Distributed Energy Resources Forecast and Potential Study

Final Report

Platte River Power Authority

Estes Park • Fort Collins • Longmont • Loveland

August 28, 2023

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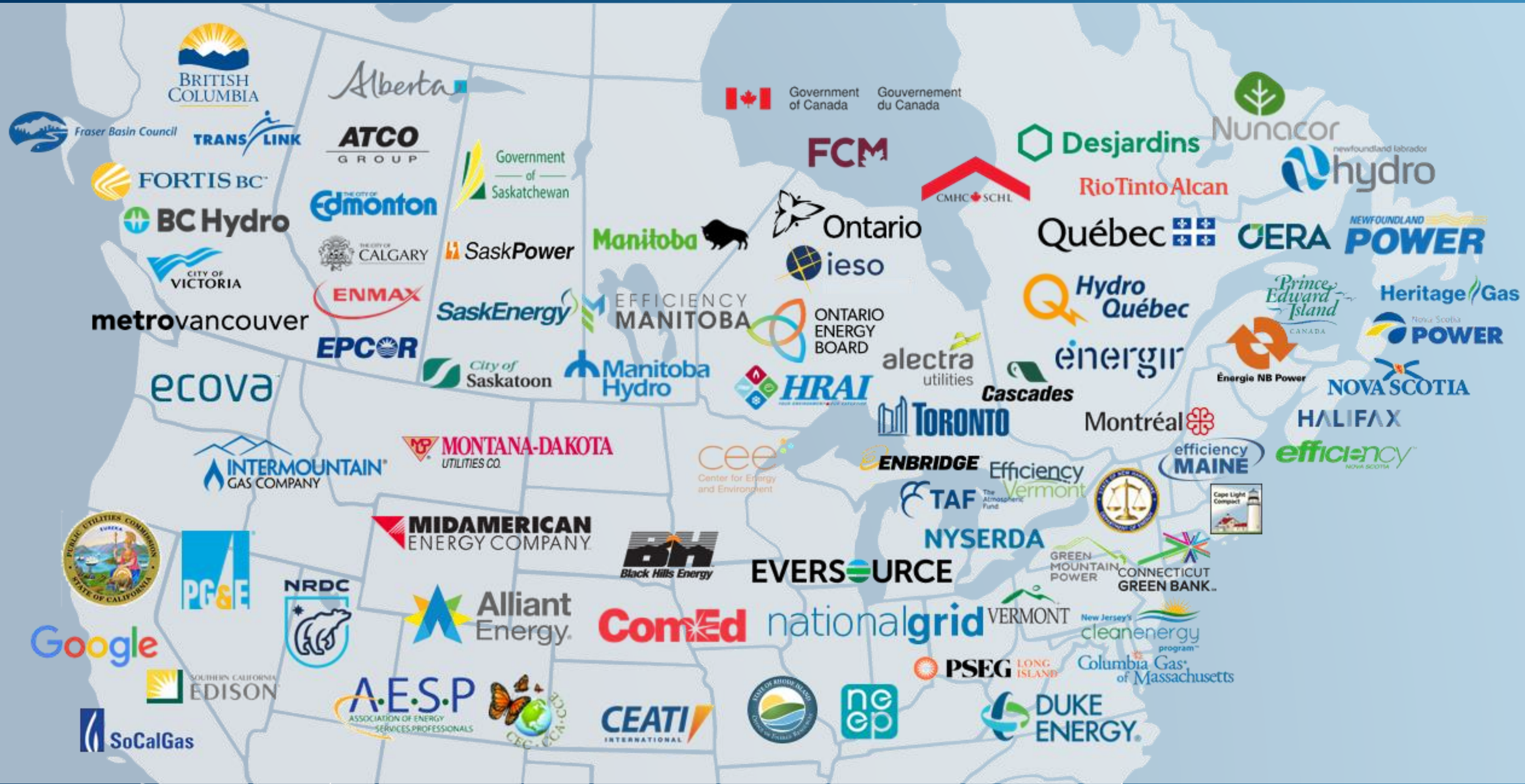

GOVERNMENTS | UTILITIES | CORPORATE + NON-PROFIT

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Overview

Project Team

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Estes Park • Fort Collins • Longmont • Loveland

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Project Scope

- **Technologies:** Energy efficiency, transportation electrification, distributed generation + storage, and demand response[1]
- **Study period:** 20 years (2024 through 2043)
- **Geographic scope**: PRPA territory
- **Scenarios**: Three market potential scenarios that consider market/technology factors and program/utility levers (e.g., incentives, rates)
- **Sectors/segments**: residential single family, residential multi-family, small commercial, large commercial
- **Outputs**: technology adoption (number of units), annual energy impacts (GWh), hourly demand impacts (MW), program metrics (budgets)
- **Deliverables**: narrative summary report + executive summary + detailed results outputs

Potential Value-add Items
(not comprehensive)

- **Additional measures[2]**
- Additional bottom-up modeling
- **Locational disaggregation[2]**
- PLEXOS aligned outputs
- **Additional scenarios / sensitivities[2]**
- Etc.

Note 1: Heating electrification is excluded from the study scope. Electrification assumptions for other modeling components will be sourced from recent electrification study conducted on behalf of PRPA.
Note 2: Value-add items were added to the scope to increase modeling accuracy, most notably the modeling of Fort Collins separately from the rest of the communities, the addition of a 4th solar and storage scenario with different NEM arrangements and the design of a TVR applied to all communities in the *Medium* and *High* scenarios.

Study Approach: Adoption forecast

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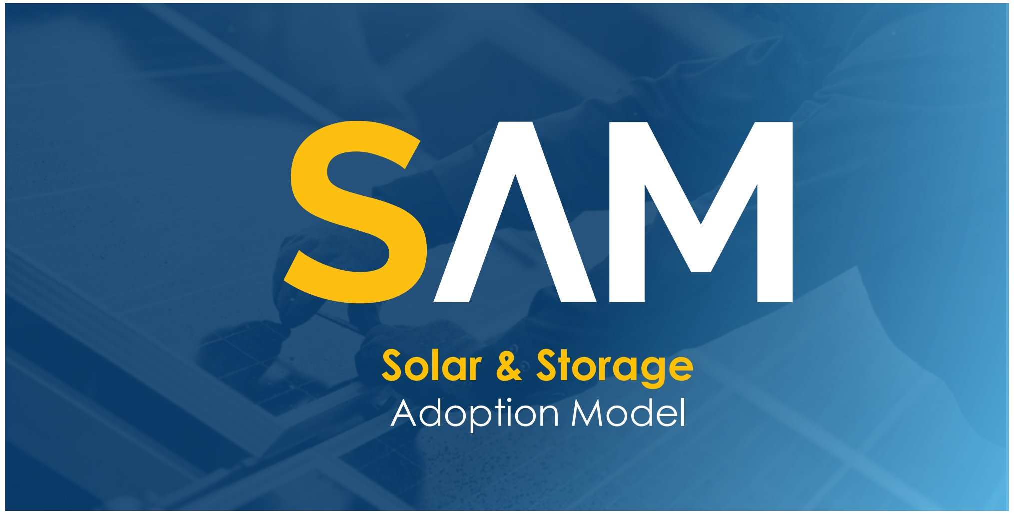
Electric Vehicles and **Distributed Generation & Storage** adoption are estimated using a suite of Dunsky's sophisticated in-house models (listed below) that forecast potential market adoption of clean energy solutions under an array of scenarios and technical, economic, and market constraints.

Medium and Heavy-Duty Electric Vehicles adoption is developed using a top-down modeling approach; a similar higher-level approach is leveraged to assess the potential of **Energy Efficiency**.

Where possible, PRPA territory and Colorado specific model inputs are leveraged. Where jurisdiction-specific information is not available or insufficient, data from other jurisdictions is leveraged to fill gaps and produce a more robust representation of market parameters.



Note: The report's appendices provide detailed descriptions of the study's modeling methodologies, data inputs, and data sources.

Dunsky's EVA Model

The study leverages Dunsky's Electric Vehicle Adoption (EVA) model to forecast the uptake of EVs.

TECHNICAL

Assess the maximum theoretical potential for deployment
- Market size and composition by vehicle class (e.g. cars, trucks, buses)
- Model availability for each vehicle powertrain (e.g. ICE, PHEV, BEV)

ECONOMIC

Calculate unconstrained economic potential uptake
- Incremental purchase cost of PHEV/BEV over ICE vehicles
- Total cost of ownership (TCO) for personal vehicles, based on operational and fuel costs and internal rate of return (IRR) for commercial vehicles

CONSTRAINTS

Account for jurisdiction-specific barriers and constraints
- Range anxiety or range requirements
- Public charging coverage, availability, and charging time
- Home charging access

MARKET

Incorporate market dynamics and non-quantifiable market constraints
- Use of technology diffusion theory to determine rate of adoption
- Market competition between electric vehicles types (PHEV vs. BEV)

Solar PV: Overview

SAM

Solar PV adoption is modeled via three sequential steps.

Technical Potential

The theoretical maximum deployment potential for solar PV based on local building stock, energy consumption, and solar insolation.

Customer Economics

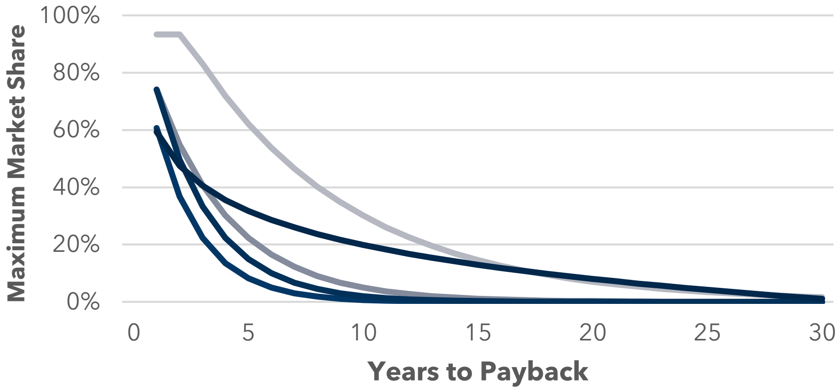
The theoretical maximum expected solar adoption driven by customer economics and willingness-to-pay.

Market Adoption

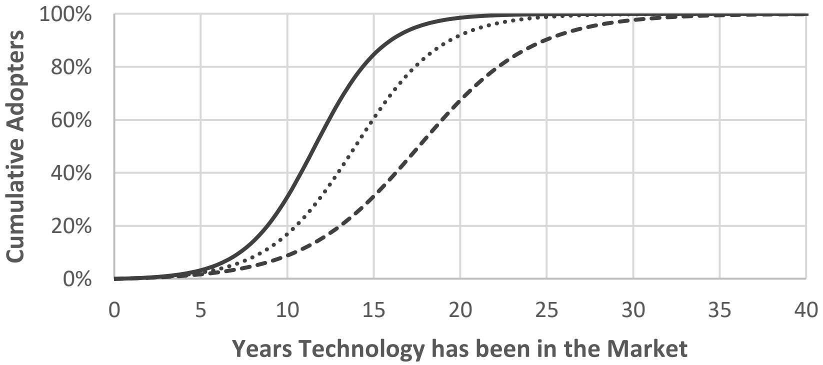
The estimated customer market demand in a given year as defined by diffusion theory to estimate technology deployment as the market matures.

Technical

Customer Economics



Technology Adoption



Study Approach: Potential Forecast

Dunsky's in-house **Demand Response & Optimization Potential (DROP™)** Model is designed to help our clients accurately understand the technical, economic, and achievable potential for **demand response** strategies and programs in their jurisdictions.

DROP ™ was designed to model **thousands of DERs** interacting and competiting with one another, **optimizing the value** they can deliver to the grid.

In this integrated study, **DROP ™** uses the forecast of the previously described adoption models as input to assess the Demand Response potential in different trajectories of market conditions.

Note: The report's appendices provide detailed descriptions of the study's modeling methodologies, data inputs, and data sources.

DROP Overview

Measure Characterization
- Load shapes
- EUL
- Costs
- Constraints

Market Characterization
- Customer segmentation
- Technology penetration and growth

Program Characterization
- Eligible markets
- Incentive design
- Program costs
- Program ramp up

Load Curve Characterization
- Peak day analysis
- End-use level analysis

DROP MODEL

Technical Potential

Total technically-feasible load impact at full participation for each measure

Economic Potential

The cost-effective load impacts across all measures.

Achievable Potential

The cost-effective load impacts across all measures, accounting for actual uptake and interactions among measures

Benchmarking & Comparisons

To provide context throughout presentation, results are compared to recent planned and achieved studies in Colorado and in similar jurisdictions.

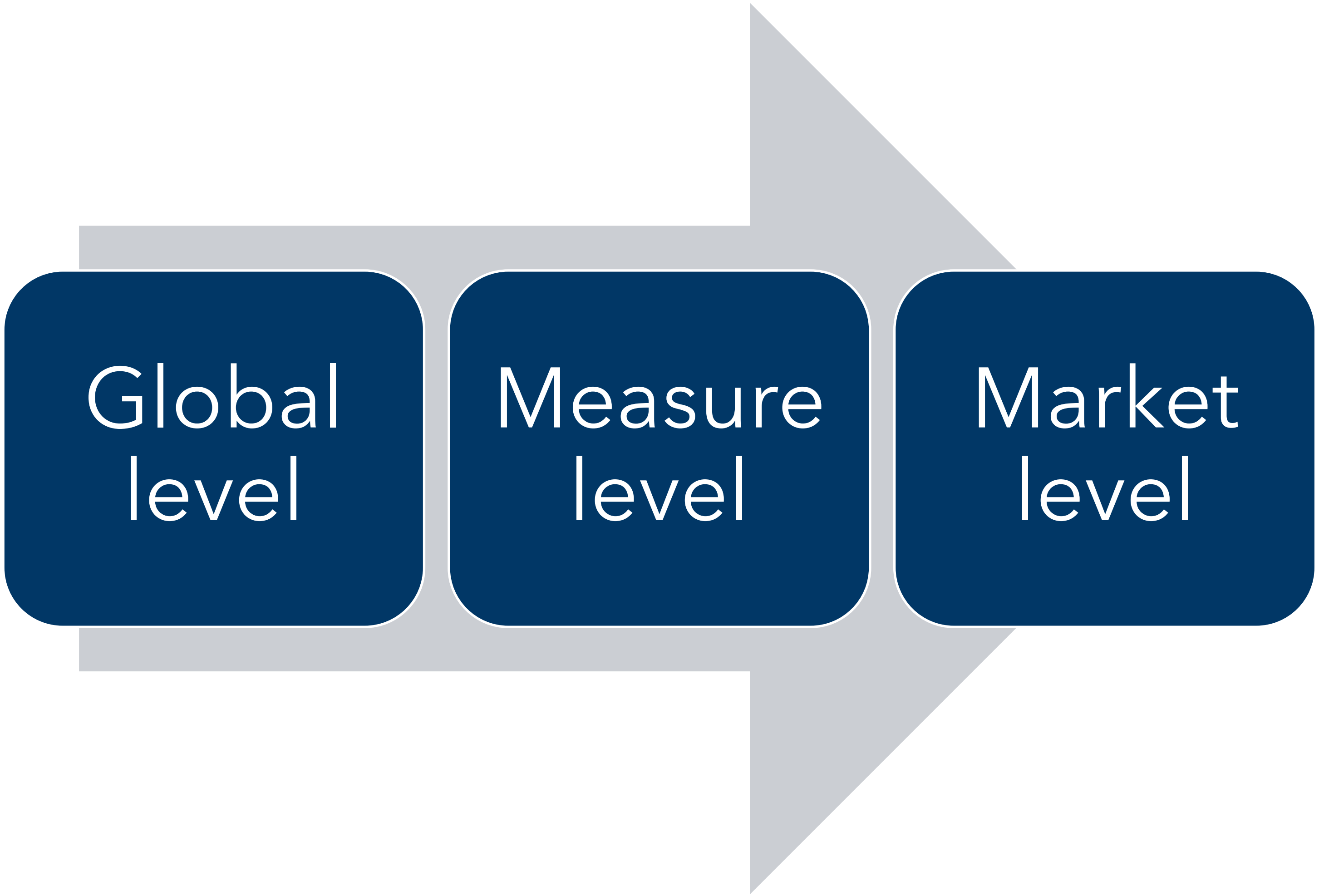
To the greatest extent possible, we attempt to compare like-to-like values.

Primary sources:

- Xcel Energy 2021 Electric Resource Plan and Clean Energy Plan
- PacifiCorp EE potential study in Wyoming (2023-2042)
- Colorado Springs Utilities (CSU) EE potential study (2020-2039)
- Xcel Energy Colorado Demand Response Study (2030)
- 2021 Colorado Medium-and Heavy Duty (M/HD) Vehicle Study produced by M.J. Bradley & Associates

Input Data

Input categories



Global level inputs

- Avoided costs
- Economics

Measure level inputs

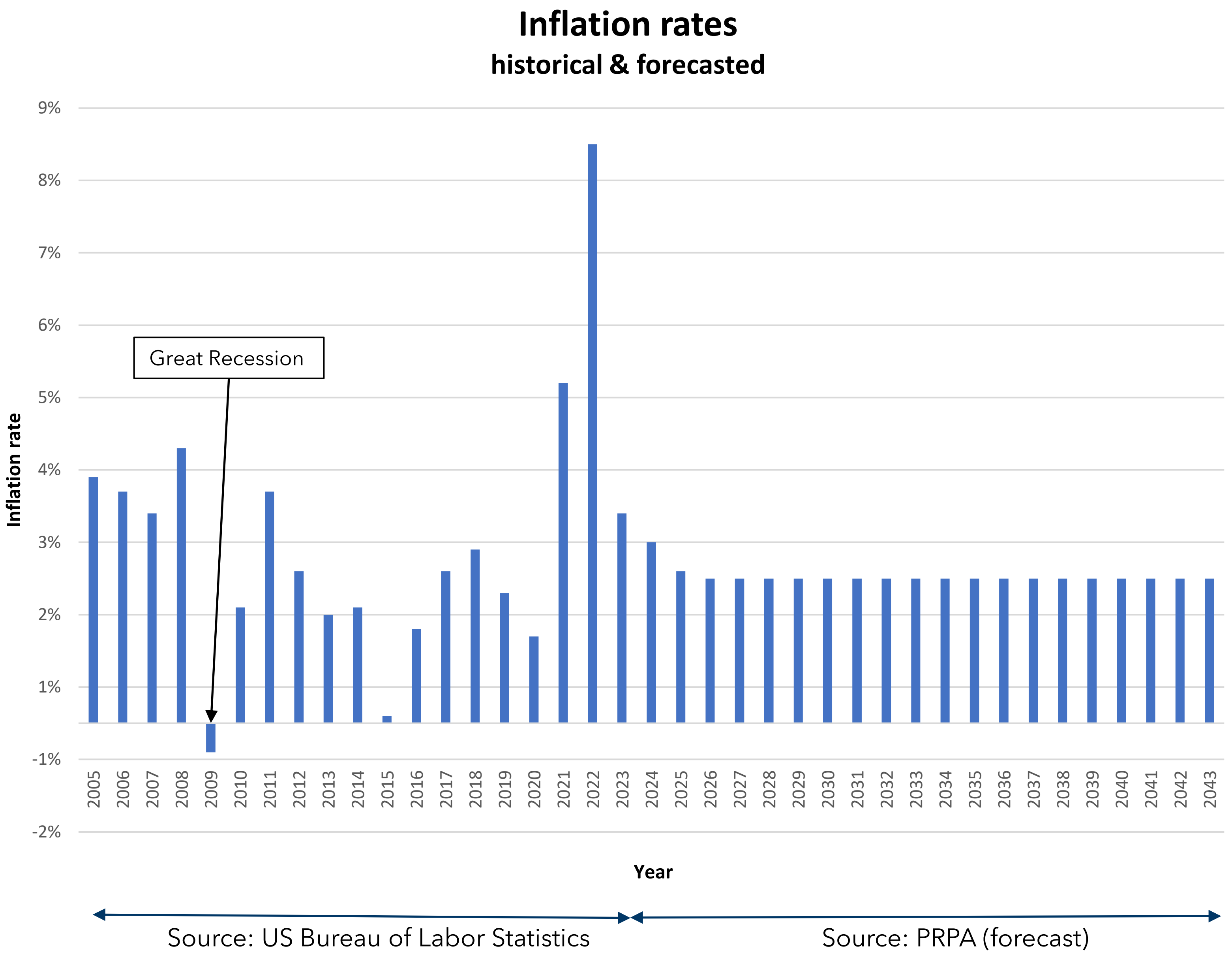
- 8760 end-use curves
- Program costs

Market level inputs

- Customer segmentation
- Retail rates

Input Data

Global Level Inputs - Economics



- Inflation rate is averaging 2.3%
- Discount rate is set at 5% (nominal)
- All the economic figures in following slides are expressed in real 2022 dollars.

Global level inputs – avoided costs

This study included to consideration of the following avoided costs:

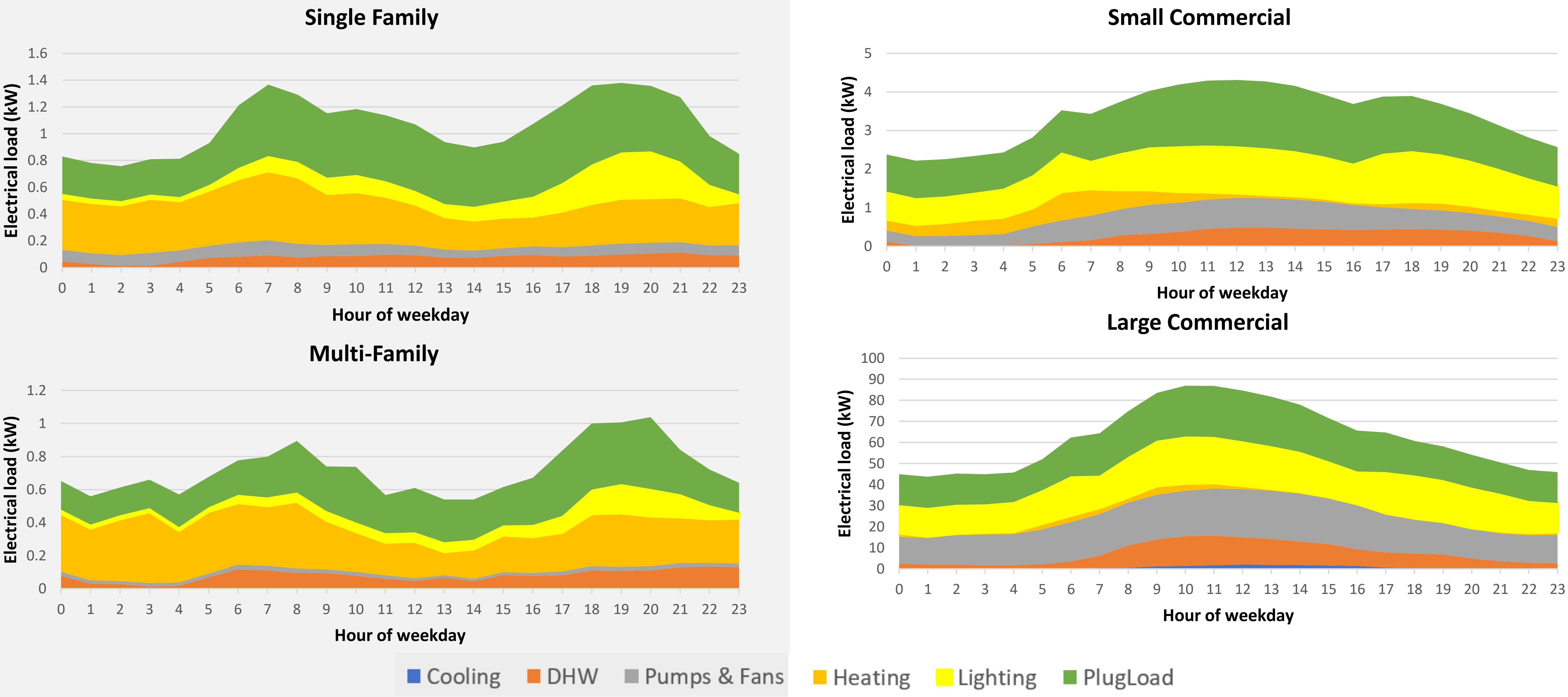
- **Energy:** Hourly Colorado power market forecast provided by PRPA.
- **Generation capacity deferral:** Deferred fixed battery costs based on NREL ATB conservative projections.
- **Avoided distribution capacity costs:** Provided by PRPA for commercial and residential distribution.
- **Carbon tax**: provided by PRPA, applied based on the average emissions rate ($/MWh)

Avoided Cost		2023	2043
Electric energy ($/kWh-hour)		$54.16 (avg)	$62.13 (avg)
Electric generation capacity ($/kW-Year)		$187	$128
Electric distribution capacity ($/kW-Year)	**Residential**	$20.37	$13.90
	Commercial	$33.28	$22.71
GHG emissions ($/MWh)		$0	$0.42

Input Data

Measure Level Inputs – 8760 End-Use Profile

Average segment load per end-use for a typical February weekday assuming 2023 average energy consumption per segment in Fort Collins

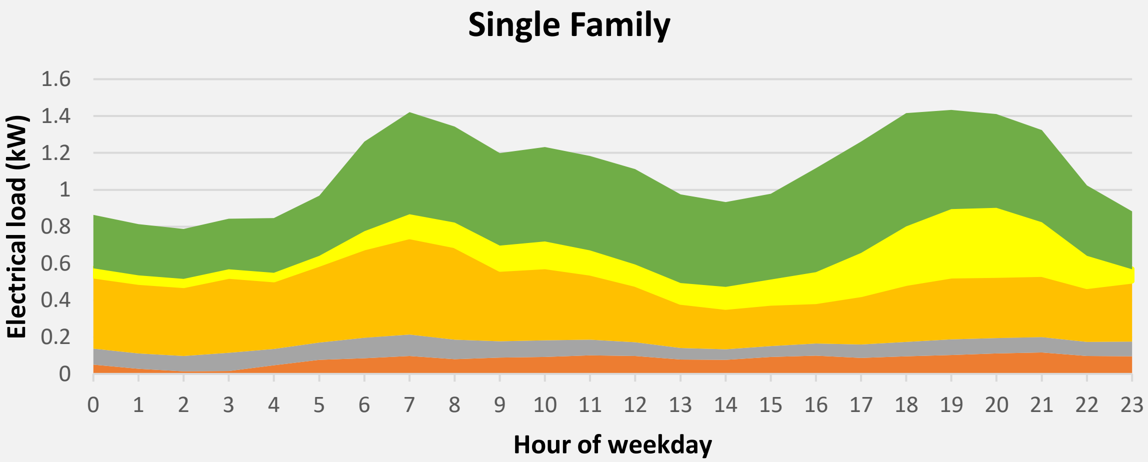


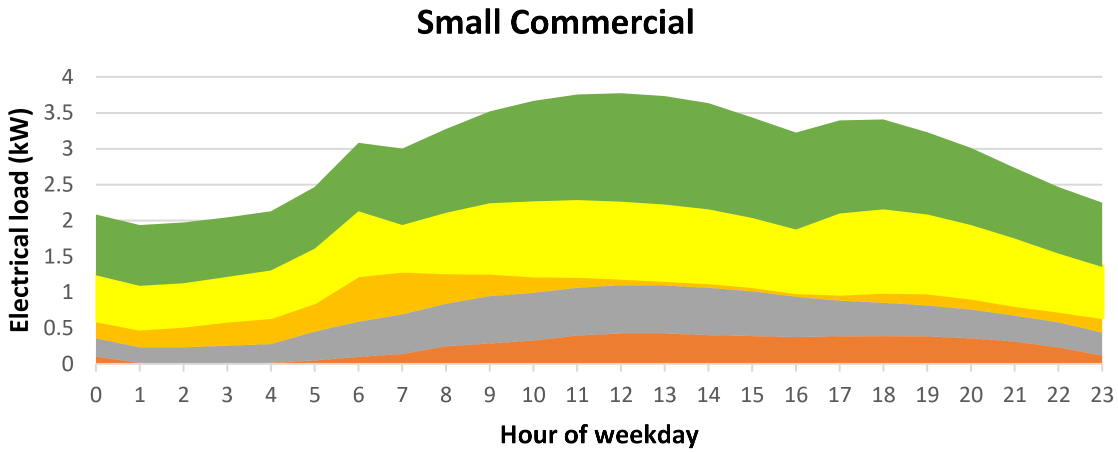
Note: End-use profiles built by leveraging NREL ResStock and ComStock databases. These profiles are used in the EE analysis and to assess the curtailable load in the DR model.

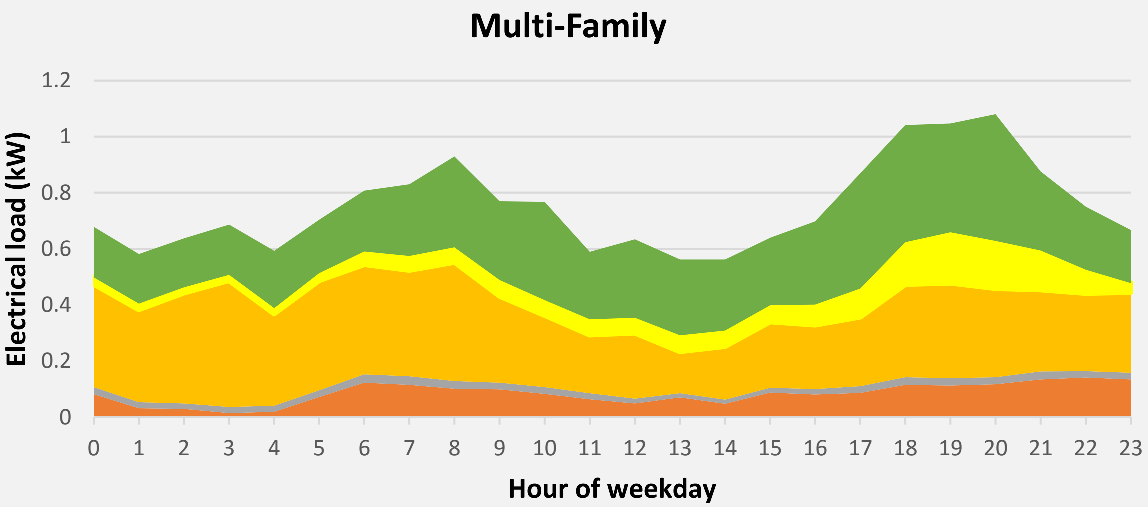
Input Data

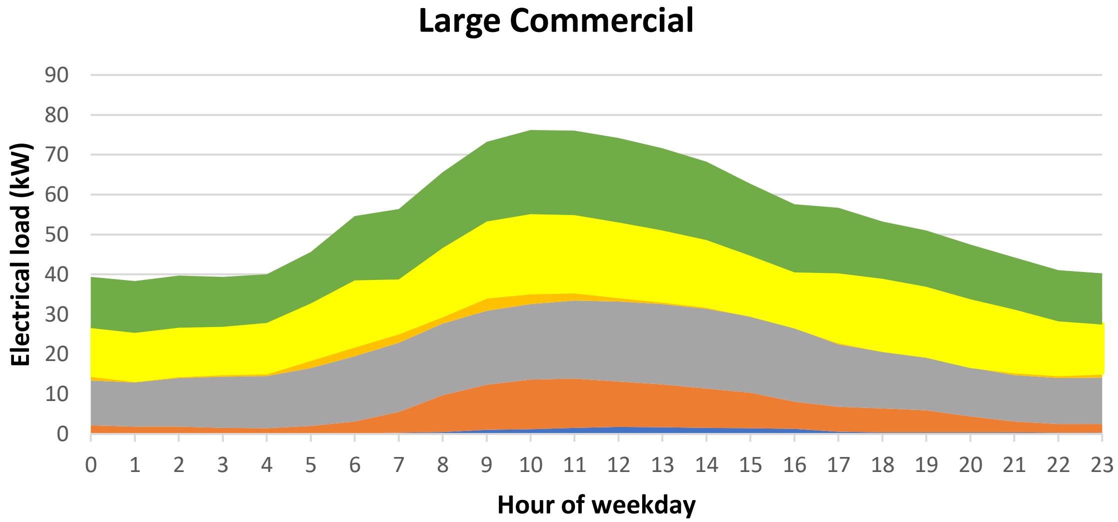
Measure Level Inputs – 8760 End-Use Profile

Average segment load per end-use for a typical February weekday assuming 2023 average energy consumption per segment in Longmont, Loveland and Estes Park









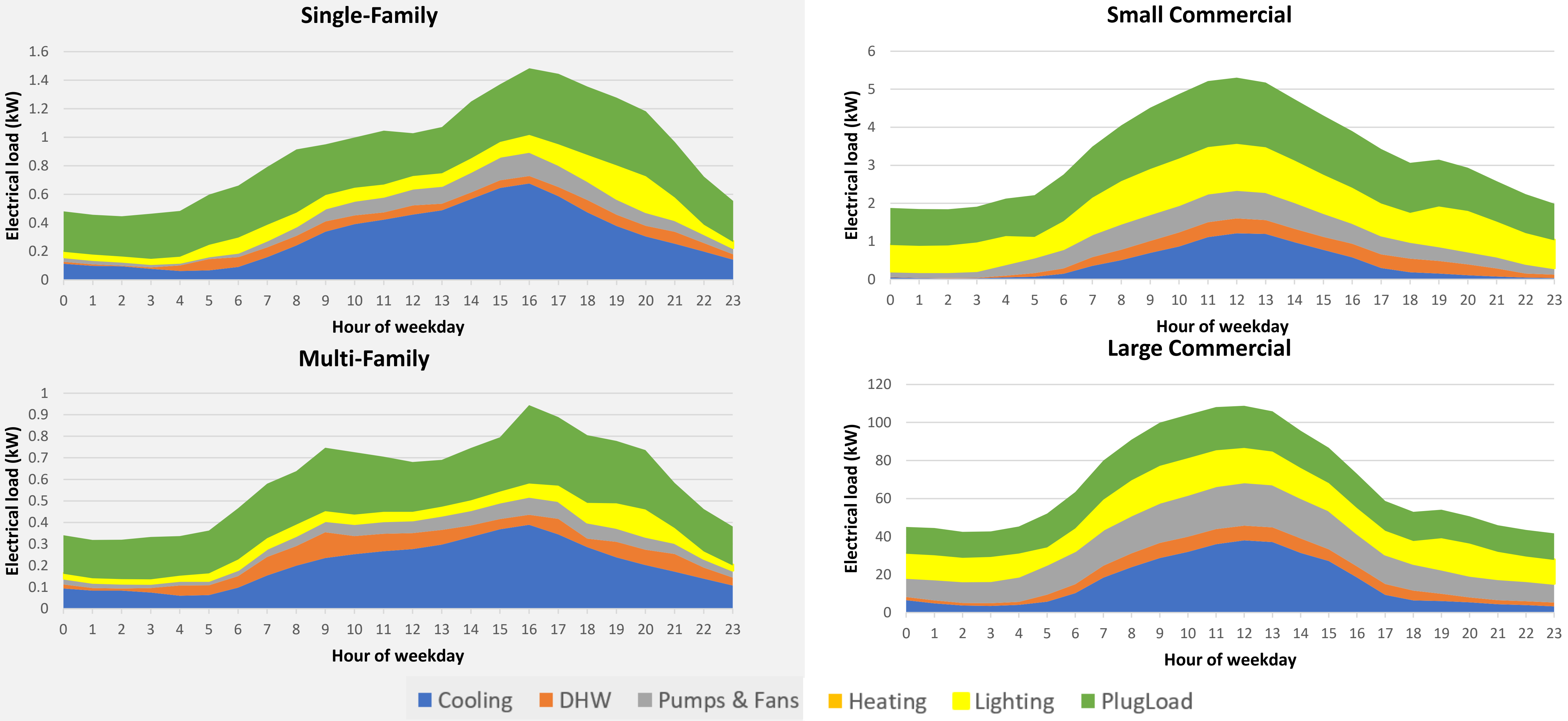
Cooling DHW Pumps & Fans Heating Lighting PlugLoad

Note: End-use profiles built by leveraging NREL ResStock and ComStock databases. These profiles are used in the EE analysis and to assess the curtailable load in the DR model.

Input Data

Measure Level Inputs – 8760 End-Use Profile

Average segment load per end-use for a typical July weekday assuming 2023 average energy consumption per segment in Fort Collins

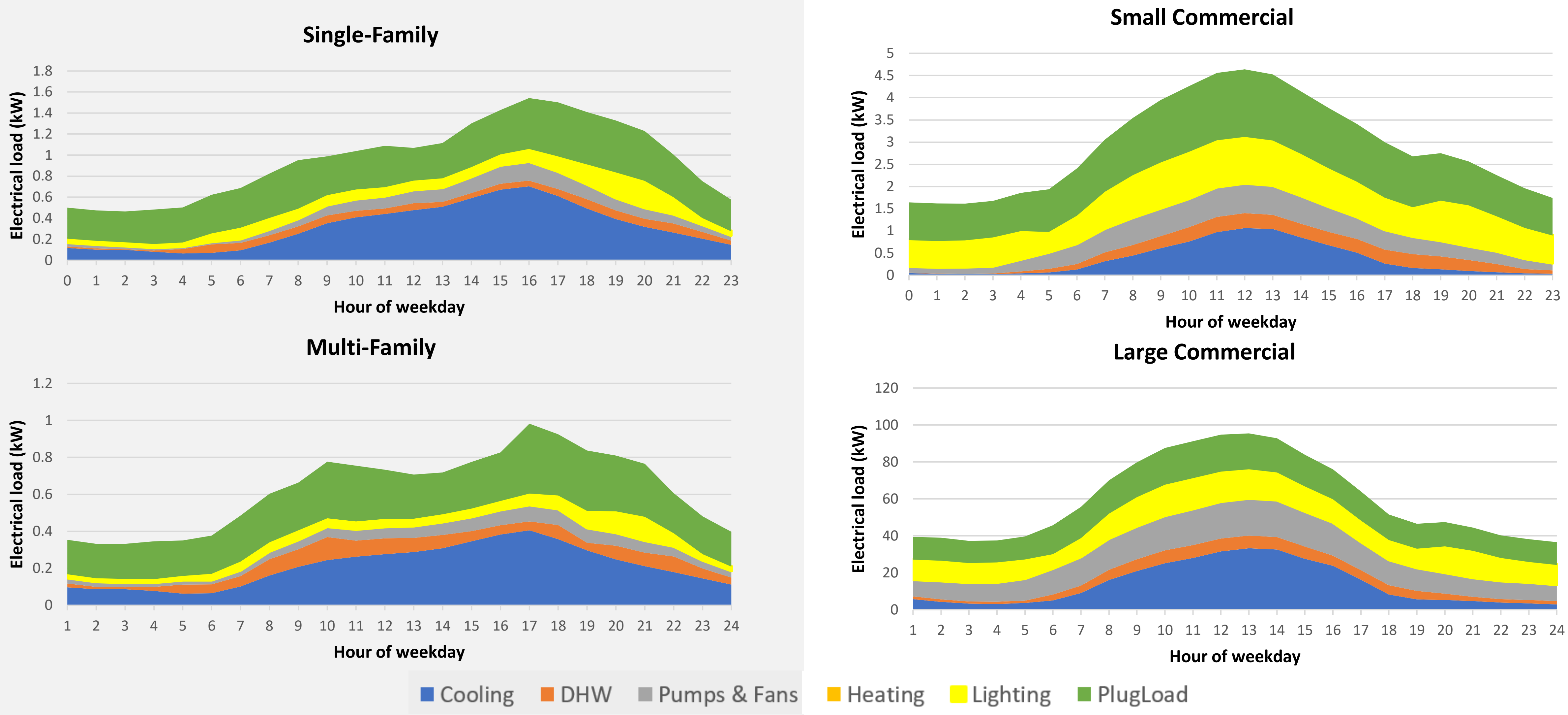


Note: End-use profiles built by leveraging NREL ResStock and ComStock databases. These profiles are used in the EE analysis and to assess the curtailable load in the DR model.

Input Data

Measure Level Inputs – 8760 End-Use Profile

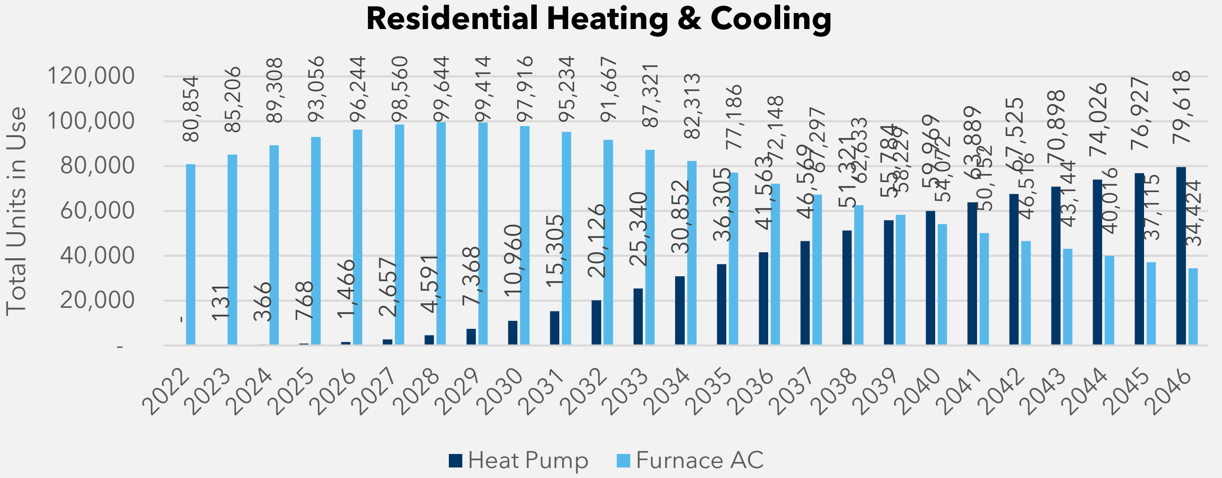
Average segment load per end-use for a typical July weekday assuming 2023 average energy consumption per segment in Longmont, Loveland and Estes Park

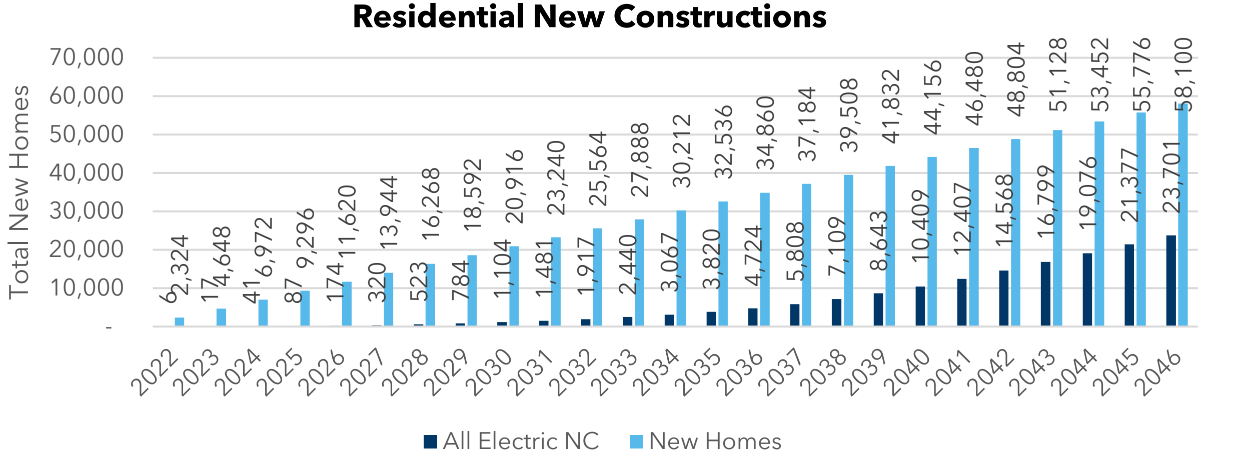


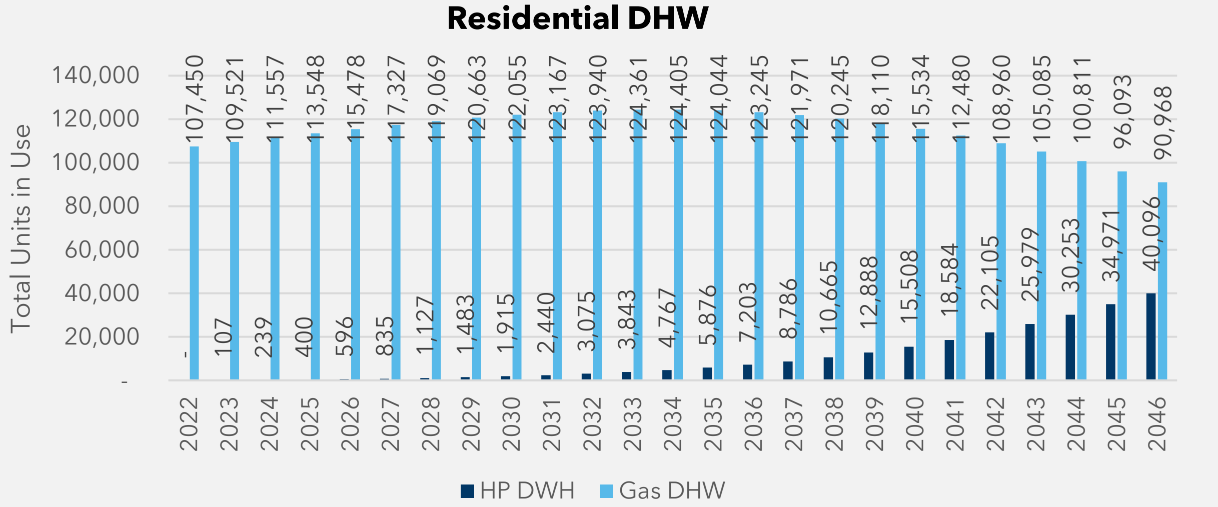
Note: End-use profiles built by leveraging NREL ResStock and ComStock databases. These profiles are used in the EE analysis and to assess the curtailable load in the DR model.

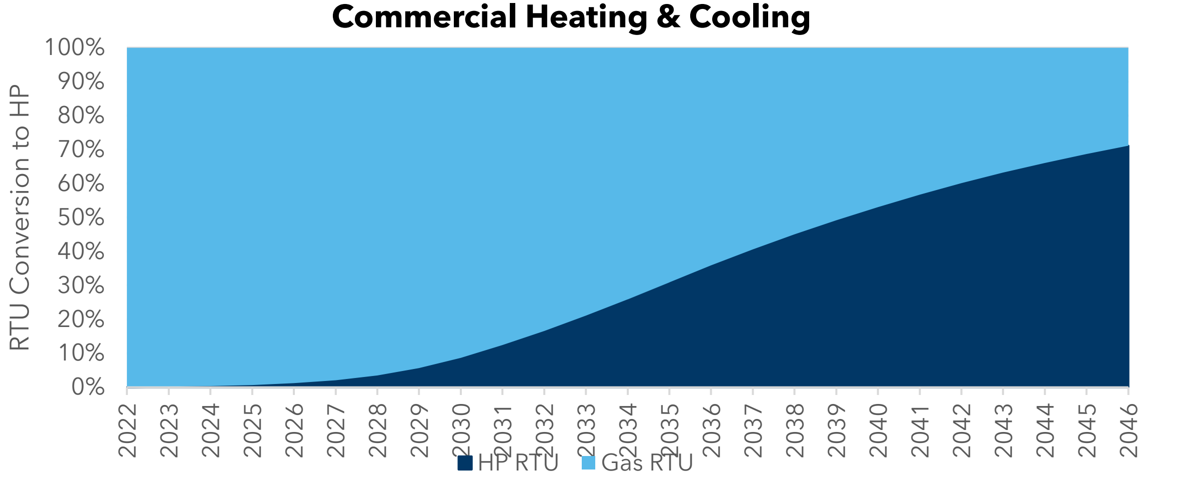
Measure Level Inputs – Building Electrification

Building Electrification assumptions are sourced from recent building electrification study conducted on behalf of PRPA[1]









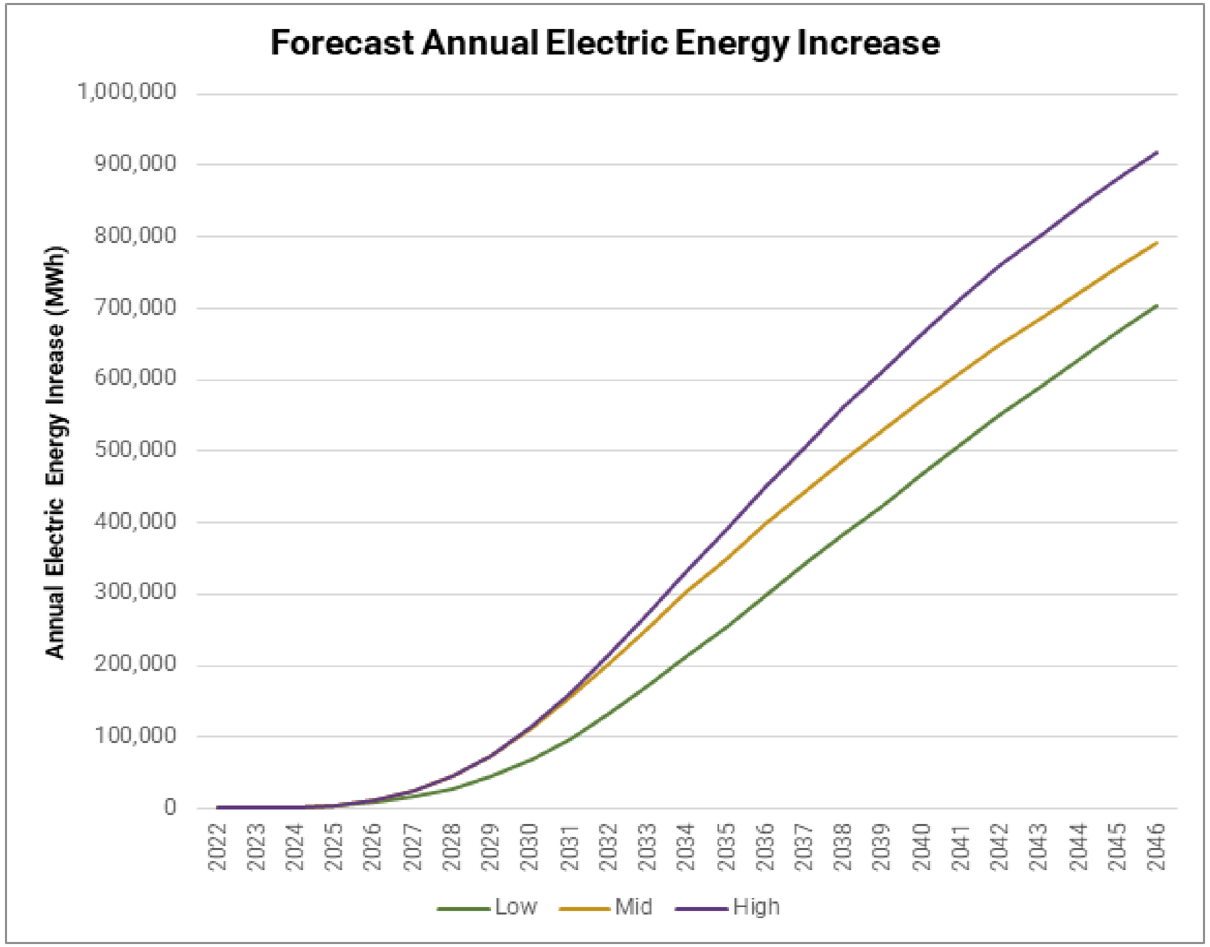
Note 1: Source: Platte River Power Authority Beneficial Buildings Electrification Forecast: FINAL, Submitted by Apex Analytics, LLC on March 12, 2022

Note 2: The forecast labeled *Low* of the study is leveraged to estimate the impact of future electrification on the base load.

Measure Level Inputs – Electrification

All scenarios of the electrification study are leveraged to estimate different trajectories of market sizes.

Segment	Low scenario - 2030 (kWh)	Mid scenario - 2030 (kWh)	High scenario - 2030 (kWh)
Single Family	9,486	9,575	9,580
Multi-Family	6,662	6,668	6,668
Small Commercial	24,882	25,164	25,179
Large Commercial	491,087	496,814	497,120



Note: *Mid* and *High* scenarios' high-level data of the electrification study are leveraged to quantify the market size of building heating and cooling electrical systems that could act as a dispatchable resource during a DR event. The electrification scenarios are matching the DROP scenarios (*Medium* electrification is used as an input for the *Medium* DROP scenario).

Measure level inputs – Program costs

Benefit-cost framework and cost-effectiveness analysis capture the following costs:

- **Program (utility administration & marketing)**
  - DR residential and Small Commercial: $50/participant[1]
  - DR large commercial and industrial: $10/kW[1]
- **Resource acquisition (utility incentives)**
  - Incentives were modelled as a portion of avoided costs. The proportion of benefits is highest in the High scenario, with almost all of the benefits being passed to customers as incentives to get the maximum level of participation. The Solar and Storage modeling incentives for DR participation[2] has been aligned with these assumptions.
- **Other costs needed to enable DR participation in markets (device acquisition and O&M)**

The costs used are based on Dunsky's DR Program Archetype Library - which builds on research and insights from utility-run DR programs.

Note 1: Costs include items such as marketing and administration costs. Do not include costs such as DERMS.
Note 2: *Medium* and *High* scenarios include a DR program incentive of $150 and $216 per kW-year, low scenario considers no DR incentive. After passing a TRC test of the solar and storage systems, the DR benefits associated to storage were proved to be sufficient to support this level of incentive. The TRC test considered the investment and operations costs of solar and storage system, DR program costs as well as capacity, distribution and energy benefits from the distributed resources and DR programs.

Market level inputs – customer segmentation

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Fort Collins is modeled separately given its specific market conditions having a considerable impact on the solar/storage adoption and the DR potential

Platte River

- Fort Collins
- Longmont, Loveland, Estes Park

- Fort Collins is using a different rate structure (Time-of-Use); Longmont, Loveland and Estes Park are using a flat rate structure.
- Fort Collins has observed a faster adoption than the other communities, mainly driven by solar rebates; Longmont, Loveland and Estes Park don't currently have a similar incentive program in place.

Market level inputs – customer segmentation

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Estes Park

Longmont

Loveland

Aggregate

Residential

Multi-Family (MF)
Customers with more than four units within the same structure (apartments, condos)

Single Family (SF)
Customers with fewer than four units in the same structure (detached-single, semi-detached, etc.)

Commercial

Small
Customers with demand <50 kW

Large
Customers with demand >= 50 kW (also includes industrial)

Market level inputs – customer segmentation

Fort Collins

Residential

Multi-Family (MF)
Customers with more than four units within the same structure (apartments, condos)

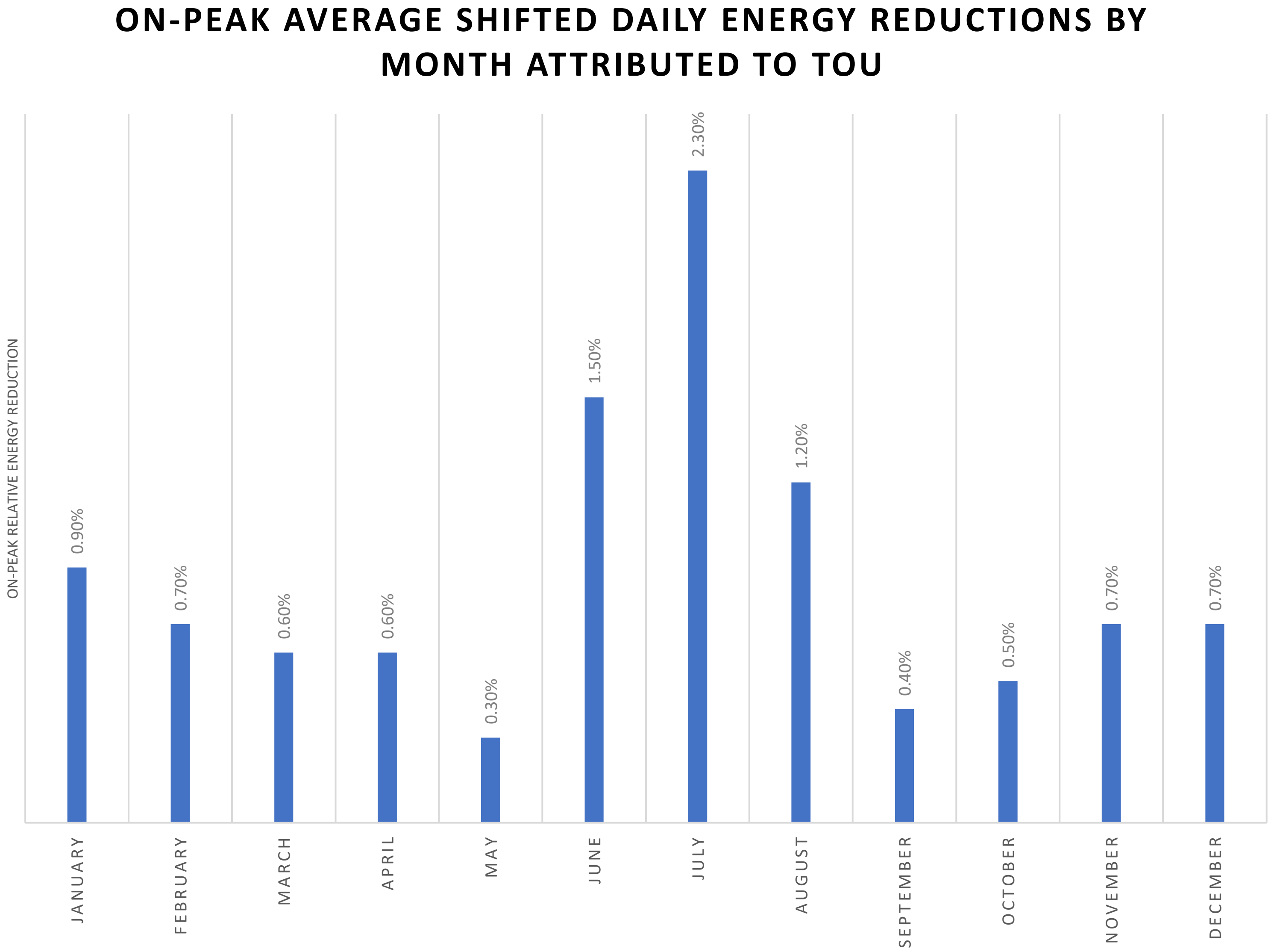
Single Family (SF)
Customers with fewer than four units in the same structure (detached-single, semi-detached, etc.)

Commercial

Small
Customers with demand <50 kW

Large
Customers with demand >= 50 kW (also includes industrial)

Market level inputs – customer segmentation



TOU effects from Fort Collins residential sector were removed from the base load

- To avoid double counting the effects of TOU
- To quantify the effects of a different rate structure

*Energy reduction attributed to conservation was not considered.

*2030 forecast is assumed to be capturing only a portion of the TOU effects observed in the referred study.

Market Level Inputs – Customer Segmentation

Residential | **Commercial**

Parameter	Method
Customer Growth Forecast (Annual %)	Longmont's customer growth rate projections were applied to all communities given it was the only forecast available.
Customer count (2023)	Customer count was provided for each community for 2021 and then extrapolated to 2023 using the customer growth forecast.
Average Electricity Consumption (2023)	1. Average consumption was provided for each community for 2021 and then extrapolated to 2023 using the customer growth forecast. 2. Average consumption of the aggregate was calculated by applying a weighted average based off each community's customer count. 3. Average consumption was finally calibrated to reflect PRPA's load projection provided for 2023.

Note: In case of specific community data unavailability, the most representative dataset to meet the granularity needs is used for all communities.

Market Level Inputs – Customer Segmentation

Residential	
Single-Family (SF)	Multi-Family (MF)

Parameter	Method
Segment split	Relative split obtained from Fort Collins' county tax historical data, which is the historical dataset available with the highest granularity level.
Primary electrical space heating ratio	Relative split obtained by doing a weighted average using Fort Collins customer rate class data and Longmont customer data. Given the high quality and reliability of these two datasets and considering the weight of the two communities in terms of customer base size, their combination yield the most representative data to be used throughout the communities.
Primary electrical water heater ratio	Relative split taken from EAI benchmark study in Colorado.

Note: In case of specific community data unavailability, the most representative dataset to meet the granularity needs is used for all communities.

Market Level Inputs – Customer Segmentation

Commercial		
Small		Large

Parameter	Method
Segment split	Relative split obtained from Fort Collins' historical data up to 2022 based on the rate class customer count. The Fort Collins' datasets were the only ones with sufficient market insights.
Primary electrical space heating ratio	Relative split taken from EAI benchmark study in Colorado.
Primary electrical water heater ratio	Relative split taken from EAI benchmark study in Colorado.

Note: In case of specific community data unavailability, the most representative dataset to meet the granularity needs is used for all communities.

Market Level Inputs – Customer Segmentation

Fort Collins

Sector	Segment	2023 customer count	Customer growth forecast	2023 average consumption (kWh)
Residential	Single Family	49,105	1.09%	8,763
	Multi-Family	21,344	1.09%	6,323
Commercial	Small commercial	7,304	0.29%	27,173
	Large commercial	1,455	0.26%	538,220

Market Level Inputs – Customer Segmentation

Longmont, Loveland & Estes Park

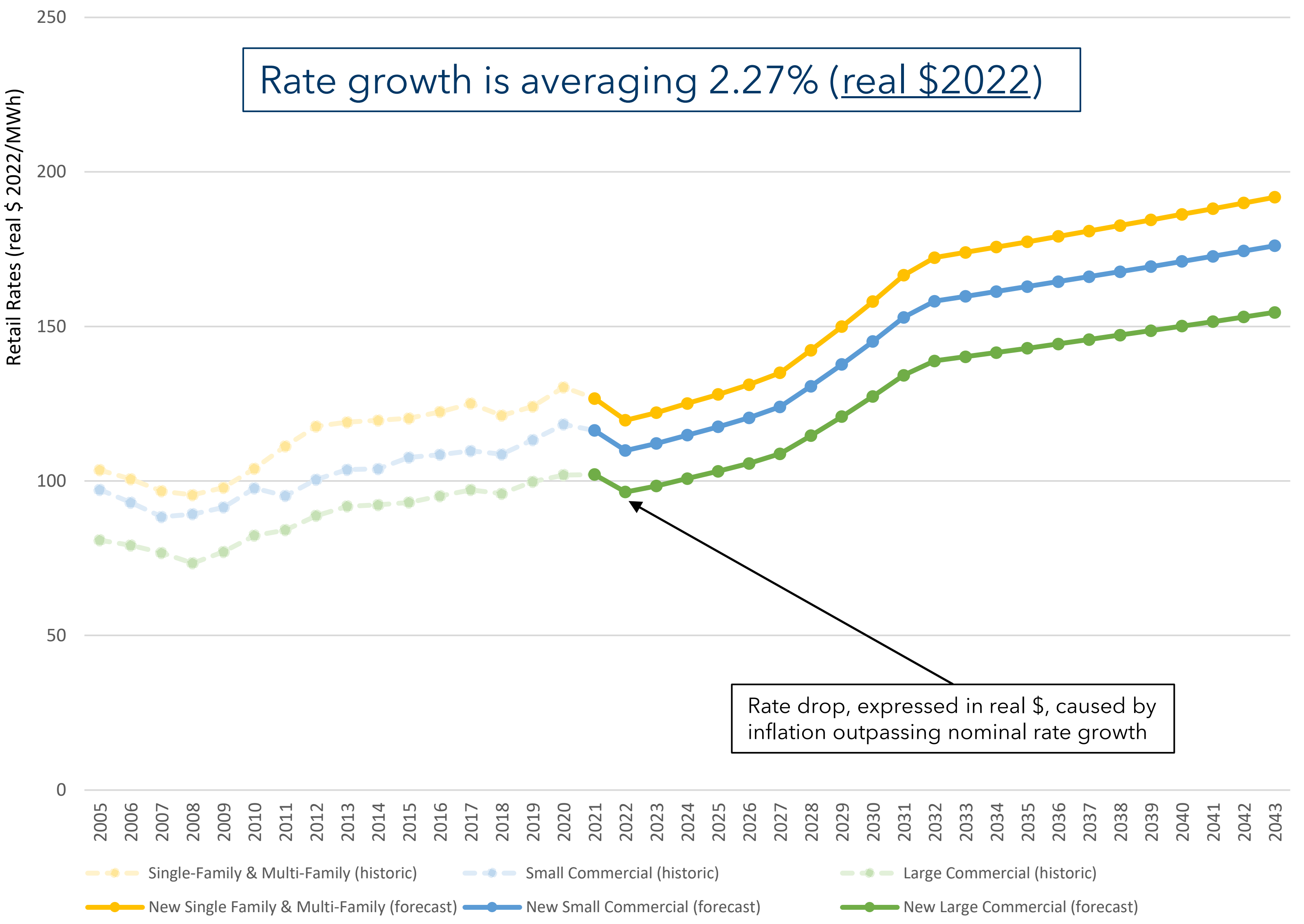
Sector	Segment	2023 customer count	Customer growth forecast	2023 average consumption (kWh)
Residential	Single Family	58,297	1.09%	9,114
	Multi-Family	25,339	1.09%	6,576
Commercial	Small commercial	8,560	0.29%	23,767
	Large commercial	1,705	0.26%	471,733

Market Level Inputs – Retail Rates

Parameter	Method
Retail rates (historical)	Fort Collins' average rate data by segment is used as the basis for the aggregate given data quality and availability.
Rate growth	Rate growth is estimated using scheduled rate increases up to 2032. Rate growth is estimated using 1% rate increase, after adjusting for inflation, post 2033.
Economics	Rates have been converted to real 2022 dollars.

Input Data

Market level inputs – retail rates



Time of Use Rate structure (Fort Collins' current rate)

- On-peak to off-peak ratio of ~3.5:1
- Weekdays only
- Summer
  - May-September
  - 14:00-19:00
- Non-Summer (Winter)
  - October-April
  - 17:00-21:00

New Time Varying Rate structure

- On-peak to off-peak ratio of 3.3:1
- Weekdays only
- Yearlong
  - 17:00-21:00

Distributed Solar and Storage Adoption

Distributed Solar and Storage Adoption

Methodological Summary

Solar PV: Technical Potential

Technical potential is defined for each modeled customer segment based on:

Input	Description	Data Inputs / Assumptions
Building Stock	Portion of customer sites technically capable of technology deployment based on building stock characteristics (*e.g.*, rooftop space and tilt, shading, floor area, etc.).	• Customer segmentation data (• Public GIS data (e.g., Google's Project Sunroof) • NREL building characteristics (Mountain census subdivision, Midsize/Small City)
System Size	Archetypal system size by segment based on electricity consumption, load profile, historically reported system sizes and other constraints (e.g., net metering or interconnection requirements).	• Lesser of maximum available rooftop space or maximum system size as constrained by annual energy consumption (*i.e.*, systems are sized to not exceed annual energy consumption).
Generation Profile	Annual generation estimates based on solar irradiation data and/or reported system performance.	• PVWatts • Reported system performance data

Technical inputs Applied to Solar PV

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Solar systems were sized to meet total annual load, considering a capacity factor of 16.09%

Segment	System size (kWac)
Residential (Fort Collins)	6.22
Small Commercial (Fort Collins)	19.82
Large Commercial (Fort Collins)	381.82
Residential (Rest of PRPA)	6.47
Small Commercial (Rest of PRPA)	16.86
Large Commercial (Rest of PRPA)	334.65

Technical Constraints Applied to Solar PV

Technical Constraints

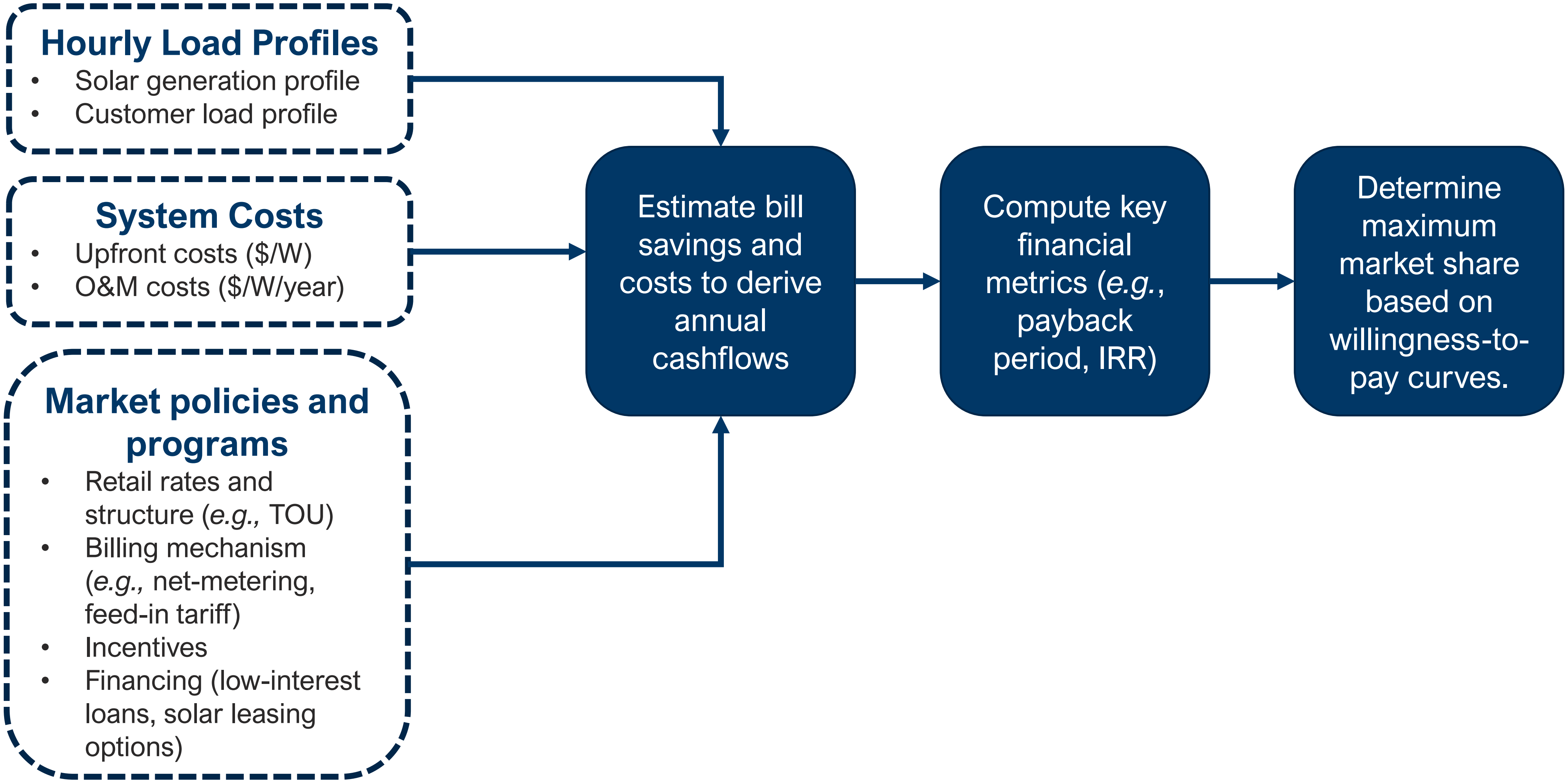
- The market size for BTM solar considered the roof suitability and typical expected system size by sector.

Factor	Value	Source
Roof Suitability	79%	NREL, Rooftop Solar Photovoltaic Technical Potential in the United States: A Detailed Assessment
Ability of PV to meet Estimated Consumption (Residential)	82%	Historic Interconnection Data from PRPA
Ability of PV to meet Estimated Consumption (Commercial)	52%	NREL, Rooftop Solar Photovoltaic Technical Potential in the United States: A Detailed Assessment

Treatment of new construction

- The annual increase in customer energy which can be met by suitable rooftops and installed PV determines the figures for New Construction.
- As per the scenarios, it is assumed that a certain percentage of these new constructions will incorporate solar PV.

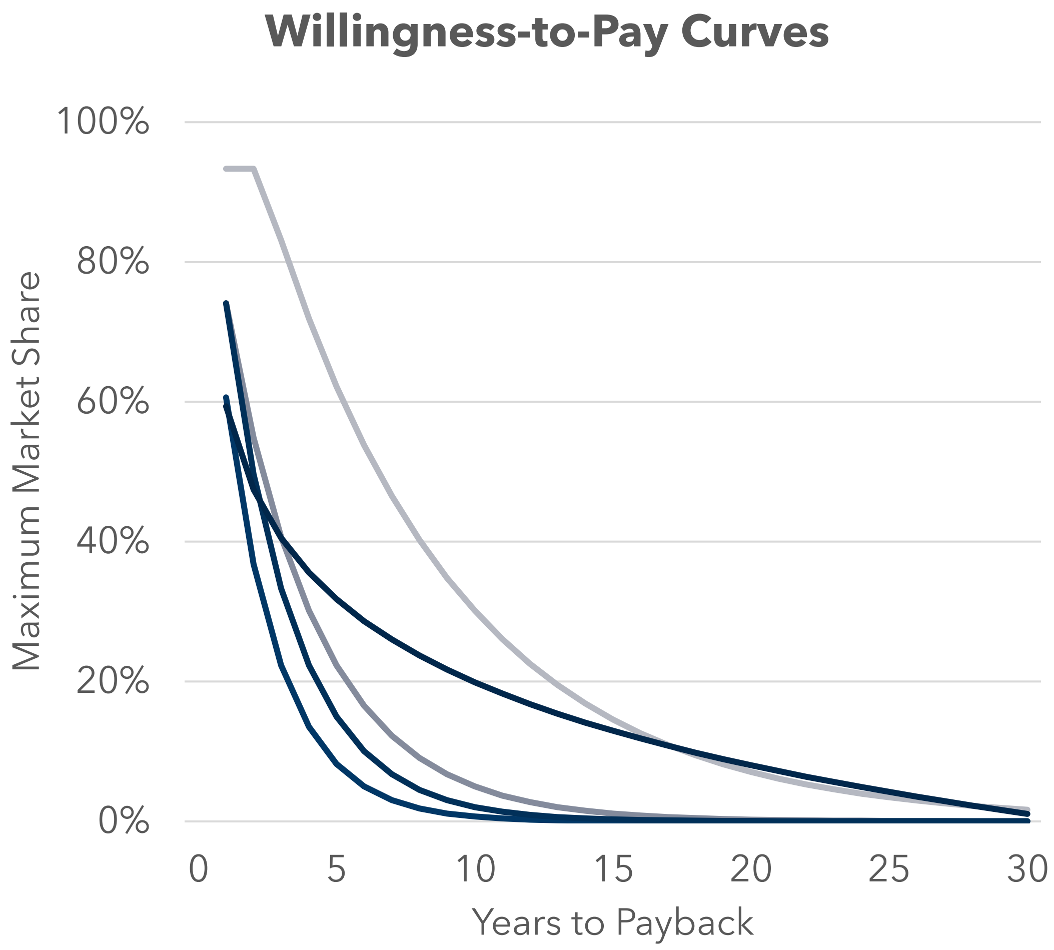
Solar PV: Customer Economics



Note: The adoption is calculated based on the cost effectiveness from the customer perspective.

Solar PV: Maximum Market Share

- **Maximum market share is determined for each customer segment based on willingness-to-pay curves.**
  - Maximum market share is applied to technical potential
  - Location on curve is determined by estimated customer economics (e.g., years to payback, IRR)
- **10+ curves developed based on empirical data from mature markets for different customer segments (e.g., residential, commercial) and customized to each market through the calibration process.**

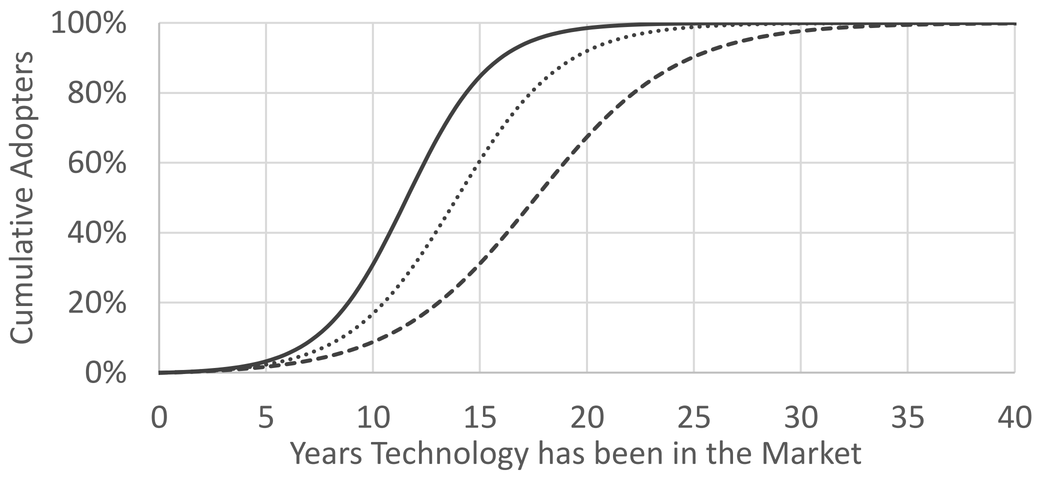


Willingness-to-pay curves are based upon maximum market share functions originally described in the documentation for NREL's Distributed Generation Market Demand Model (dGen).

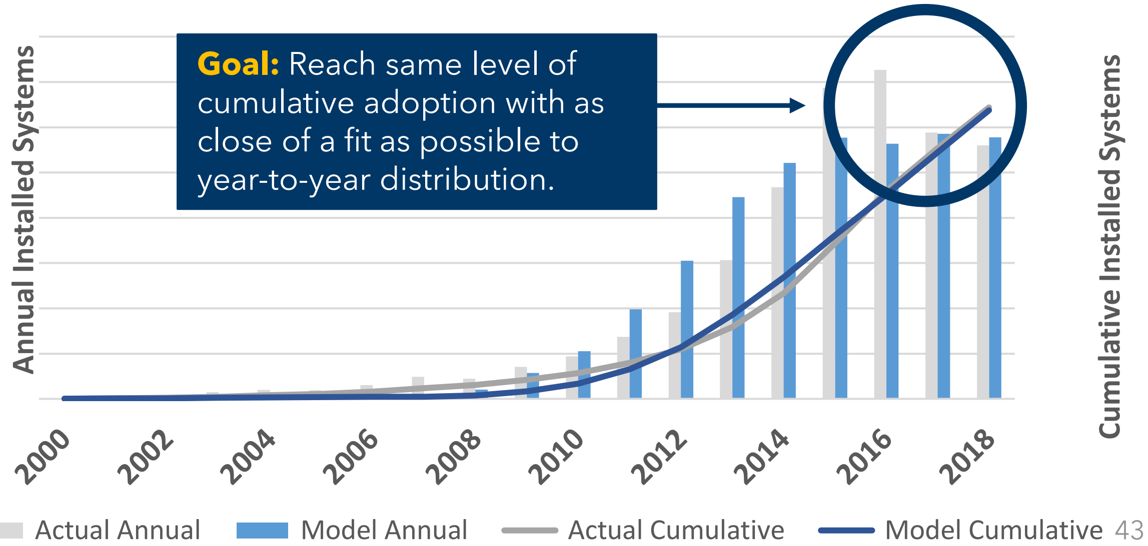
Solar PV: Market Adoption

- **Bass diffusion curves define achievable market size given the technology and market maturity.**
- **Historically observed adoption is used to calibrate diffusion curve parameters to capture local barriers and market characteristics**
- **The model is calibrated to moving-average cumulative adoption to account for project processing timelines in historic data.**

Sample Bass Diffusion Curves

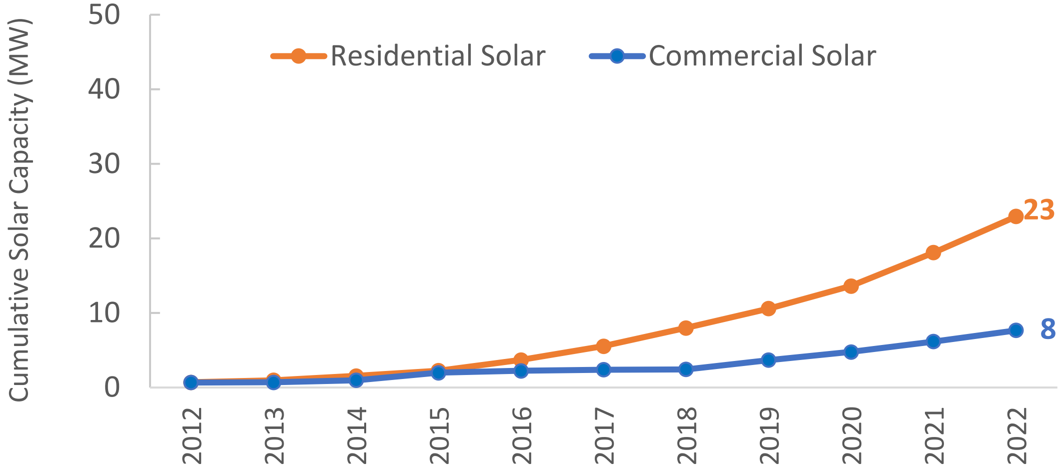


Sample Model Calibration

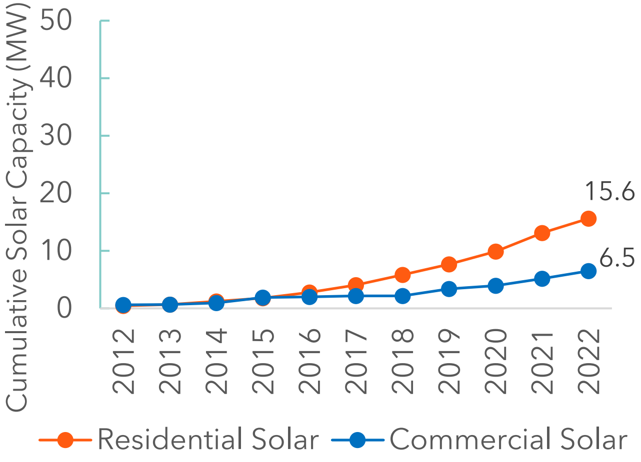


Current Market

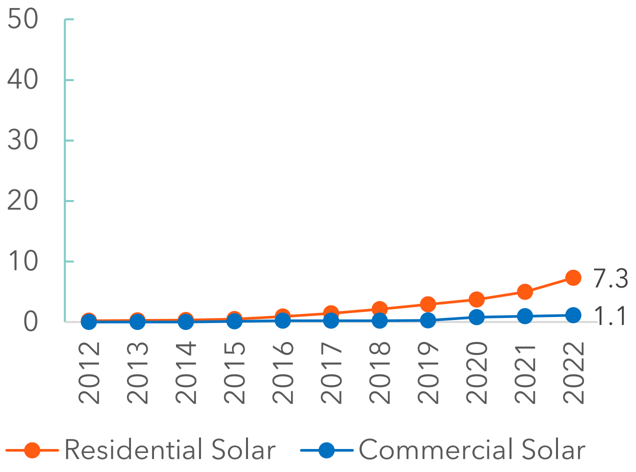
Historic Overall Solar Adoption



Historic Solar Adoption - Fort Collins



Historic Solar Adoption - Rest of PRPA



Of the 31 MW solar PV of the total BTM solar PV capacity, **75% is installed by residential customers**. Additionally, it is worth noting that in 2022, approximately **0.9 MW of residential storage** was integrated with solar systems.

Municipal programs, federal ITC, and net metering policies have all contributed significantly to the expansion of the distributed solar PV market.

Several factors may affect the growth of distributed energy resources in PRPA, such as:

- Extension or phase out of key incentives:
    1. Investment Tax Credit for Solar and Storage
    2. Municipal incentives for distributed solar PV
- Solar mandates on new construction

Based on the above factors, **four possible scenarios forecast the extent of DER adoption** in PRPA.

Note: DG and DS load shown above and in subsequent slides are at the customer end-use level and therefore have not been grossed up to account for transmission and distribution losses.

Solar + Storage Pairing

The study will assess standalone solar, standalone storage and paired systems.

- For solar + storage pairing, the modeling approach assumes a portion of the standalone solar market will be storage-paired based on relative economics of the combined system and technology diffusion theory.
- If and when the addition of storage to a solar PV installation increases the expected economic payback of the system, storage will increase market demand for solar.

The model accounts for the following impacts storage may have on solar customer economics:

Incremental benefits[1]

- Renewable self-supply
  - The net exports from the solar are assumed to be fed into the storage system.
- Bill management (demand charges, energy arbitrage)
  - The storage charges during low-cost off-peak hours and discharges during peak hours to capture the arbitrage value. For demand charge management, the monthly reduction in the customer's peak demand due to the storage system shaving is recorded.
- Demand response revenues
  - Top net peak days with high likelihood of DR calls are identified. The storage is assumed to discharge during those events; demand charge benefits are considered to be foregone during a DR call.

Incremental costs

- Upfront capital costs for battery
- Ongoing O&M costs

1: Appropriate considerations are made regarding the round-trip efficiency losses, storage capacity, charging power rating, etc.

Market Assumptions for Solar + Energy Storage

Low Growth Scenario

- Based on historical adoption and relative cost-effectiveness, **10% of the solar market is solar paired with energy storage (ES),** whereas the **remaining 90% is standalone solar**.[1]

Medium and High Growth Scenarios

- **Medium and High** paired solar is showing preferable economics to standalone solar in the early years, hence the market share of **paired solar is ramped to 30%**.

Future NEM Scenario

- Paired solar is showing better customer economics to standalone solar, so the market is modeled as a **50-50 split.**

All Scenarios

- For **new construction** mandates, **solar paired with ES** is assumed to increase to take **50%** of the market, the other **50% being with standalone solar**

1. Galen Berbose et al, Lawrence Berkeley National Laboratory, Tracking the Sun: Pricing and Design Trends for Distributed Photovoltaic Systems in the United States, 2022 Edition.

Technical Constraints Applied to Energy Storage

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Paired Solar + ES:

- Residential systems are sized to leverage internal solar consumption, and for resiliency, resulting in residential storage to be sized at 90% of the solar PV technical capacity.
- Commercial systems are sized considering demand charge reduction opportunities to10% of the solar PV technical capacity.
- We assume that approximately 20% of the residential storage capacity will be allocated towards enhancing resiliency, whereas the remaining can be used for energy arbitrage. The resiliency allocation is greater during peak hours due to an overall greater energy use.

Paired Solar + ES:

- Due to to limited historical adoption, the standalone storage market for the initial years has been adjusted as a fraction of the solar paired storage market. The adjustment ratio is derived from Paired Storage to Standalone Storage ratio of California's energy storage market, where Residential sector sees a 0.28% of total paired storage market to be standalone storage while commercial sector standalone storage market is 19.1% of paired storage market.

Scenario Parameters

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The adoption of solar PV will be assessed under three scenarios that vary policy and program levers and solar system costs as described below.

<table>
<tr><th>Parameter</th><th>Low</th><th>Medium</th><th>Medium Future NEM</th><th>High</th></tr>
<tr><td colspan="5">Policy/Program Interventions</td></tr>
<tr><td>Solar and Storage Incentives</td><td>No municipal incentives. Federal ITC benefits phased out prematurely by 2028</td><td colspan="2">Current municipal incentives for Fort Collins phased out by 2028. Federal ITC benefits as phased out as planned by 2035</td><td>Current municipal incentives for Fort Collins also applied to rest of PRPA, phased out by 2028. Federal ITC benefits extended beyond currently planned to 2040</td></tr>
<tr><td>Codes and Standards</td><td>No mandates</td><td colspan="2">All newly constructed buildings must have solar beginning in 2030. A gradual increment to 100% is assumed between 2024 and 2030</td><td>All newly constructed buildings must have solar beginning in 2024 (Commercial) and 2027 (Residential)</td></tr>
<tr><td>Export Compensation</td><td>Current net metering arrangements (Fort Collins), Existing Flat rates (Rest of PRPA)</td><td>Current net metering rates with peak hours applied to system net peak under TVR. Non-TVR export rates 5% less than retail rates</td><td>Export rates aligned with Future NEM, with lower exported energy rate based on forecasted wholesale market rates.</td><td>Current net metering rates with peak hours applied to system net peak under TVR. Non-TVR export rates 5% less than retail rates</td></tr>
<tr><td>DR Programs</td><td>None</td><td>$150/kW-yr</td><td>$150/kW-yr</td><td>216/kW-yr</td></tr>
<tr><td colspan="5">Technology Uncertainties</td></tr>
<tr><td>Solar Costs</td><td>Limited cost declines (historic PRPA cost + future NREL decline)</td><td colspan="2">Moderate cost declines (historic PRPA cost + future NREL decline)</td><td>Aggressive cost declines (historic PRPA cost + future NREL decline)</td></tr>
<tr><td>Storage Costs</td><td>Limited cost declines (NREL)</td><td colspan="2">Moderate cost declines (NREL)</td><td>Aggressive cost declines (NREL)</td></tr>
<tr><td colspan="5">Market Factors</td></tr>
<tr><td>Electricity Rates</td><td colspan="4">Aligned with study-wide rate assumptions described in demand response scenario</td></tr>
</table>

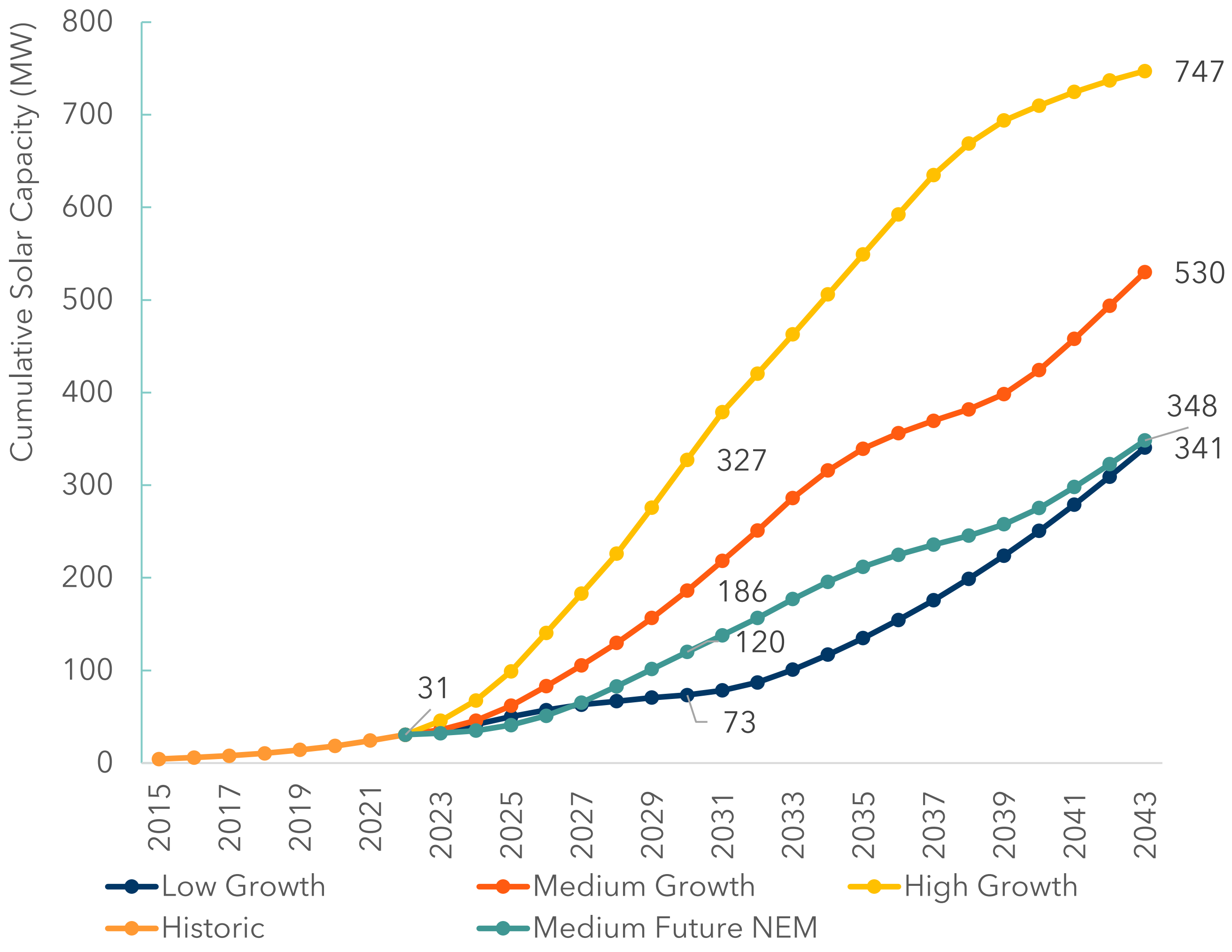
Note 1: For solar incentives, the study will assume customers receiving incentives assign any produced renewable energy credits (RECs) to the incentive provider for 20 years. Once incentives are no longer available, customers may receive the value for these RECs.
Note 2: Solar and storage incentives are considered financial support by the municipalities to cover the acquisition and installation of the system. On top of that, DR program incentives are assumed to be financed by the utility to enroll participants for operational access to their system for modulation during peak periods.
Note 3: The study is relying on a range of federal, state and local financial interventions observed in the jurisdiction. Cost-effectiveness of these interventions from the program administrator perspective is not covered in the study's scope.
Note 4: Source for NREL cost decline: https://data.openei.org/files/5865/2023_v2_Workbook_07_20_23.xlsx

Distributed Solar and Storage Adoption

Total Distributed Solar PV Forecast

Distributed Solar PV Forecast

Anticipated Distributed Solar Adoption (Standalone Solar & Solar + ES)



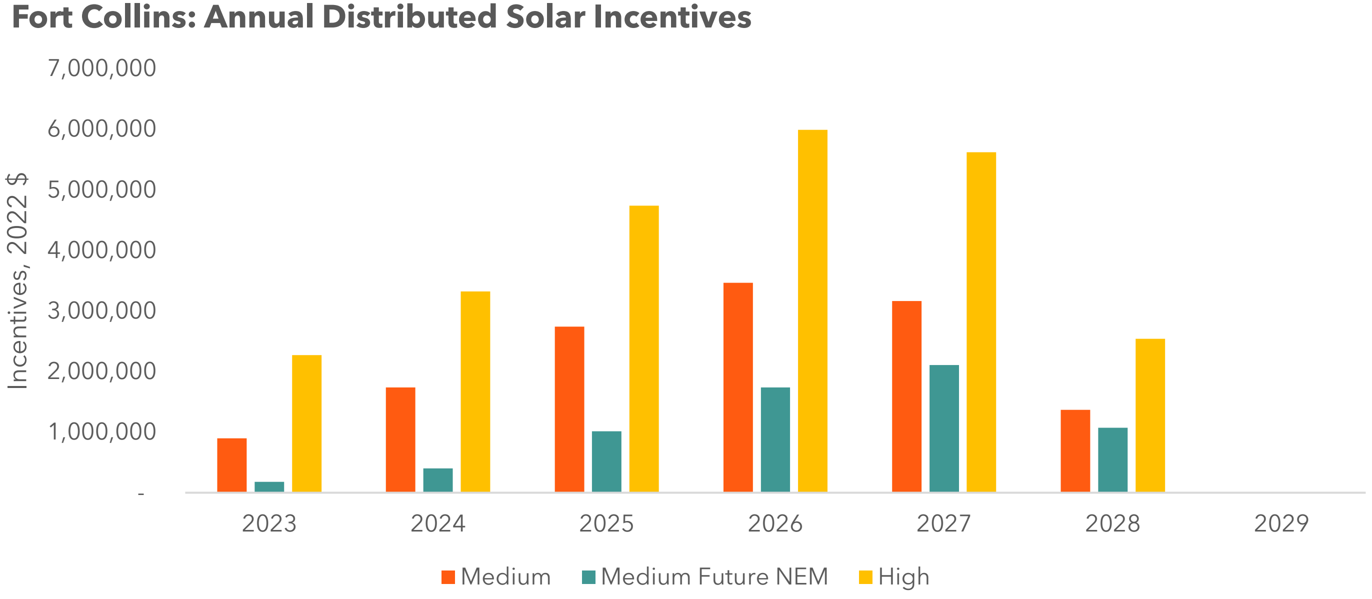
High Growth Scenario: Characterized by strong policy support in the form of municipal incentives and extended federal incentives and solar mandates on new construction starting in 2024 (Commercial) and 2027 (Residential). The high scenario could double the market size within the initial years.

Medium Growth Scenario: Characterized by modest policy support in the form of current municipal and federal incentives and solar mandates on new construction starting in 2030. The mid scenario could increase the market size by 55% with a significant adoption increase in the initial years.

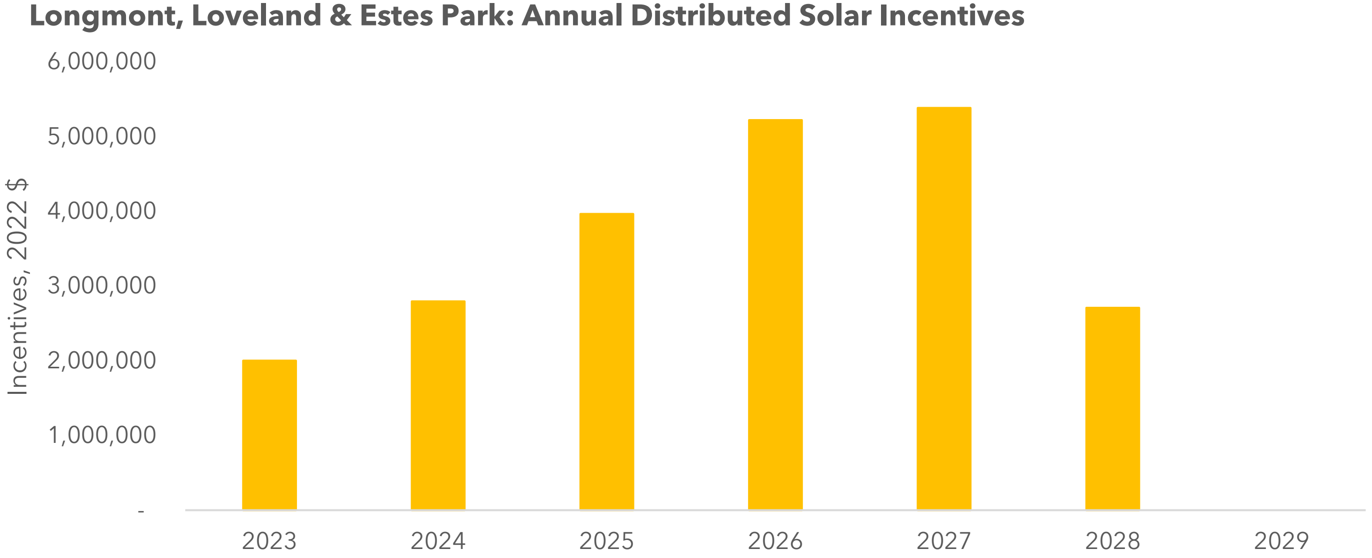
Medium Growth Future NEM Scenario: Characterized by the same policy and technology support as Medium Growth Scenario, but with lower exported energy rate based on forecasted wholesale market rates. It results in similar solar adoption number to Low scenario, supported by DR incentive, but provides more system benefits by reducing exported energy due to higher proportion of solar paired with storage.

Low Growth Scenario: Characterized by phased-out incentives, the absence of DR revenues for battery storage, and the absence of solar mandates for new construction, which may restrict its market potential. Limited increase in adoption in the early years.

Distributed Solar PV Incentive Forecast



- Annual Incentives are based on current municipal incentives for Fort Collins phased out by 2028.
- For **Medium**, **Medium Future-NEM**, and **High** scenario, Residential incentive is $200/kW, and Commercial incentives are $500/kW.
- A ramp down is applied to 2028 in order to gradually phase out the incentive.
- Cumulative incentives top at **~$24.5M for the High** scenario, **~ $13.5M for the Medium** and **~ $6.5M for the Medium Future-NEM.**



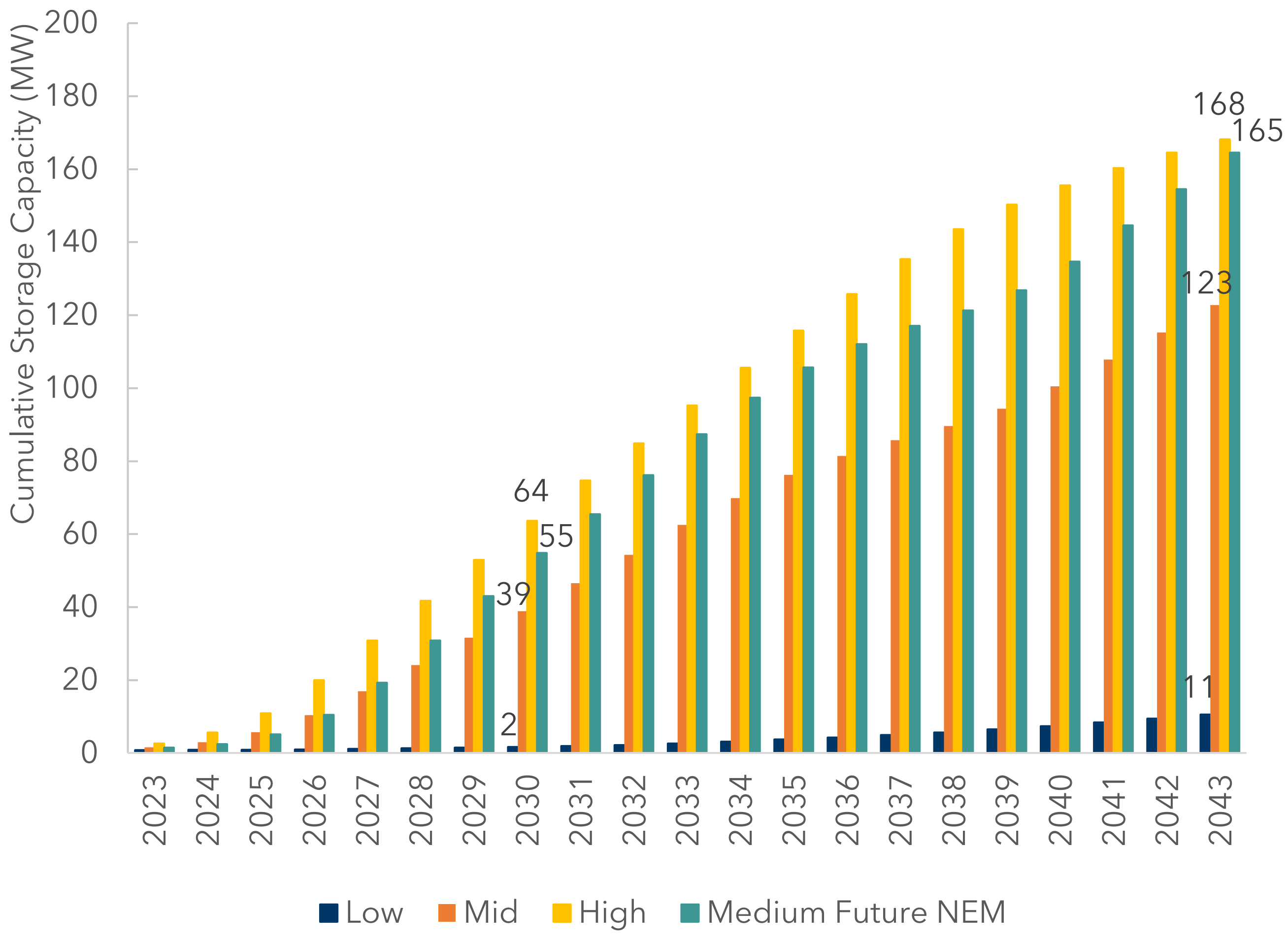
- Only the **High** scenario entails storage incentives for Longmont, Loveland & Estes Park.
- The amount of the incentives are the same as Fort Collins.
- Cumulative incentives top at ~$22M.

Distributed Solar and Storage Adoption

Total Distributed Storage Forecast

Distributed Storage Forecast

Anticipated Overall Storage Adoption (Standalone Storage & Solar + ES)



High Growth Scenario: Characterized by strong policy support in the form of extended federal incentives and strong DR incentives, along with an expansion in the solar paired storage market. Leading to a market that is 15 times larger than the low scenario.

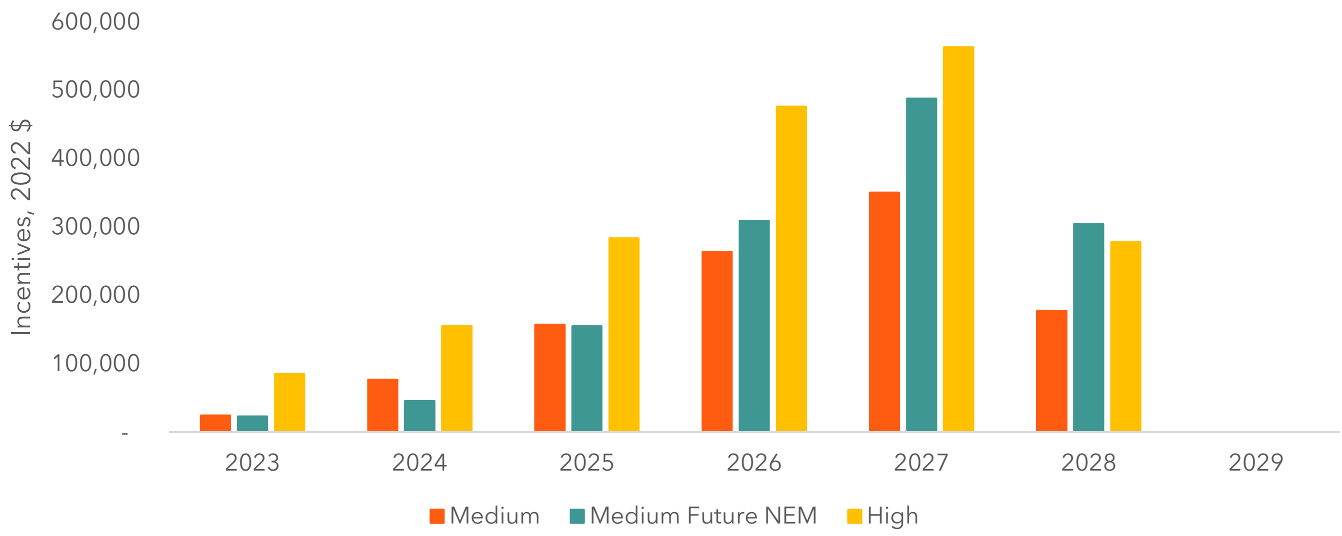
Medium Growth Scenario: Characterized by modest policy support in the form of current federal incentives and moderate DR incentives, along with an expansion in the solar paired storage market. Leading to a market that is 11 times larger than the low scenario.

Medium Future NEM Growth Scenario: Characterized by modest policy support in the form of current federal incentives and moderate DR incentives. As standalone solar market stagnates with reduced net-metering rates, the solar paired storage market quickly ramps up given additional incentives/revenue streams, and expansion in market

Low Growth Scenario: The early phase-out of ITC and limited revenue opportunity could slow Distributed Storage growth in the initial study period. However, reduced technology costs will continue to propel it beyond 2030.

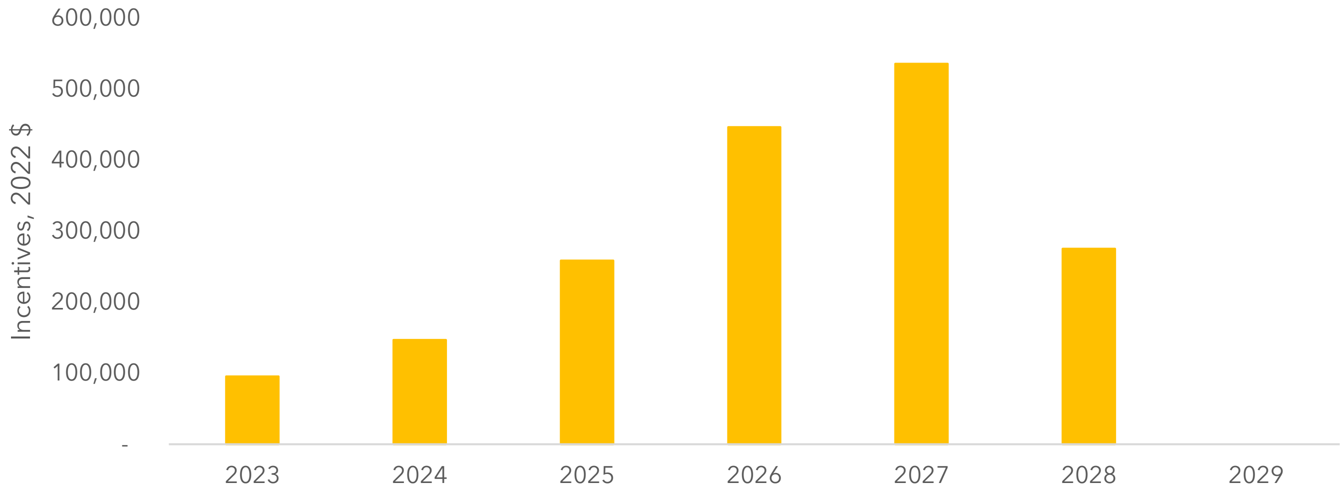
Distributed Storage Incentive Forecast

Fort Collins: Annual Distributed Storage Incentives



- Annual Incentives are based on current municipal incentives for Fort Collins phased out by 2028.
- For **Medium**, **Medium Future-NEM**, and **High** scenario, Small Commercial customers receive an incentive of $100/kW.
- A ramp down is applied to 2028 in order to gradually phase out the incentive.
- Cumulative incentives top at **~ $1.8M for the High** scenario, **~ $1.3M for Medium Future-NEM** and **~ $1M for Medium**.

Longmont, Loveland & Estes Park: Annual Distributed Storage Incentives



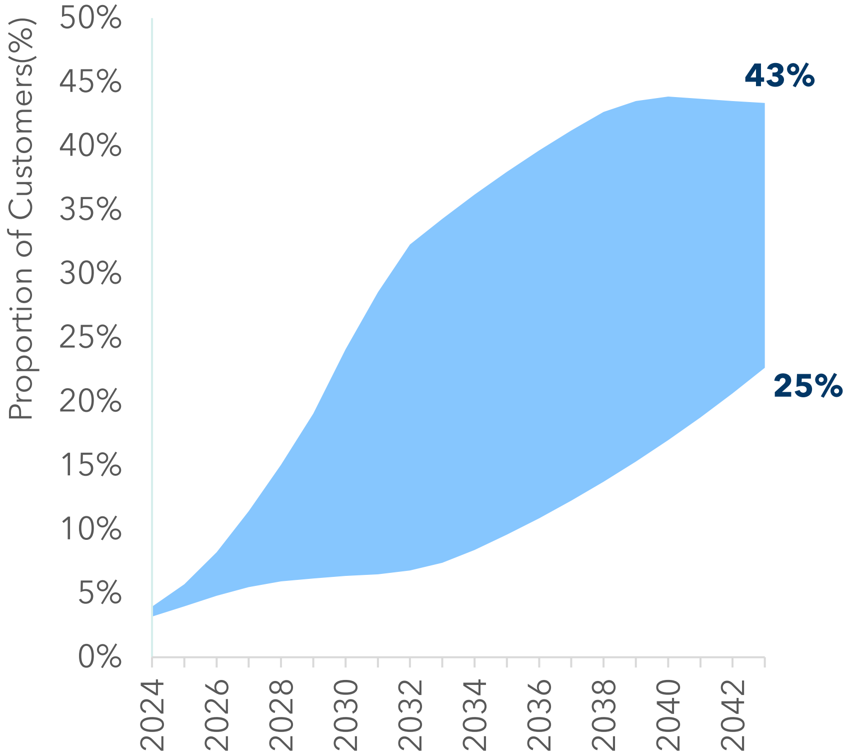
- Only the **High** scenario entails storage incentives for Longmont, Loveland & Estes Park.
- The amount of the incentives are the same as Fort Collins.
- Cumulative incentives top at ~$1.75M.

Distributed Solar and Storage Adoption

Distributed Standalone Solar PV Forecast

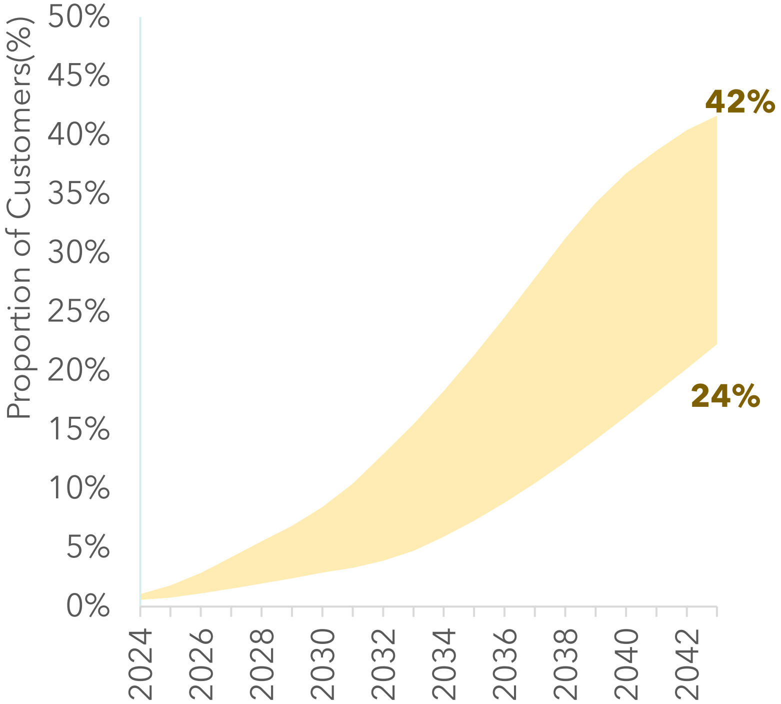
Standalone Solar Adoption as % of Customers

Residential



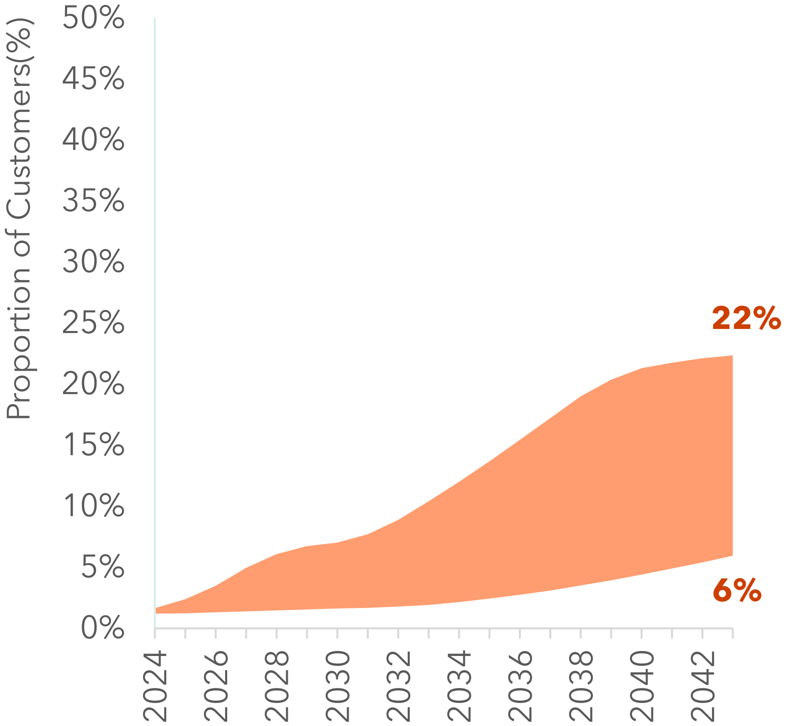
All residential properties that utilize solar PV are assumed to be single-family homes.

Small Commerical



By 2043, around 24% to 42% of all small commercial customers will have standalone PV systems installed.

Large Commercial



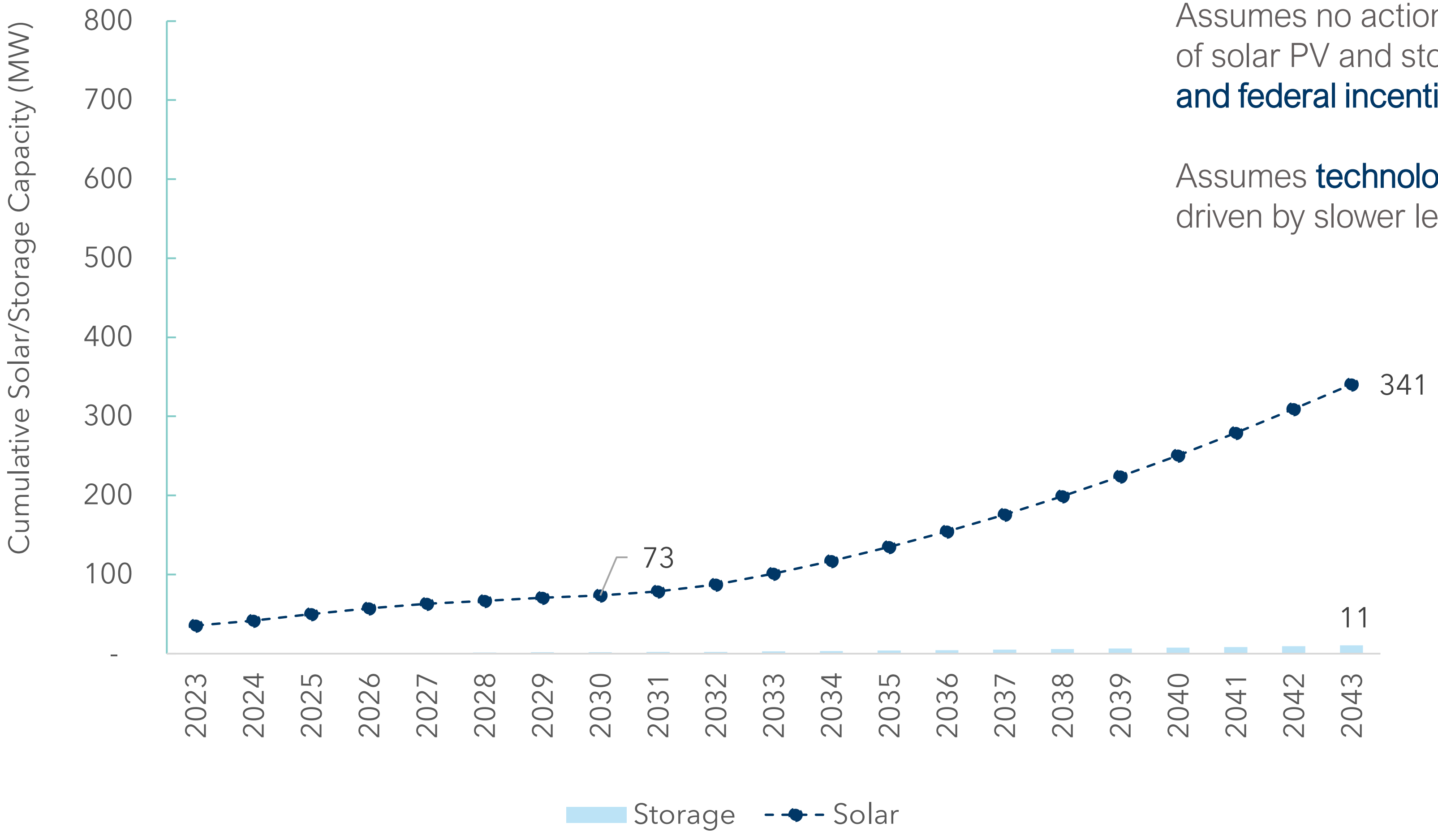
By 2043, around 6% to 22% of all large commercial customers will have standalone PV systems installed.

Distributed Solar and Storage Adoption

Scenario Results: Low Growth

Low Growth Scenario: Snapshot

Anticipated Distributed Solar and Storage Adoption (Low)

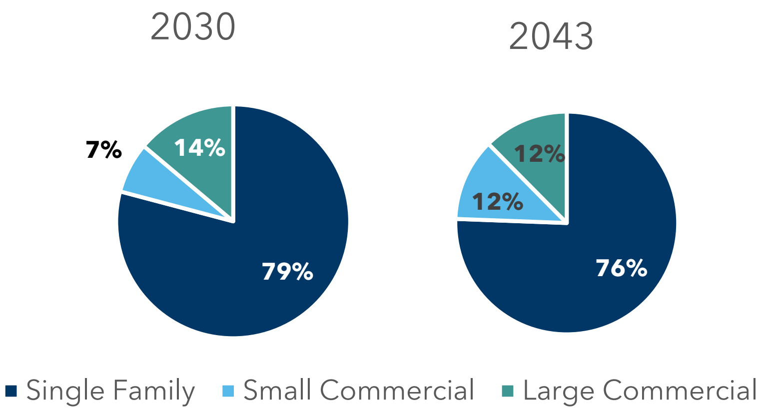


No intervention of policy or programs

Assumes no actions are taken to accelerate or increase the adoption of solar PV and storage in PRPA communities and existing municipal and federal incentives are withdrawn from the market

Assumes technology improvements are slower than anticipated - driven by slower learning rates due to limited technology deployment

Total Solar Potential by Market



Standalone Solar: Low Growth Scenario

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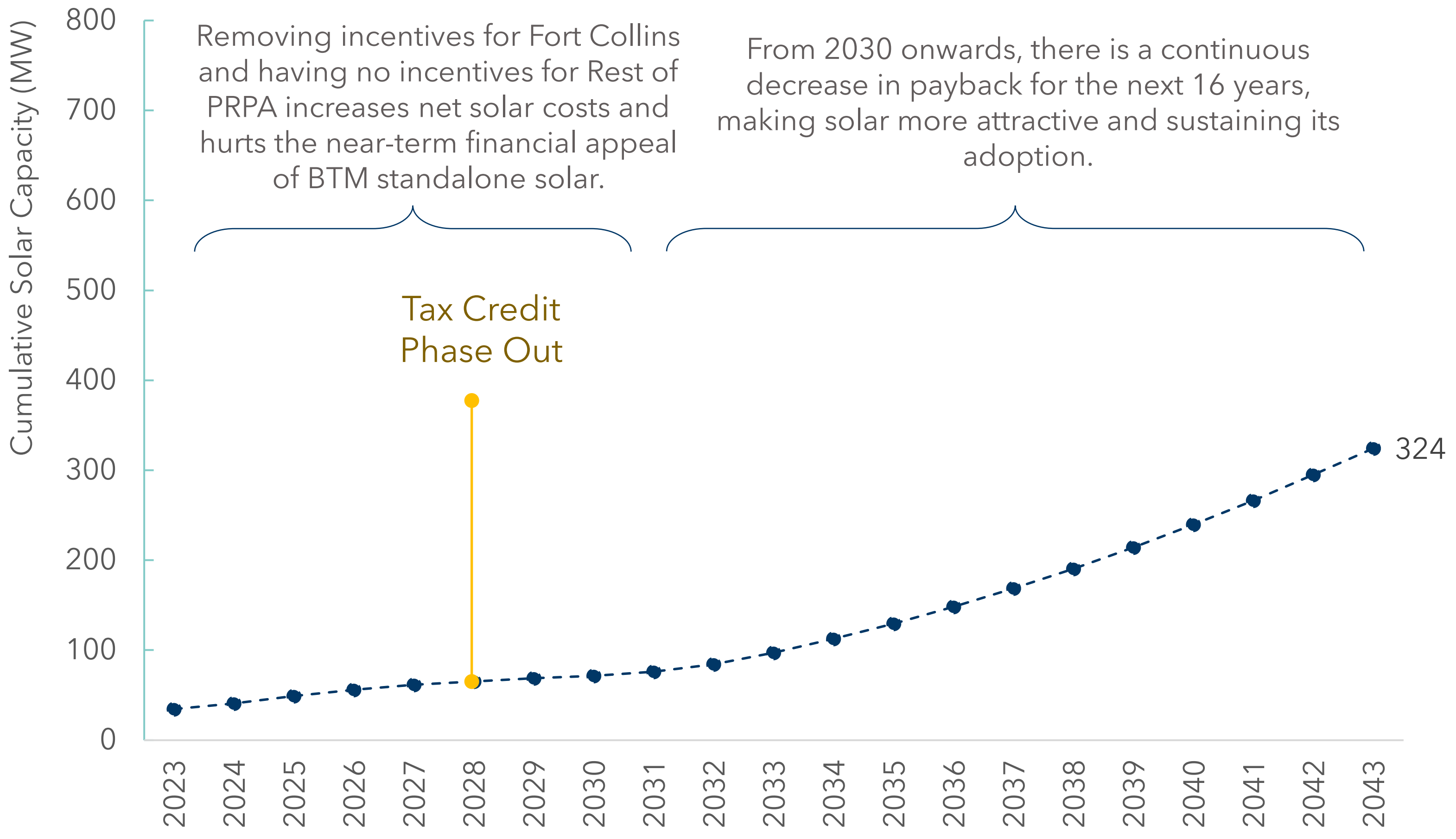
Anticipated Standalone Solar Adoption (Low)

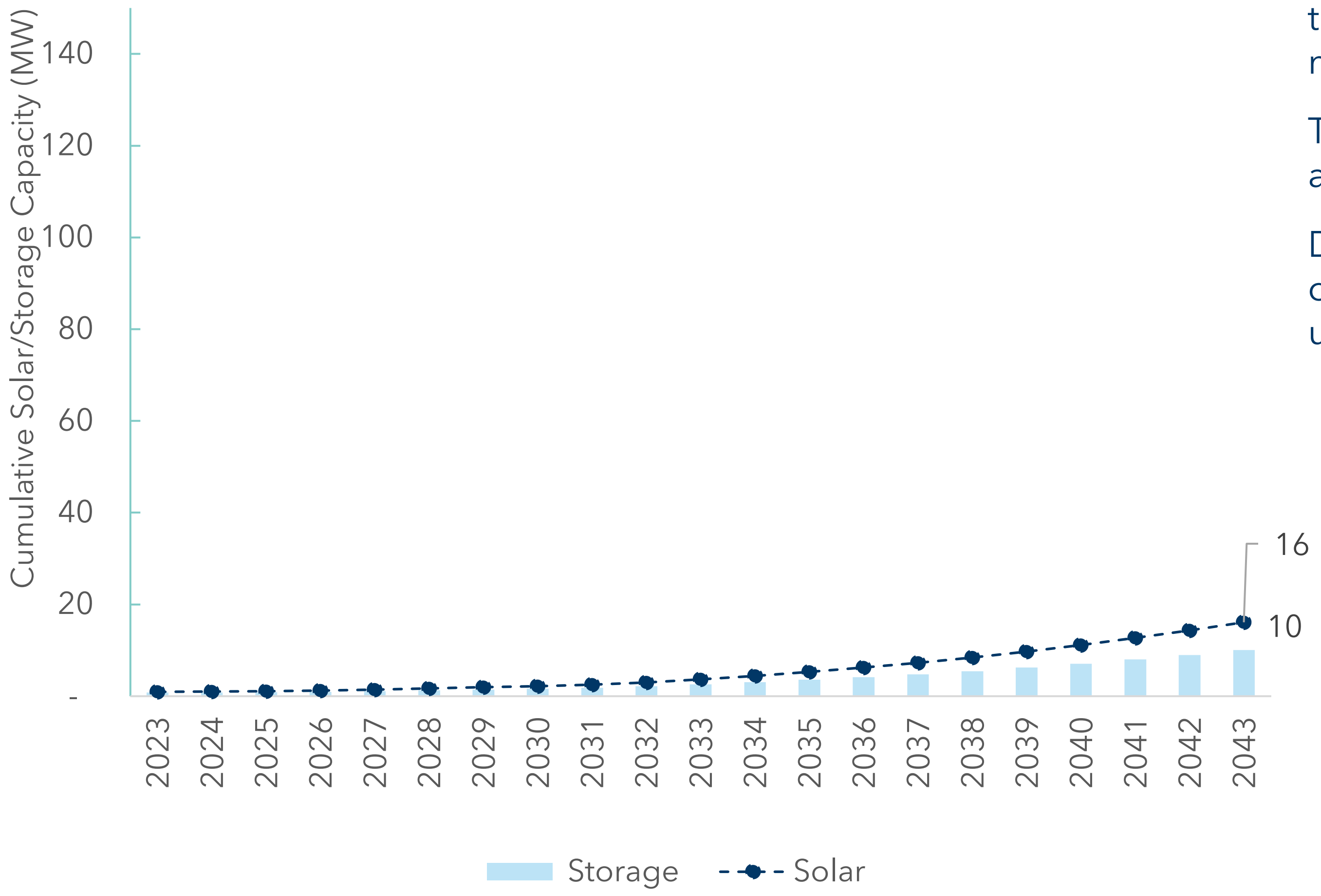


As paybacks stagnate or increase, adoption falls to near zero in existing buildings, assuming that customers who accept higher paybacks have already adopted systems.

The absence of a solar mandate for new constructions narrows the potential market for solar PV.

Paired Solar + Storage: Low Growth Scenario

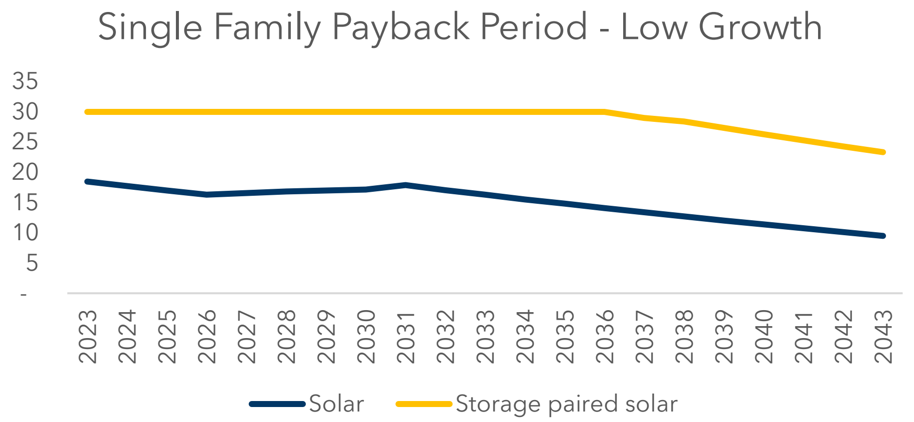
Anticipated Distributed Solar + ES Adoption (Low)



In the absence of favourable storage incentives under the Low Growth scenario and no mandates on new construction, the uptake of storage-paired solar is limited, especially in the next decade.

The residential segment accounts for 2/3 of the solar + ES adoption forecast in 2043.

Driven by time-of-use benefits, storage uptake is mostly concentrated in the residential sector, leading to similar MW uptake for both technologies.



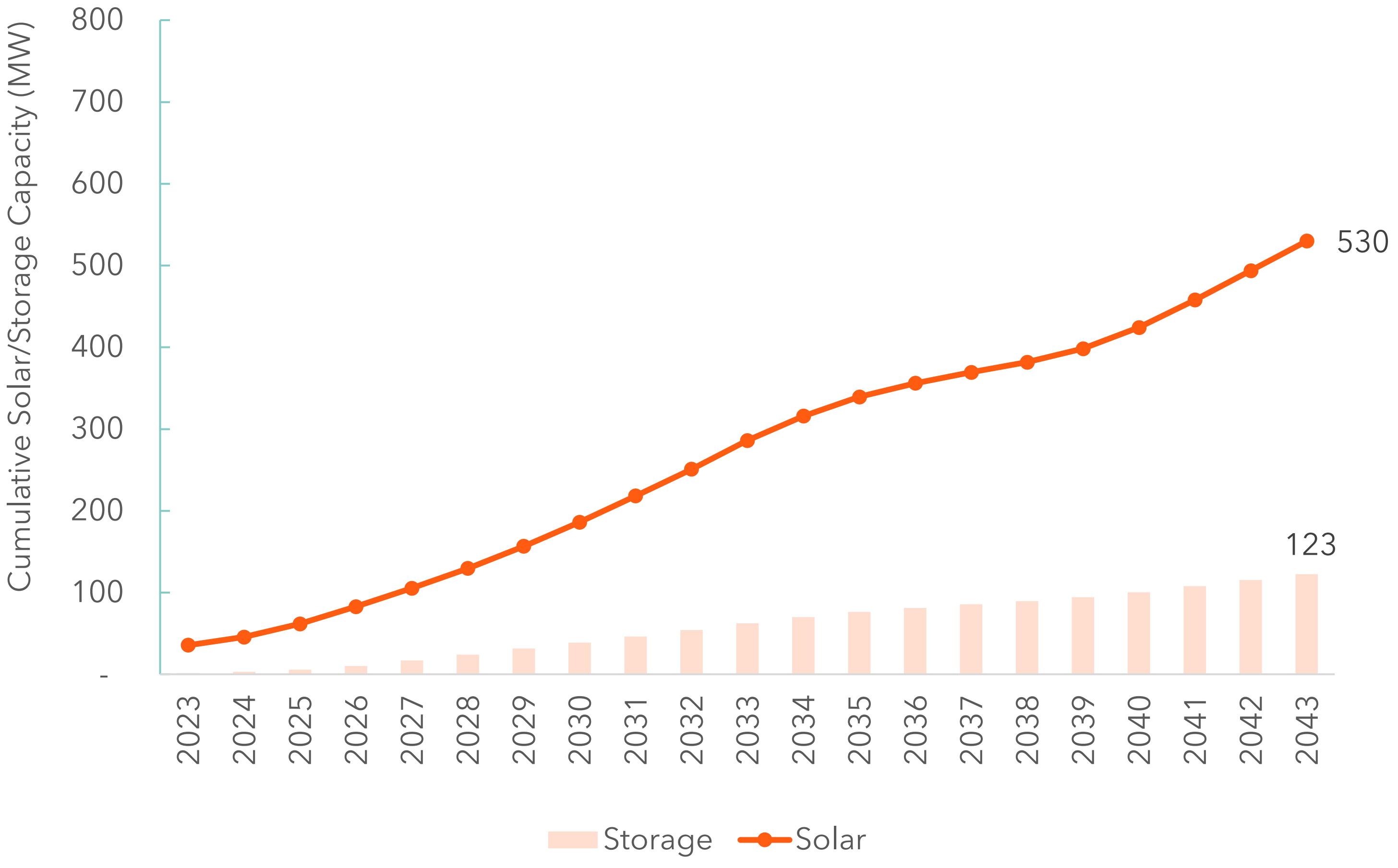
Note: Residential storage is assumed to represent 90% of solar capacity, while non-residential storage is one-tenth of the solar capacity.

Distributed Solar and Storage Adoption

Scenario Results: Medium Growth

Mid Growth Scenario: Snapshot

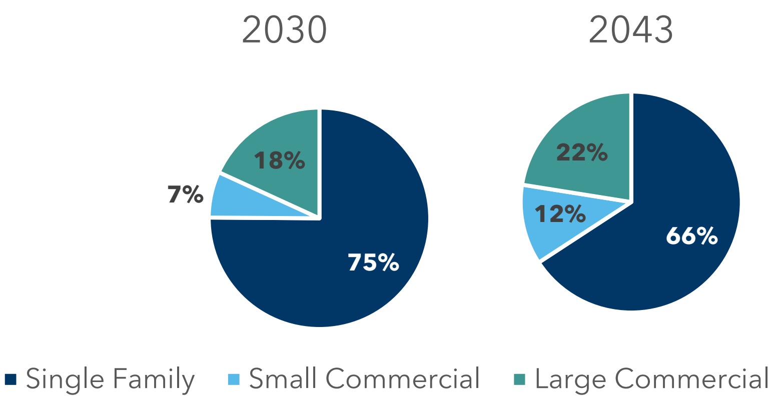
Anticipated Solar and Storage Adoption (Mid)



Moderate intervention

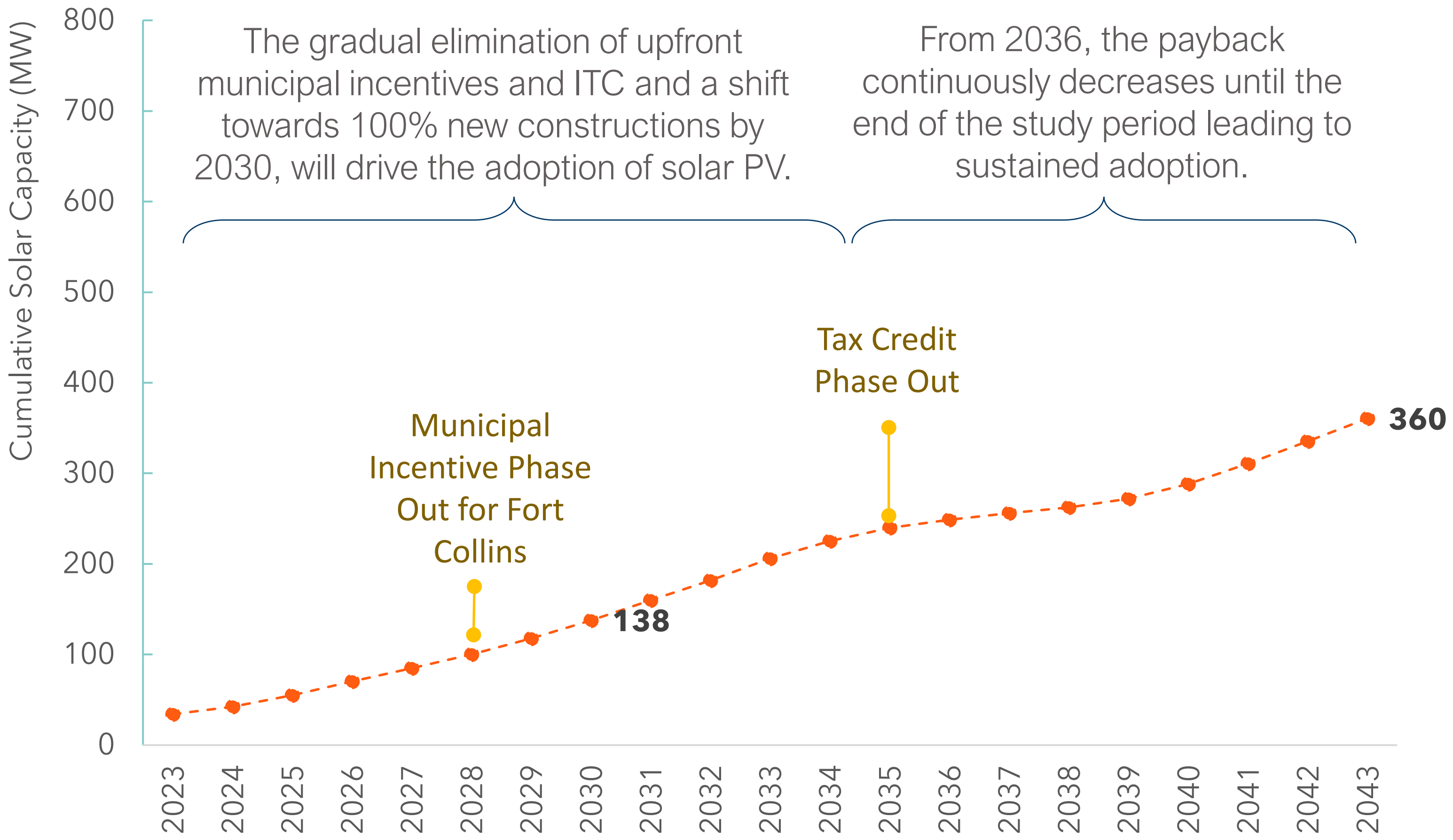
- Assumes moderate policy support, including the continuation of planned municipal and federal incentives and modest revenue opportunities for storage via demand response (DR) program participation
- Assumes solar PV becomes a standard feature in a portion of new buildings
- Assumes technology improvements align with baseline forecasts

Total Solar Potential by Market



Standalone Solar

Anticipated Standalone Solar Adoption (Mid)



Elimination of ITC in the mid 2030's could impede demand. DR incentives to increase demand for solar + ES could help.

The presence of a solar mandate for new constructions expands the potential market for solar PV.

Paired Solar + Storage

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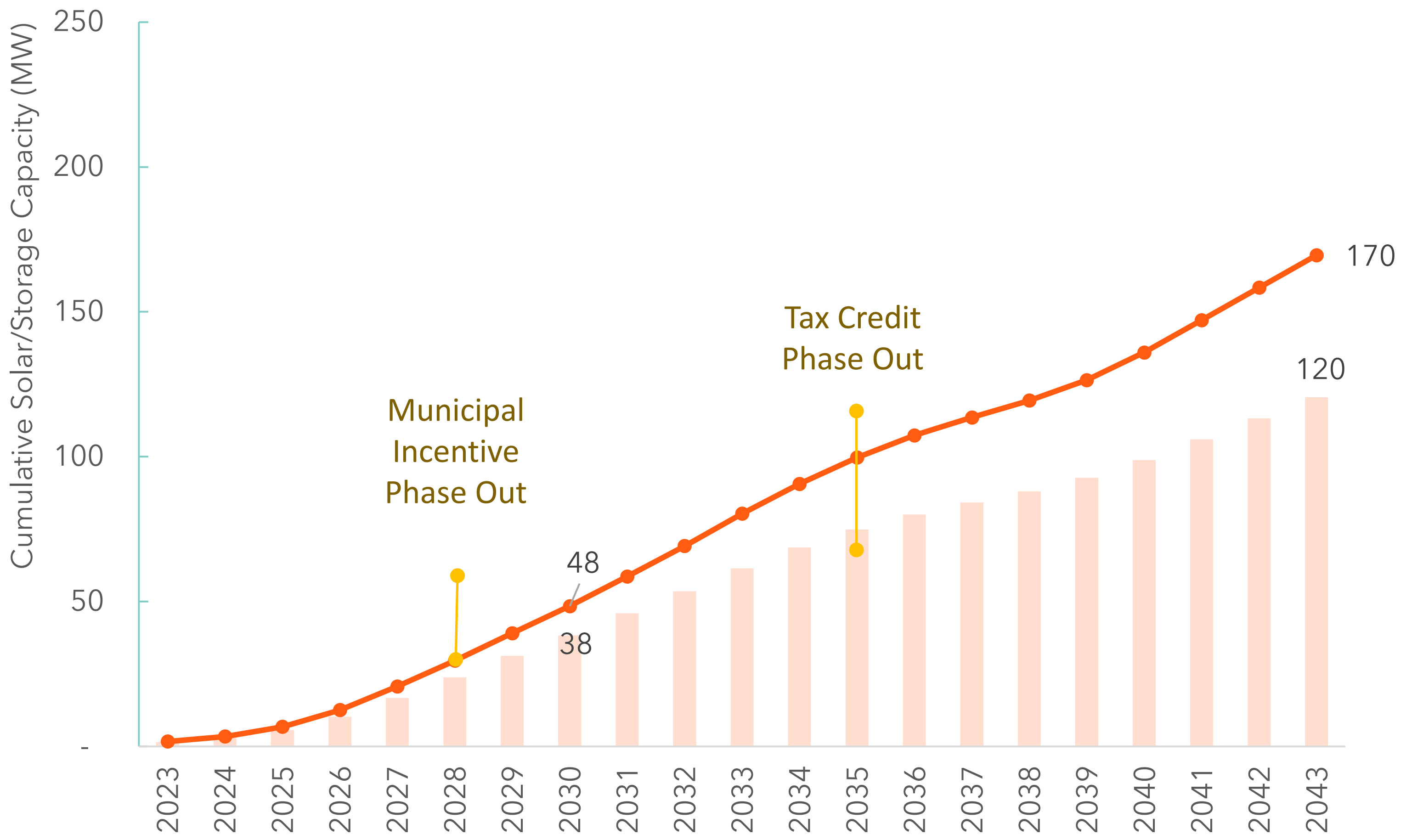
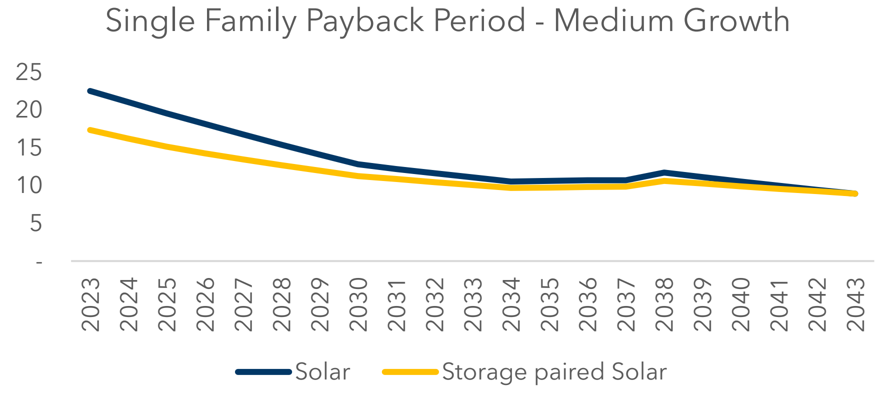
Anticipated Solar + Storage Adoption (Mid)



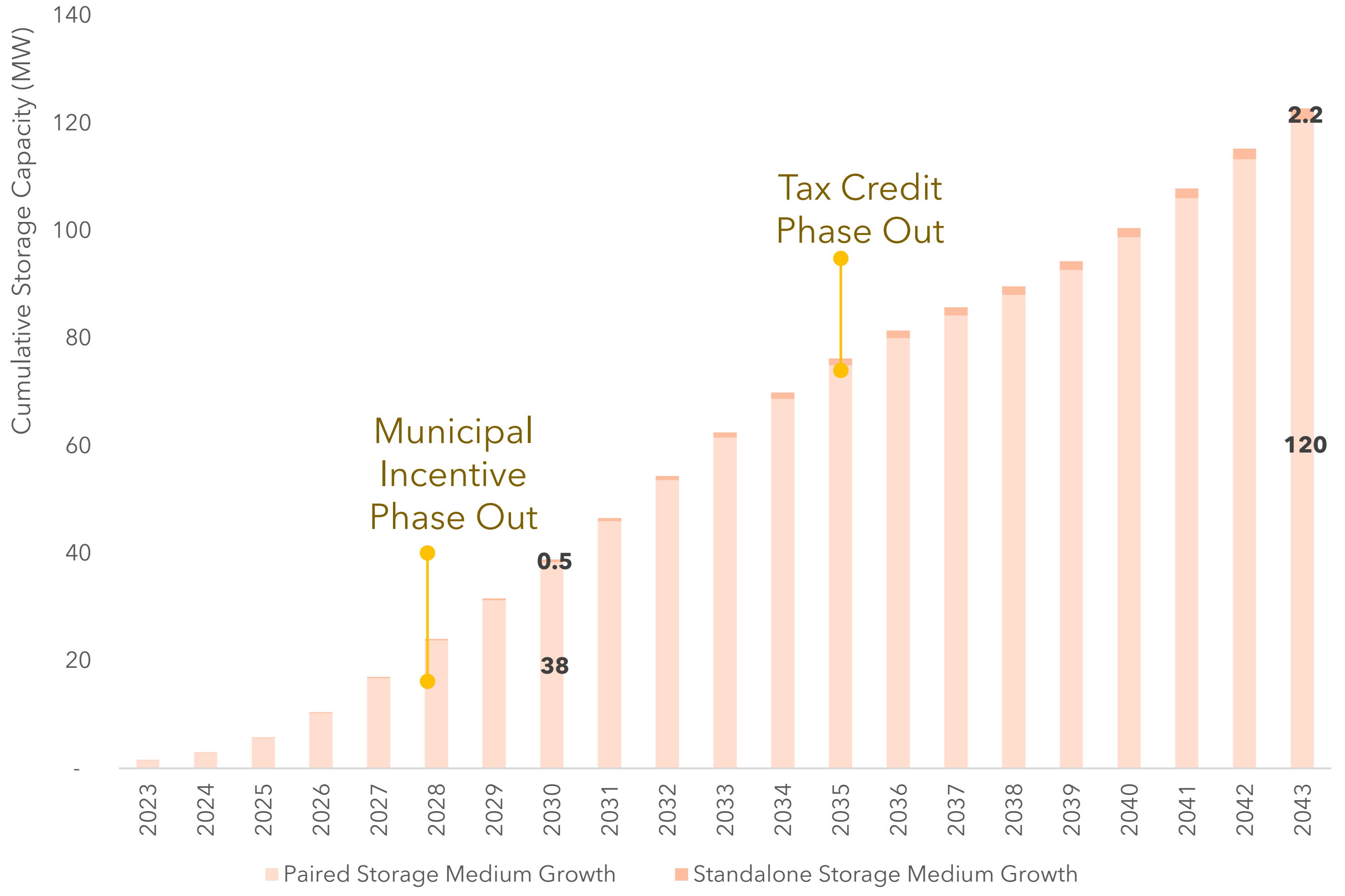
- In the Mid Growth scenario, there is an increasing trend of pairing storage with solar energy. Some new constructions now choose to install solar and storage systems instead of just standalone solar.
- Non-residential sector has significantly more adoption in this scenario due to the additional revenue streams for storage
- Note: These results reflect a gradual increase of market from 90-10 to 70-30 solar vs solar + ES split assumption, due to solar + ES having preferable paybacks for Residential customer. Standalone solar payback period for residential sector in 2030 is 12.8 years compared to 11.3 years for storage paired solar.



Note: Residential storage is assumed to represent 90% of solar capacity, while non-residential storage is one-tenth of the solar capacity.

Total Storage

Anticipated Distributed Storage Adoption (Mid)



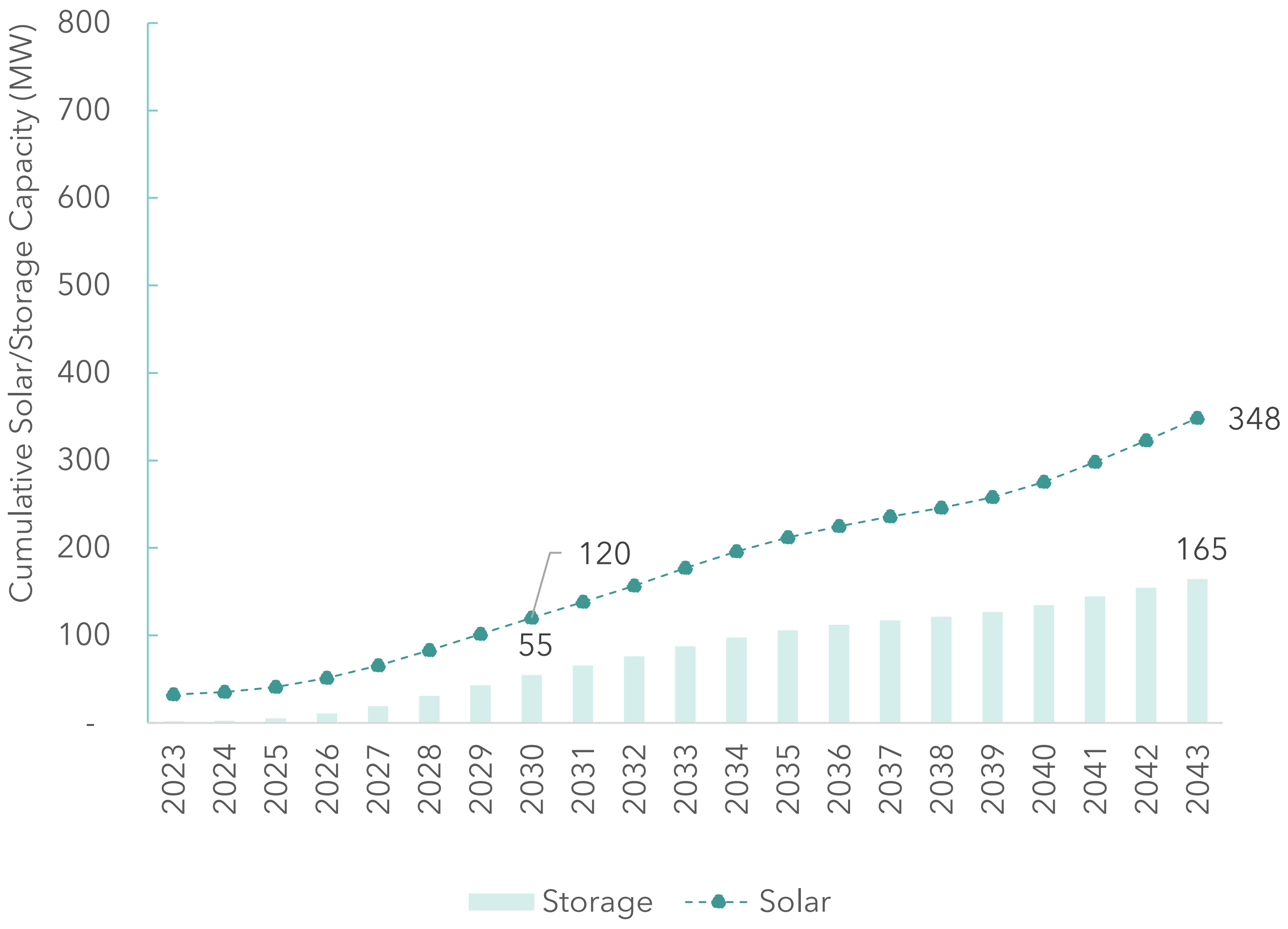
- The non-residential sector has experienced an increase in uptake, due to the introduction of revenue opportunities from storage through DR.
- During the years when incentives are removed, there is an increase in payback, which results in a decrease in the adoption rate.
- Standalone storage is viable in the residential market with the new TVR design in medium scenario improving paybacks
- Solar paired storage continues to dominate storage potentials.

Distributed Solar and Storage Adoption

Scenario Results: Medium Growth Future NEM

Medium Future NEM Scenario: Snapshot

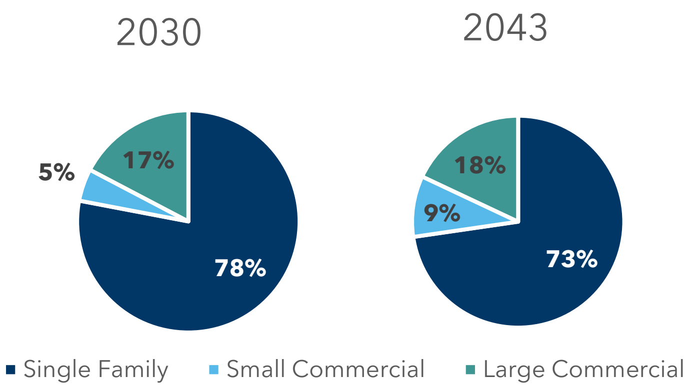
Anticipated Solar and Storage Adoption (Medium Future NEM)



Moderate intervention with reduced NEM rates

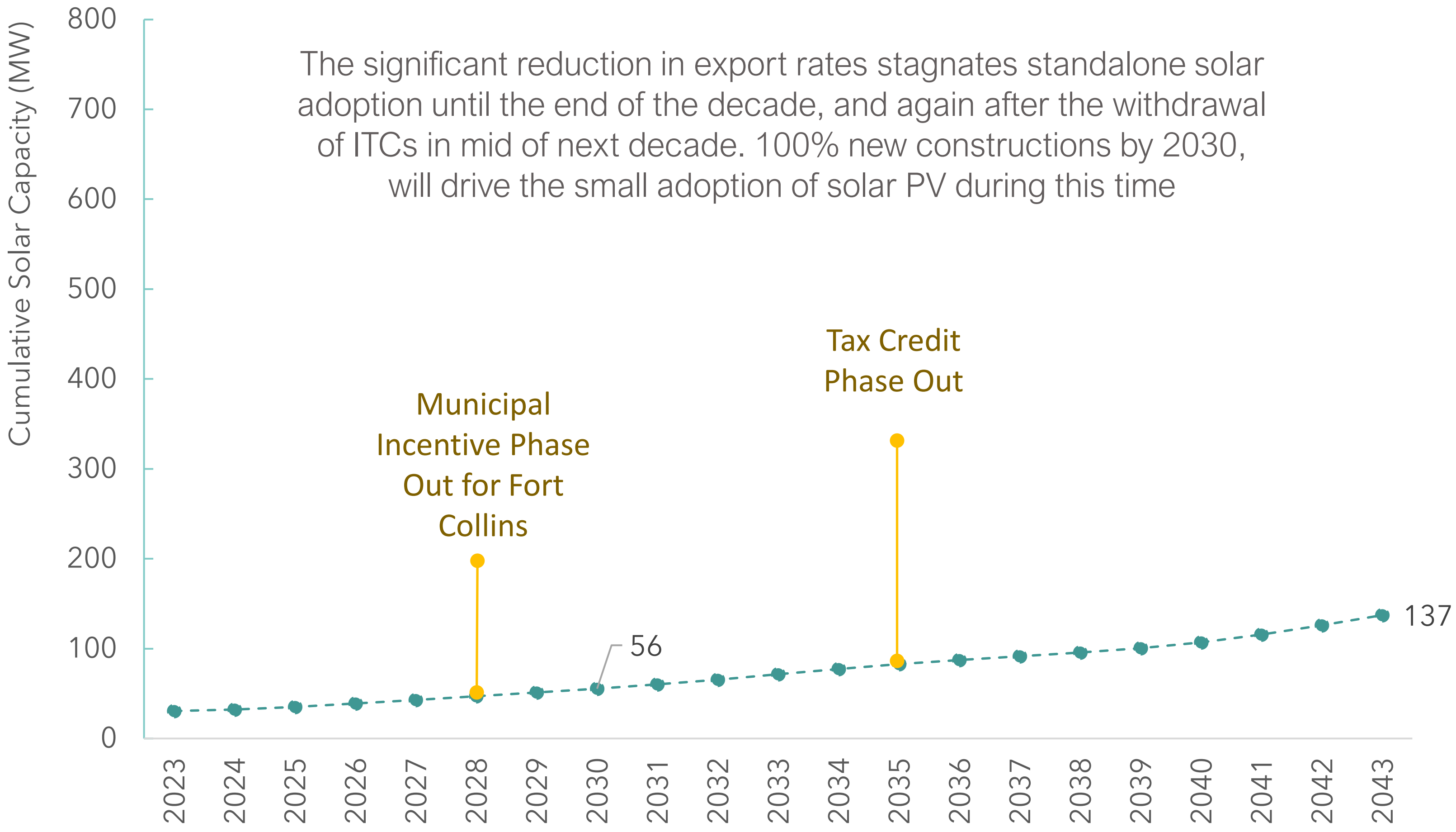
- Assumes lower exported energy rate based on forecasted wholesale market rates to align with Future NEM
- Assumes moderate policy support, including the continuation of planned municipal and federal incentives and modest revenue opportunities for storage via demand response (DR) program participation
- Assumes technology improvements align with baseline forecasts

Total Solar Potential by Market



Standalone Solar

Anticipated Standalone Solar Adoption (Medium Future NEM)

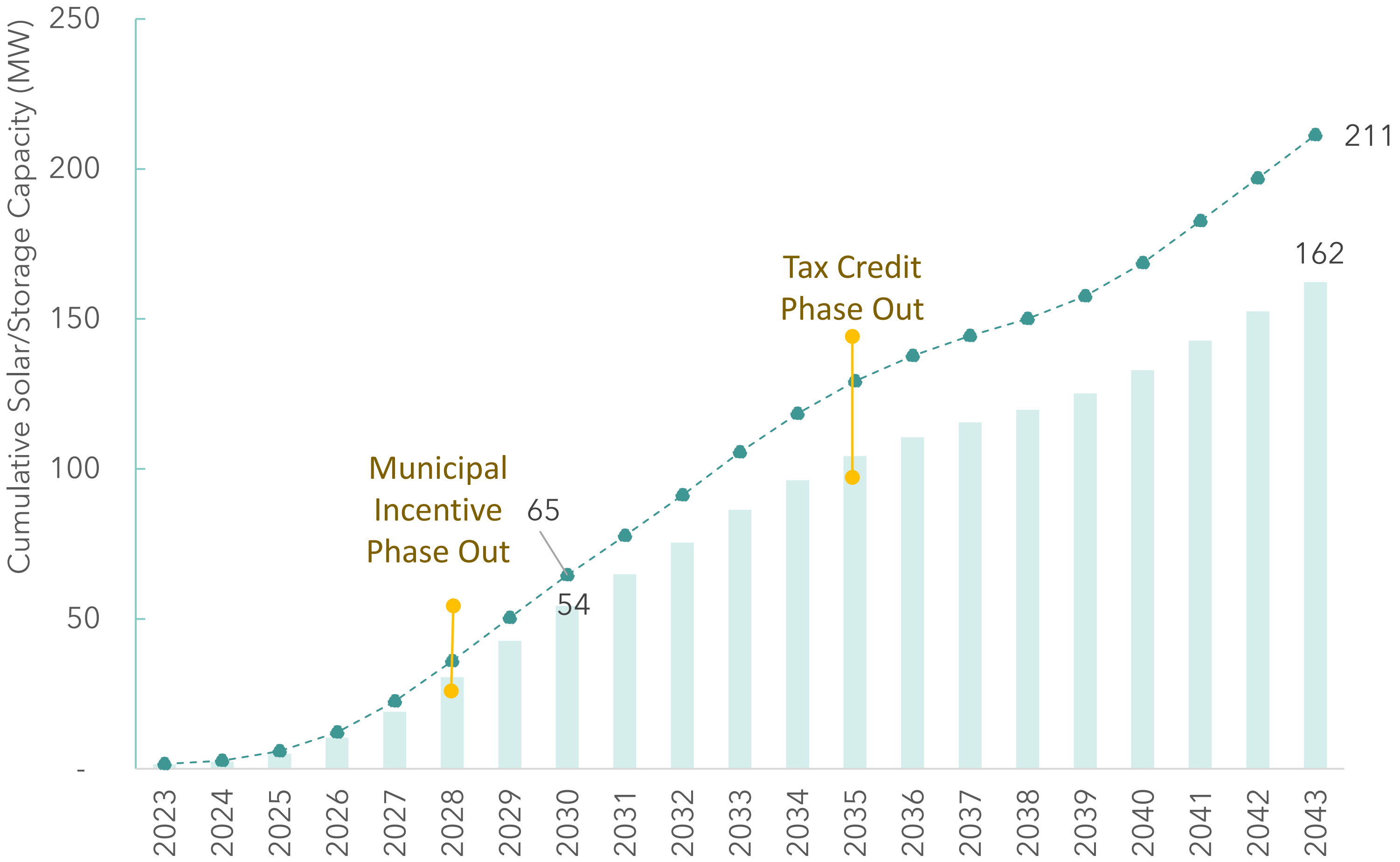


The market for standalone solar is significantly impacted due to lower export rates

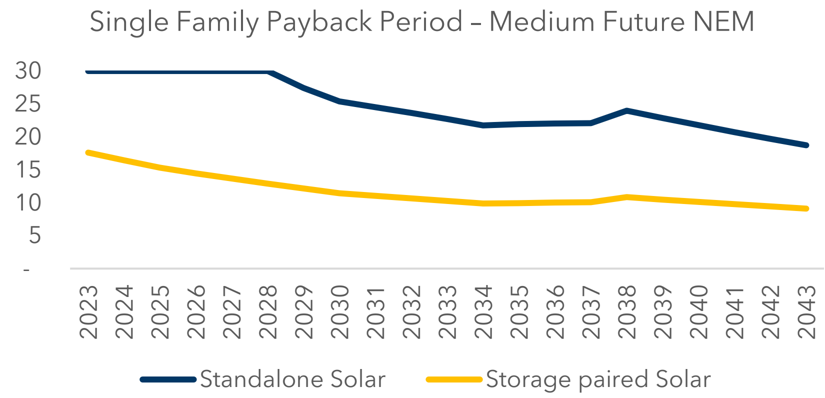
The payback are no longer favorable for standalone solar market

Paired Solar + Storage

Anticipated Solar + Storage Adoption (Mid Future NEM)



- Storage paired solar dominates the market due to better economics and increased technical market size for paired solar compared to standalone solar
- Non-residential sector has significantly more adoption in this scenario compared to low growth scenario due to the additional revenue streams for storage
- Under Future NEM, in 2030, the solar paired storage payback is 55% and 2% lower than standalone solar for residential and small commercial while payback for large commercial is still 5% higher
- Under Medium growth, in 2030, the solar paired storage is 12%, lower than residential standalone solar, while payback for commercial solar paired storage is still 12%-19% higher



Note: Residential storage is assumed to represent 90% of solar capacity, while non-residential storage is one-tenth of the solar capacity.

Total Storage

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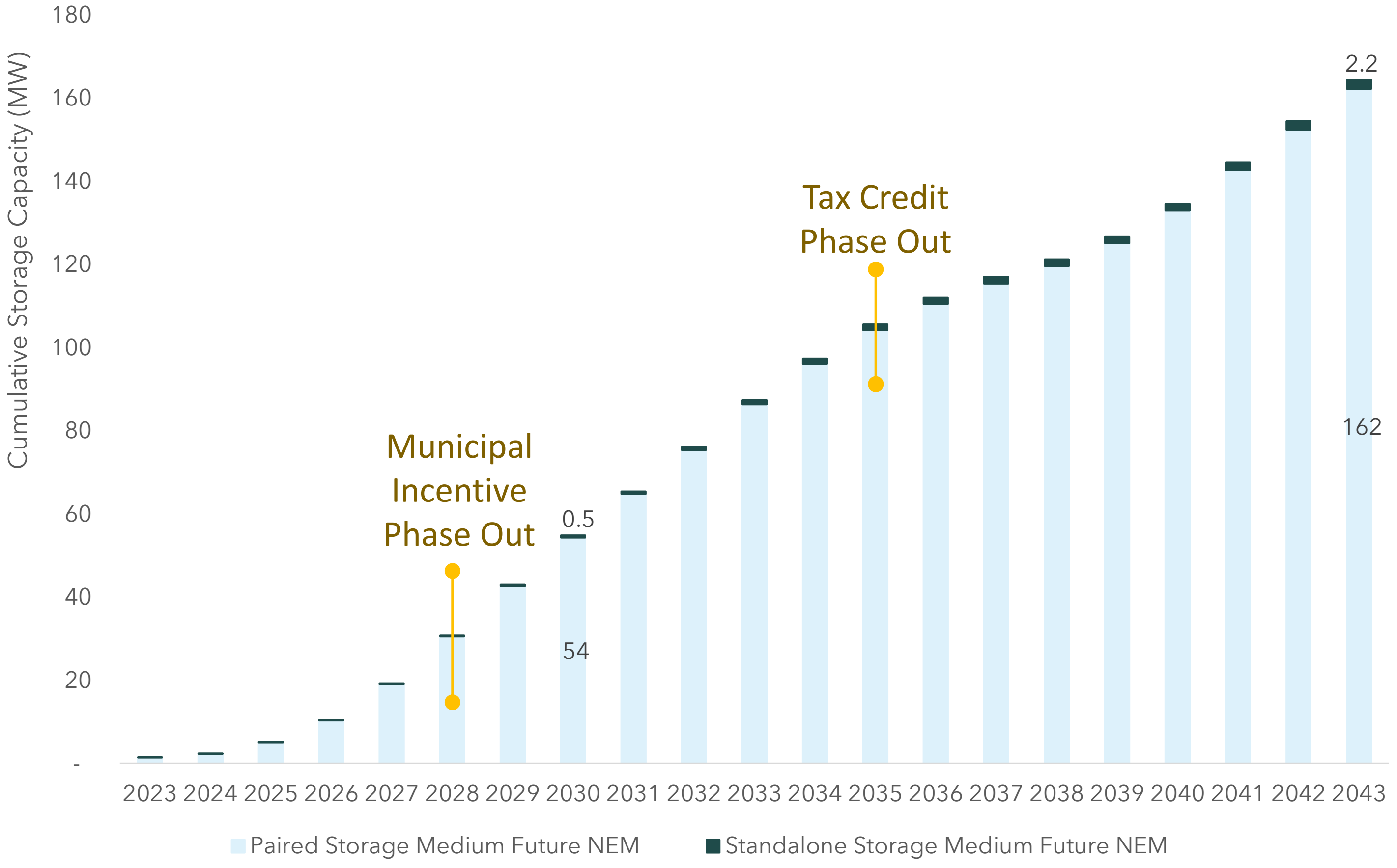
Anticipated Distributed Standalone Storage Adoption (Medium Future NEM)



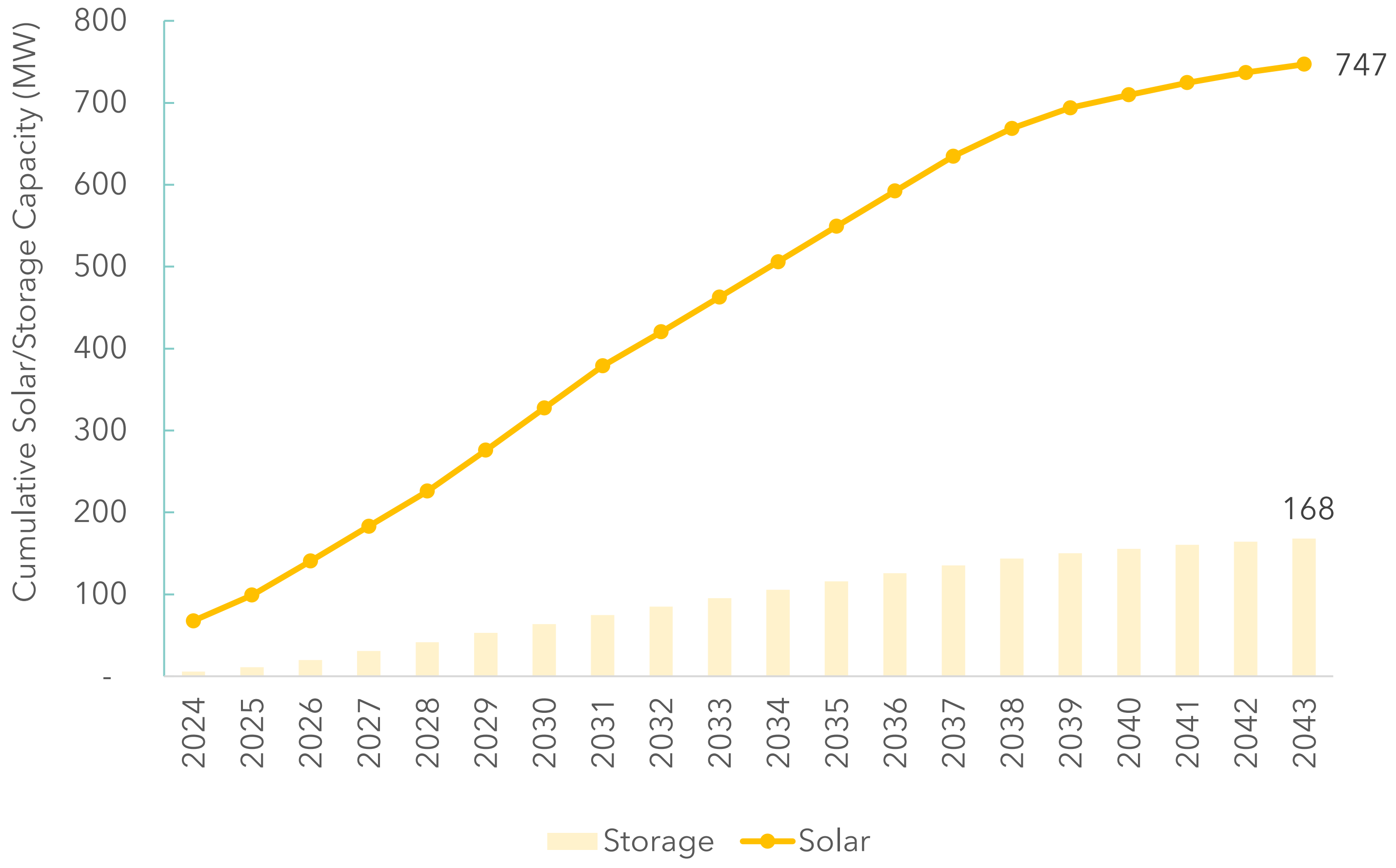
- Solar paired storage continues to dominate storage potentials driven by 50-50 technical market split

Distributed Solar and Storage Adoption

Scenario Results: High Growth

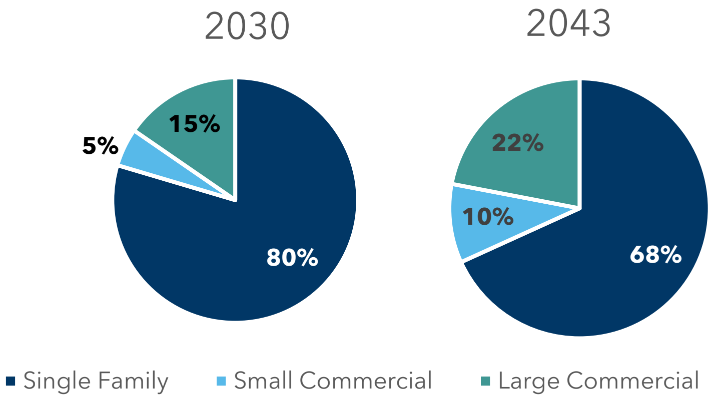
High Growth Scenario: Snapshot

Anticipated Solar and Storage Adoption (High)



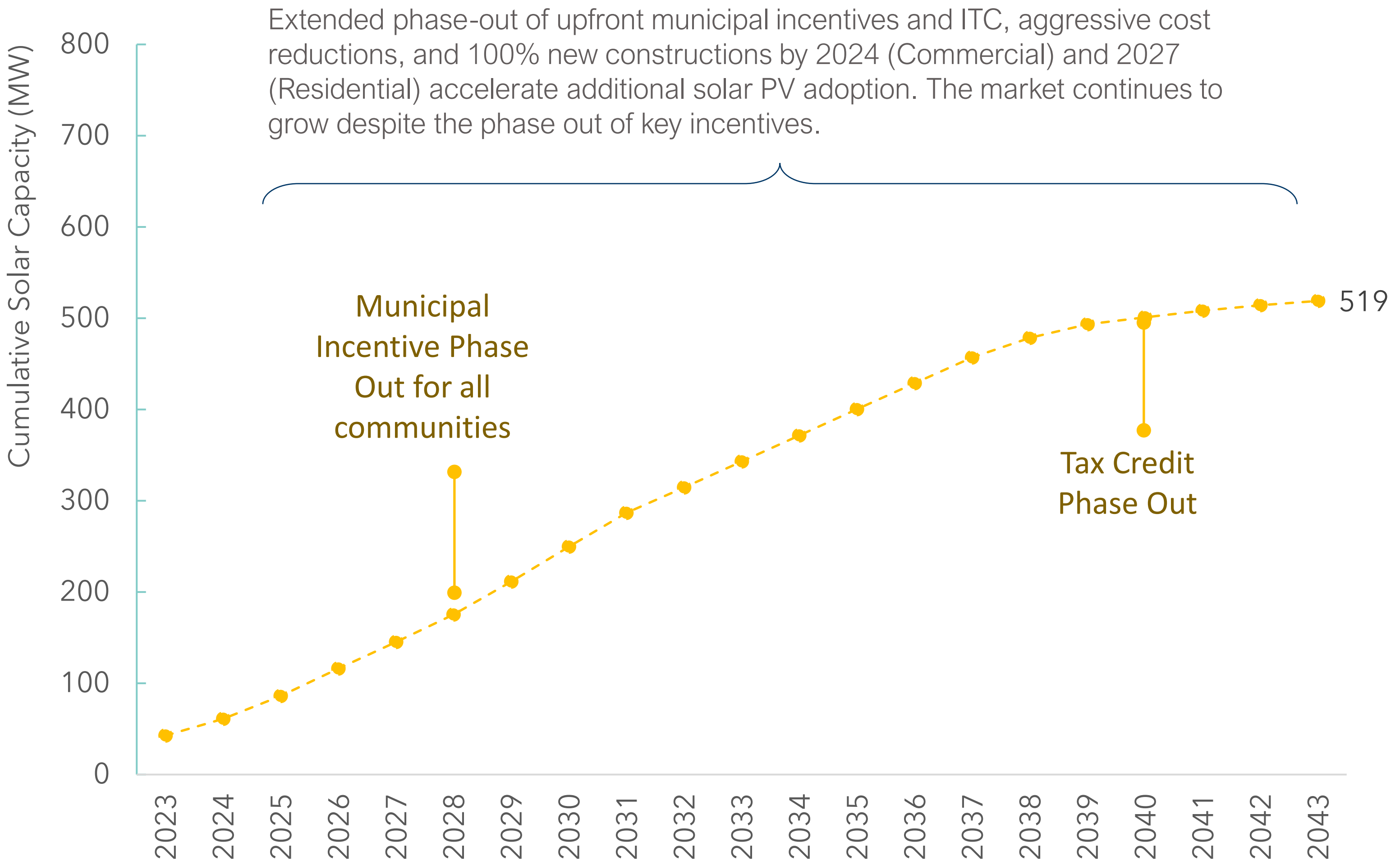
Accelerated intervention

- Assumes strong policy support, including extended municipal and federal incentives and stronger revenue opportunities for storage via DR program participation
- Assumes stronger efforts to deploy solar PV in new buildings than Medium Growth scenario
- Assumes technology improvements are faster than anticipated – driven by faster learning rates via increased technology deployment
- 95% of paired storage is Residential



Standalone Solar

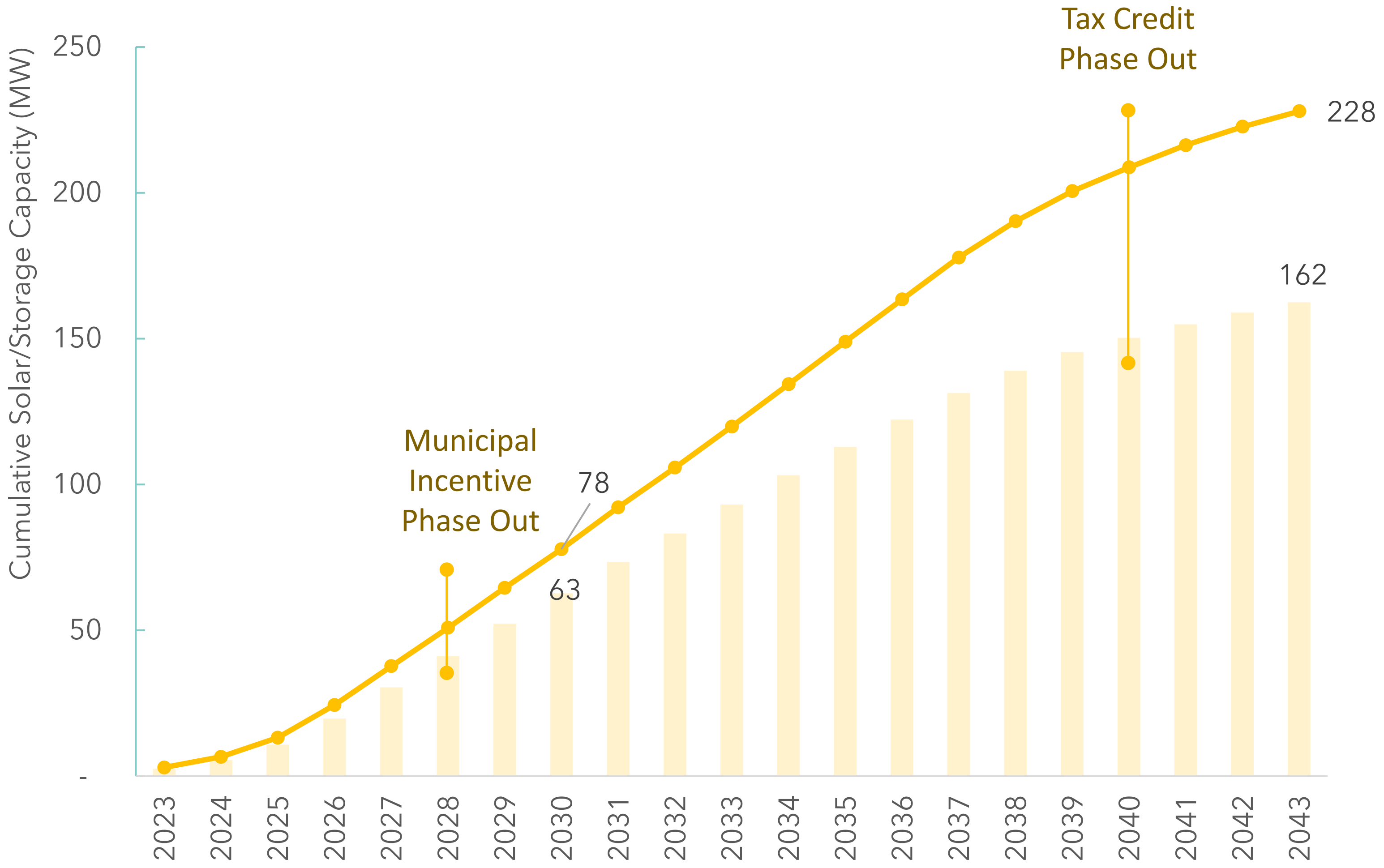
Anticipated Standalone Solar Adoption (High)



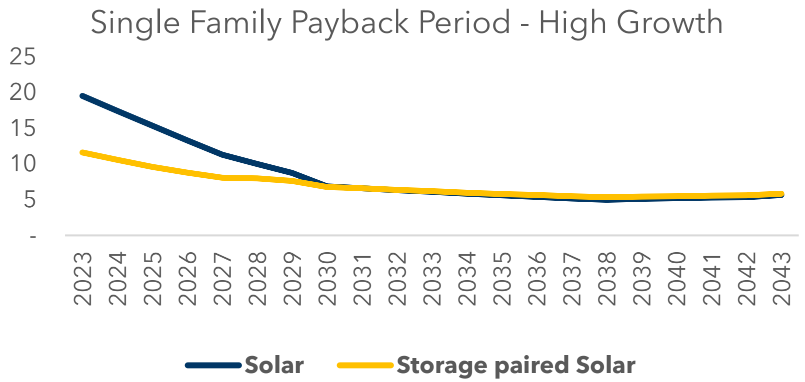
- Paybacks decrease consistently thereby maintaining sustainable adoption. Toward end of study residential solar market begins to saturate.
- A solar mandate for new constructions expands the potential market for solar PV.

Paired Solar + Storage

Anticipated Solar + Storage Adoption (High)



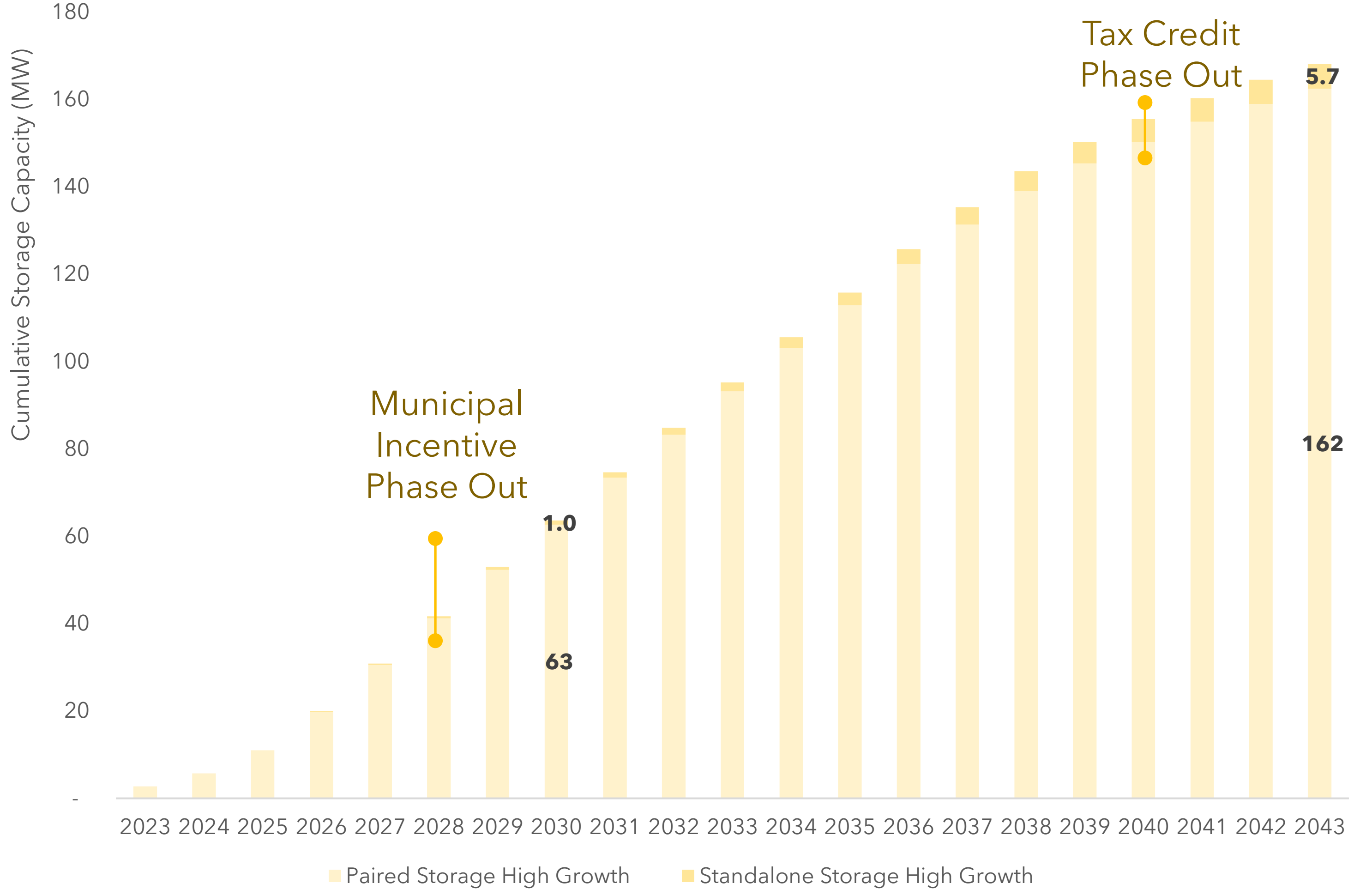
- The adoption of solar and storage systems in new constructions is on the rise, particularly in the High Growth scenario.
- In this scenario, the non-residential sector shows higher adoption levels than the low and mid-growth scenarios, mainly because of the additional revenue streams generated from storage through Demand Response.



Note: Residential storage is assumed to represent 90% of solar capacity, while non-residential storage is one-tenth of the solar capacity.

Total Storage

Anticipated Distributed Storage Adoption (High)



- Uptake of Standalone storage increases further in Non-residential sector with the extended phase-out of ITC and strong DR revenue opportunities from storage
- Increased payback periods when ITC is phased out leads to dampening of adoption rate

Distributed Solar and Storage Adoption

Conclusion

Xcel Colorado 2021 Clean Energy Filing Plan – Solar

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Xcel CO Distributed Solar Forecast (Nameplate MW Behind the Meter)[1]	
Year	MW
2024	705
2030	**1,250**
2035	1,851
2040	2,552
2043	2,987

PRPA Medium Future NEM Scenario	
MW	% relative to Xcel CO
35	5%
120	**10%**
212	11%
275	11%
348	12%

PRPA/Xcel Retail Load Ratio: 10%

Source: 1) Volume 2 Technical Appendix (PDF), Table 2.14-23. *Note: The Xcel study was completed in 2021*

Key Takeaways

By 2043, it is predicted that solar adoption will range from 341 to 747 MW and storage adoption will range from 11 to 168 MW, dominated by solar paired with storage. The adoption of solar paired with storage is impelled by DR incentives and even further by net metering arrangements that place a higher value of solar energy that is locally used through onsite storage rather than exported to the grid.

Policy support measures like the ITC and demand response payments can encourage customers to adopt residential storage. Residential customers may also be motivated to adopt storage due to time varying rates (TVR) arbitrage opportunities.

Federal ITC is a main driver to solar growth in the early years of the study. In the long run, the forecasted decline of solar cost, on top of to the utility projected rate increase, enhances the economics case for local generation from the customer perspective and is the biggest contributor to solar adoption.

Enforcing a solar mandate for new construction can significantly boost the distributed generation market. In the mid-case scenario, implementing a solar mandate on new construction resulted in a 33% increase in the overall market size. In the high-case scenario, the similar mandate led to a 24% growth in the market size by 2043.

Transportation Electrification Adoption

Transportation Electrification Adoption

Context and Market Overview

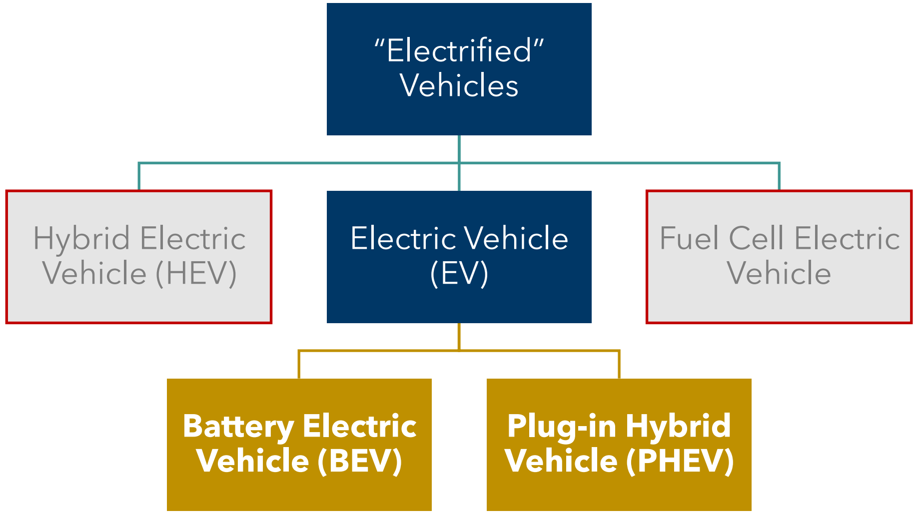
Overview

The EV analysis considers plug-in electric vehicles. Specifically, it considers the following vehicle types:

- Battery electric vehicles (BEV): "pure" electric vehicles that only have an electric powertrain and that must be plugged into an electric source to charge (e.g., Tesla Model 3, Chevy Bolt, Nissan Leaf).
- Plug-in hybrid electric vehicles (PHEV): vehicles that can plug in to charge and operate in electric mode for short distances (e.g., 20 to 50 miles), but that also include a combustion powertrain for longer trips. (e.g., Chevy Volt, Toyota Prius Prime).

The following vehicle types are excluded from the analysis:

- Hybrid electric vehicles that do not plug in to charge and are considered internal combustion engine (ICE) vehicles.
- Fuel cell electric vehicles such as hydrogen vehicles where the market is assumed to be minimal in the timeframe of the study.



Chevrolet Bolt, a BEV with 417 km of range.

Toyota Prius Prime, a PHEV with 40 km of EV range

Characterize Vehicle Segments

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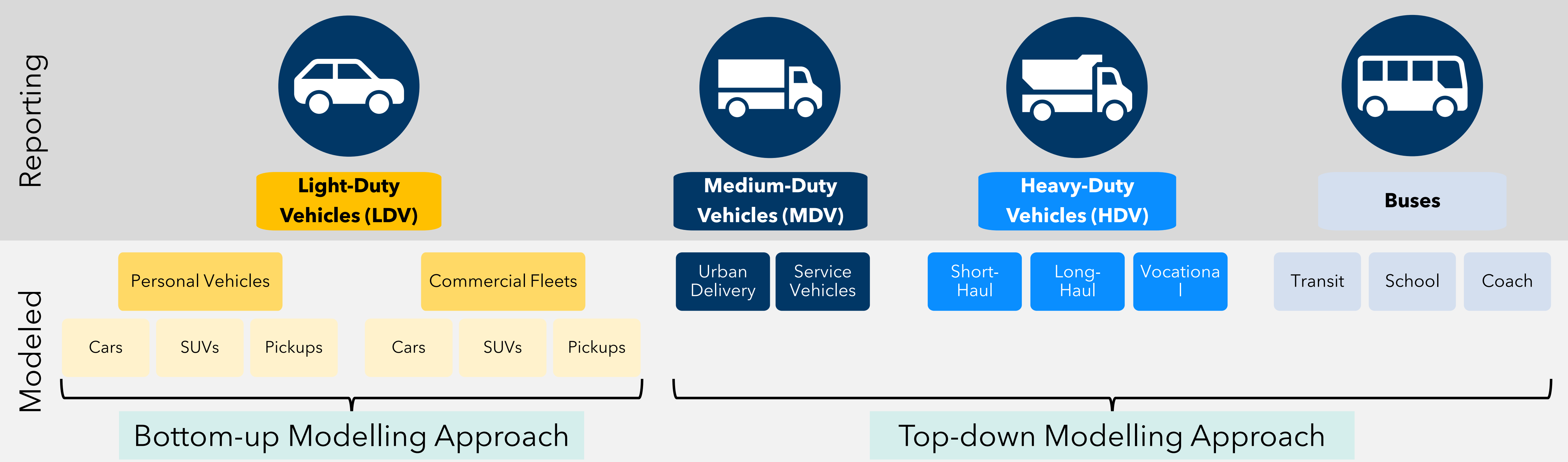
Multiple vehicle classification systems exist. However, for the purpose of this study, we break down the on-road vehicle market into several key segments that share common characteristics.

- Results are broken down by LDVs, MDVs, HDVs, and buses.
- More granular vehicle sub-segments are included in the model to capture distinct sub-segment characteristics that may influence EV adoption (e.g. EV model availability, driving patterns, or technical requirements).



Vehicle Market

Approximately 290,000 vehicles on the road in Platte River's service territory

- Light-duty vehicles (LDVs), both personal and commercial, represent 95% of vehicles (277,000 vehicles on the road).
- 13,000 medium-and heavy-duty vehicles (MHDVs) are estimated to be on the road, representing 5% of all vehicles.

Approximately 14,000 new LDVs estimated to be registered annually in the region

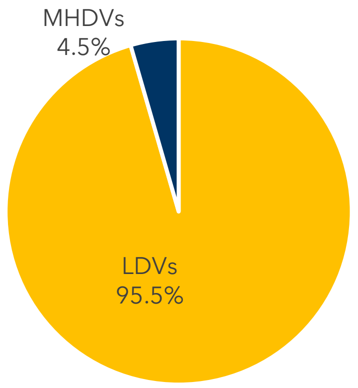
- Majority (90%) of LDVs assumed predominantly passenger/personal use, with the remaining being commercial/institutional fleets
- SUVs and Pickups make up 77% of new vehicle sales in Platte River's territory, and 66% of vehicles currently in circulation, reflecting an ongoing trends towards SUVs.

Approximately 13,000 new MHDVs estimated to be registered annually

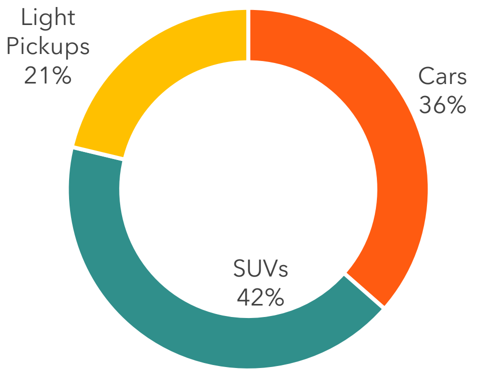
- Medium-Duty Vehicles make up 89% of MHDVs in circulation

Note: Available data on annual vehicle sales and total number of vehicles registered in Platte River's territory was limited. The estimated vehicle market sizes used in the study represent the project team's best judgement based on analysis of statewide Auto Alliance data, Atlas EV hub, and Colorado specific MHDV reports.

Total Vehicles (2021)

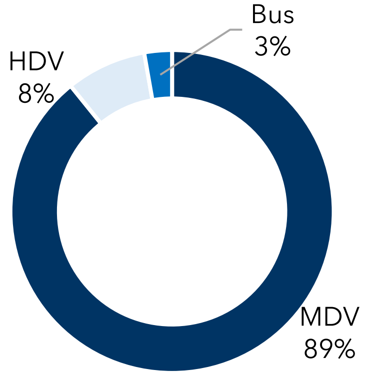


LDV Segment Split



% of Total Vehicles 2021

MHDV Segment Split

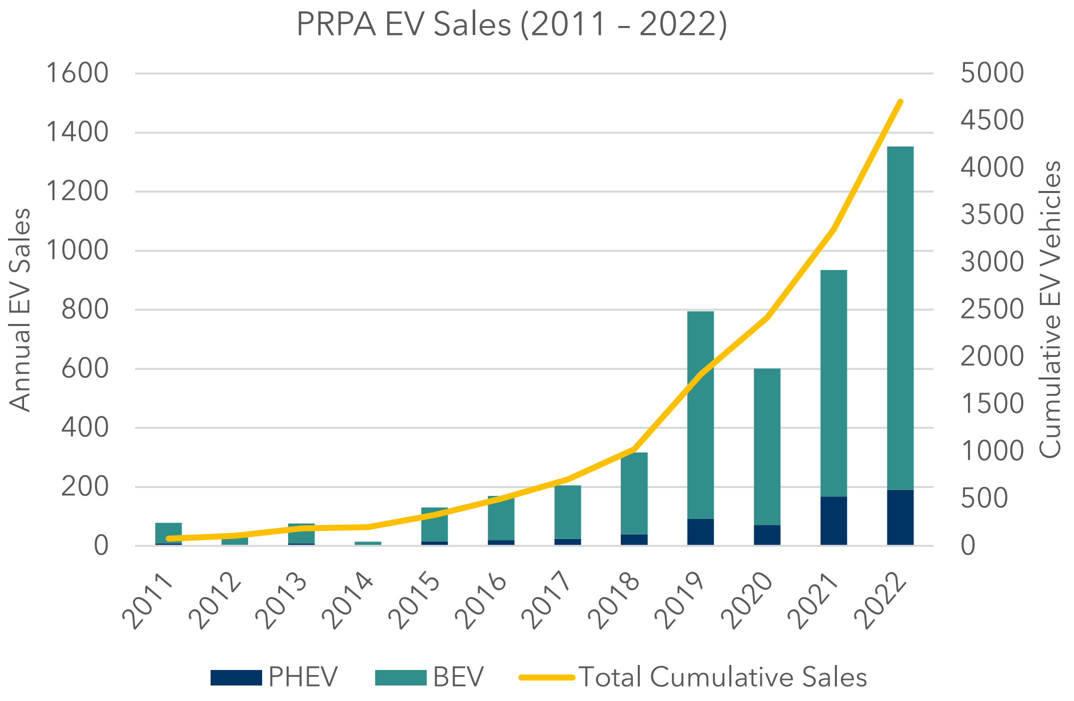


% of Total Vehicles 2021

Electric Vehicle Market

In PRPA's service territory, ~4,700 EVs are estimated to be on the road in 2022

- Modest year-over-year growth, with a significant increase in uptake observed in 2019 and drop in annual sales in 2020
- EVs represented ~9% of new vehicle sales in 2022
- EVs represented ~1.7% of vehicles on the road in 2022



Note: Historical EV sales in PRPA's service territory were estimated based on client data provided for Fort Collins and Longmont.

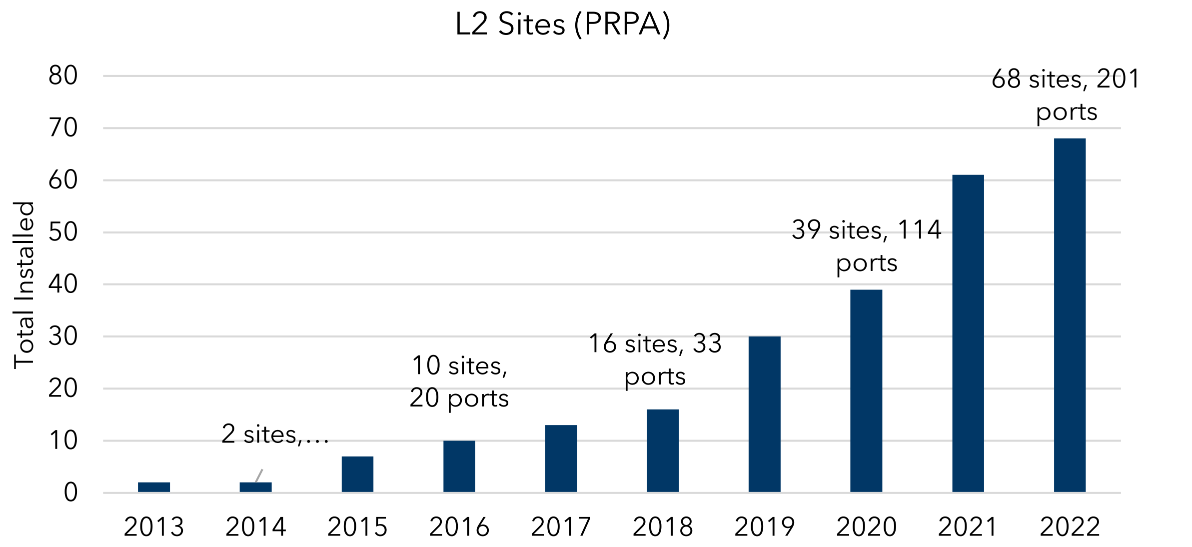
Charging Infrastructure

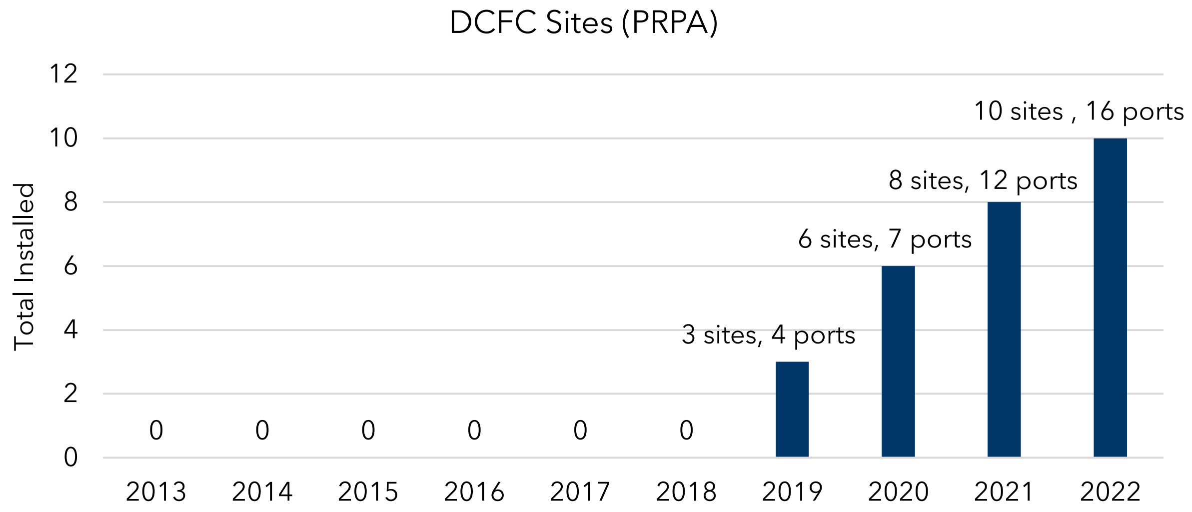
Significant growth in public charging infrastructure across the service territory in the past 4 years

- By the end of 2022, 68 Level-2 Sites (201 Ports) and 10 DCFC Sites (16 Ports) estimated to be deployed

The following terminology is used for charging infrastructure in this study:

- **"Site"** refers to a facility or location that provides charging services, can provide charging to one or more EVs at a time depending on the number of ports it includes. Represented by a single marker on a map
- **"Port"** reflects an individual connector that can charge one vehicle at a time. (Note that some "dual port" stations include connectors for different vehicle types, but can only charge one vehicle at a time – considered as a single port in this analysis)





Transportation Electrification Adoption

Methodological Summary

EV Modeling Approach

1. **Market Characterization:** Divide the market into three vehicle archetypes (cars, SUVs, trucks), develop representative characteristics for each segment and collect data on annual vehicle sales, fleet size and other key market inputs.

2. **Model Calibration:** Using historical inputs on vehicle sales, energy prices, vehicle costs, incentive programs and infrastructure deployment to benchmark the model to historical adoption and calibrate key model parameters to local market conditions.

3. **Scenario Analysis:** Forecast service territory-wide EV adoption under scenarios reflecting different program/policy interventions (e.g. infrastructure deployment, incentives) as well as market and technology conditions (e.g. battery costs, energy prices).

Bottom-up vs. Top-down EV Modeling Approach

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Modelling electric vehicle adoption will utilize a hybrid bottom-up / top-down approach.

Bottom-up: LDVs

- Adoption rates based on **Dunsky's Electric Vehicle Adoption (EVA)** model
- Enables nuanced scenario analysis based explicit modelling of influencing factors

Top-down: MHDVs

- Adoption rates based on **credible secondary forecasts and/or targets**
- Scenario analysis limited to high-level adoption trajectories

Scenario Parameters: Light Duty Vehicles

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Parameter	Scenario 1: **Low Growth**	Scenario 2: **Medium Growth**	Scenario 3: **High Growth**
Policy/Program Interventions			
Public charging infrastructure expansion	**Limited** Planned investments + current growth trajectory.	**Moderate** Planned investments + accelerated growth trajectory aligned with CO NEVI plan.	**Significant** Expanded infrastructure to ensure adoption is not constrained.
Vehicle incentives[1]	Current federal and state EV incentives, phased out prematurely in 2028 and 2026, respectively	Current federal and state EV incentives, phased out as currently planned in 2032 and 2028, respectively	Increased incentives and extended beyond currently planned in 2035 and 2030 respectively
Existing building charging infrastructure retrofits	**Limited** 15% of multi-unit buildings with access to charging by 2035	**Moderate** 40% of multi-unit buildings with access to charging by 2035	**Significant** 90% of multi-unit buildings with access to charging by 2035
Zero-emission vehicle (ZEV) mandates	None	None	Stringent 100% by 2035
Technology Uncertainties			
Battery Costs	**Limited** cost declines	**Moderate** cost declines	**Aggressive** cost declines
EV Model Availability	**Limited** availability	**Moderate** availability	**High** availability
Market Factors			
Vehicle Sales	Maintain historical trends in vehicle sales		
Electricity Rates	Aligned with study-wide rate assumptions described in demand response scenario		
Fuel Prices	**Limited** escalation	**Moderate** escalation	**Rapid** escalation

Scenarios: Medium and Heavy Duty Vehicles

The adoption rate of electric vehicles assessed based on credible secondary forecasts* and/or targets

Low Growth

- **Limited programs and policies intervention**
  - Assumes **limited policies and programs** are put in place to support or incentivize electric vehicle adoption
  - Assumes technology improvements are **slower than anticipated** due to limited technology deployment

Medium Growth

- **Current push for MDHV electric vehicle adoption**
  - Models the impacts of Colorado adopting California's Advanced Clean Trucks (ACT Rule).
  - Rule assumes technology improvements **align with baseline forecasts today.**

High Growth

- **Aspirational policy pathway for MDHV electric vehicle adoption.**
  - Further builds upon the ACT scenario by increasing ZEV sales to 90-100 percent by 2040.
  - This scenario assumes that the state and federal government adopt additional policies to increase ZEV adoption

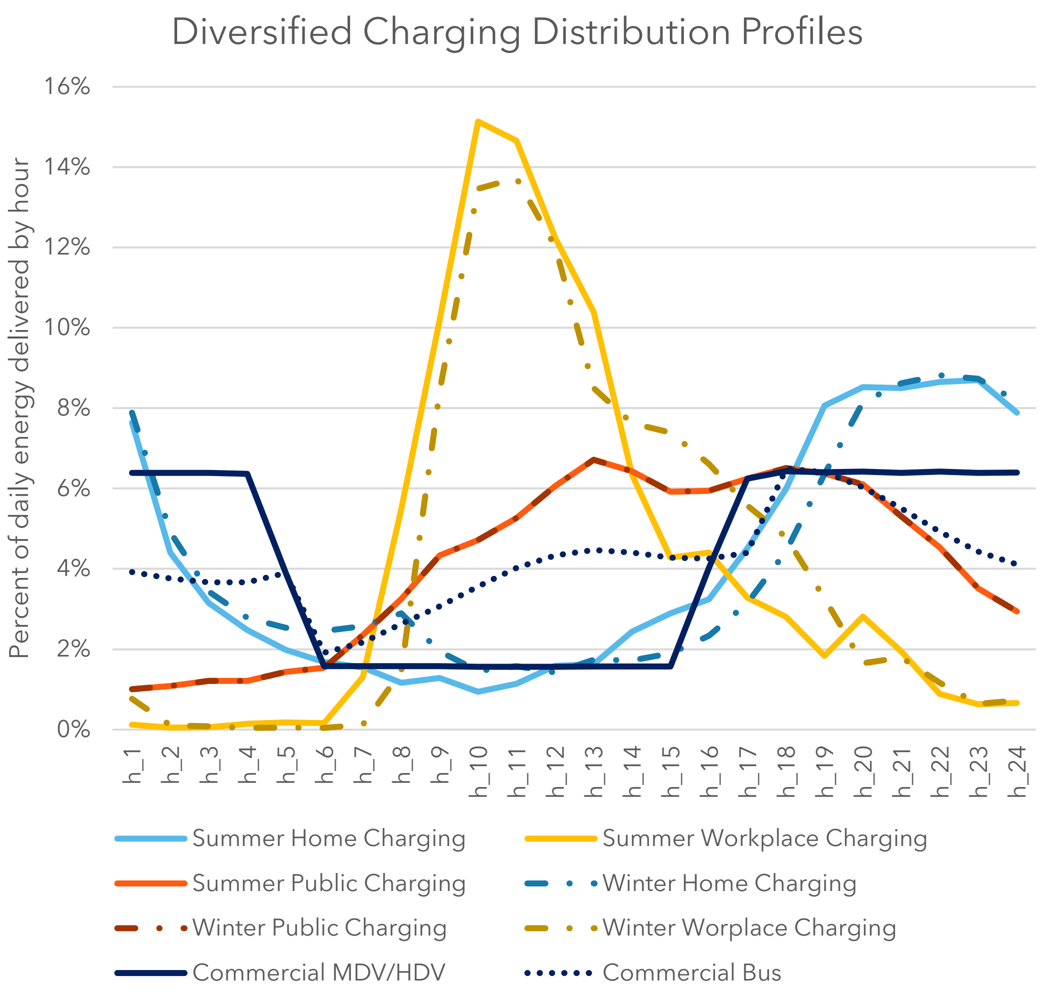
Note: Medium and High forecasts are aligned with scenario's modeled in the 2021 Colorado Medium-and Heavy Duty (M/HD) Vehicle Study produced by M.J. Bradley & Associates. M.J. Bradley & Associates' proprietary State Emissions Pathway (STEP) Tool and Toolkit for Advanced Transportation Policies were used to model forecasts.

Diversified Charging Distribution Profiles

EV charging load impacts are assessed using 24-hour diversified charging distribution profiles that capture the distribution of a vehicle's daily energy consumption across hours of the day. The distribution profiles are differentiated by vehicle type, charging type, and season and scaled to daily energy requirements for each combination.

Charging event types include:

- LDV Home Charging
- LDV Workplace Charging
- LDV Public Charging
- LDV Depot Charging
- MHDV Depot Charging
- Bus Depot Charging



Note: The charging distribution profiles were developed by leveraging data sets from a range of government and utility-led pilot programs including: California Energy Commission. California Investor-Owned Utility Electricity Load Shapes; ISO New England 2020 Transportation Electrification Forecast; Rocky Mountain Institute. DCFC Rate Design Study. 2019.

8760 Load Curves – Unmitigated

Unmitigated 8760 load curves for an average single vehicle were developed for each vehicle segment (LDV, MDV, HDV, and Bus) using the 24-hour diversified charging distribution profiles and the following assumptions that calculate an average annual energy consumption for each vehicle segment:

- Annual distance driven for each sub-segment (mi)
- Vehicle efficiency for each sub-segment (kwh/mile)
- Ratio of vehicle within each sub-segment
- LDV charging split (80% home charging, 10% work, and 10% public)
- 8760 hourly temperature curve for the jurisdiction
- BEV/PHEV split

These 8760 curves for an average single vehicle by segment can then be multiplied by cumulative number of EVs for each year of the study period. **Note that these 8760 load curves can be normalized but changing the maximum charging allowed would inherently change the shape of the load curve.**

Transportation Electrification Adoption

Results

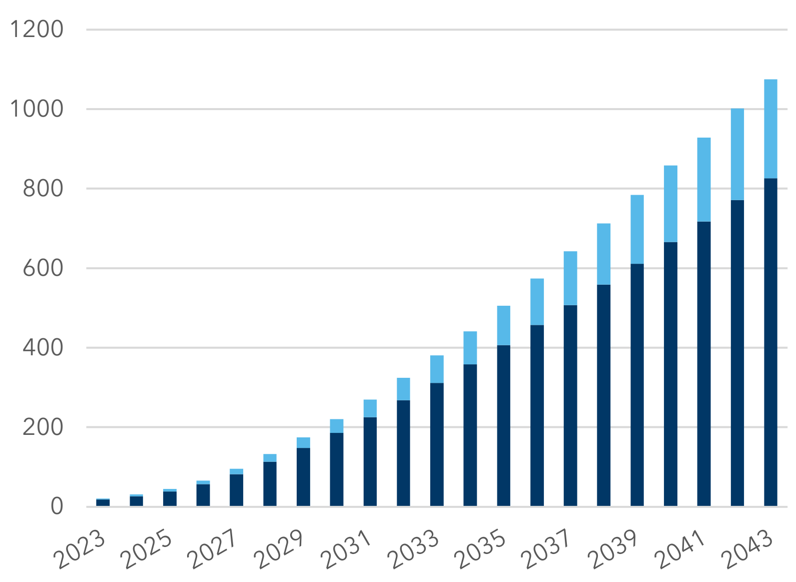
Annual Load Impacts

EVs will increase baseline annual load by 18% in 2043 under the High Growth scenario and 11% under the Low Growth scenario.

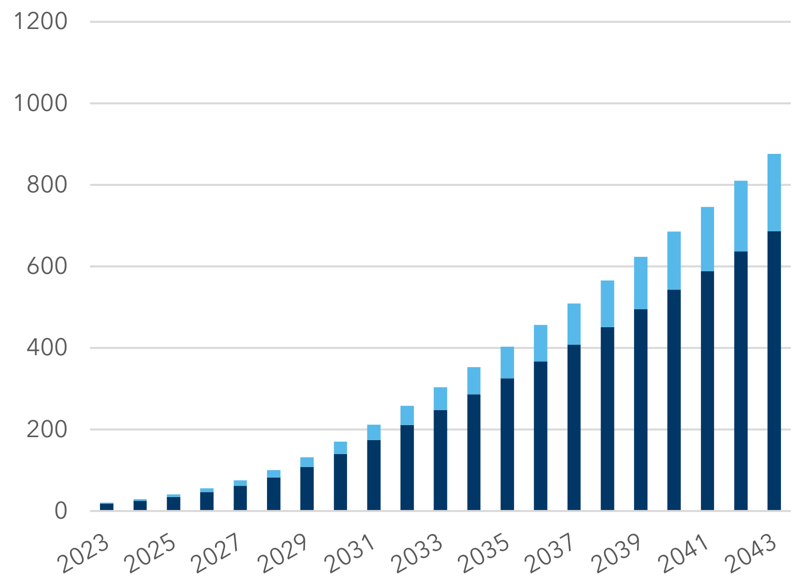
Despite MHDVs representing 3% to 4% of on-road electric vehicles in 2043 they represent 19% to 23% of annual EV energy consumption. This is driven by their higher driving distance coupled with the higher energy consumption per vehicle.

LDV energy consumption will drive the majority of EV load (~81% - 77% for the low and high scenario respectively).

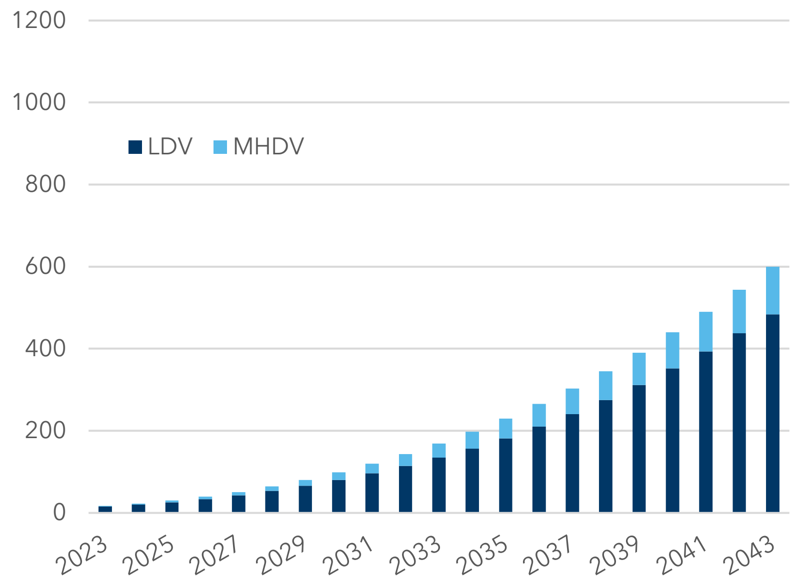
High Growth (GWh)



Medium Growth (GWh)



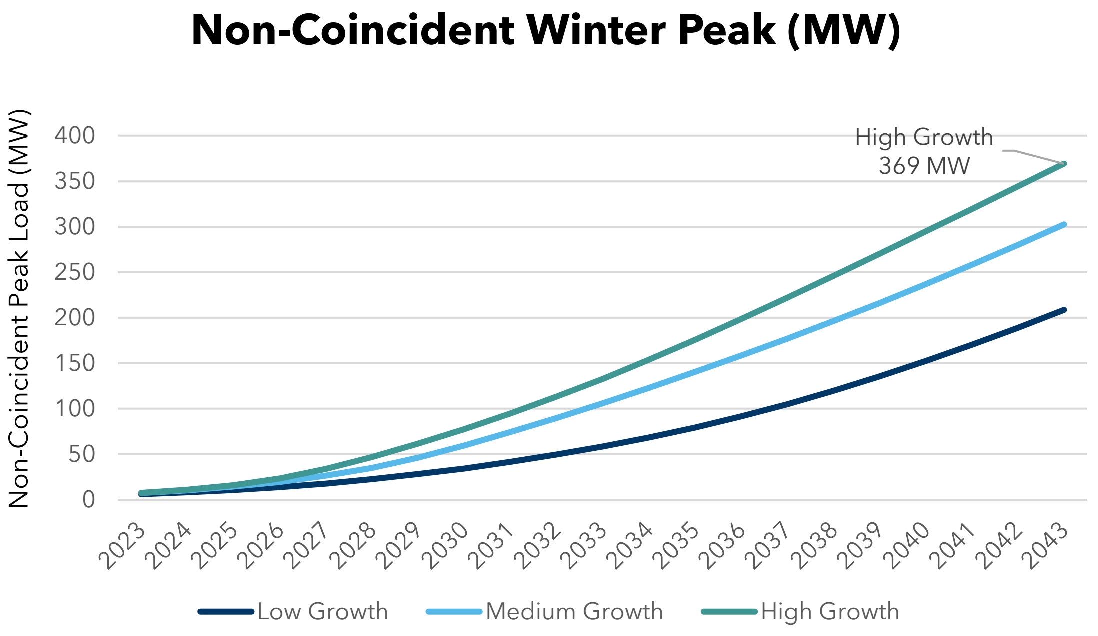
Low Growth (GWh)

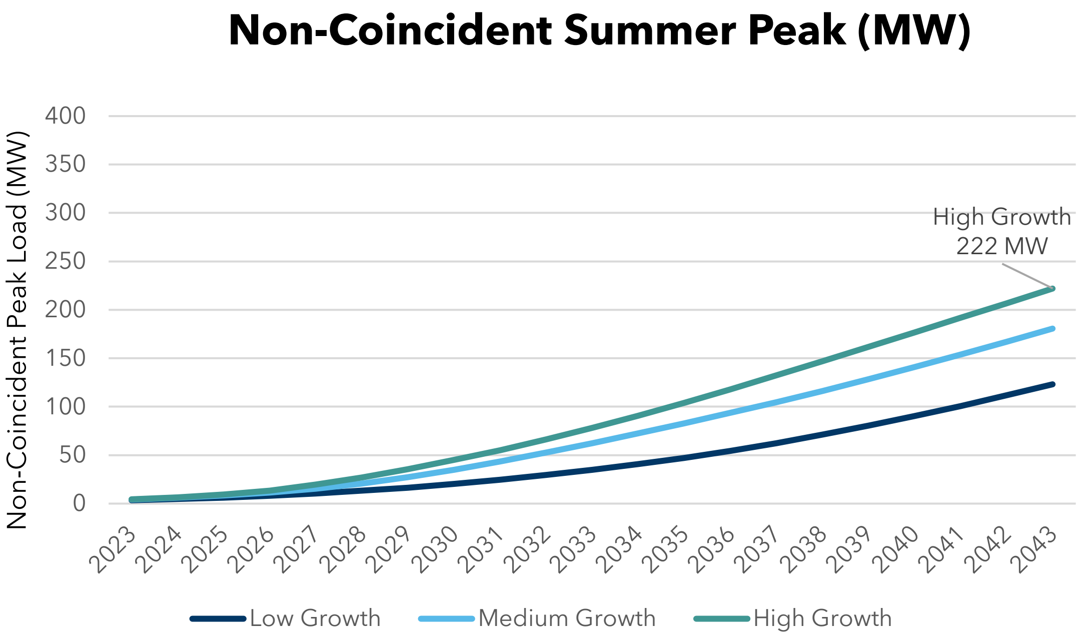


Non-coincident Peak Demand

Non-coincident peak demand impacts are nearly 66% higher on a typical peak winter day relative to a peak summer day due to higher average energy consumption in the colder months.

Cold outdoor air temperatures can increase energy needs by up to two times relative to summer requirements primarily due to cabin heating requirements.[1]





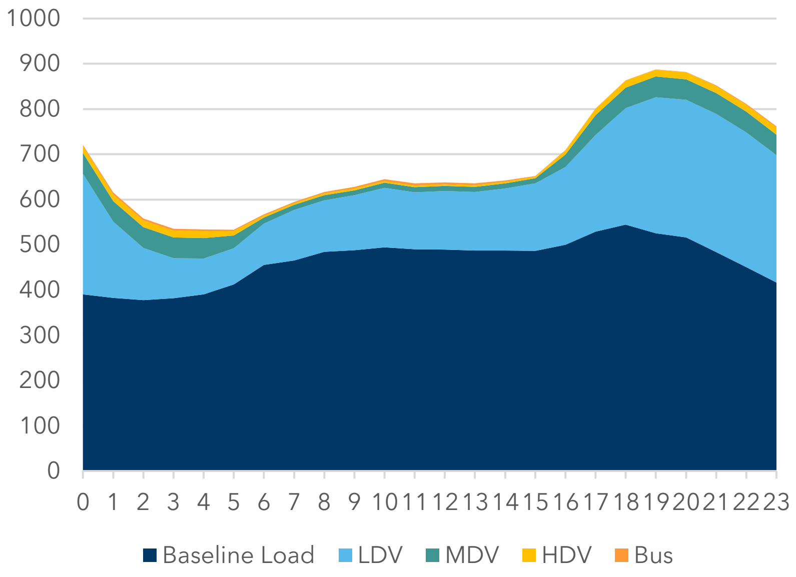
[1] Geotab. *To what degree does temperature impact EV range?*

Unmitigated Winter Peak Demand Impacts - 2043

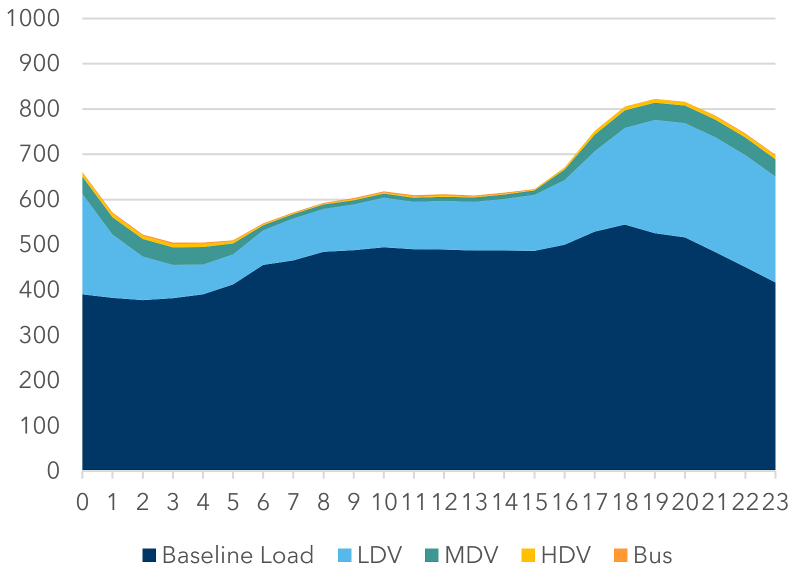
Unmitigated EV load can drive system peak from summer to winter

Under all scenario's unmitigated EV loads contribute to significant peak load increases. The influence of the unmitigated load impacts create an evening winter peak. The evening EV peak (~9pm) is driven by overnight EV charging.

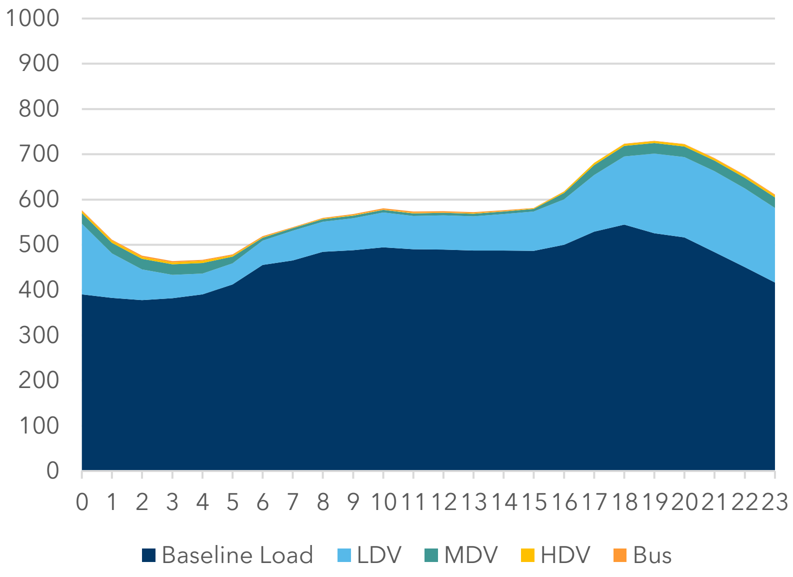
High Growth, 2043 (MW)



Medium Growth, 2043 (MW)



Low Growth, 2043 (MW)

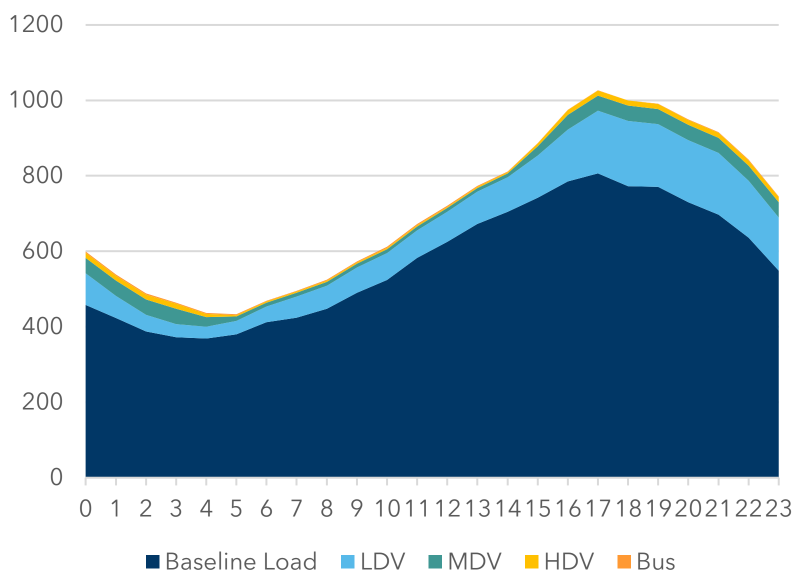


Unmitigated Summer Peak Demand Impacts - 2043

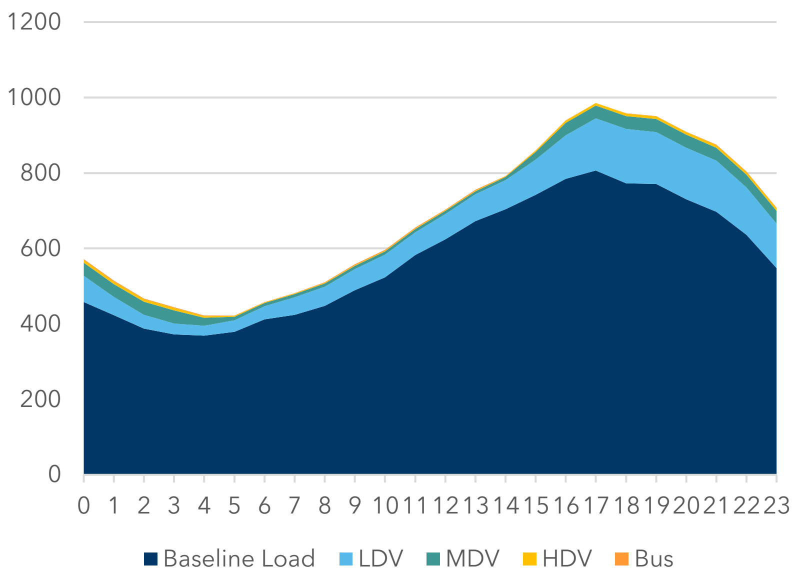
Unmitigated EV load can drive system peak from summer to winter

While summer peak load impacts are not as substantial as winter impacts, increasing EV loads will still result in elevated summer peaks relative to baseline forecasts.

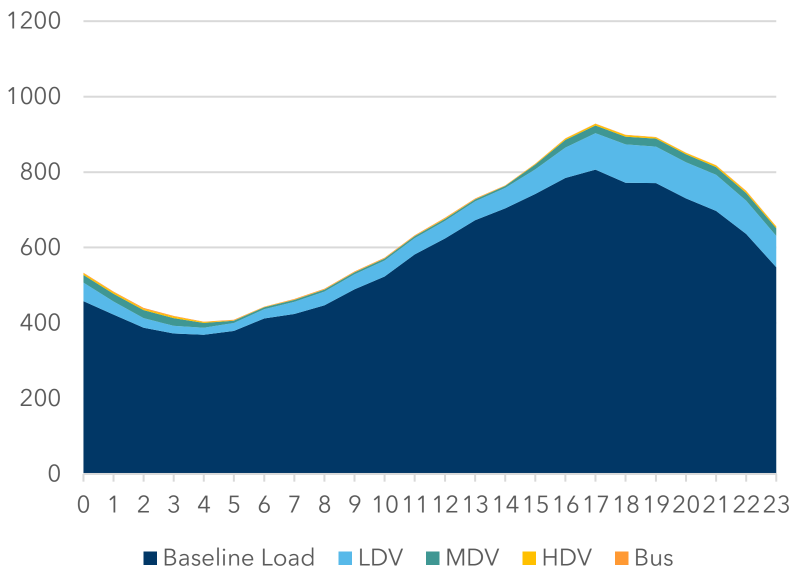
High Growth, 2043 (MW)



Medium Growth, 2043 (MW)



Low Growth, 2043 (MW)

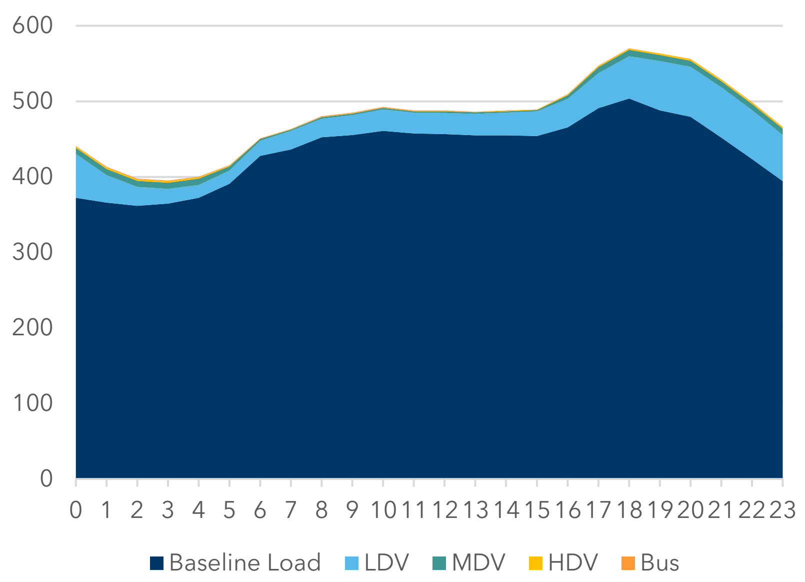


Unmitigated Winter Peak Demand Impacts - 2030

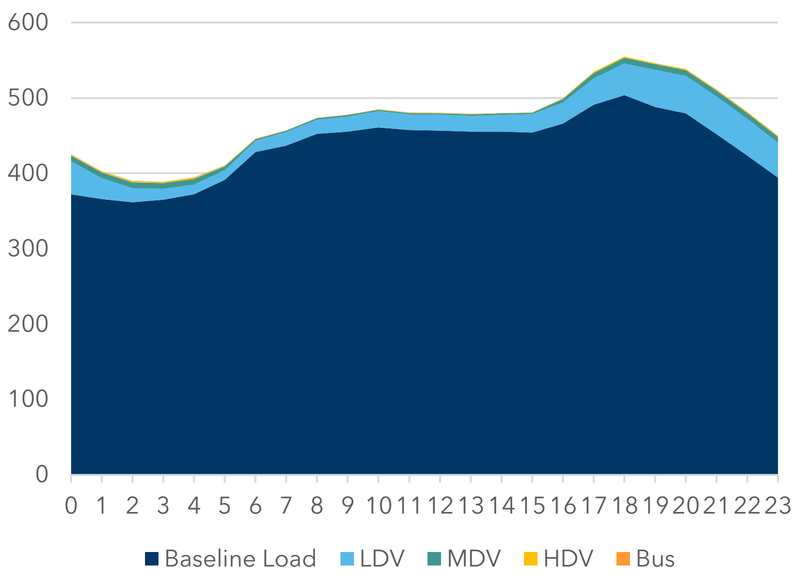
Unmitigated EV load can drive system peak from summer to winter

While much lower in 2030 than 2043, the influence of the EV unmitigated load impacts create an evening winter peak.

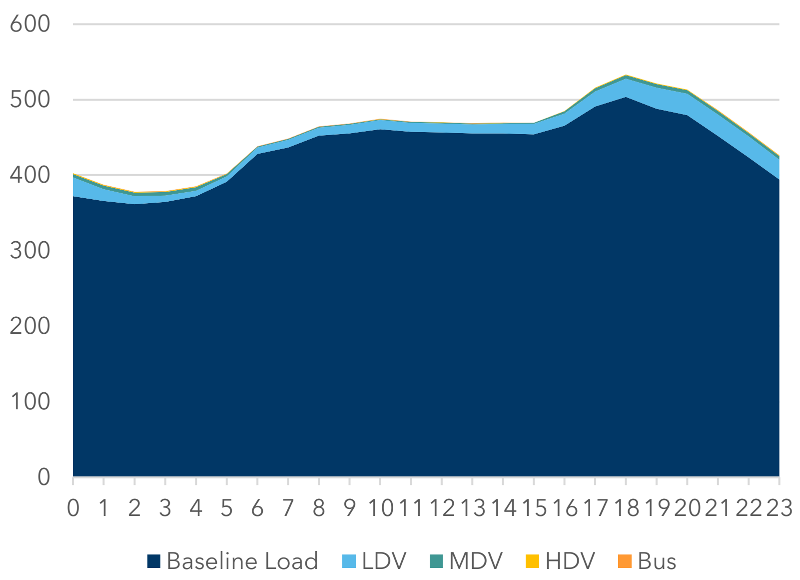
High Growth, 2030 (MW)



Medium Growth, 2030 (MW)



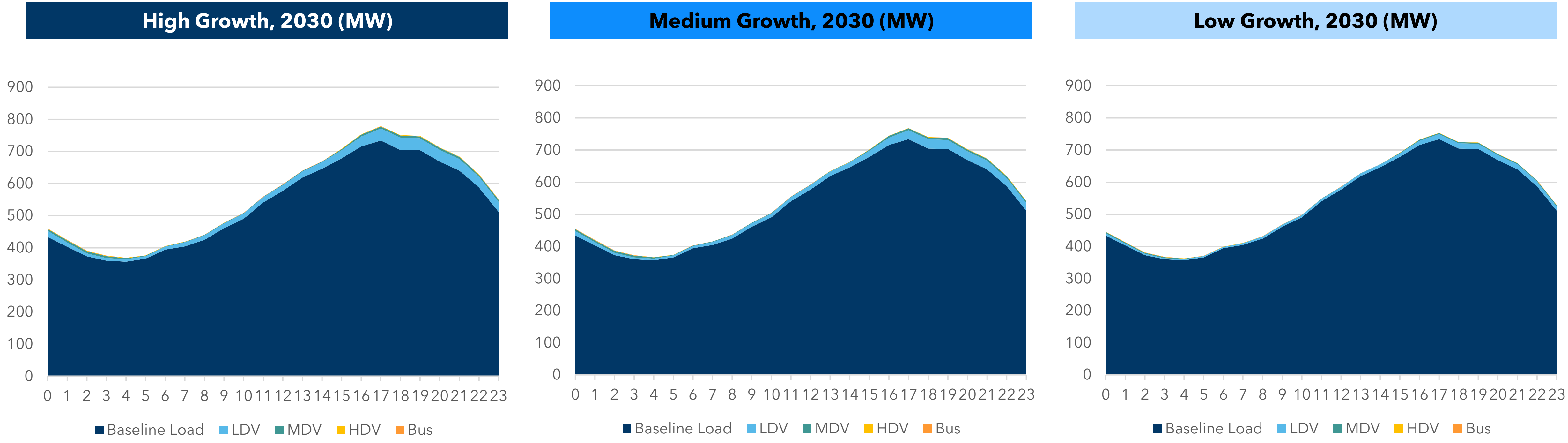
Low Growth, 2030 (MW)



Unmitigated Summer Peak Demand Impacts - 2030

Unmitigated EV load can drive system peak from summer to winter

While summer peak load impacts are not as substantial as winter impacts, increasing EV loads will still result in elevated summer peaks relative to baseline forecasts.



Transportation Electrification Adoption

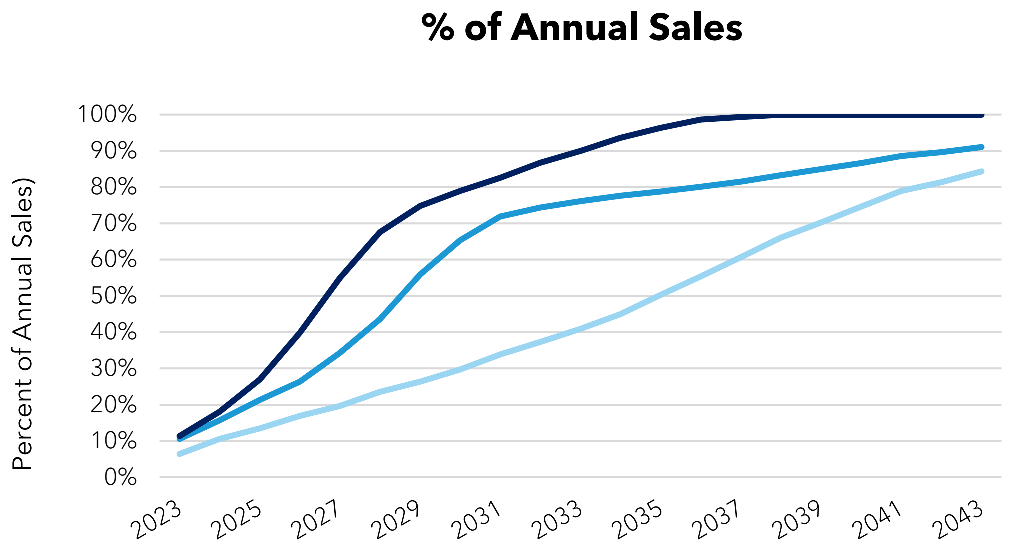
Light-Duty Vehicle Results

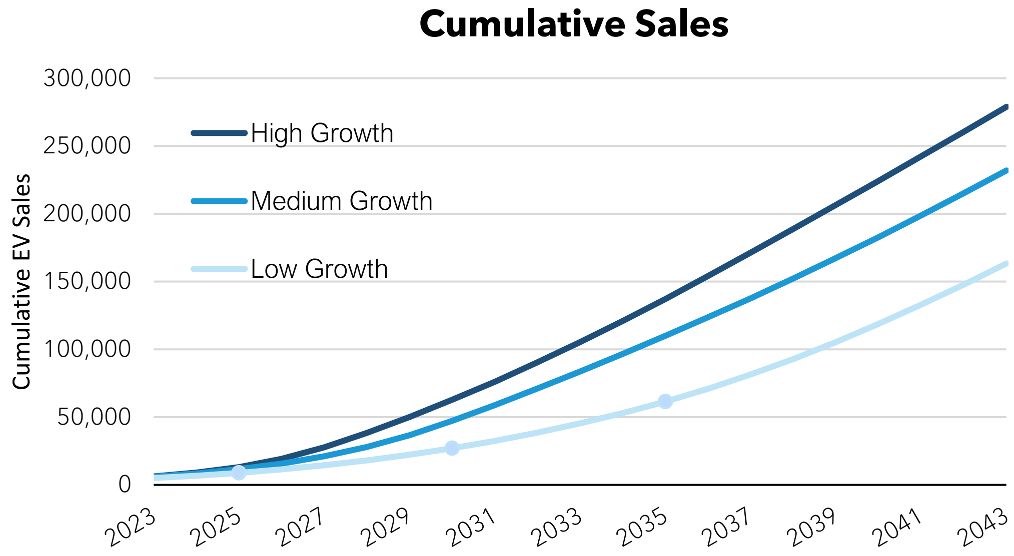
LDVs: Summary

The adoption of LDV EVs in PRPA's service territory is forecasted to increase rapidly over the study period

However, the degree of adoption will depend on the level of policy and program interventions in place to accelerate EV adoption.

- Without significant policy and program support, EV adoption in the service territory will be more limited in the Low Growth scenario, reaching 163,000 EVs by 2043. The Medium and High growth scenarios will reach 232,000 and 279,000 by 2043, respectively.
- Under the High Growth scenario, the proportion of annual sales steadily increases towards the 100% ZEV mandate in 2035 due to additional policy supports including public charging, home charging access, and upfront cost reductions.

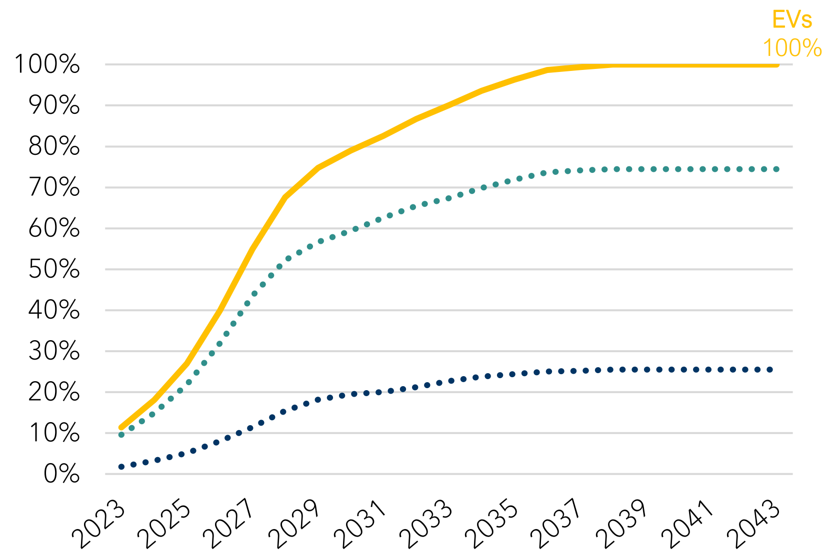




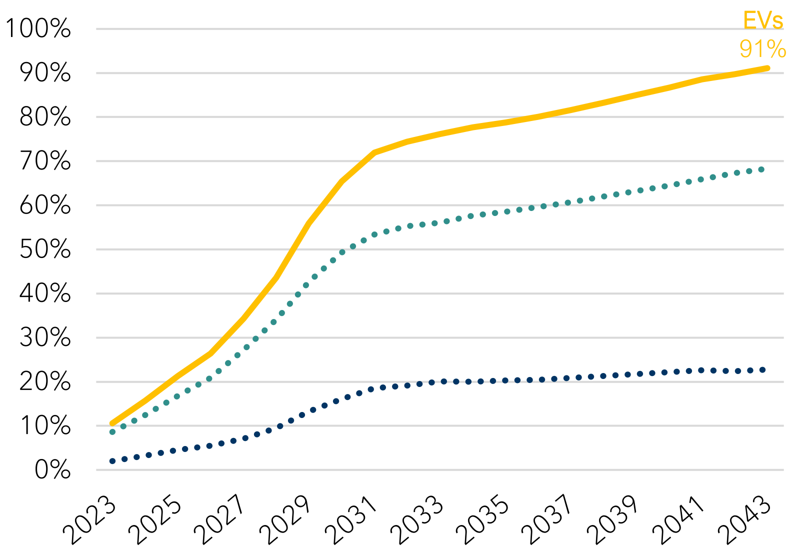
LDVs: Annual Sales Targets

EV adoption in PRPA's service territory reaches the 2035 ZEV Target of 100% of sales under the High Growth scenario. Adoption will fall short under the Low and Medium Growth scenario, reaching only 50% and 79% of new sales, respectively, by 2035.

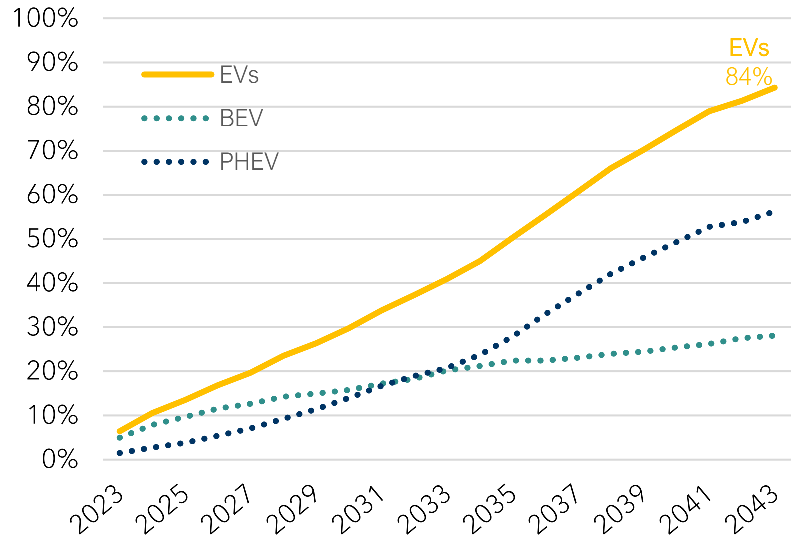
High Growth (% of sales)



Medium Growth (% of sales)



Low Growth (% of sales)



LDVs: Annual Load Impacts

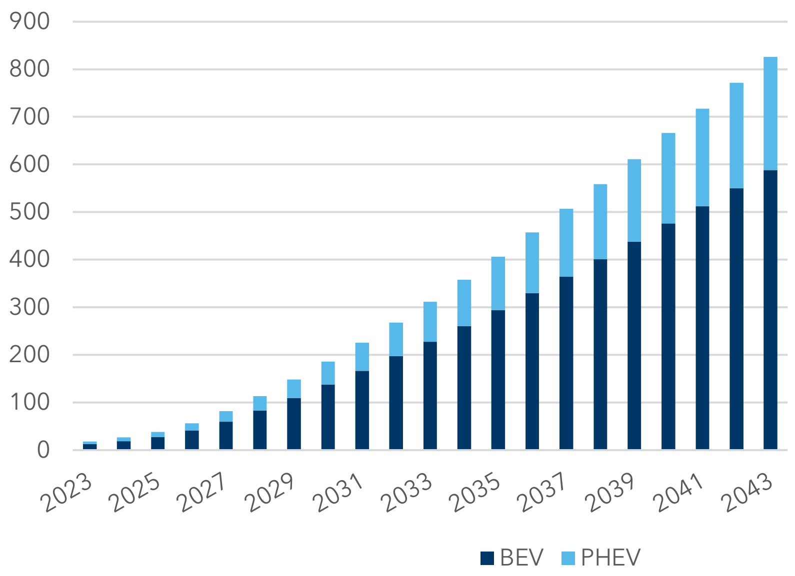
Annual load impacts could range from 454 to 775 GWh by 2043 under the Low and High Growth scenarios, respectively, mirroring cumulative EV adoption.

The relative proportion of BEV and PHEVs adopted will also impact annual load growth, as BEVs run on an electric powertrain 100% of the time as opposed to PHEVs that have the option to use an internal combustion engine resulting in higher energy consumption for BEVs.

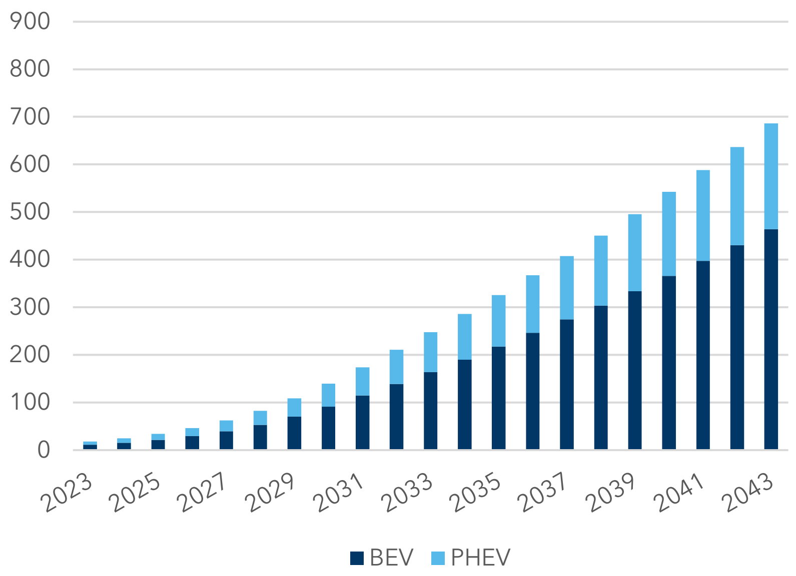
The breakdown of these two EV types is driven primarily by public charging availability.

- Under the Low Growth scenario, where charging infrastructure is limited, 50% of annual load impacts result from PHEVs.
- In the Medium and High Growth scenarios, where charging infrastructure is more prevalent, the majority of load impacts result from BEVs (~80% -82%).

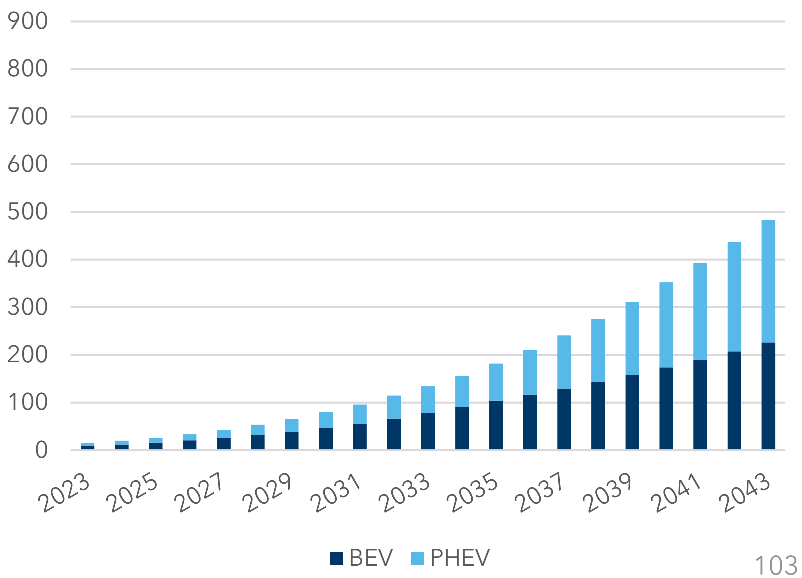
High Growth (GWh)



Medium Growth (GWh)



Low Growth (GWh)

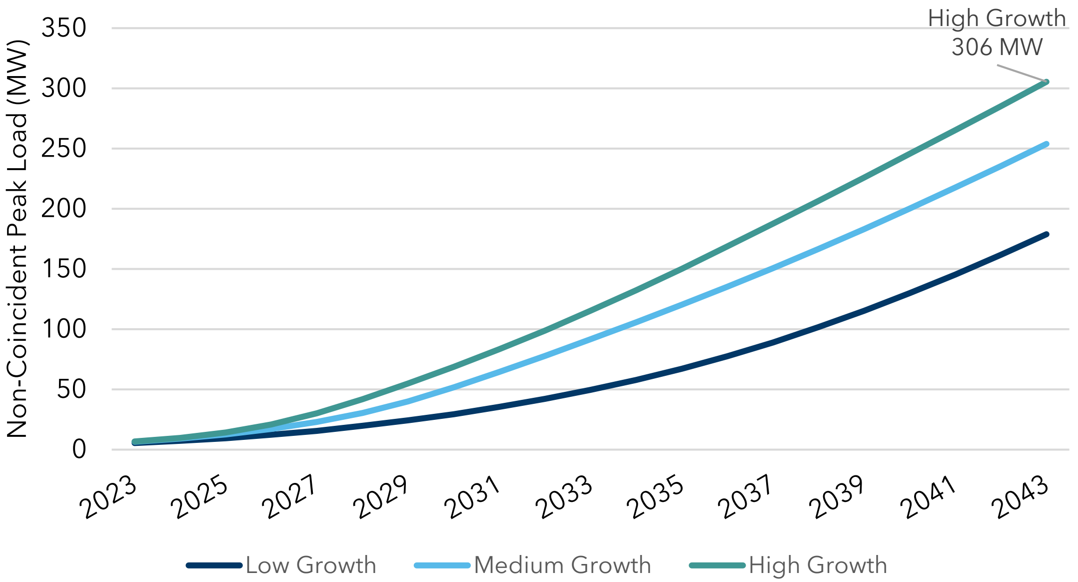


LDVs: Non-coincident Peak Demand

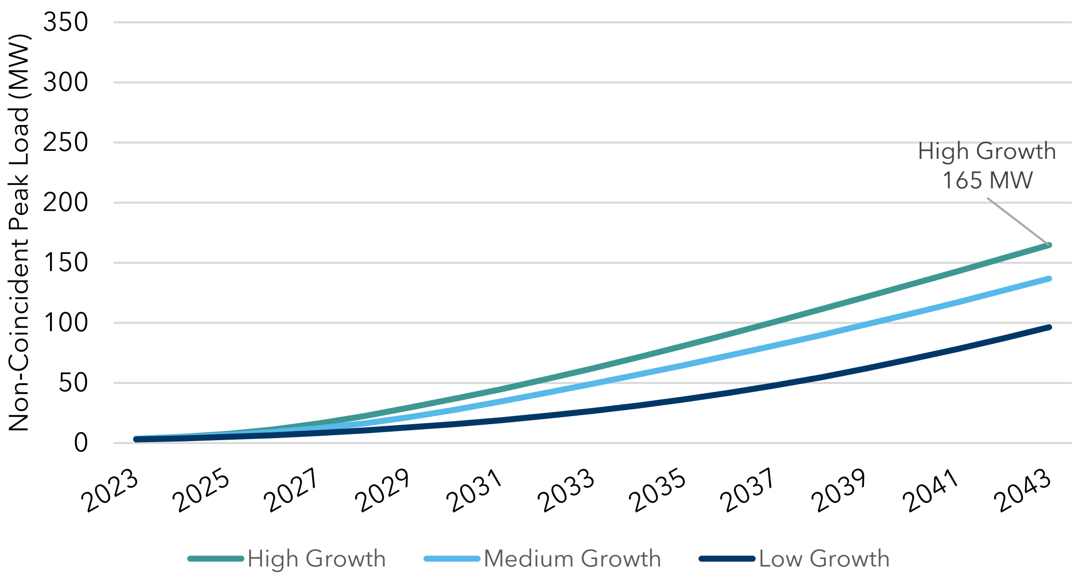
Demand impacts will be significantly higher on a typical peak winter day relative to a peak summer day due to higher EV energy consumption in the colder months.

Cold outdoor air temperatures can increase energy needs by up to two times relative to summer requirements primarily due to cabin heating requirements.[1]

Non-Coincident Winter Peak (MW)



Non-Coincident Summer Peak (MW)



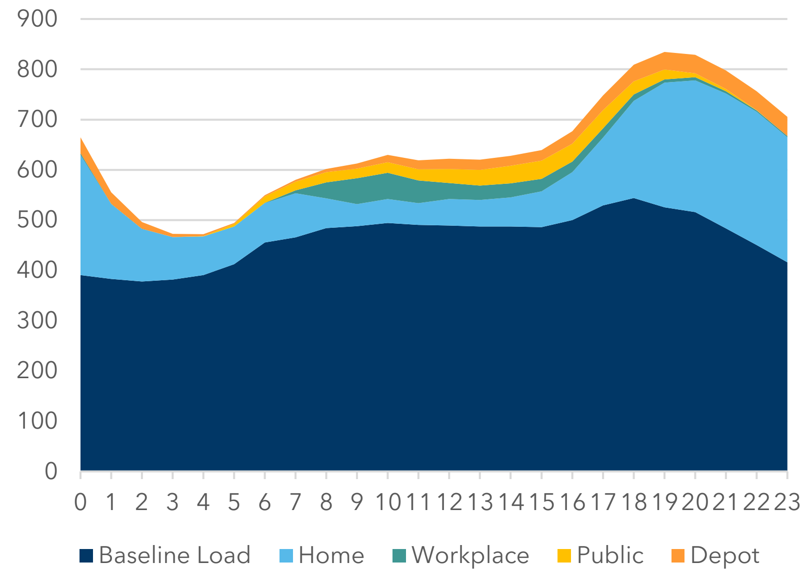
[1] Geotab. *To what degree does temperature impact EV range?*

LDVs: Winter Peak Demand Impacts - 2043

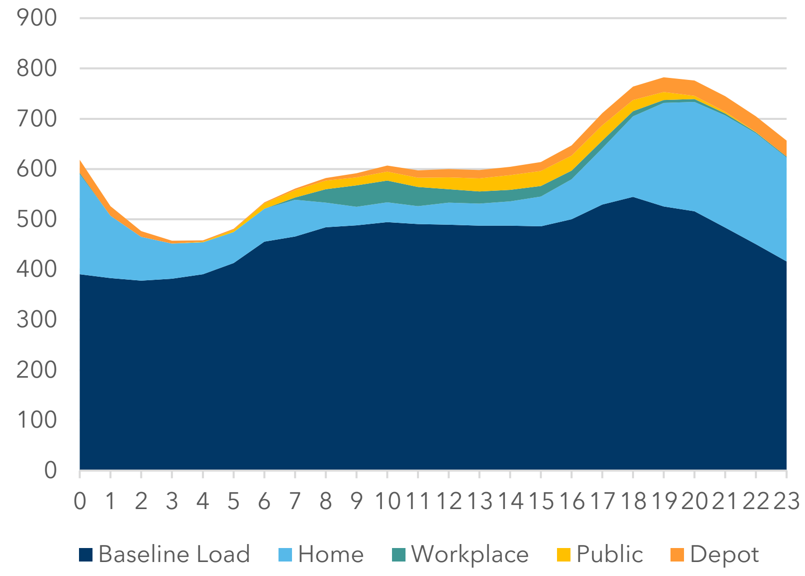
When applied to a typical peak winter day, unmitigated load from passenger EVs will significantly increase peak demand in the evening. This impact is primarily driven by home charging, and to a lesser degree commercial fleet charging (LDV depot charging) as personal-use and commercial-use LDVs will typically charge in the evening and overnight. Public charging has some impact in the early evening as most commuters head home.

Workplace charging is not expected to result in a significant peak impact at the system-level given the low proportion of charging events that take place in the evening.

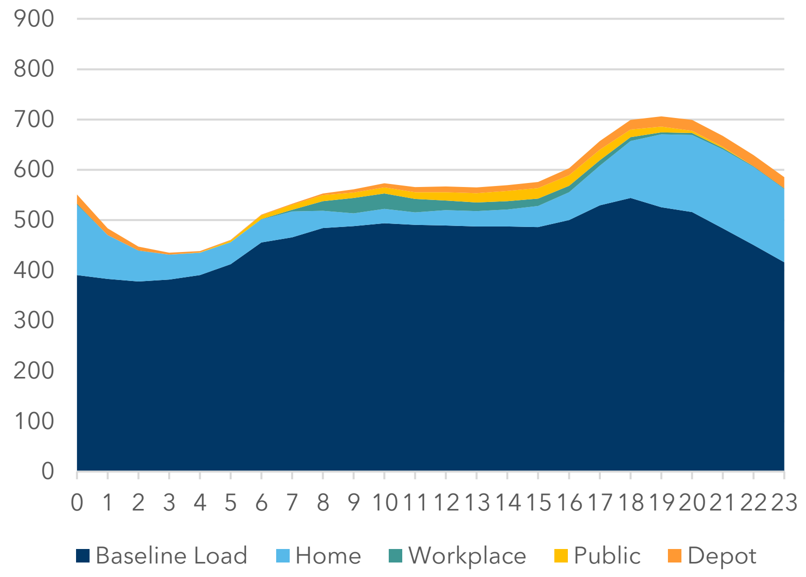
High Growth, 2043 (MW)



Medium Growth, 2043 (MW)



Low Growth, 2043 (MW)

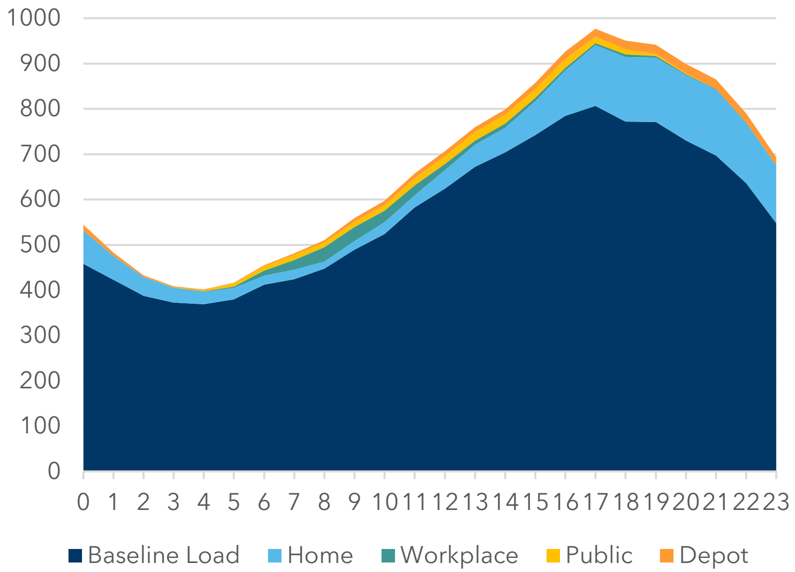


LDVs: Summer Peak Demand Impacts - 2043

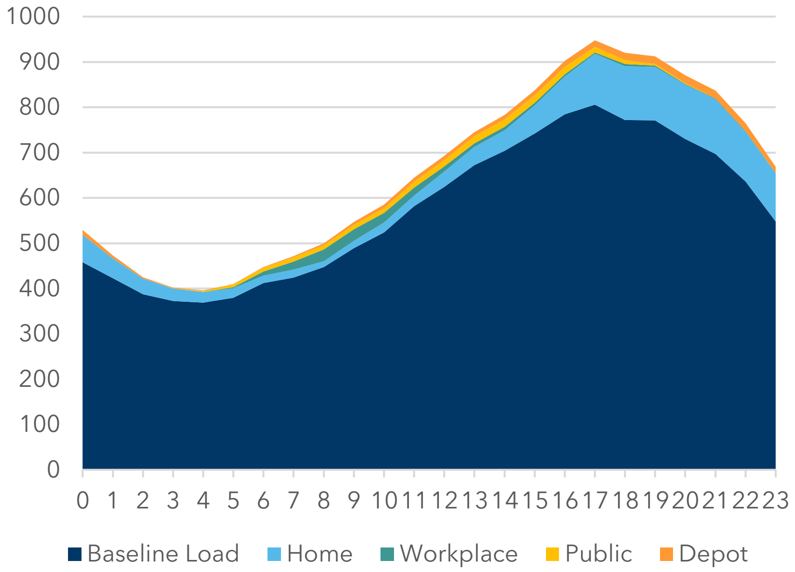
When applied to a typical peak summer day, passenger EVs will similarly increase peak demand and push the peak hour to later in the evening as observed for typical peak winter days.

As previously discussed, summer EV peak impacts are lower than winter impacts as cabin heating is not required, diminishing the impact of EVs on the summer peaking system.

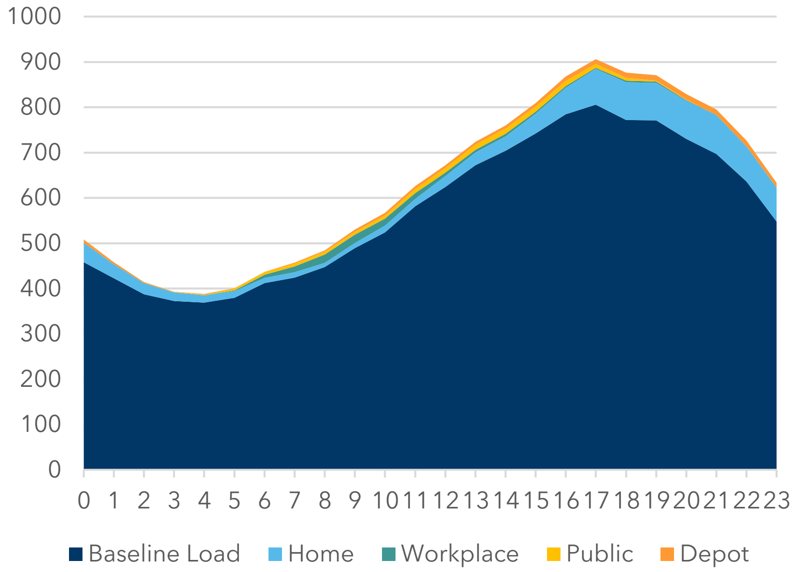
High Growth, 2043 (MW)



Medium Growth, 2043 (MW)



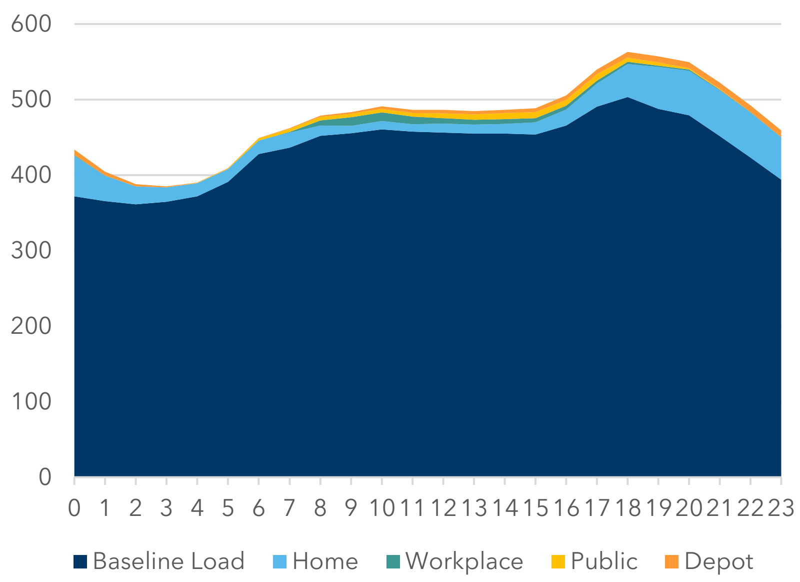
Low Growth, 2043 (MW)



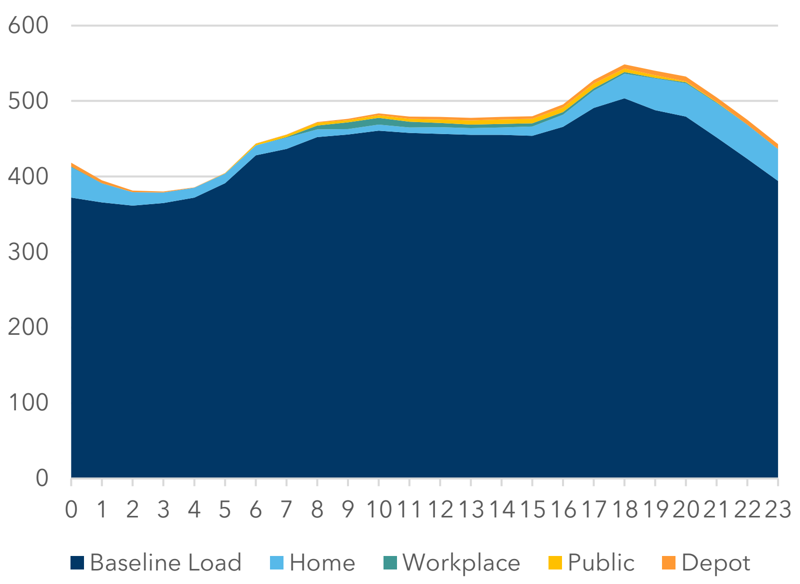
LDVs: Winter Peak Demand Impacts - 2030

Similarly, to 2043 peak impacts, unmitigated load from passenger EVs will increase peak demand in the evening. This impact is less substantial in 2030 due to less electric vehicles on the road.

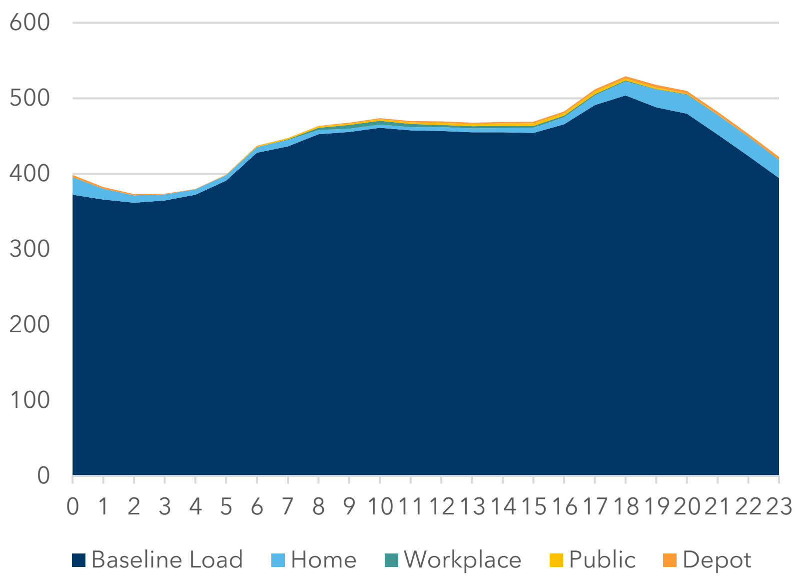
High Growth, 2030 (MW)



Medium Growth, 2030 (MW)



Low Growth, 2030 (MW)



LDVs: Summer Peak Demand Impacts - 2030

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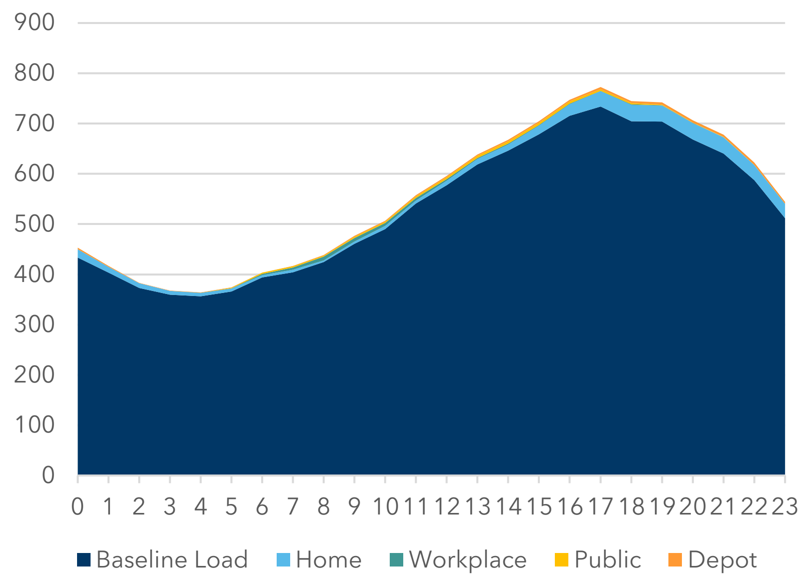
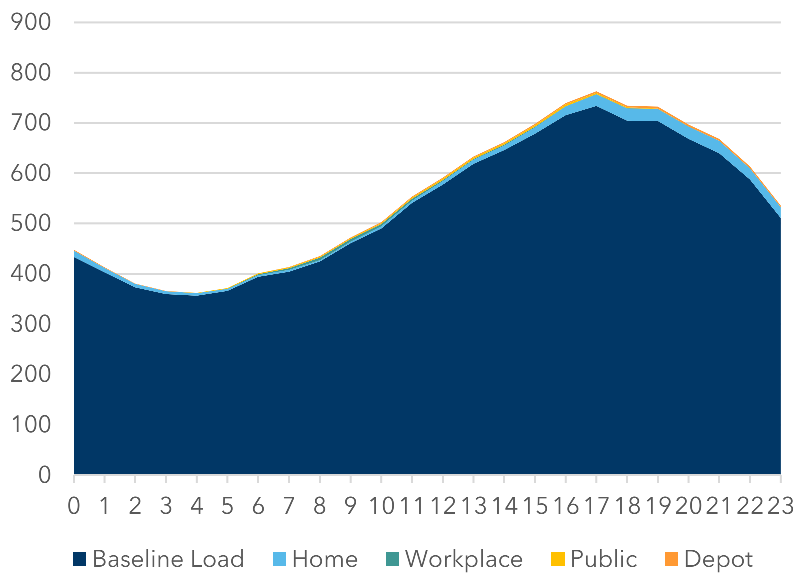
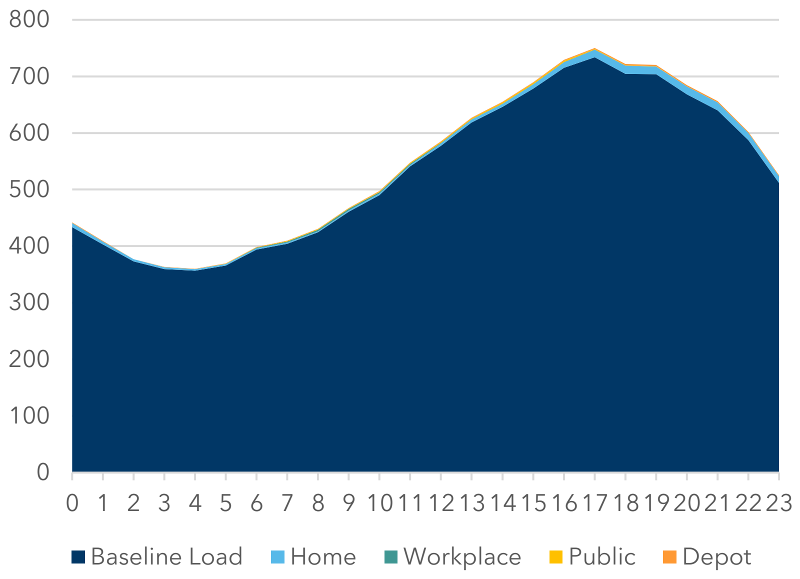
High Growth, 2030 (MW)



Medium Growth, 2030 (MW)



Low Growth, 2030 (MW)



Transportation Electrification Adoption

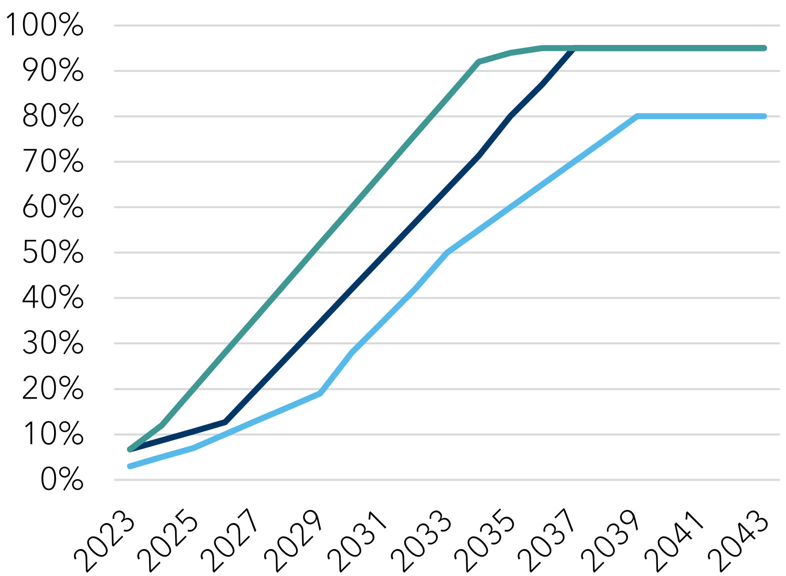
Medium and Heavy-Duty Vehicle Results

MHDVs: Annual Sales

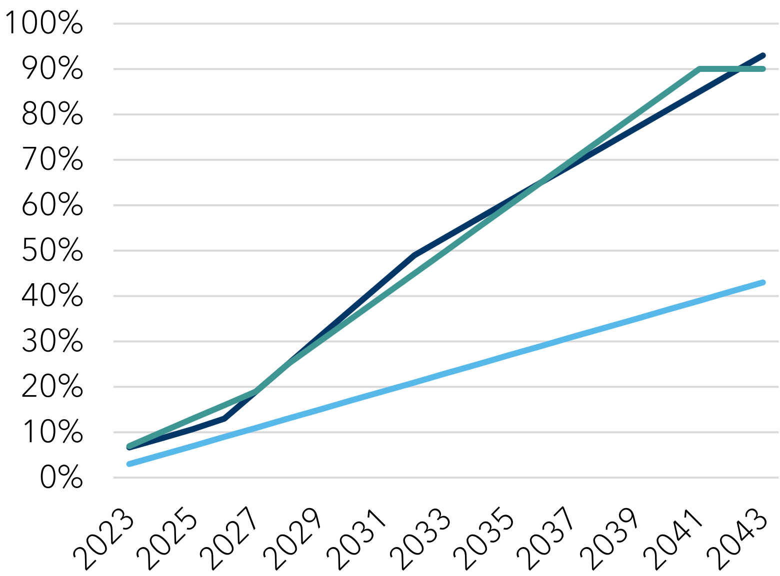
MHDV EV sales are expected to grow substantially after 2026 for all three scenarios.

- MDV trucks will lead the MHDV market, with the highest market share. This segment is largely comprised of urban delivery vehicles that benefit from a strong business case for electrification due to consistent daily usage with high overall annual driving distances.
- Buses also have a strong business case to electrify with high drive cycles.
- The HDV truck segment is expected to experience the lowest EV demand, especially due to a portion of the HDV truck market focused on either long-haul or other vocational applications (e.g., dump trucks) with greater technical challenges (range requirements, payload capacity) and weaker economics in the case of vocational trucks (due to lower annual driving distances and fuel savings potential).

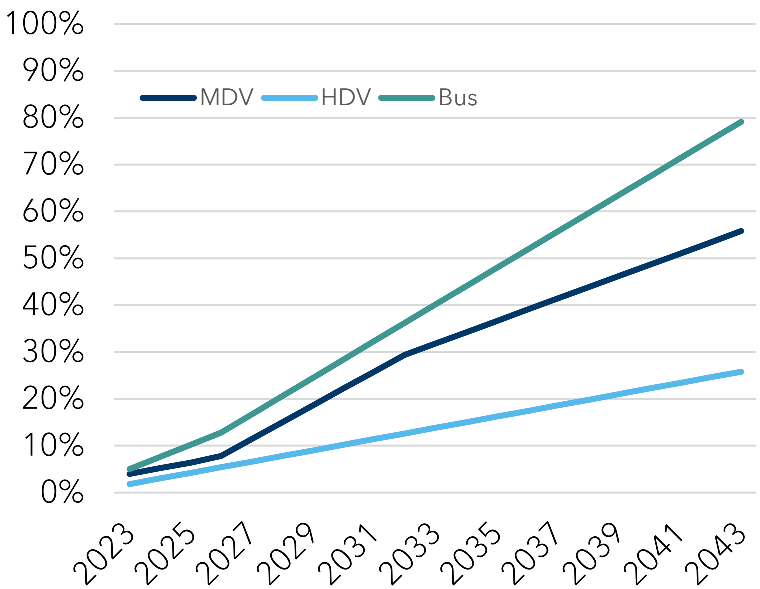
High Growth (% of sales)



Medium Growth (% of sales)



Low Growth (% of sales)

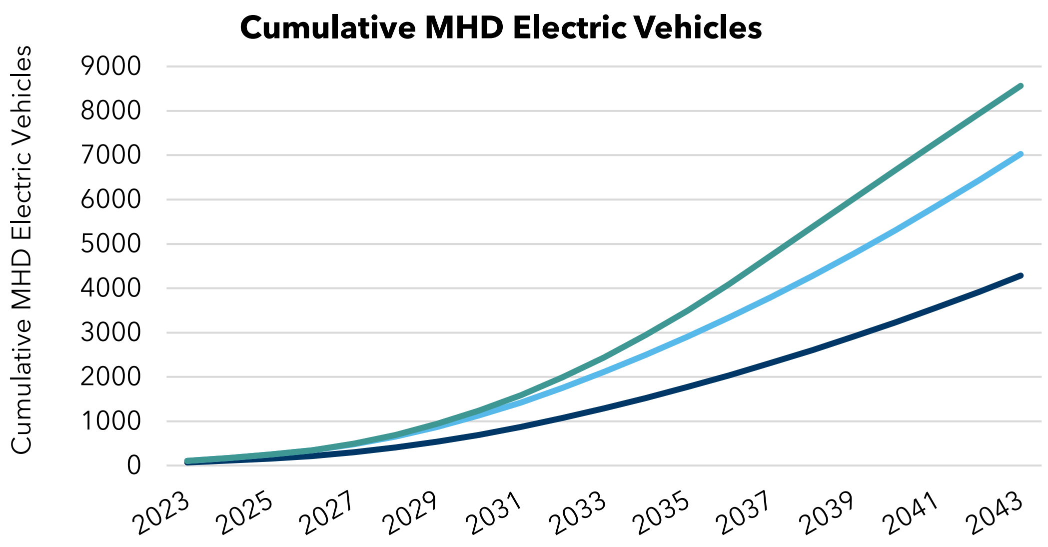


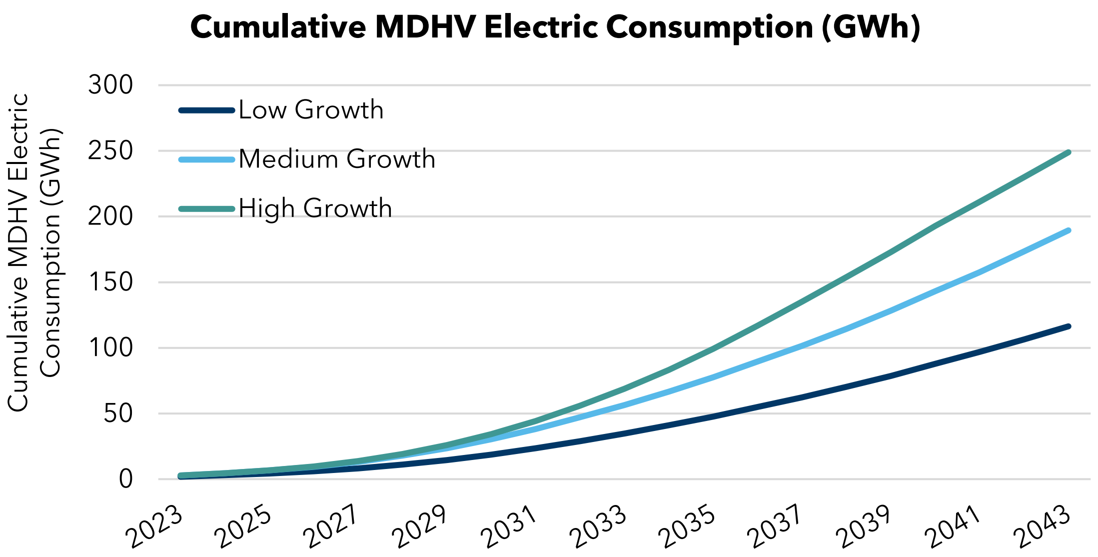
MHDVs: Annual Load Impacts

Annual load impacts grow proportionally with forecasted level of adoption in terms of cumulative EVs in circulation.

The relationship between the number of EVs in circulation and the annual load impact depends on assumptions for the energy intensity (kWh/mile) and annual miles driven for each vehicle segment.

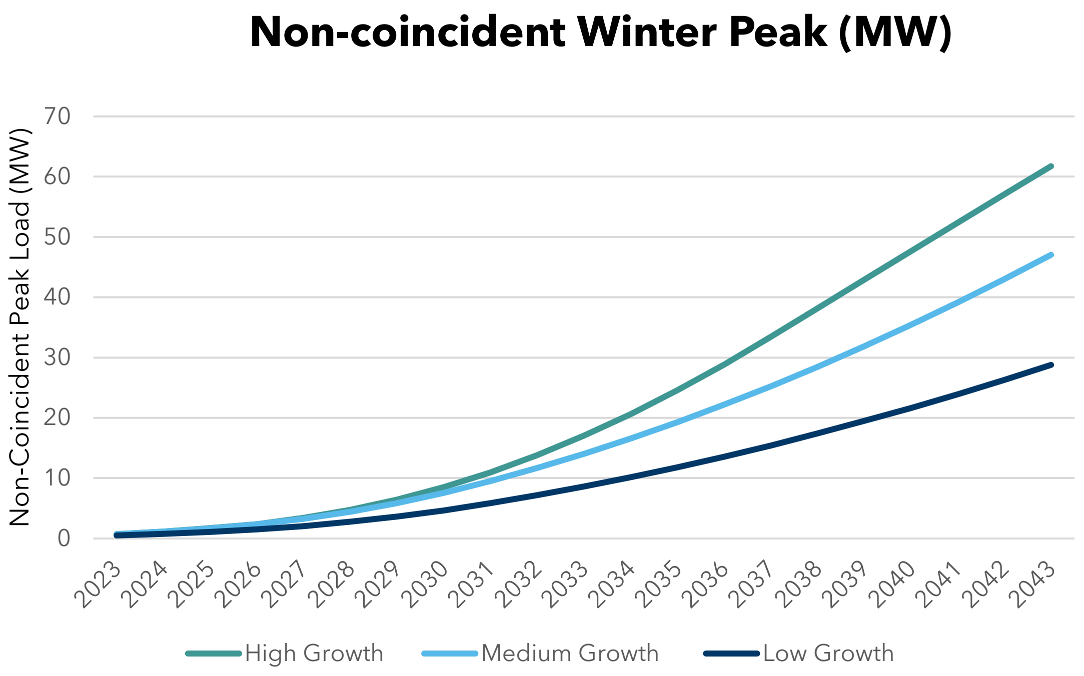
Overall, MHDVs have a significantly higher energy intensity than LDVs, and in some cases (transit buses, short- and long-haul HDV trucks) significantly higher annual miles driven.

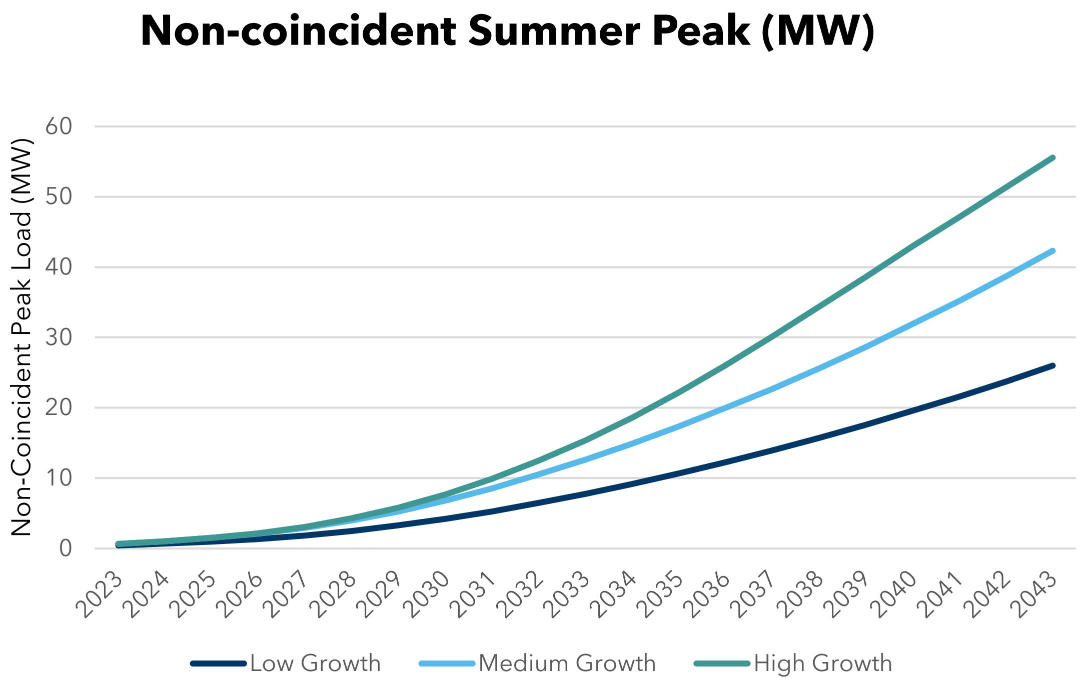




MHDVs: Non-coincident Peak Impacts

While peak impacts for MHDVs are more pronounced in winter compared to summer due to cabin heating, unlike LDVs, the difference of the seasonal peak is much less substantial as predominantly cabin heating is a smaller proportion of the vehicles total energy needs than an LDV.



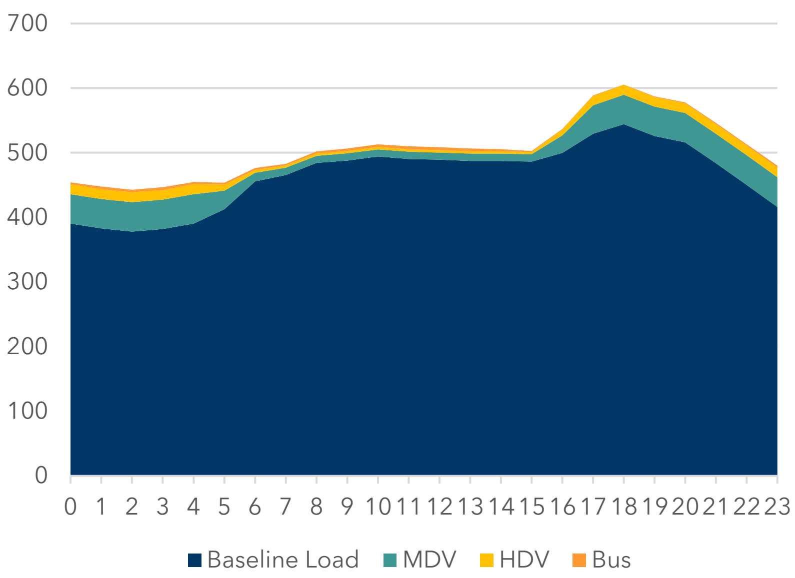


MHDVs: Winter Peak Impacts - 2043

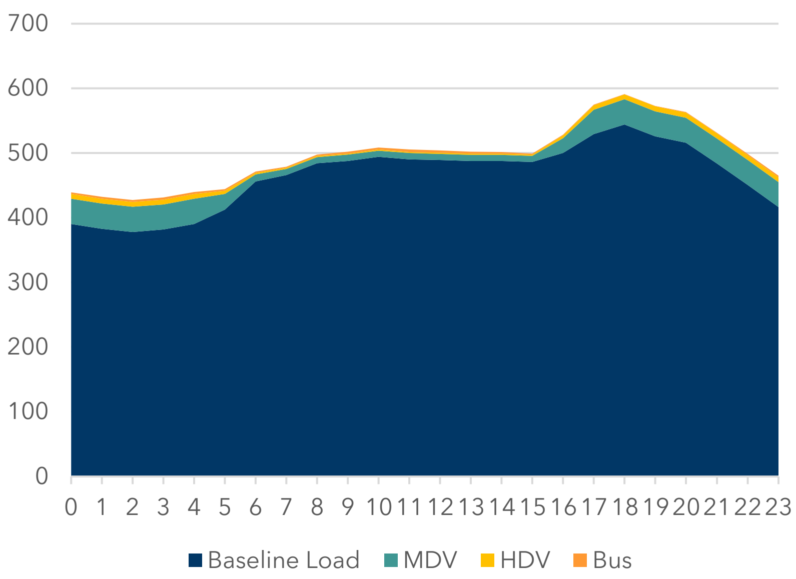
MDVs represent the largest portion of grid impacts as they are the largest vehicle segment and benefit from a strong business case for electrification resulting in a high market share for EVs.

Unlike with personal vehicles, many MHDV fleets will already be financially motivated to minimize peak load impacts of EVs to minimize demand charges and customer-side electrical infrastructure costs, which can limit the ability to apply load management strategies to this segment.

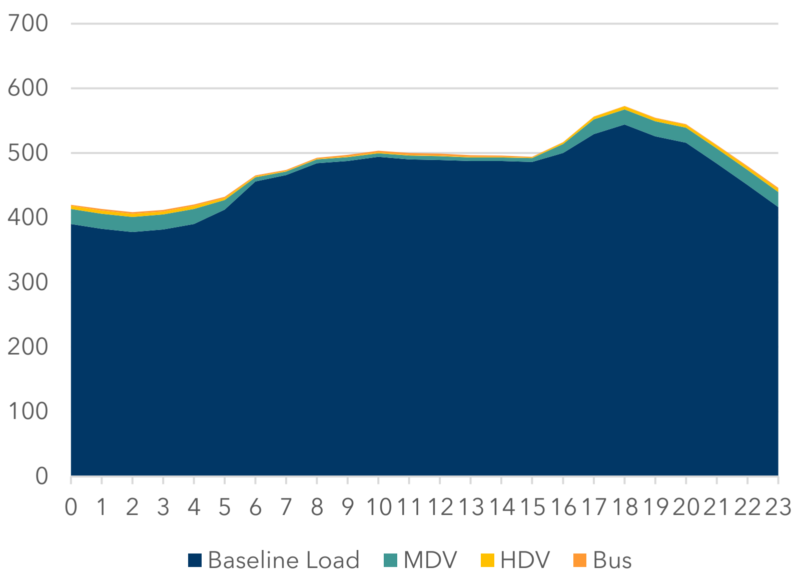
High Growth, 2043 (MW)



Medium Growth, 2043 (MW)



Low Growth, 2043 (MW)

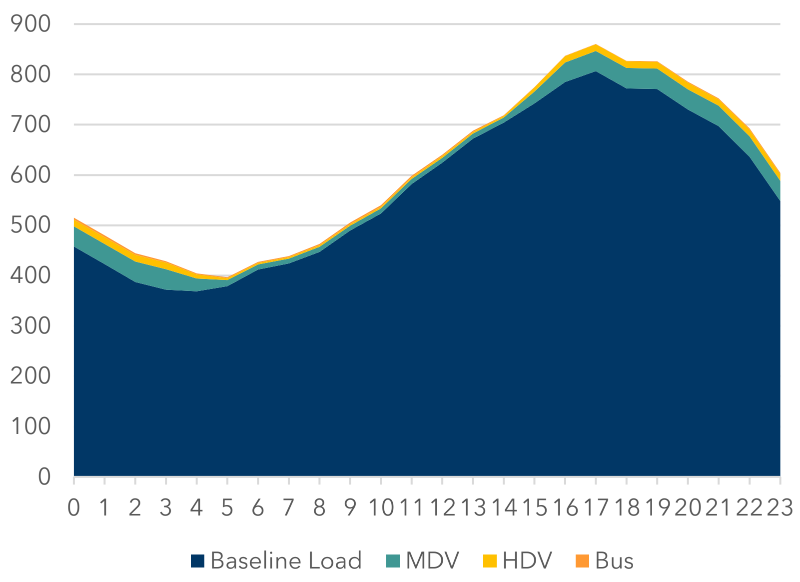


MHDVs: Summer Peak Impacts - 2043

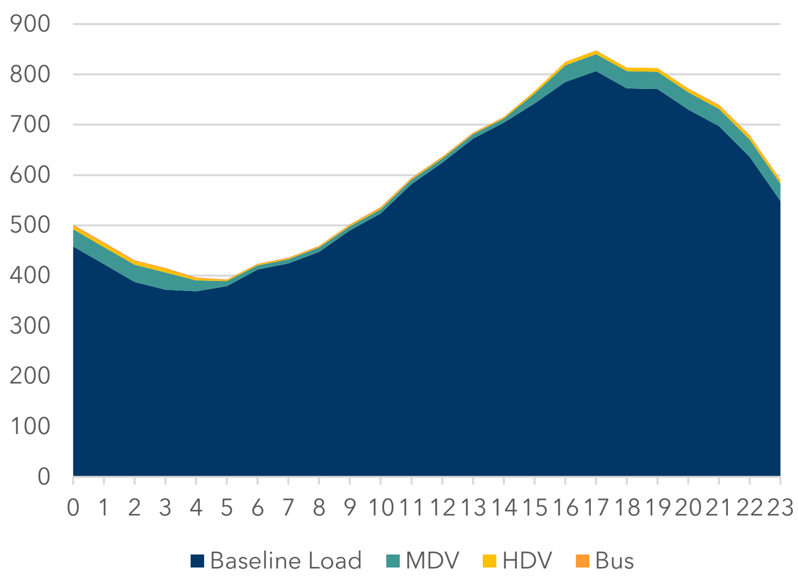
Similar to LDV's, summer EV peak impacts are lower than winter impacts, though less substantially than LDVs, as cabin heating is not required, diminishing the impact of EVs on a summer peaking system.

MHDV load impacts are highest in the late afternoon / early evening – driven by the return of vehicles to charging depots after typical work hours.

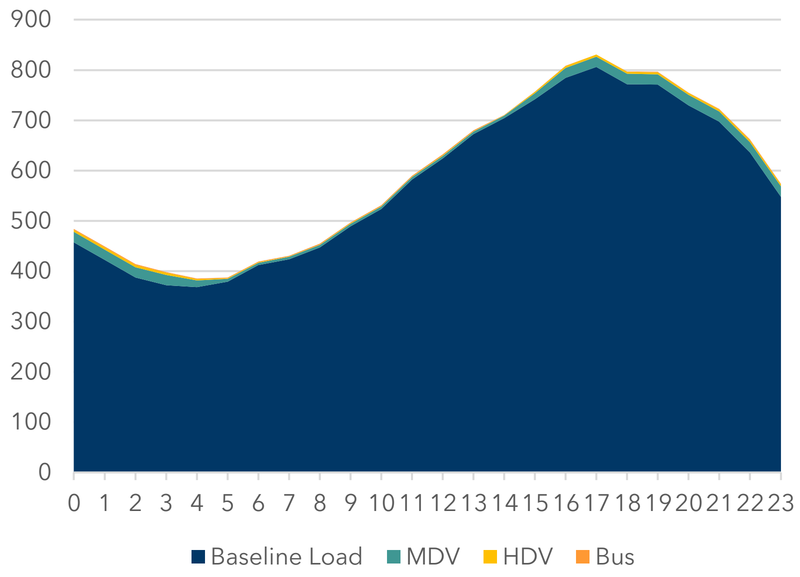
High Growth, 2043 (MW)



Medium Growth, 2043 (MW)



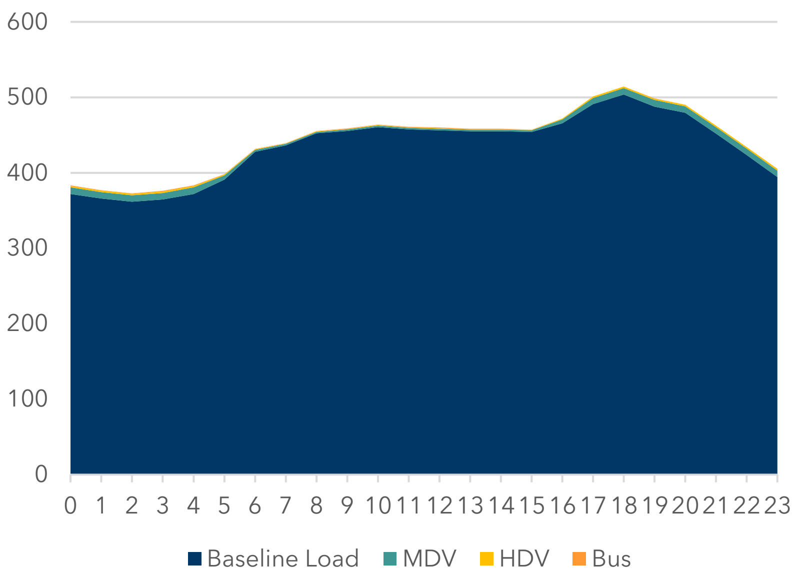
Low Growth, 2043 (MW)



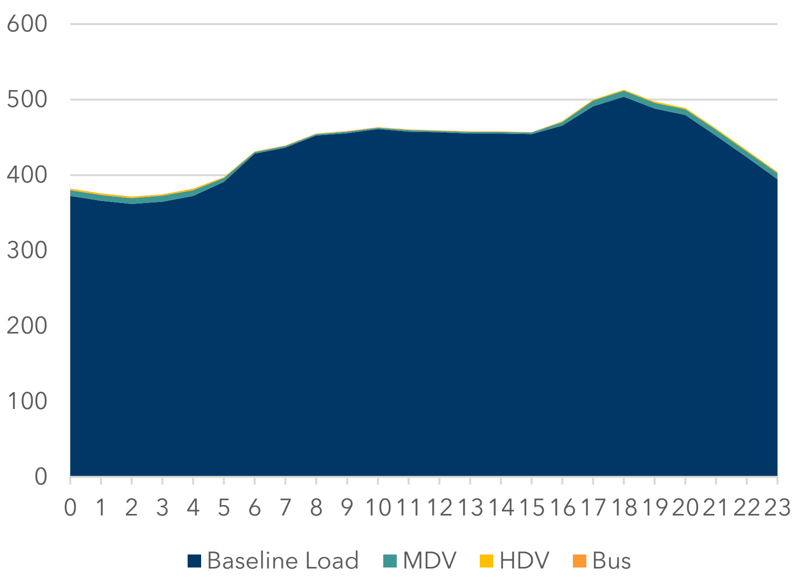
MHDVs: Winter Peak Impacts - 2030

The 2030 impact of EVs is much less substantially than 2043 due to very few electric MHDVs on the road.

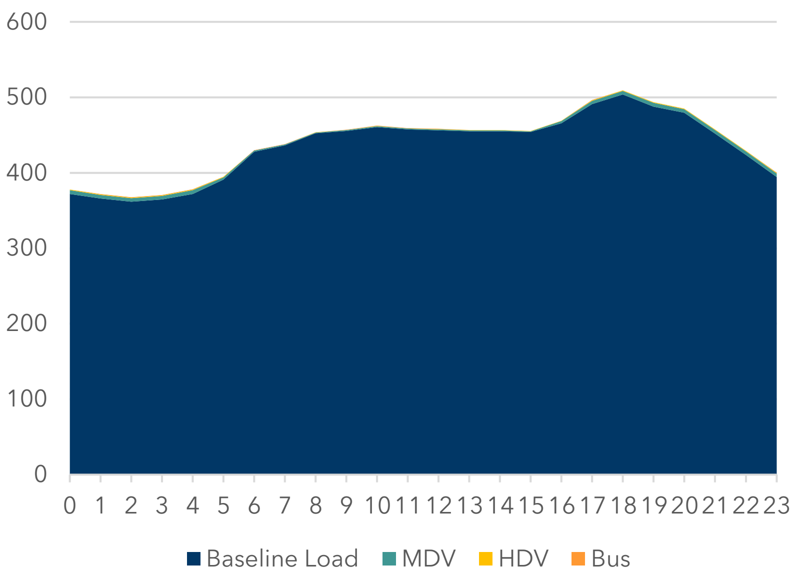
High Growth, 2030 (MW)



Medium Growth, 2030 (MW)



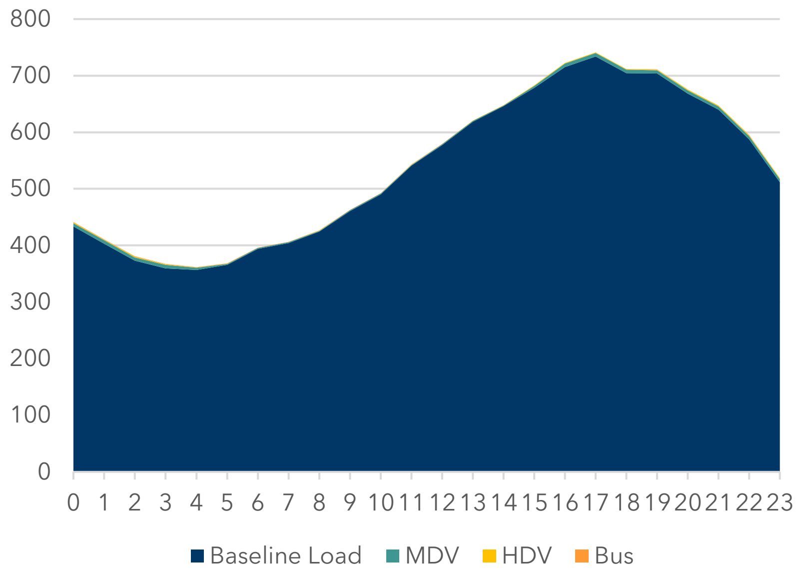
Low Growth, 2030 (MW)



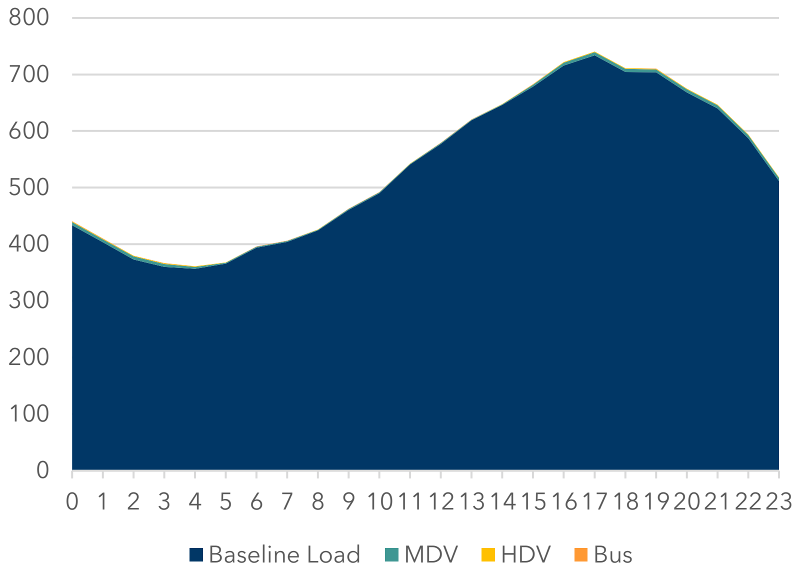
MHDVs: Summer Peak Impacts - 2030

The 2030 impact of EVs is much less substantially than 2043 due to very few electric MHDVs on the road.

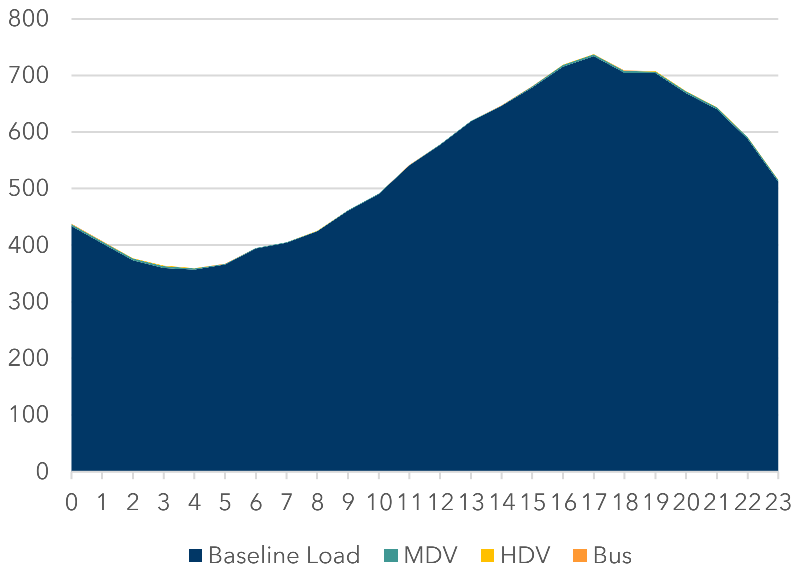
High Growth, 2030 (MW)



Medium Growth, 2030 (MW)



Low Growth, 2030 (MW)



MHDVs: Considerations

MHDV fleets present unique challenges and opportunities for mitigation of peak load impacts.

- MHDVs are often part of larger fleets with centralized charging stations, which makes their load impact easier to anticipate from a distribution congestion perspective than LDVs that are more numerous and scattered in terms of charging locations.
- With the potential for a large number of vehicles charging in a single facility, charging load can represent a significant impact relative to a building's existing load. Fleet electrification decisions can also result in notable step-changes in load over a short lapse of time ensuing more acute load impacts at the distribution level.
- While currently, adoption of EVs in some segments may be limited by EV model availability, manufacturers are responding rapidly to market demand and ramping up production of EVs across almost all MHDV segments.
- It will be important to engage with fleet owners early on, understand their objectives for electrification, and anticipate increased demand accordingly.

Unlike with LDVs, many MHDV fleets may already be financially supported to minimize peak load impacts of EVs to reduce demand charges and customer-side electrical infrastructure costs.

- Instead of providing financial support, utilities can play an advisory role by providing guidance to fleets on their options for EV load management, helping to address both customer- and utility-side peak load impacts.

Transportation Electrification Adoption

Conclusion

Xcel Colorado 2021 Clean Energy Filing Plan – EV Sales (%)

Xcel	Xcel CO Base Case Sales Forecast[1]			Xcel CO Roadmap Sales Forecast[1]		
Year	LDV	MDV	HDV	LDV	MDV	HDV
2024	11%	3%	1%	26%	17%	17%
2025	11%	5%	2%	30%	21%	21%
2030	**26%**	**28%**	**10%**	**45%**	**43%**	**49%**
2035	29%	42%	15%	53%	95%	80%
2040	31%	55%	21%	55%	100%	86%

PRPA – Low Scenario			PRPA – Medium Scenario		
LDV	MDV	HDV	LDV	MDV	HDV
11%	5%	3%	16%	9%	5%
14%	6%	4%	21%	11%	7%
30%	**22%**	**11%**	**65%**	**37%**	**17%**
50%	37%	16%	79%	61%	27%
75%	49%	21%	87%	81%	37%

Source: 1) Volume 2 Technical Appendix (PDF), Table 2.2-6.

Key Takeaways

EV adoption is forecasted to increase rapidly over the study period and policy levers will have a significant impact on the rate of growth. The High Growth scenario would see over 287k light-duty EVs in circulation in Platte River's service territory by 2043.

If unmanaged, LDVs can increase winter evening peak loads by as much as 300 MW by 2043. Demand impacts will be significantly higher on a typical peak winter day relative to a peak summer day due to higher EV energy consumption in the colder months.

The inherent flexibility of EV charging loads means that they can be controlled, managed and potentially leveraged as Distributed Energy Resources (DERs) to reduce the peak demand impacts. Several EV load management strategies can be employed to shift charging loads from peak to off-peak hours, including time varying rates and direct load control.

For the MHDV segment, regulatory targets, along with availability of vehicles, drive the pace of adoption as most of the market is medium-duty vehicles which have a strong business case for electrification across all three scenario's due to high overall annual driving distances as well as consistent daily usage. Buses also have a strong business case to electrify with high drive cycles.

The HDV truck segment is expected to experience the lowest EV adoption, with weaker economics in the case of vocational trucks due to lower annual driving distances and fuel savings potential, as well as greater technical challenges such as range requirements and payload capacity. The HDV segment, especially long-haul trucks, is the most likely segment to adopt hydrogen fuel cell technology.

Despite the smaller number of MHDVs on the road, their higher driving distance coupled with the higher energy consumption per vehicle results in significant load impacts.

Energy Efficiency Potential

Context and Overview

Energy Efficiency Overview

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Inputs to the Top-Down Approach

- Key potential studies leveraged:
  - **PacifiCorp** – 2023-2042 (WY Customers)
  - **Colorado Springs Utilities** – 2020-2039
  - **Manitoba & Rhode Island Dunsky Studies** (Costs)
- PRPA's ***Beneficial Buildings Electrification Forecast Study***
  - Heat pump adoption & heating electrification
- PRPA's ***Historical DSM Program Data***
  - Used to understand historical EE trends and inform future ones

Achievable Scenario Descriptions

Scenario	Description
Low	• Typical program investments and savings. • Closest scenario to PRPA's current EE initiatives.
Medium	• Midpoint between Low & High Scenarios • Provides greater range across results & costs
High	• Maximum achievable investments and savings.

Top-Down Modelling Overview

1. **Studies & Inputs**
   PacifiCorp, Colorado Springs Utilities (CSU), PRPA Data, Dunsky EE Cost Data
2. **End-Use Curves**
   Calibrate & normalize EE curves by sector & end-use
3. **Annual EE % Savings**
   Savings unique to each scenario & segment
4. **Final Benchmarking Checks & Adjustments**
   High-level adjustments made where necessary

Energy Efficiency Potential

Methodological Summary

Scenario Modeling Overview – Low Potential Scenario

1. From the CSU study, smoothened **EE curves by sector** (Residential & Commercial) were developed for PRPA.

2. These curves were benchmarked to the most recent year (2022*) of sector level EE program savings provided by PRPA to obtain the annual EE savings by sector throughout the study period.

3. Annual EE savings at the sector level were disaggregated to the segment & end-use levels based on each segment's consumption profile.

*** Assumes EE programs started around the same date between the two regions in Colorado.**

Scenario Modeling Overview – Medium Potential Scenario

1. Modeled as the midpoint between the Low & High potential scenarios.

2. EE curves were adjusted to fit midpoint savings from the other two scenarios and benchmarked on factors unique to PRPA. These include heat pump adoption metrics, lighting market saturation, and historical DSM program data.

3. Annual & cumulative savings were calculated based on each segment's electricity consumption profile.

Scenario Modeling Overview – High Potential Scenario

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1. PRPA's High scenario was based on PacifiCorp's the Technical scenario savings.
2. Gross-up factors outlining the expected increased savings between PacifiCorp's Achievable Technical* (Baseline) and Technical (High) scenarios were calculated for each PRPA end-use.
3. An equivalent 'Achievable Technical' scenario was developed for PRPA.
4. The end-use gross up factors were then applied to each segment's consumption profile for the equivalent PRPA 'Achievable Technical' scenario and summed to develop annual and cumulative savings.

***Note**: The Pacificorp study references nonstandard terminology by using achievable technical to define its Baseline scenario which can be more closely related to the Achievable Potential definition outlined within the Energy Efficiency Potential Studies Catalog. An overview of the Pacificorp definitions are outlined within the Appendix.

EE Cost Methodology

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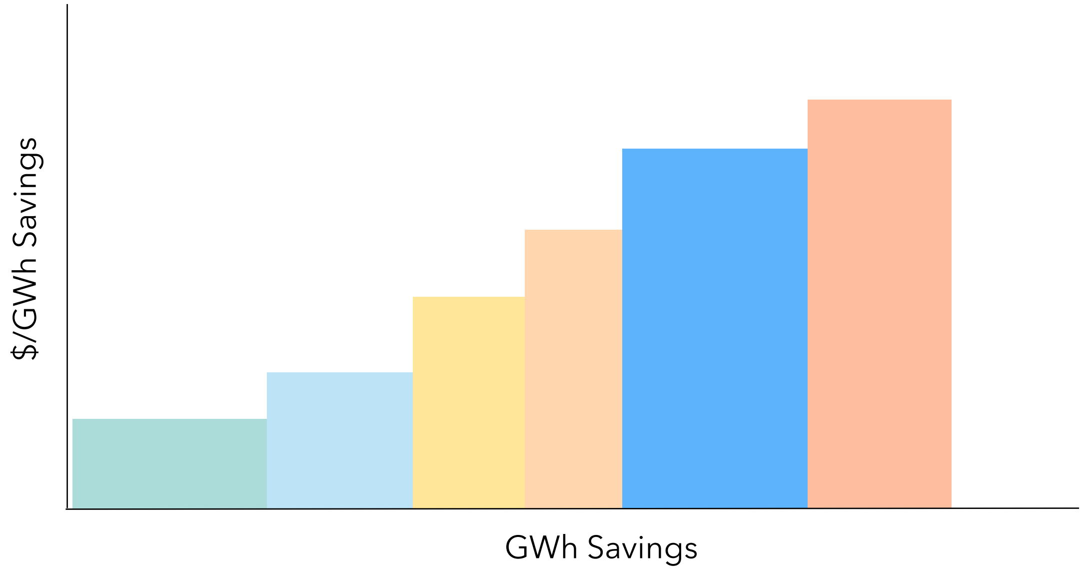
1. Calculate first year **Cost-Curves** based on internal program cost data (Dunsky).

   Manitoba & Rhode Island Dunsky studies

2. Assess **additional EE ('lift')** required to maintain cumulative savings, accounting for estimated useful life of measures – by segment and end-use for each scenario

3. Calculate **first year costs by segment** – in relation with the level of EE achieved in each year.

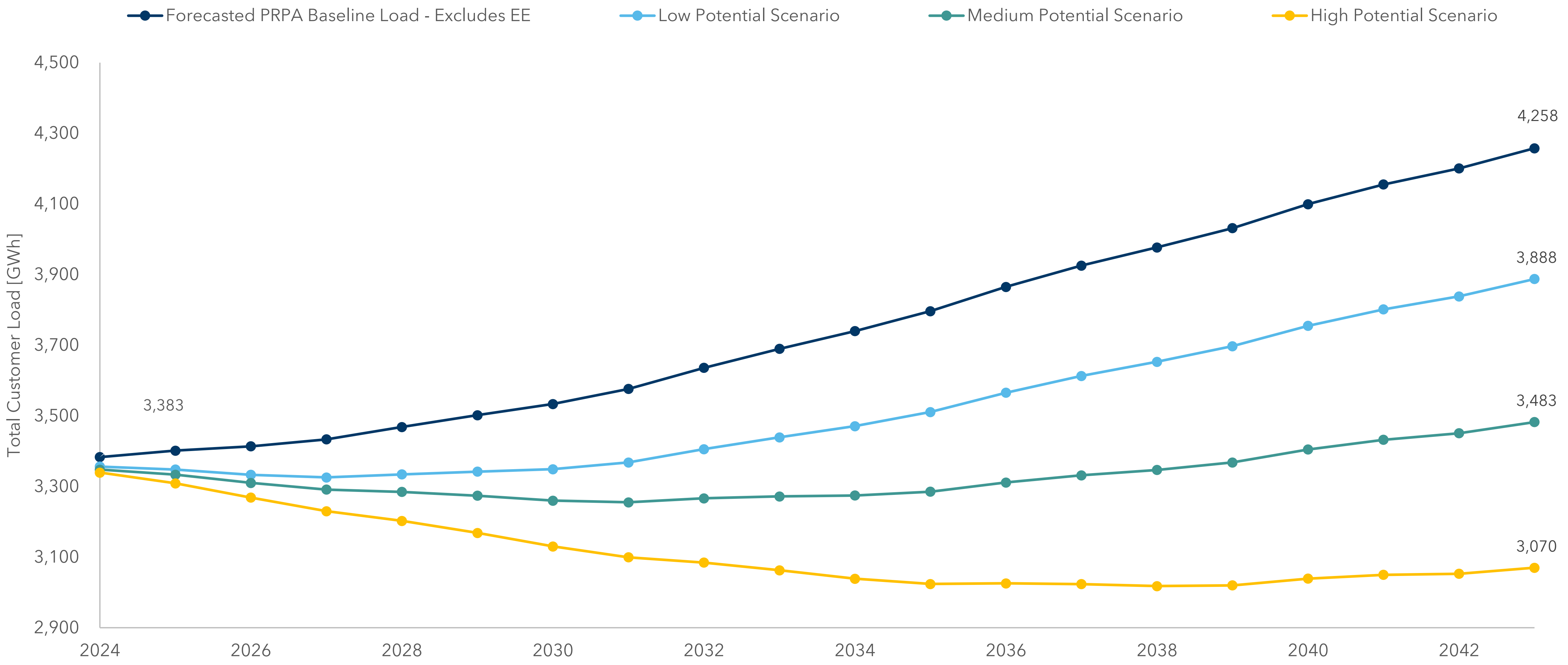
4. Calculate **total costs by segment.**



Energy Efficiency Potential

Results

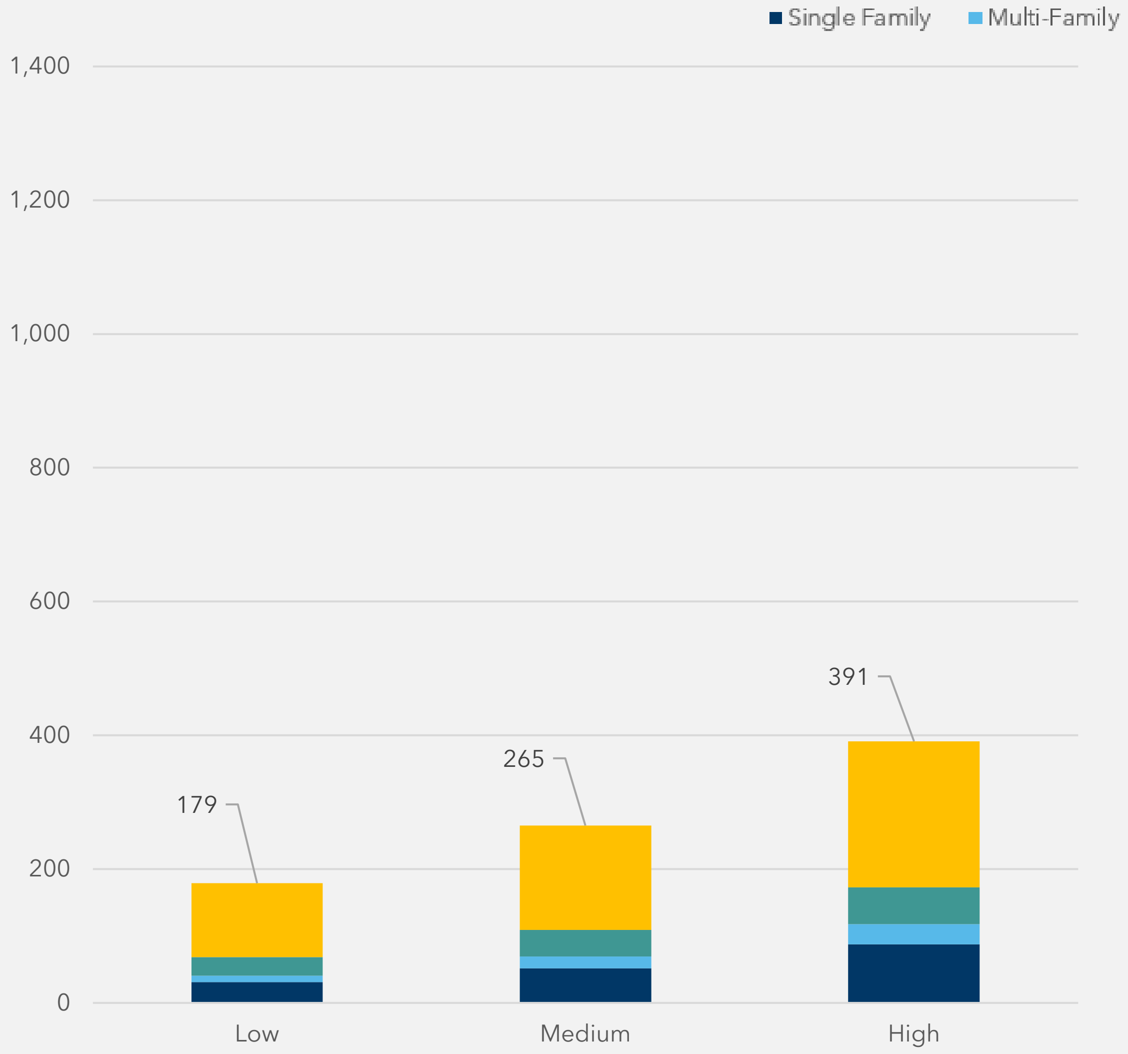
Total Annual Consumption by Scenario



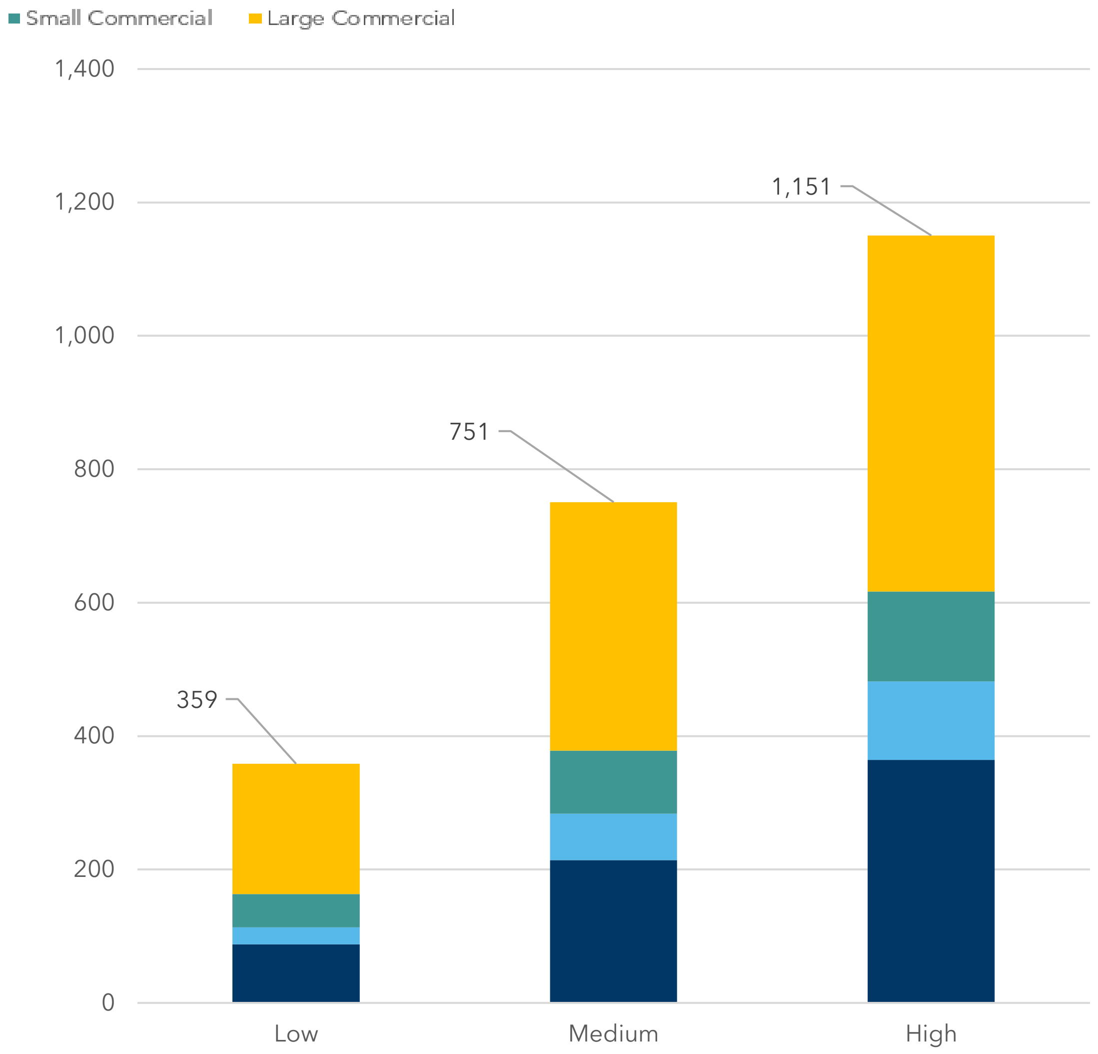
Note: The baseline load includes expected customer load growth & electrification growth (PRPA baseline load + building electrification Low projection). Transportation electrification and distributed solar load are not included in the baseline load.

Cumulative Potential Savings (GWh)

2030 Cumulative Potential Savings (GWh)

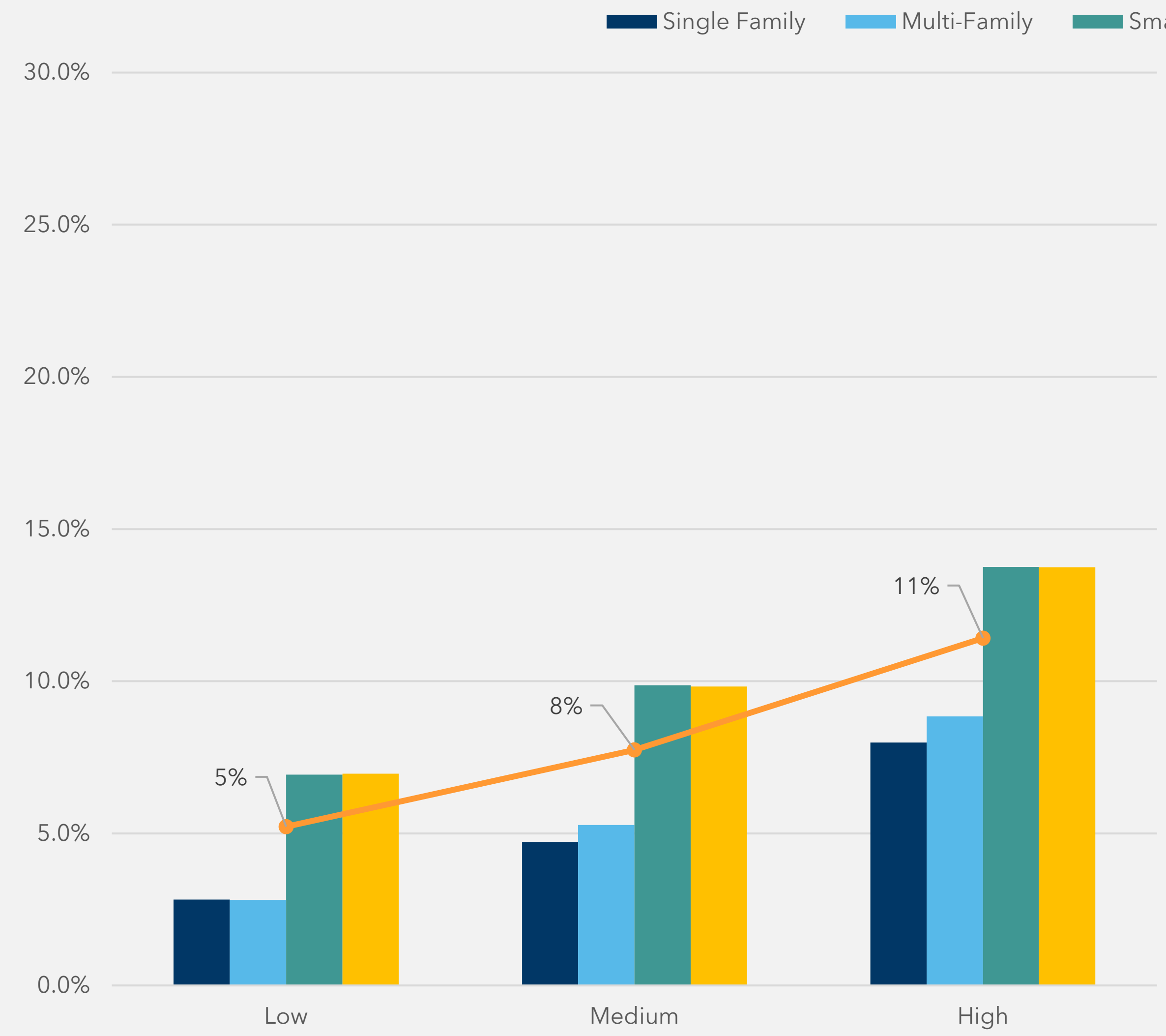


2043 Cumulative Potential Savings (GWh)

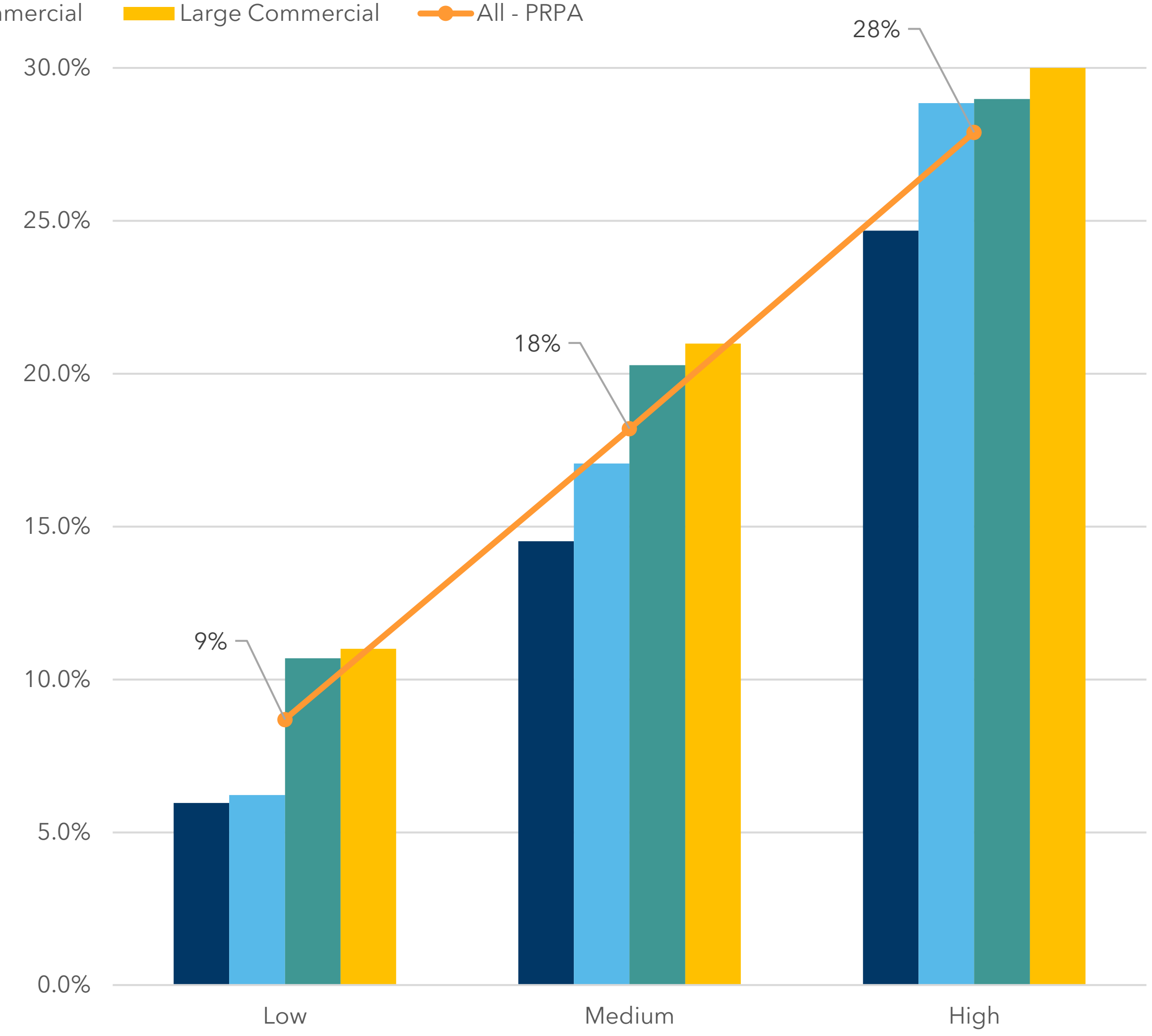


Cumulative Potential Savings (%)

2030 Cumulative Potential Savings (%)

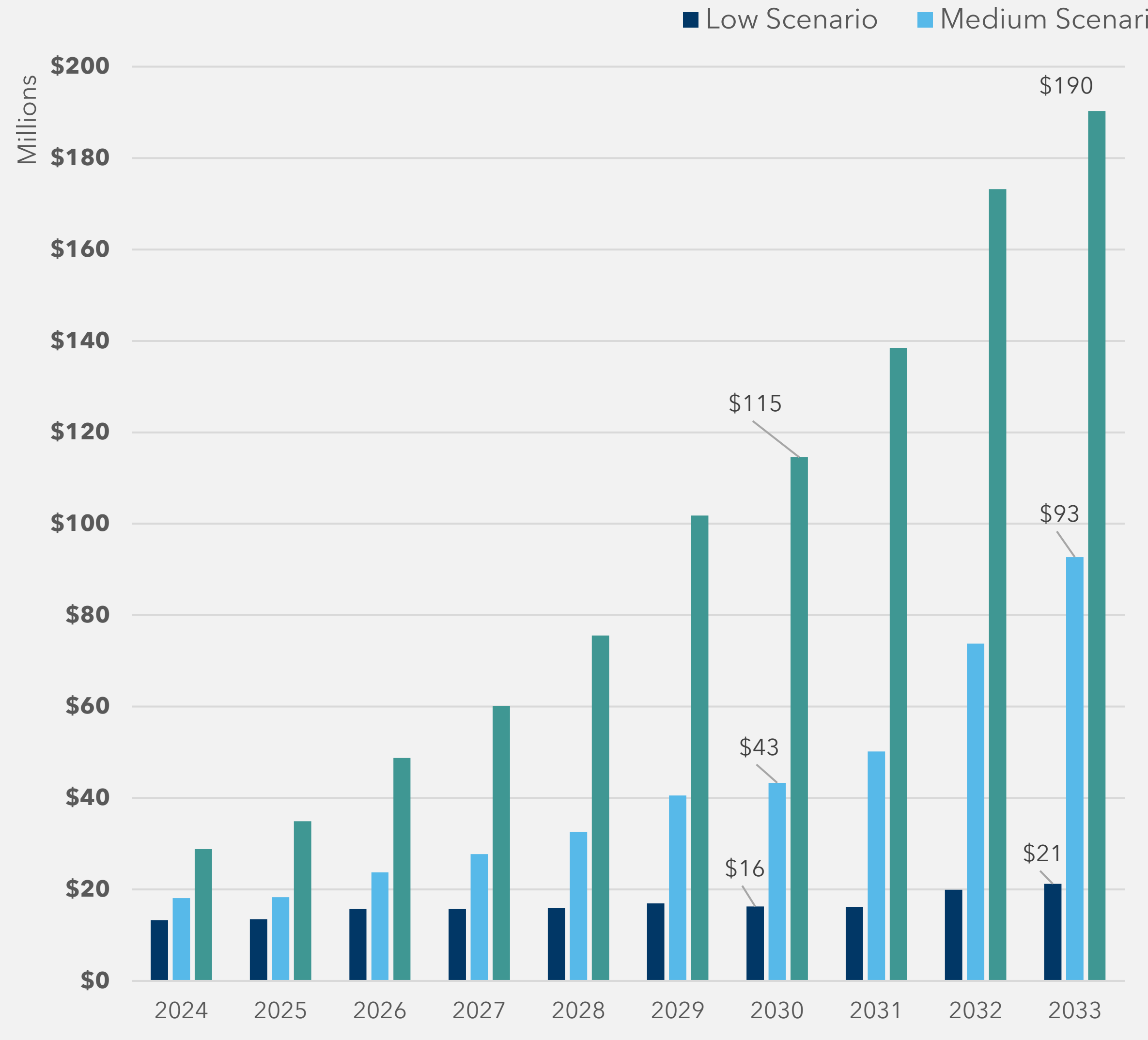


2043 Cumulative Potential Savings (%)

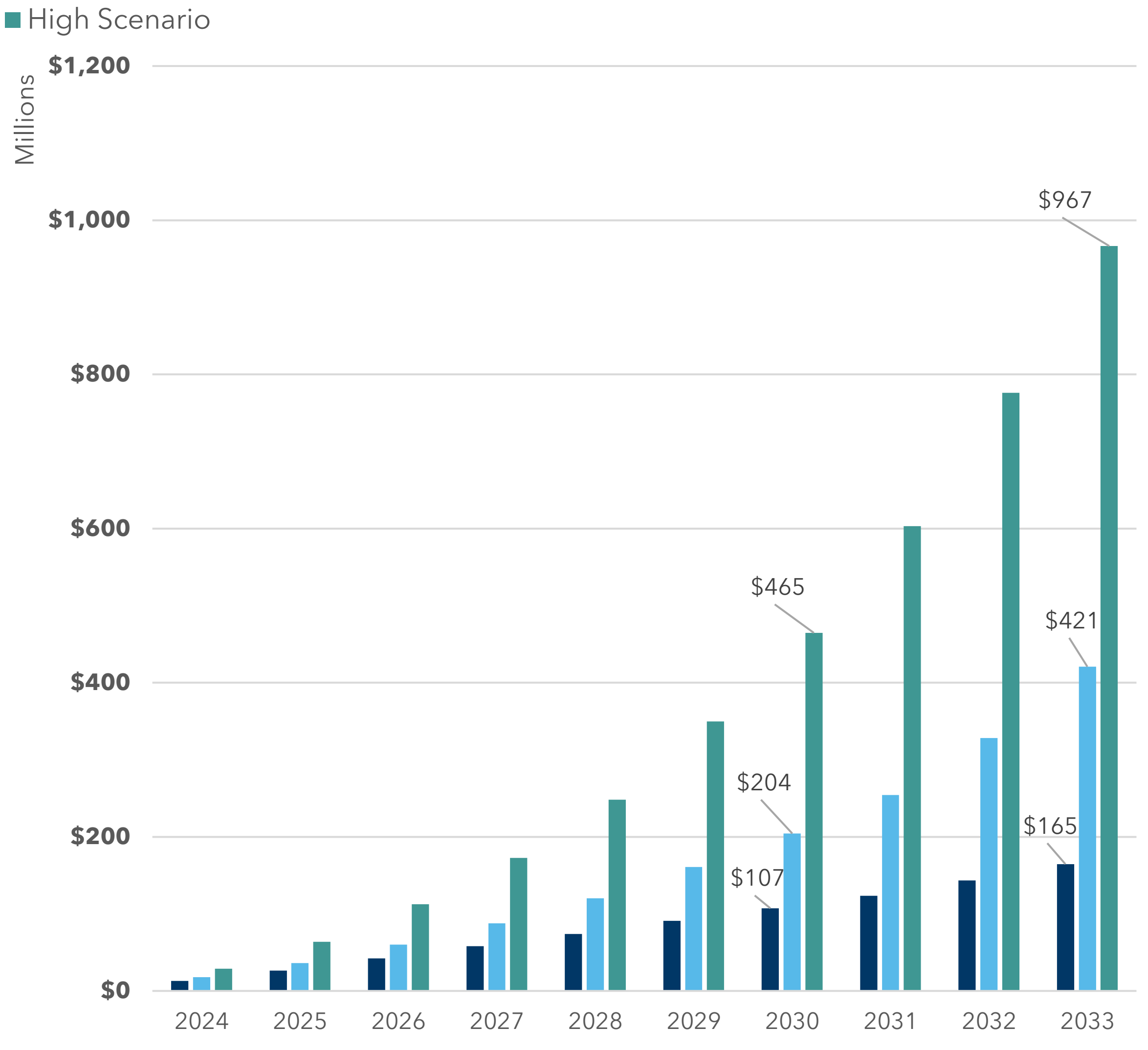


EE Program Costs, 10 Year Outlook

Annual Costs



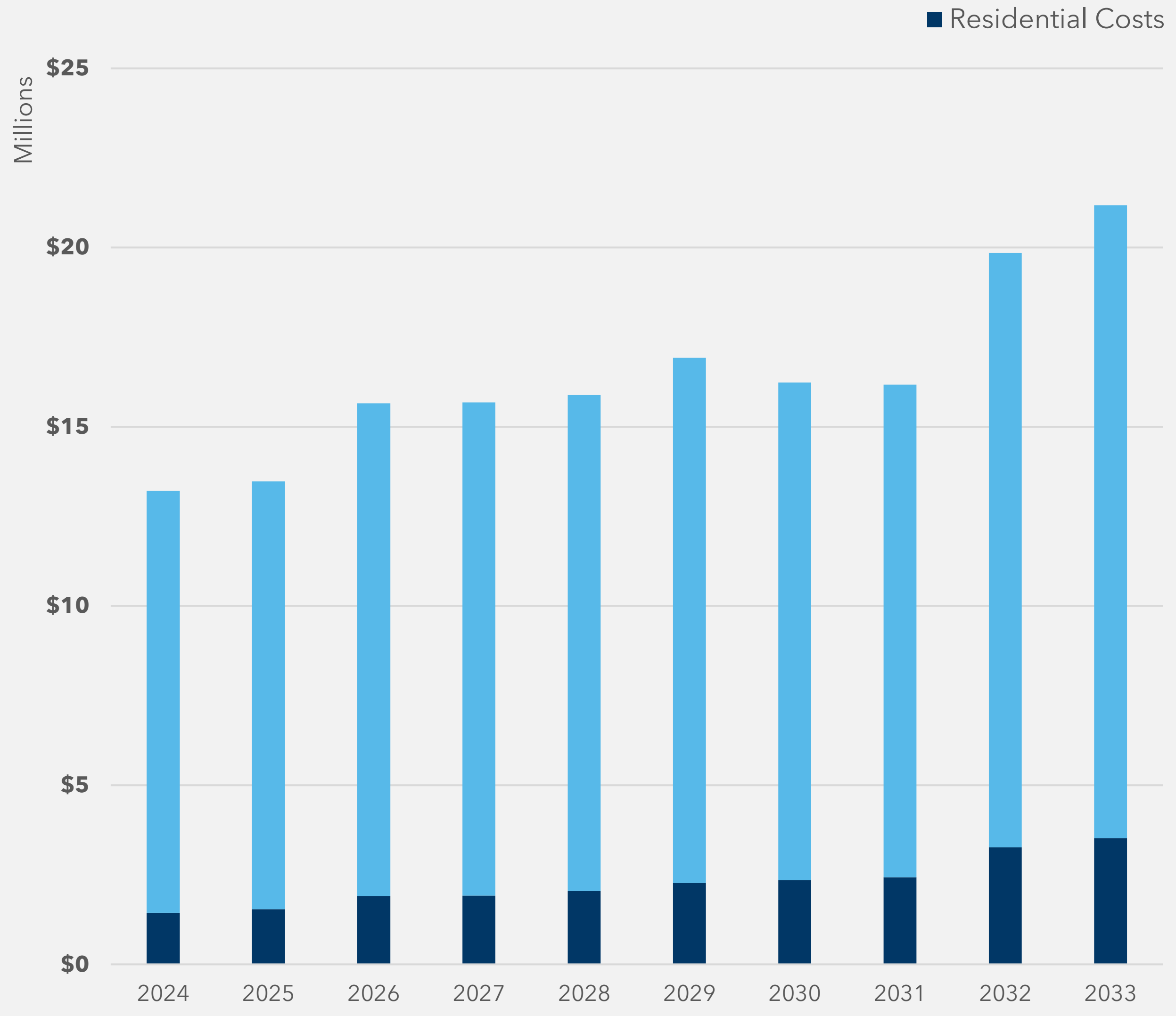
Cumulative Costs



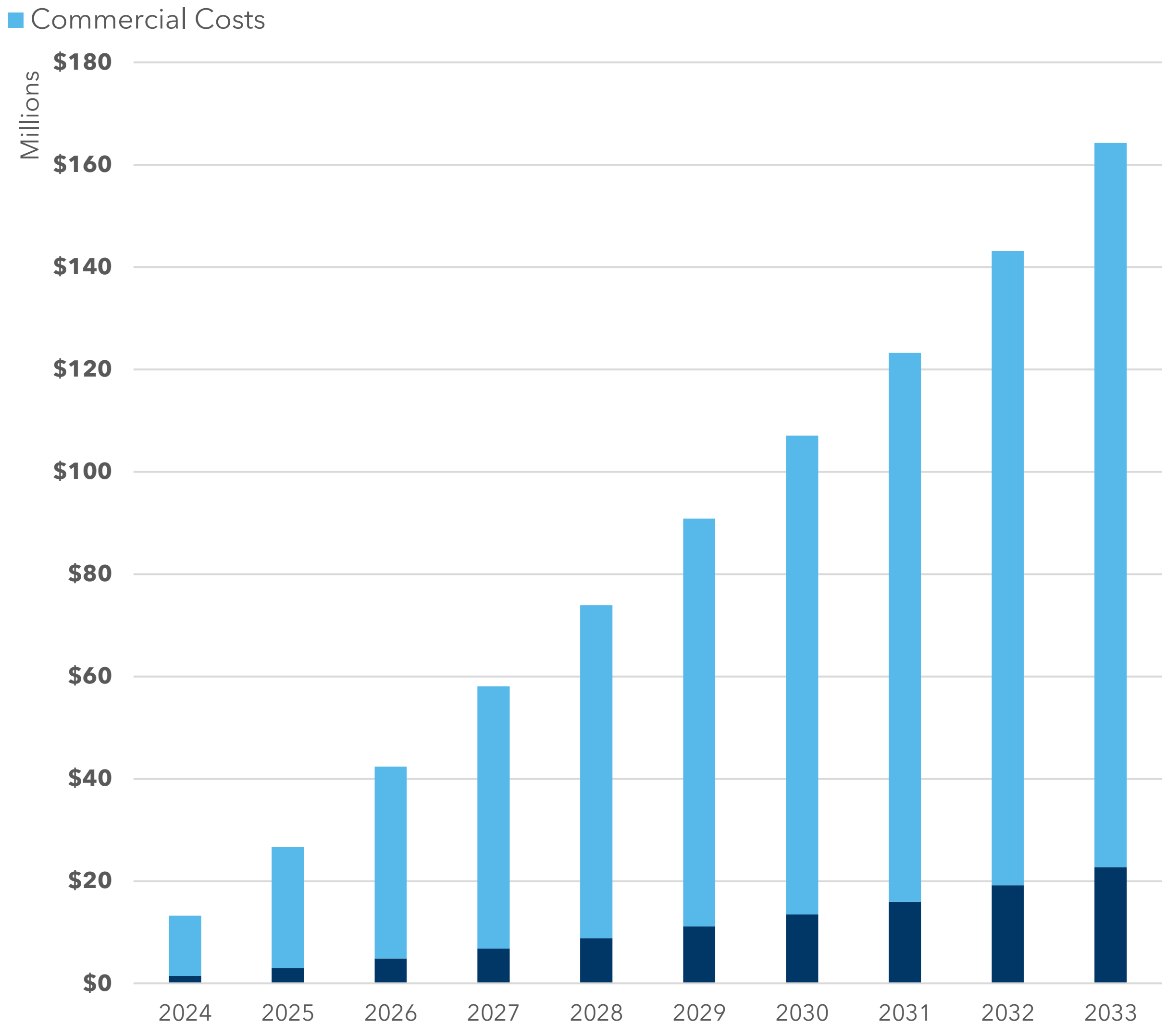
Note: *Differences in y scale axis*

EE Program Costs, 10 Year Outlook - Low

Annual Costs



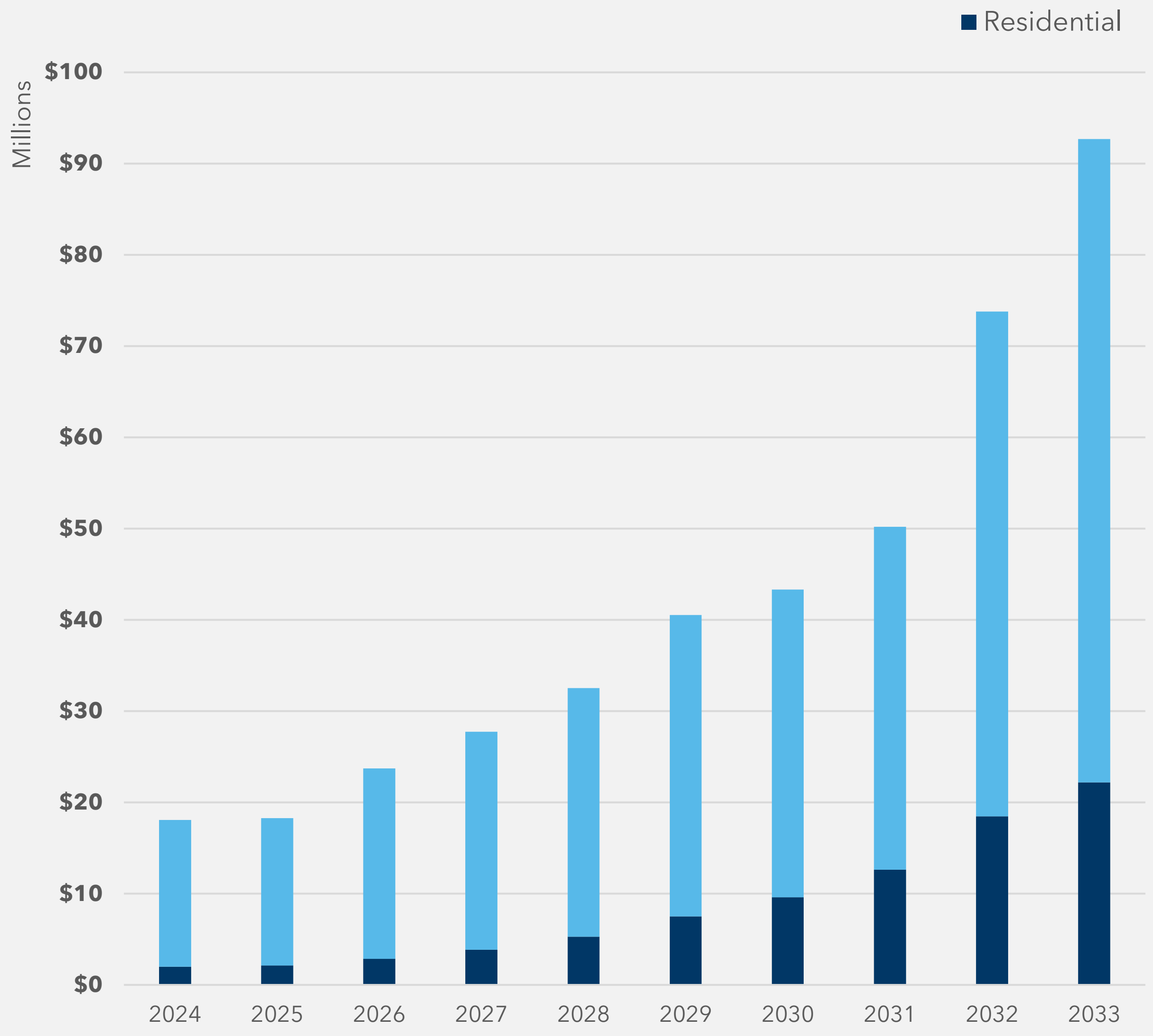
Cumulative Costs



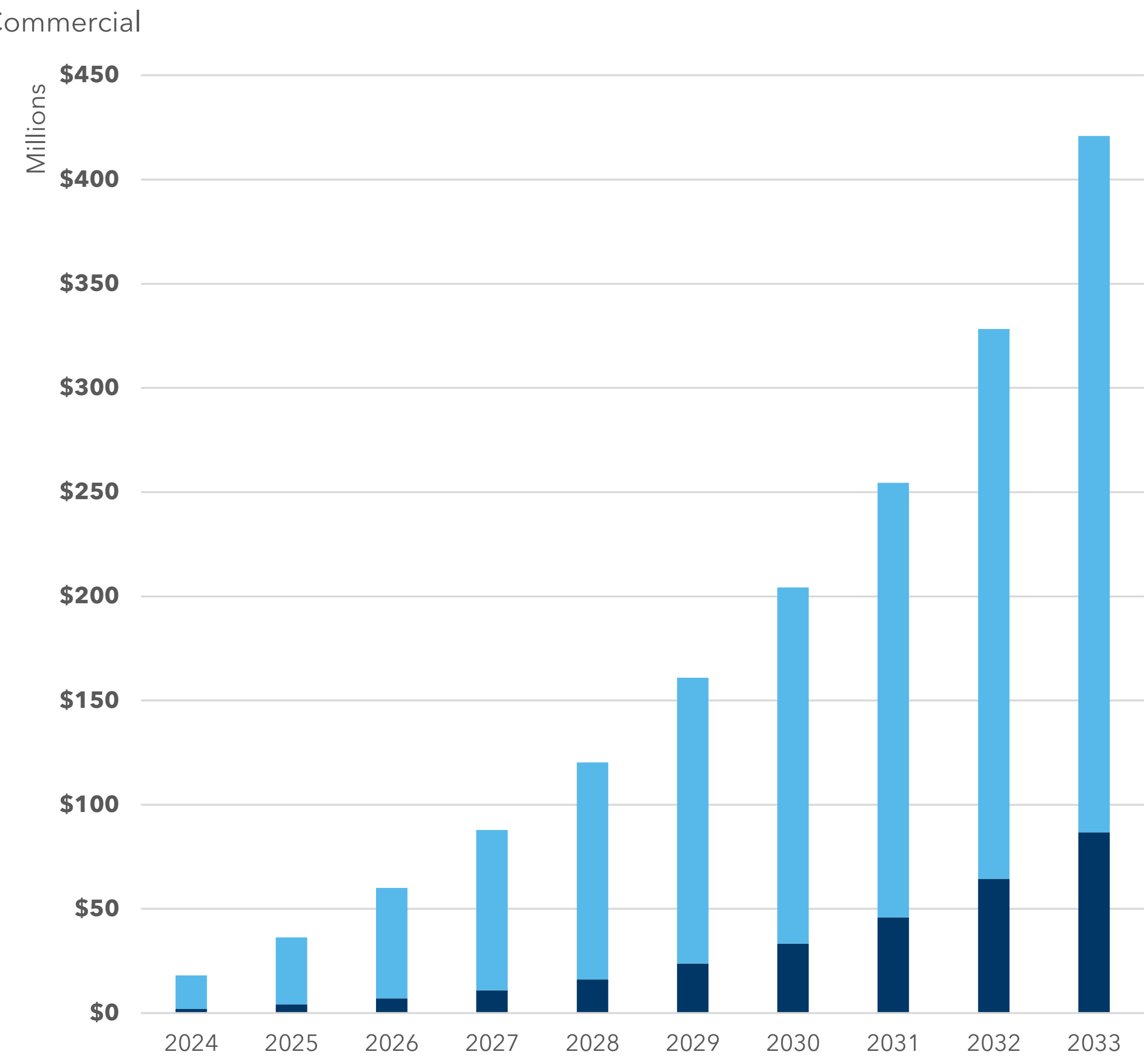
Note: *Differences in y scale axis*

EE Program Costs, 10 Year Outlook - Medium

Annual Costs



Cumulative Costs

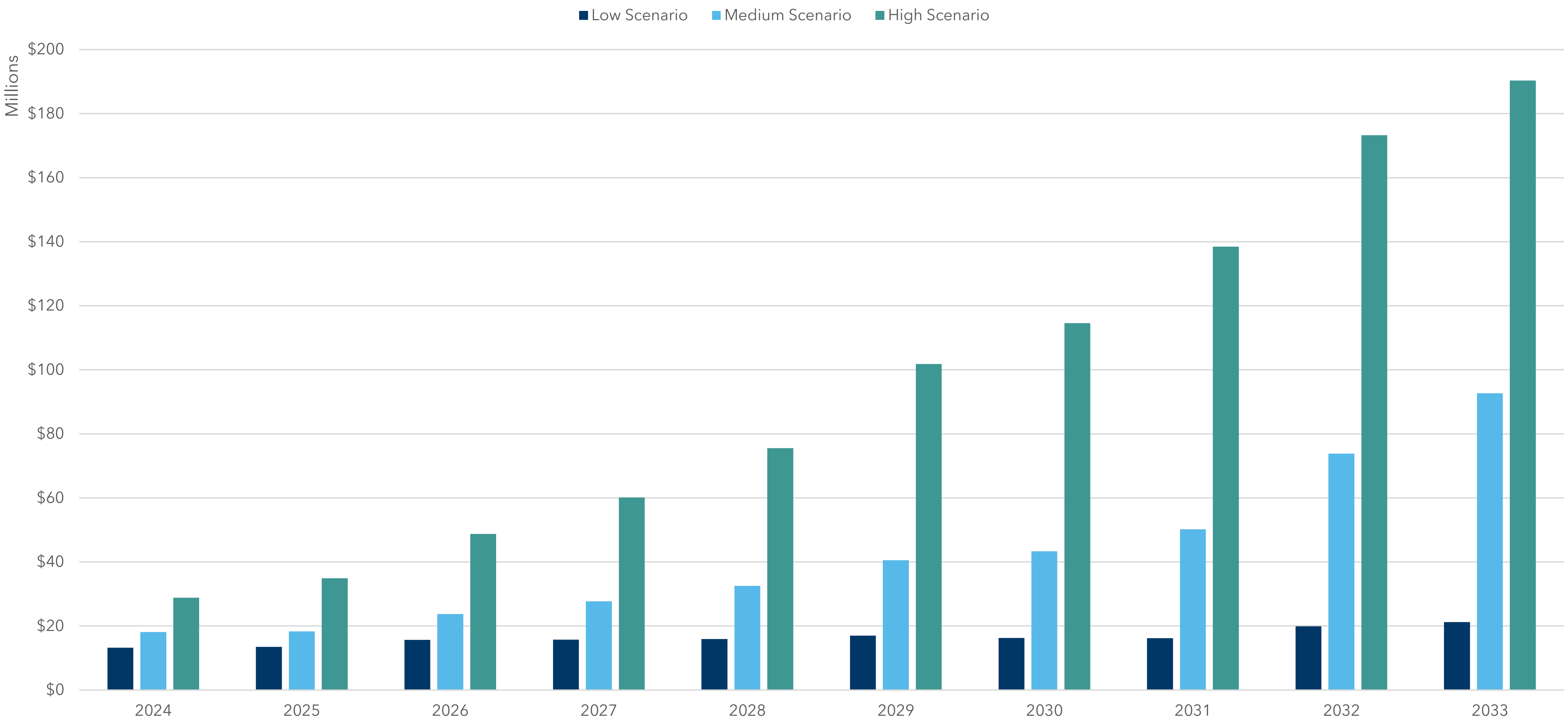


Note: *Differences in y scale axis*

Energy Efficiency

EE Program Cost Allocation, 10 Year Outlook

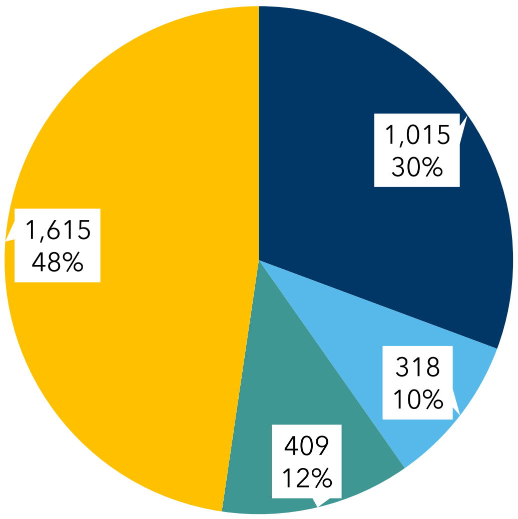
Annual Costs – All Scenarios



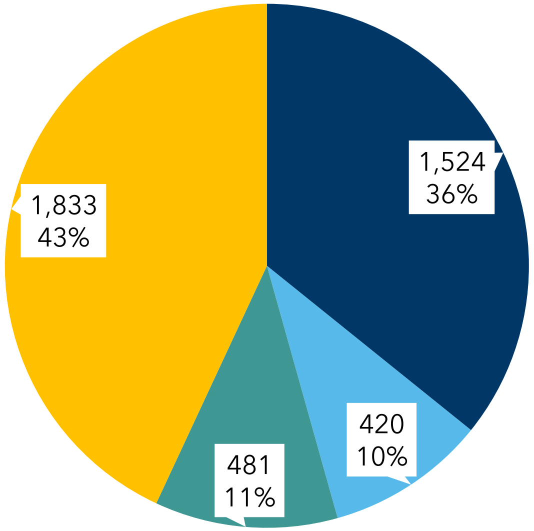
Consumption by Sector & Impact of Medium Scenario

- **Throughout the study period, residential's consumption share is expected to grow:**
  - Higher customer growth
  - Greater heating electrification impacts
  - Lower energy efficiency opportunities (when compared to Commercial) across each scenario

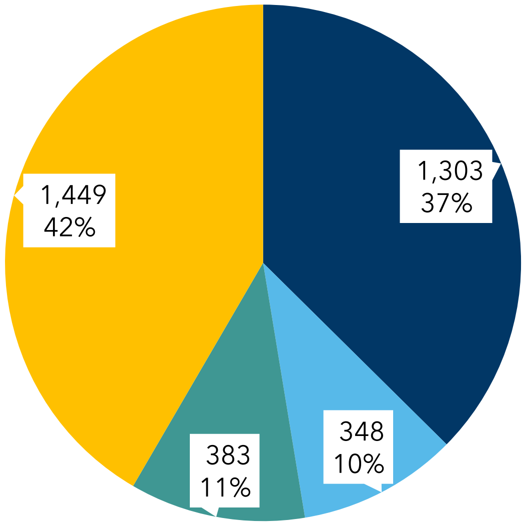
2024 Customer Load – Excludes EE (GWh)



2043 Customer Load – Excludes EE (GWh)



2043 Customer Load – Medium Scenario (GWh)



■ Single Family ■ Multi-Family ■ Small Commercial ■ Large Commercial

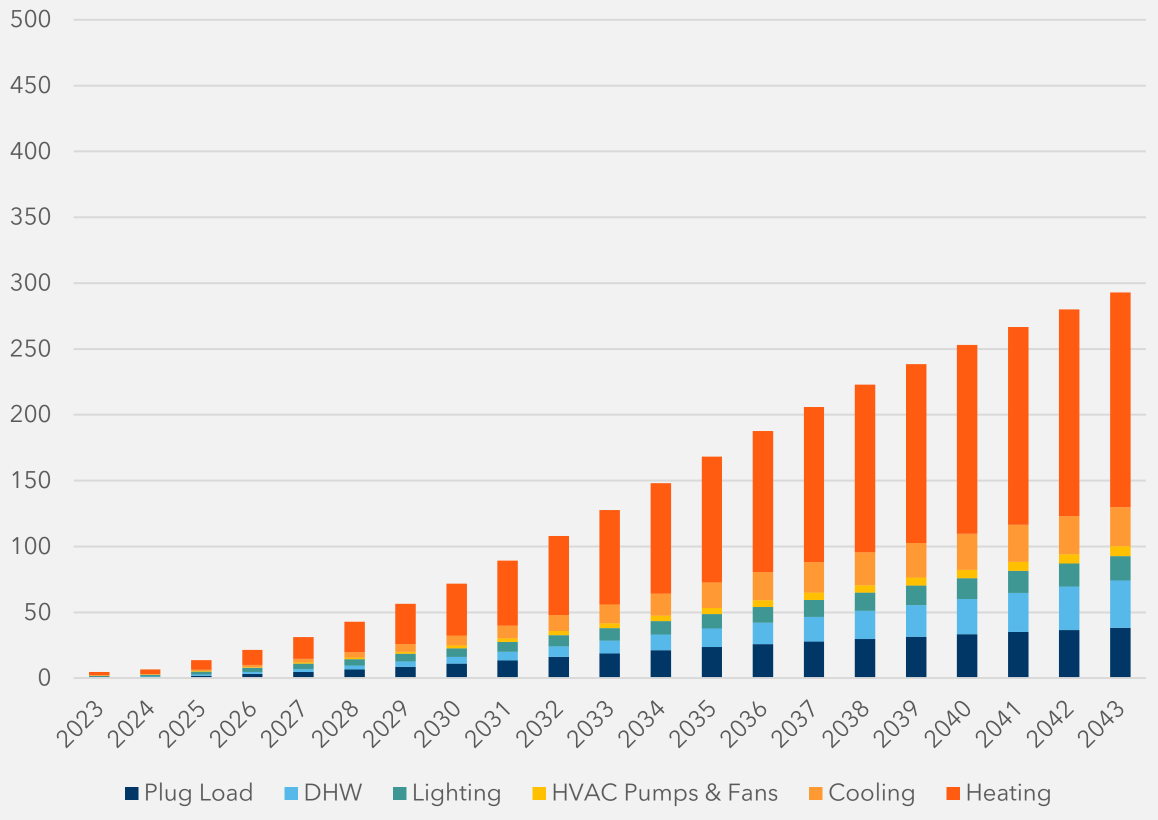
Note: Pie charts above include expected customer load growth & electrification growth (PRPA baseline load + electrification projection).

Cumulative Savings by Sector & End-Use, Medium Scenario

Residential (GWh)

Share of Total Savings

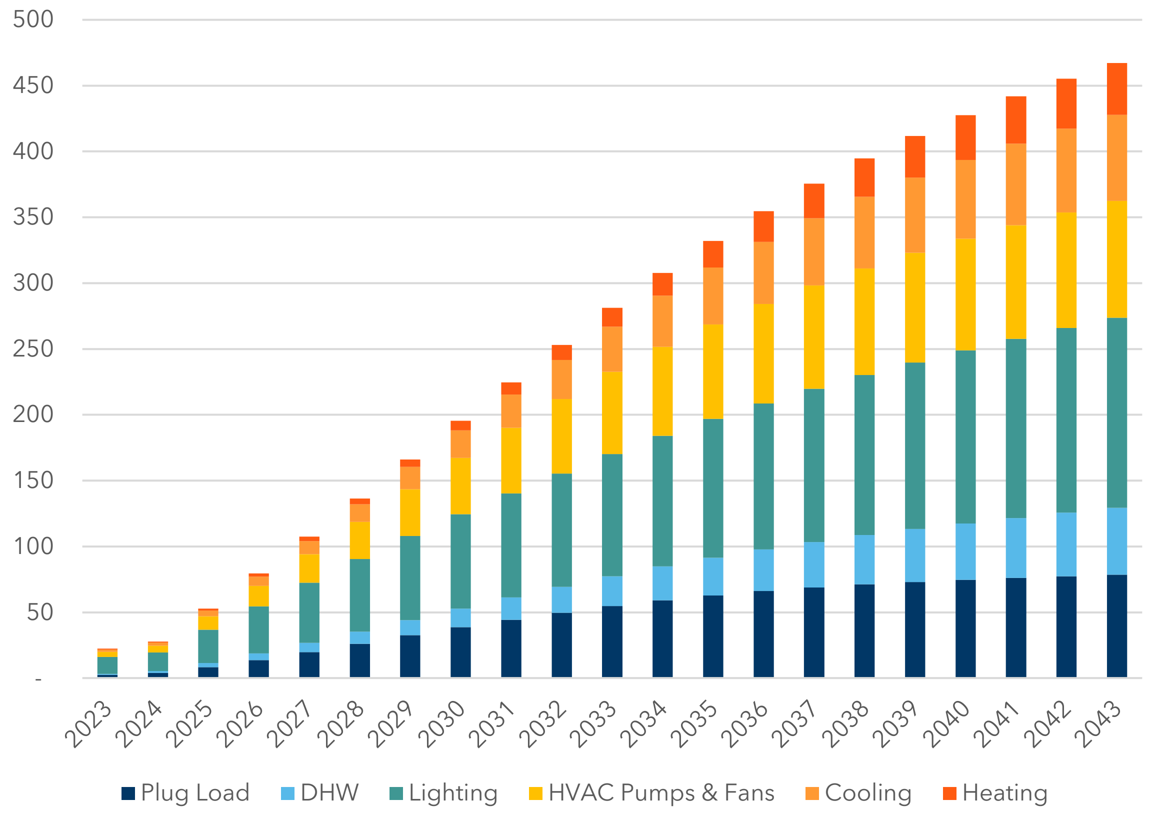
1) Heating (56%) 2) Plug Load (13%) 3) DHW (12%)



Commercial (GWh)

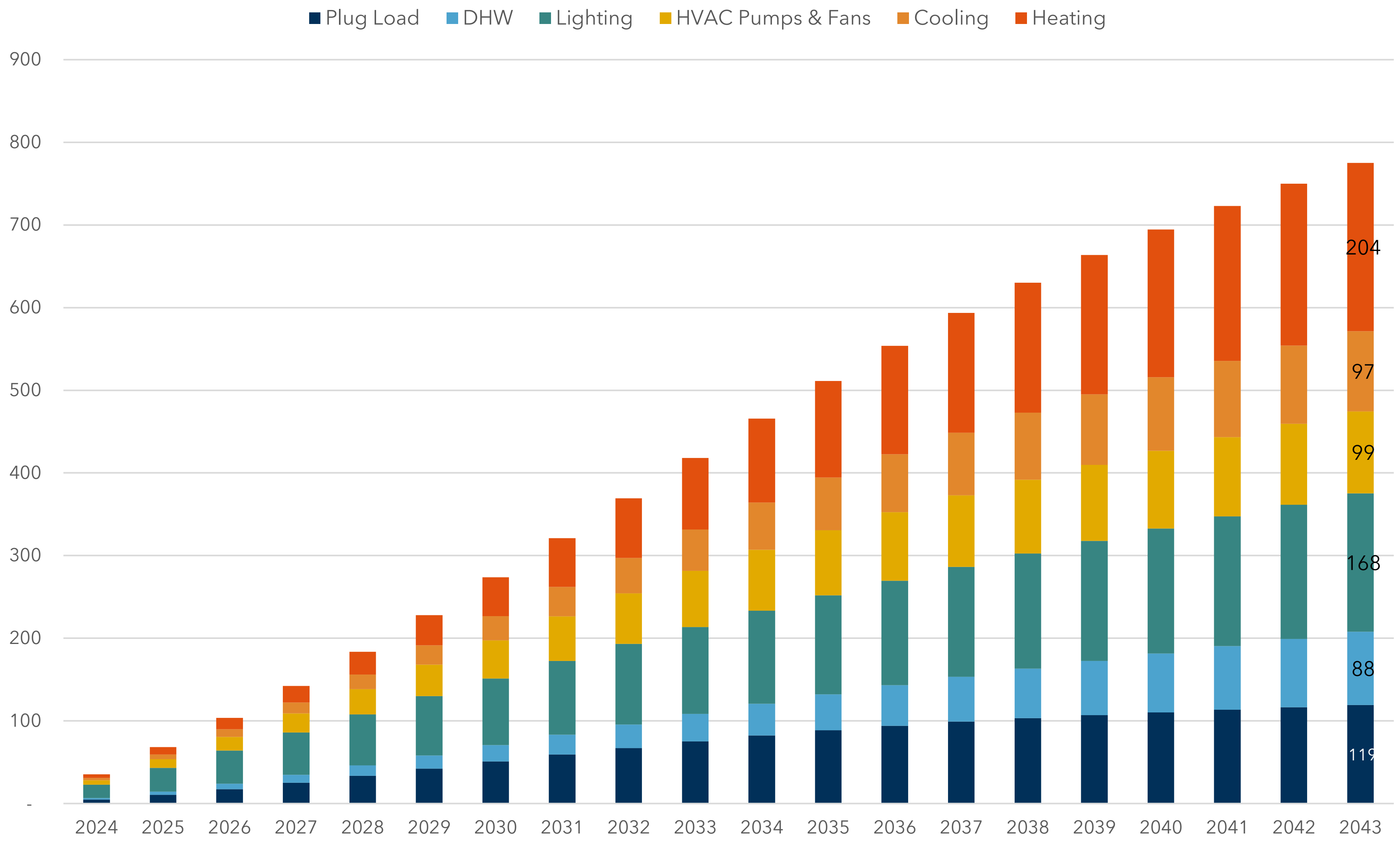
Share of Total Savings

1) Lighting (31%) 2) HVAC Pumps & Fans (19%) 3) Plug Load (17%)



Cumulative Savings by End-Use, Medium Scenario

All PRPA (GWh)

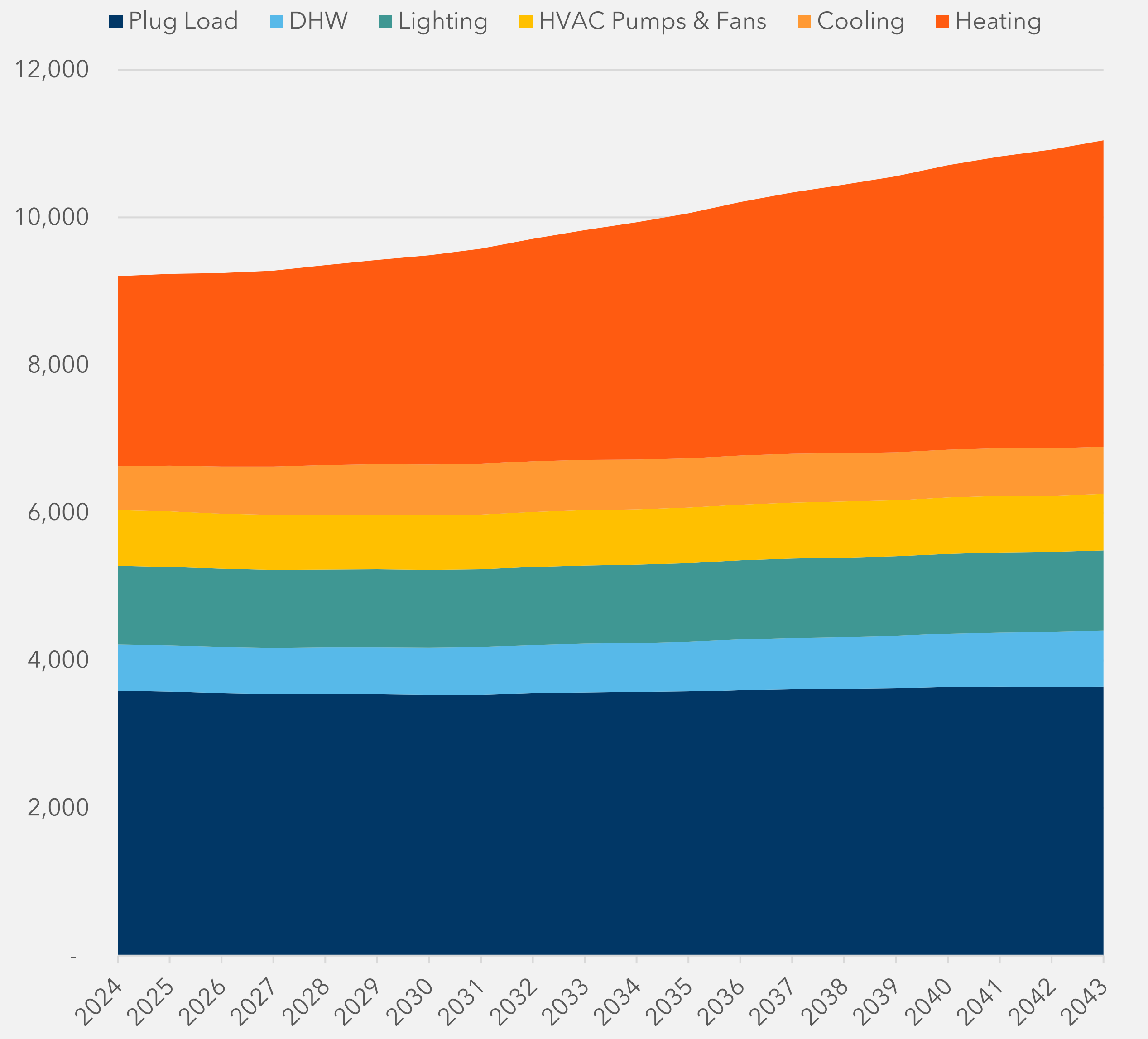


For heating savings, 19% is related to an electrical system upgrade after converting from a fuel-based system. For instance, electrification measures inducing a conversion of gas heating to electric resistance heating, and then energy efficiency measures inducing an upgrade of the system to heat pump heating.

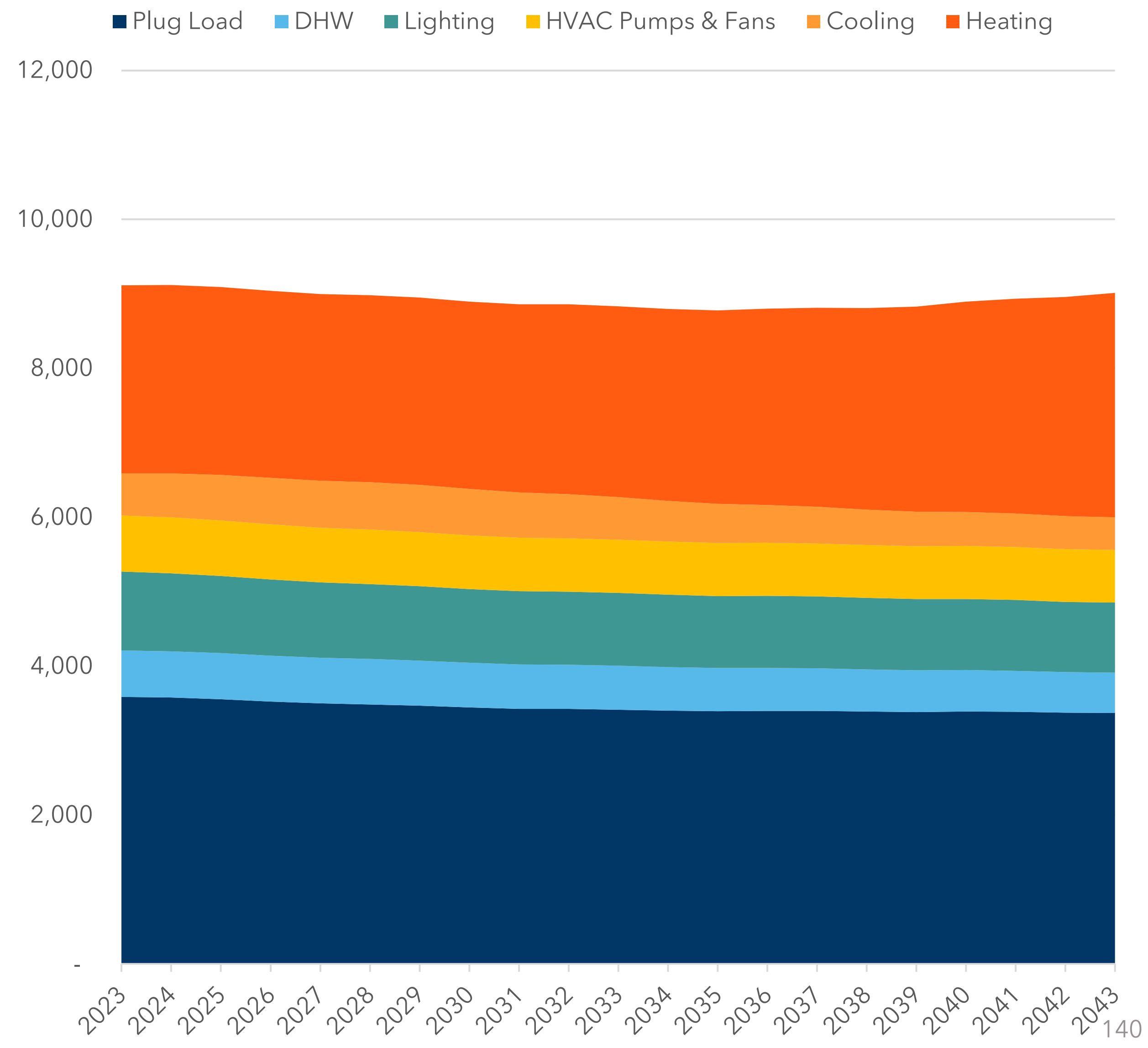
Therefore, planning electrification and energy efficiency together could prevent doing intermediary steps and result into more cost-effective solutions overall.

Single Family Consumption Profile

AVG Consumption per customer [kWh] – without EE

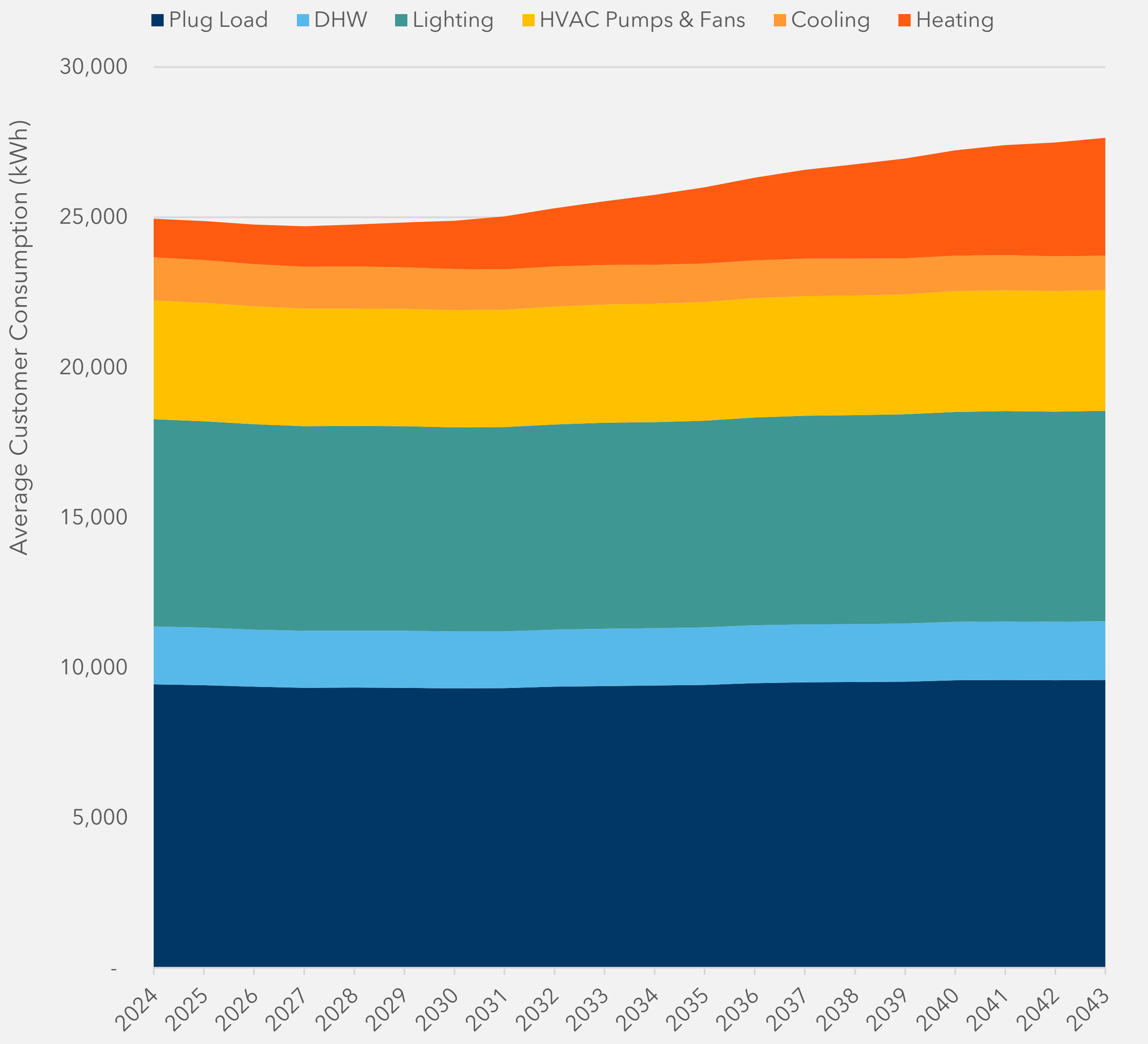


AVG Consumption per customer [kWh] – with EE (Medium Scenario)

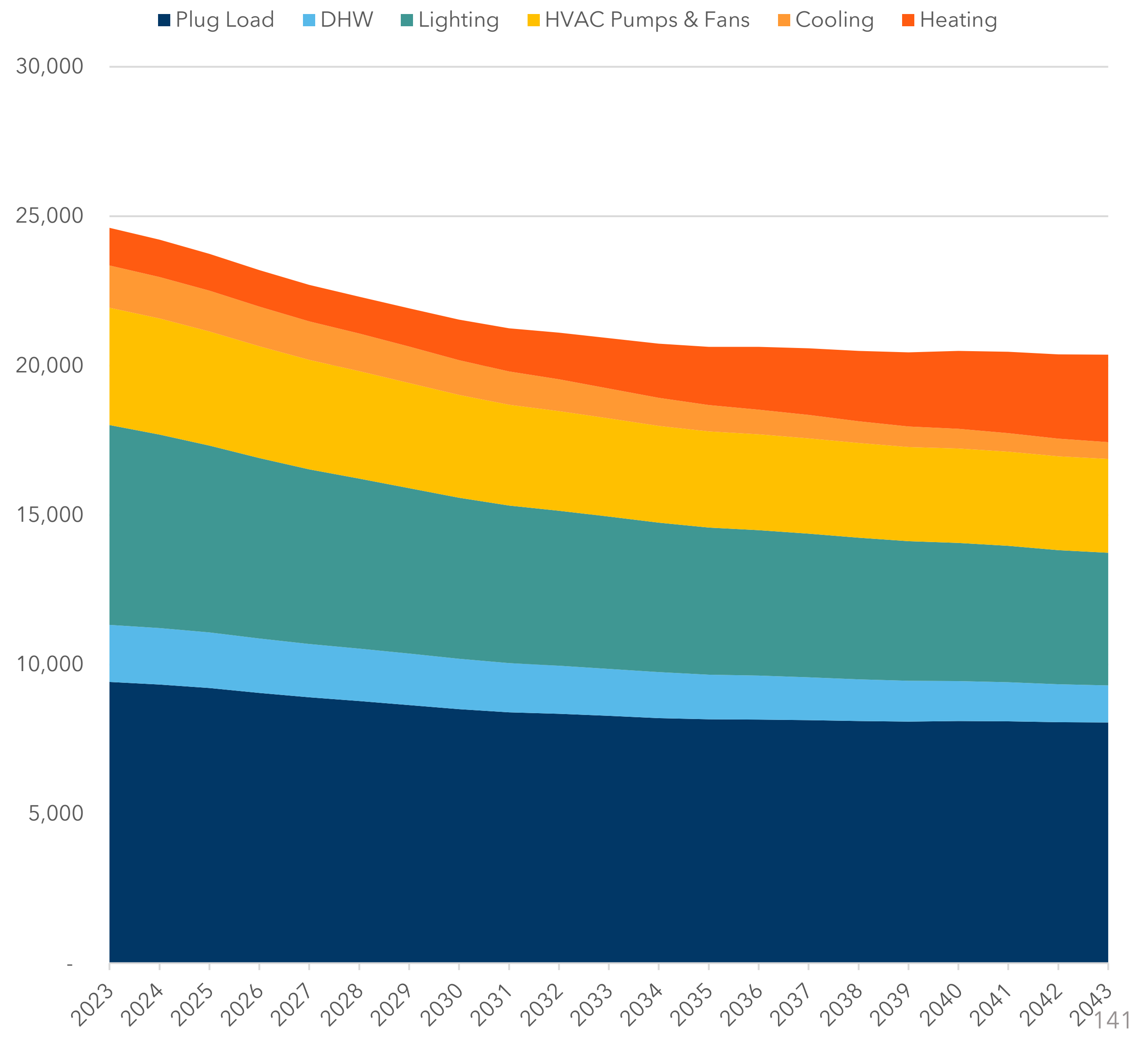


Small Commercial Consumption Profile

AVG Consumption per customer [kWh] – without EE



AVG Consumption per customer [kWh] – with EE (Medium Scenario)



Energy Efficiency Potential

Conclusion

Cumulative Savings: PRPA vs Others

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Scenario	Sector	PacifiCorp	Colorado Springs Utilities	*Xcel Energy Colorado
Achievable (Xcel)	Residential	N/A	N/A	8%
	Commercial			8%
Achievable Technical (PacifiCorp & CSU) / Economic (Xcel)	Residential	21%	19%	14%
	Commercial	32%	15%	
Technical	Residential	29%	31%	17%
	Commercial	38%	24%	
Study Range		2023-2042	2020-2039	*2018-2028

Scenario	PRPA
Low	***6%***
	11%
Medium	***15%***
	21%
High	***26%***
	30%
Study Range	2024-2043

Note: Xcel Energy's Colorado Study outlines its three scenarios as Achievable, Economic, and Technical whereas PacifiCorp and CSU outline its two scenarios as Achievable Technical and Technical.

Xcel Colorado 2021 Clean Energy Filing Plan – EE Goals

Year	Xcel CO Base Case Electricity Forecast (GWh)[1]	Annual Incremental EE Target (GWh)[2 3]	Xcel EE% - Goal	PRPA EE% - Low	PRPA EE% - Medium
2024	33,766	500	1.48%	0.80%	0.91%
2025	34,170	500	1.46%	0.81%	1.01%
2026	33,737	500	1.48%	0.81%	1.09%
2027	34,131	500	1.46%	0.80%	1.20%
2028	34,685	500	1.44%	0.78%	1.30%
2029	35,104	500	1.42%	0.75%	1.40%
2030	35,627	500	1.40%	0.72%	1.45%

Sources: 1) Volume 2 Technical Appendix (PDF), Table 2.2-5. 2) Table 2.4-20. 3) PUC Colorado, Proceeding NO. 17A-0462EG. (Xcel EE% - Goal is calculated based on preceding columns)

Key Takeaways

PRPA could achieve an average incremental savings rate of almost **0.78%** between 2024 and 2030 in the low scenario, **1.15%** in the medium scenario, **1.71%** in the high scenario; But it would come respectively at a cost of **~$105M, ~$200M , ~$460M** (cumulative 2024-2030).

Lighting, HVAC pumps and fans and plug load energy efficiency savings **make up over 60%** of total forecasted savings by 2043 for the commercial sector. For the residential sector, **heating itself takes almost 60%** of the energy efficiency savings shares, followed by plug load and domestic hot water.

Under the low, medium, and high scenarios, highest annual incremental savings would each take place in **2026 (0.81%), 2033 (1.54%), and 2033 (2.39%)**, respectively.

Combined Load Curve Analysis

Combined Load Curve Analysis

Methodological Summary

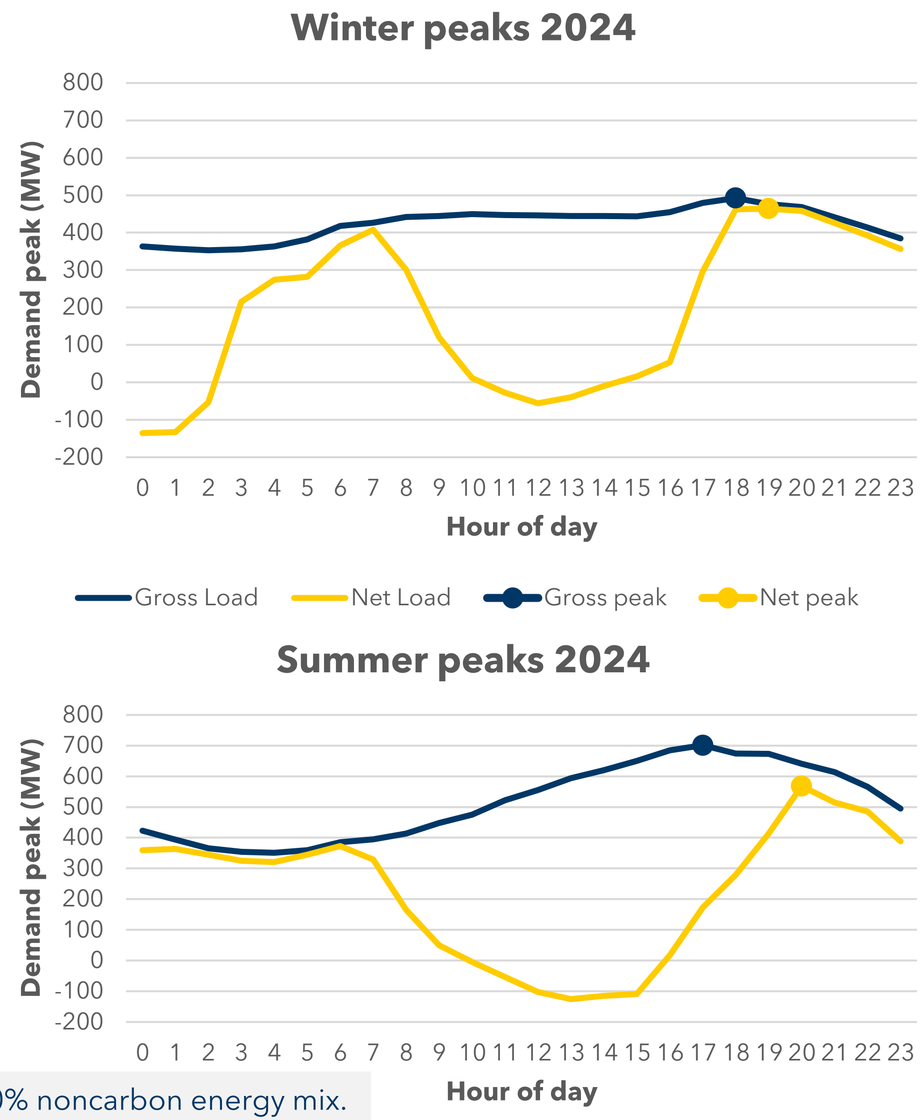
Gross peak vs net peak

System gross peak:

- Highest one-hour load requirement on PRPA's grid.
- Occurs at 18:00 in Winter and 17:00 in Summer.

System net peak:

- Highest one-hour load requirement once the grid variable renewable energy is netted out (based on 2030 forecast).[1]
- Occurs at 19:00 in Winter and 20:00 in Summer



1: Depending on the coincidence between generation and demand, the net peak can remain even with a 100% noncarbon energy mix.

Combined Load Curve Analysis

Unmitigated Figures

Annual Peak Demand

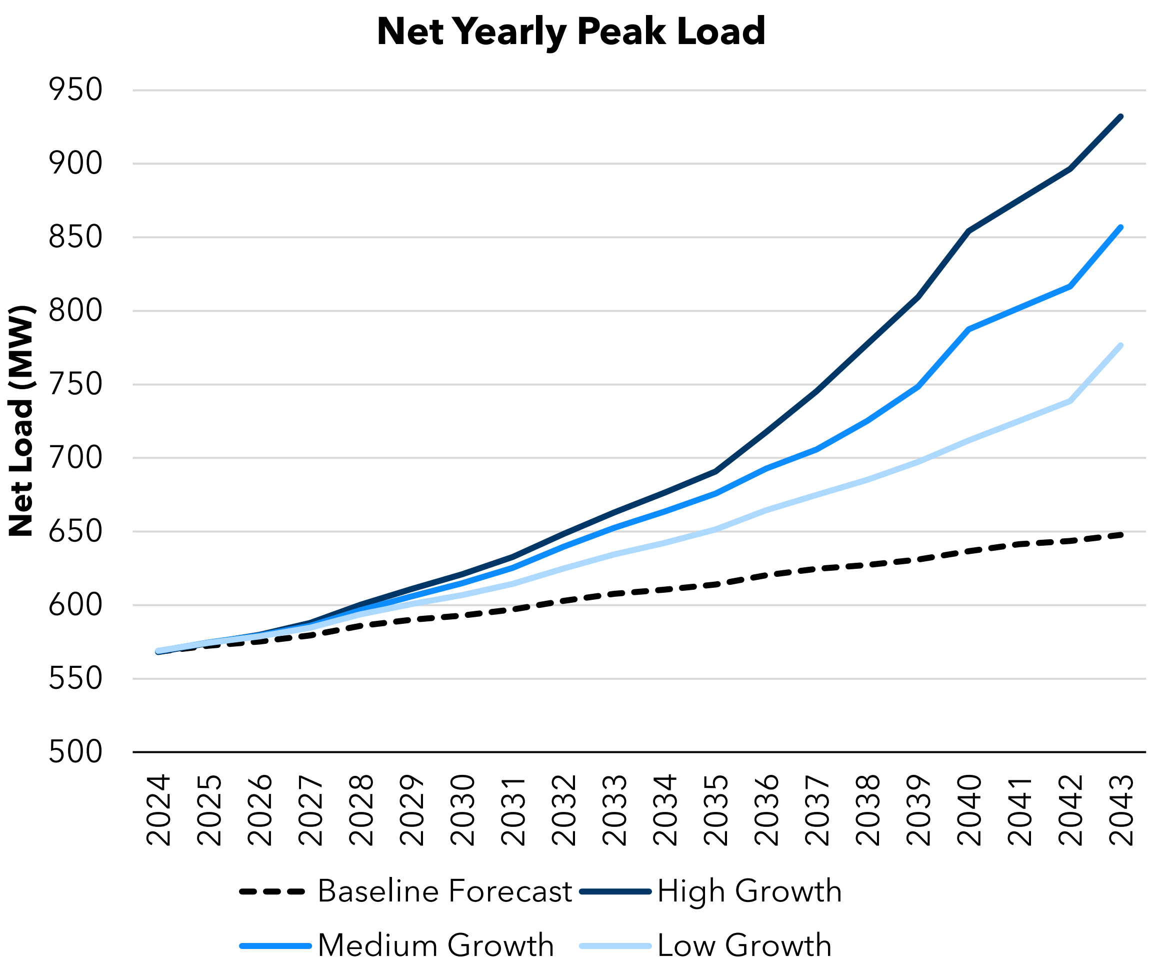
Relative to the baseline peak demand forecast, the **unmitigated customer adoption of the analyzed technologies will increase PRPA's peak demand** over the long-term.

Net peak demand is estimated to be approximately 20% to 44% higher in 2043 under the Low and High Growth scenarios, respectively.

This range in outcomes highlights the **substantial and uncertain influence of market factors** (such as technology costs, which are also influenced by policy) on the future requirements of PRPA's electric system.

% Difference Relative to Baseline Peak Demand

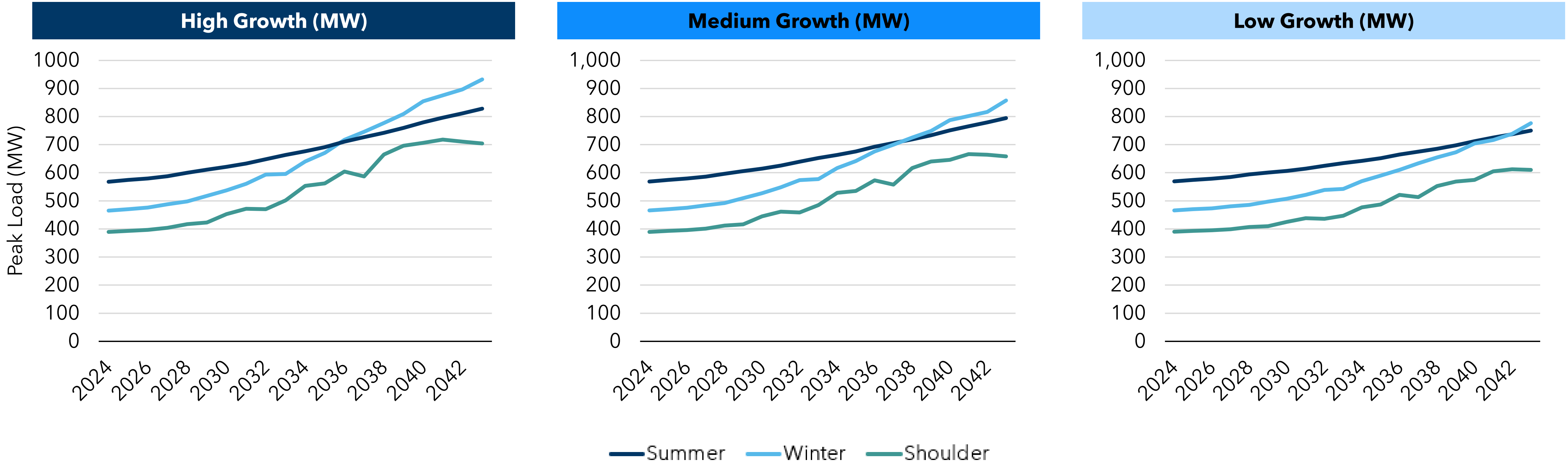
Scenario	2024	2030	2036
High Growth	0.0%	4.7%	15.7%
Medium Growth	0.3%	4.3%	12.2%
Low Growth	0.1%	2.3%	7.1%



Peak Demand: Growing Winter Demand

The impact of the analyzed technologies is likely to **transition PRPA's distribution system to a predominantly winter peaking regime**. This transition is most pronounced in the High and Medium Growth scenarios.

The seasonal shift is driven by EV and HE peak load impacts, which are most pronounced in the cold winter months. Additionally, solar PV will mitigate peak load impacts in the summer, but it has less impact on winter peaks due to a limited window of sunlight.



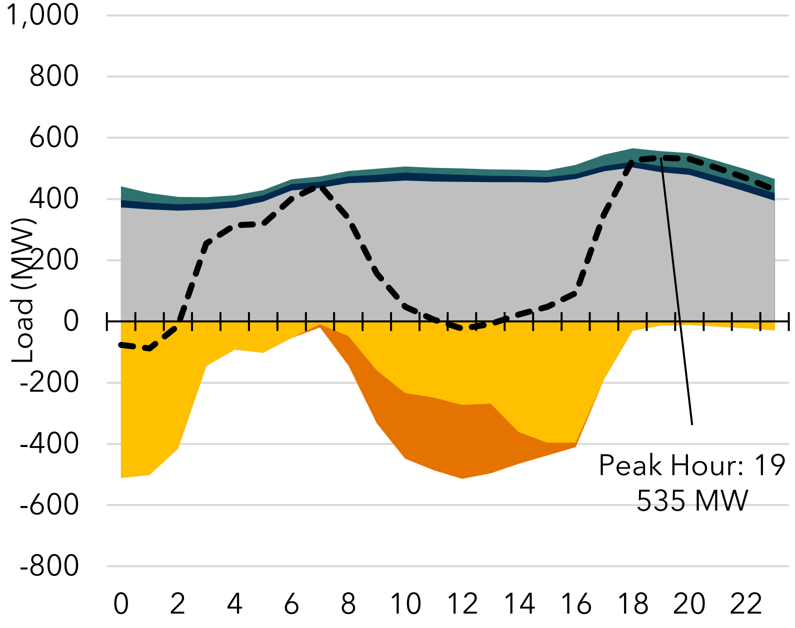
Peak Demand: Winter

Under all scenarios, EV adoption contribute to significant peak load increases. The late evening peak is driven by overnight EV charging.

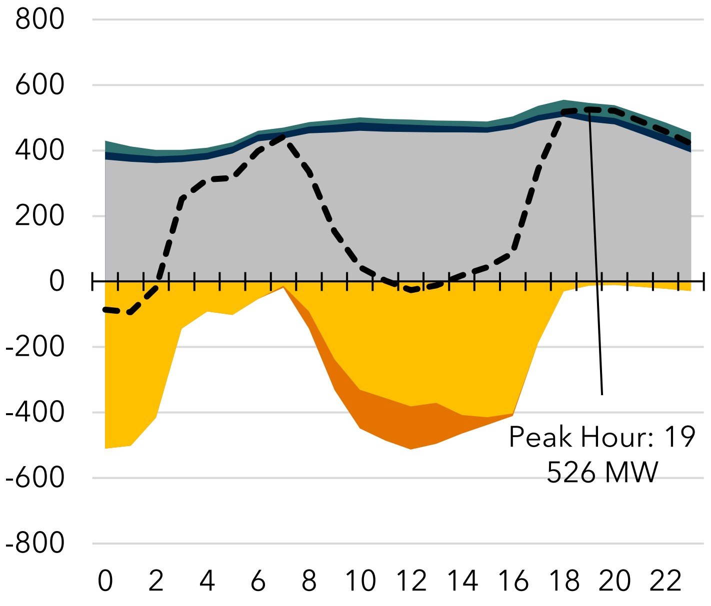
Distributed solar generation does have a limited peak load impact as its production is not coincident with the system-wide peak during the winter. With storage paired systems, some solar production can be shifted to the new peak hours. Almost half of the **grid-scale variable renewable energy** is expected to be solar, hence there is a potential to use storage pairing to shift the peak even more, especially with the net generation excess observed around noon.

***Energy efficiency** is not shown on the below graphs due difference in scale but is considered in the net load.

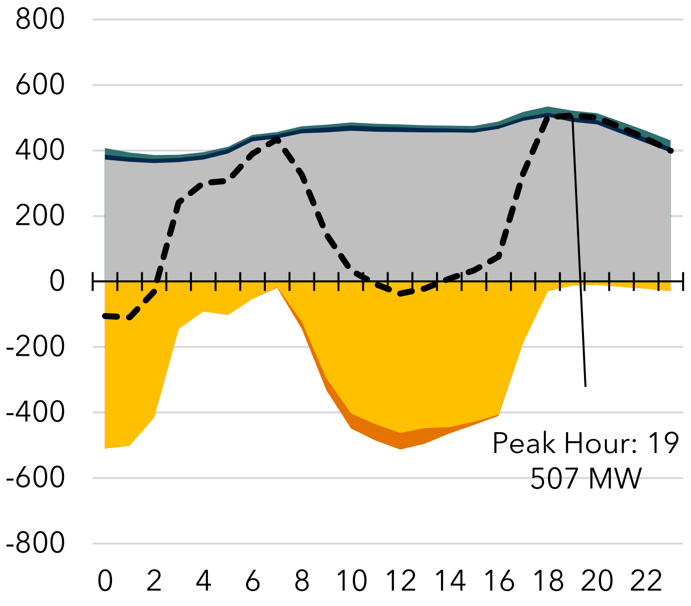
High Growth, 2030 (MW)



Medium Growth, 2030 (MW)



Low Growth, 2030 (MW)



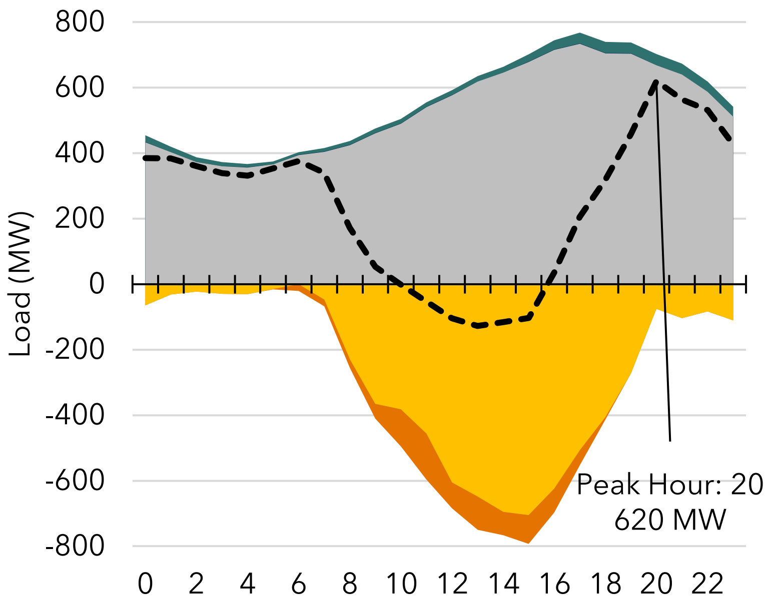
Distributed Solar Generation | Electric Vehicles | Grid scale VRE | Building Electrification | Baseline Load | Net Load

Peak Demand: Summer

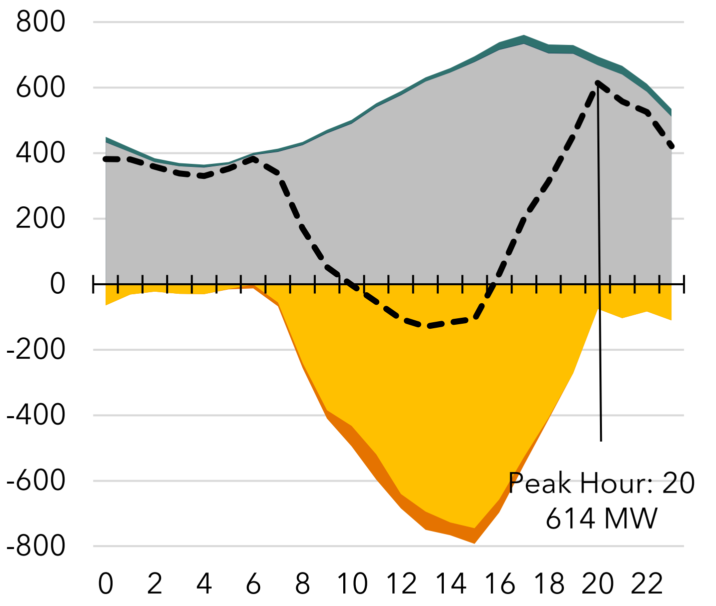
While summer peak load impacts are not as substantial as winter impacts, **increasing EV loads will still result in elevated summer peaks relative to baseline forecasts**.

These impacts are mitigated, however, by **distributed solar** adoption and **grid-scale variable renewable energy**. In the summer, solar PV generation is coincident with system-wide peak demand and ultimately shifts the peak hour to later in the evening.

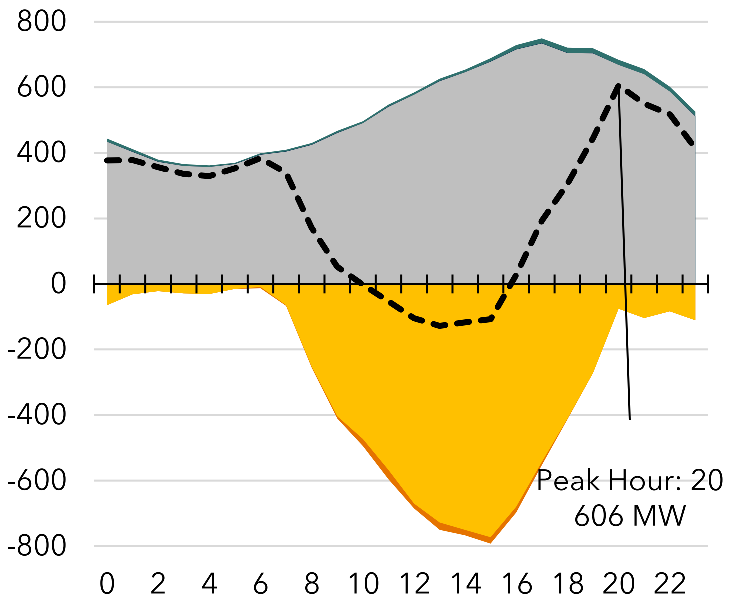
High Growth, 2030 (MW)



Medium Growth, 2030 (MW)



Low Growth, 2030 (MW)



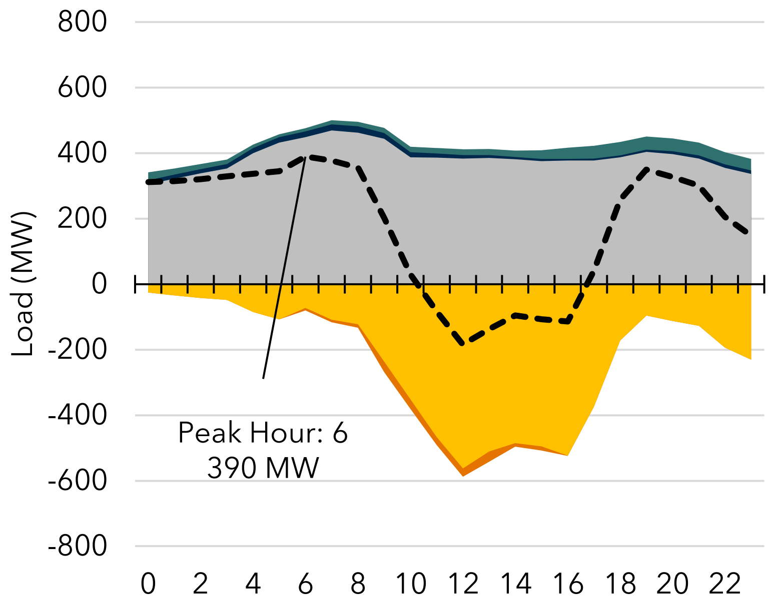
Distributed Solar Generation | Electric Vehicles | Grid scale VRE | Building Electrification | Baseline Load | Net Load

Peak Demand: Shoulder

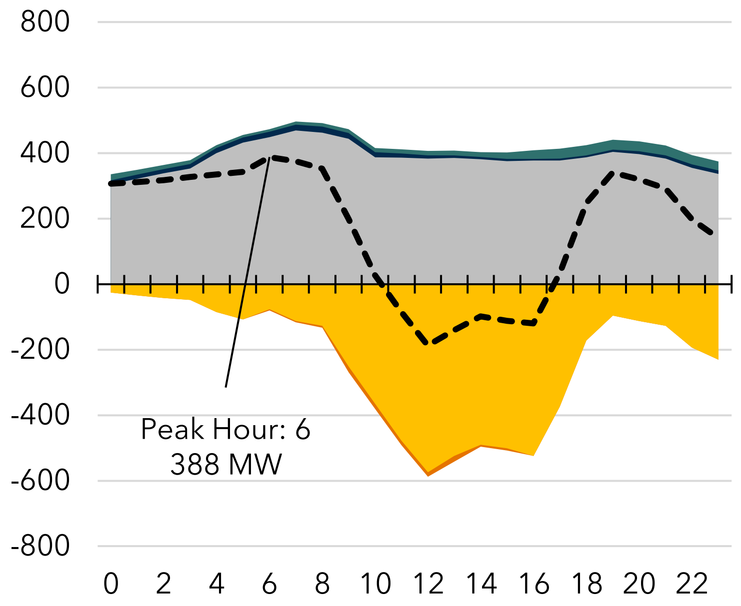
While shoulder peak load impacts are not as substantial as winter and summer impacts, **increasing EV loads will still result in elevated shoulder relative to baseline forecasts**, and the net peak would be a morning one rather than an evening one in this case.

Similarly to Winter**, Distributed solar generation** does have a limited peak load impact as its production is not coincident with the system-wide peak during the shoulder seasons. Similarly to Summer, the grid- scale VRE, mostly driven by wind in the morning, seems to significantly less during the fall season, as shown in the graphs below.

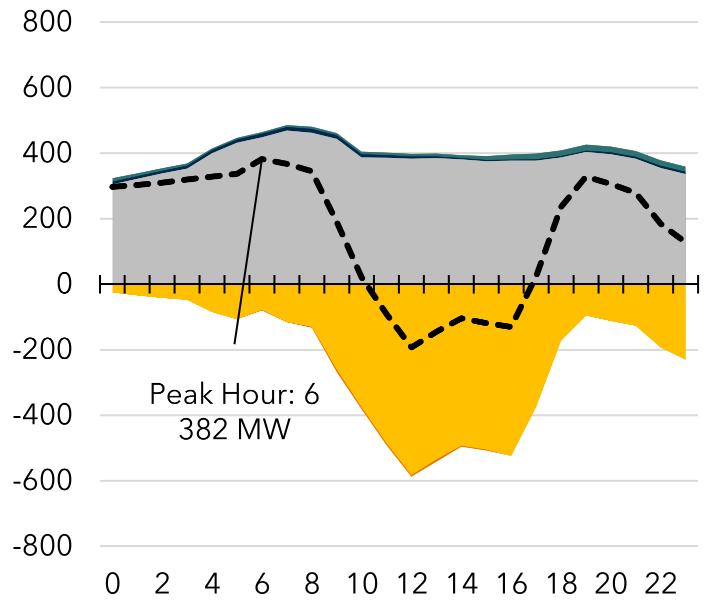
High Growth, 2030 (MW)



Medium Growth, 2030 (MW)



Low Growth, 2030 (MW)



Distributed Solar Generation | Electric Vehicles | Grid scale VRE | Building Electrification | Baseline Load | Net Load

Peak Demand: Mitigation Solutions

Results presented in previous sections represent **unmitigated** load impacts of forecasted EVs and solar PV, coupled with storage, adoption in PRPA's service territory.

- **The projected load impacts of the DER technologies in the study are Substantial.** These DERs can escalate PRPA's peak demand across all scenarios if left unmanaged, requiring capacity enlargement investments in the distribution and generation systems to accommodate this load growth.

There are many **potential solutions for mitigating peak demand impacts**:

- **Deploying load management strategies that favors consumption during off-peak hours.** EVs are inherently suited as a solution as vehicles are usually connected to a charger for a long time even after completing a charge cycle, hence charging loads can be delayed with while being seamless to drivers.
- **Ramping up energy efficiency.** Effective energy efficiency measures are also likely to contribute to the demand reduction side during peak hours. Unlike load shifting strategies that are limited by the net load profile (unless there is enough energy surplus to even out the load, the peak can be reduced with these strategies but not fully eliminated), energy efficiency is able to provide value on the peak reduction independently of the generation profile.
- **Incentivizing technologies with a focus on limiting peak demand impacts.** For example, energy efficiency measures with similar level of energy savings can have a significantly different impact on the peak. Programs and policies that nudge customers towards technologies in consideration of their load impacts can also help mitigate peaks.

These solutions can be implemented **directly into programs** or induced **through the rate structure**, as described in the following section.

Combined Load Curve Analysis

Mitigated Figures (TOU/TVR)

Mitigation Induced by Rate Structure

Putting in place a time-based rate structure is one way to incentivize the energy consumption outside of peak hours. Different structures can be deployed.

- In this study, the low scenario is applying the existing Time of Use (TOU) structure already in place in Fort Collins, whereas the other communities are assumed to operate with a flat rate structure.
- The other scenarios are introducing a new time varying rates (TVR) structure, with similar characteristics than the Fort Collins' TOU, aside from on-peak periods more adapted to the forecasted net peak when taking into account the adoption of the unmitigated DERs presented in the previous sections.

Scenarios

Scenario	Description
Low	• Existing TOU – Only applied to Fort Collins
Medium	• New TVR – applied to all communities
High	• New TVR – applied to all communities

TVR Design

Existing TOU

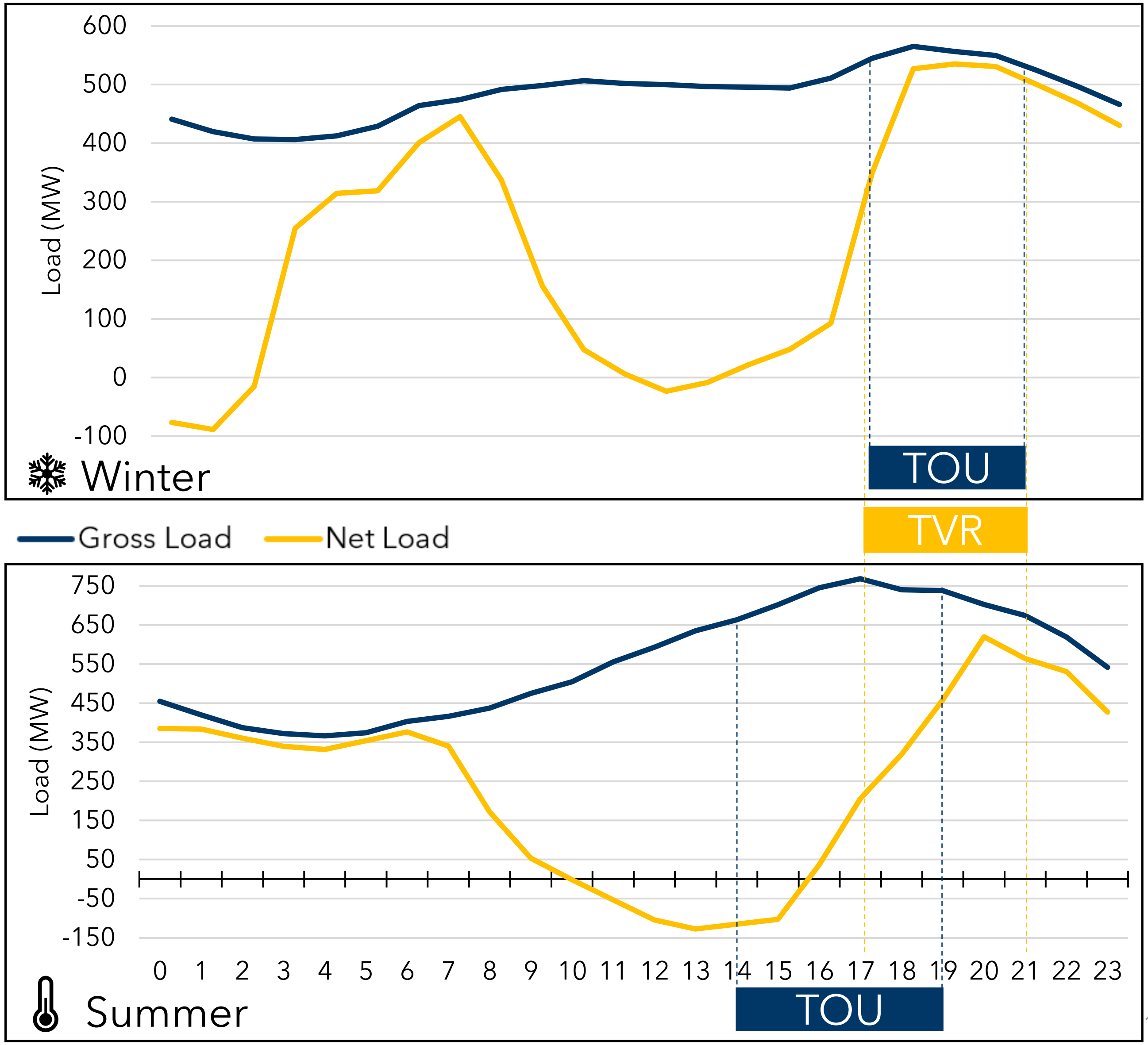
- Entailing peak-to-off peak ratio of ~3.3:1
- Targeting the afternoon during the Summer (on-peak hours: 14-19)
- Targeting the evening during the Winter (on-peak hours: 17-21)

New TVR

- Assuming peak-to-off peak ratio of ~3.3:1
- Targeting evening/night hours when solar is not available in Summer and Winter (on-peak hours: 17-21)
- Assuming mandatory rate
- Assuming majority of load is rebounded

With more renewables in the energy mix, the net peak is expected to shift later in the evening in all seasons and the on-peak rate period is expected to follow

Example of load profiles on a 2030 peak day



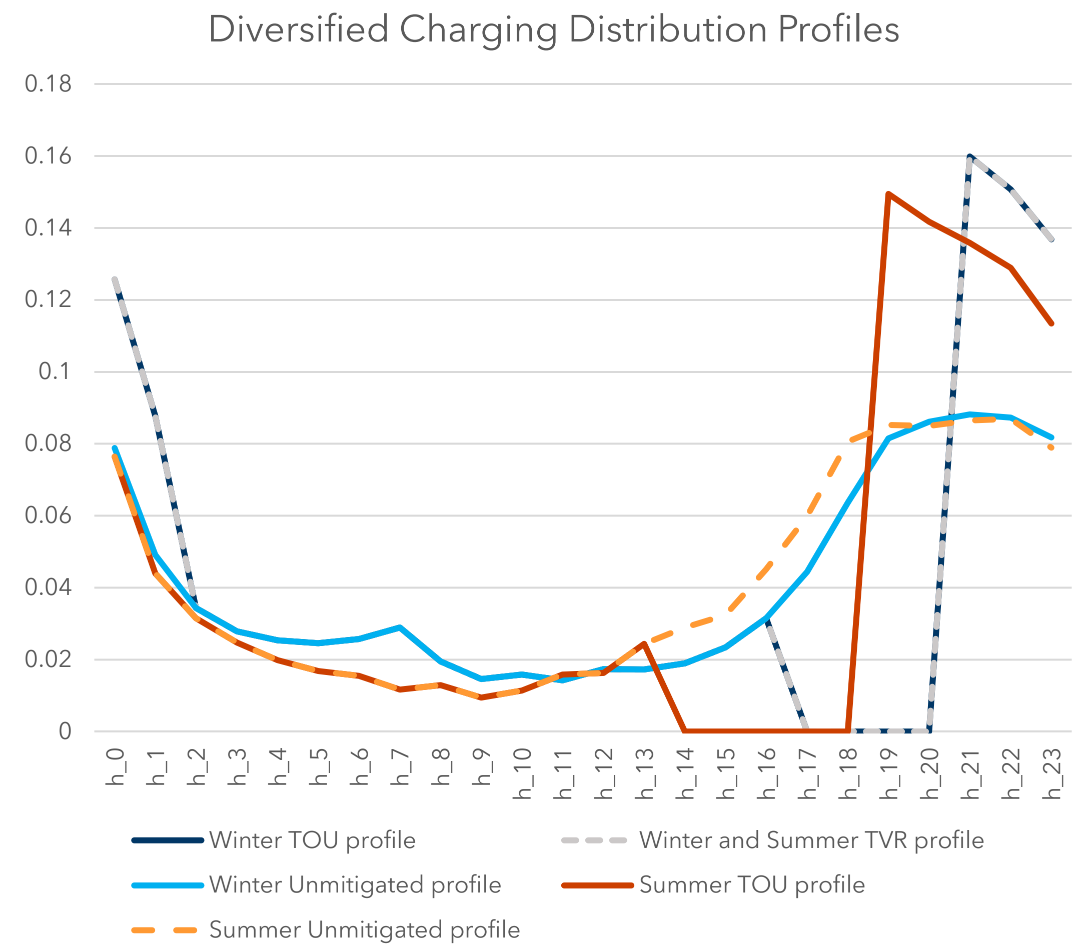
Mitigated Charging Distribution Profiles of EVs

Charging distribution profiles were developed for Passenger LDVs for TOU and TVR profiles

- A TOU and TVR 24-hour charging distribution profile was created by altering the unmanaged LDV home charging profile to have 0% of charging taking place at on peak times for each season.
- Note that these curves are only applied to populations that fully participate and adhere to TOU's and TVR's (discussed in next slide).
- We assume that those adhering to mitigated charging signals will begin to charge immediately after the peak period, with delayed charging recovered within 5 hours.

This load shifting behavior can result in a significant rebound effect that could potentially create a new peak in the off-peak rate period. To prevent that, the on-peak period must be long enough to cover the extended net peak.

Additional demand response programs involving smart chargers can also be deployed to mitigate the rebound effect by spreading the EVs' charging during the off-peak period.



EVs 8760 Load Curves

Mitigated 8760 load curves for an average single vehicle were developed for LDVs using the same approach as unmitigated. An 8760 for each scenario with mitigated charging incorporated was calculated by distributing the vehicle population into two segments:

a) those that adhere to TOU's and TVR's and use those home charging profiles and,

b) those that do not adhere to TOU's and TVR's and use an unmitigated home charging profiles.

The following table shows assumed market breakdown for % of EVs adhering to mitigated charging

Metric	2023	2025	2030	2035	2040	2043
% market reacting to TVR	59%	62%	69%	69%	69%	69%
% market reacting to TVR (smart charger)	29%	34%	50%	50%	50%	50%
% market reacting to TVR (non-smart charger)	30%	28%	19%	19%	19%	19%
% market not (unmitigated)	41%	38%	31%	31%	31%	31%

Note: Given the lack of access to exhaustive local market data, a baseline assumption of 59% of the market reacting to TVR was developed based on a small sample of local data comparing usage differences at peak times between Non-TOU customers and TOU customers. Additionally, we assumed that the smart charger market grows from 29% to 50% by 2030, based on professional judgement. We assume half of the additional smart chargers were not previously reacting to TVR rates and half were. This is what causes a growth in % market reacting to TVR from 2023 – 2030 of 10%.

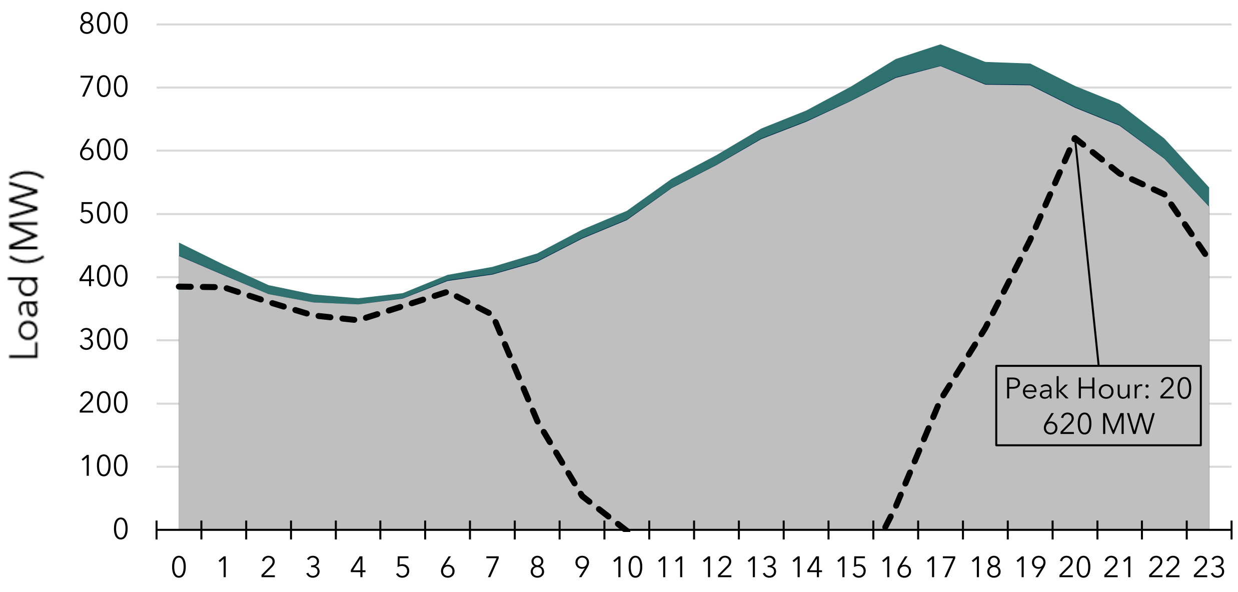
EVs Mitigated Summer Peak Demand Impacts

Mitigating EV load through Time Variable Rates can reduce the system net peak by over 2% in the Summer.

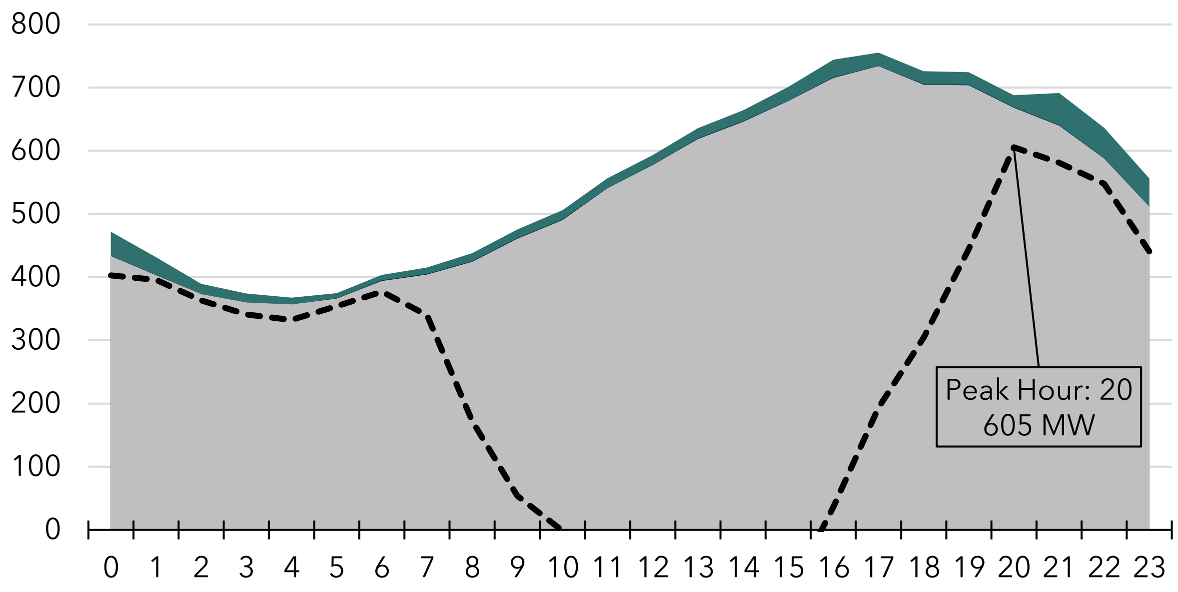
In the high scenario mitigated figure where the TVR on-peak period is from 17:00 to 21:00, the rebound effect right after the end of the on-peak period is noticeable.

Applying the current Fort Collins' TOU, targeting the gross peak occurring earlier in the evening, while the mitigated EVs adoption is high could lead to a significant rebound effect after the on-peak period and result into increasing the net peak at 20:00. The on-peak period should be defined in consideration of both the gross and net peaks.

Unmanaged, High Growth, 2030 (MW)



Mitigated, High Growth, 2030 (MW)



Electric Vehicles | Building Electrification | Baseline Load | Net Load

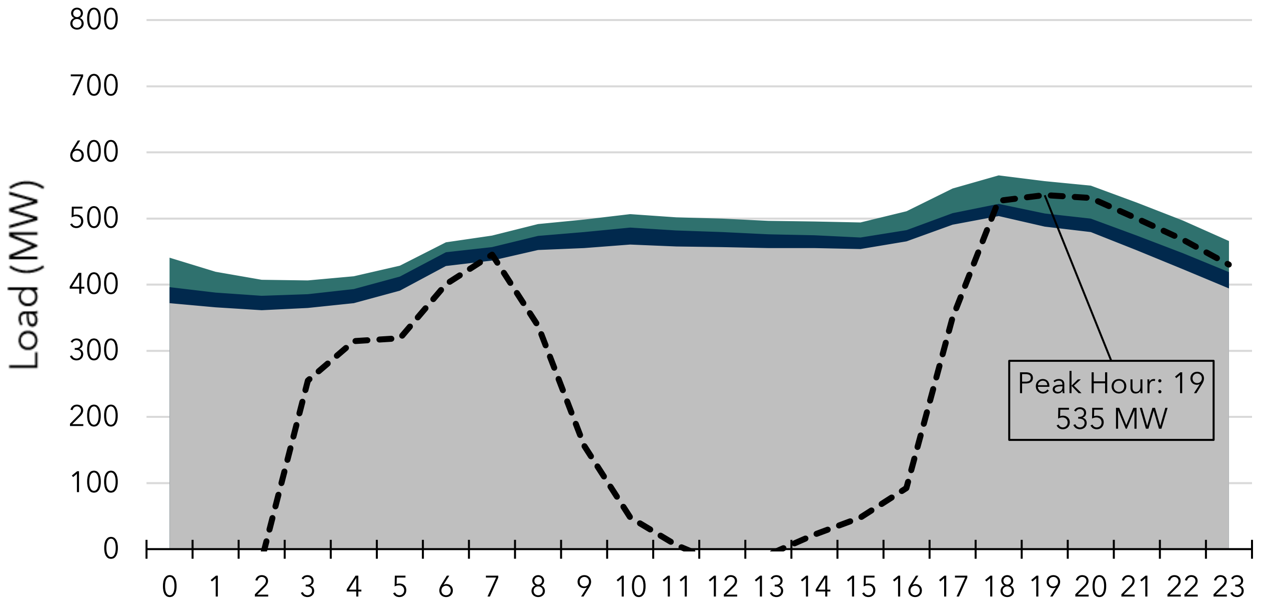
EVs Mitigated Winter Peak Demand Impacts

Mitigating EV load through Time Variable Rates can reduce the system net peak by over 1.5% in the Winter.

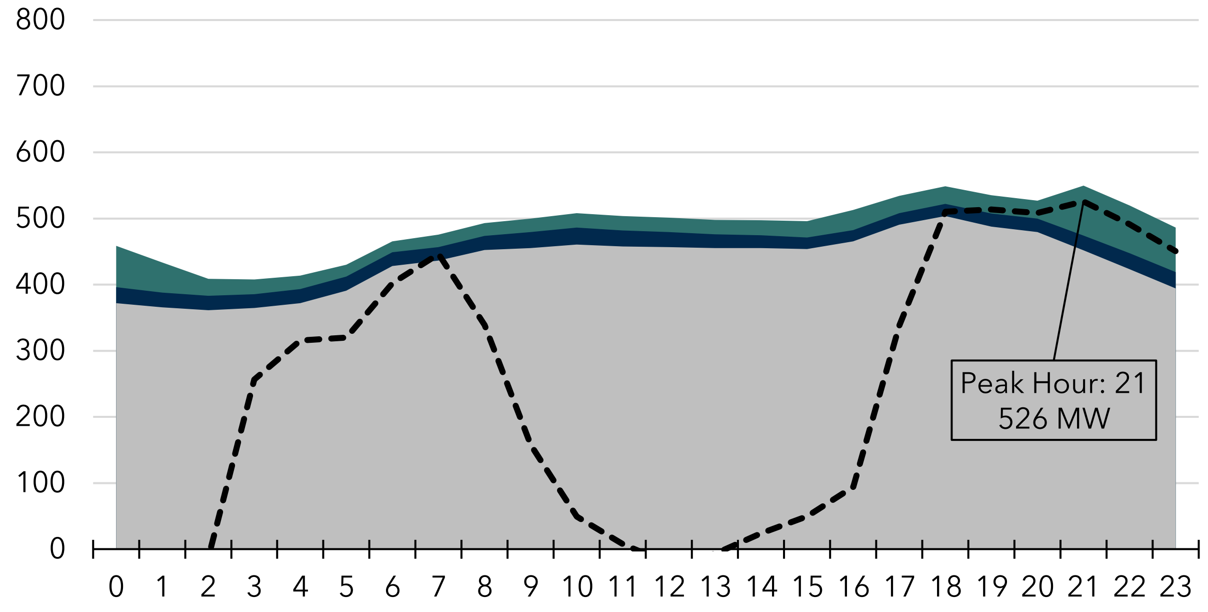
In the high scenario mitigated figure, a new peak is created by the rebound effect at 21:00.

With load shifting strategies, any energy reduction at a given time is balanced by an increase at another time. Considering that the load profile does not offer a deep enough valley after the peak to absorb the rebound effect, the on-peak period must be long enough to prevent creating a new peak that would make the TVR mitigation approach counter-productive or less efficient.

Unmanaged, High Growth, 2030 (MW)



Mitigated, High Growth, 2030 (MW)



Electric Vehicles | Building Electrification | Baseline Load | Net Load

Combined Load Curve Analysis

Conclusion

Key Takeaways

Mature solutions to mitigate these peak impacts are available, such as incentivizing peak efficient technologies, deploying load management strategies and ramping up energy efficiency. These non-wires solutions are expected to be cost-effective and faster to deploy than traditional capacity infrastructures. From a distribution perspective, the mitigation solutions targeting the gross peak are more relevant, whereas the mitigation solutions targeting the net peak are paramount to the renewable generation and reliability resources.

A mitigation solutions bringing benefits to the distribution system by targeting the gross peak is not necessarily suited for the system net peak, and vice versa, especially when the two peaks are occurring at a few hours interval.

Mitigation solutions through a time varying rate structure are showing a significant potential of peak reduction, but also the risk of a notable rebound effect as a trade-off. DR programs with direct load control seem to offer a better grasp on the rebound effect; the potential of DR for mitigation is detailed in the following slides.

Demand Response Potential

Demand Response Potential

Methodological Summary

Overview

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The DR Assessment aims to answer three key questions:

1. **Technical:** How much DER capacity theoretically exists in PRPA?
2. **Economic:** How much of that potential is economically viable?
3. **Achievable:** How much of that potential is likely to emerge over the study period and what is the combined impacts on seasonal peaks?

DR potential largely depends on the coincidence of loads with the system net peak.

DROP assesses DR against standardized 8760 load curve based on historical data.

- Study will use a forecasted 8760 load curve based on annual load/consumption, and forecasted peak demand increase

Achievable Scenarios

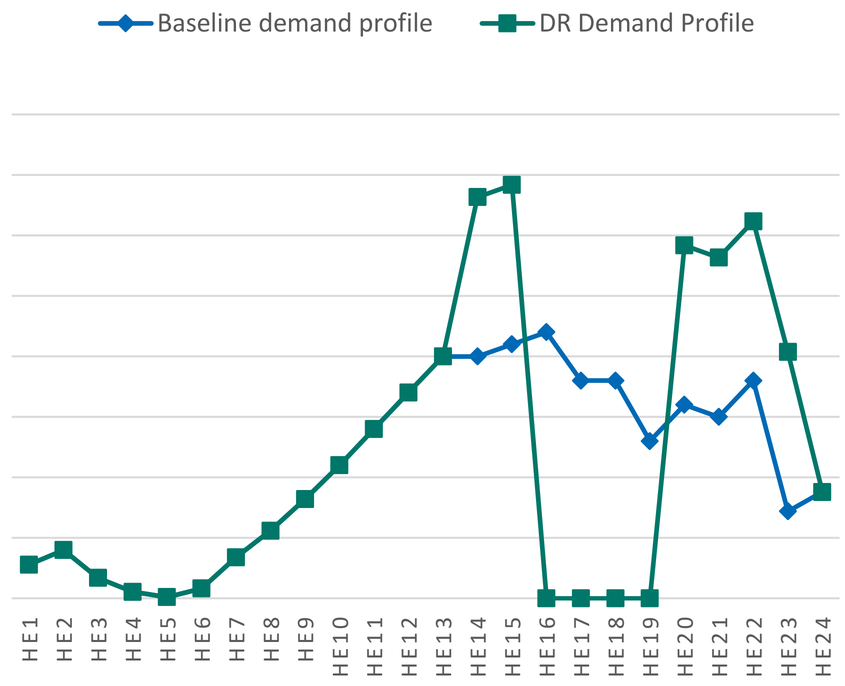
Scenario	Description
Low	• Industry standard incentives and market efforts • Existing time varying rates (TVR) – Fort Collins • Low scenario penetration of EVs, EE and DG
Medium	• Industry standard incentives and market efforts • TVR for all communities • Medium scenario penetration of EVs and DG • Low scenario penetration of EE
High	• Maximum cost-effective DR incentives • TVR for all communities • High scenario penetration of EVs, EE and DG

Measure Characterization

Key Parameters were developed using local data and recognized industry sources

1. **Load Impact:** Connected equipment capacity and curtailable load. Also, define control strategy under DR program (e.g. batteries)
2. **Market Size:** Current number of devices, and projected growth (i.e. Heat Pump + Smart Thermostat adoption)
3. **Baseline Load Profile:** Hourly demand profile of targeted load. (ComStock and ResStock databases, using load curve data for Fort Collins + customer data)

Demand Response Measures Example



Classification of DR measures: Key Characteristics (1/2)

The table below summarizes key characteristic for each measure group.

Measure Group	Measure Sub-Groups	Characteristics						
		Curtailment Potential	Event Duration (hours)	Pre-charge time	Pre-charge Sizing	Rebound Time	Rebound Sizing (per hour)	Event Frequency (per year)
HVAC Controls	**Smart Thermostats**	[75%, 33%]	Up to 2 h	1 h	40%	2 h	30%	20
EV Charging	**EV Smart Chargers**	100%	4 h +	N/A	N/A	6 h	17%	300+
	Vehicle-to-Grid	100%	4 h +	N/A	N/A	6 h	17%	300+
Water Heating	**Electric Water Heaters**	100%	Up to 4 h	2 h	17%	4 h	17%	15
Other Load Flexibility	**Large C&I Curtailment**	25%	Up to 4 h	N/A	N/A	N/A	N/A	15

Note: Pre-charge and rebound sizing is the percentage increase to load in the hours leading up to, or after, a DR event, which recovers all or part of the curtailed load

Classification of DR measures: Key Characteristics (2/2)

The table below summarizes key characteristic for battery storage.

Measure Group	Measure Sub-Groups		Characteristics				
		Size (kW)	Curtailment Potential	Round Trip Efficiency	Typical Event Duration (hours)	Typical Rebound / Pre-charge Time	Typical Event Frequency (per year)
Storage	**Battery Storage - Residential**	3.3	33%	85%	4 h	4 h	300+
	Battery Storage – Small Commercial	5	100%	85%	4 h	4 h	300+
	Battery Storage – Large Commercial	50	100%	85%	4 h	4 h	300+

For residential, it is assumed 33% of the battery is available for DR, and the remainder is used for customer resiliency.

For commercial batteries, 100% is available for DR, as batteries are typically used for peak load management, and backup generators are used for resiliency.

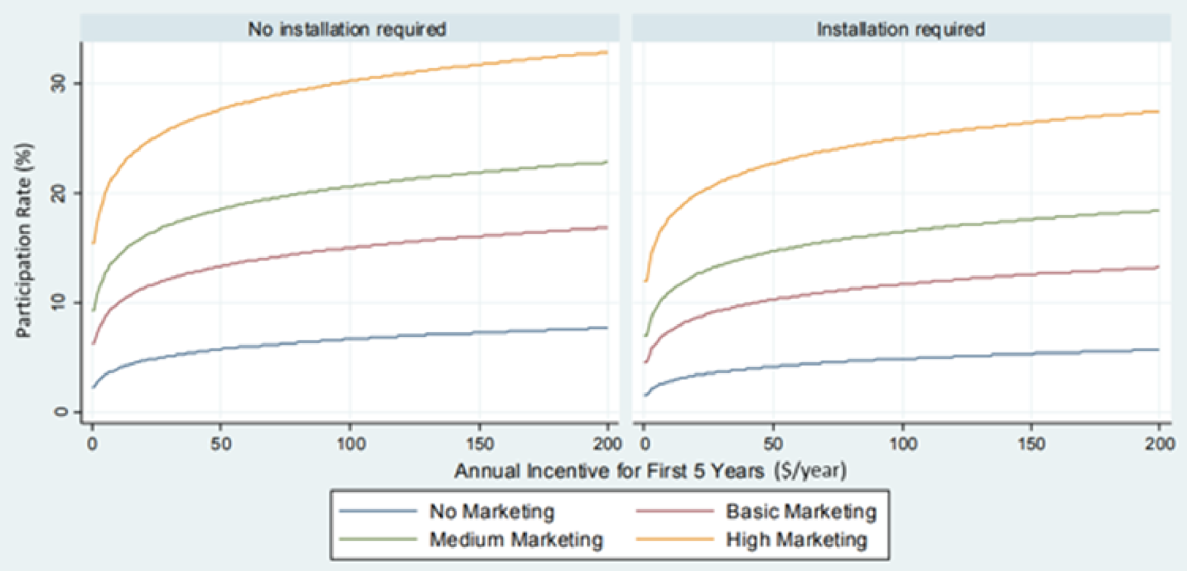
Achievable Potential

Achievable potential is defined as the cost-effective load impacts across all measures, accounting for actual uptake and interactions among measures.

First, individual measure markets are established. Individual measure markets are limited by the lesser of:

- The impact on the utility curve (e.g., number of units that can be applied to reduce utility peak), or
- The maximum market participation as defined by propensity curves (see right)

Sample Propensity Curves Used for Residential Sector



- Propensity curves define participation rates and vary according to incentive levels and marketing efforts. They indicate the likelihood of a group of customers to participate in a program.
- DR propensity curves were developed by LBNL based on a meta-analysis of empirical data from real-world DR programs.

DER Contribution: Approach

Considering PRPA's specific system load patterns, we calculate the estimated contribution of DER measures to peak capacity as follows:

Enrolled Effective Capacity (kW) =

Technical Size (kW) x Operational or technical constraints (for example, we assume a residential AC can reduce its load by up to 73%, so the effective capacity is 1.13 for a nameplate capacity of 1.54)

Achievable Peak Reduction Potential (kW) =

Enrolled Effective Capacity (kW) x Coincidence Factor (% of load that coincides with peak times)

Assessing the effective achievable peak load reduction

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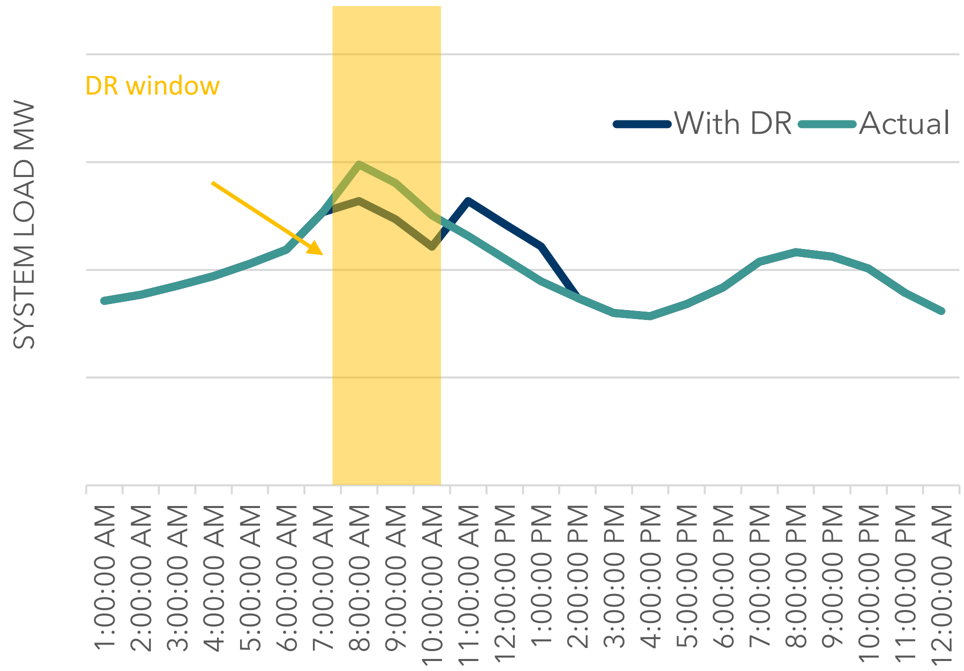
The analysis presents achievable potentials expressed in terms of the actual effective impact on the system peak load, after bounce back and peak shifting have been considered for the full set of applied measures.

Example: Water heaters: By considering the bounce-back effect associated with water heaters recharging their reservoirs after the evening DR window has passed, the figure presented illustrates how adding too many water heaters to the DR program would risk creating a new peak outside of the DR window. This new peak is used to assess the net impact of the measures, which is determined as the difference between the peak before the DHW controls were applied and the new peak after the DHW controls were applied.

Thus, in this case, the effective achievable peak reduction is the difference between the initial peak load, and the new peak created by the bounce-back effect.



Cost-Effectiveness Framework

To assess the cost-effectiveness of DERs:

- **Benefits** are calculated based on the value associated with avoiding or deferring costs of providing the service through an alternative resource (based on avoided costs provided from Platte River)
  - Measures dispatched for different grid services to maximize benefits, while considering defined technical and operational constraints.
  - DERs can contribute to additional system benefits as well as non-energy benefits for customers that are not considered here.

- **Costs** are based on the incremental costs of securing the DER capacity for the identified service provision, considering all applicable upfront and operational costs.
  - Transfer payments such as financial incentives are not considered in the analysis as the cost-effectiveness is evaluated from a combined customer and utility standpoint.

Benefits

A. Energy shifting
B. Generation capacity deferral
C. Avoided distribution capacity costs

Costs

A. Measure costs
B. Measure O&M costs
C. Program costs

Cost-Effectiveness Framework: Costs

Measure upfront and O&M costs considered were based on the DR type / baseline:

DER Type	Assumption	Examples	Measure Cost
A	***Not primarily driven*** by financial benefits of market / program participation (i.e. DR functionality is a by-product)	***Smart thermostats, smart appliances or back-up generators*** are adopted by customers predominantly for other benefits (e.g. energy savings, comfort, resiliency)	**Cost of controls** (if applicable) (e.g. $0 for Wi-Fi-enabled smart thermostats)
B	***Somewhat driven*** by financial benefits of market / program participation (i.e. DR functionality is a co-benefit)	Choice to install a ***smart EV charger or a smart Water Heater*** is partly influenced by the incremental benefits	**Incremental cost** of the measure over the assumed baseline technology (e.g. incremental cost of smart charger over "dumb" charger)

Program Costs are based on high-level estimates of program delivery costs (admin, marketing, etc.) from other jurisdictions

- **Residential and small commercial:** $50/participant (excluding participation incentives)
- **Large C&I**: $10/kW (excluding participation incentives)

Achievable Potential

Finally, all measures are combined to assess the aggregate load reduction impact.

- Measures that are most constrained applied first (dynamic rates), those that are least constrained applied last (unconstrained)
- Within each measure category (dynamic rates, load control and curtailment, and unconstrained), measures applied in order of cost-effectiveness.

Apply Dynamic Rates (if applicable)

↓ Adjust load curve

Apply Load Control and Curtailment Measures

↓ Adjust load curve

Apply Unconstrained Measures
(measures that do not exhibit a bounce-back effect, such as storage and backup generators)

Demand Response Potential

Results Summary

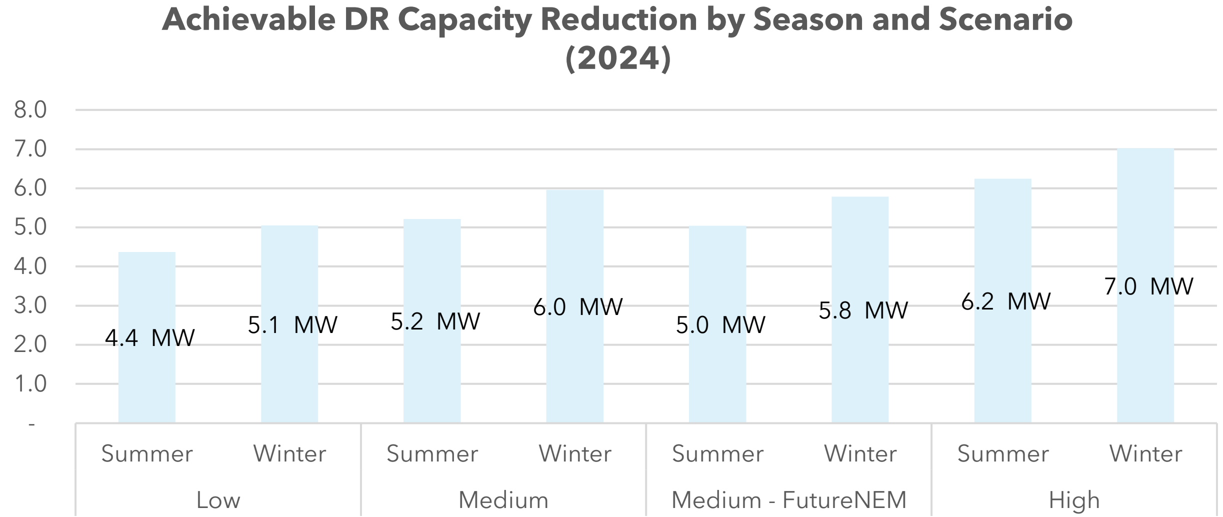
Results: Overview

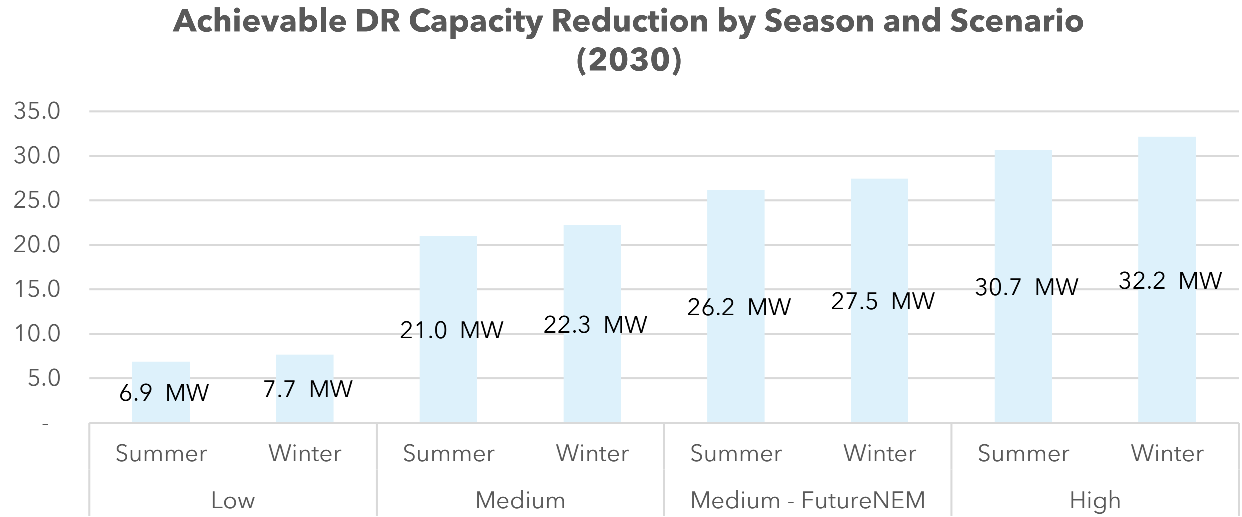
The achievable DR capacity reduction will increase 2 to 5 times from 2024 to 2030, depending on the scenario and season

- Driven primarily by increased penetrations of EVs and battery storage (solar paired and commercial)
- The high scenario delivers higher impacts in 2030 due to higher EV and battery penetrations and increased participation incentives.

The winter peak impact is larger than the summer peak

- EV charging loads increase in winter
- Heating and hot water measures offer increasing potential and have higher coincidence factors

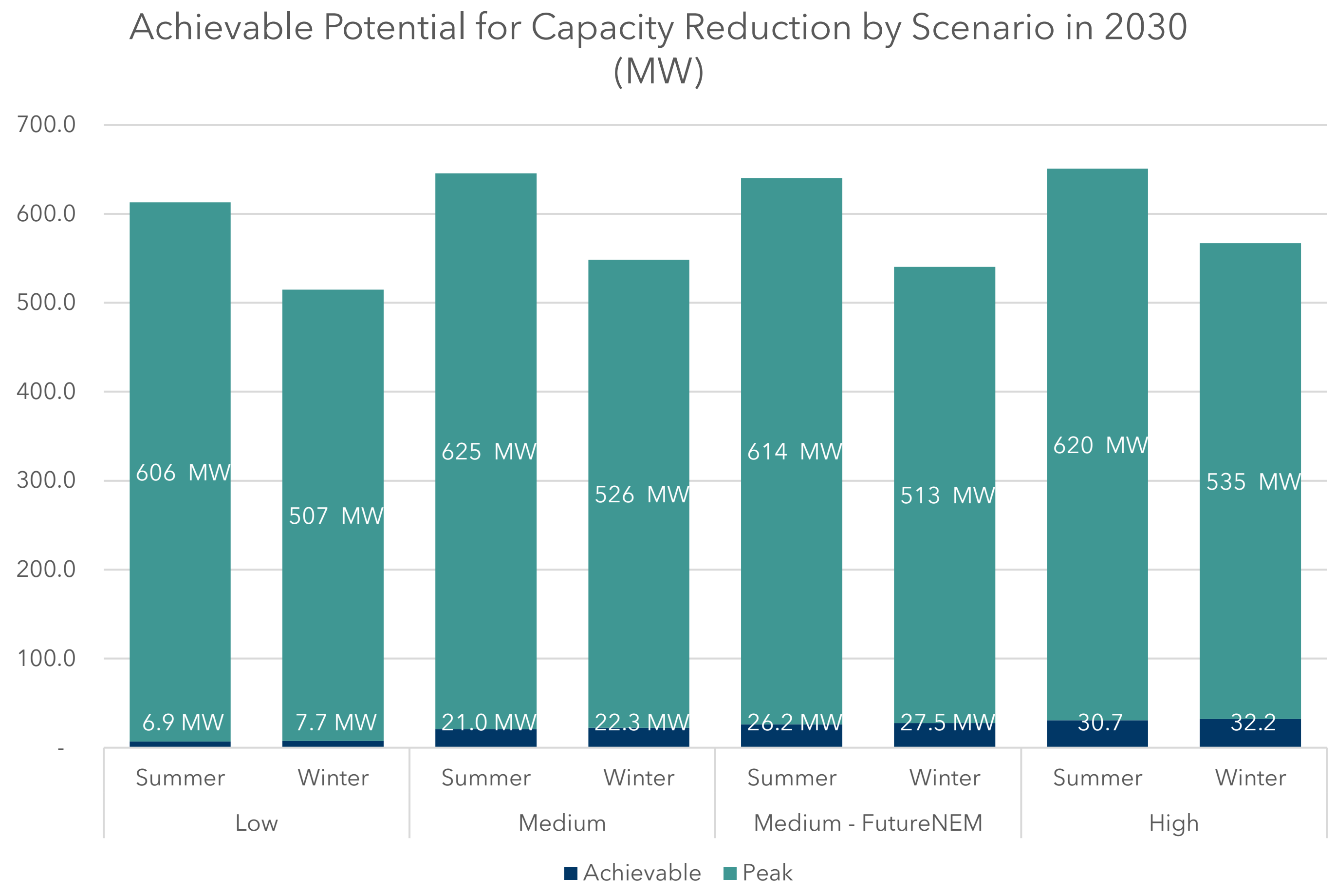




Results: Overview

Achievable DR Potentials represent a notable proportion of the system net peak load by 2030

- Seasonal peak load reductions range from 1%-6% of system net peak in 2030
- Summer/Winter peak capacity reductions represent similar portions of peak load



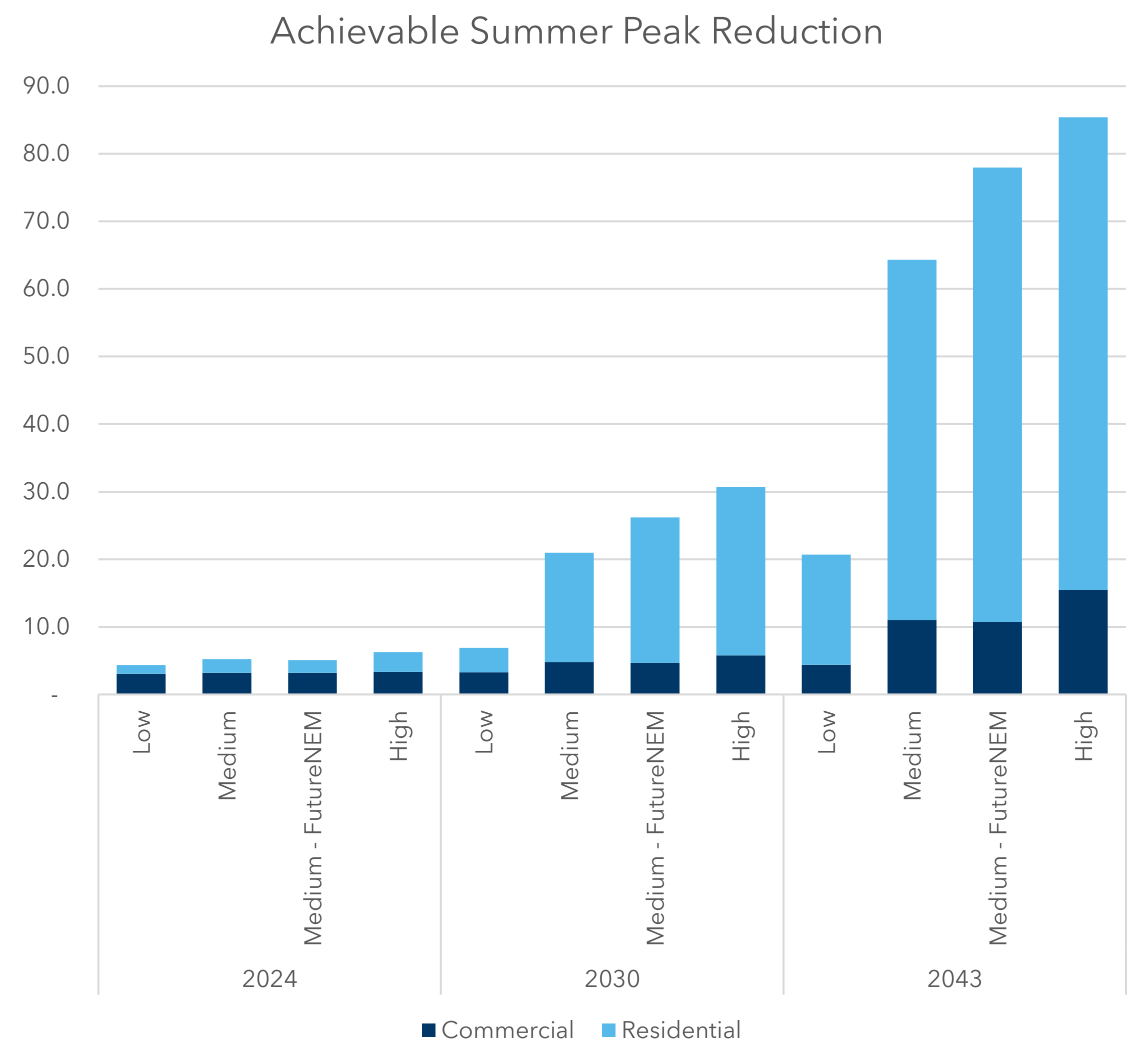
Sectoral Potentials

Under all scenarios residential potentials increase significantly

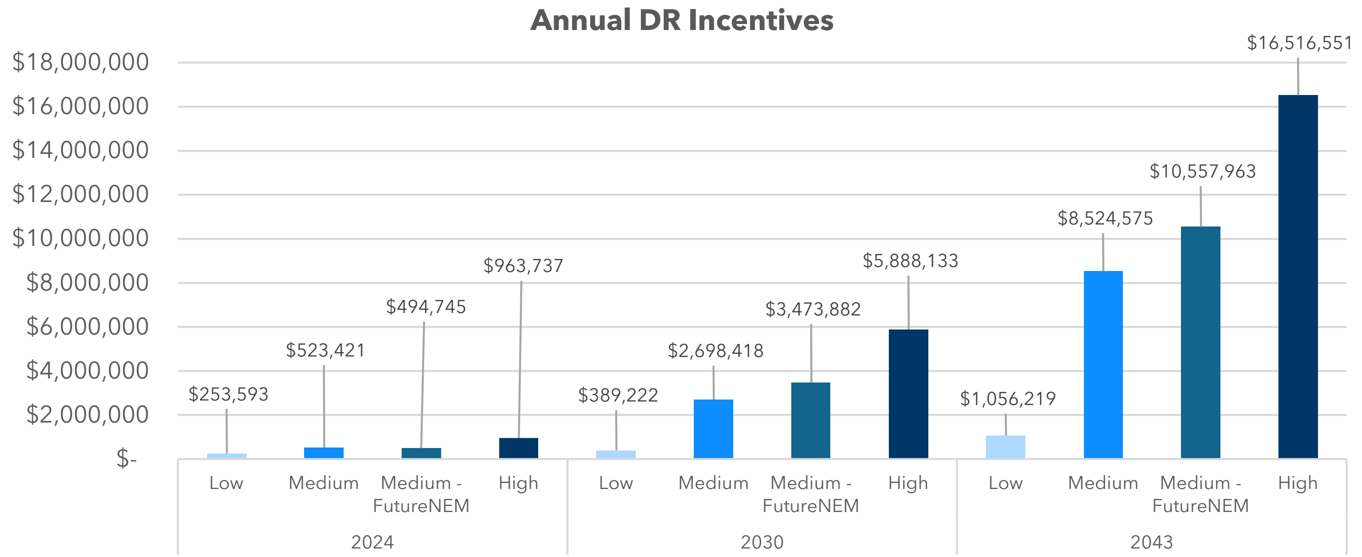
- Growing EV and battery storage penetrations drive most growth
- Heating and hot water measures grow modestly due to increasing market sizes
- Under mid and high scenarios residential DR exceeds commercial potential

Commercial potentials seeing slower growth

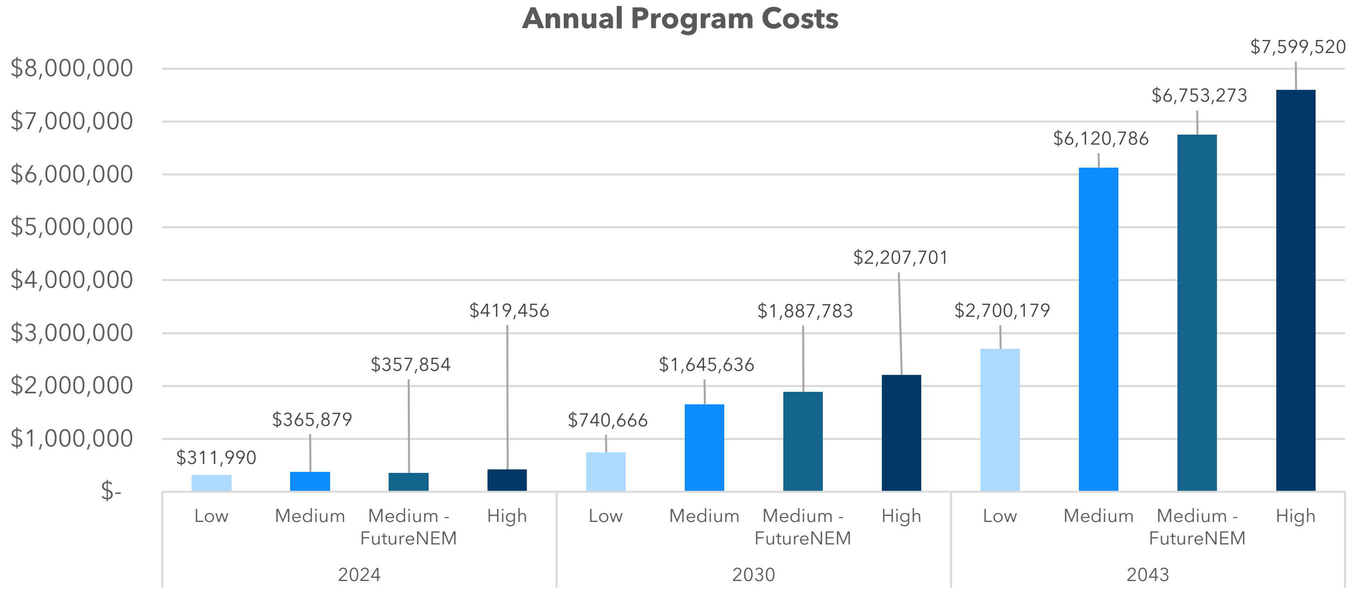
- Relatively smaller MDV/LDV fleets
- Commercial batteries sized to optimize non-coincidence demand charges
- Less penetration of electric heating and hot water equipment



Demand Response Incentive and Program Costs



- Annual Incentives are based on a portion of avoided costs going to customer incentives, with the highest proportion of avoided costs passed to customers in the high scenario.
- Total incentives top at ~$16.5 M for the High scenario, ~ $10.5 M for the Medium Future-NEM and ~ $8.5 M for the Medium in 2043.

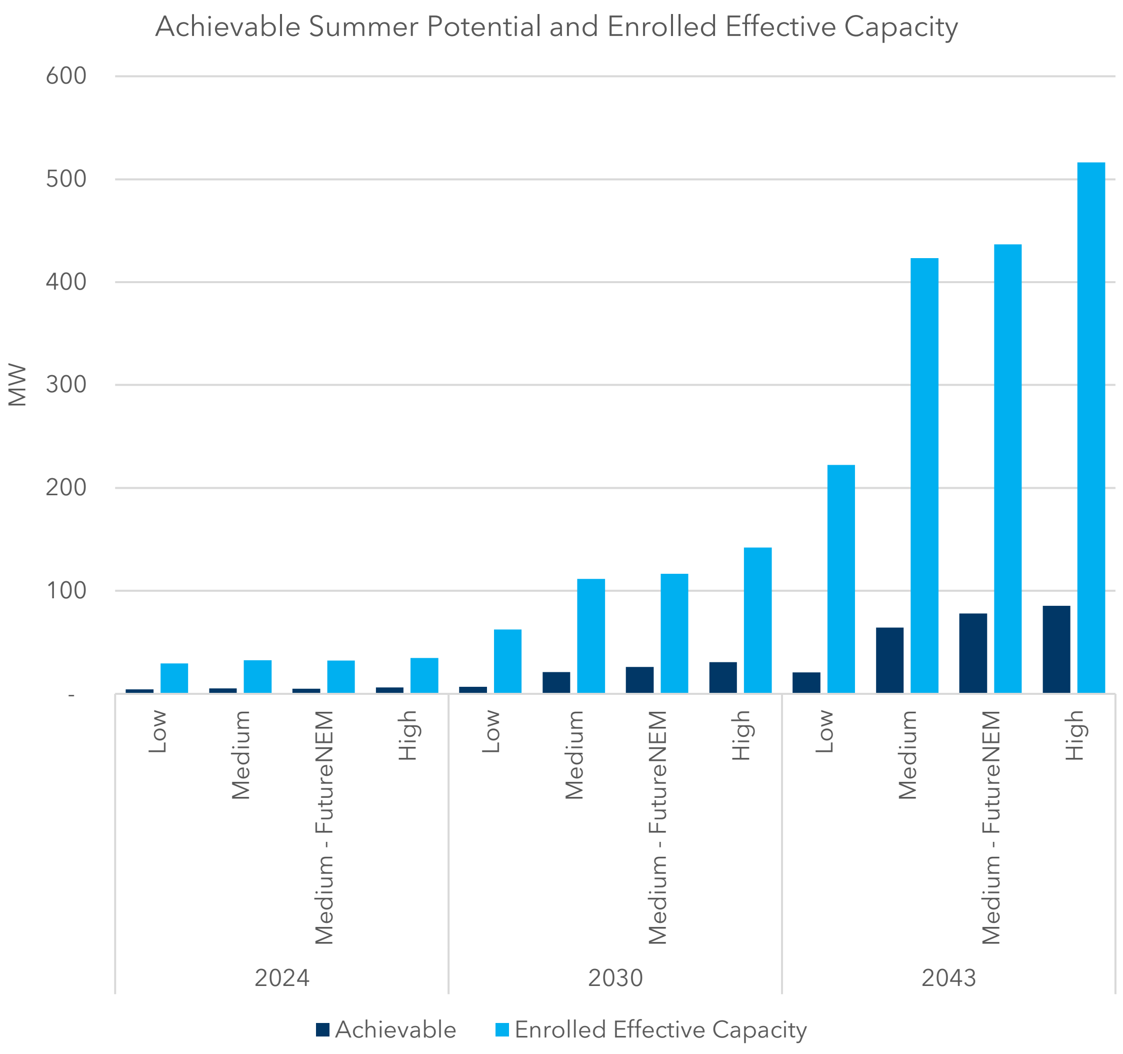


- Program costs are assumed to be $50/participant for residential, $10/kW for commercial
- Total program costs reach ~$7.6 M in the High scenario, ~$6.1 M for the Medium, and ~$6.8 M for the Medium Future-NEM in 2043

Enrolled Effective Capacity

Enrolled capacities far outstrip peak load impact potentials

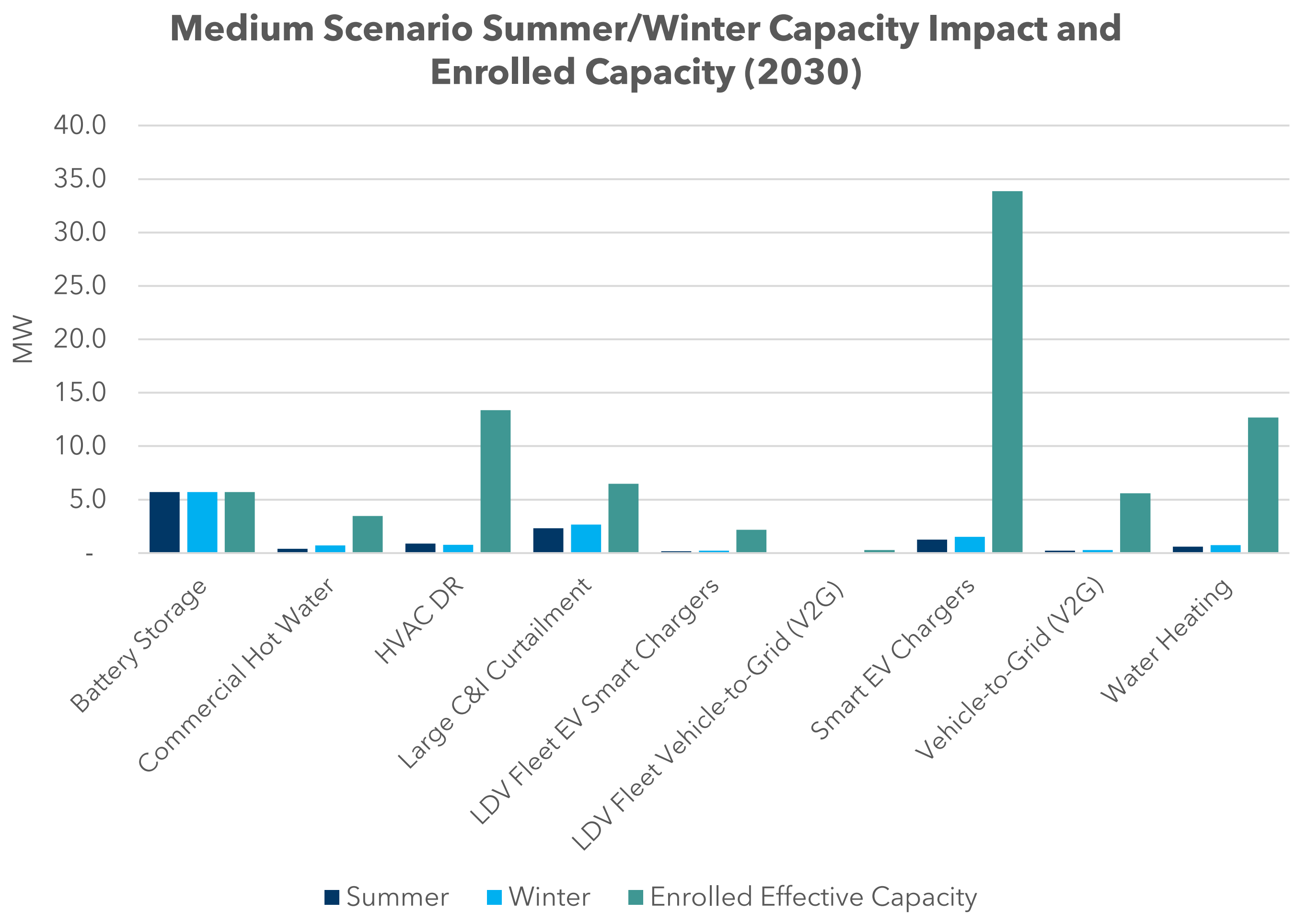
- Model assesses all enrollment based on customer propensity, not system need.
- Model assesses the "net" achievable impact on the seasonal system peak, accounting for peak timing shifts, bounce-back and pre-charge
- Not all enrolled capacity will necessarily deliver peak reductions, only a portion of the enrolled capacity is coincident with the peak times
- Some measures have very high enrolled capacity, but offer minimal net reductions. Could be omitted from programs, or have participation limits.
- There might be an opportunity to leverage the potential of these enrolled resources outside PRPA's peak hours in function of the energy market needs



Enrolled Capacity by Measure

Some measures have notably high enrolled capacities

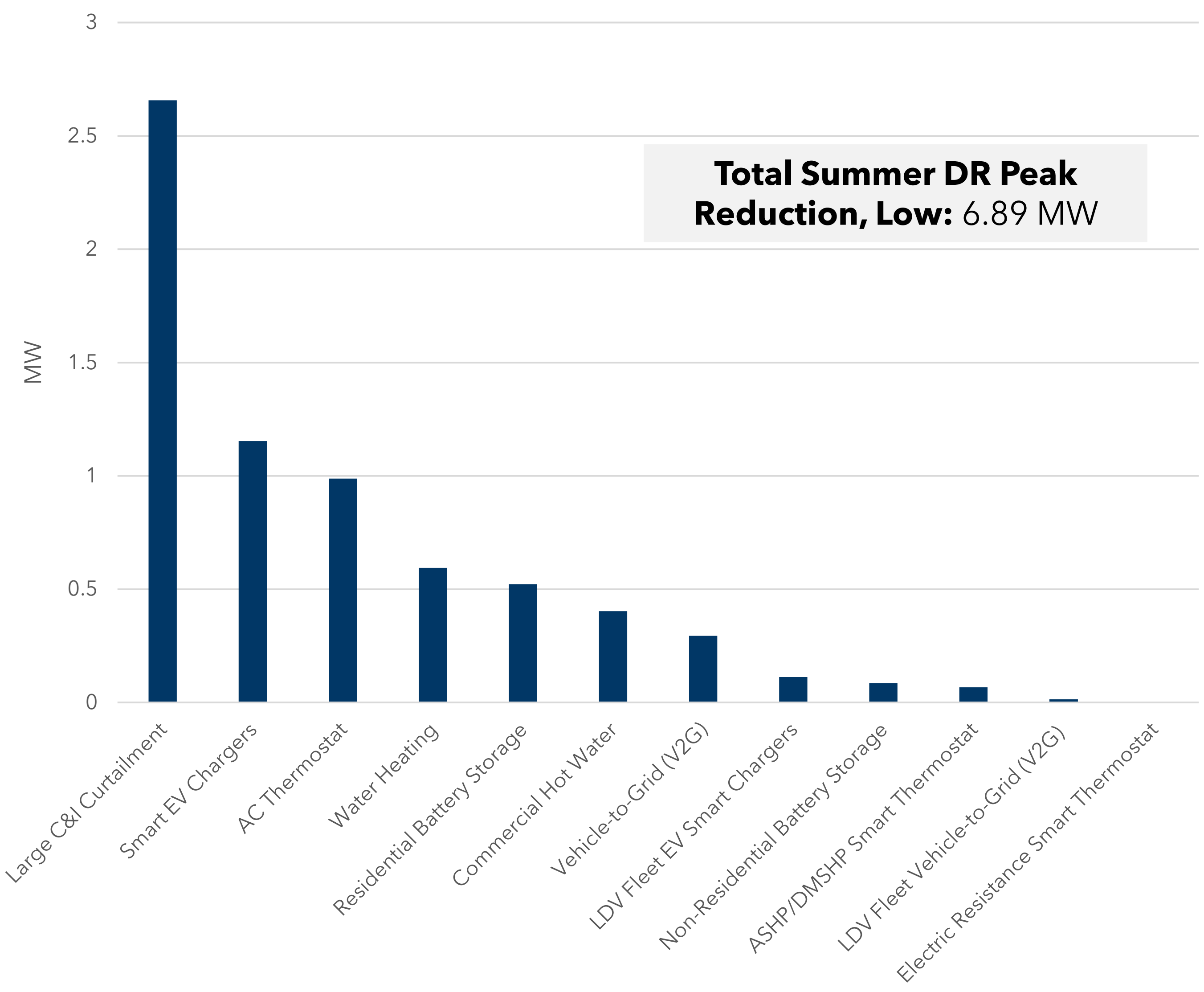
- There is a big gap between EV charger enrolled capacity and the reduction potential during peak hours due to relatively low coincidence factor, particularly affecting the customers already applying load shifting strategies as a reaction to the TOU rate.
- Water heaters and HVAC DR have notable enrollment, but deliver just a fraction of the potential benefits due to low coincidence factors and rebound effects.



Low Scenario (2030)

Under the low scenario commercial DR measures predominate

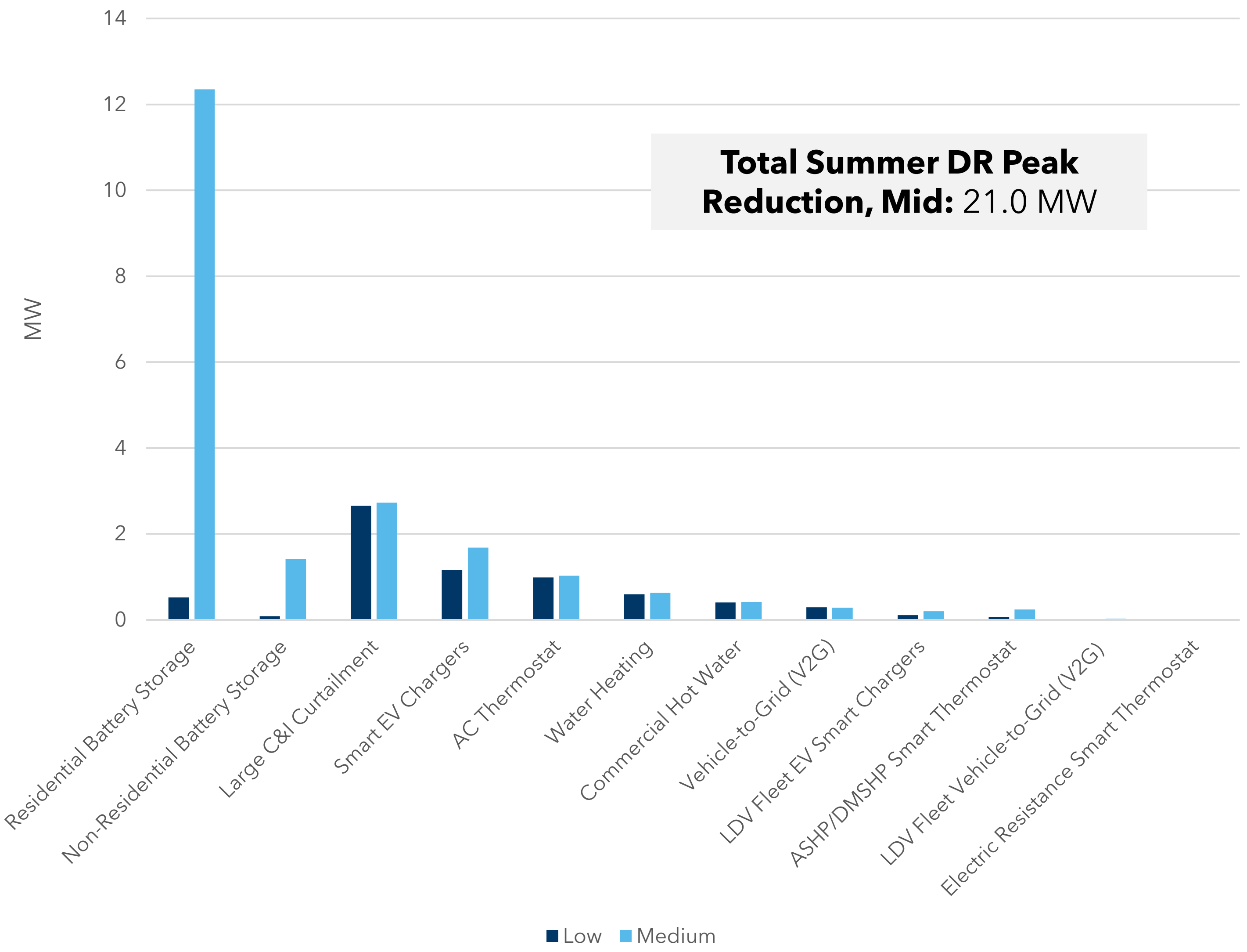
- Large C&I curtailment offers a significant proportion of the benefits
- Residential smart EV chargers provide significant savings as EV adoption in the residential segment is larger than the commercial segment
- Residential AC and hot water measures offer some potential



Mid Scenario (2030)

Under the Mid scenario residential storage become the primary measure

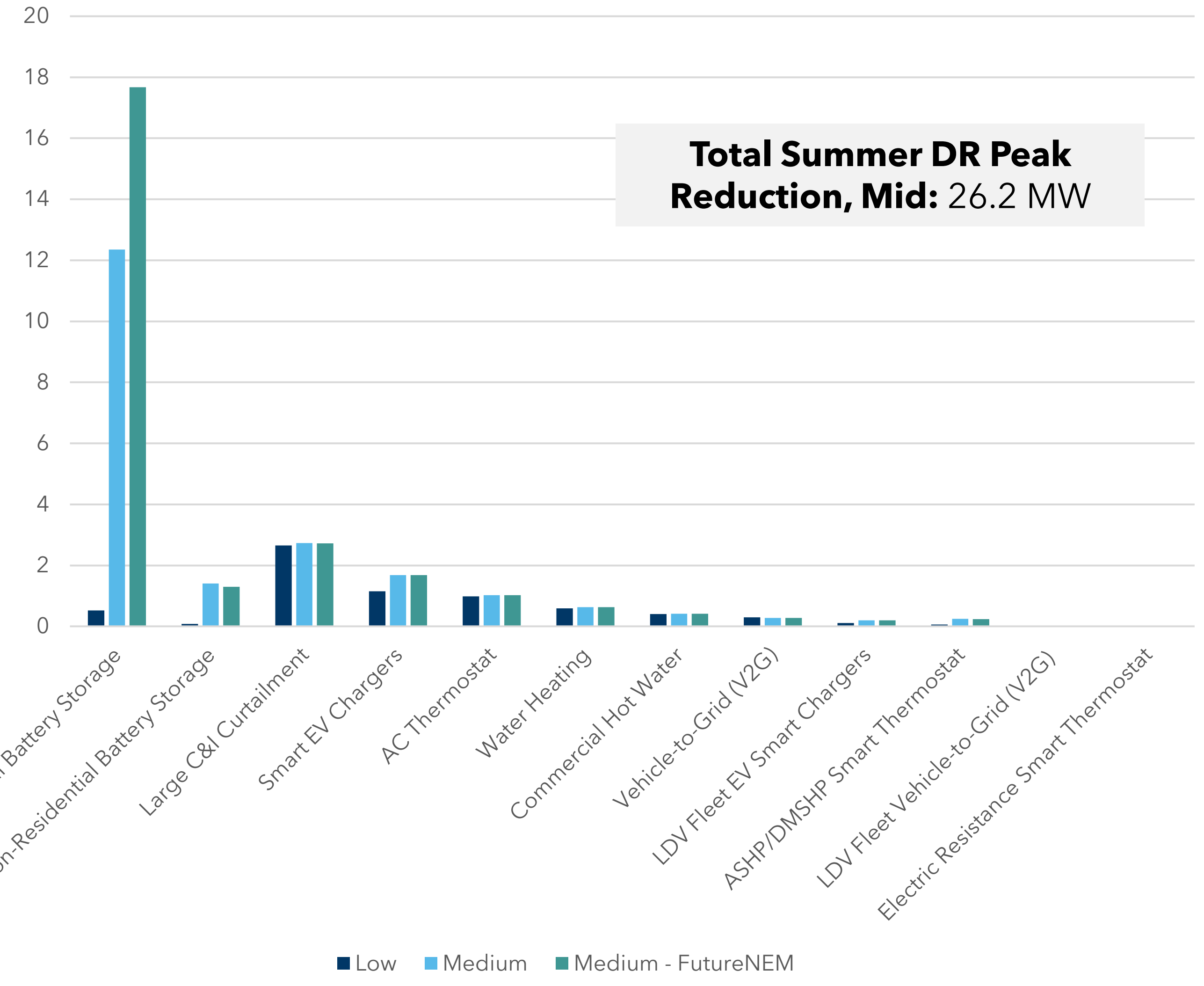
- Commercial battery penetration also sees significant increases in the Mid scenario
- Large C&I curtailment still offers significant benefits
- Higher penetrations of electric vehicles and building electrification leads to higher reductions from EV and heat pump measures



Mid – Future NEM Scenario (2030)

Under the Mid - Future NEM scenario residential storage potential increases further

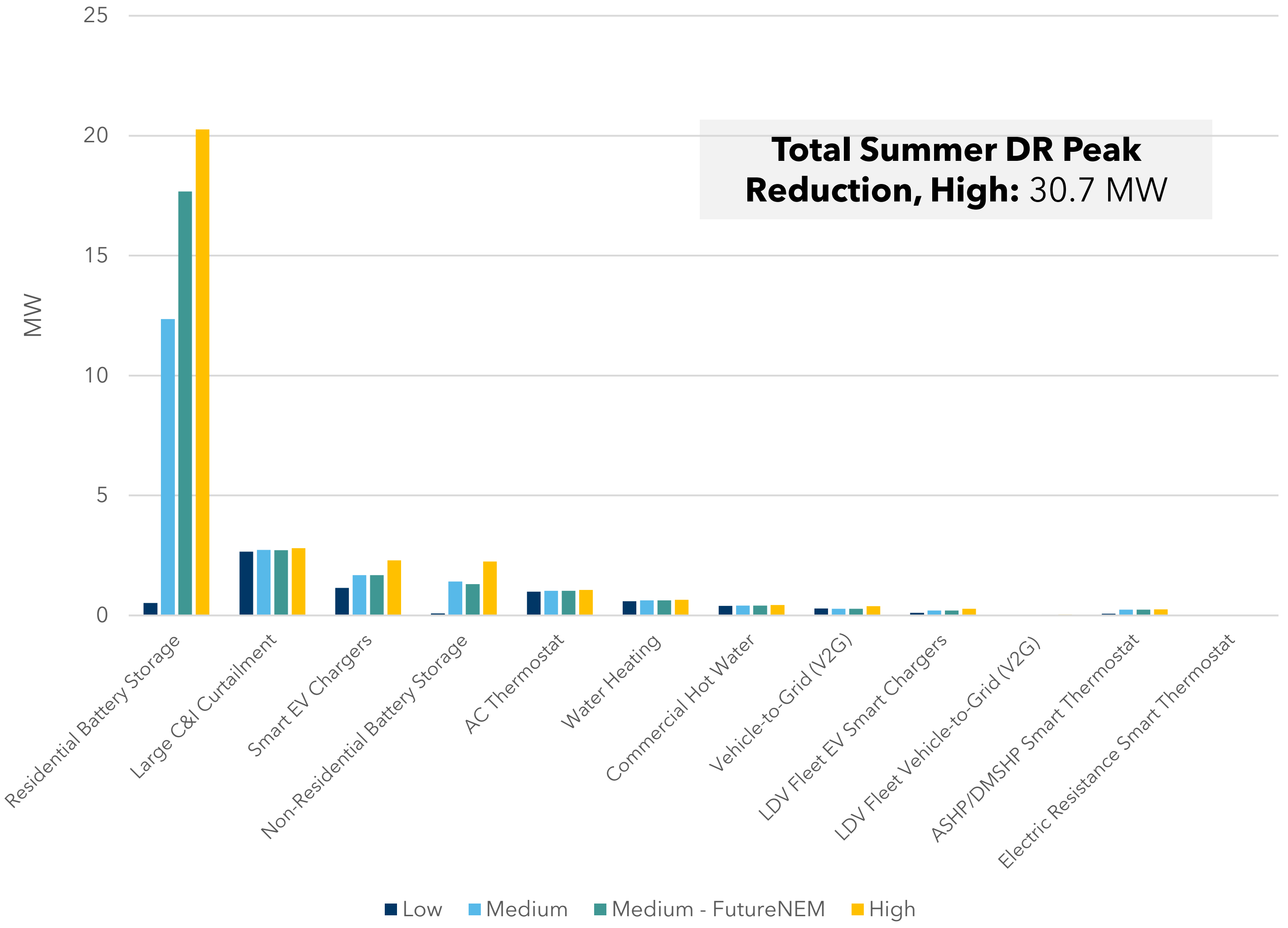
- Slight decline in commercial battery storage given a smaller market size.
- Other measures stay consistent with the mid scenario.



High Scenario (2030)

Under the High scenario residential storage remains the primary measure

- Large C&I curtailment and smart EV chargers continue to offer the most reductions
- High incentives drive slightly higher heating and hot water potentials – optimal incentive levels may be closer to Mid scenario settings



High Scenario (2043)

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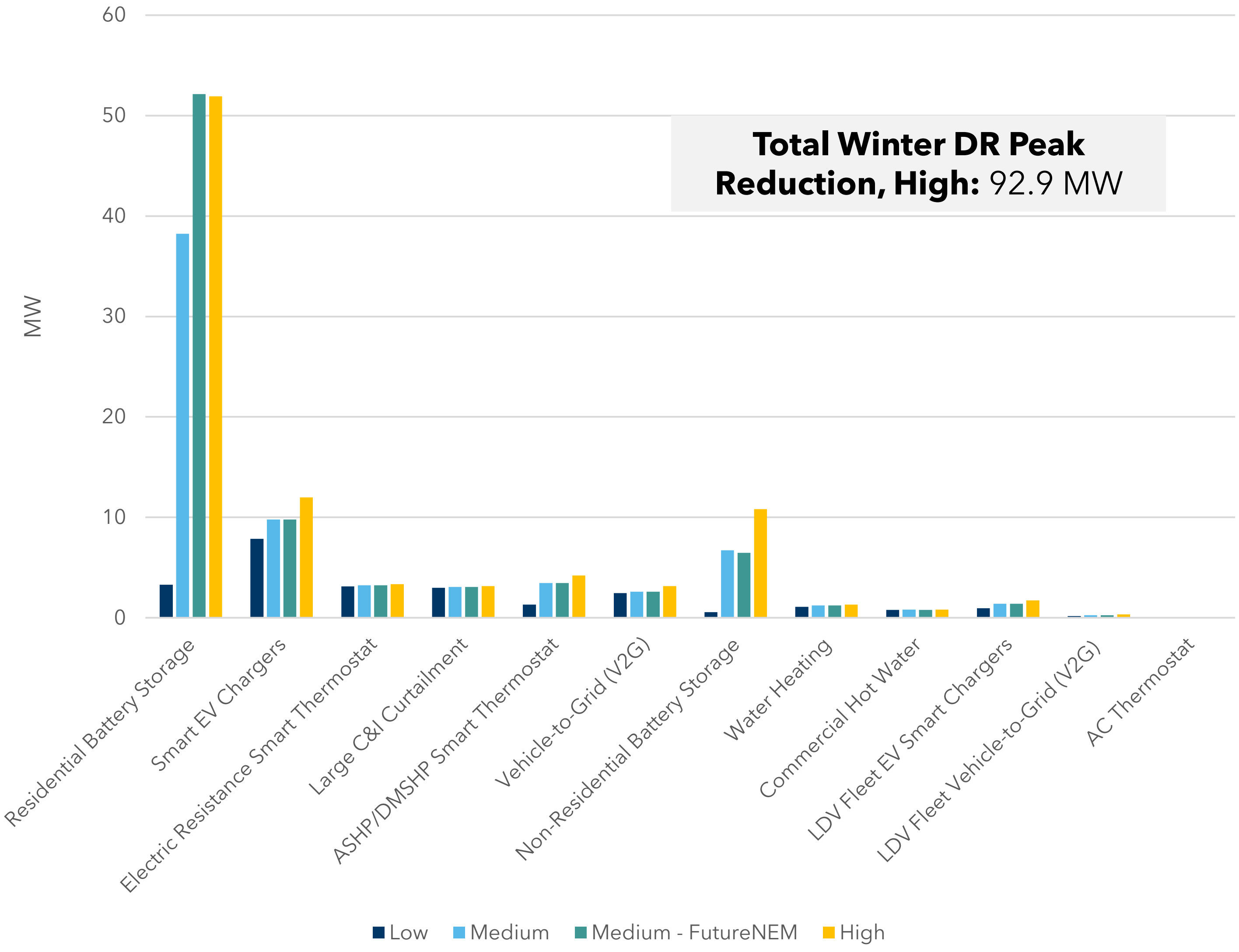
In the latter years of the study, the biggest peak day is expected to shift from Summer to Winter

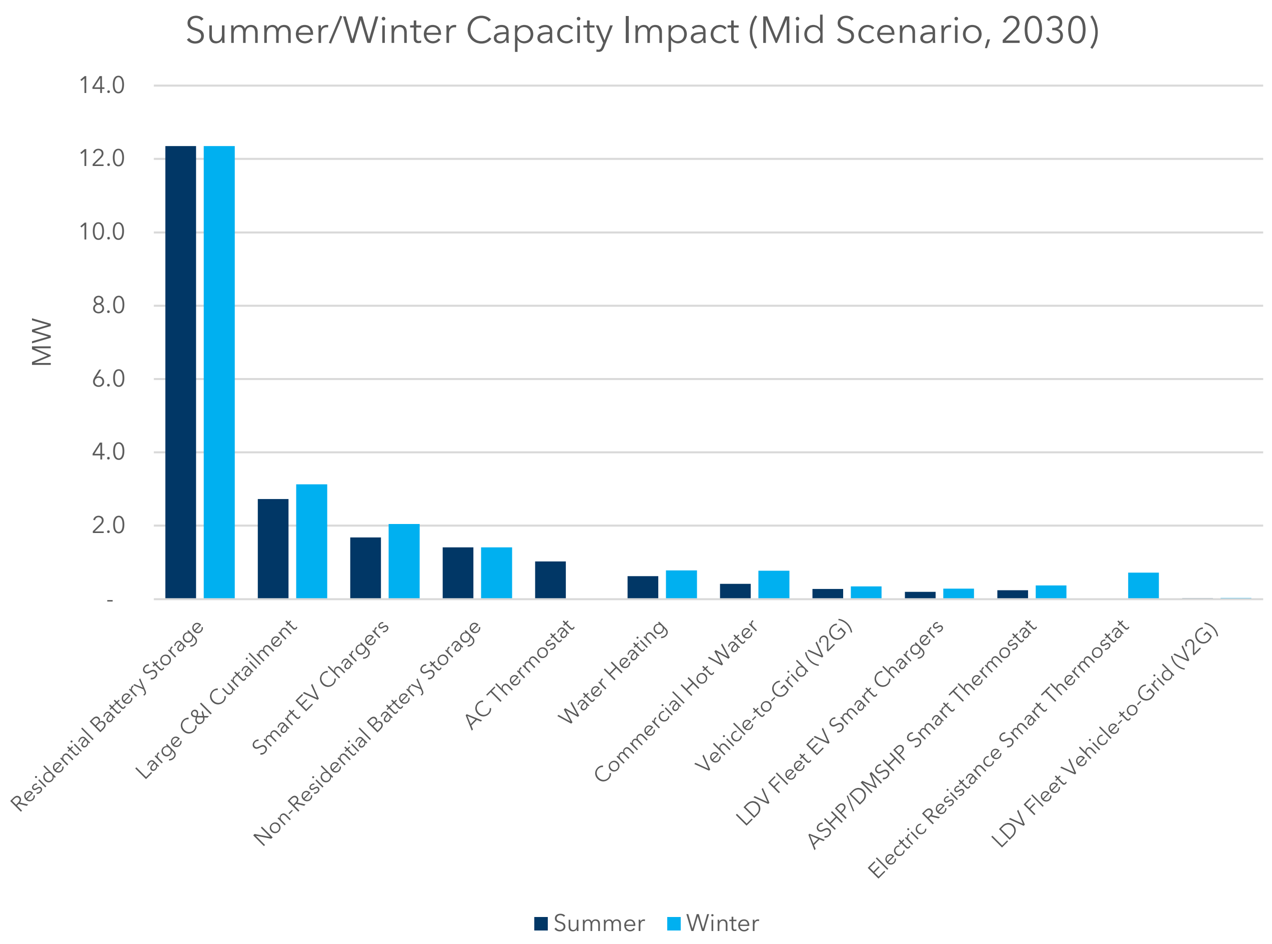
- Under the High scenario residential storage remains the primary measure
- Smart EV chargers play an increasing role in addressing winter peak
- Heating measures (Electric Resistance Smart Thermostat and ASHP/DMSHP Smart Thermostat) can offer increasing reductions



Summer / Winter Measure Impact Comparison

Summer/Winter peak impacts are similar for most measures

- Battery storage measures have the same summer/winter benefits due to their flexibility
- EV charging has higher winter benefits due to higher winter charging loads
- Heating and hot water measures have higher winter peak benefits due to higher loads and coincidence with peak



Demand Response Potential

Conclusion

Key Takeaways

Seasonal peak load reductions range from 6.9 MW to 32.2 MW (1%-6% of system net peak) across the different scenarios in 2030.

The residential sector is forecasted to have the most DR potential in 2043, with around 7 times more reduction potential than the commercial sector in the high scenario, even if the commercial sector predominates early in the study period, and under the low scenario

For the residential sector, battery storage is expected to be by far the most prominent measure in all scenarios except the low one, followed by smart EV chargers and AC smart thermostats in the Summer or electric resistance smart thermostat in the Winter. With time, EVs is anticipated to gain more and more ground.

The commercial DR potential is primarily driven by large C&I opportunities, followed by battery storage and water heating.

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