	1.9
23	2.0	2.8	1.1	0.8	1.1	2.4	2.8	3.0	1.3	0.9	0.9	1.5
24	1.7	2.6	1.1	0.8	1.1	2.2	2.7	3.0	1.0	0.7	0.9	1.6

Approach for Step 2

Example load components for illustrative winter day in Massachusetts, 2050 (GWh)

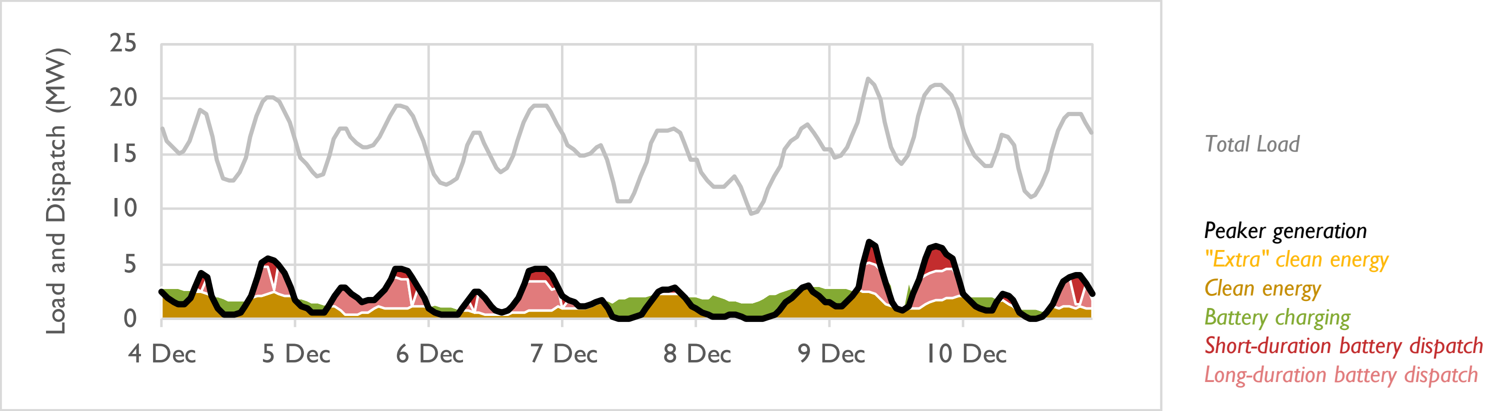


- These figures are illustrative, and are meant to represent the types of load shapes that MA might experience on a typical winter day in 2050.
- Total Load =

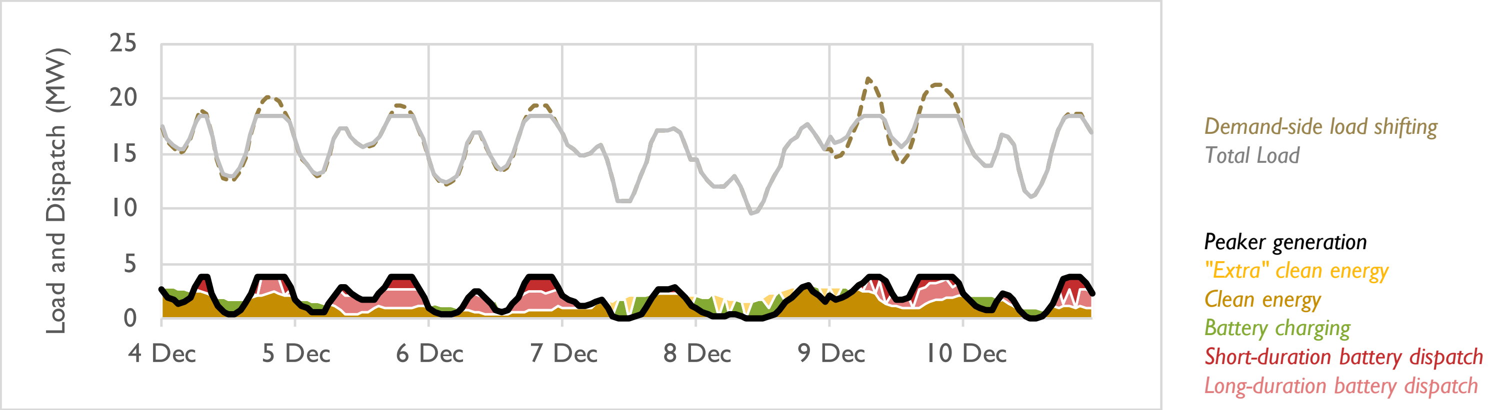
  Conventional Load + EVs + HPs – EE – Dist. Solar
- By modeling each load component separately, we can capture changing load shapes and increasing or decreasing peaks.
- Using 24 years of historical weather data, which inform the load shape (as well as overall load and peak) for each load component.
- Analyzing 24 years (2000-2023) allows us to model solutions for the most extreme winter cold and summer heat.

Example results

No additional demand-side measures



With additional demand-side measures



Timing of peakiest hours

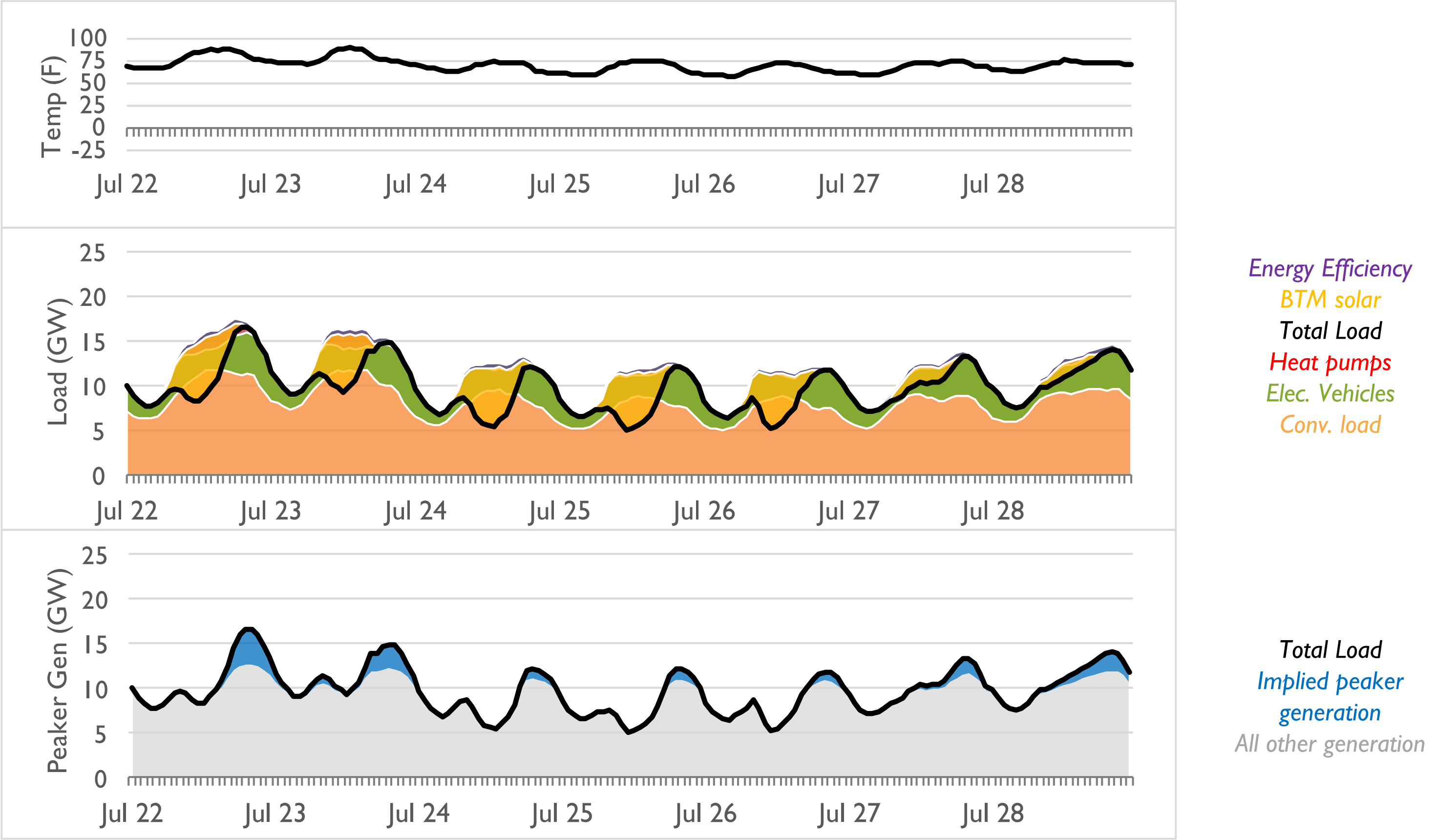
Timing of peakiest hours (~21,000 data points), 2050

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	1%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2	1%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
3	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
4	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
5	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
6	1%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
7	1%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
8	2%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%
9	2%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%
10	1%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%
11	1%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
12	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
13	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
14	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
15	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
16	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
17	2%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%
18	3%	2%	0%	0%	0%	0%	0%	0%	0%	0%	0%	2%
19	3%	3%	1%	0%	0%	0%	0%	0%	0%	0%	0%	2%
20	3%	3%	2%	0%	0%	0%	1%	0%	0%	0%	1%	3%
21	3%	3%	2%	0%	0%	0%	1%	0%	0%	0%	1%	2%
22	3%	2%	1%	0%	0%	0%	0%	0%	0%	0%	0%	2%
23	2%	2%	1%	0%	0%	0%	0%	0%	0%	0%	0%	2%
24	2%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%

- In 2050, the highest peaks are projected to occur in December-March
- Peaks are largely coincident with heat pump demand related to heating

2050 Peak Demand: Summer

Extreme summer weather in MA: Implied demand and peaker generation



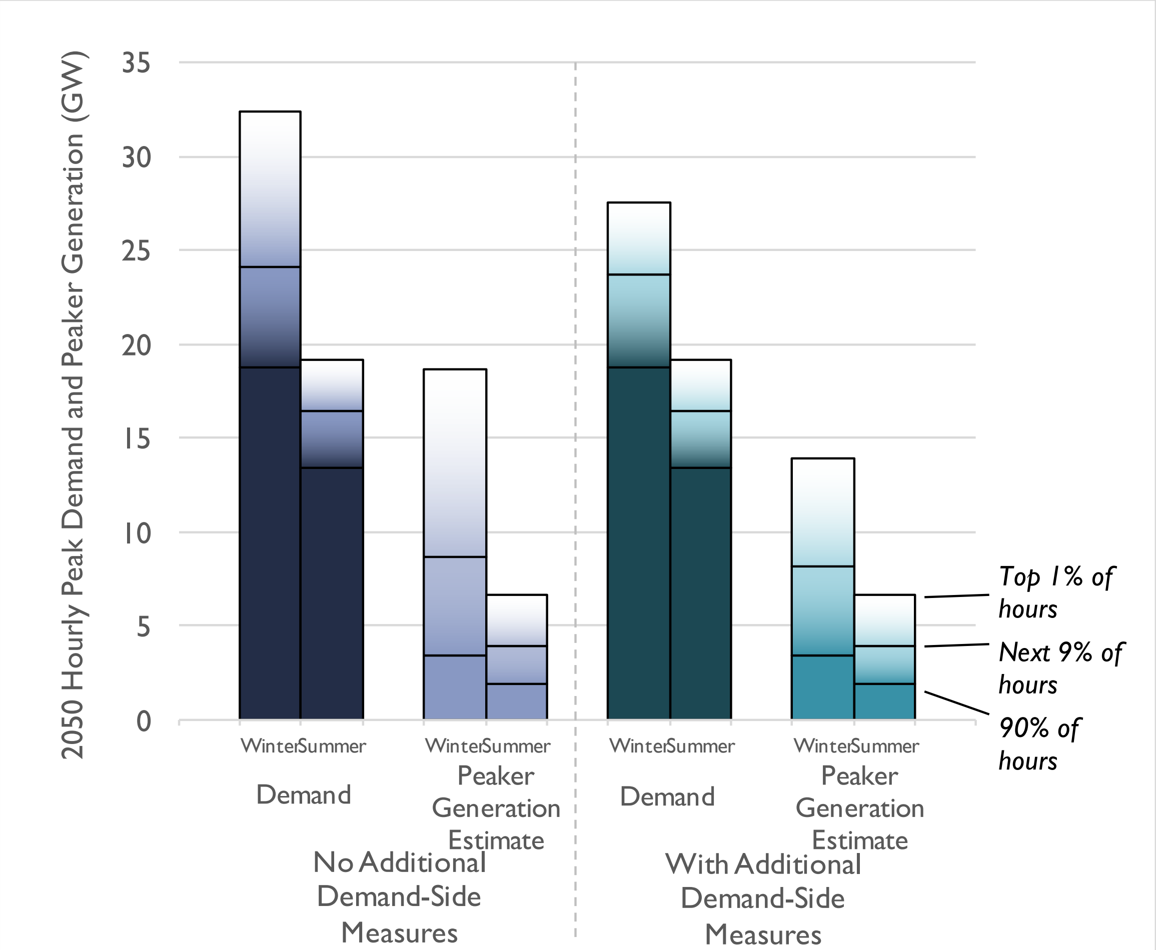
- Summer demand in 2050 is higher than today, but is lower than winter demand in 2050 as heat pumps affect winter demand more than summer demand.
- One peak per day: 6PM-11PM.
- Example shown is for weather year 2023.

Demand-side measure methodology

1. In each weather year, find the day with the highest hourly peak. These peaks are always in the winter.
2. Reduce the hourly peak by 15%. Call this new, reduced value Max_{Peak}.
3. Look over the rest of the year. Modify every hour that exceeds Max_{Peak} such that it no longer exceeds Max_{Peak}. This includes hours in the same day the peak hour occurs, as well as hours in other days.
4. Estimate impacts of load shifting: In each day with a demand-side reduction, sum the total MWh of demand-side reductions that take place. Multiply this quantity by 50% to reflect the amount of load that is assumed to be shifted to other hours. Redistribute load to hours in the same day that do not have demand-side reductions, in a way that does not create new peaks.
5. Re-estimate peaker generation using the new load profile.

2050 Peak Demand and Estimated Peaker Generation

Projected variability in MA demand and peak generation



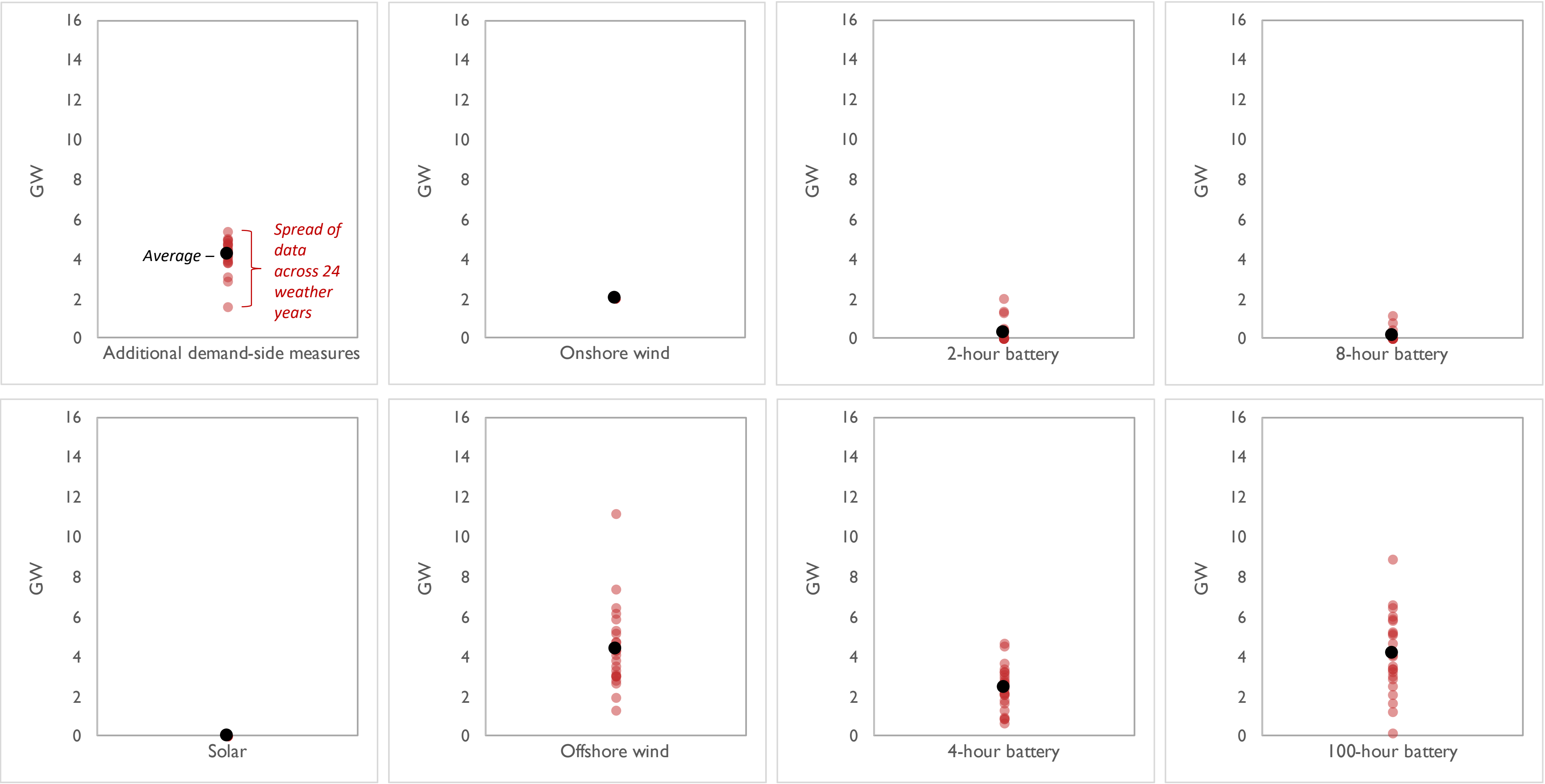
For this figure, Summer is June through September, while Winter is December through March. Other months have lower peaks and are not included.

- Demand is reduced by demand-side measures in only the peakiest hours. In our assumptions, demand-side measures impact the top 2% of hours, almost all of which occur in the winter.
- Only a fraction of total demand is met by peaker generation (see appendix for more).
- In 90% of all hours, peaker generation does not exceed 3.4 GW. This number is unchanged with additional demand-side measures.
- In 99% of all hours, peaker generation does not exceed 8.7 GW. With additional demand-side measures, this falls to 8.2 GW.
- In the max hour, peaker generation reaches 18.7 GW. With additional demand-side measures, this falls to 13.9 GW.
- The top of each bar represents single hour across 24 years of data, or 0.001% of all hours.

Modeling the solutions: Detailed work plan

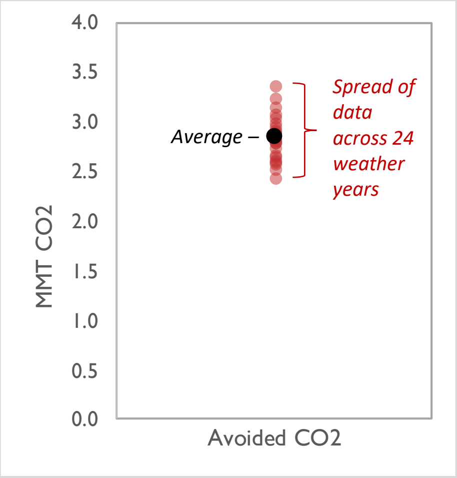
- Using the EnCompass model to make finding solution sets faster.
- Currently analyzing the following "solution" resources:
  - Additional demand-side measures (see slide 12 for more)
  - Onshore wind
  - Offshore wind
  - Utility-scale solar
  - Short-duration battery storage (2-hr, 4-hr)
  - Mid-duration battery storage (8-hr)
  - Multi-day storage (100-hr)
- Resources are chosen based on estimate of costs in 2035-2050 (we assume all resources are built in that period)
- Model will build least-cost combination of resources needed to meet every hour of generation, for each weather year.
- Reporting on the following metrics:
  - Modeled peaker generation required
  - Replacement resources (GW, in total and by resource)
  - Capital cost of replacement resources ($, $/kW)
  - Avoided CO_2, NO_X, SO_2
  - Each set of results contains 24 results (one for each weather year)

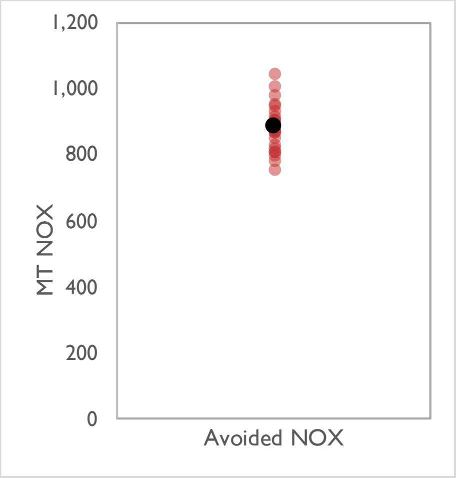
Results: Resource builds

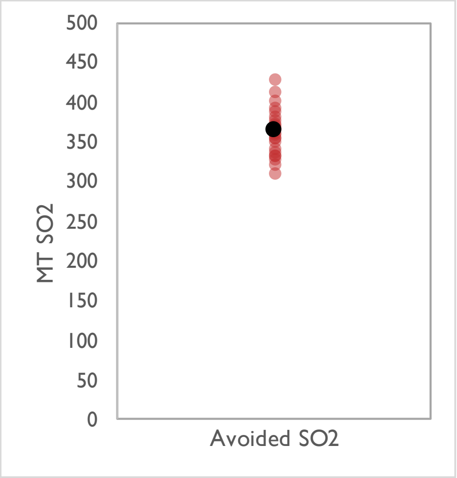


- All solutions require some amount of demand side resources, wind, short-duration battery, and long-duration battery.
    - >100-hour storage is needed in most scenarios, as there are many situations where peaking events occur on consecutive days, without the opportunity to charge shorter-duration batteries.
- No solutions require solar, as it is largely non-coincident with winter peaks.

Results: Avoided CO_2, NOx, and SO_2 emissions

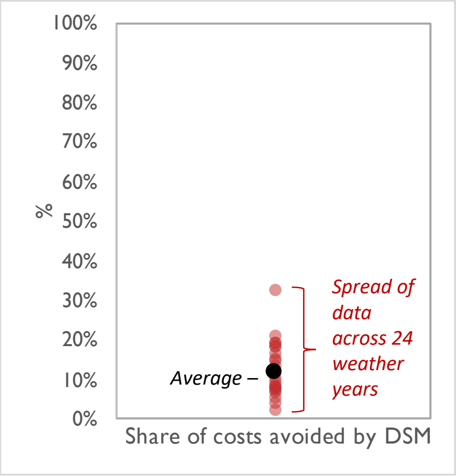


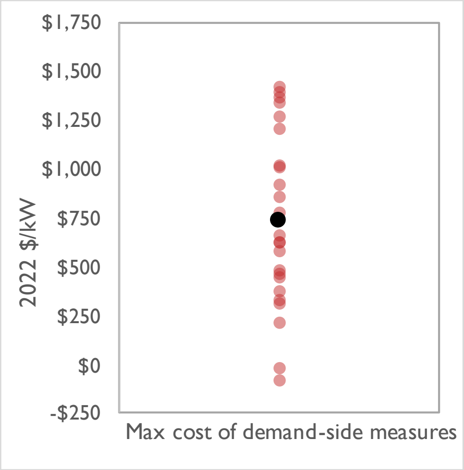




- Across 24 weather years, the average amount of avoided CO2 emissions is 2.8 MMT CO2.
  - This can be compared to recent historical emissions in MA, which have totaled about 20-25 MMT in the electric sector and about 70 MMT economy-wide.
- Avoided NOX emissions average 885 metric tons.
  - Recent historical NOX emissions from MA's power sector have totaled about 6,400 metric tons.
- Avoided SO2 emissions average 364 metric tons.
  - Recent historical SO2 emissions from MA's power sector have totaled about 3,000 metric tons.

Results: Costs of Demand-Side Measures





- Additional demand-side measures avoid about 12 percent of utility-scale capital costs.
- We can calculate the implied maximum cost of demand-side measures by comparing this set of runs with the set of runs that don't include demand-side measures.
  - For each run, we can calculate the delta costs, and divide that result by the avoided kW to estimate a $/kW cost.
  - As long as the demand-side measures cost less than this, they are cost-effective.
  - On average, this cost is about $730/kW. This can be compared this with the cost to build 4-hour storage (assumed to be about $1,100/kW).
  - In some instances, the implied cost is very low or even negative. This happens when the targeted peaks are not very avoidable (e.g., the same quantity of wind and batteries are generating or needed in other hours, regardless of reductions in load in the peakiest hours).

