Evaluating Load Management Strategies for a Net Zero Grid in Massachusetts

Prepared for the Massachusetts Department of Energy Resources (DOER)

Applied Economics Clinic

Energy+Environmental Economics

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Load Management Study Scope

Goals

+ Quantify the potential for load management to reduce electric system costs
+ Provide technical assumptions and modeling to support DOER load management strategy, program design, & advocacy

Key Questions

+ How much can different load management strategies reduce peak load in the near- and long-term?
+ Which load management strategies are most cost-effective at reducing electric system costs?
+ What are feasible levels of adoption and participation that can be achieved in the near- and long-term?
+ What are the key implementation barriers to scaling up load management in Massachusetts?

Overview of Methodology

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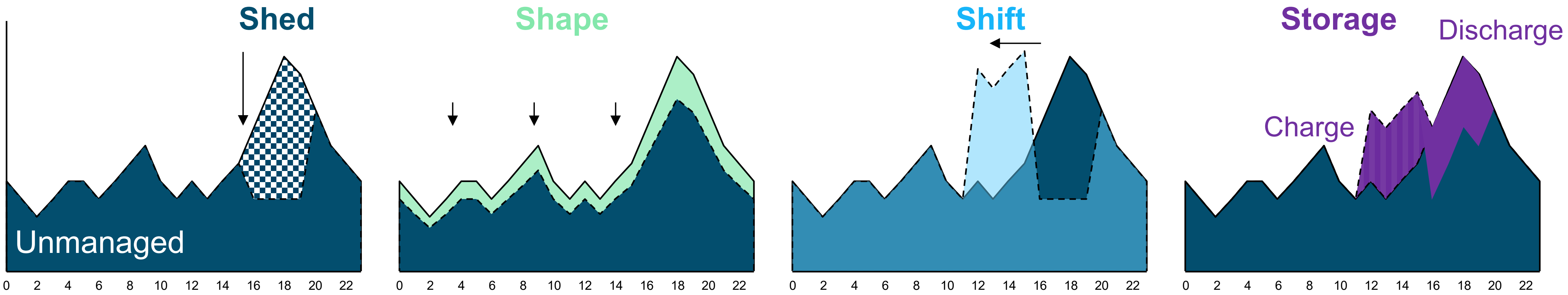
Different load management strategies modeled to help lower and align electricity demand with electricity supply

- **Diverse range of load management and flexibility technologies, organized here in three categories**
  - **Shed:** Loads that can be curtailed to provide capacity reductions, during peak hours (e.g., demand response)
  - **Shape:** Reshaping load for significant portions of the year (e.g., energy efficiency, price responsiveness, behavioral change)
  - **Shift:** Loads that can be shifted between hours, during peak hours (e.g., managed electric vehicle charging)
- **Storage provides similar service, shifting supply from hours with excess energy to discharge during challenging hours**
- **<u>Key point</u>: Most load management technologies and storage directly compete to flatten the same peak demand – the order in which they are deployed directly influences how much is needed or available from remaining options**

Hourly Load



Passive measures reduce energy year-round
Active measures target critical hour peak reduction

Passive

- Cold-climate heat pumps
- Ground source heat pumps
- Stretch code for new construction
- Shell retrofits

Active

Shift

- HVAC flexibility
- Water heating
- Appliances
- V1G and V2G
- BTM Storage

Shed

- Grid-enabled hybrid heat pumps*
- Industrial demand response

* Modeled both under passive and active set-ups; Gas or fuel oil back-up heating system

This study performed a total resource cost test to evaluate the benefits and costs of different load management strategies

- **Load management measure cost-effectiveness is assessed based on Total Resource Cost (TRC) Test**
  - Compares total benefits of a program or measure to the total costs, from the perspective of both the utility system and the participant, excluding any utility incentives or transfers.
  - Aggregate avoided costs are estimated by combining hourly changes achieved by portfolio of load management strategies in each feasible potential scenario with hourly avoided cost streams

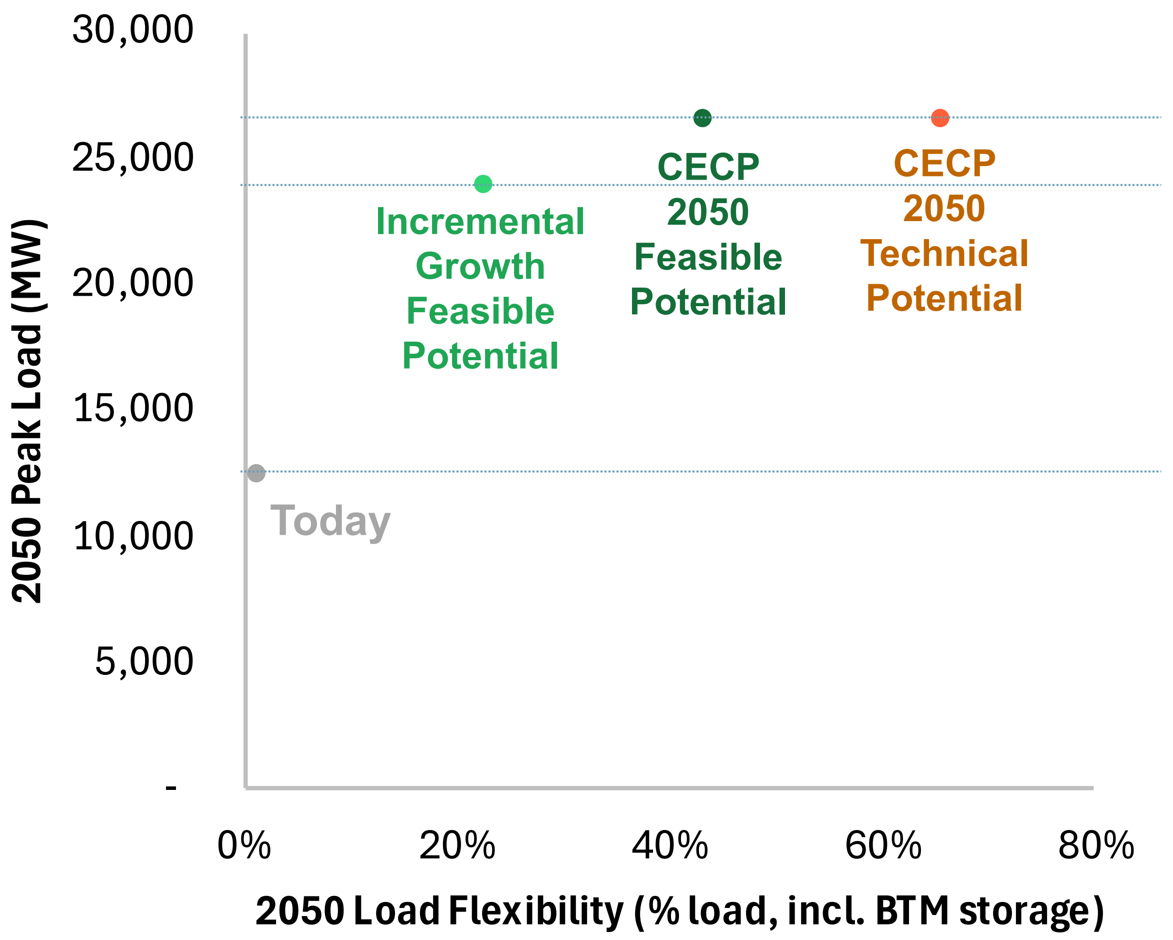
Component	Total Resource Cost
Avoided utility marginal costs	Benefit
Upfront and maintenance costs	Cost
Environmental benefits (carbon only)	Benefit*
Administrative costs	Cost
Bill Savings	Not included

- **Key data sources include:**
  - Avoided Energy Supply Costs data on avoided emissions, electric and gas supply and delivery costs
  - Lawrence Berkeley National Laboratory, Massachusetts Clean Energy Center & Mass Save for other key categories, including the participant costs of enabling grid flexibility & overhead program administrative costs

**Dept. of Public Utilities "Modified TRC" test includes avoided emissions and 1.5% social cost of carbon in evaluation of 3-year energy efficiency plans*

Three scenarios explore potential under different load growth and flexibility worldviews

Scenario Design – Load Growth and Flexibility



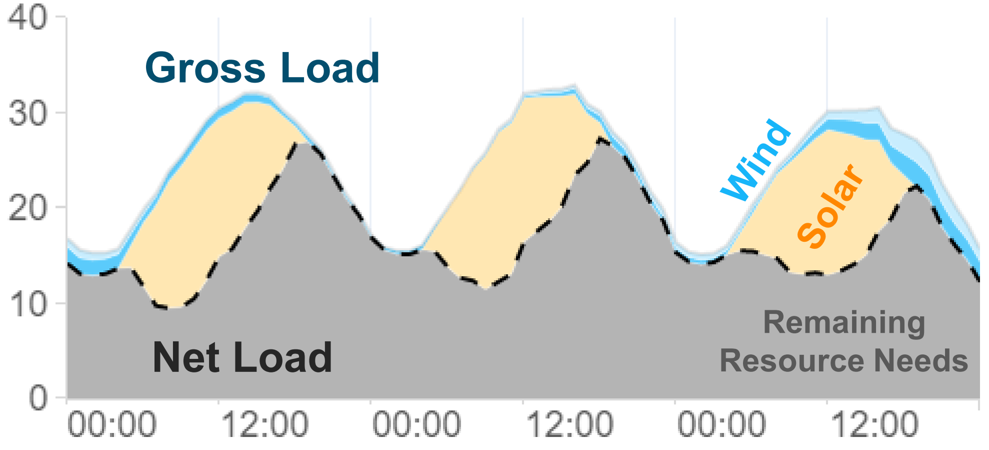
	Incremental Growth	CECP 2050 Growth	Technical Potential
Load Growth Scenario	**Based on expected trends**	**CECP 2050 Phased scenario**	**CECP 2050 Phased scenario**
Load Flexibility	**Lower flexibility** • Baseline technology rollout (e.g., AMI) • Individual customer response	**Higher flexibility** • Enabling technology investment (e.g., DERMS and VPPs) • Targeted response to barriers to adoption.	**Maximum resource load flexibility** • Complete participation assumed • Physical resource constraints (e.g., vehicle driving patterns) included

Note: Future projections based on bottom-up assessment. Peak loads are reported with passive measure adoption.

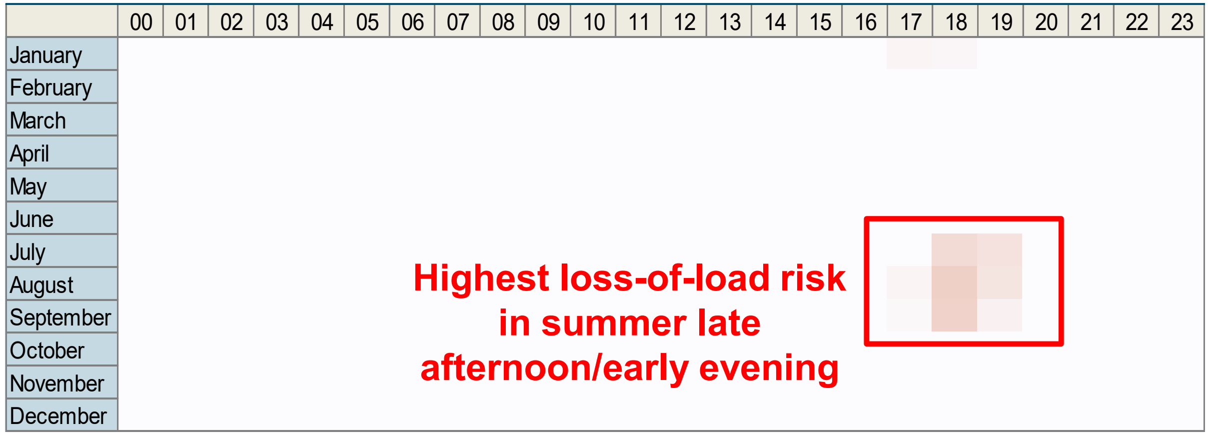
Load management strategies dispatched to meet system peak demand net of renewable generation: summer evenings in 2030 and winter evenings/mornings in 2050

Example Summer Week in July 2030

Renewable Output and Net Load (GW) – *Before Storage*

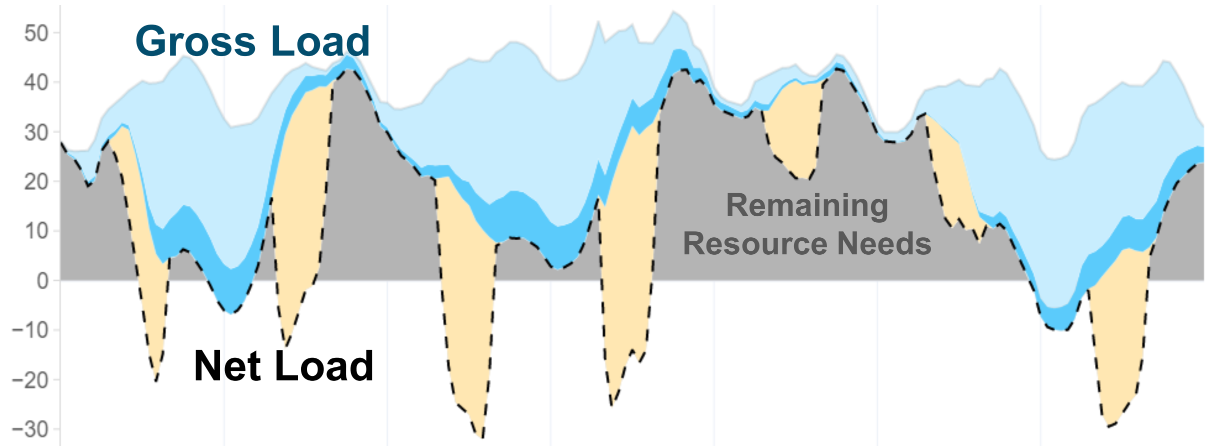


Month-hour System Firm Resource Needs

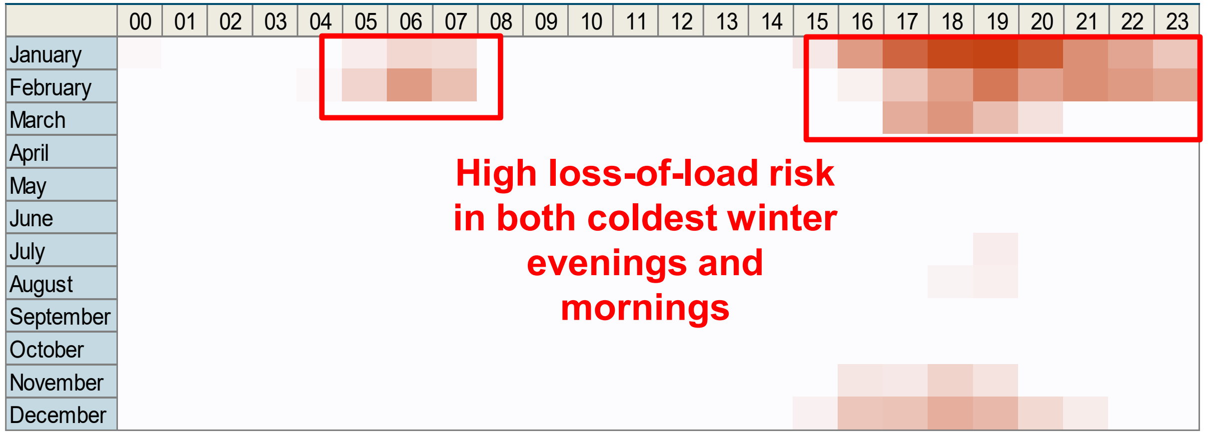


Example Winter Week in January 2050

Renewable Output and Net Load (GW) - *Before Storage*



Month-hour System Firm Resource Needs



Scenario Adoption Assumptions

Passive Measure Adoption Assumptions in Feasible Potential Scenarios

Measure	Description	Technical Potential and CECP Growth Scenario Adoption		Incremental Growth Scenario Adoption	
		2030	2050	2030	2050
Residential ccASHP	High-efficiency heat pump, high capacity retention at low temps (relative to standard HP)	4% of households	57% of households	3% of households	44% of households
Residential GSHP	Very high efficiency individual ground source heat pump (relative to standard HP).	2% of households	13% of households	1% of households	5% of households
Hybrid Heat Pump	Heat pumps which can reduce electricity consumption and switch to gas backup in cold temperatures.	21% of households	16% of households	12% of households	11% of households
Basic Shell (Retrofit)	Air sealing and attic insulation improvements, ~20% heating load reduction.	30% of existing buildings	65% of existing buildings	30% of existing buildings	65% of existing buildings
Deep Shell (Retrofit)	Whole-home retrofit including foundation and wall insulation improvements, ~35% heating load reduction.	3% of existing buildings	13% of existing buildings	0% of existing buildings	0% of existing buildings
Opt-In Stretch / Specialized Building Code	Reduction in thermal load over base code new construction - 60% reduction for residential, 24% reduction for commercial	90% of new construction	90% of new construction	70% of new construction	70% of new construction

Active Measure Adoption Assumptions in Feasible Potential Scenarios – I

Measure	Modeled Load Flexibility Assumptions		
	Technical Potential in CECP 2050 Scenario	Feasible Potential in CECP 2050 Scenario	Feasible Potential in Incremental Growth Scenario
Residential Hybrid HPs (Grid-Enabled) *Lower efficiency heat pump, switchover to gas backup at low temps as well as during critical electric system hours*	**Adoption and participation**: 100% of households with hybrid heat pumps from CECP 2050 Phased scenario	**Adoption**: 100% of hybrid heat pumps. **Participation**: 100% of hybrid heat pump electric load responds to load management event in 2030, 100% in 2050. **Realization rate:** 100%.	**Adoption**: 100% of hybrid heat pumps. **Participation**: 100% of hybrid heat pump electric load responds to load management event in 2030, 100% in 2050. **Realization rate:** 100%.
Industrial Process Loads *Shed measure modeled for existing Connected Solutions curtailment realization (80.5%).*	**Participation**: 100% of industrial electric load enrolled in Daily Dispatch Connected Solutions program.	**Participation**: 202 MW in 2030, 477 MW in 2050. **Realization rate:** 80.5%.	**Participation**: 162 MW in 2030, 382 MW in 2050 **Realization rate:** 80.5%.
HVAC Flexibility *Load is shifted evenly into the preceding hours. Assuming 1-to-4-hour event, 100% to 65% load shifted for cooling; 20% to 13% load shifted for heating.*	**Adoption and participation**: 100% of households with electric space heating from CECP 2050 Phased scenario, across modeled time-horizon.	**Adoption**: 60% of households with smart thermostats in 2030, 90% in 2050. **Participation**: 30% of smart thermostats in 2030, 40% in 2050. **Realization rate**: 55%.	**Adoption**: 60% of households with smart thermostats 2030, 90% in 2050. **Participation**: 60% of smart thermostats in 2030, 80% in 2050. **Realization rate**: 55%.

"Realization rate" here refers to the expected customer response among those enrolled to participate in demand response programs.

Active Measure Adoption Assumptions in Feasible Potential Scenarios – II

<table>
<tr><th rowspan="2">Measure</th><th colspan="3">Modeled Load Flexibility Assumptions</th></tr>
<tr><th>Technical Potential in CECP 2050 Scenario</th><th>Feasible Potential in CECP 2050 Scenario</th><th>Feasible Potential in Incremental Growth Scenario</th></tr>
<tr><td>Water Heater Flexibility

Load is shifted evenly into the preceding hours. Assuming 1-to-4-hour event, 100% to 40% load shifted.</td><td>Adoption and participation: 100% of households with electric water heaters from CECP 2050 Phased scenario, across modeled time-horizon.</td><td>Adoption: 100% of homes with heat pump water heaters.
Participation: 50% of water heater electric load responds to load management event in 2030, 90% in 2050.
Realization rate: 100%.</td><td>Adoption: 100% of homes with heat pump water heaters.
Participation: 20% of water heater electric load responds to load management event in 2030, 60% in 2050.
Realization rate of 100%.</td></tr>
<tr><td>Residential Appliance Shed + Shift

Dishwasher, washer, dryer, pool pump: 100% of load is shifted evenly to the preceding 8 hrs. Spa, plug load, pool heater, oven, well pump, fans: Load is shed by 32.5% during top 200 critical hours.</td><td>Adoption and participation: 100% of appliance load.</td><td>Adoption not modeled.
Participation: 20% of appliance load responds to load management event in 2030, 40% in 2050.
Realization rate: 100%.</td><td>Adoption not modeled.
Participation: 10% of appliance load responds to load management event in 2030, 30% in 2050.
Realization rate: 100%.</td></tr>
<tr><td>Commercial Refrigeration

100% of load is shifted evenly to the preceding 4 hours.</td><td>Adoption and participation: 100% of commercial square footage with refrigeration energy demand.</td><td>Adoption not modeled.
Participation: 20% of appliance load responds to load management event in 2030, 40% in 2050.
Realization rate of 100%.</td><td>Adoption not modeled.
Participation: 10% of appliance load responds to load management event in 2030, 30% in 2050.
Realization rate of 100%.</td></tr>
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“Realization rate” here refers to the expected customer response among those enrolled to participate in demand response programs.

Active Measure Adoption Assumptions in Feasible Potential Scenarios – III

Measure	Modeled Load Flexibility Assumptions		
	Technical Potential in CECP 2050 Scenario	Feasible Potential in CECP 2050 Scenario	Feasible Potential in Incremental Growth Scenario
V1G (Managed Charging) *V1G shifts all charging out of daily peak period to low-cost period contingent on vehicle location.*	**Adoption and participation**: 100% of EV charging load.	**EV Adoption**: 18% of light-duty vehicles in 2030, 91% in 2050. **Participation**: 25% of electric vehicle charging load responds to load management event in 2030, 45% in 2050 (V2G described below). **Realization rate:** 100%.	**EV Adoption**: 7% of light-duty vehicles in 2030, 66% in 2050. **Participation**: 15% of electric vehicle charging load responds to load management event in 2030, 75% in 2050. **Realization rate:** 100%.
V2G (Vehicle-to-Grid) *V2G discharges during peak period and charges in low-cost period contingent on vehicle location.*	**Adoption and participation**: 100% of EV charging load.	**Participation**: 0% of electric vehicle charging load responds to load management event in 2030, 50% in 2050 for LDV and 90% in 2050 for MHDV. **Realization rate:** 100%.	**Participation**: No V2G uptake. **Realization rate:** 100%.
BTM Energy Storage *BTM residential and commercial 3-hour battery systems deployed to minimize net peak.*	**Adoption**: 278 MW in 2030, 3 GW in 2050.	**Adoption**: 278 MW in 2030, 3 GW in 2050. **Participation and realization rate**: 100%.	**Adoption**: 167 MW in 2030, 462 MW in 2050. **Participation and realization rate**: 100%.

"Realization rate" here refers to the expected customer response among those enrolled to participate in demand response programs.

Key Findings

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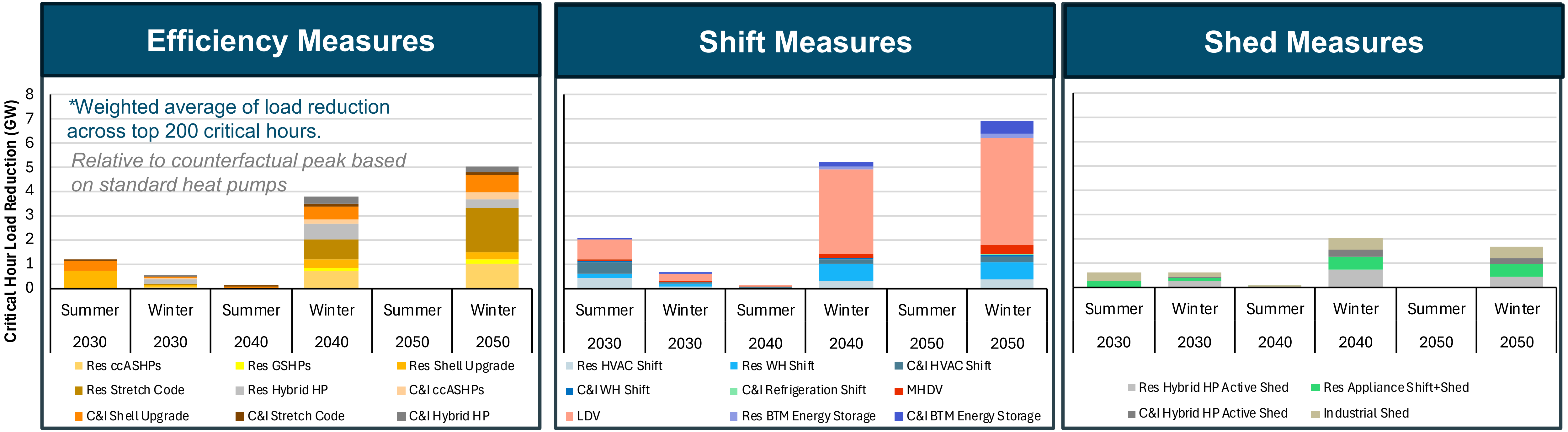
EV load management, residential shell measures, and high-efficiency heat pumps emerge as highest technical potential measures

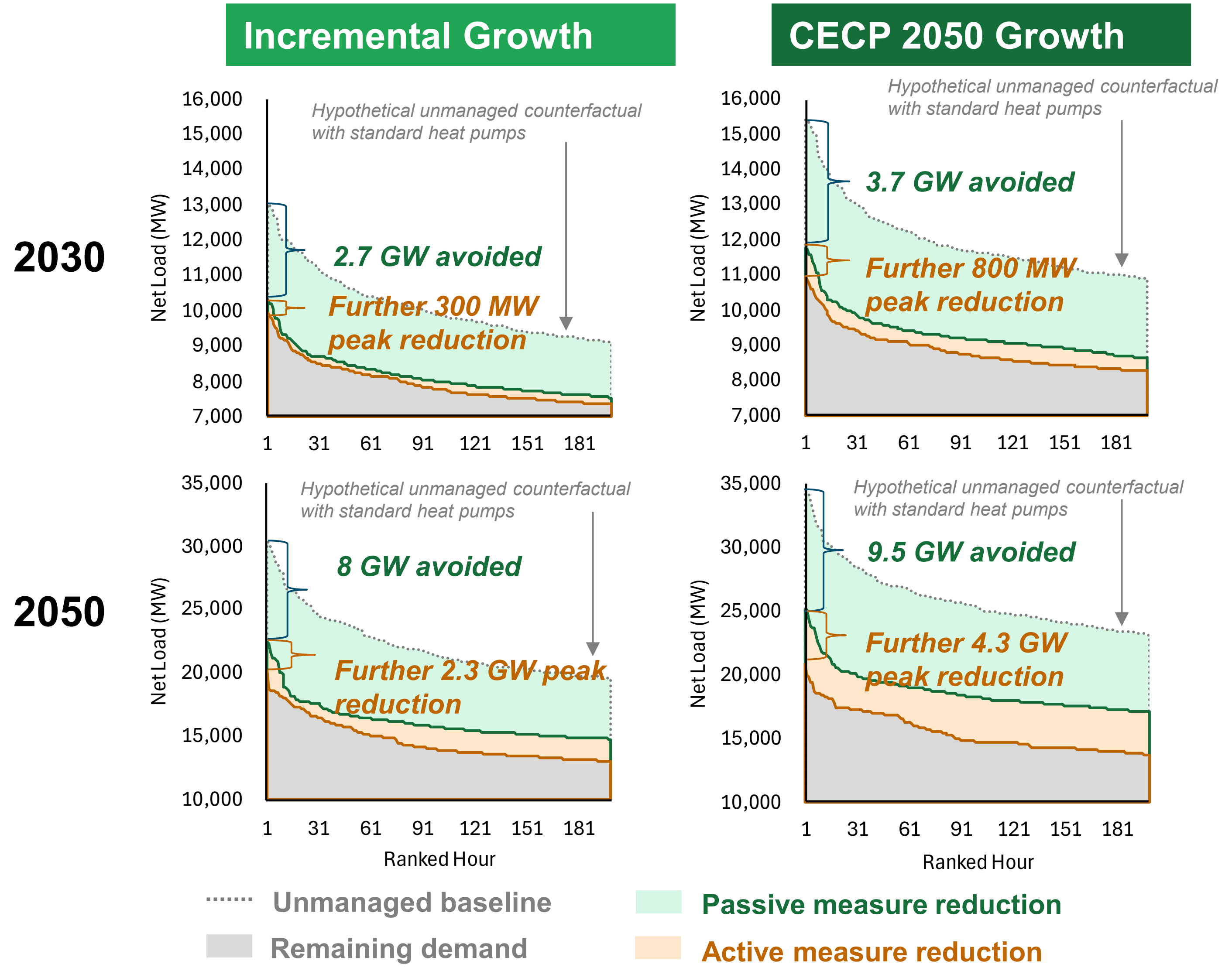


- **Passive energy efficiency measures avoid extreme peak demand increases from inefficient electric heating.**
  - Stretch codes for new construction are key for mitigating peak demand growth from the Commonwealth’s expanding building stock
- **High-potential active measures include EV charging management, space and water heating load shifting, and hybrid heat pumps.***
- **The adoption trajectories shown here are aligned with the CECP Phased Scenario, and do not reflect maximum feasible deployment per measure.**

*This study assumed passive measures reduce peak demand first, before active measures are applied, with storage dispatched last. With different dispatch order/strategies (e.g. least cost first), the technical potential of different strategies could appear significantly higher/lower.

Passive load management can avoid 2.7 to 3.7 GW by 2030, and 8 to 9.5 GW by 2050. Active load management can further flatten peak demand by 300 to 800 MW by 2030, and 2.3 to 4.3 GW by 2050

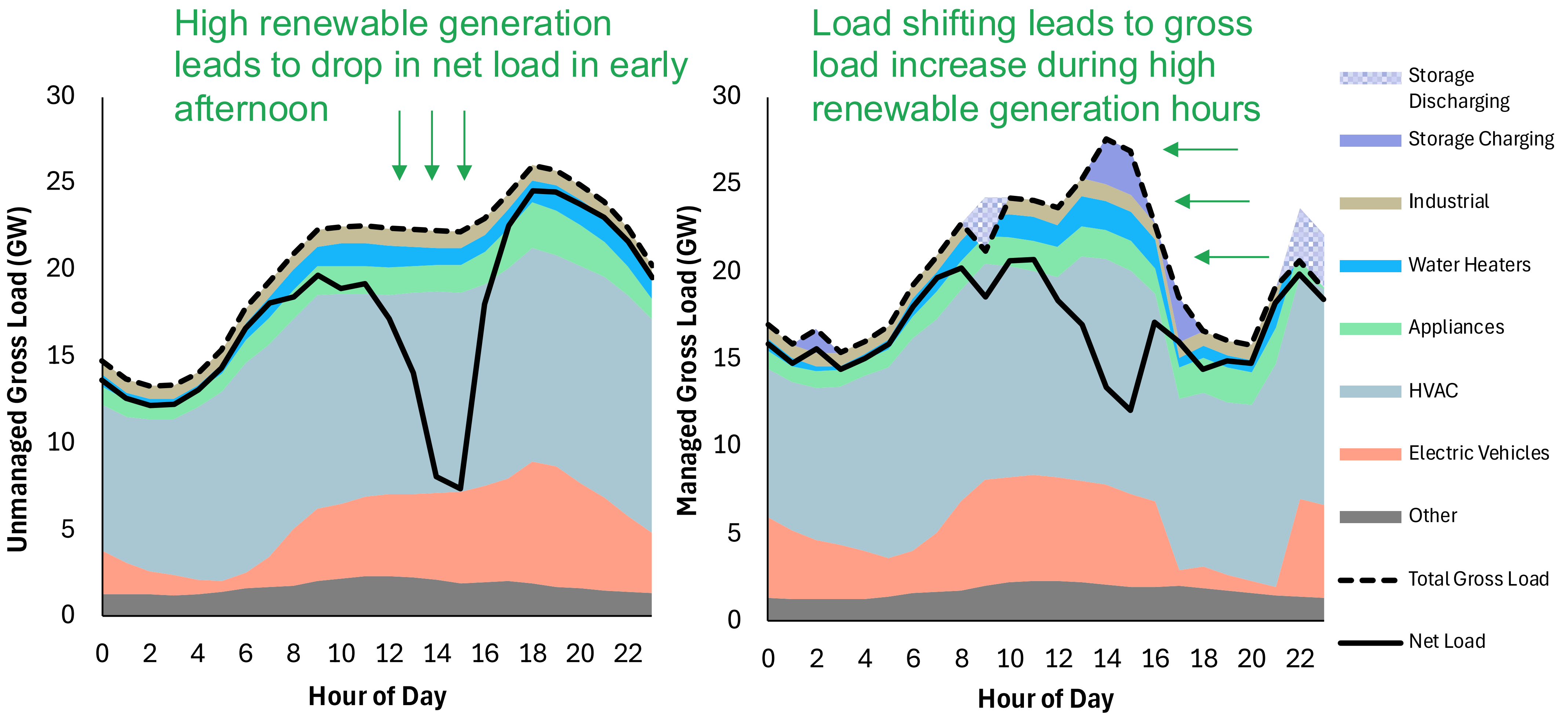
- **Passive high-efficiency electrification and building shell improvement measures help avoid significant peak demand growth***
- **Active load management measures focus on high net peak hours, shedding and shifting load to periods with lower resource adequacy risk, flattening net peak demand**
- **The active measure peak reductions shown do not reflect "perfect capacity" reductions**
  - Further research is required to understand the reliability of load management strategies



*Relative to electrification with standard heat pumps

Load shifting measures can better align demand with hours of low-cost renewable supply, potentially increasing gross peak demand while reducing net peak demand

Example Unmanaged (left) and Managed (right) Gross Loads on Peak Winter Day, 2050

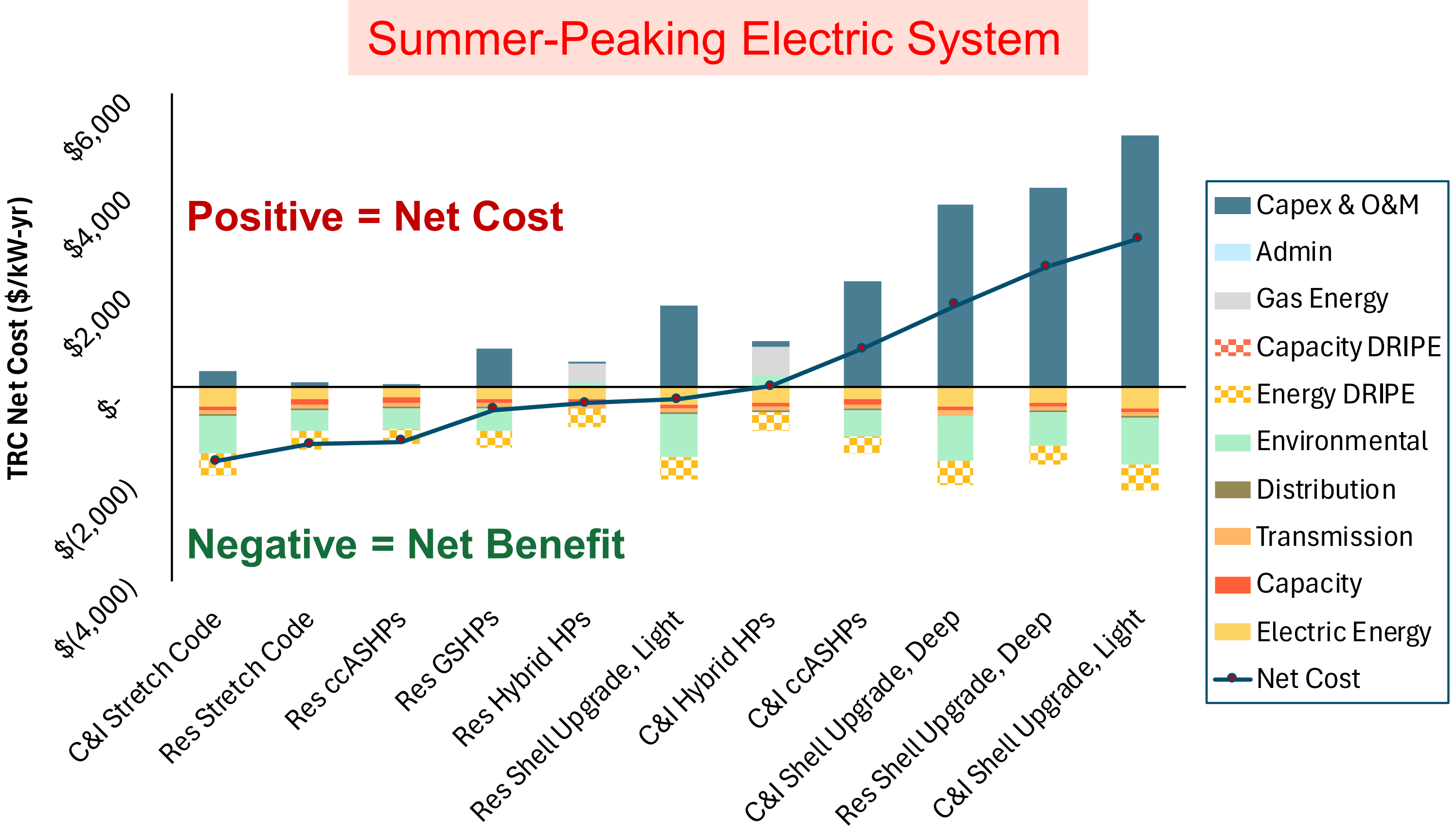


Cost-effective measure deployment can yield $3.1-$4.8B in annual avoided electric system costs in 2050, and $7-$9.1B in annual total resource cost (TRC) net benefits across scenarios (active and passive combined)

Passive Measures

- Passive load management and/or efficiency measures provided valuable energy and emissions reductions year-round
- Stretch codes and building shell retrofits ensure cost-effective improved building energy performance, but high upfront costs can lead to net TRC costs for retrofits
- The analysis presented emphasizes the importance of efficient electric load growth in buildings

Levelized Lifetime TRC Net Cost* for Passive Measures, $/kW-yr, 2030



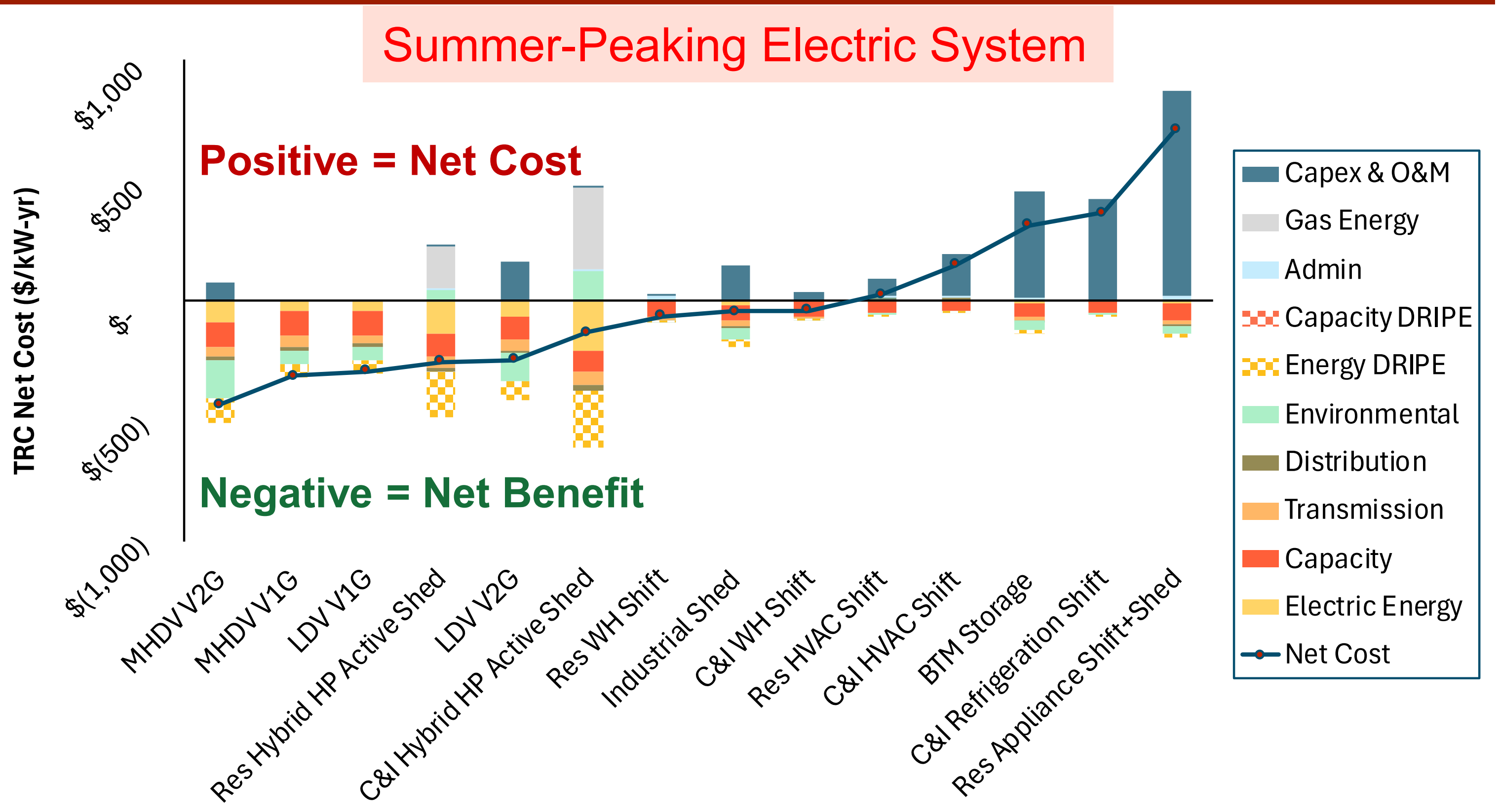
*Lifetime NPV of avoided and incurred costs levelized over device lifetime, normalized "per kW" of critical hour load reduction, incremental to a standard air source heat pump

Cost-effective measure deployment can yield $3.1-$4.8B in annual avoided electric system costs in 2050, and $7-$9.1B in annual total resource cost (TRC) net benefits across scenarios (active and passive combined)

Active Measures

- Active load management can help avoid future capacity and transmission costs via targeted dispatch to reduce critical hour load
- Electric vehicle management leads to the highest net benefits, with no-cost smart charging being an early "no-regrets" strategy to pursue
- High enabling capital costs for technologies with limited shift potential can lead to lower relative cost-effectiveness
  - This includes the inability to cover long critical hour stretches or low hourly kW potential

Levelized Lifetime TRC Net Cost* for Active Measures, $/kW-yr, 2030

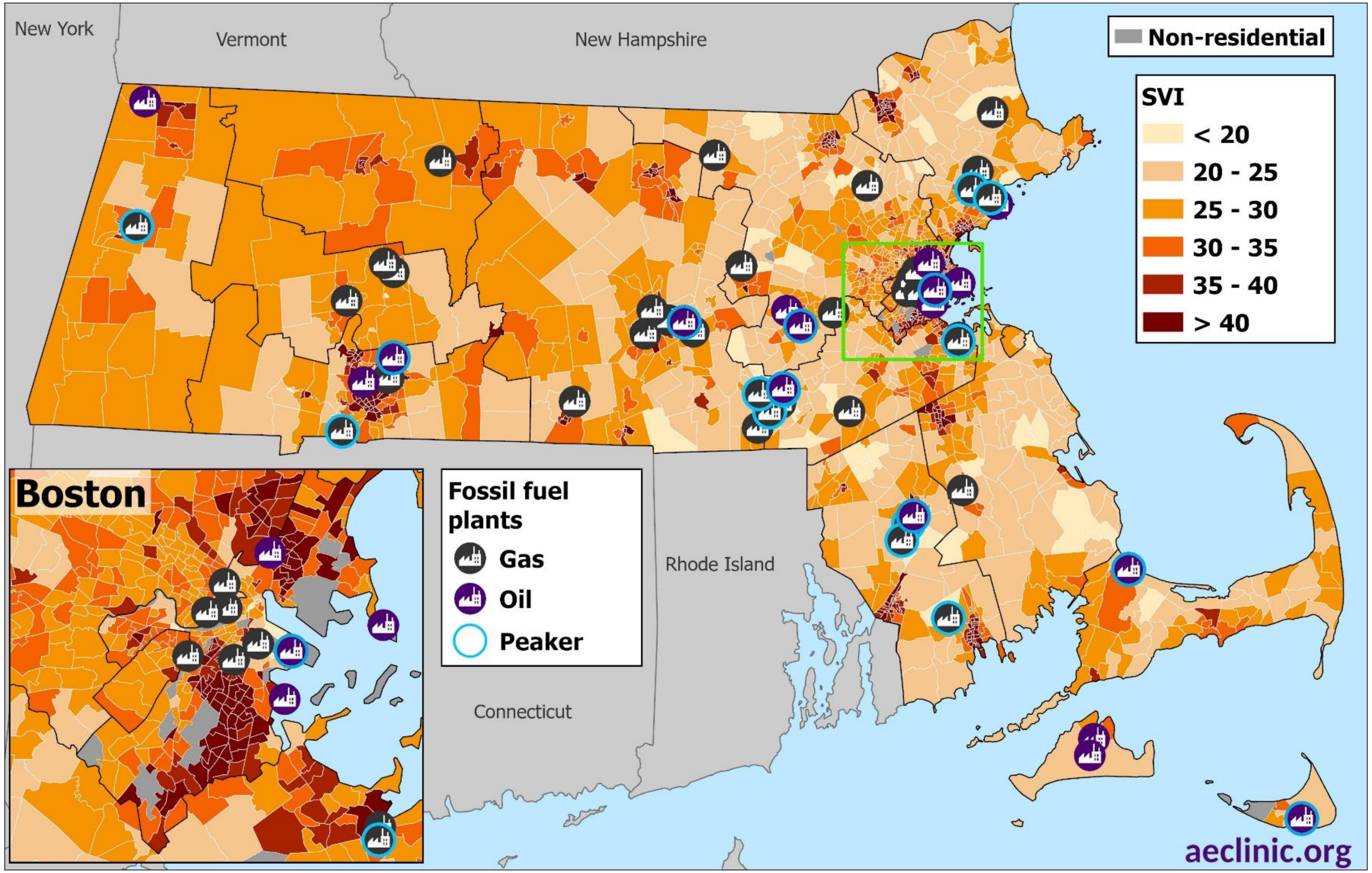


*Lifetime NPV of avoided and incurred costs levelized over device lifetime, normalized "per kW" of critical hour load reduction

Load management has the potential to have positive equity and resiliency impacts for disadvantaged communities

Load Management Impact	Relevance to Disadvantaged Communities in Massachusetts
Avoided power outages Enhanced building-level resilience Avoided disruptions to critical facilities	• Loss of power is most harmful for some groups: elderly, disabled, low-income, those with serious health conditions, or those reliant on electronic medical devices • Low-income households and other vulnerable individuals are less likely to have backup power, transportation for evacuation, or funds for alternative housing
Lower energy use and bill impacts	• Low-income and BIPOC households, older adults, and rural residents are more likely to be energy-burdened and to fall behind on their energy bills • Cost shifts could occur through ratepayer-backed programs
Environmental and public health benefits	• Fossil fuel-fired power plants are typically located near low-income and BIPOC areas, putting these areas at higher risk for negative health outcomes
Enhanced indoor health, comfort, and safety	• Low-income households tend to live in lower-quality housing and are more likely to keep their homes at unsafe temperatures to reduce expense
Job creation	• Low-income and BIPOC communities are less likely to have access to well-paid employment opportunities
Increased property values	• Higher property values boost homeowner wealth but also increase property taxes and rents, which can lead to gentrification and displacement

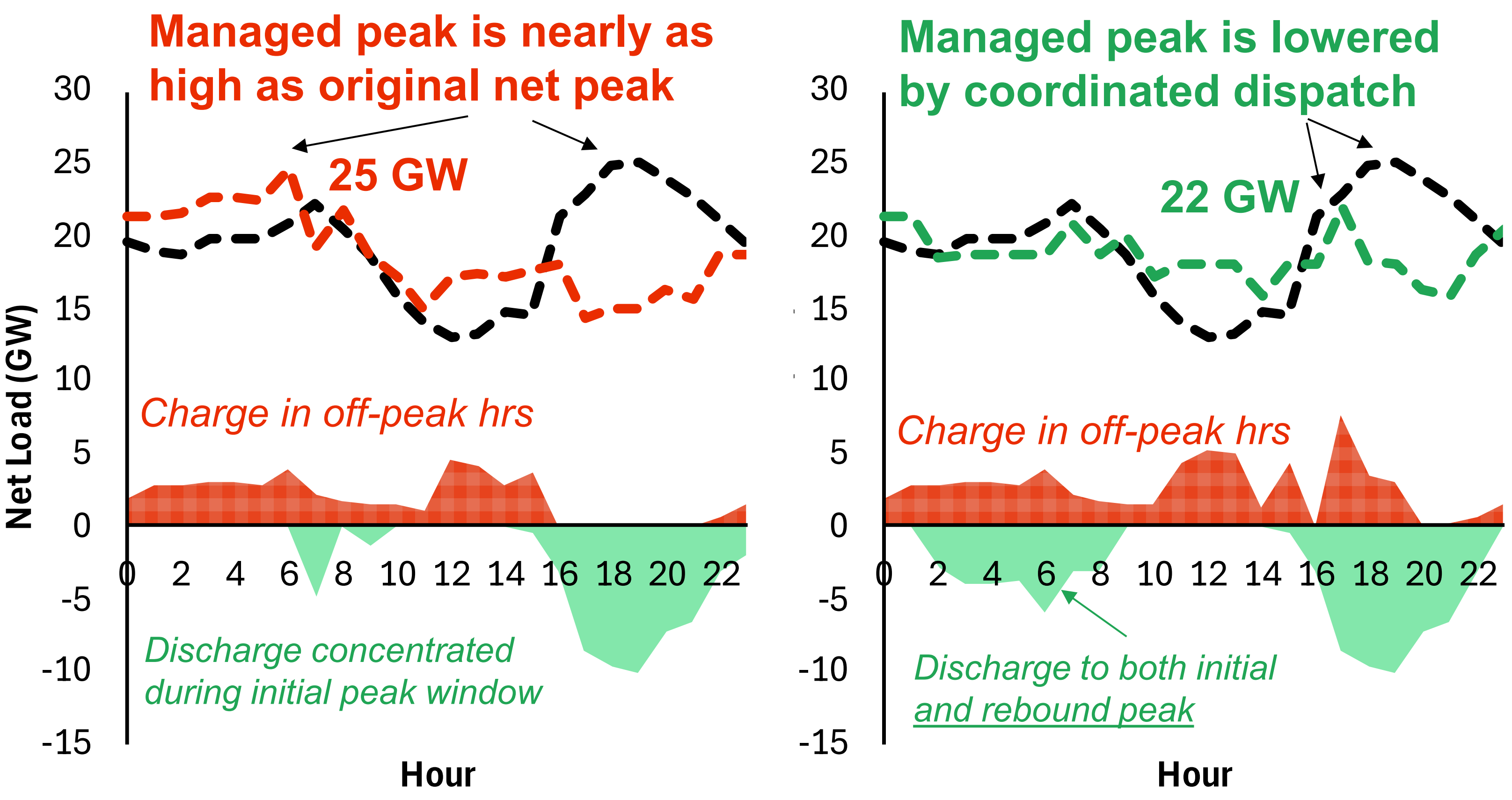
Programs to encourage load management that consider and center equity can deliver benefits to disadvantaged communities



- **Social Vulnerability Index (SVI) combines values from ten measures of vulnerability, including measures of socioeconomic vulnerability and housing vulnerability**
  - A higher SVI score indicates multiple, overlapping vulnerabilities
- **SVI analysis can help to identify communities that have disproportionate socioeconomic burdens and challenges to adopting load management technologies.**
  - SVI can better enable targeted approaches in program design to ensure that these communities are able to see positive economic benefits, and avoid regressive outcomes

Clear price signals that reflect real-time electric system costs, through market participation and/or rates and programs, can increase benefits across the different components of the electric system

Simplified Example of Uncoordinated Load Flexibility Creating Rebound Peak Demand – Jan 5, 2050



+ **Uncoordinated price signals run the risk of rebound peaks emerging, and peak reduction potential left unrealized**
  - Programs, rates, and market participation can ensure price signals reflect true electric system costs to encourage load management that is aligned with system needs.
+ **Orchestration and aggregation can create dispatchable and diverse load shift and shed portfolios across multiple customers, increasing resource reliability and enabling the integration of load management into utility planning**

Scaling up load management will entail transforming electric retail rates, deploying participant- and utility-side hardware and software to enable flexibility, and increasing visibility into electric distribution system planning.

Key barriers identified in this study include the following, with the DOER Recommendations Report discussing strategies to address these challenges:

+ **Market participation, rate design, and other compensation**
    - Transitioning to cost-reflective retail rates, enabling aggregated DER participation in wholesale markets, and carefully considering the interactions of rates and programs will be essential to ensuring that customers see the right price signals to manage loads. This will entail utilities improving visibility into avoidable system costs across supply and delivery and ensuring that load management strategies are compensated for grid services provided.
+ **Technology-readiness**
    - Inadequate technology-readiness with metering infrastructure, device interoperability, and utility distributed energy resource management systems (DERMS) has limited the deployment of active load management to date, although there are ongoing efforts to modernize and improve these technologies.
+ **Upfront costs**
    - High-performance measures such as ground-source heat pumps and deep building shell retrofits have significant upfront costs, limiting customer cost-effectiveness relative to lower-efficiency alternatives. High upfront costs are also a challenge for some active measures, such as BTM storage, smart household devices, and thermal energy storage for commercial customers.

Conclusions

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Study Conclusions

- **Strategies to manage load may collectively deliver significant electric demand reductions in the Commonwealth.**
  - Passive load management measures such as cold-climate heat pumps and building shell improvements can avoid 2.7 to 3.7 GW by 2030 and 8 to 9.5 GW by 2050. Active load management such as EV charging management and building load flexibility can further flatten peak demand by 300 to 800 MW by 2030 and 2.3 to 4.3 GW by 2050.
- **EV charging management, cold-climate heat pumps, and stretch codes for new construction provide the greatest net benefits of measures analyzed.**
  - Total avoided electric system costs from cost-effective measures reach $3.1-$4.8B annually in 2050 prior to considering program costs, with $7-$9.1B annually in total resource cost net benefits across Incremental and CECP 2050 Growth scenarios respectively.
- **Load management, when paired with careful program design, has the potential to have positive equity and resiliency impacts for disadvantaged communities if programs are designed with this specific intention in mind.**
- **Scaling up load management in the Commonwealth will entail transforming price signals that reflect real-time electric system costs through market participation, rates, and programs, deploying participant- and utility-side hardware and software to enable flexibility, and increasing visibility into electric distribution system planning.**

Areas of Further Study

- **Reliability of load management portfolios and performance of load management, especially under different weather conditions**
  - Integrating load management into long-term electric planning will require a deeper understanding of the reliability of load management strategies, especially during weather conditions that contribute to grid stress.
  - Aggregation can help increase load management reliability by diversifying across different measures, but there are limited examples of this at scale to date.
- **Impacts of rates and program design on load management potential**
  - Further study is needed on how to design rates, programs, and wholesale market participation so that load management and other DERs receive appropriate price signals that reflect different electric system costs.
- **Evaluating geospatial bulk system and distribution system value**
  - Research should focus on identifying how periods of locational system value align with bulk system value across different segments of utility distribution systems.
- **System-level modeling of impacts at scale**
  - Robust capacity expansion modeling is needed to better capture avoidable costs from load management strategy deployment at scale.