Maryland Building Decarbonization Study

Final Report

September 16, 2021

Energy+Environmental Economics

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Summary of Updates

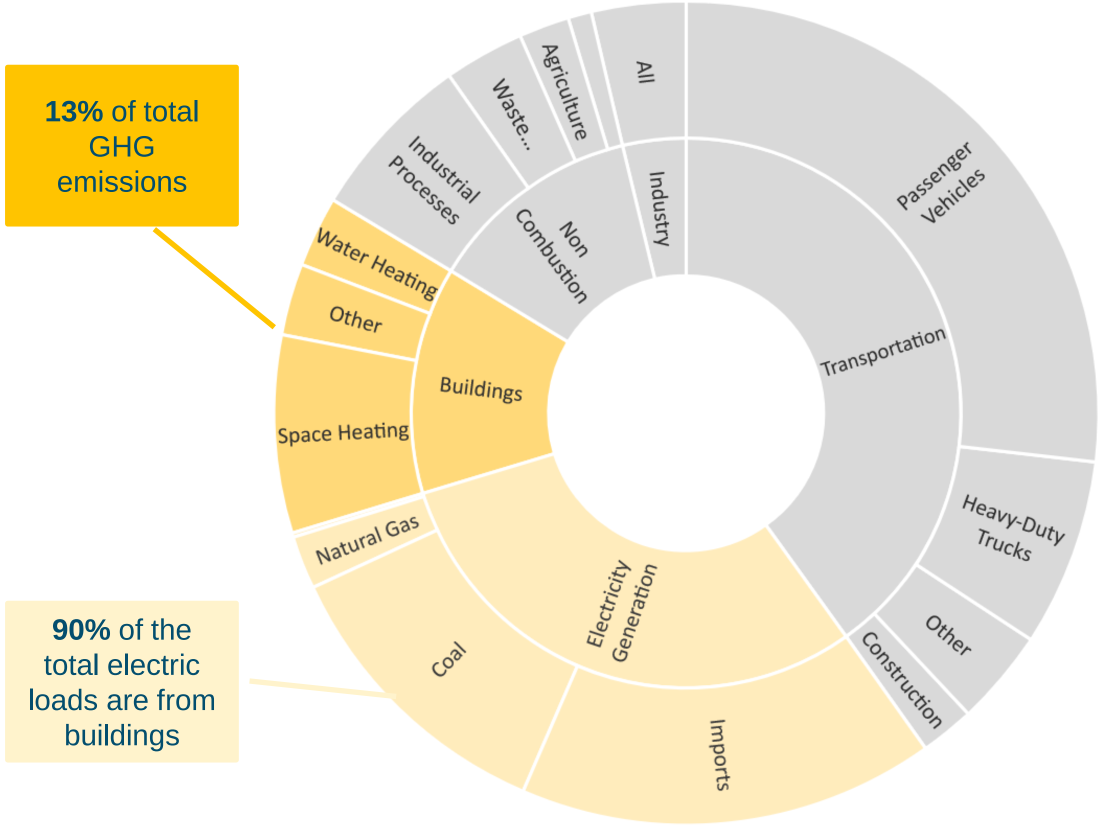
+ **E3 has made the following updates to the analysis based on feedback from the Buildings Subgroup and MWG participants**
  - Updated the **electric efficiency assumptions** in the High Decarb Methane scenario assuming **extension of EMPOWER**
  - Halved the **gas revenue requirement growth rate after 2035**, to be consistent with GGRA assumption that **STRIDE** will complete by then
  - Adjusted the **optimistic RNG scenario** to reflect **competition from liquid fuels**
  - Estimated GHG emissions from **methane leakage** for each scenario
  - Corrected **an error in the electric system cost** estimate
  - Adjusted the **equipment cost** for the **High Electrification with Improved System Configuration** case to reflect larger tonnage for heat pumps
  - Conducted a **climate impact** sensitivity analysis

Background and Scenario Design

Project objective: a Maryland-specific pathway to achieve deep decarbonization of building end-uses by mid-century

+ **Based on the most recent Maryland GHG Inventory for 2017, building direct-use emissions account for 13% of economywide GHG emissions in Maryland**
  - 80% of direct building emissions are from space heating and water heating
+ **90% of the statewide electric load are from buildings, which contribute to upstream emissions in electricity generation**
  - Currently, electricity generation accounts for 30% of total GHG emissions, but will decrease as clean and renewable energy becomes a larger share
+ **Key questions of this project:**
  - What are the potential pathways to achieve deep decarbonization of Maryland's building stock by mid-century?
  - What are the costs and benefits of each pathway from a total system cost perspective, as well as impacts on consumers?

MD 2017 Gross GHG Emissions by Sector and Subsector



This study investigates opportunities for building decarbonization through 3 scenarios

+ E3 and MDE held a 4-hour workshop with the Buildings Ad-hoc Group, where we received feedback and input from stakeholders on scenario design that informed the selection of the following scenarios

Reference	High Electrification	Electrification with Fuel Backup	High Decarbonized Methane
+ Same as the Reference scenario in the GGRA analysis reflecting current policies + Buildings keep using existing devices with no electrification and little efficiency improvement + Building energy demand grows at 0.6%/yr, same as EIA's projected annual growth rate of Maryland households	+ Almost all buildings switch to ASHPs and GSHPs. Heating is supplied by electricity throughout the entire year + High efficiency through deep building retrofits	+ Existing buildings keep using fuels for heating and are supplied with a heat pump combined with existing furnace/boiler that serves as back up in the coldest hours of the year + All-electric for new construction	+ Buildings keep using fuels for heating while fossil fuels are gradually replaced by low-carbon renewable fuels. Some features: • RNG supplied by biomethane and synthetic natural gas • 7% hydrogen blend • High efficiency through deep building retrofits

3 steps to analyze the impacts of building decarbonization scenarios

3 selected scenarios

- **Scenario Specification**: Development of decarbonization scenarios, heating equipment costs and renewable fuel supply curve
- **Assess Energy System Impacts and Cost Implications**: Analysis of incremental equipment costs, electric system costs and fuel costs.
- **Electric and Gas Rate Impacts**: Development of electric and gas revenue requirement models to estimate rate impacts

Overview of technical and economic implications

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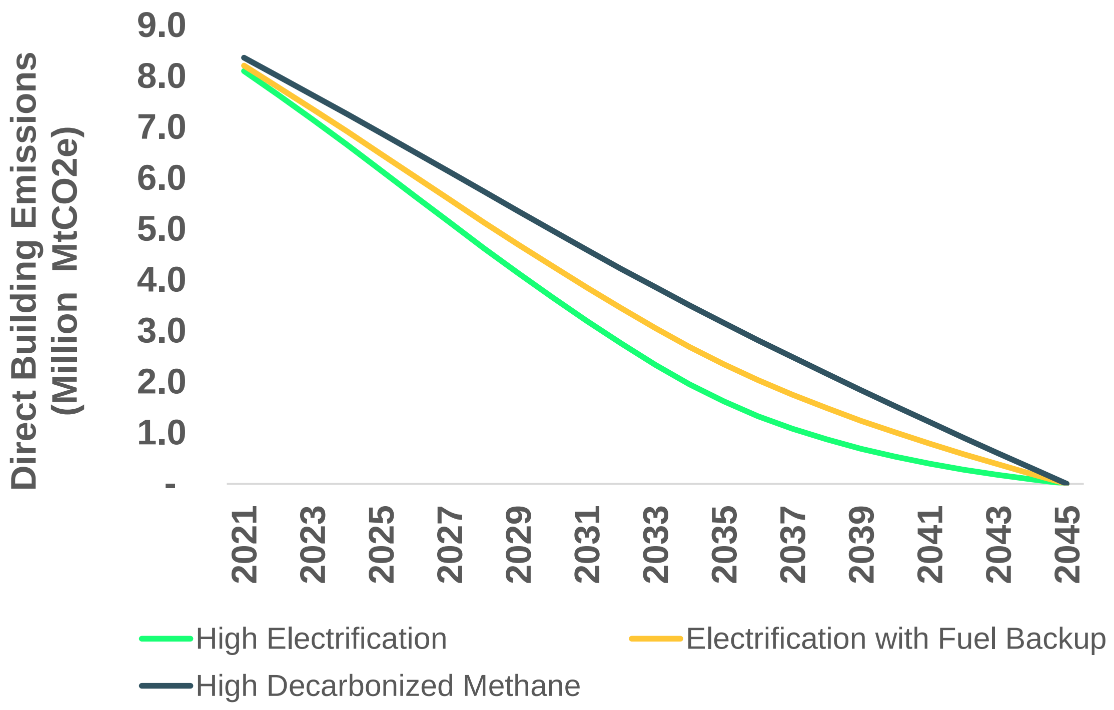
GHG Emissions and Energy Consumption

All scenarios achieve zero direct building emissions by 2045

Direct building GHG emissions trajectory (MMtCO2e per year)

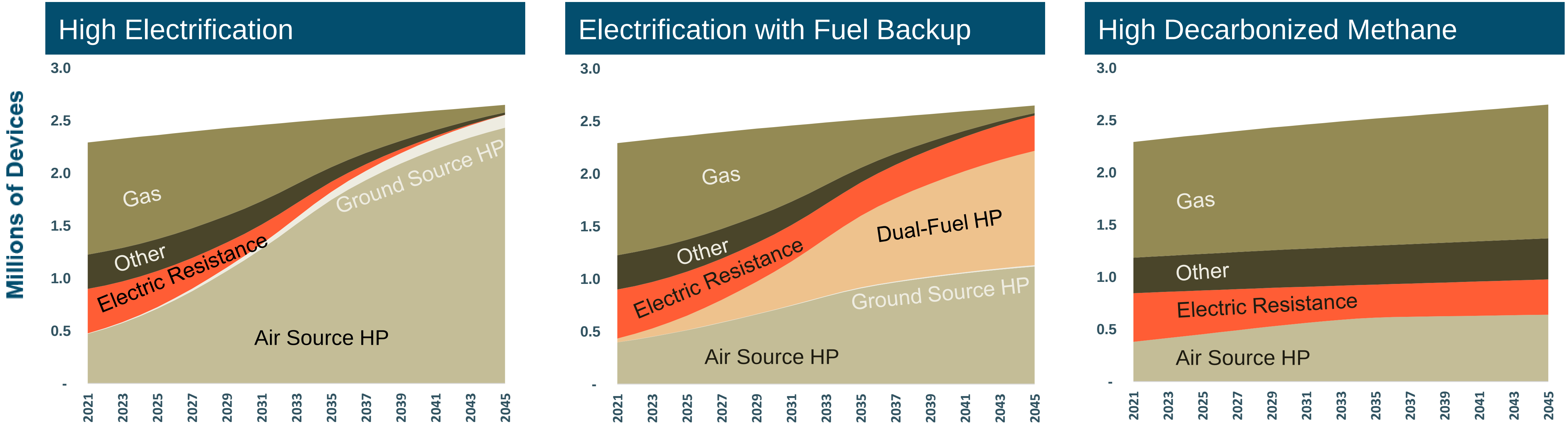


- Cumulative direct emissions and methane leakage from 2021 to 2045 add to 90 MMT CO2e in the High Electrification scenario, 103 MMT CO2e in the Electrification with Fuel Backup scenario, and 117 MMT CO2e in the High Decarbonized Methane scenario.
- CAVEAT: Cumulative emissions are subject to assumptions about timing of key policies and measures that drive the decarbonization trajectory; any comparisons among the scenarios should use caution.

+ **All scenarios achieve zero direct building emissions by 2045 through electrification, efficiency improvement and use of low-carbon fuels**
  - This is consistent with the MCCC-recommended economy-wide target of carbon neutrality by 2045
+ **Methane leakage from in-state gas pipelines may still contribute to indirect emissions**
  - Current emissions from methane leakage associated with building gas consumption are ~0.5 MMT CO2e
  - By 2045, methane leakage from each scenario is shown below, assuming that in-state pipeline leakage rate will decrease by 58% by 2045 relative to 2017 consistent with assumptions from the 2030 GGRA Plan
    - High Electrification - 0.02 MMT CO2e
    - Electrification with Fuel Backup - 0.09 MMT CO2e
    - High Decarbonized Methane - 0.19 MMT CO2e

Space heating end-uses are mostly electrified by 2045 in the two electrification scenarios

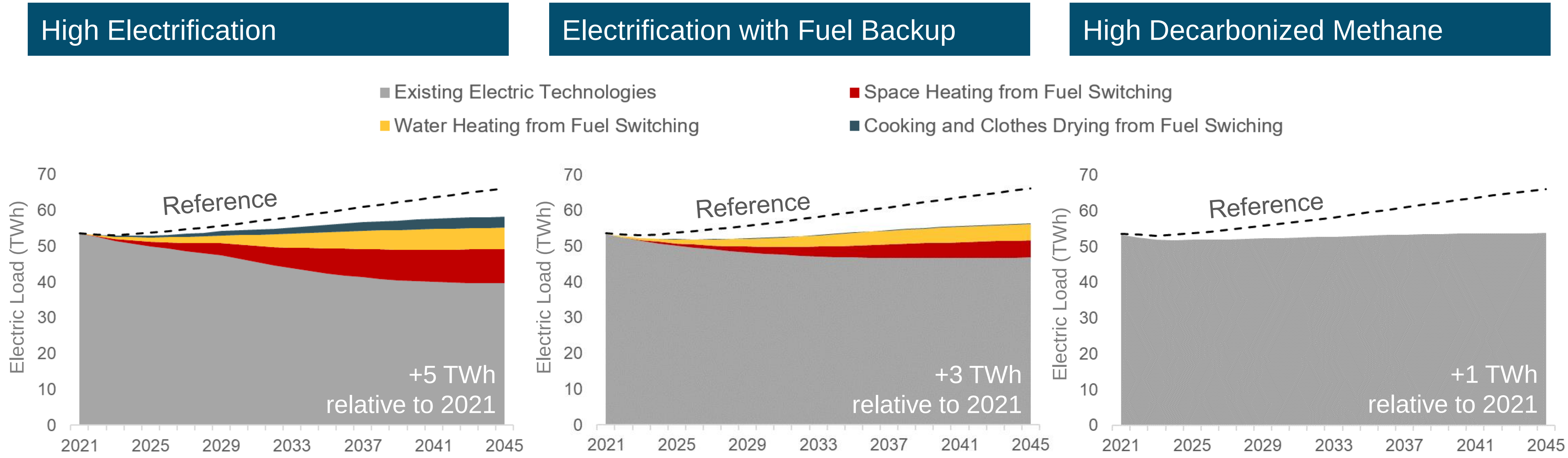
- Heat pumps become the major space heating equipment in the High Electrification scenario
- Dual-fuel heat pumps are added to most retrofit buildings in the Electrification with Fuel Backup scenario, pairing with existing fuel-based systems
- Electric resistance currently accounts for about 20% of space heating devices



* “Other” space heating devices mainly include fuel oil and LPG-based furnaces and boilers
* Consistent with the 2030 GGRA Plan, the Electrification with Fuel Backup and High Decarbonized Methane scenarios assume continuation of EMPOWER program after 2023
* E3 is working with MDE to evaluate the impact of geothermal heating and cooling carve-out requirement in the RPS on GSHP adoption assumptions across the scenarios

Electricity demand in all scenarios are lower than Reference due to energy efficiency gains

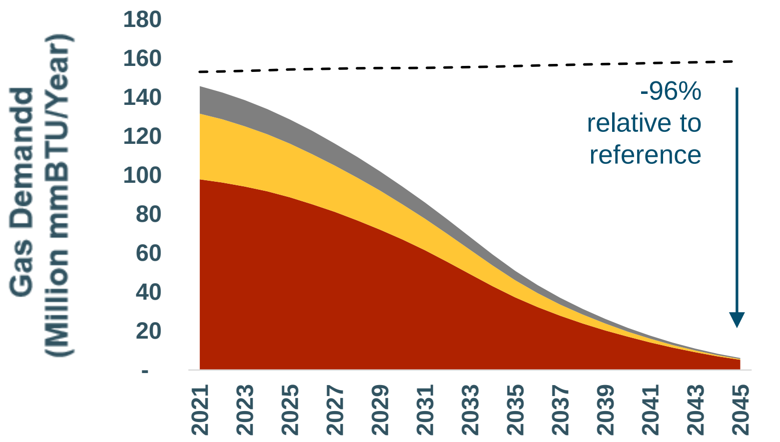
- **Electricity demand increases in all scenarios due to growth in households**
  - **High Electrification** scenario has the highest load growth among the three scenarios due to new space heating, water heating and other loads as a result of fuel switching
- **Compared to Reference, all scenarios have lower electricity demand due to energy efficiency gains**
  - **High Electrification** scenario also has the largest reduction in existing loads due to higher levels of efficiency from building shell improvement and efficient electric device adoption



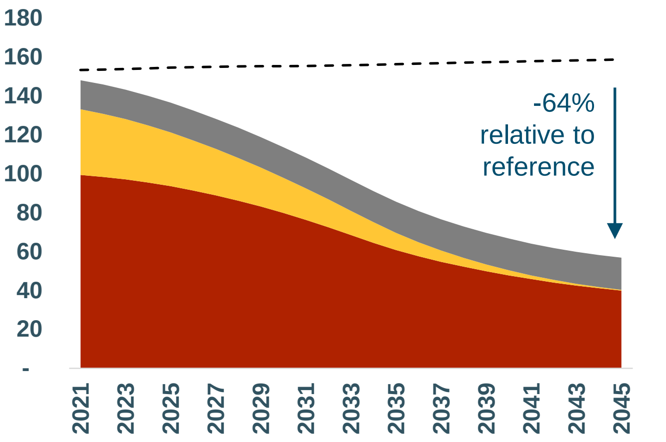
Natural gas demand declines in all scenarios due to energy efficiency gains and fuel switching offsetting growth

+ **Natural gas use in buildings is expected to decline in all scenarios due to energy efficiency gains offsetting growth in households, and this decline is accelerated in scenarios with significant building electrification**
  - **High Electrification** reduces gas demand by 96% by 2045 due to aggressive electrification of all building end-uses
  - **Electrification with Fuel Backup scenario** has lower reduction in gas demand by 2045 at 62%, as most customers adopt dual-fuel heat pumps that use gas with gas as a backup heating source during coldest hours of the year
  - **High Decarbonized Methane** scenario results in a 19% reduction in gas demand by 2045 due to efficient gas appliance adoption and building shell improvements

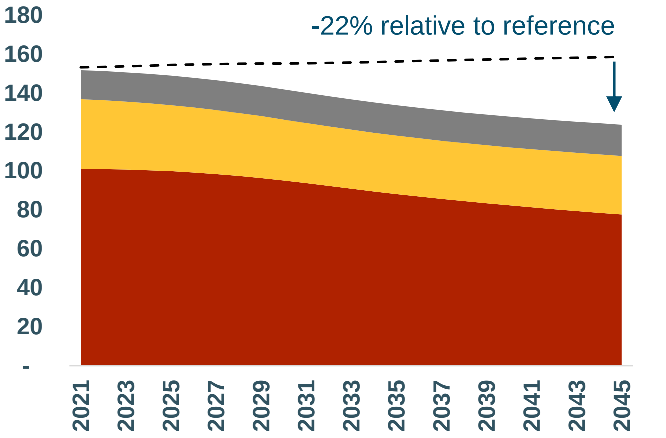
High Electrification



Electrification with Fuel Backup



High Decarbonized Methane

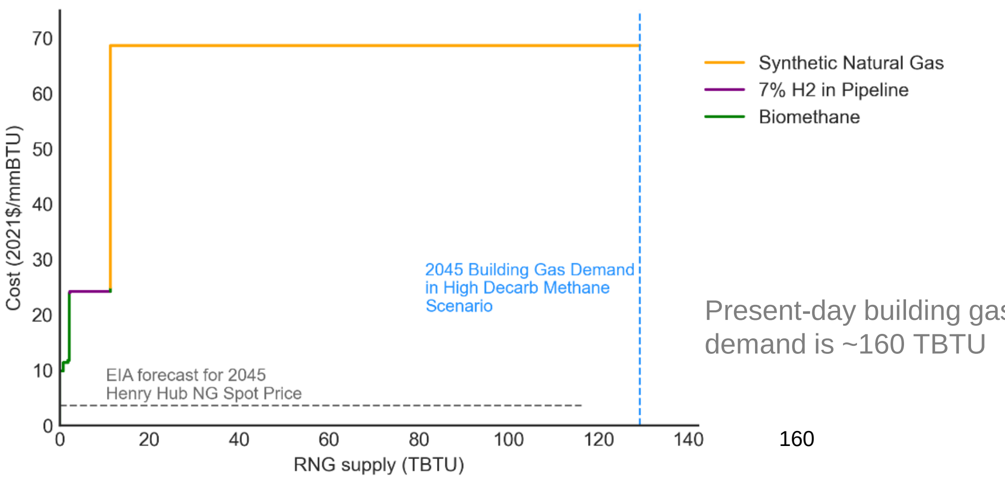


Space Heating Water Heating Other Reference

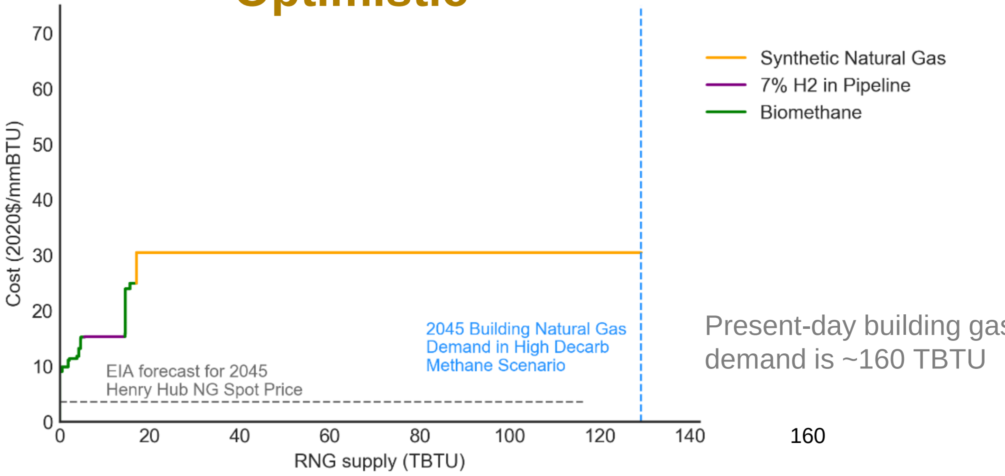
The E3 Biofuels Module models two bookends for RNG Supply

- **RNG Supply Curve assumptions are developed using E3 biofuels optimization module, which determines the most cost-effective way to convert biomass into biofuel across all sectors.**
- **Conservative and Optimistic scenarios modeled here represent two bookends for the supply of RNG towards 2045 to reflect uncertainties with technology commercialization and scalability**
  - **Conservative** scenario has heavy reliance on Synthetic Natural Gas (SNG); it assumes
    - MD only gets access in-state biomass feedstocks
    - Conservative projection of learning rate for electrolyzers, which is the main component of H2 production
  - **Optimistic** scenario has moderate reliance on SNG; it assumes
    - MD gets access to its population weighted-share of national feedstocks
    - Optimistic projection of learning rate for electrolyzers
  - Both scenarios assume that ALL cellulosic feedstocks would be more cost-effectively used to produce liquid fuels - such as renewable diesel or jet fuel (due to higher prices and carbon intensities for these fuels)

Conservative



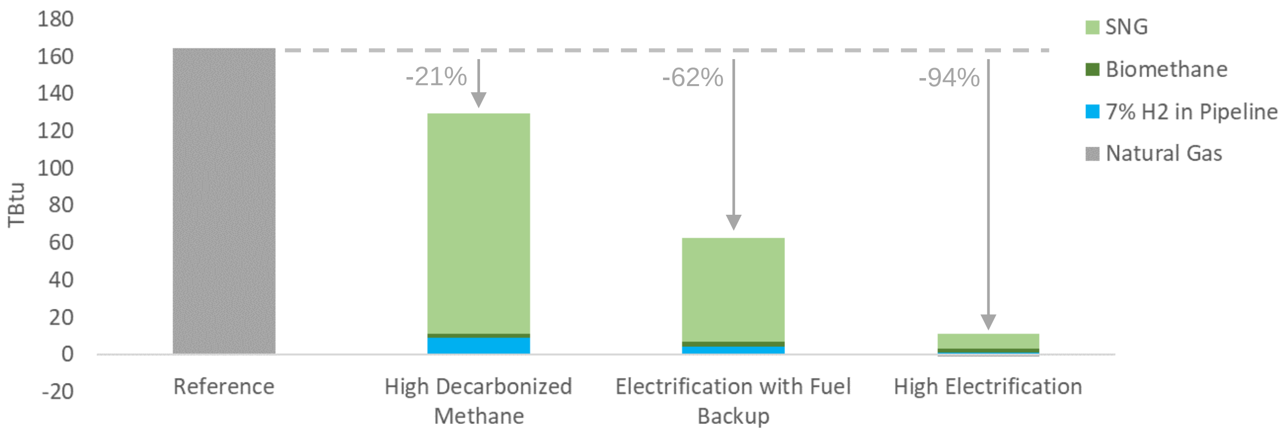
Optimistic



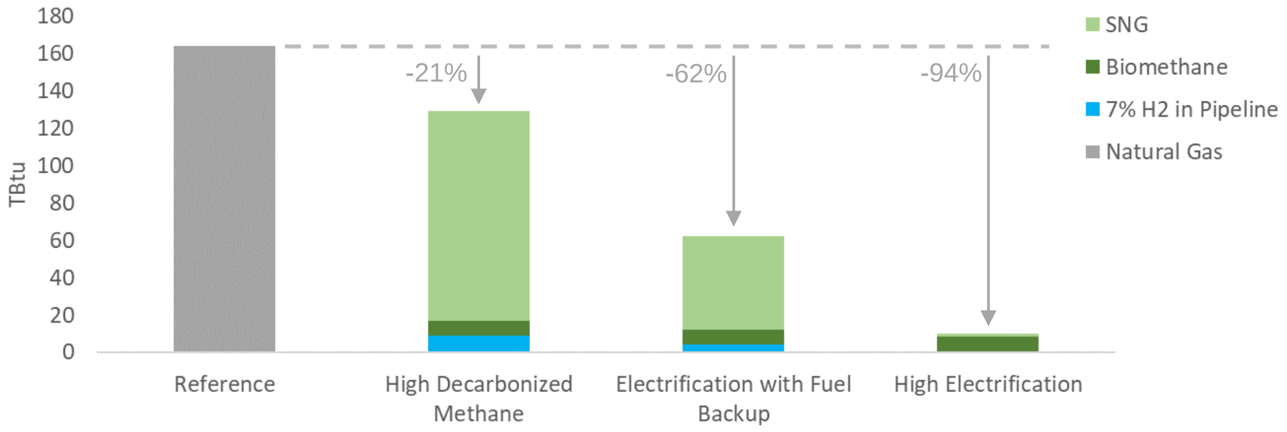
Sources & assumptions: Biomass supply assumptions are developed from the 2016 Billion Ton Report (DOE, 2016), with supplemental landfill gas assumptions from the Renewable Sources of Natural Gas report (American Gas Foundation, 2019). The conservative scenario assumes SNG is produced with CO_2 from Direct Air Capture (DAC), the optimistic scenario assumes SNG is produced using waste bio-CO2 from biofuels. The 7% hydrogen blend is as a percentage of energy content. More background on cost assumptions are included in the Appendix.

Gas composition transitions to RNG

Gas commodity blend in 2045 (Conservative)



Gas commodity blend in 2045 (Optimistic)

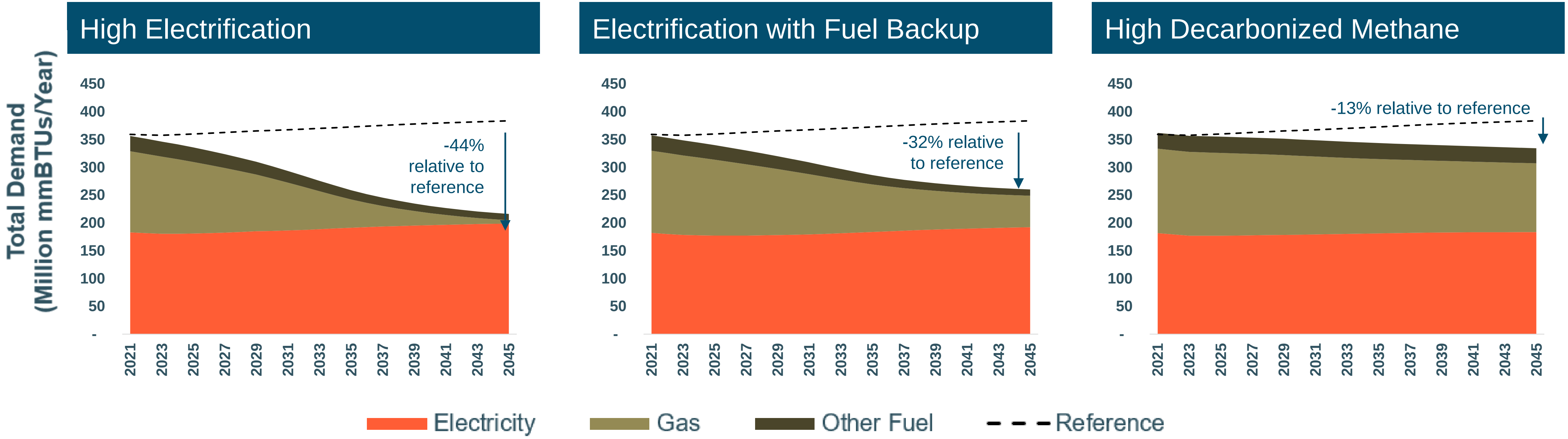


+ **By 2045, all building scenarios have 100% blend of RNG in the remaining gas demand**
  - This helps all scenarios reach zero direct building emissions target by 2045
  - Hydrogen blend in pipeline is assumed in all scenarios where it makes economic sense, up to 7% in energy content (20% in volume) which is the maximum current natural gas pipelines can take without significant modification
+ **In a conservative RNG scenario where biomass supply is limited, SNG is the main source of low-carbon gas in all scenarios**
+ **In an optimistic RNG scenario, SNG is still needed across all scenarios due to the limit in biomass supply**

All scenarios reduce total energy demand

+ Overall energy demand decreases through 2045 in all scenarios

- Deep electrification almost eliminates gas demand by 2045 under the High Electrification Scenario
- Gas demand decreases ~62% in the fuel backup scenario due to adoption of dual-fuel heat pumps, while overall energy demand falls 32%
- Efficiency gains from building shell improvements and efficient appliance adoption reduce overall demand by 13% in the High Decarbonized Methane Scenario



* Year 2021 will not perfectly match reference because electrification/efficiency adoption begins in model year 2017

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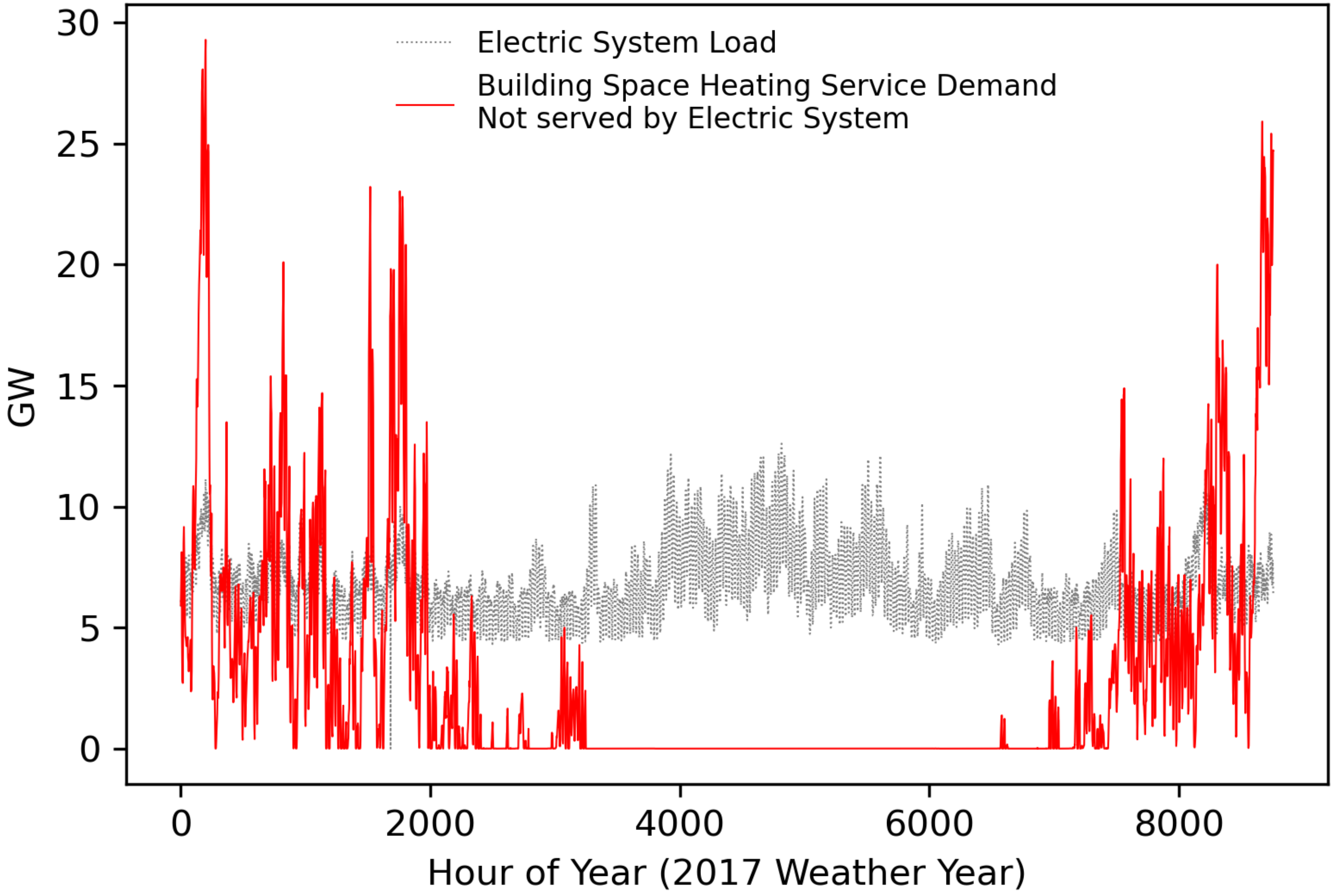
Electric system peak impacts

Maryland's current electric system peaks in summer



Electric system summer peak in 2017 was approximate 12.6 GW and the winter peak was approximately 11.1 GW.

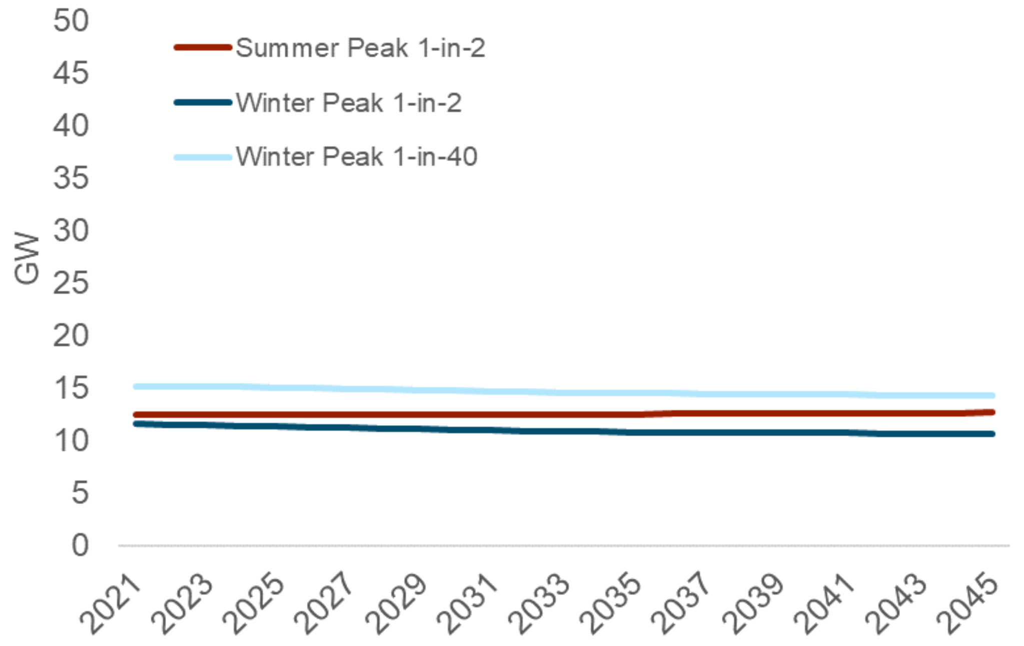
+ **Currently, Maryland's electricity system experiences peak load in summer months**
  - Load peaks at around 13 GW, mainly as a result of residential and commercial air conditioning
+ **Maryland's *building heat load,* however, currently mainly supplied by gas, shows a large peak in winter as a result of the state's cold winter climate**
  - Building heat loads represent *service demand* of both space and water heating, i.e. total heating load if all supplied by electric resistance
  - Moving the thermal load from gas to electric will result in a significant increase in electric peak in winter

Sources & assumptions: Building thermal load is based on PATHWAYS total space and water heating service. Shape of the thermal load is calculated using E3's RESHAPE model. Note that the chart shows imputed system load for November and December as a result of data gaps.

Maryland is expected to have little peak load growth in the High Decarbonized Methane scenario

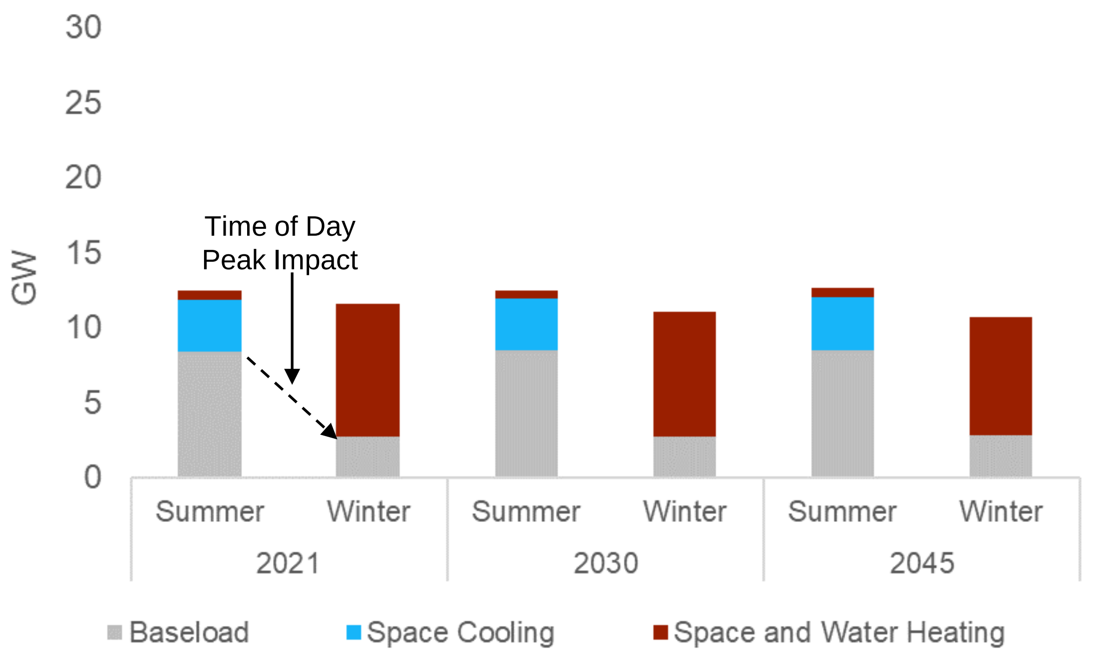
+ **In the High Decarbonized Methane scenario, the small peak load growth is due to growth of households and economy.**

Peak Load Projection 2021-2050
High Decarbonized Methane



*In 2045, the 1-in-10 and 1-in-40 summer peak is 0.6 and 0.7 GW higher than the 1-in-2 peak, respectively.

Contribution to 1-in-2 System Peak by Sector
High Decarbonized Methane

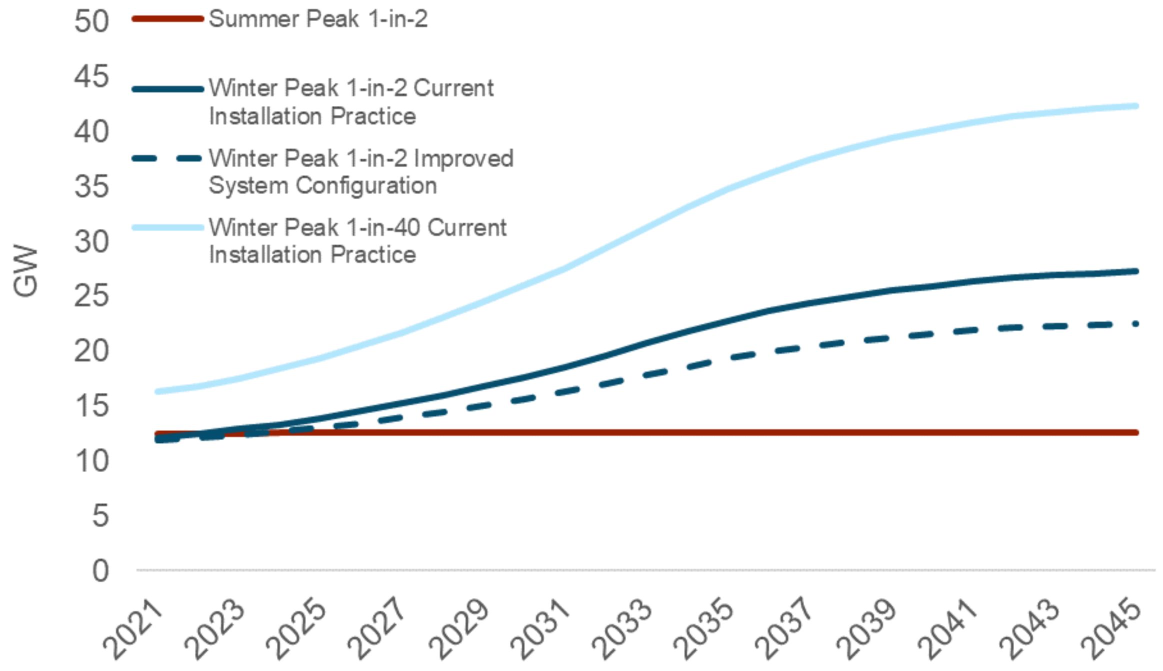


Sources & assumptions: Coincident peak load is based on a modeled hourly load for MD. The projected hourly load is calculated using incremental load in 2050 modeled from PATHWAYS and end-use shapes from RESHAPE based on 2017 weather added to the 2017 historical load.

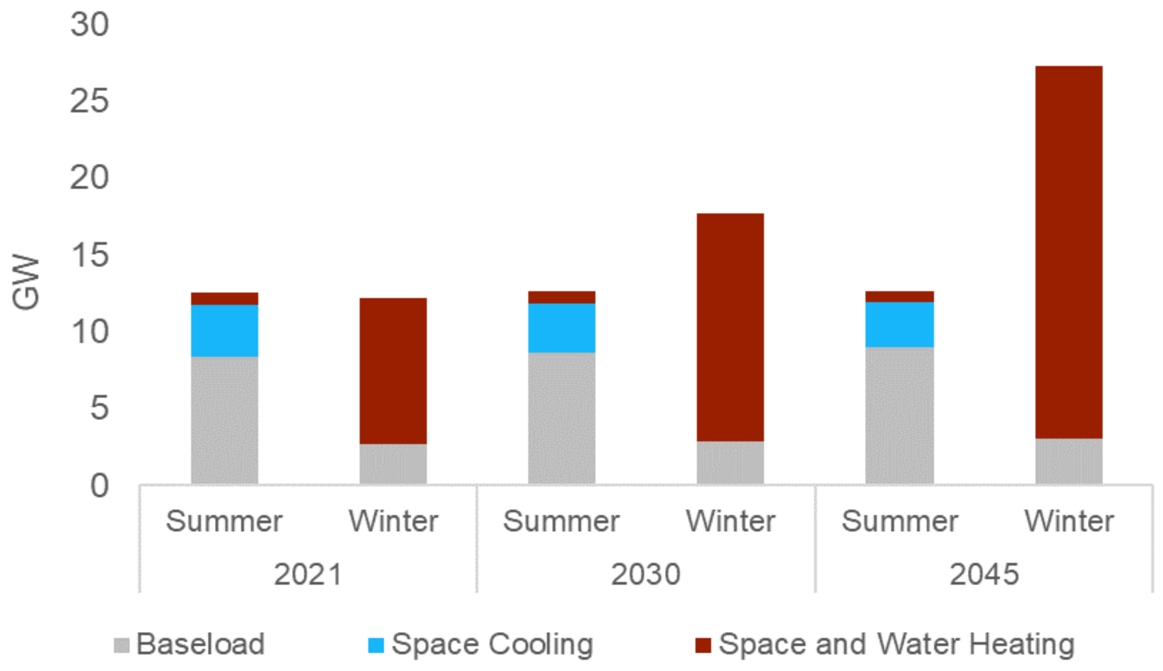
Winter peak load is expected to grow by 15 GW by 2045 in the High Electrification scenario

- **In the High Electrification scenario, Maryland's electricity system is expected to become winter peaking in the near future, and will more than double the current system peak by 2045**
  - Switching to heat pumps from electric resistance heating, which is currently used in about 25% of Maryland households, has a much smaller impact on peak heating load than on annual total heating loads

Peak Load Projection 2021-2045
High Electrification



Contribution to 1-in-2 System Peak by Sector
High Electrification – Current Installation Practice



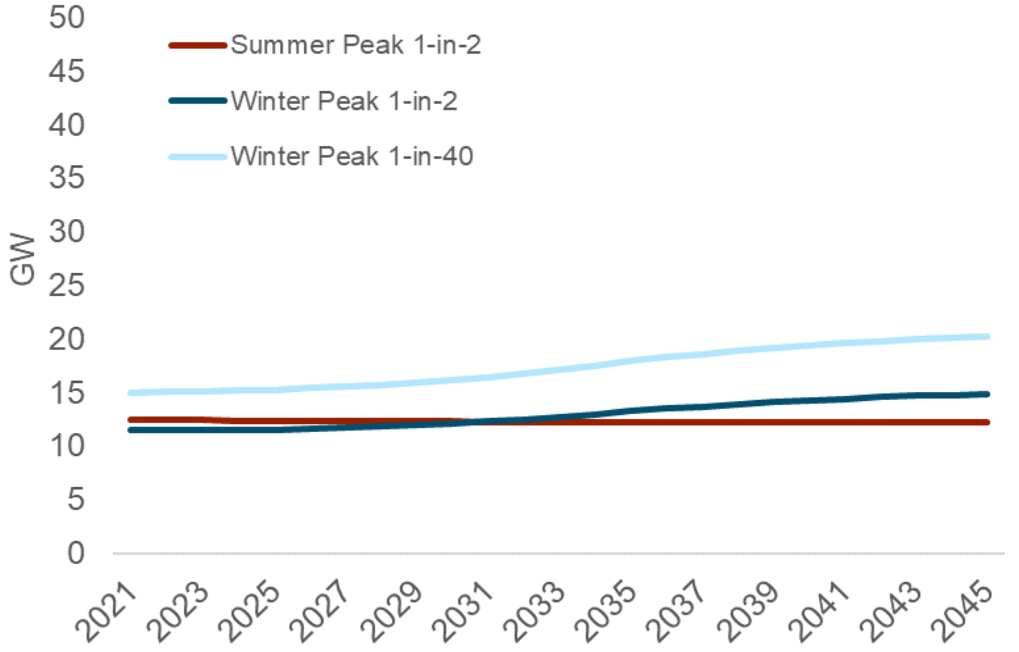
*In 2045, the 1-in-10 and 1-in-40 summer peak is 0.5 GW higher than the 1-in-2 peak

Sources & assumptions: Coincident peak load is based on a modeled hourly load for MD. The projected hourly load is calculated using incremental load in 2050 modeled from PATHWAYS and end-use shapes from RESHAPE based on 2017 weather added to the 2017 historical load.

Electrification with Fuel Backup scenario has much smaller winter peak load growth

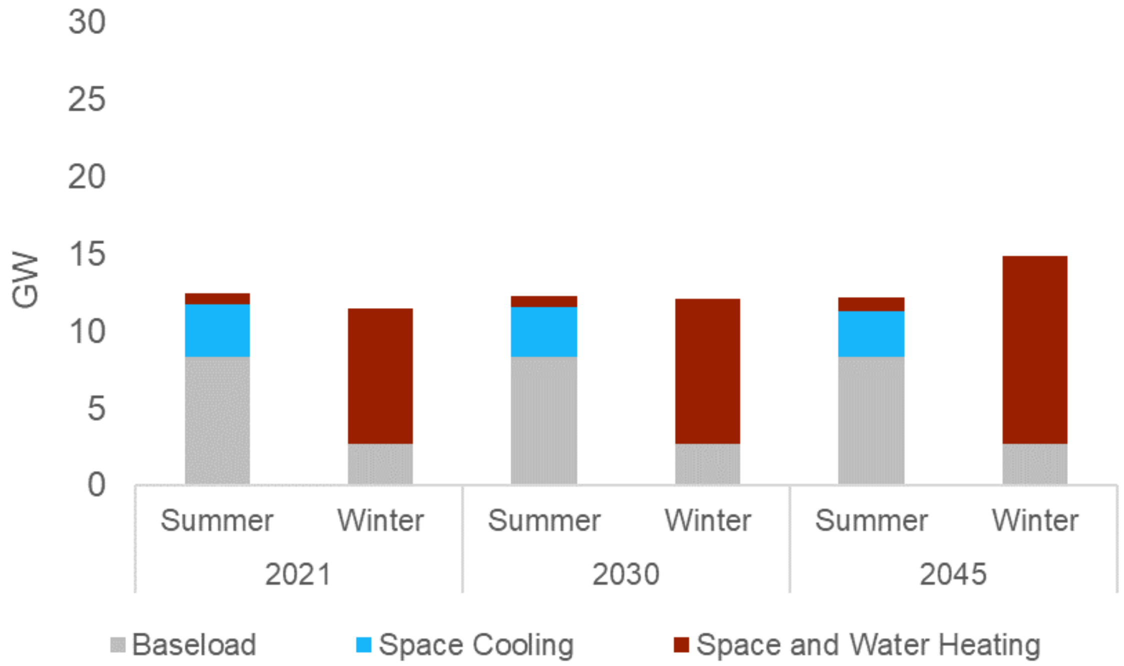
+ **Compared to the High Electrification scenario, Maryland's electricity system becomes winter peaking about a decade later**
+ **Peak load growth is also significantly smaller, ~2 GW by 2045 compared to the current system peak**

Peak Load Projection 2021-2045
Electrification with Fuel Backup



*In 2045, the 1-in-10 and 1-in-40 summer peak is 0.5 GW higher than the 1-in-2 peak

Contribution to 1-in-2 System Peak by Sector
Electrification with Fuel Backup



Sources & assumptions: Coincident peak load is based on a modeled hourly load for MD. The projected hourly load is calculated using incremental load in 2050 modeled from PATHWAYS and end-use shapes from RESHAPE based on 2017 weather added to the 2017 historical load.

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System Cost Impact

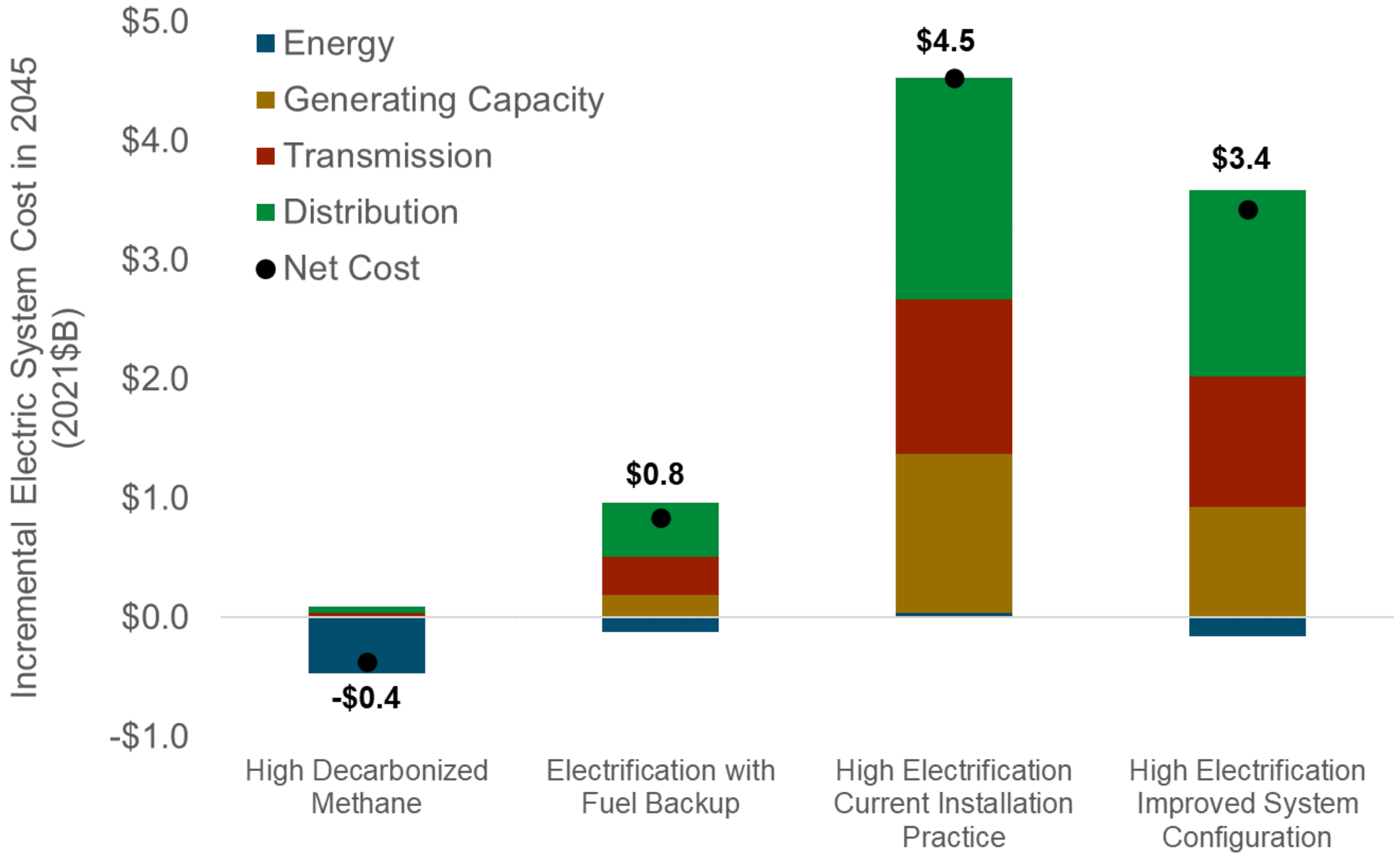
Approach for system cost impact analysis

- The following four cost components are considered in the system cost impact analysis
- System costs of the three main scenarios are calculated as incremental to Reference

Electric System	Gas System	Equipment	Other Fuels
❑ Investment in additional transmission and distribution infrastructure ❑ Investment in additional generating capacity to meet the peak electric demand ❑ Generation cost to meet the additional electricity demand	❑ Capital expenditure for reinvestment in the gas system ❑ Operating costs to maintain the gas system ❑ Gas commodity costs for RNG to replace natural gas	❑ Investment in efficient or electric appliances relative to a reference appliance ❑ Investment in building shell improvement	❑ Fuel commodity costs for bio-based liquid fuels to replace fossil fuels, mainly bio-diesel replacing fossil-based heating oil

Meeting electric loads in the High Electrification scenario requires around $3-4 billion of annual incremental system costs

Annual Incremental Electric System Costs relative to Reference in 2045 (2021$ Billions per year)

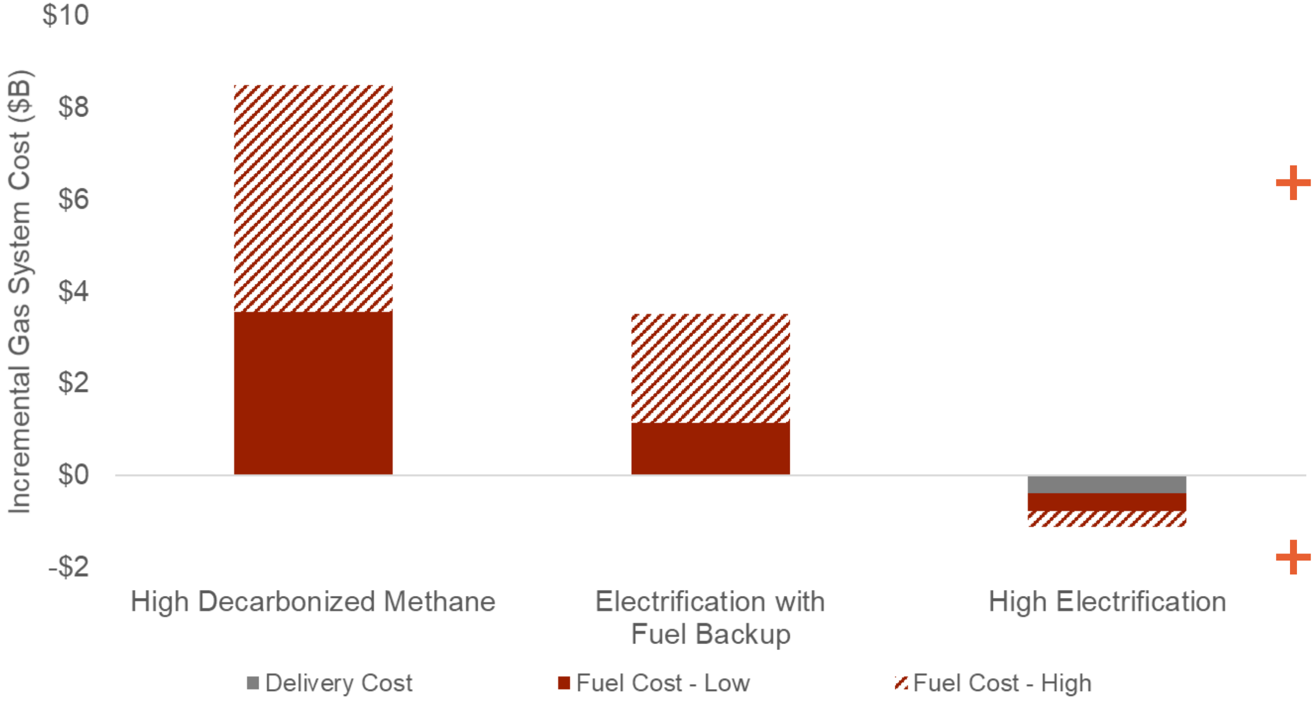


+ **High levels of electrification significantly increase electricity system costs, mainly for meeting peak capacity needs.**
  - Improving system installation practices would result in less increase in electric system costs, only ~75% of that in the High Electrification scenario
+ **Pairing ASHPs with fuel systems can save more than 80% of the incremental costs, mainly by avoiding T&D infrastructure and generating capacities**
  - System costs in the Electrification with Fuel Back Up scenario are $0.8 billion in 2045 compared to $4.5 billion for the High Electrification scenario

Sources & assumptions: Details of the electric sector cost assumptions are documented in the Appendix. T&D costs are high-level assumption reflecting new investment in lines. This captures the high-level investment requirement in the High Electrification Scenario given the magnitude of the peak impact from electrification. Further analysis is needed to explore near term opportunities for using headroom in existing T&D infrastructure and for expanding existing lines, which are likely going to be less expensive.

Gas system cost in all scenarios show wide ranges because of the large uncertainty associated with RNG commodity costs

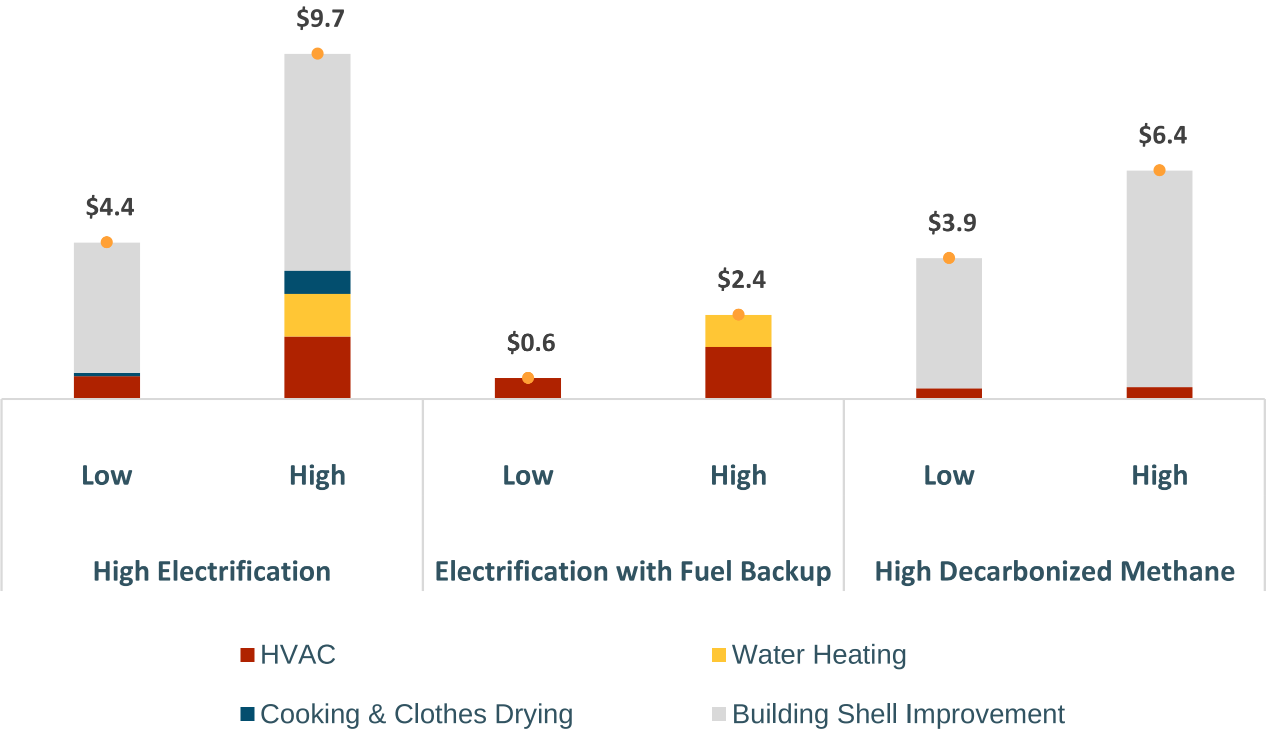
Annual Incremental Gas System Costs relative to Reference in 2045 ($2021 Billions per year)



- **High Decarbonized Methane** scenario has the biggest range of incremental system costs due to its high gas demand
  - Meeting all gas demand with RNG in the High Decarb Methane scenario can increase the annual gas system cost by up to $12B
- Reduced throughput in the **Electrification with Fuel Backup** scenario results in much lower system costs and less wide cost ranges
  - The blend of RNG results in higher gas commodity costs and overall gas system costs relative to Reference even though throughput is less
- **High Electrification** scenario has lower gas system costs relative to Reference due to both lower gas demand and lower infrastructure costs
  - We assume that reduced peak gas throughput in this scenario would require less capital reinvestment and O&M to maintain the gas system

The two book-end scenarios have relatively high incremental equipment costs due to building shell improvement

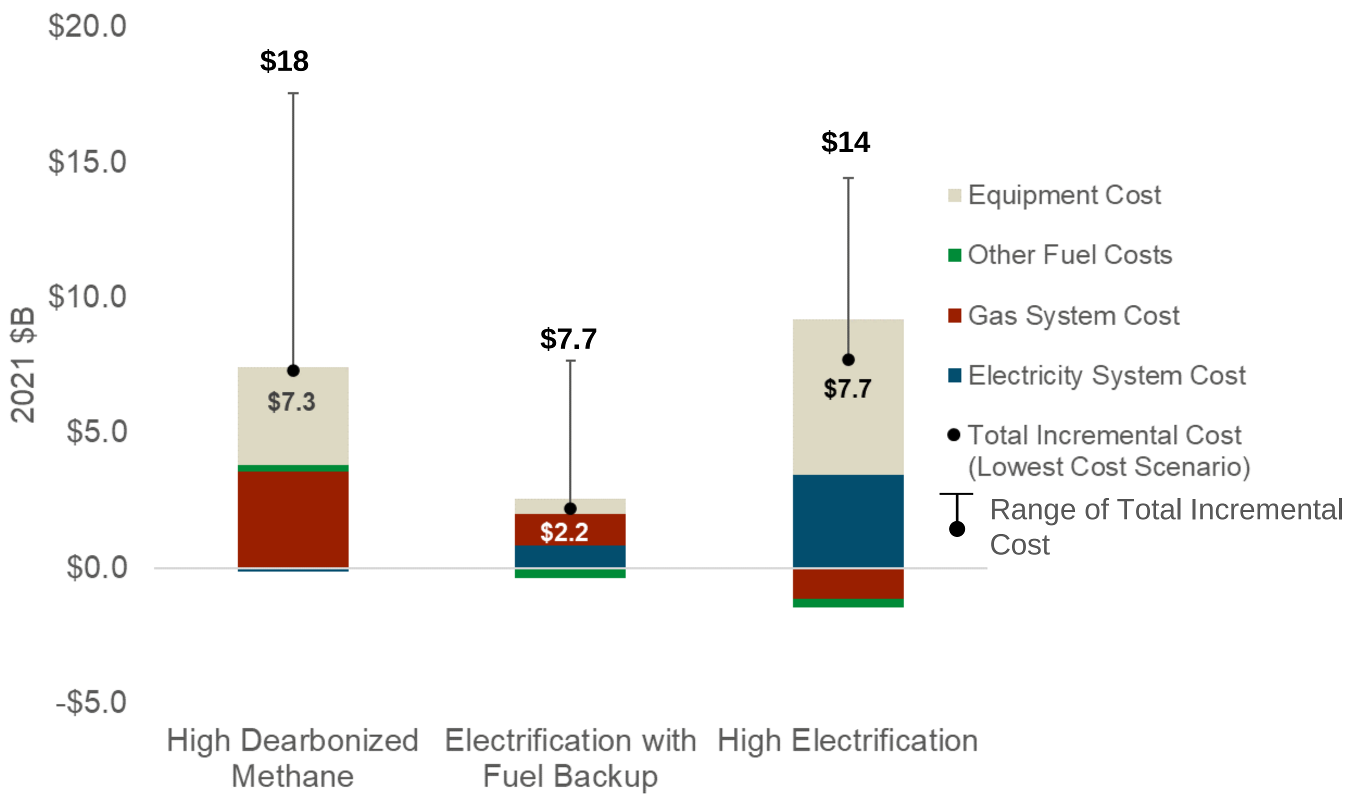
Levelized Total Incremental Equipment Costs in 2045 ($2021 Billions per year)



- **High and low equipment cost profiles creates uncertainty around future costs in the two book-end scenarios**
  - Building shell upgrades account for the majority of equipment costs
  - Current costs are based on deep shell retrofits that include energy efficiency and heat recovery, and are highly uncertain and location-specific
- **Electrification with Fuel Backup is the lowest-cost scenario because it does not include building shell improvement**

Electrification with Fuel Backup scenario is expected to be the relatively low-cost and low-risk among the three scenarios

Incremental Total Resource Costs for Buildings (2045) ($2021 Billions per year)



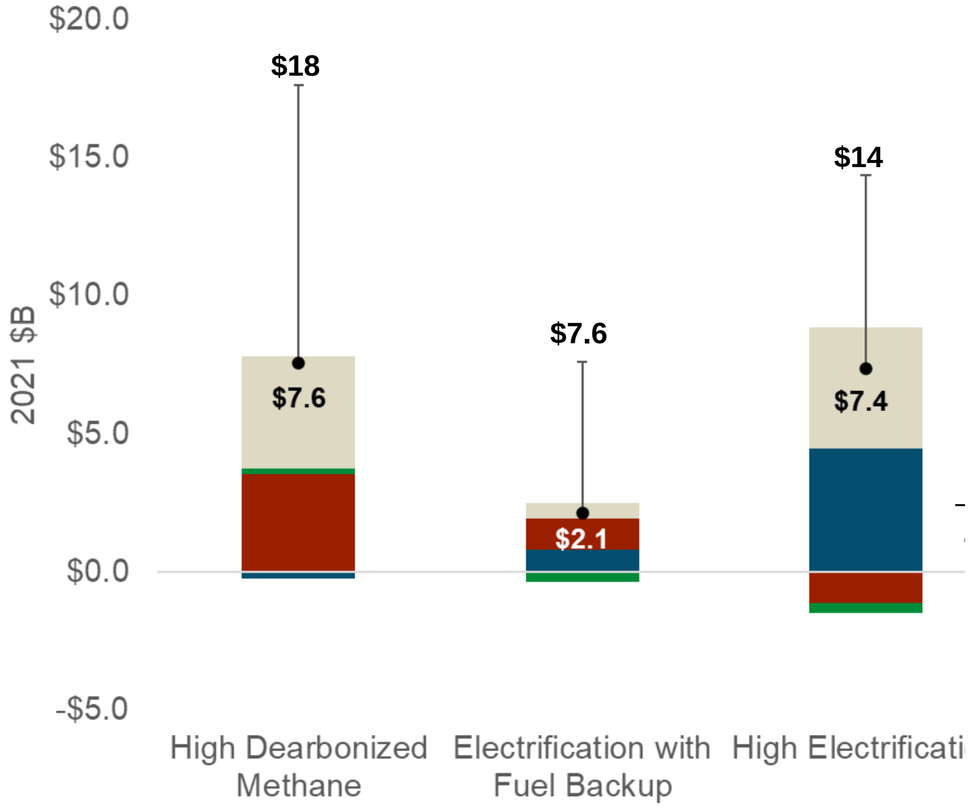
Total cost range reflects assumptions regarding fuel costs, equipment cost, and heat pump installation practices

Sources & assumptions: These charts show incremental resource costs of the scenarios compared to the reference scenario.

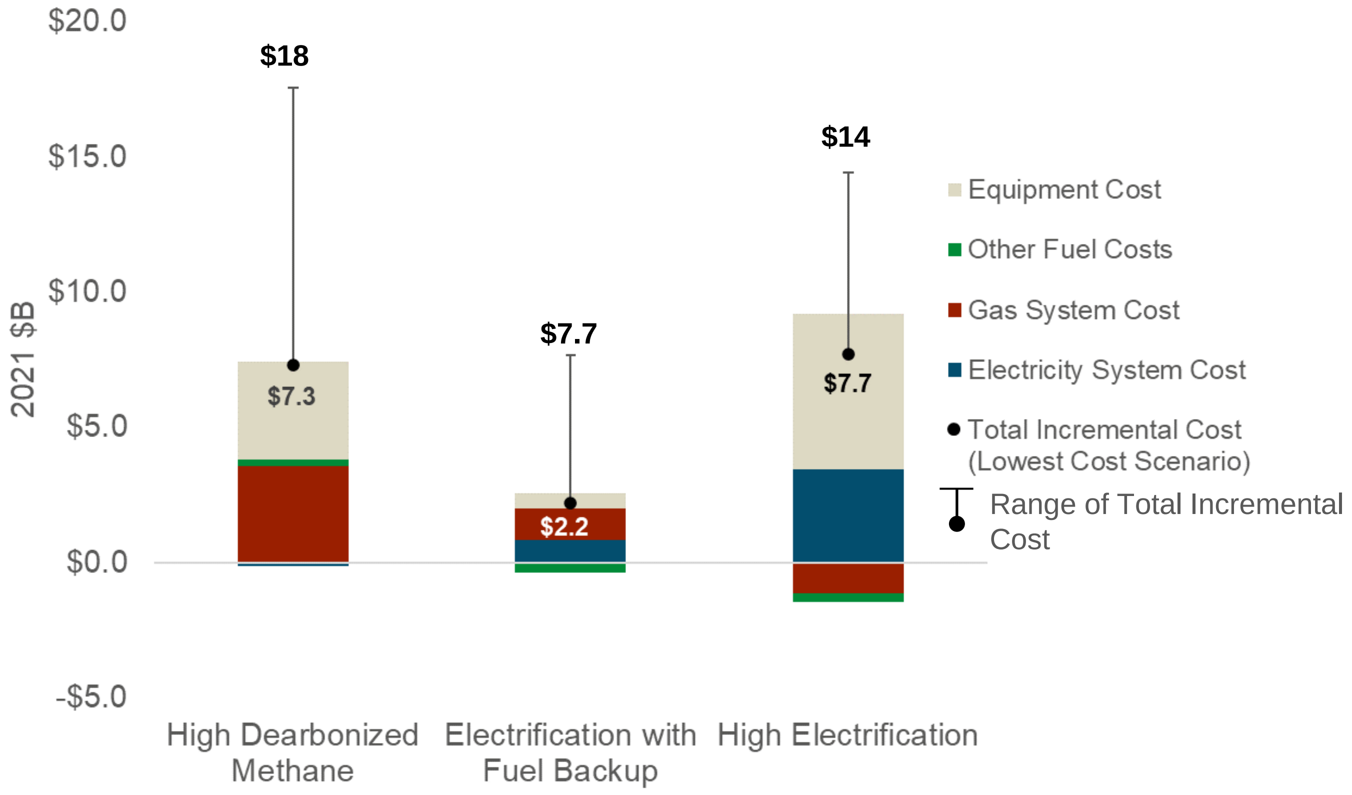
+ **Building sector costs show large variation across scenarios depending on:**
  - Gas fuel costs (optimistic/conservative supply curve)
  - Equipment costs (mainly building shell upgrade costs)
  - Installation practice for electric heating systems
+ **A hybrid scenario could potentially “hedge” for this uncertainty given its lower overall costs and narrow cost ranges**

With climate impact considered, Electrification with Fuel Backup scenario is still expected to be the relatively low-cost and low-risk scenario

With Climate Impact
Incremental Total Resource Costs ($2021 Billions/year)



Without Climate Impact
Incremental Total Resource Costs ($2021 Billions/year)



Total cost range reflects assumptions regarding fuel costs, equipment cost, and heat pump installation practices

Sources & assumptions: These charts show incremental resource costs of the scenarios compared to the reference scenario. See appendix for detailed results from the climate impact sensitivity analysis.

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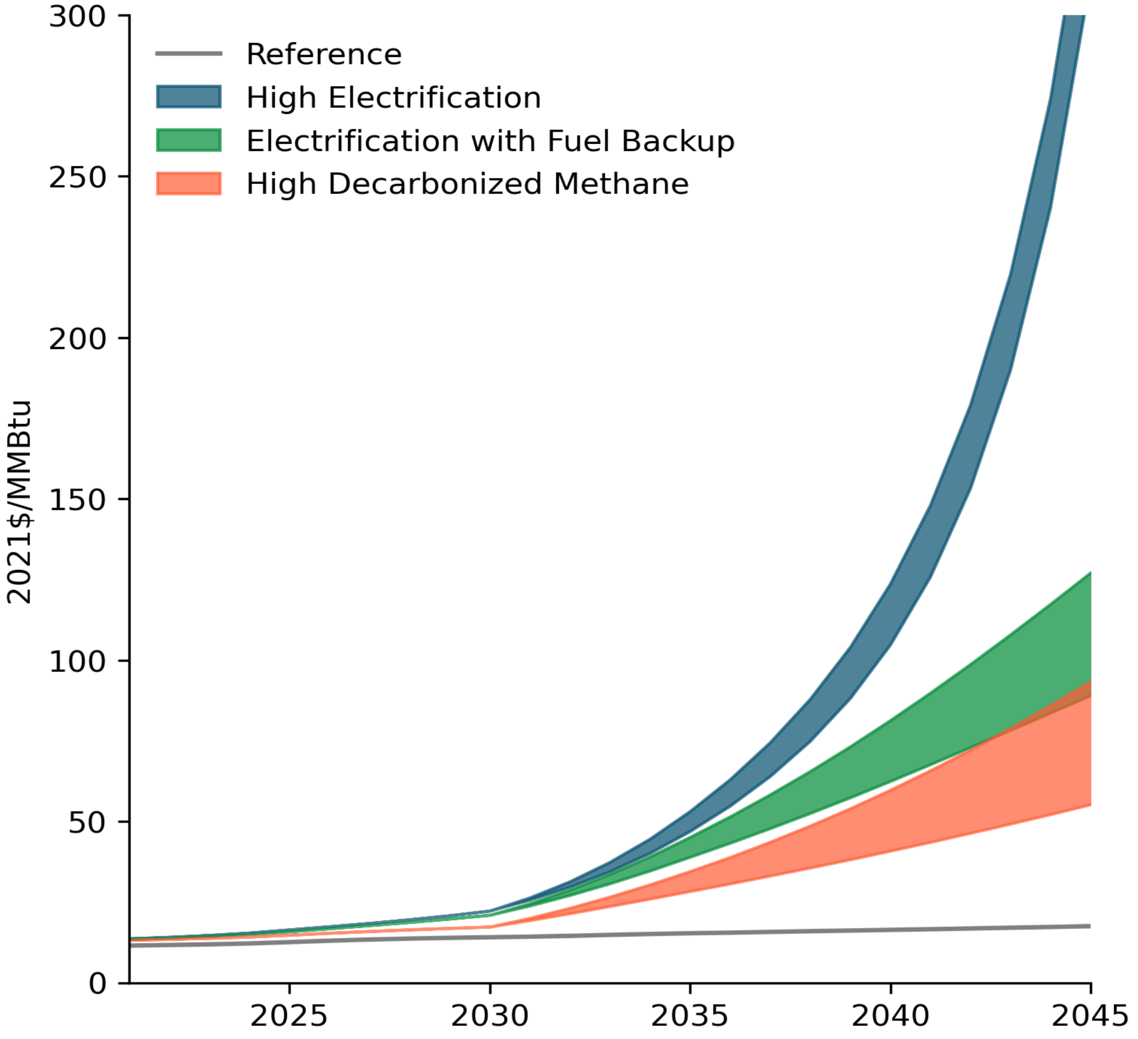
Gas and Electric Rate Impact

Gas rates increase significantly across all scenarios

Residential gas rates (2021$/MMBtu)



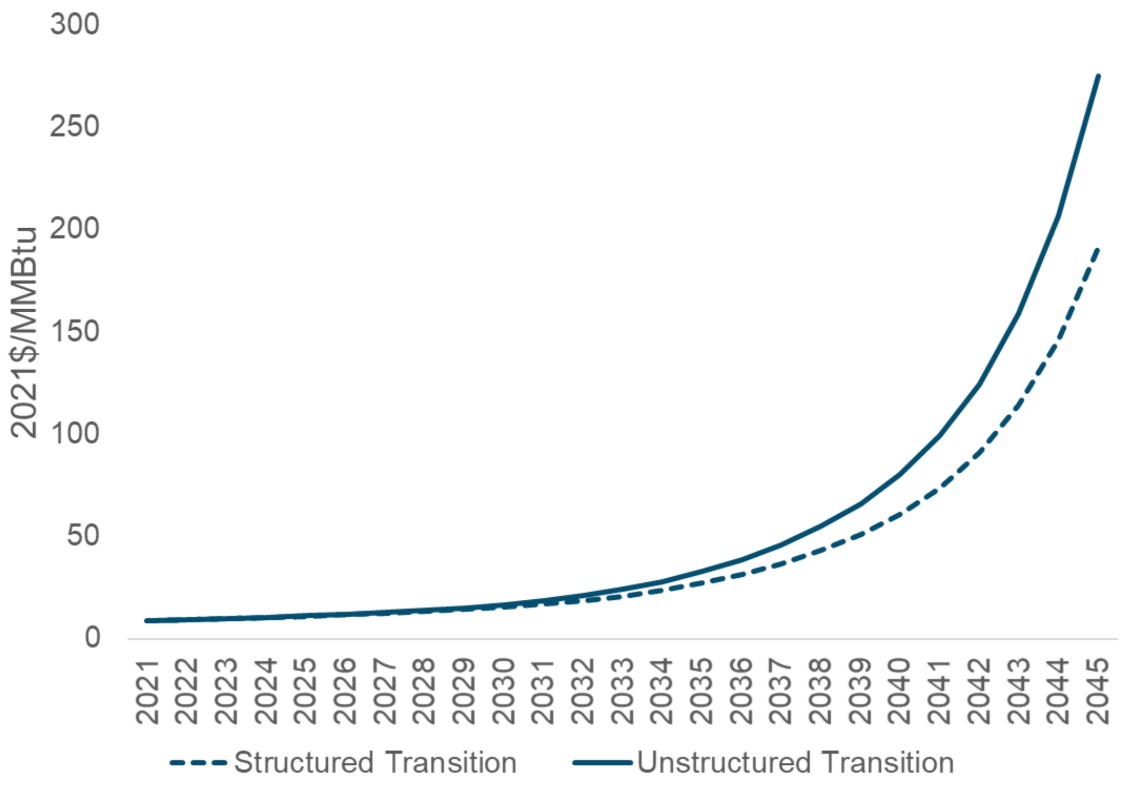
+ **High Electrification scenario** experiences a rapid rate increase driven by declining throughput despite lower total delivery and commodity costs
+ Rate increases in the **High Decarbonized Methane scenario** are driven primarily by the commodity cost for zero carbon fuel
+ **Electrification with Fuel Backup scenario** has higher gas rates than the High Decarbonized Methane scenario, due to its lower throughput and the resulting higher per MMBtu delivery cost

*Range shown in figure reflects the commodity cost forecast uncertainty

Gas delivery rate under a structured gas transition may still remain high due to significantly reduced throughput

Residential gas delivery costs (2021$/MMBtu)

High Electrification with Structured Gas Transition

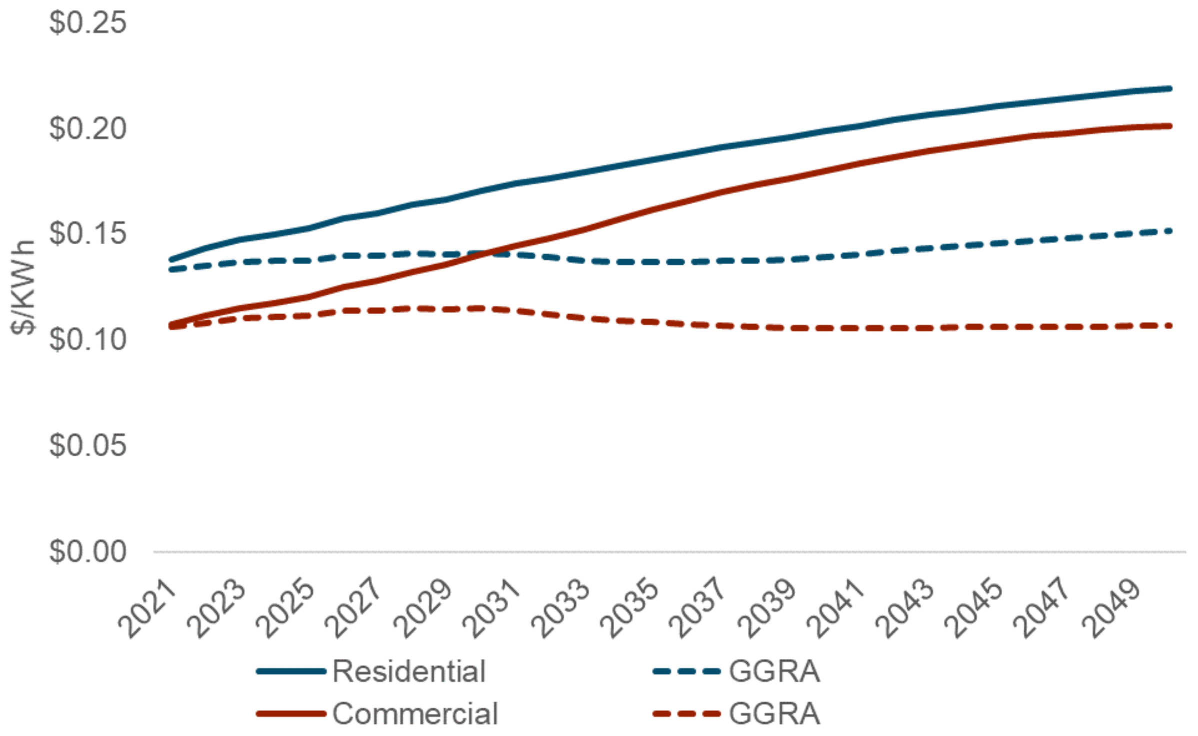


- **E3 modeled an illustrative sensitivity scenario reflecting a high electrification future with structured gas transition, which would result in reduced level of revenue requirement compared to a base case**
  - Capital-related expenditure and pipeline maintenance costs become flat after 2030, which reflects half of the reinvestment level compared to today
    - Data source: E3 (2020), The Challenge of Retail Gas in California's Low Carbon Future
  - Administrative costs are reduced by 0.6% with every 1% reduction in customer base
    - Data source: Davis and Hausman (2021), Who Will Pay for Legacy Utility Costs?
- **The structured transition reduces residential delivery rates by 30%, but the rates remain high**
- **This sensitivity does not address the question of how utilities would reduce the revenue requirement or who would bear the cost gap between reduced revenue requirement and unavoidable costs for the remaining gas system**
- **More legislative and regulatory efforts are needed to address the issues of stranded gas assets in a high electrification future**

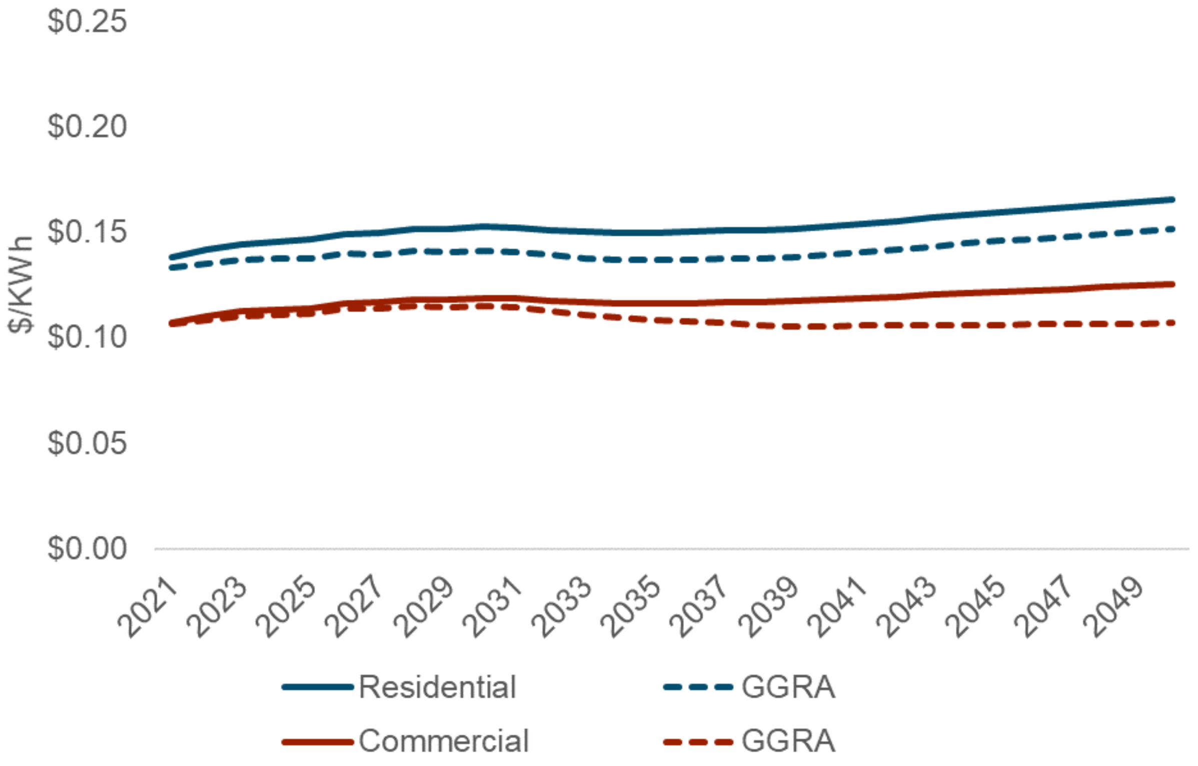
High Electrification scenario shows a more rapid electric rate increase compared to Electrification with Gas Back Up

+ **The Electrification + Gas Back-up scenario is projected to have a lower rate increase because it has a smaller load factor and manages to avoid the expensive peak capacity investment.**

Electric rates in the High Electrification Scenario (2021$/kWh)



Electric rates in the Electrification + Gas Back-up Scenario (2021$/kWh)



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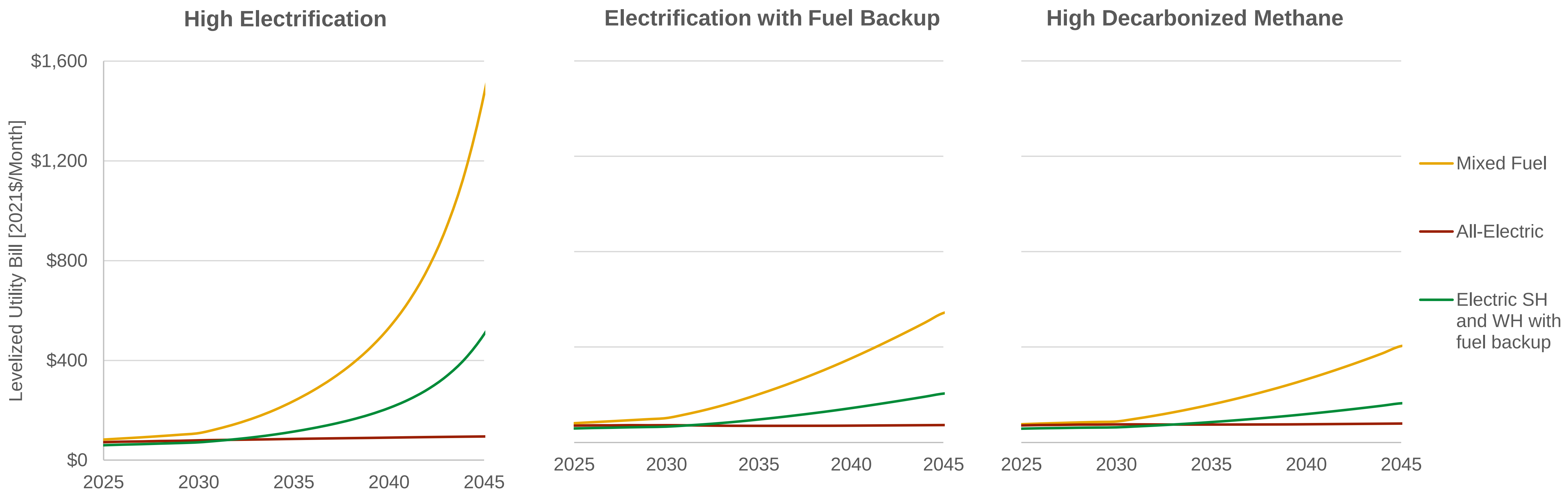
Consumer Economics

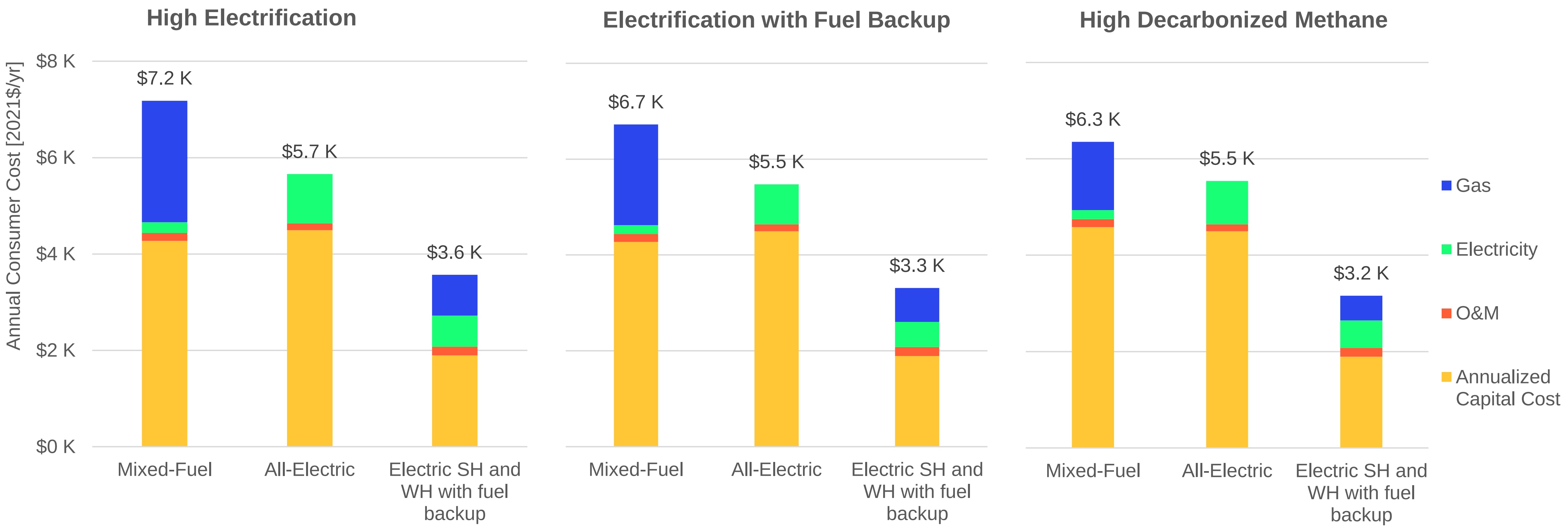
Illustrative customer bill impacts – residential single-family

- **Across all scenarios, customers remaining on the gas system may experience a large increase in utility bills due to the blend of expensive RNG to decarbonize gas use**
- **CAVEAT: These are not predictions of customer bills, but a representation of the potential dynamics under the current ratemaking model. These results indicate the potential equity and affordability challenges that will require systemic changes to the current dynamics.**



Electrifying heating with fuel backup is expected to be the least expensive option when both capital and operating costs are considered

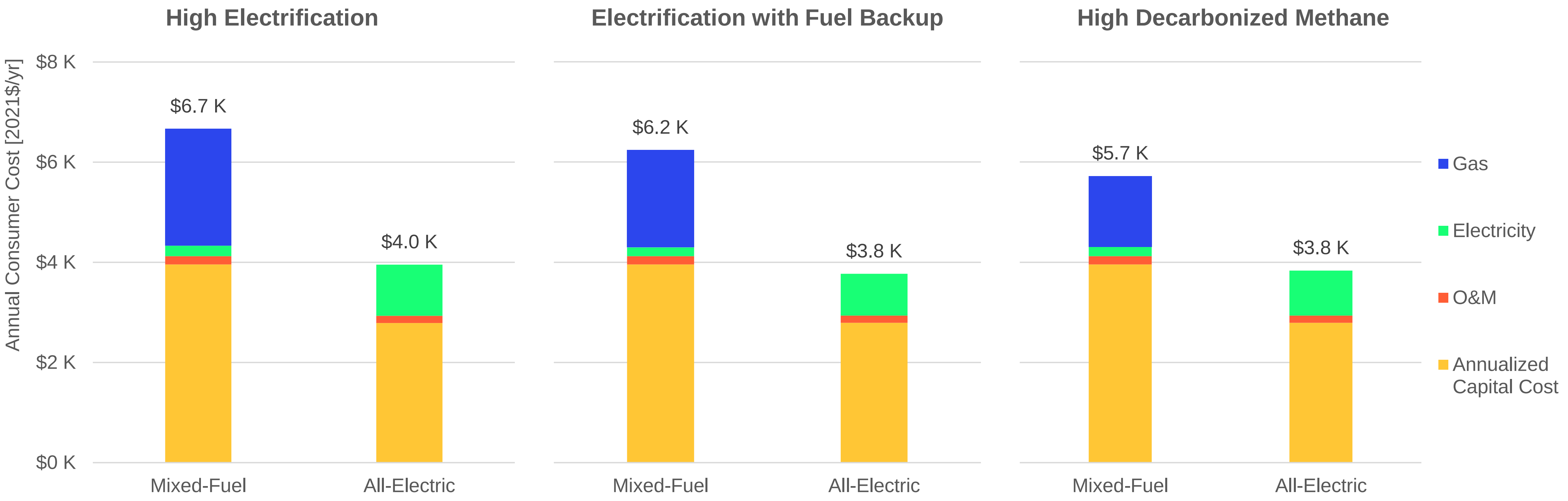
+ **"Hybrid" customers can save money by utilizing their existing fuel-based heating equipment to provide backup heating during coldest hours of a year, and by not having to upgrade building shells**



* Gas costs, electricity costs, and equipment costs are based on 2035 rates; Gas costs represent "optimistic" rate scenario ("conservative" gas scenario has 4% higher total cost for mixed-fuel)

All-electric design is expected to be the less expensive option

+ **All-electric new construction is cheaper than mixed-fuel new construction for single-family residential homes across all decarbonization scenarios due to both lower capital (with avoided gas connection) and operating costs**



* Gas costs, electricity costs, and equipment costs are based on 2035 rates; Gas costs represent "optimistic" rate scenario ("conservative" gas scenario has 6% higher total cost for mixed-fuel)

Conclusions

Conclusions

- **All scenarios** demonstrate technologically feasible pathways to achieve zero direct building emissions by 2045, but require extensive technology deployment and commercialization efforts.
- The **Electrification with Fuel Backup** pathway shows lowest overall costs while also reducing reliance on technologies that have not yet been widely commercialized or that are uncertain in their scalability.
  - The **High Decarbonized Methane** pathway requires high demand for zero-carbon fuels, resulting in high incremental fuel costs with significant cost uncertainty
  - The **High Electrification** pathway results in a shift from a summer peak to a winter peak, mainly as a result of space heating loads in winter.
- Consumers in **retrofit buildings** can save costs by employing a dual-fuel heating system with heat pumps providing majority of the heating need and fuel system providing backup during the coldest hours
  - **All-electric new construction** is found to be less expensive considering both equipment and fuel costs than those connecting to gas grid and using fuels for heating

Conclusions (cont'd)

- **Achieving the Electrification with Fuel Backup pathway** would require careful policy design that incentivizes consumers to employ dual-fuel heating systems
  - For example, the current ratemaking model likely needs to be revisited, so that the right price signals are reflected in gas and electric rates and incentive consumers to switch to fuel backups during cold hours
- **Each scenario** presents its own equity and affordability challenges
  - The average costs of the gas service are likely to increase in an electrification scenario as customers leave the system and infrastructure costs are spread over a smaller customer base.
  - Emphasis on mitigating the energy burden with customers 'staying behind' is important.
- **Other factors** including but not limited to health impact, job impact and methane leakage, which are beyond the scope of this study, need further investigation to provide a more complete evaluation of impact of the different pathways

Appendix

Energy+Environmental Economics

Scenario parameters

Sector	Parameter	Reference (2020 Reference Scenario from the GGRA work)	High Electrification	Electrification with Fuel Backup	High Decarbonized Methane
Buildings (residential + commercial)	Appliance efficiency	Current EMPOWER program • 50% of new sales of electric appliances are assumed to be efficient through 2023	Increased EE targets from utilities (consistent with GGRA Optimistic Sensitivity) • 100% new sales of electric appliances are assumed to be efficient through 2030 • 25% new sales of natural gas appliances by 2030	Renewed EMPOWER through 2030 (consistent with 2030 GGRA Plan) • 50% new sales of electric appliances are assumed to be efficient through 2030 • 25% new sales of natural gas appliances by 2030	Increased EE targets from gas utilities • 100% new sales of efficient natural gas appliances by 2030 • Electric appliance sales
	Building shell efficiency	Improved building shell sales in all residential new construction by 2030	Improved building shell sales in all new construction retrofit buildings by 2030 (An improved building shell reduces heating demand of a residential home by 29% and that of a commercial building by 34% relative to a typical existing building)	Reference	Improved building shell sales in all new construction and retrofit buildings by 2030
	Building electrification (heat pump sales share)	Linear adoption trend from historical sales of heat pumps (20% of space heater sales are heat pumps by 2045)	50% sales of electric heat pumps by 2025 (consistent with GGRA Optimistic Sensitivity), 100% sales by 2035 • 90% ccASHP • 10% GSHP (targeting medium/large rural homes currently on non-NG heating and campuses) • Electric resistance back-up	• 100% sales by 2035 of regular ASHP with gas furnace backup for non-new construction natural replacements • All-electric new construction with 90% ccASHP and 10% GSHP	• Reference for electric HPs • Gas in new construction
	Behavioral conservation and other non-stock sectors	Consistent with 2020 Reference	Consistent with 2030 GGRA Plan		
Decarbonized fuels	Fuel blend in 2050	100% natural gas and fuel oil	100% RNG (used mainly for remaining gas customers): • 93% RNG from biomass and Synthetic Natural Gas • 7% RNG with blended hydrogen blend	100% RNG (used mainly for gas backup): • 93% RNG from biomass and Synthetic Natural Gas • 7% RNG with blended hydrogen	100% RNG and renewable diesel: • 93% RNG from biomass and Synthetic Natural Gas • 7% RNG with blended hydrogen
Electricity	Electricity sector emission intensity	Consistent with 2020 Reference	Consistent with 2030 GGRA Plan (additional load will be met by a mix of renewable build and PJM imports; additional capacity need will be provided by a mix of renewables and storage with their corresponding ELCC values with the rest covered by new CTs build; this study will not identify the specific location of the new resource build, which could be in MD or other PJM states. For details, see the input assumptions deck)		

Summary of key findings

Reducing direct building emissions to zero is feasible in all scenarios, but requires technology commercialization and accelerated implementation.

Electrification with Fuel Backup shows lowest overall costs while also reducing reliance on technologies that have not yet been widely commercialized or that are uncertain in their scalability

- **High Decarbonized Methane** requires large quantities of zero-carbon fuels, resulting in high incremental fuel costs with significant cost uncertainty depending on the commercialization of RNG
- **High Electrification** causes a Summer to Winter peak-shift and significant increase in peak electricity demand, resulting in high incremental electricity system costs

Consumers in **retrofit buildings** can save costs by employing a **dual-fuel heating system** with heat pumps providing majority of the heating need and fuel system providing backup during the coldest hours

All-electric new construction is found to be less expensive for consumers considering all costs including equipment and fuel costs compared to mixed-fuel new construction that uses fuels for heating

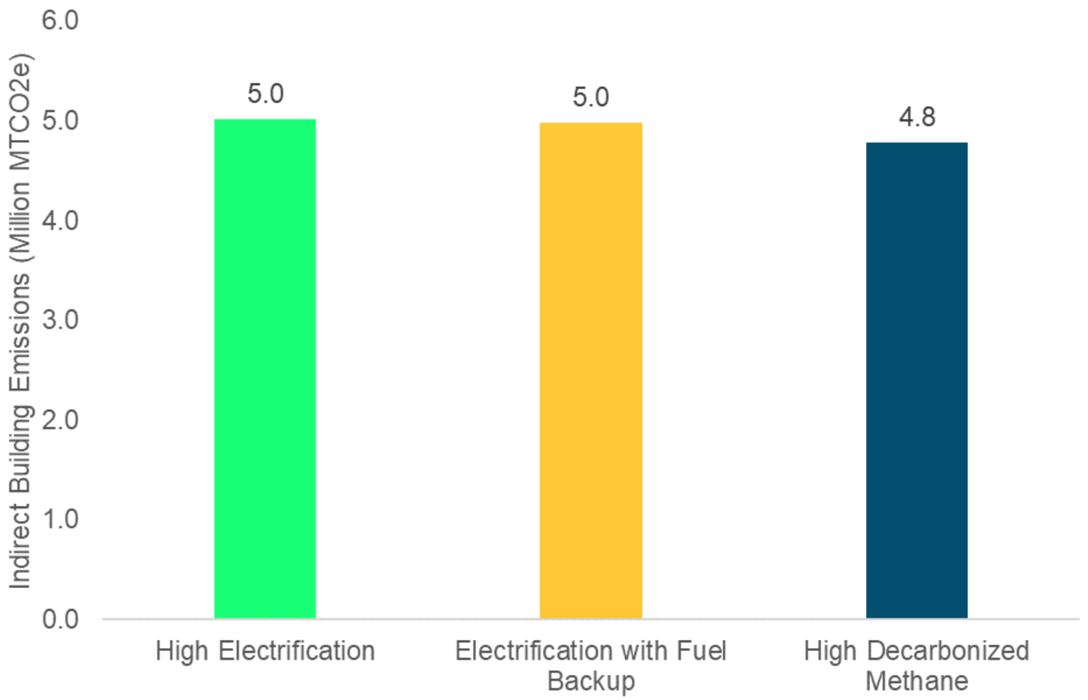
Achieving the Electrification with Fuel Backup scenario would require careful policy design that incentivizes consumers to employ dual-fuel heating systems

Costs of gas increase in all scenarios as a result of zero-carbon fuels and higher delivery costs (due to lower gas demand in the electrification scenarios); emphasis on mitigating the energy burden with customers **'staying behind'** is important.

Indirect emissions from upstream electricity generation still remain by 2045

- **Indirect emissions from upstream electricity generation still remain by 2045**
  - Using GGRA assumptions that by 2045 all in-state generations are carbon-free but there are still GHG emissions associated with PJM imports

Indirect building GHG emissions from upstream electricity generation in 2045 (MMtCO2e per year)



*Upstream emissions electricity generation for information purposes. This does not include fugitive emissions from upstream natural gas extraction.

Climate Impact Analysis

Energy+Environmental Economics

Climate Impact Sensitivity Assumptions

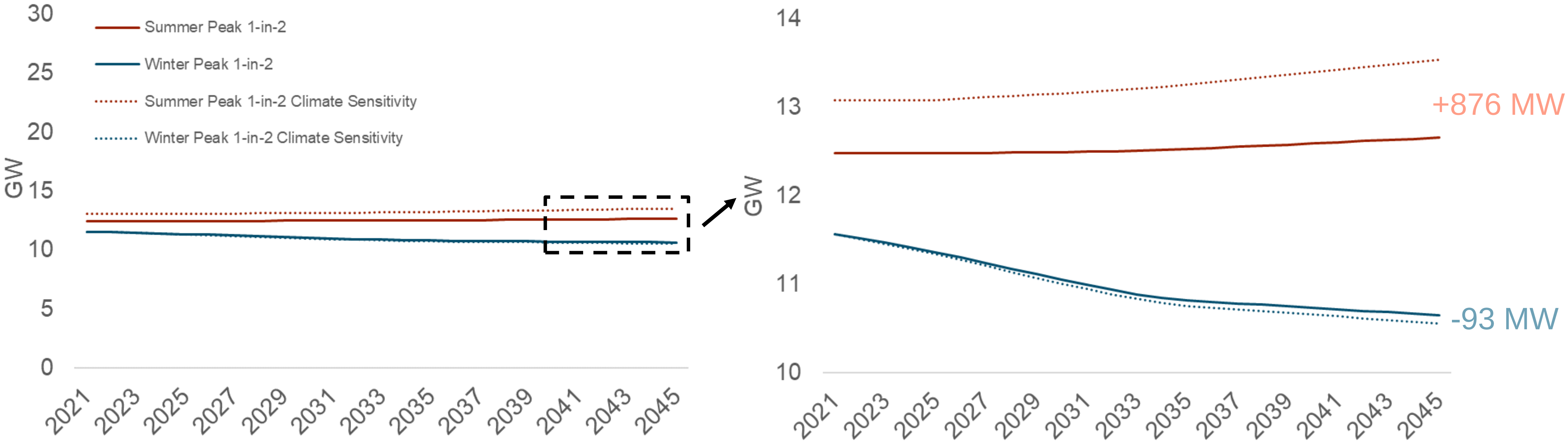
+ **The climate impact sensitivity analysis includes three illustrative effects due to climate change**

1. **All buildings in Maryland will need air conditioning by 2045**
   - A/C saturation reaches 100% by 2045, increased from the current 94% penetration level
2. **Annual heating demand decreases over time, while annual cooling demand increases**
   - Annual heating demand decreases at -0.05% per year from now through 2045
   - Annual cooling demand increases at 0.71% per year from now through 2045
   - Both are based on EIA's projection from the 2020 Annual Energy Outlook
3. **Extreme summer weather will happen more frequently, while extreme winter weather still comes as often even though the average winter temperature increases**
   - We assume that a once-every-10-year (1-in-10) heat event will come every 2 years (1-in-2), and a 1-in-40 heat event becomes 1-in-10

Peak Load – High Decarbonized Methane

- Climate change is expected to increase cooling loads leading to a higher peak load of about 0.9 GW in 2045.
- In the High Decarbonized Methane scenario, climate change is expected to impact the winter 1-in-2 peak minimally.

Peak Load Projection 2021-2045
High Decarbonized Methane

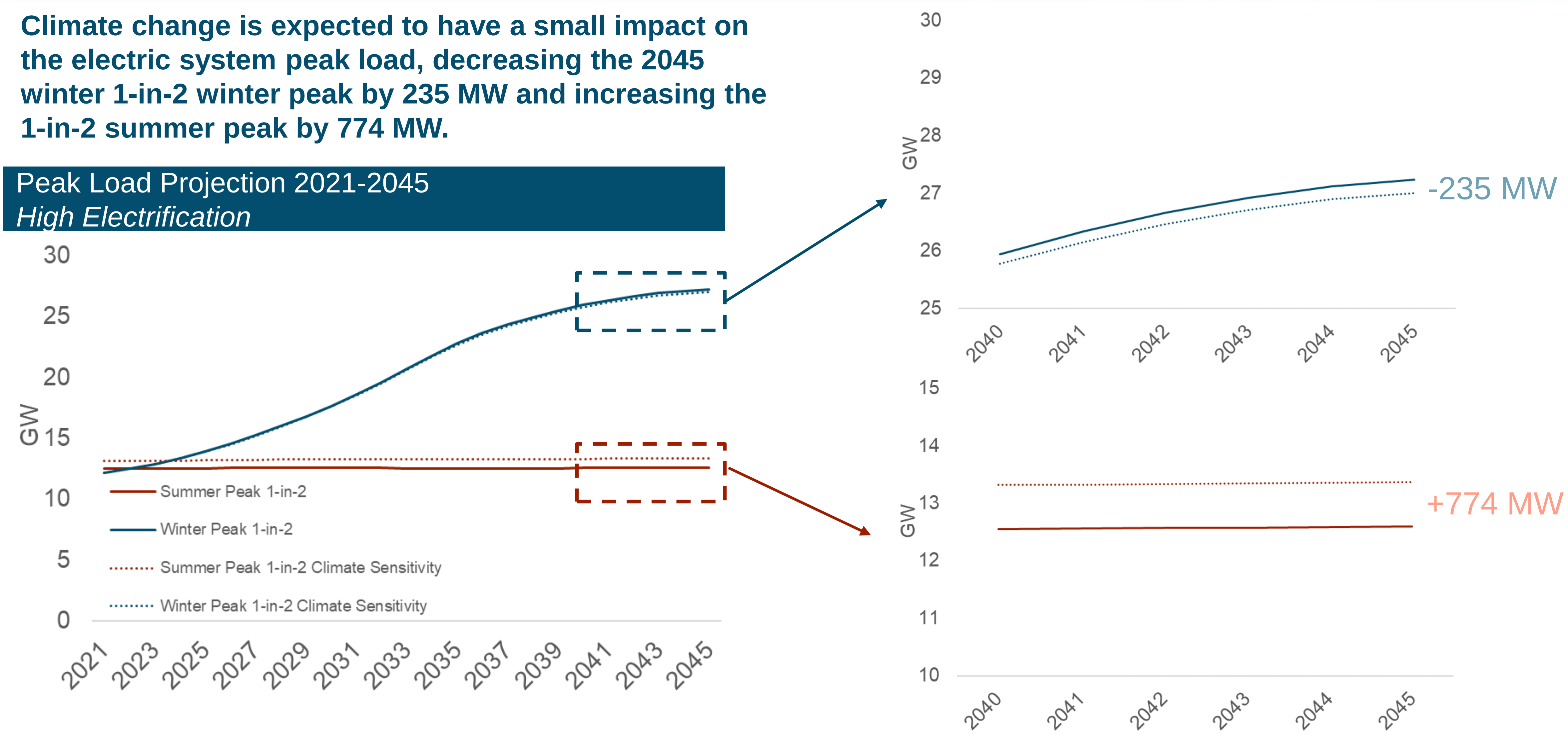


Sources & assumptions: Coincident peak load is based on a modeled hourly load for MD. The projected hourly load is calculated using incremental load in 2050 modeled from PATHWAYS and end-use shapes from RESHAPE based on 2017 weather added to the 2017 historical load.

Peak Load - High Electrification scenario

+ **Climate change is expected to have a small impact on the electric system peak load, decreasing the 2045 winter 1-in-2 winter peak by 235 MW and increasing the 1-in-2 summer peak by 774 MW.**

Peak Load Projection 2021-2045
High Electrification

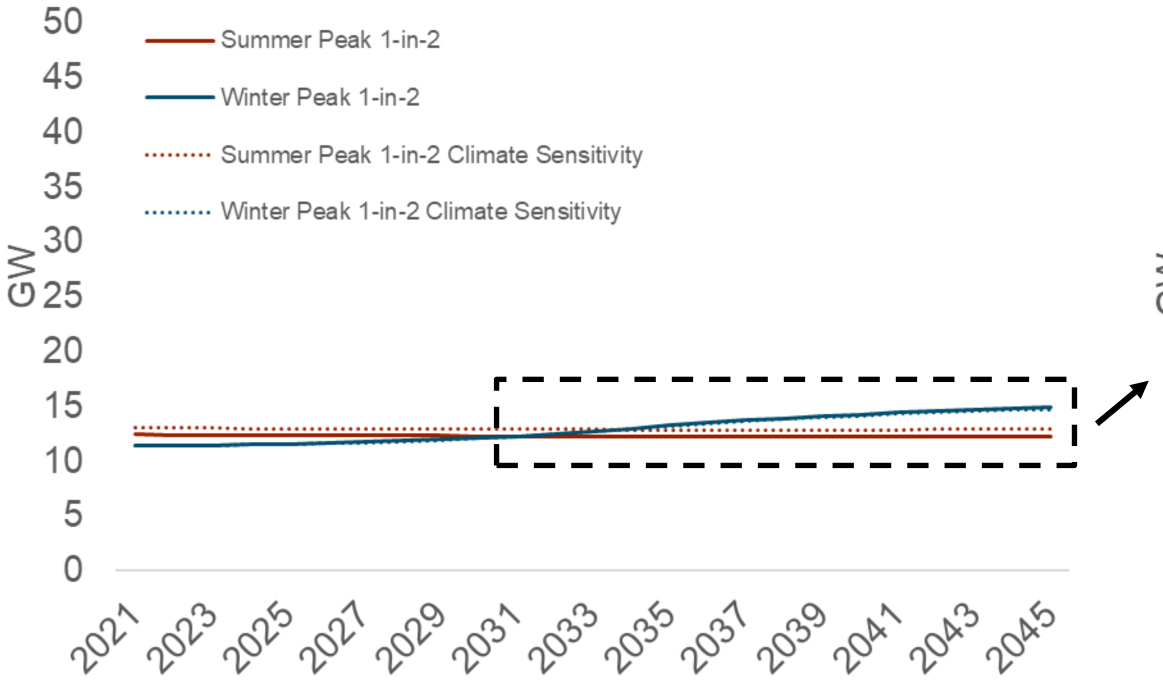


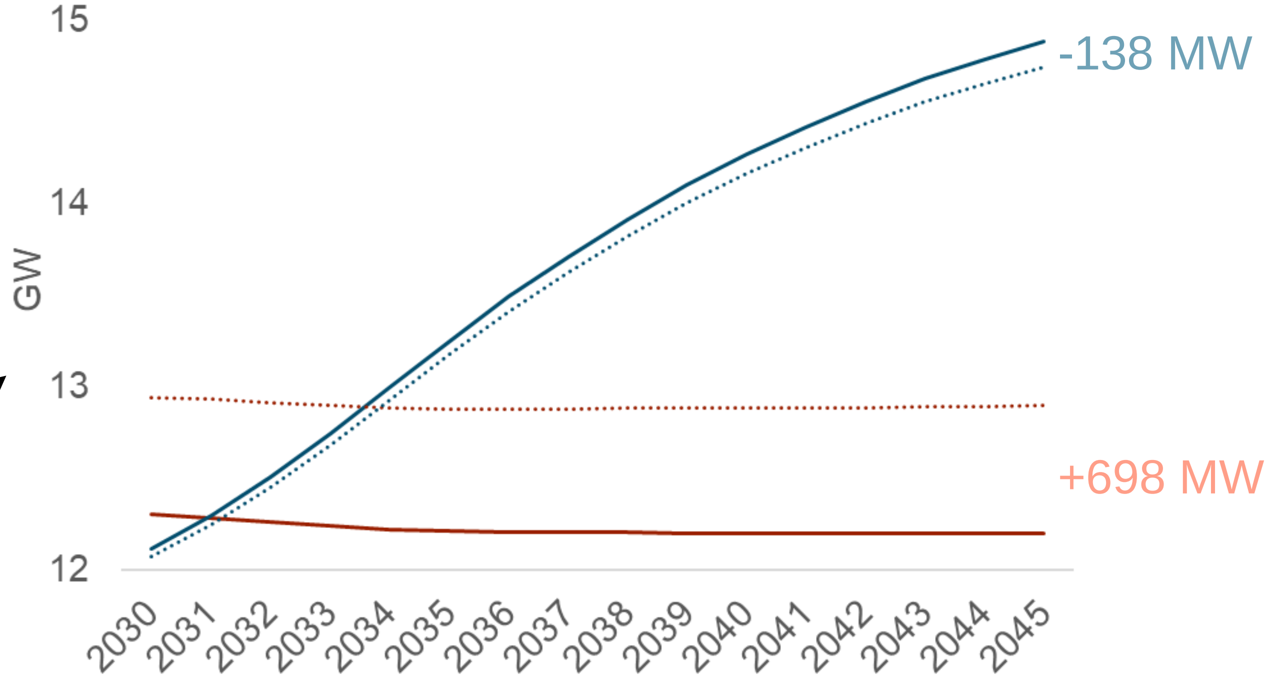
Sources & assumptions: Coincident peak load is based on a modeled hourly load for MD. The projected hourly load is calculated using incremental load in 2050 modeled from PATHWAYS and end-use shapes from RESHAPE based on 2017 weather added to the 2017 historical load.

Peak Load – Electrification with Fuel Backup

+ **In the Electrification with Fuel Backup Scenario, Maryland is still expected to become winter peaking between 2030-2035.**
+ **Considering the impacts of climate, the winter 1-in-2 peak in the intermediate scenario is expected to be 12 GW lower than the 1-in-2 peak in the High Electrification scenario.**

Peak Load Projection 2021-2050
Electrification with Fuel Backup

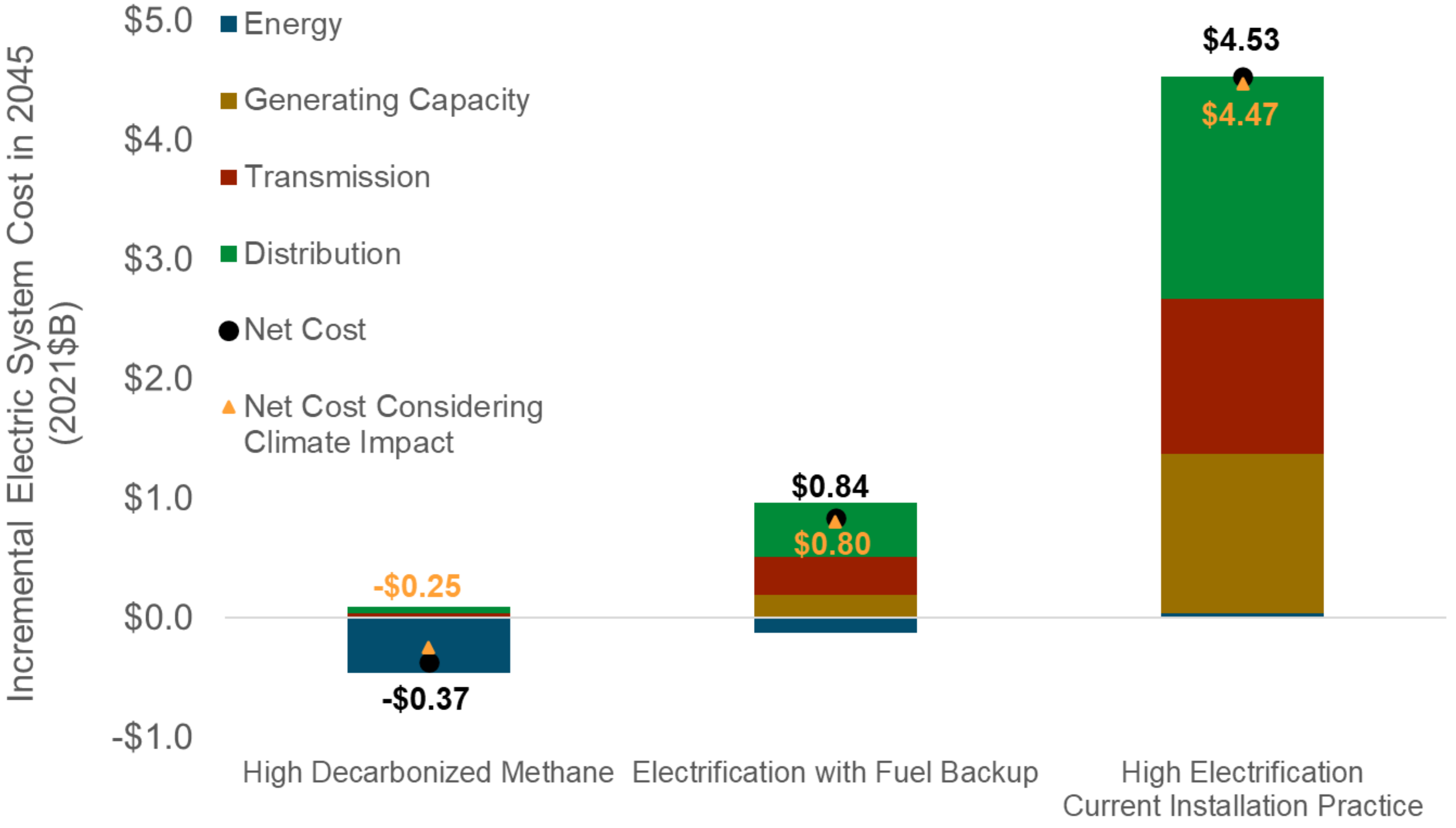




Sources & assumptions: Coincident peak load is based on a modeled hourly load for MD. The projected hourly load is calculated using incremental load in 2050 modeled from PATHWAYS and end-use shapes from RESHAPE based on 2017 weather added to the 2017 historical load.

Incremental electric system costs

Annual Incremental Electric System Costs relative to Reference in 2045 (2021$ Billions per year)

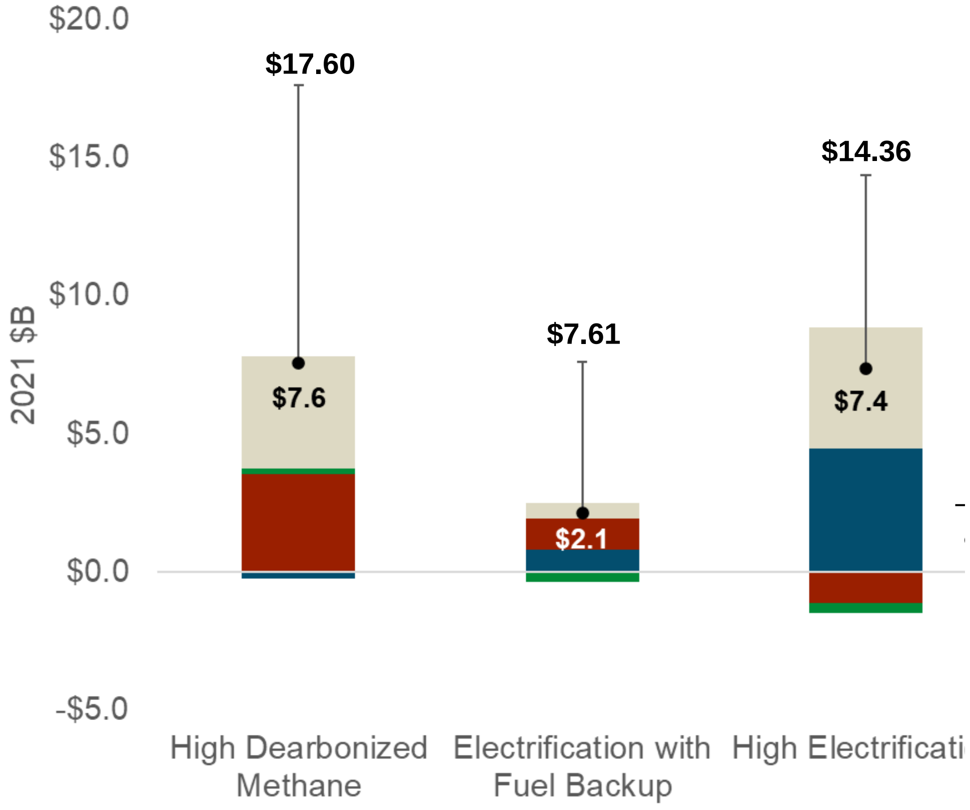


+ In the High Electrification and Electrification with Fuel Backup scenarios, the incremental electric system costs are slightly lower in the climate sensitivity driven by lower space heating loads in a warmer climate.
+ In the High Decarbonized Methane scenario, where the Maryland system is expected to remain summer peaking, electric system costs are expected to increase due to higher cool demand.

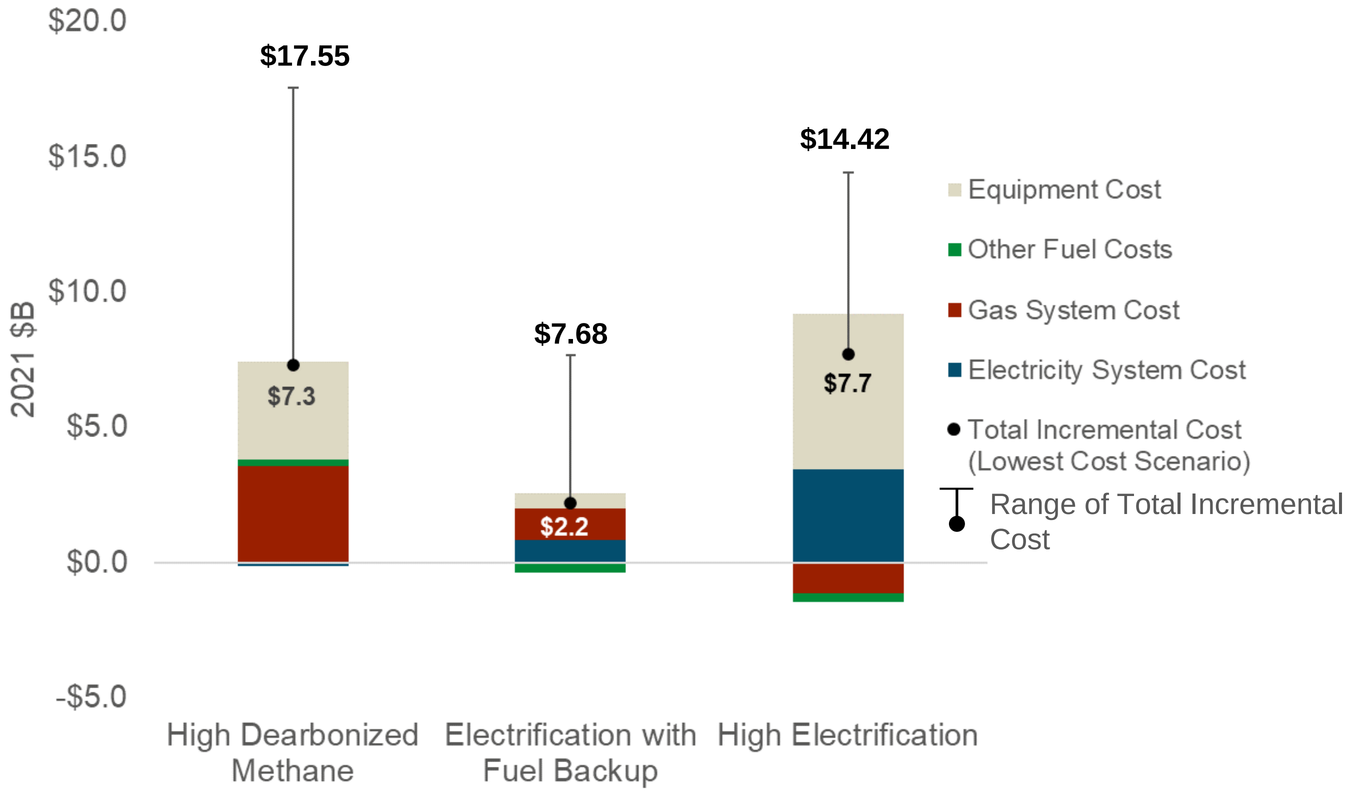
Sources & assumptions: Details of the electric sector cost assumptions are documented in the Appendix. T&D costs are high-level assumption reflecting new investment in lines. This captures the high-level investment requirement in the High Electrification Scenario given the magnitude of the peak impact from electrification. Further analysis is needed to explore near term opportunities for using headroom in existing T&D infrastructure and for expanding existing lines, which are likely going to be less expensive.

Electrification with Fuel Backup scenario is still expected to be the relatively low-cost and low-risk path among the three scenarios with climate impact included

With Climate Impact
Incremental Total Resource Costs ($2021 Billions/year)



Without Climate Impact
Incremental Total Resource Costs ($2021 Billions/year)



Total cost range reflects assumptions regarding fuel costs and equipment cost. Note that the without climate impact scenario also reflects changes to heat pump installation practices.

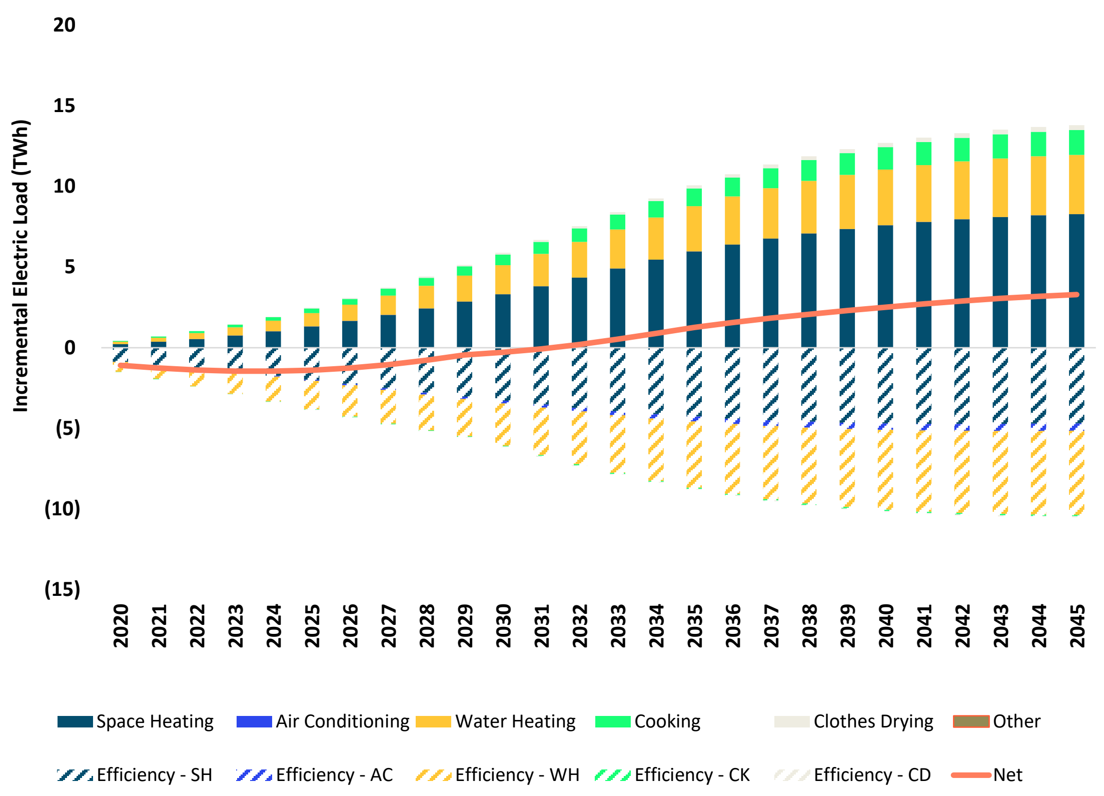
Sources & assumptions: These charts show incremental resource costs of the scenarios compared to the reference scenario.

Energy+Environmental Economics

Detail Scenario Results

Incremental Electric Load: High Electrification

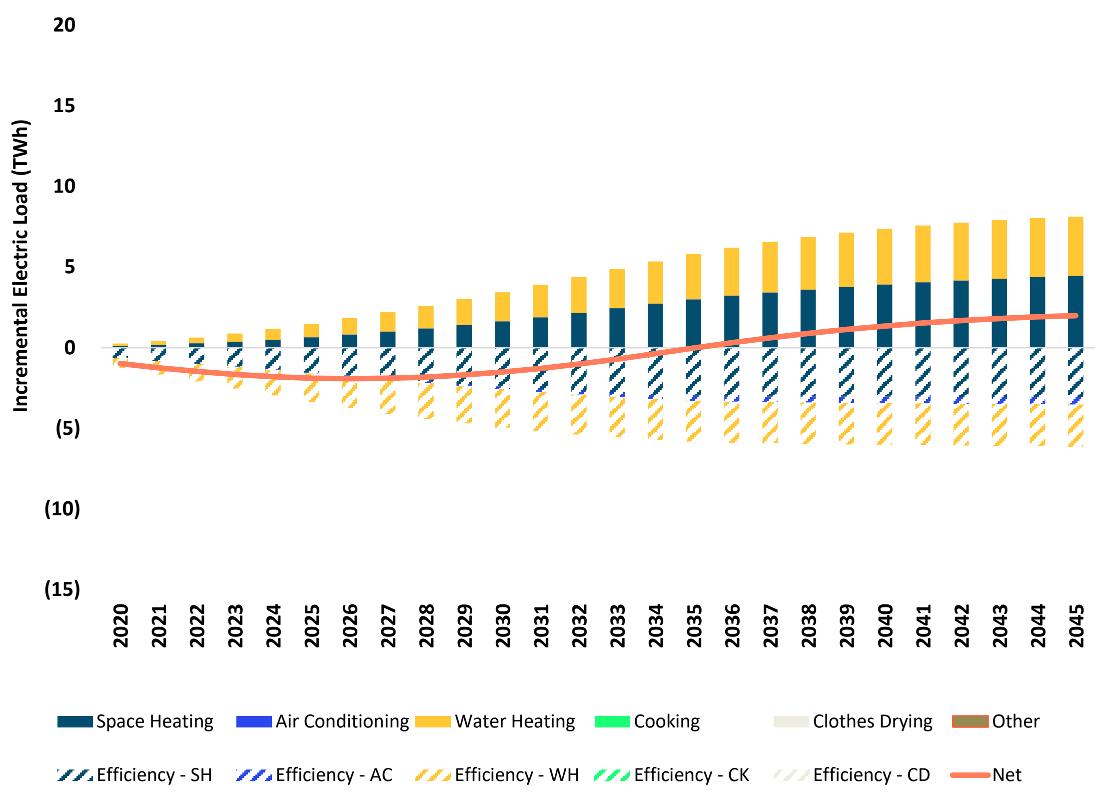
High Electrification



- **Electric devices reach 100% sales share by 2045**
  - Customers adopt electric air- or ground-source heat pumps
- **Net load increase through 2050**
  - Large **growth** in incremental load from fuel switching
  - Moderate **reduction** in incremental load from shift to high-efficiency

Incremental Electric Load: Fuel Backup

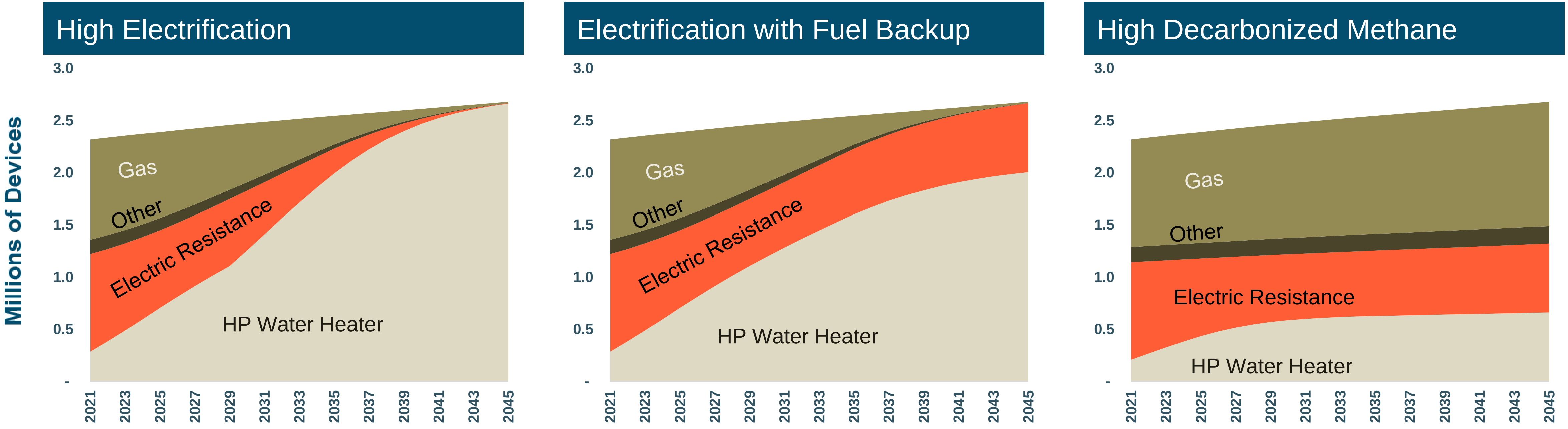
Electrification with Fuel Backup



- **Electric devices reach 100% sales share by 2045**
  - Most existing gas customers upgrade to dual-fuel heat pumps with gas backup
- **Load decreases through 2035 and increases from 2036 to 2045**
  - Efficient electrification initially outweighs load growth from fuel switching
  - Net load growth in later years with deep electrification

Water heating end-uses are all electrified by 2045 in the two electrification scenarios

+ **All fuel-based water heating end-uses switch to heat pump water heaters in the High Electrification and Electrification with Fuel Backup scenarios**
+ **Electric resistance currently accounts for about 40% of water heating devices**
  - EMPOWER program incentives continue after 2023

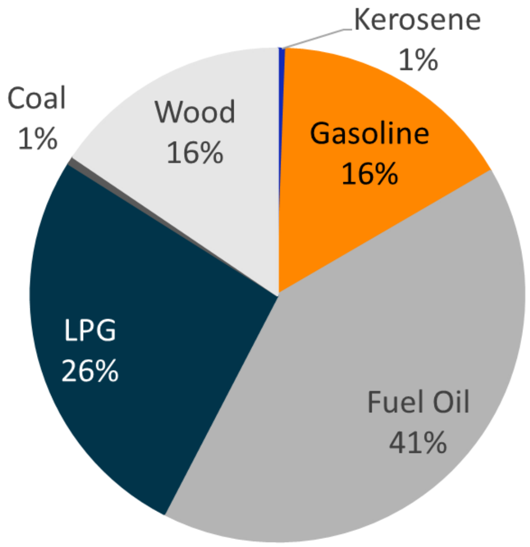


* "Other" water heating devices mainly include fuel oil and LPG-based furnaces and boilers

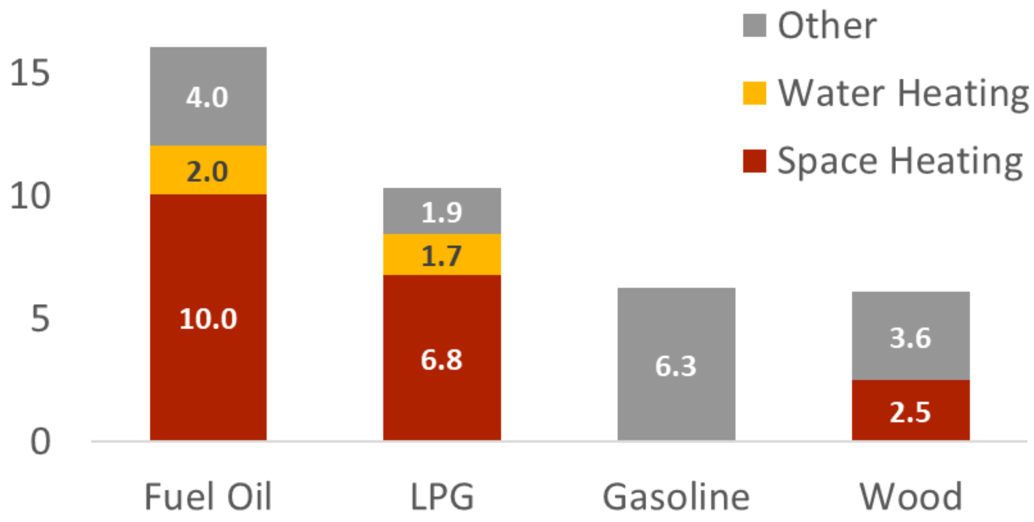
Other building fuel demand mainly consists of liquid fuels, such as fuel oil, LPG and gasoline

- Other building fossil fuels are mainly used for heating by customers that do not have natural gas connections
- There are also miscellaneous usage of these liquid fuels, mainly in the commercial sector, such as gasoline- or diesel-powered electricity generators

Current Mix of Other Fuel Demand in Maryland Buildings



Other Fuel Demand by Fuel and End-use (TBtu)



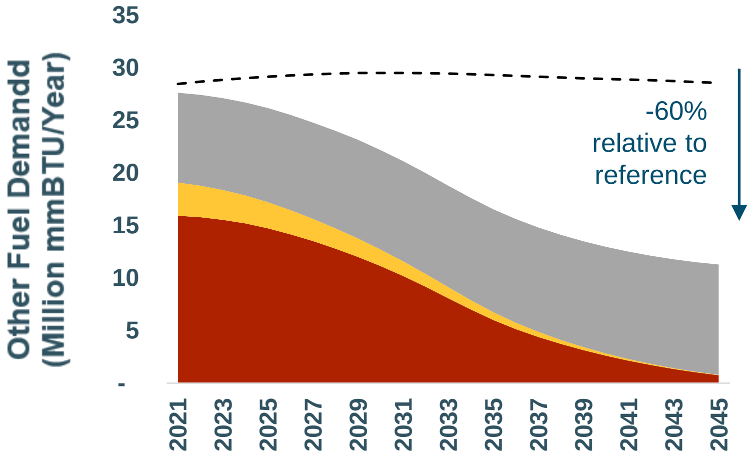
Other fuel demand declines due to energy efficiency and fuel switching, and are all converted to biofuels by 2045

+ Usage of non-gas fuels (mostly fuel oil and liquid propane gas) decreases in all scenarios

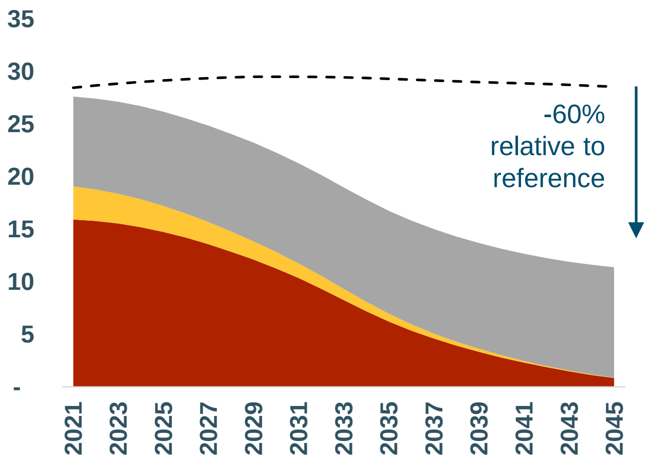
- Fuels are displaced as customers electrify in the High Electrification and Electrification with Fuel Backup scenarios
- Fuel demand decreases in the High Decarbonized Methane scenario due to efficient device adoption and building shell improvement

+ By 2045, fossil fuels used for remaining end uses are all converted to biofuels

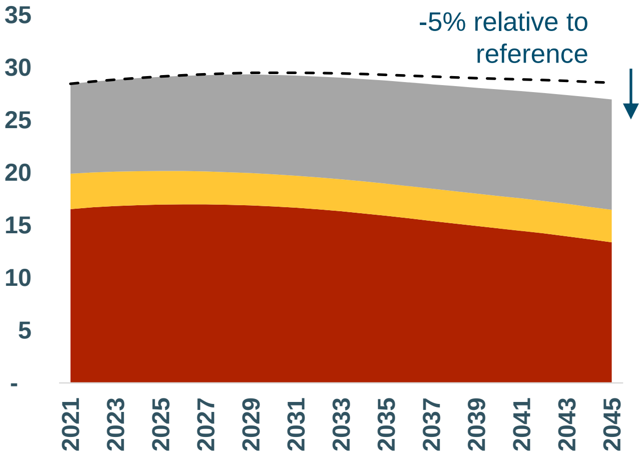
High Electrification



Electrification with Fuel Backup



High Decarbonized Methane



Space Heating   Water Heating   Other   Reference

RNG Cost Assumptions

Different types of decarbonized gas considered

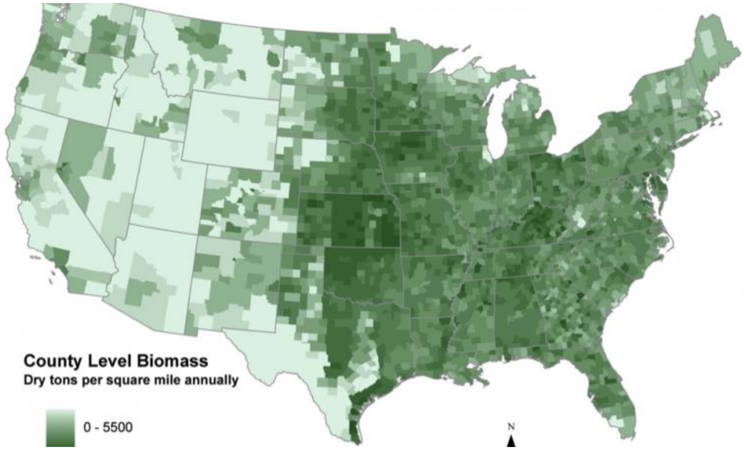
+ **E3 considers a variety of decarbonized gas sources and has compiled a supply curve based on estimates of the availability and costs of each source.**

Waste biogas	Gasification of biomass	Hydrogen	Synthetic Natural Gas (SNG)
		H_2	
Sources: Municipal waste, manure, landfill gas	**Sources:** Agriculture and forest residues, and purpose grown crops, e.g. switchgrass;	**Sources:** Electrolysis + zero-carbon electricity or Steam Methane Reforming of natural gas with Carbon Capture and Sequestration (not considered in this study)	**Sources:** Renewable hydrogen + CO2 from biowaste (bi-product of biofuel production) and/or direct air capture (DAC)
Constraints: Very limited supply	**Constraints:** Limited supply and competing uses for biofuels	**Constraints:** Limited pipeline blends (7% by energy) without infrastructure upgrades, cost	**Constraints:** Limited commercialization, low round-trip efficiency, high cost

Biofuels Supply and Cost Estimates

- E3's Biofuels Model optimizes the allocation of scarce biomass and identifies a lowest-cost portfolio of biofuels
- The model outputs quantity of production by fuel, their production costs and a market clearing price for each fuel
- E3 derives biomass supply estimates from the US Department of Energy *Billion Ton Report*

Biomass Supply based on the DOE Billion Ton Report



E3's Biofuels Optimization Model

Biofuels Supply Curve

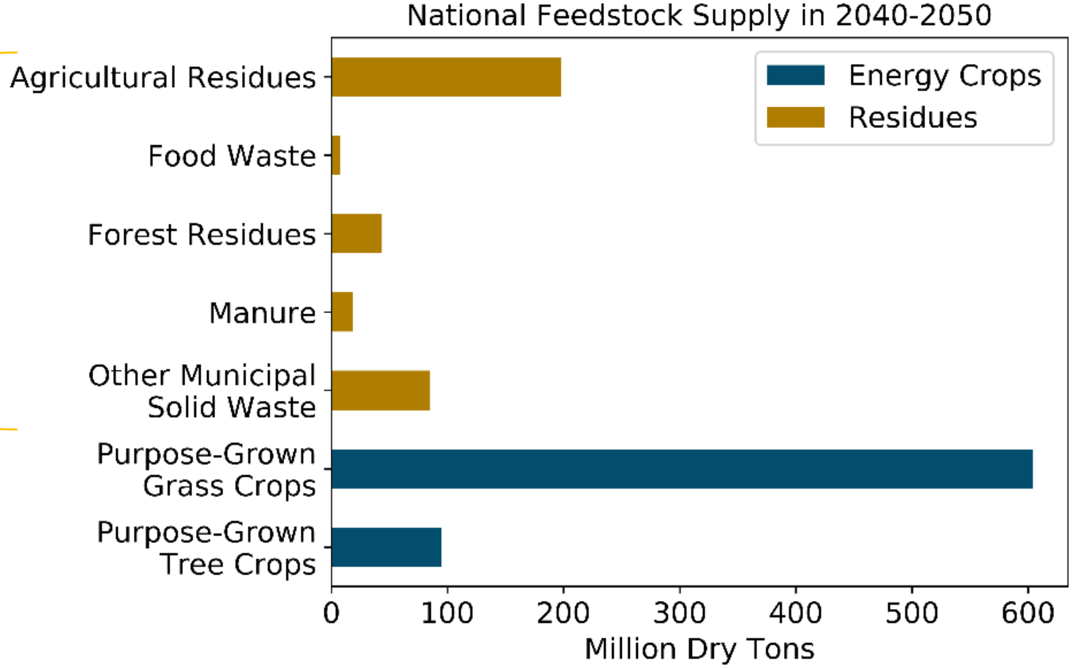
Biomass Feedstock Selected

Biofuel Production and Prices

Feedstock Potential

+ **The Billion Ton Study includes two major categories of feedstock:**
  - **"Residues" include feedstocks such as agricultural residues, forest thinnings, and food waste**
  - **"Energy Crops" include dedicated land to grow high-energy crops or new forests for conversion to biofuels. *These have been excluded for this analysis due to land-use concerns***

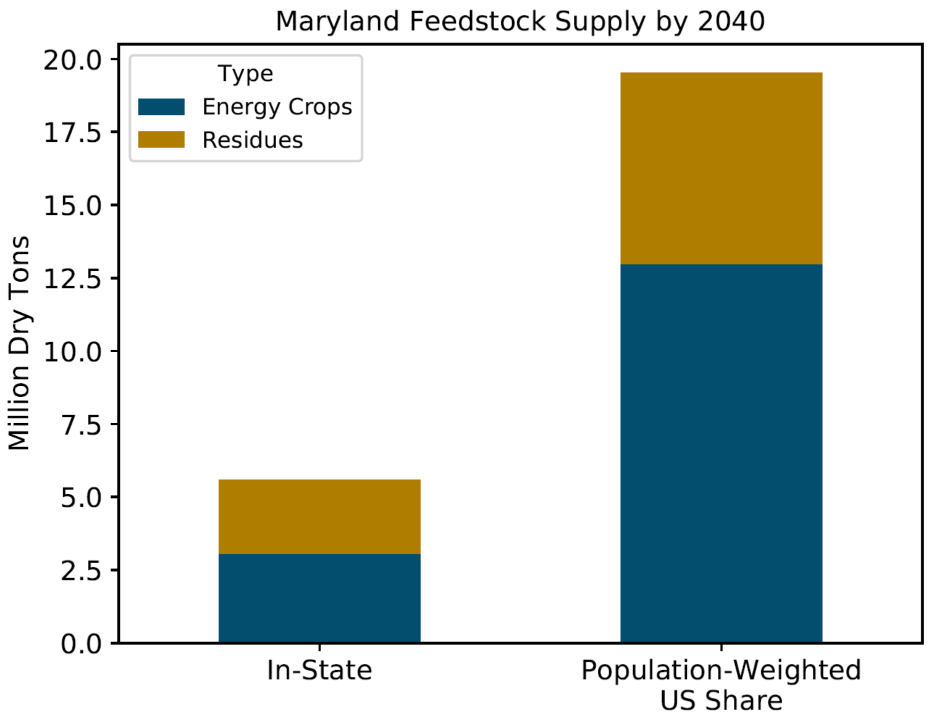
Categories Included in this analysis



Source: DOE, 2016. Billion Ton Update

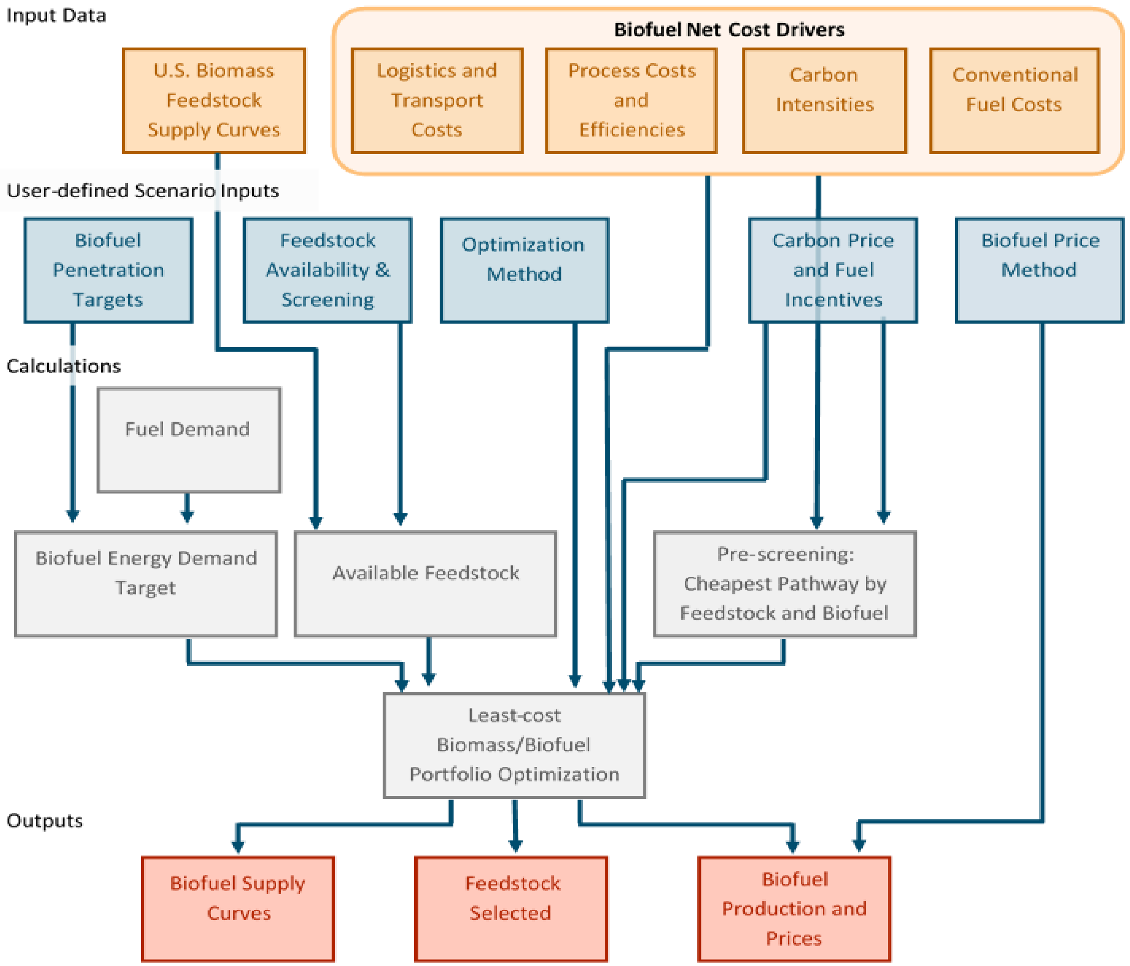
Maryland Biomass Feedstocks

- Maryland has limited in-state biomass resource potential
- Using the population-weighted share of the US supply (1.9%), MD has access to more than 2x the in-state potential of residues and wastes



Source: DOE, 2016. Billion Ton Update

E3 Biofuels Optimization Model



E3's Biofuels Model optimizes the allocation of scarce biomass to decarbonize fuels.

Given liquid and gaseous demands, it identifies a portfolio of fuels with the highest "bang" per GHG mitigation "buck"

The model returns biofuels produced by fuel, their production costs and a market clearing price for each fuel

Biomass Gasification: Process Cost Assumptions

- Costs developed by University of California, Irvine (UCI) based on literature review of actual gasification plant costs, with an assumed learning rate over time
- Interconnection costs are implicitly included in the assumed capital costs

	2020	2025	2030	2035	2040	2045	2050
Gasification plant capital costs (2016$/kWth)*	1400	1134	927.6	834.8	761	719	695
Fixed O&M (2016$/kW-yr)	59	47.8	39.1	35.2	32.1	30.3	29.3
Variable O&M (2016$/MWh)	13	10.5	8.6	7.8	7	6.7	6.5
Resulting process costs for gasification of corn stover (2016$/dry ton)**	153.1	125.3	103.1	93.1	85.1	80.6	78.1

*Interconnection costs are included in gasification plant capital costs and average at $2.3 million in 2020 (capital costs only) with a 12% learning rate, based on a 50 MW plant (cost developed by UCI and outlined in Appendix C of the CEC Study on The Challenge of Retail Gas in California's Low Carbon Future.

**Process costs are different for each feedstock, as they are dependent on the HHV for the specific conversion pathway. Corn stover is used as an example, as it makes up the majority of available MN biomass in the DOE Billion Ton Study. The costs for all pathways are shown on the next slide.

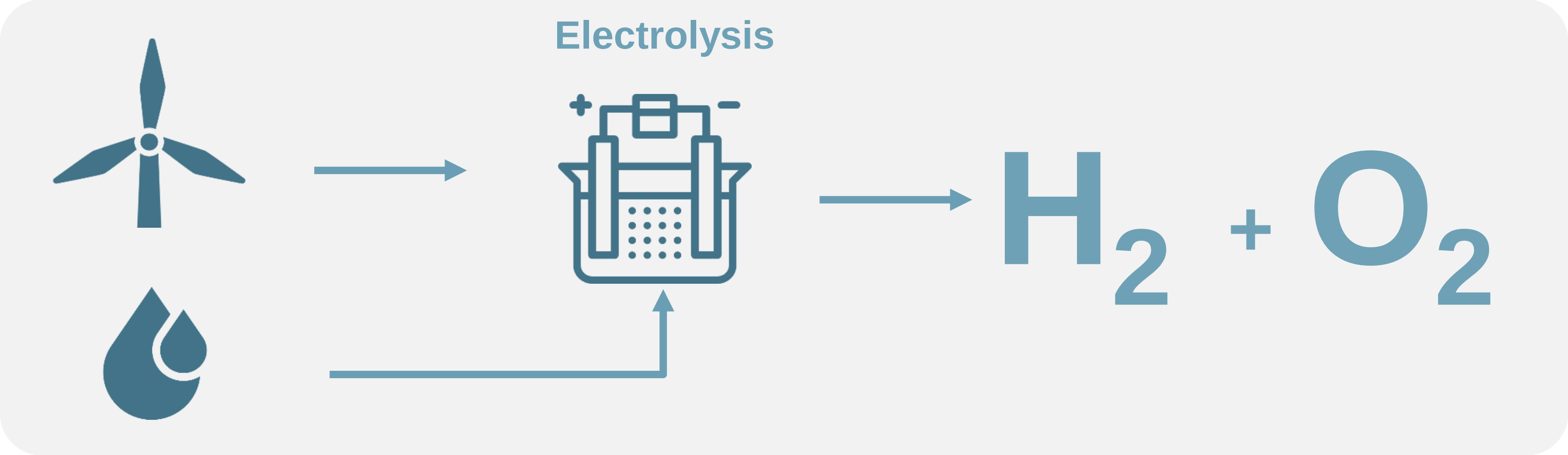
Full gasification process cost assumptions

Gasification process costs by feedstock (2016$/dry ton)

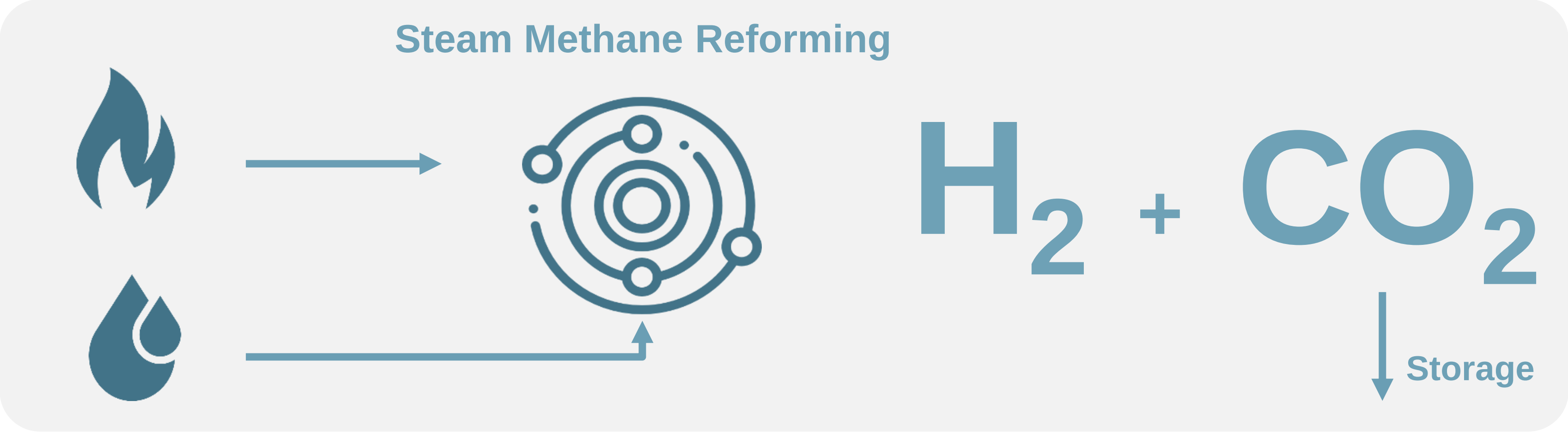
	2020	2025	2030	2035	2040	2045	2050
Barley straw	$ 158.09	$ 129.36	$ 106.46	$ 96.10	$ 87.88	$ 83.26	$ 80.65
CD waste	$ 157.98	$ 129.27	$ 106.39	$ 96.04	$ 87.82	$ 83.21	$ 80.59
Corn stover	$ 153.10	$ 125.28	$ 103.10	$ 93.07	$ 85.10	$ 80.63	$ 78.10
Hardwood, lowland, residue	$ 165.90	$ 135.75	$ 111.72	$ 100.85	$ 92.22	$ 87.38	$ 84.63
Hardwood, upland, residue	$ 165.90	$ 135.75	$ 111.72	$ 100.85	$ 92.22	$ 87.38	$ 84.63
MSW wood	$ 162.24	$ 132.76	$ 109.26	$ 98.63	$ 90.19	$ 85.45	$ 82.76
Mixedwood, residue	$ 165.90	$ 135.75	$ 111.72	$ 100.85	$ 92.22	$ 87.38	$ 84.63
Noncitrus residues	$ 152.76	$ 125.01	$ 102.89	$ 92.88	$ 84.93	$ 80.47	$ 77.95
Other	$ 144.16	$ 117.97	$ 97.09	$ 87.64	$ 80.15	$ 75.94	$ 73.55
Other forest residue	$ 152.76	$ 125.01	$ 102.89	$ 92.88	$ 84.93	$ 80.47	$ 77.95
Paper and paperboard	$ 179.05	$ 146.51	$ 120.57	$ 108.84	$ 99.53	$ 94.30	$ 91.34
Primary mill residue	$ 172.78	$ 141.39	$ 116.36	$ 105.04	$ 96.05	$ 91.01	$ 88.15
Rubber and leather	$ 239.64	$ 196.11	$ 161.40	$ 145.70	$ 133.23	$ 126.24	$ 122.27
Secondary mill residue	$ 172.78	$ 141.39	$ 116.36	$ 105.04	$ 96.05	$ 91.01	$ 88.15
Softwood, natural, residue	$ 167.42	$ 137.00	$ 112.75	$ 101.78	$ 93.07	$ 88.18	$ 85.41
Softwood, planted, residue	$ 167.42	$ 137.00	$ 112.75	$ 101.78	$ 93.07	$ 88.18	$ 85.41
Textiles	$ 157.81	$ 129.14	$ 106.29	$ 95.95	$ 87.74	$ 83.13	$ 80.52
Tree nut residues	$ 172.00	$ 140.75	$ 115.84	$ 104.57	$ 95.62	$ 90.60	$ 87.75
Wheat straw	$ 176.00	$ 144.03	$ 118.53	$ 107.01	$ 97.85	$ 92.71	$ 89.80
Yard trimmings	$ 154.08	$ 126.09	$ 103.77	$ 93.67	$ 85.66	$ 81.16	$ 78.61

Hydrogen Production

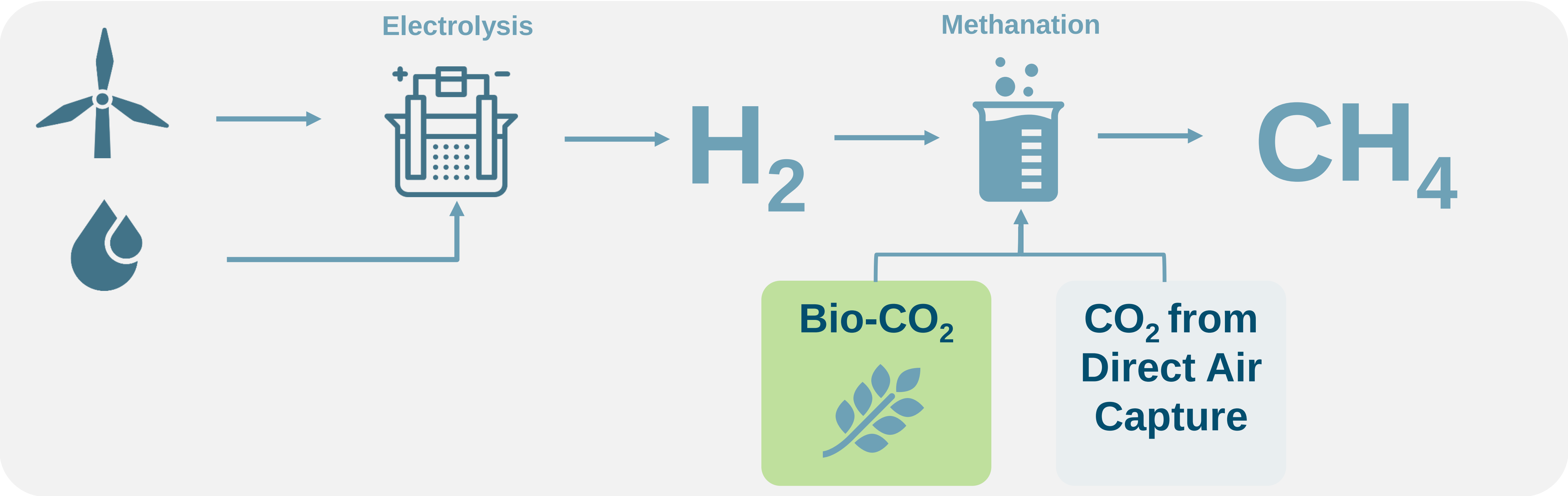
“Green” Hydrogen



“Blue” Hydrogen

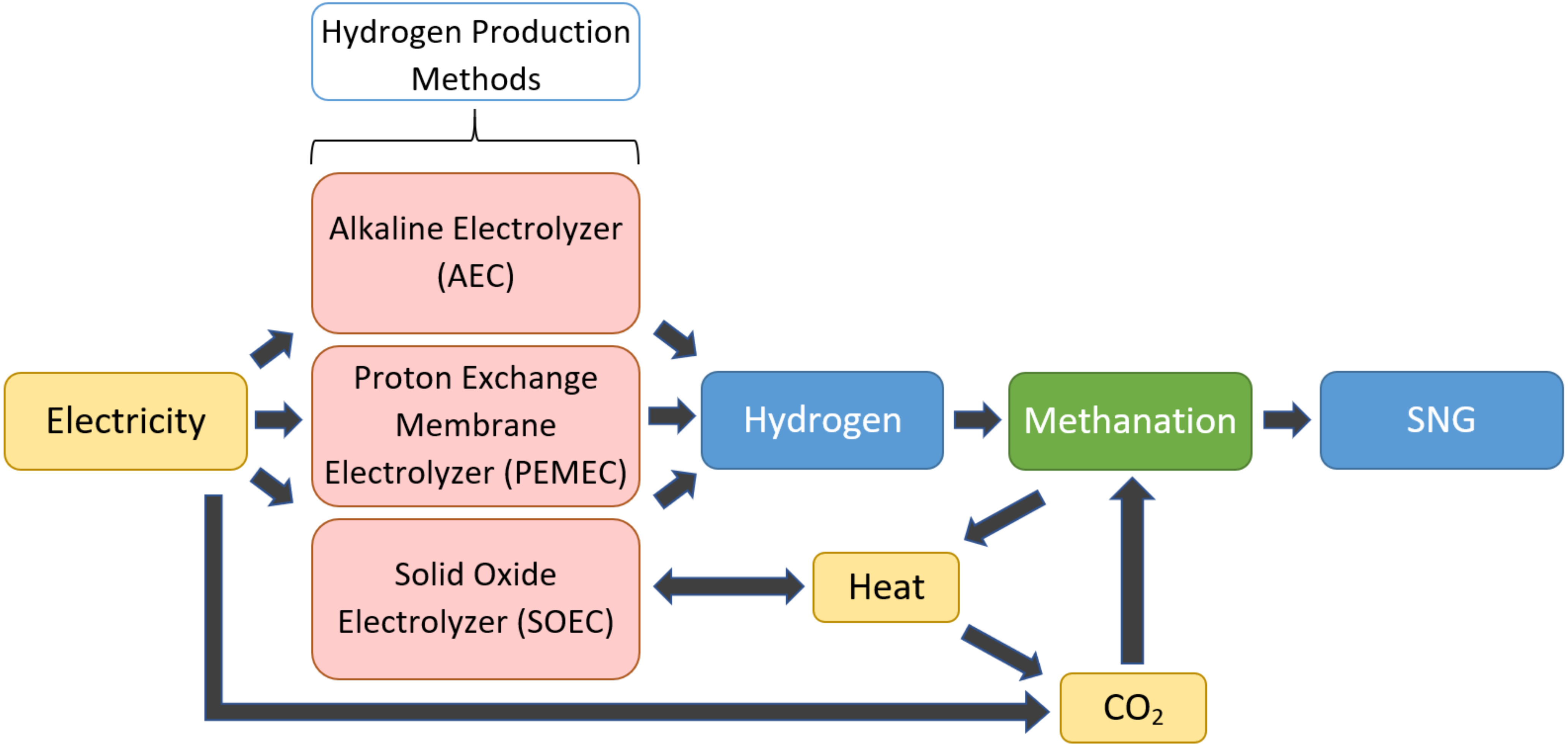


Synthetic Natural Gas (SNG) Production



- SNG production requires a combination of climate neutral hydrogen and climate neutral CO2.
- E3 considers two sources of climate neutral CO2: 1) less costly bio-CO2 from biofuels production, 2) more costly CO2 from direct air capture.

SNG Production Process

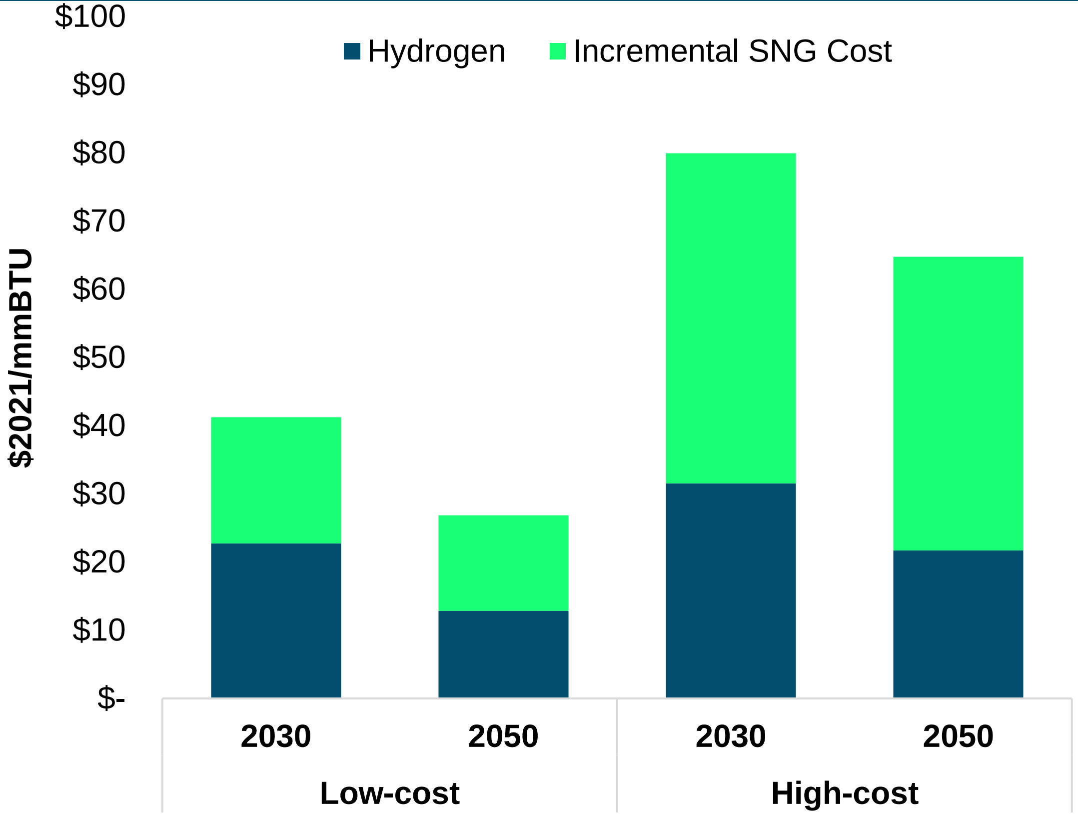


H2 and SNG Cost Assumptions

	Hydrogen (H2)		Synthetic Methane (SNG)	
Feedstock Elec	**Low**	**High**	**Low**	**High**
Cost Trajectory (main component is electrolyzer learning rate)	Optimistic - 25% electrochemcial - 14% non-electrochemical	Conservative - 10% electrochemcial - 14% non-electrochemical	Optimistic - 25% electrochemcial - 14% non-electrochemical	Conservative - 10% electrochemcial - 14% non-electrochemical
Electricity Feedstock	Input electricity price uses cost of new solar in PJM-E (cheapest available option)	Input electricity price uses cost of new solar in PJM-E (cheapest available option)	Input electricity price uses cost of new wind in PJM-E (cheapest available option)	Input electricity price uses cost of new wind in PJM-E (cheapest available option)
Infrastructure Requirement	None	None	None	None
Production Pathway	Alkaline Electrolysis (AEC)	Alkaline Electrolysis (AEC)	Biofuel Synthesis	Direct Air Capture (DAC)

Summary of Hydrogen and SNG Costs

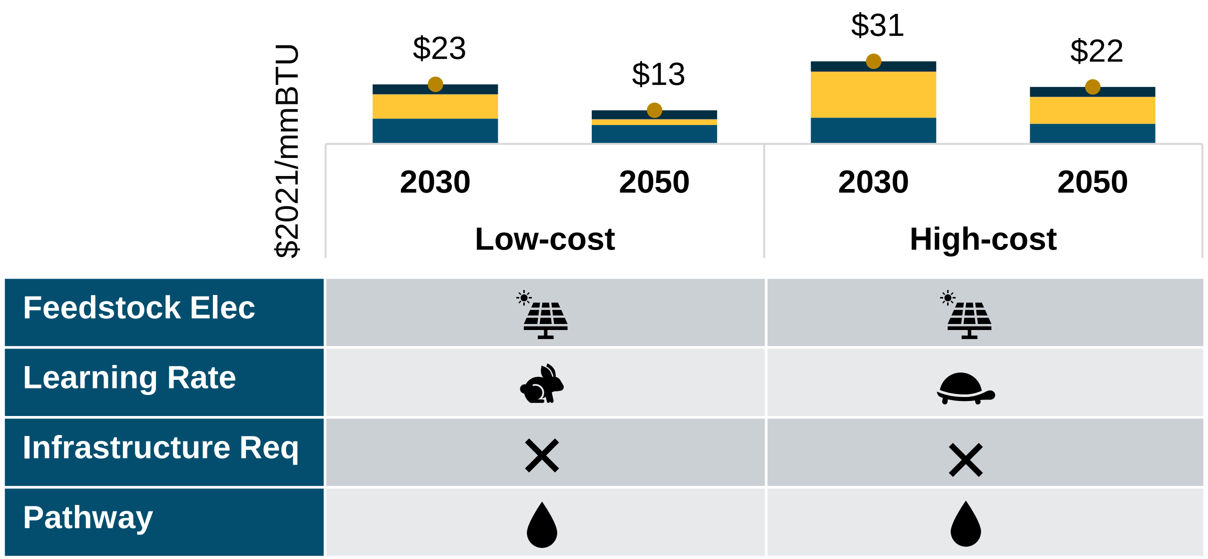
Hydrogen and Incremental SNG cost, low- and high-cost scenarios



- **Hydrogen is produced through electrolysis with off-grid solar**
- **SNG is produced with hydrogen and climate neutral CO2 through methanation**
  - SNG is tied to H2 costs
  - Low-cost scenario assumes SNG can be produced through biofuel synthesis (cheaper)
  - High-cost assumes DAC, which substantially increases associated capital costs (more expensive)
  - Additional uncertainties due primarily to electrolyzer learning rates (14% conservative, 25% optimistic)
- **We can work with MDE to evaluate the land-use implication of the off-grid renewable resources for the renewable fuel production**
- **E3 will develop biofuel costs using the Biofuel Optimization Model pending draft scenario results for fuel demand**

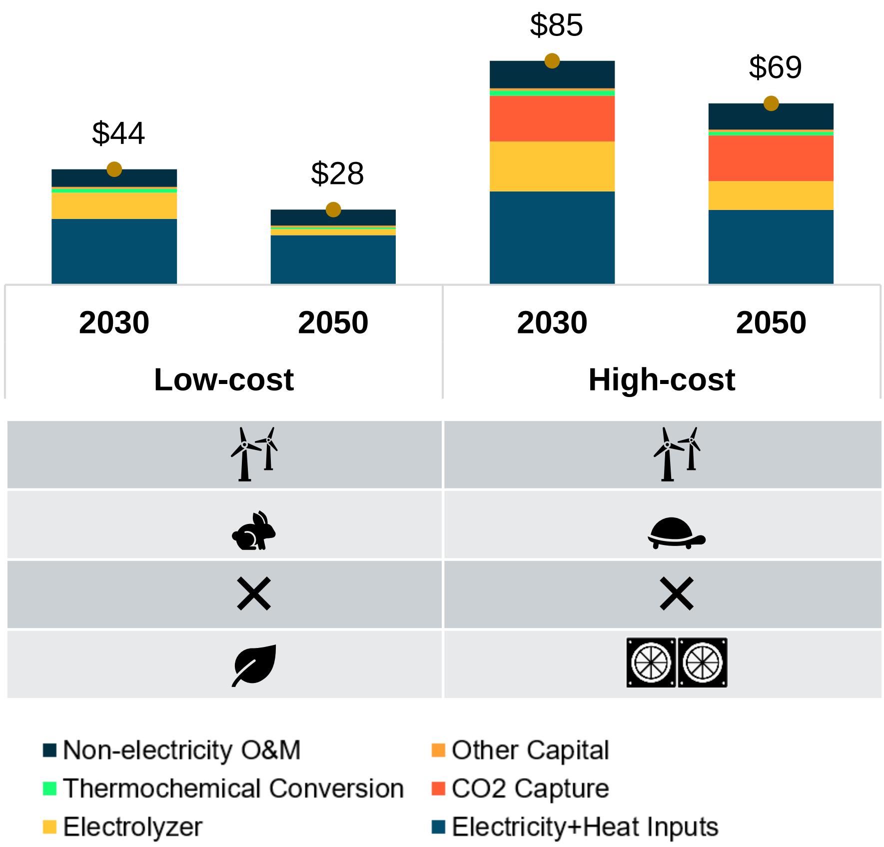
Cost breakdown

Hydrogen is cheaper under low- and high-cost scenarios



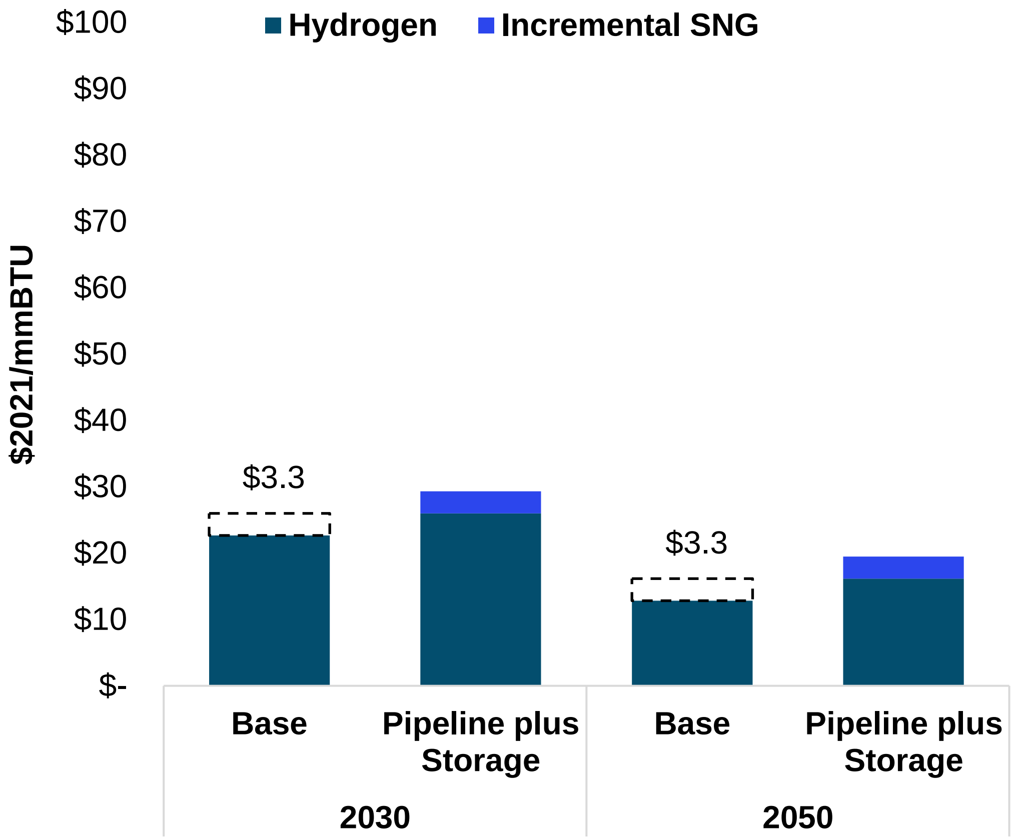
We assume H2 blends below 7% by energy such that no new storage or pipeline infrastructure is needed

SNG is more expensive with higher uncertainty

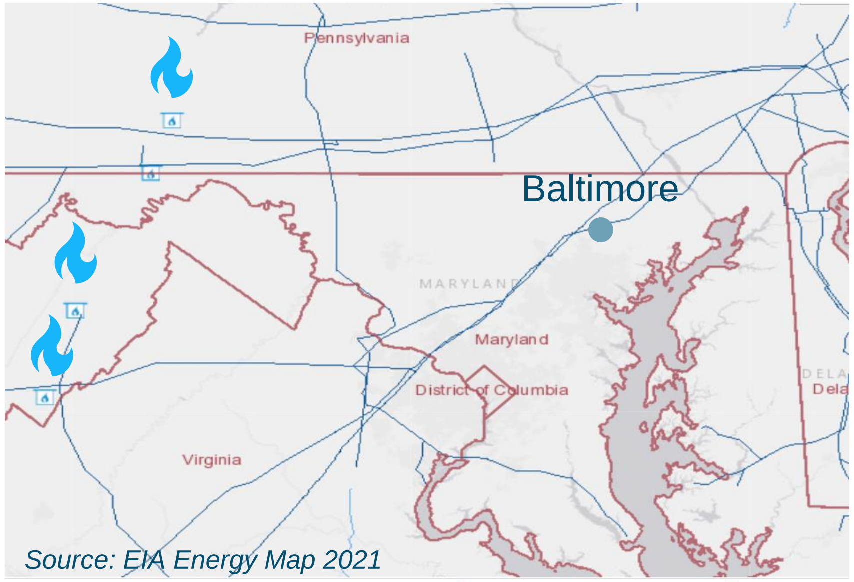


Hypothetical H2 Infrastructure

Incremental Cost of H2 Infrastructure, 2030 vs 2050



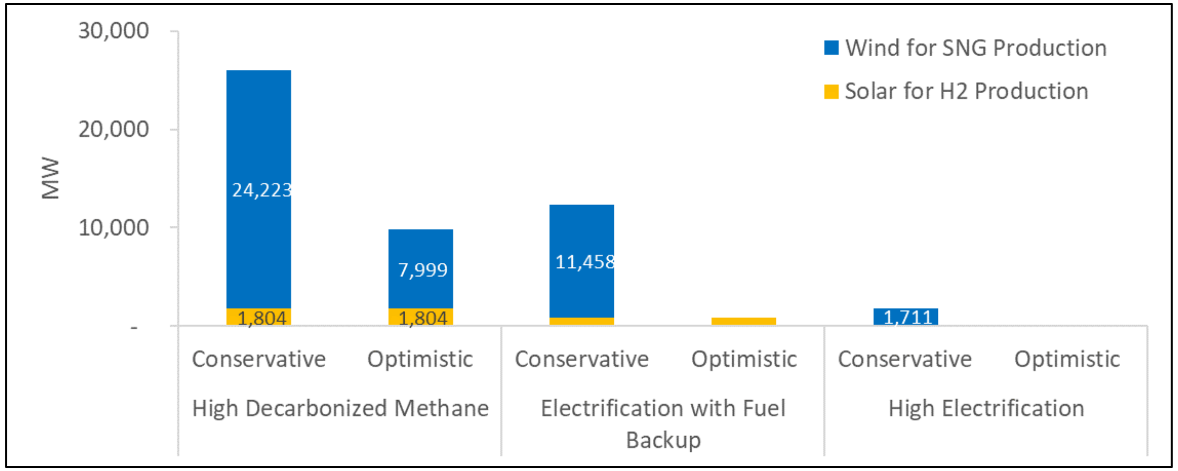
+ **Infrastructure requirements adds ~$3.3/mmBTU through 2050 to base H2 costs**



+ **Dedicated infrastructure assumes:**
  - 300 miles of new pipeline
  - Construction of underground storage

Off-grid Renewable Capacity Build for H2 and SNG Production

Renewable Capacity for H2 and SNG Production in 2045



+ **This study assumes that off-grid solar will be built to supply electricity for H2 production and onshore wind for SNG production.**
+ **Wind capacity totals 8-24 GW in the High Decarbonized Gas scenario by 2045 to support the large SNG demand in buildings.**
+ **Energetically, it is more efficient to directly electrify end-uses than to use H2/SNG produced by renewable electricity.**
  - Heat pumps are more efficient than furnaces/boilers in supplying heat
  - H2 production has an efficiency loss of 20-30%, though can serve as an important source of storage

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RESHAPE Input Assumptions

Building shell upgrades

- **Efficient building shells are assumed to lead to a 29% reduction in residential heating service demand, 10% reduction in residential cooling service demand, 34% reduction in commercial heating service demand, and 13% reduction in commercial cooling service demand**
- **A building shell upgrade consists of wall insulation, roof insulation, glazing, air-tightness, and heat recovery**

Shell Component	Upgrade Description	Low Cost ($/sq ft)*	High Cost ($/sq ft)*
Wall Insulation	Assembly R-15.6	$6.90	$15.55
Roof Insulation	Assembly R-30.0	$3.13	$5.25
Glazing	Assembly U-0.42	$1.77	$2.11
Air-Tightness	0.0448 cfm/sq ft facade	$3.75	$7.44
Heat Recovery	50% effectiveness	$0.44	$2.00

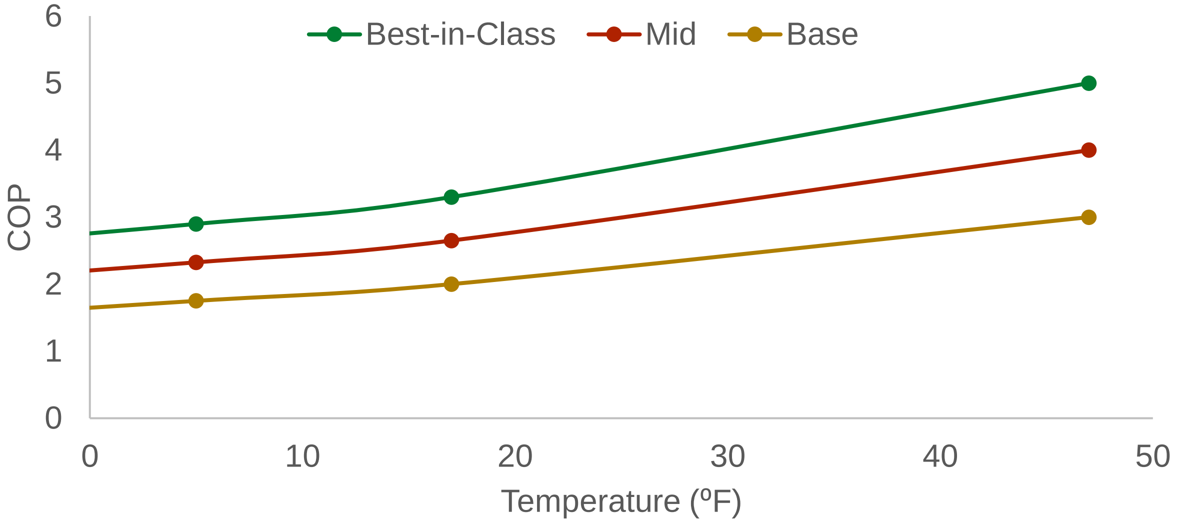
Source: Building Sector Report, A Technical Report of the Massachusetts 2050 Decarbonization Roadmap Study, Massachusetts Executive Office of Energy & Environmental Affairs

Sizing criteria for ASHPs

- **ASHP with resistance backup is sized to serve the 99% peak demand, with the ASHP sized to serve the 97% peak demand for residential and the 95% peak demand for commercial**
- **ASHPs with Gas Backup are sized to serve the 80% peak demand for residential and the 88% peak demand for commercial**
- **We base the size criteria on system type assumptions and differentiate between different building types:**
  - ASHPs with resistance backup are assumed to be high-efficiency heat pumps sized to operate at full capacity down to **20ºF**
  - ASHPs with gas backup are assumed to be medium-efficiency heat pumps sized to operate at full capacity down to **30ºF**

Heat pump configuration sensitivity

RESHAPE COP Curves



Configuration	Current Installation Practice	Improved System Configuration
COP Curve	Mid	Best-in-Class
TMY Heating COP		
Residential	3.2	4.0
Commercial	2.5	3.6
Heating Sizing Percentile		
Residential	97% (~24ºF)	99% (~18ºF)
Commercial	95% (~27ºF)	99% (~18ºF)
Cooling Sizing Percentile		
Residential	99% (~89ºF)	99% (~89ºF)
Commercial	99% (~89ºF)	99% (~89ºF)

- **E3 used manufacturer reported data on the performance of ccASHPs provided by NEEP in its Cold Climate Product Specification product listing to characterize COPs as a function of outdoor air temperature.**
- **Three representative ccASHP systems are considered:**
  - **Best-in-Class**: consistent with the best performing systems available today COP of 2.3 @-17F
  - **Mid**: high efficiency systems COP of 1.8 @-17F
  - **Base**: systems that only just meet the NEEP requirement of a COP of 1.75 @5F, 1.3 @-17F

Average COPs and efficiency levels of appliances

Efficiency levels of ccASHPs

	Residential	Commercial
Average heating COP of ASHP with elec. resist. backup	3.17	2.48
Average cooling COP of ASHP with elec. resist. backup	4.49	4.83
Average heating COP of ASHP with fuel backup	4.57	6.19
Average cooling COP of ASHP with fuel backup	4.49	4.83
Supp Heat % of Total SD for Hybrid ASHP (with fuel backup)	25.5%	47.9%

Other efficiency levels

	Residential	Commercial
Average cooling COP of Reference AC	3.20	3.22
Average cooling COP of High Efficiency AC	3.40	3.72
Average heating COP of Reference Gas Furnace	82%	80%
Average heating COP of High Efficiency Gas Furnace	96%	98%
Average heating COP of Reference Electric Resistance	98%	99%
Average heating COP of Reference Fuel Oil	83%	80%
Average heating COP of Reference Heat Pump	2.43	1.89
Average heating COP of Reference Gas Water Heater	60%	80%
Average cooling COP of Heat Pump Water Heater	250%	300%

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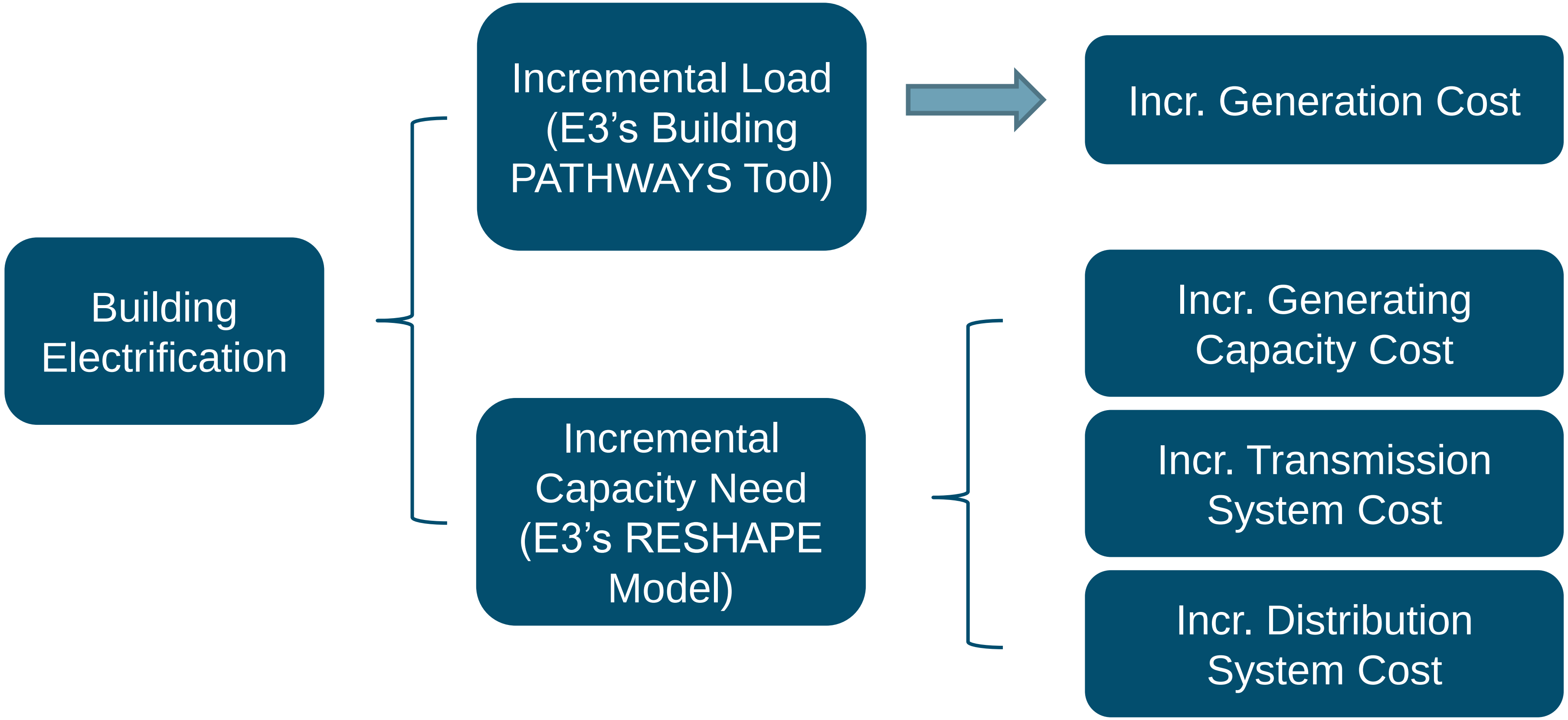
Revenue Requirement Model Assumptions

Modeling Approach –Electric System Cost

- E3 will model the incremental electric system cost relative to the total electric system costs under the 2030 GGRA plan through the following framework.



- Each cost component will be allocated to residential and commercial sectors based on its contribution to load and the coincident peak

Electricity System – Generation + Storage

+ **Incremental electricity demand will be met by renewable generation in the RGGI PJM states (a combination of 63% solar and 28% onshore wind) and imports from the rest of PJM (9%)**
  - The share of imports from the non-RGGI PJM states are consistent with the 2030 GGRA Plan
  - The share of solar and onshore wind serving the rest of the incremental load is determined based on E3's capacity expansion modeling of PJM East under an ambitious RGGI decarbonization scenario.
  - The cost of generation will be the weighted average LCOE of these resources available in PJM East, based on NREL ATB 2020 mid cost trajectories.

Resource	2021 Cost	Cost Escalation (Real %/yr)
Generation ($/MWh)	$49	-0.56%
Storage ($/kW-yr)	$144	-2.12%

Resource	Marginal ELCC %
Solar + Storage	33%
Wind	13%

+ **Energy storage capacity build will be 4.5% of peak load in 2040 with the build beginning in 2030, consistent with E3 modeling of PJM East under an ambitious decarbonization trajectory.**

+ **Generation capacity needs will be assessed based on the incremental coincident peak load net of the effective load carrying capability (ELCC) of solar + storage, wind and imports to meet the increase in annual load from electrification.**

Electric System - Capacity

+ **Transmission:** Estimated based on a 2019 Brattle Report as $200/kW and levelized using a revenue requirement multiplier of 1.61 and an assumed cost of capital of 7.74%.
+ **Distribution:** Distribution cost estimated based on E3's review of publicly available data on distribution investment and deferral values.
+ **Generation**:
  - Near term value determined by the averaged results of the PJM capacity auction for PEPCO and BGE LDA's ($111/MW-day)
  - Long term values determined as the cost of a greenfield CT.

Component	Cost (2021$/kW-yr)		Cost Escalation (Real %/yr)	Source
	2021-2023	2024-2045		
Transmission Capacity	$28		2.35%	2019 Brattle Report
Distribution Capacity	$40		2.35%	E3 Review of Public Data
Generation Capacity	$41	$90	0.10%	PJM Capacity Auction, Greenfield CT Cost

Modeling Approach – Gas System Cost

- **E3 models both commodity costs and delivery costs for the gas system**
- **Commodity (cost of gas):**
  - $/MMBtu commodity rate will depend on the blend of zero-carbon fuels into the pipeline and the cost to produce biogas, hydrogen and synthetic natural gas
- **Delivery (cost of infrastructure):**
  - Delivery or fixed cost of the gas system will depend on growth or retirement of the system
  - In the case where there is reduced gas throughput due to building electrification and the gas system is not paired down at the same pace, the average $/MMBtu delivery rate must increase to meet system revenue requirement

Gas System

- **Current Maryland gas system delivery costs** were determined based on **EIA reports** of statewide rates and natural gas sales as well as current allocation of delivery costs to customer classes.
- **Delivery cost** consists of **rate base, O&M, depreciation** and **taxes**
- 10-K filings for Baltimore Gas and Electric and Washington Gas Light Company were used to estimate for each delivery cost component the current breakdown and statewide historical annual growth rate.

2019 Total Delivery Cost: $1,023 MM

Class	Allocation
Residential	61%
Commercial	37%
Other	2%

Revenue Requirement Breakdown and Growth

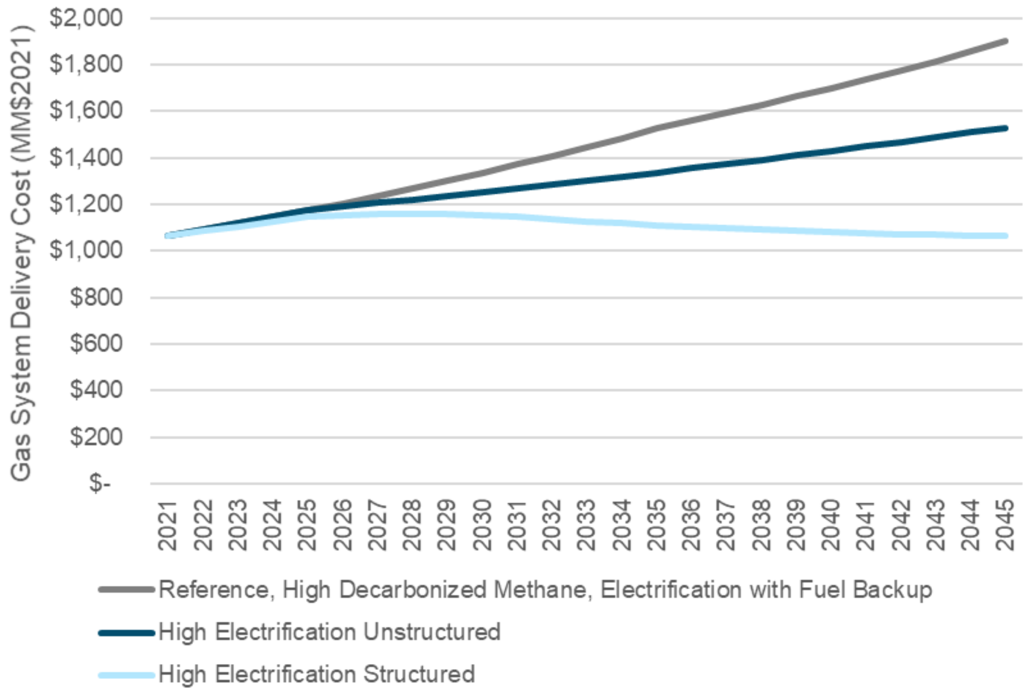
	Share of Current Delivery Cost	CAGR (2016-2020) Nominal %
Rate Base	43%	6.25%
O&M	30%	2.93%
Depreciation	18%	6.58%
Taxes	9%	4.06%

Gas System – Delivery Cost Scenarios

+ In the **Reference, High Decarbonized Methane,** and **Electrification with Fuel Backup** scenarios, the historical growth rates for each component of the delivery cost are assumed to continue into the future except for the rate base growth rate, which is assumed to decline to 3.12% (nominal) starting in 2035 consistent with the STRIDE program.

+ In the **Unstructured High Electrification** scenario, the historical growth rates of all components of the delivery cost are assumed to decline by 50% starting in 2025 due to reduced throughput.

+ In the **Structured High Electrification** scenario:
  - The rate base, depreciation, and taxes growth rates declines to 50% of the historical rate from 2025 to 2030. The rate base, depreciation, and taxes costs remain flat after 2030.
  - Distribution system maintenance is assumed to be 33% of the O&M cost. The growth rate for distribution cost is assumed to decline by 50% of the historical rate from 2025 to 2030 after which the distribution system maintenance cost will remain flat.
  - Administration costs are assumed to be 67% of the O&M cost. Administration costs are assumed to decline by 0.6% per 1% decline in customer base as customers electrify.



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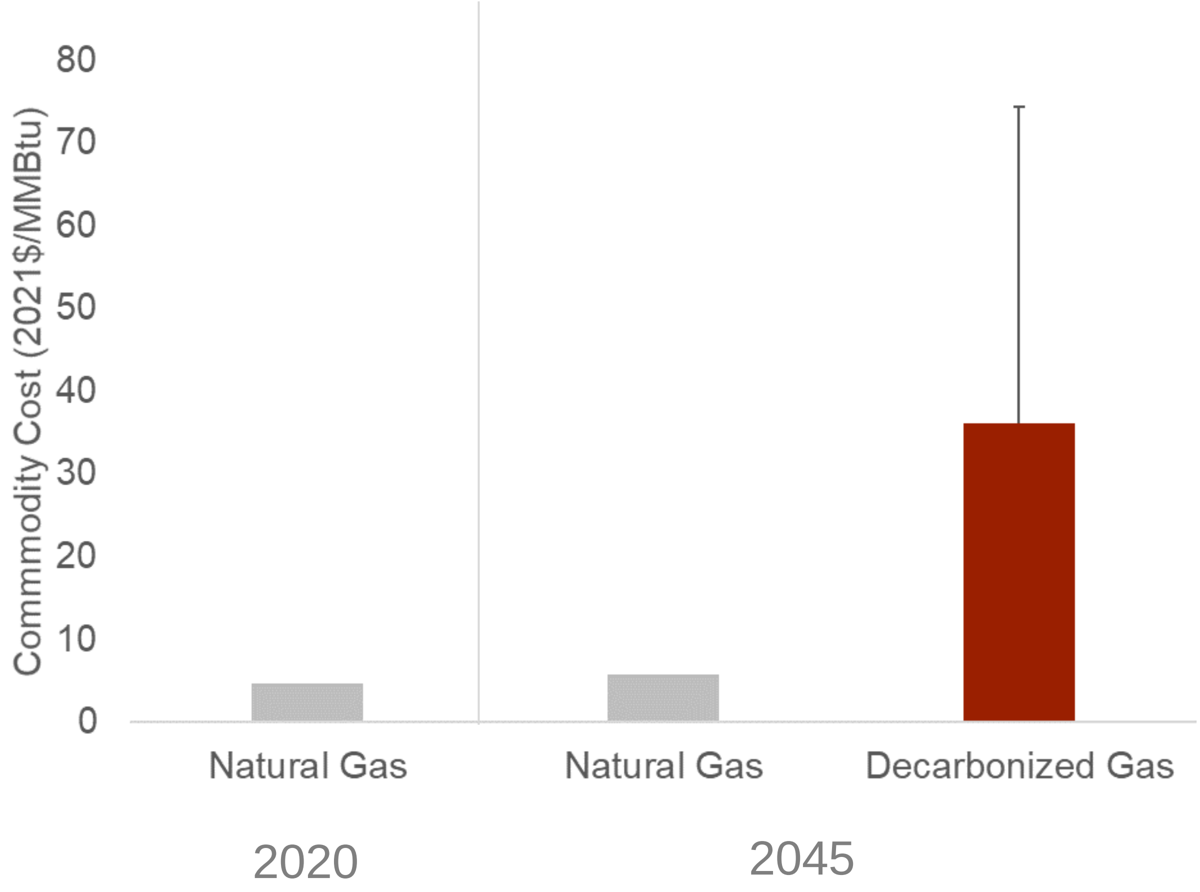
Detail Rate Impact

Commodity costs of gas grow as a result of an increased zero-carbon fuels blend

Average gas commodity costs (2021$/MMBtu)

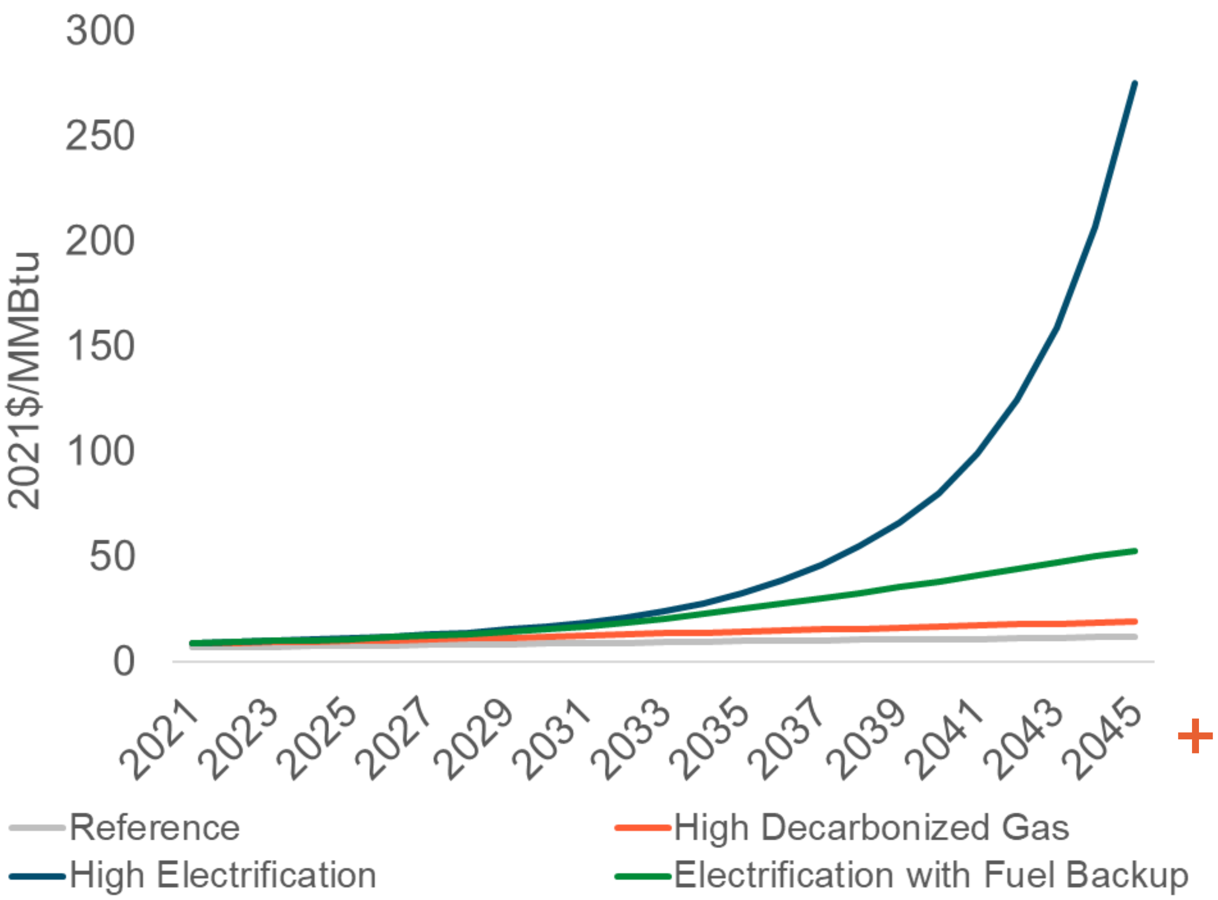


- Commodity costs of gas increase steeply as a result of blending of zero-carbon fuels
- Uncertainty range shows difference between ‘optimistic’ and ‘conservative’ RNG Supply assumptions, resulting in a significant differentiation.
- All scenarios have the same range of commodity costs as the SNG is the marginal resource in all scenarios.

Sources & assumptions: cost assumptions for RNG and hydrogen based on E3’s biofuels module and Hydrogen Production module (see Appendix). Costs in the reference case are based on natural gas prices from EIA AEO 2020.

Delivery costs of gas increase dramatically as more and more households electrify

Residential gas delivery costs (2021$/MMBtu)



+ **High Electrification scenario experiences a rapid increase in per unit delivery costs after 2025 due to the reduced gas throughput, regardless of the fact that total delivery cost is lower than in other scenarios**
  - High Electrification scenario assumes earning on rate base, depreciation, and O&M growth rates halved after 2025 leading to a 25% decline in total delivery costs by 2045.
  - As gas throughput and peak gas demand declines in the High Electrification scenario, reinvestment and maintenance for the gas system are expected to scale down.
+ **Reference, High Decarbonized Gas, and Electrification with Fuel Backup scenarios assume the historical earning on rate base growth rate is halved beginning 2035 assuming STRIDE is completed.**

Sources & assumptions: current Revenue Requirement (RR) is estimated using Maryland specific delivery prices per sector from EIA. Rate base increases are based on historical averages and flat capital expenditures (see Appendix). Scenarios assume a "Business as Usual" allocation of Revenue Requirement to customer groups. Cost allocations might shift as the ratio of consumption changes.

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Building Stock Characterization

Draft Results

Building Stock Characterization: Original Criteria

+ **Objective: Represent and model different customer segments to evaluate consumer economics**
+ **Considerations:**
  - Capital cost is a key driver of consumer economics
  - Equipment type and retrofit efforts are main factors of capital costs

Residential Criteria	Variants
Building Type	Single Family, Multi-Family
Building Vintage	Retrofit New Construction
Existing AC	AC No AC
Existing Equipment – Space Heating	Electric Resistance Natural Gas Fuel Oil
Climate Zone (IECC)	IECC Zone 4A IECC Zone 5A

Commercial Criteria	Variants
Existing System/Vintage/Size	Packaged/window units for heating and cooling (~ smaller/older) Boiler + Chiller (~ larger/newer) New construction
Existing Fuel	Electric Resistance Natural Gas Fuel Oil
Existing AC	AC No AC
Climate Zone	IECC Zone 4A IECC Zone 5A

Building Stock Characterization: Adjustments to criteria

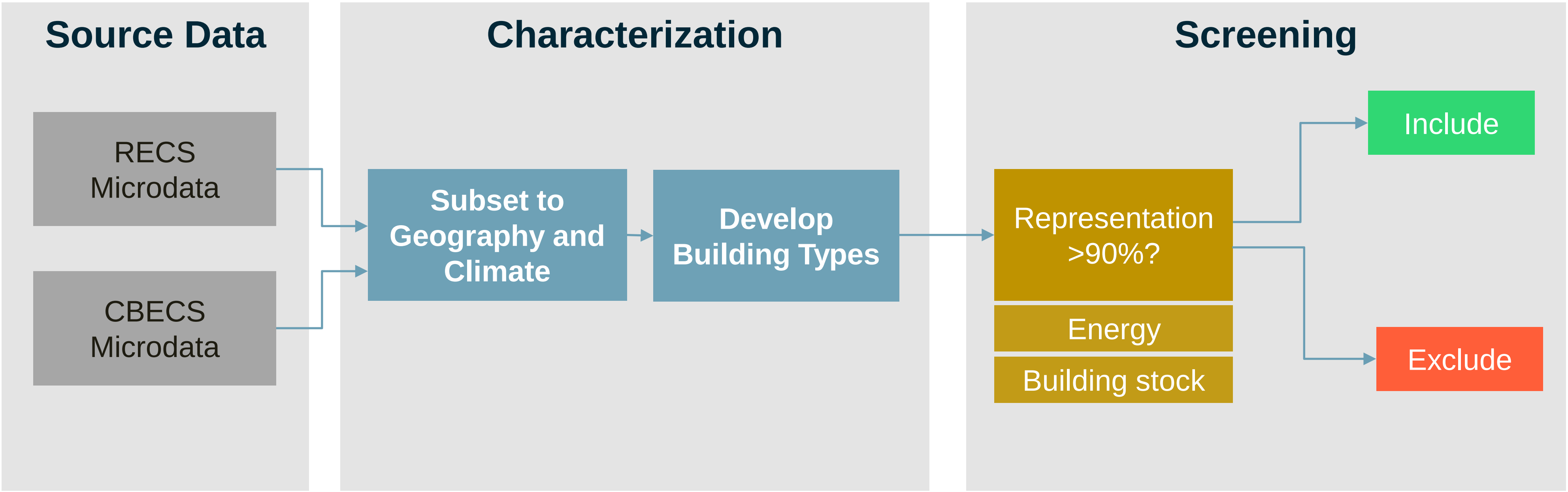
- **Eliminated Climate Zone Criteria** - Zone 5A < 1.5% of population
- **Modified vintaging** – Use RECS/CBECS for reference shell, add assumptions for new construction
- **Refined commercial equipment** – considered existing AC and space heating equipment

Residential Criteria	Variants
Building Type	Single Family, Multi-Family
Building Vintage	Retrofit New Construction
Existing AC	AC No AC
Existing Equipment – Space Heating	Electric Resistance Natural Gas Fuel Oil
~~Climate Zone (IECC)~~	~~IECC Zone 4A~~ ~~IECC Zone 5A~~

Commercial Criteria	Variants
Air Conditioning	**Central AC** **Packaged AC** **Other AC**
Space Heating	**Central SH** **District SH**
Heat Pump	**Heat Pump**
~~Climate Zone~~	~~IECC Zone 4A~~ ~~IECC Zone 5A~~

Building Stock Characterization: Approach

- Develop representative building types based on RECS and CBECS microdata
- Determine average stock share and energy consumption for each building type
- Include most representative building types



Residential Characterization: Representative Building Types

Ten building types selected

- represents 97% of residential households and 98% of residential energy use

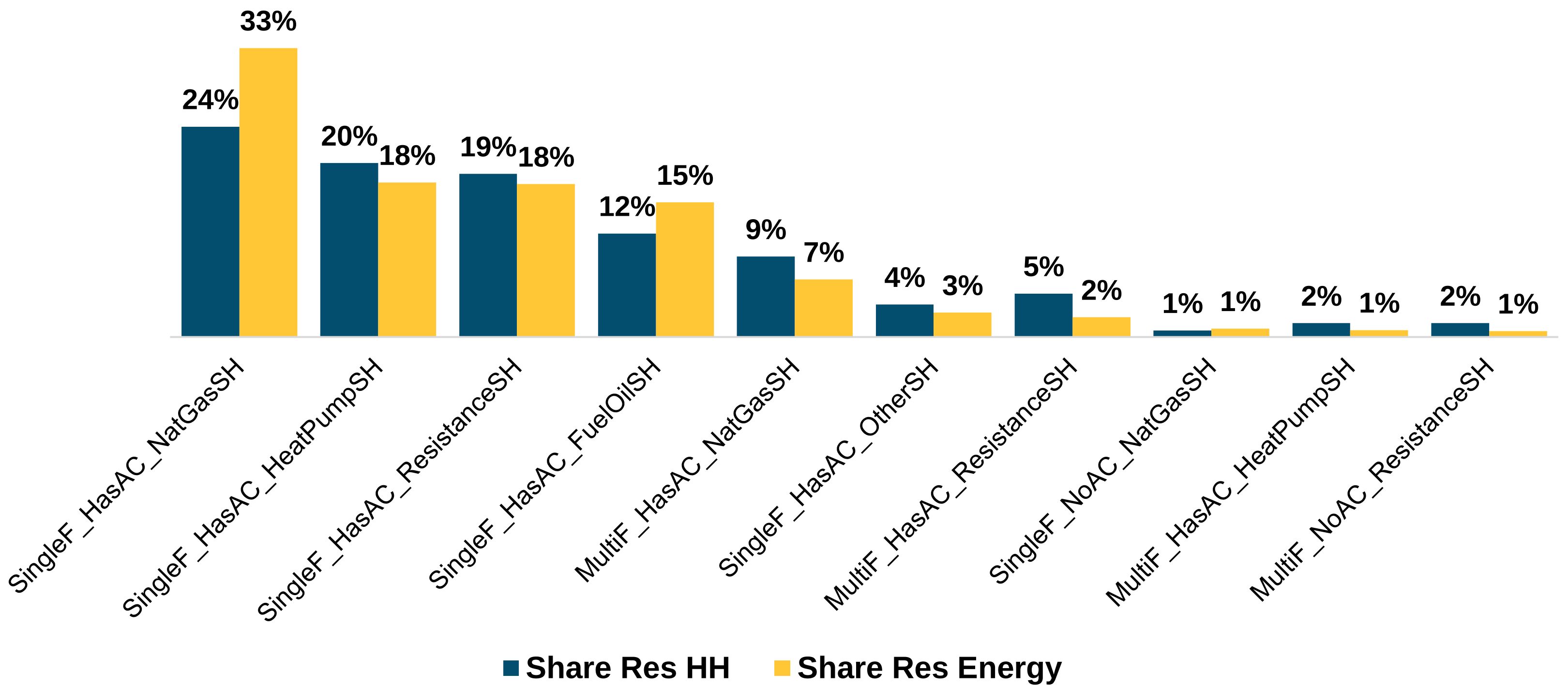
Segment	Single Family		Multifamily	
Space Heating Equipment	**Has AC**	**No AC**	**Has AC**	**No AC**
Electric Resistance	19%		5%	2%
Natural Gas	24%	<1%	10%	
Fuel Oil	12%			
Heat Pump	20%		2%	
Other	4%			
Share of Res Households	**78%**	**<1%**	**17%**	**2%**

Excluded categories represent <4% of total households

= Equipment combination excluded from analysis

Residential Building Stock Characterization

+ **Ten building categories represent the vast majority of residential buildings**
  - > 98% of residential energy use
  - > 96% of residential households



Commercial Characterization: Representative Building Types

+ Five building types selected

- Represent 93% of commercial floorspace and 95% of commercial energy use

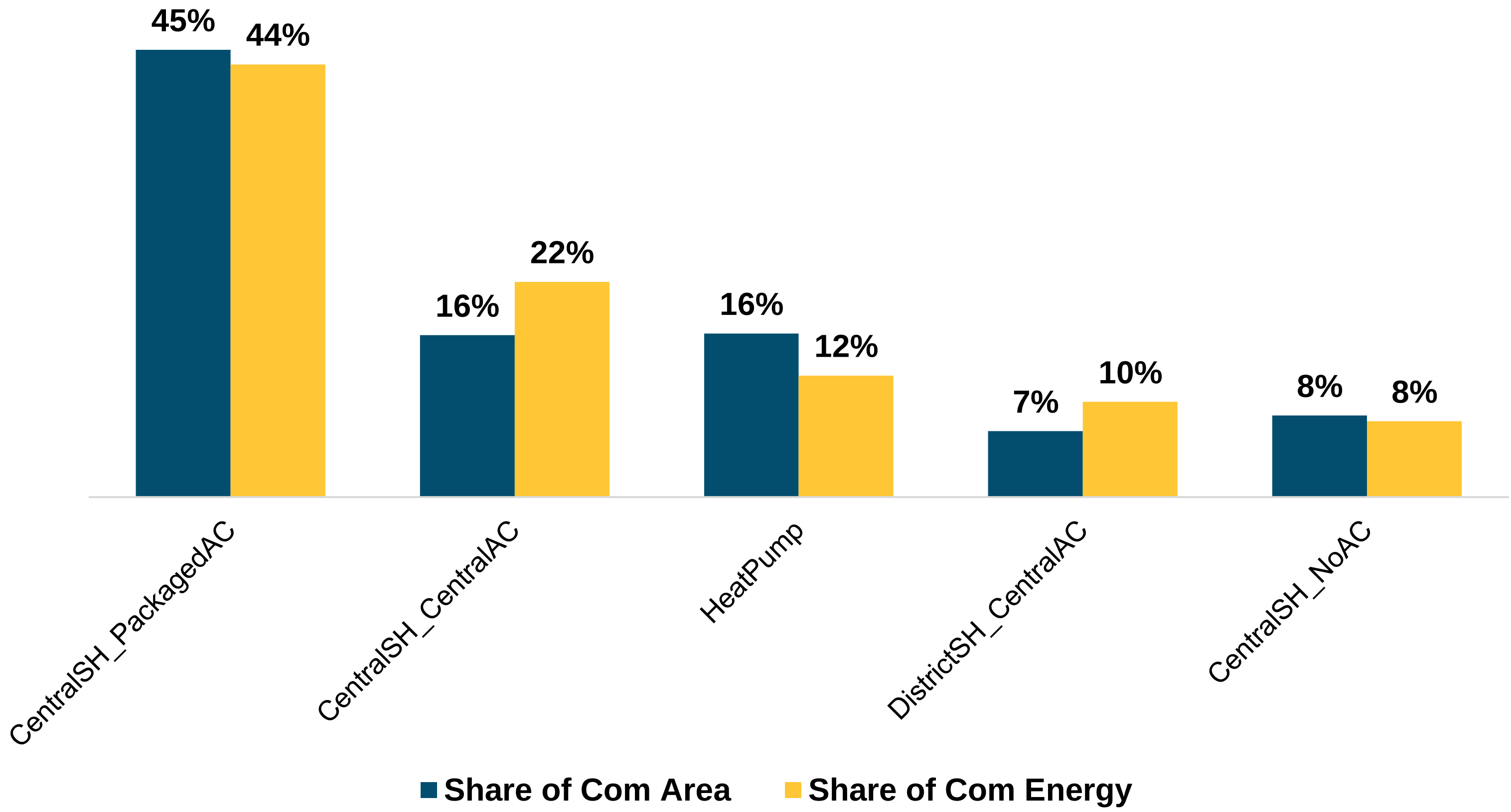
Space Heating Equipment	Central AC	Packaged AC	No AC	Heat Pump
Central Heating	16%	45%	8%	
Heat Pump				17%
District Heating	6%			
Share of Com Floorspace	**22%**	**45%**	**8%**	**17%**

Excluded categories represent < 8% of commercial floorspace

= Equipment combination excluded from analysis

Commercial Building Stock Characterization

+ **Five building categories represent the majority of commercial buildings**
  - > 94% of commercial energy use
  - > 92% of commercial floorspace



Appendix: Residential Building Types

Building Type	Share of Area	Share of Energy
SingleF_HasAC_NatGasSH	24.15%	33.18%
SingleF_HasAC_HeatPumpSH	19.96%	17.74%
SingleF_HasAC_ResistanceSH	18.72%	17.55%
SingleF_HasAC_FuelOilSH	11.87%	15.46%
MultiF_HasAC_NatGasSH	9.22%	6.61%
SingleF_HasAC_OtherSH	3.73%	2.79%
MultiF_HasAC_ResistanceSH	4.97%	2.25%
SingleF_NoAC_NatGasSH	0.74%	0.96%
MultiF_HasAC_HeatPumpSH	1.57%	0.78%
MultiF_NoAC_ResistanceSH	1.58%	0.68%
Totals	**96.5%**	**98.0%**

Appendix: Commercial Building Types

Building Type	Share of Area	Share of Energy	Median Square Feet	Median Annual kBTUs	Median Year Constructed
CentralSH_PackagedAC	44.99%	43.54%	24,000	1,689,634	1988
CentralSH_CentralAC	16.28%	21.66%	205,000	17,333,404	1985
HeatPump	16.46%	12.23%	6,400	418,621	1988
DistrictSH_CentralAC	6.62%	9.58%	282,500	30,916,029	1969
CentralSH_NoAC	8.20%	7.63%	5,900	364,809	1984
Totals	**90.7%**	**94.2%**			

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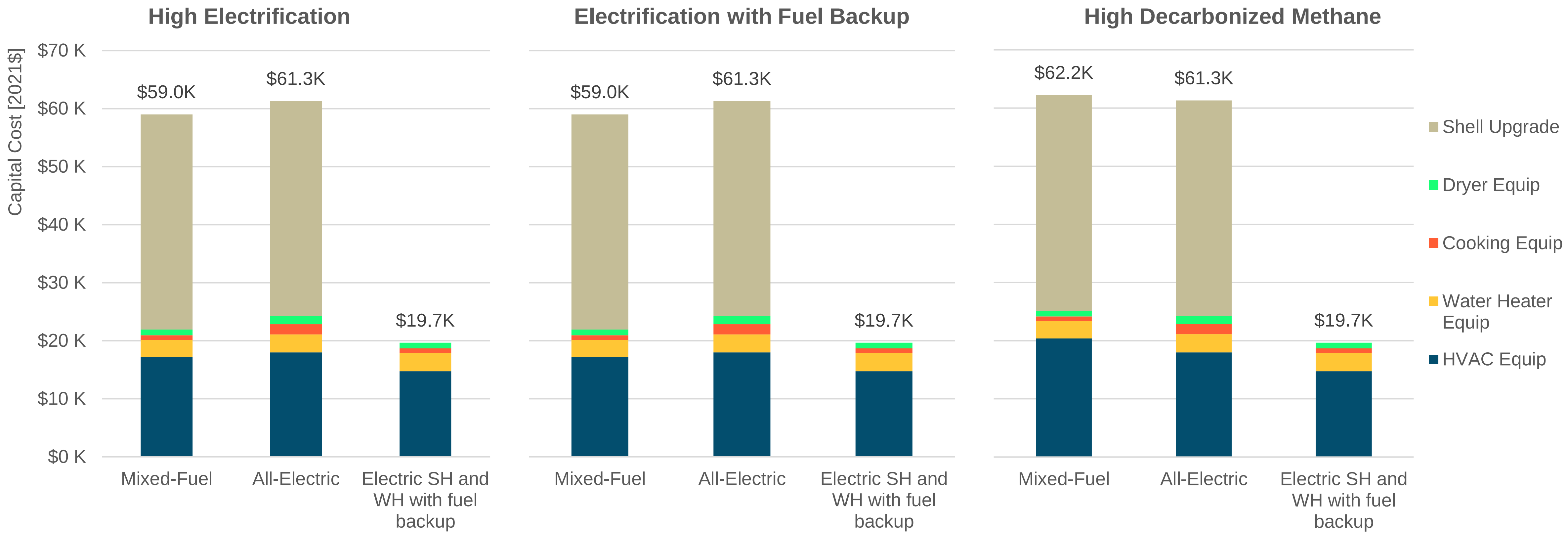
Additional Consumer Cost Results

Draft Results

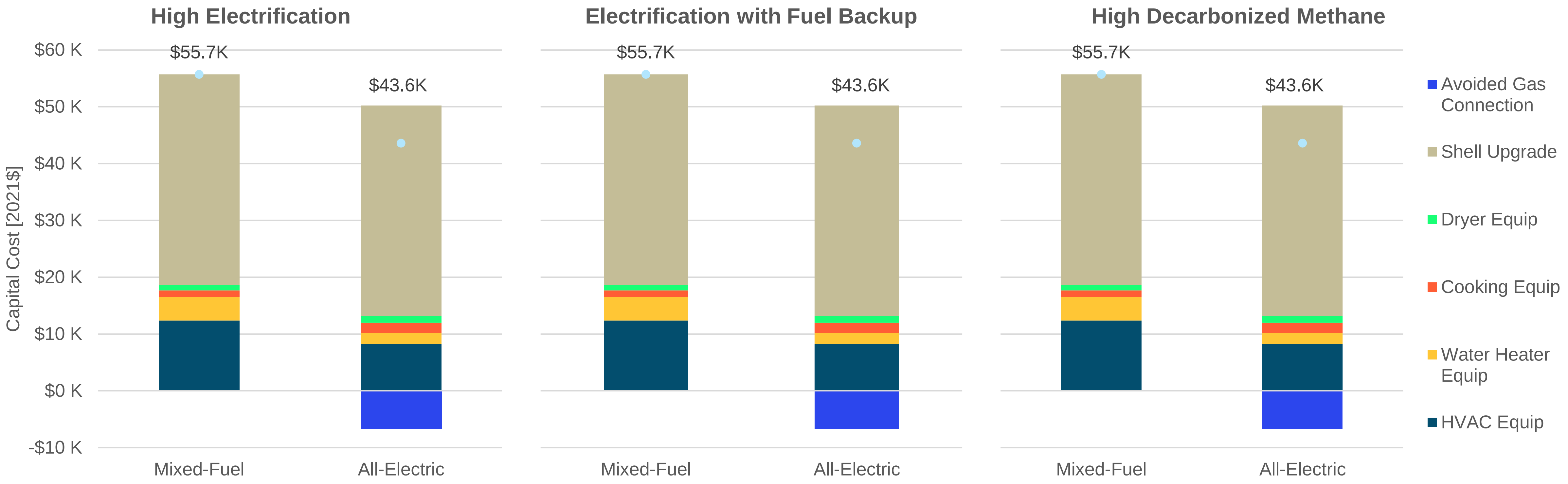
Switching to heat pumps saves costs for both retrofit and new construction residential single-family customers

+ For single-family residential retrofit customers, installing a heat pump instead of a combined high-efficiency gas furnace + A/C system saves upfront cost



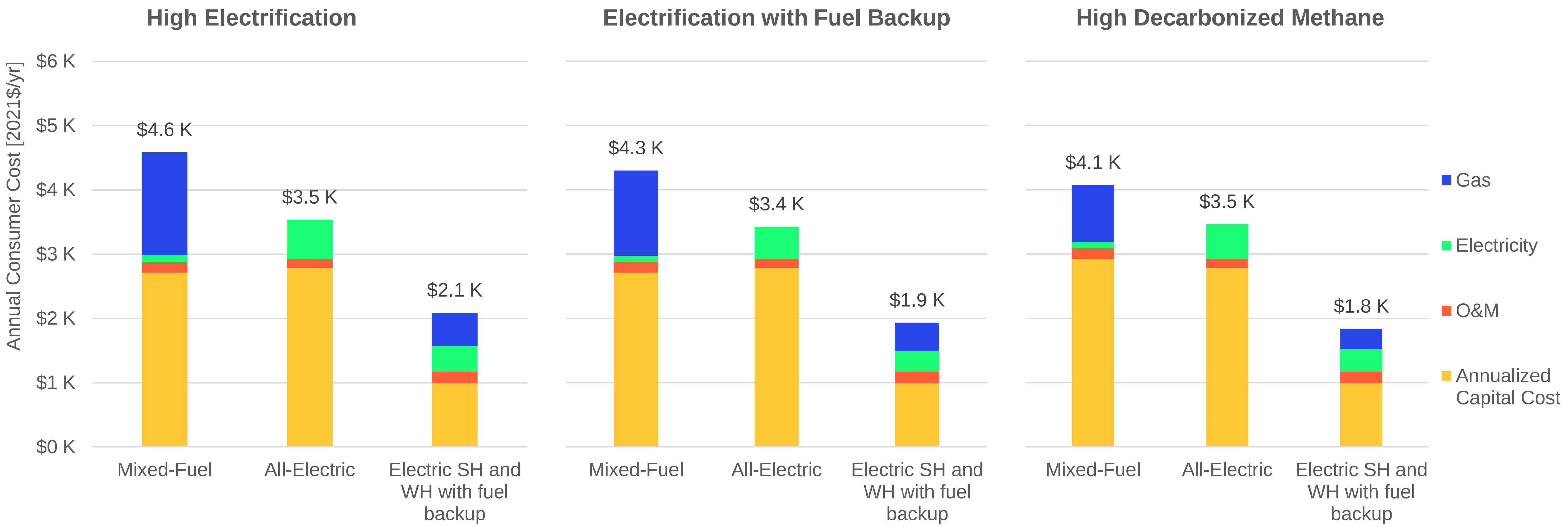
Switching to heat pumps saves costs for both retrofit and new construction residential single-family customers

+ **All-electric new construction buildings are less expensive than mixed-fuel buildings**



Multifamily residential retrofit consumer cost impact

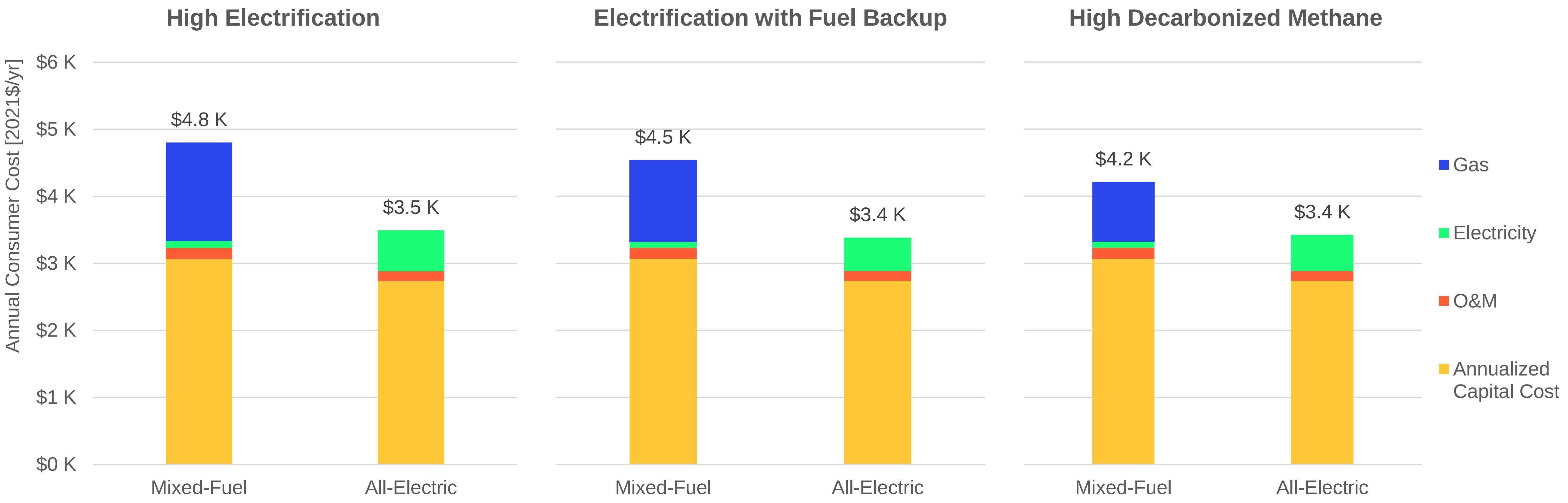
- **“Hybrid” customers can save money by utilizing their existing fuel-based heating equipment to provide backup heating during coldest hours of a year, and by not having to upgrade building shells**



* Gas costs, electricity costs, and equipment costs are based on 2035 rates; Gas costs represent “optimistic” rate scenario (“conservative” gas scenario has 4% higher total cost for mixed-fuel)

Multifamily residential new construction consumer cost impact

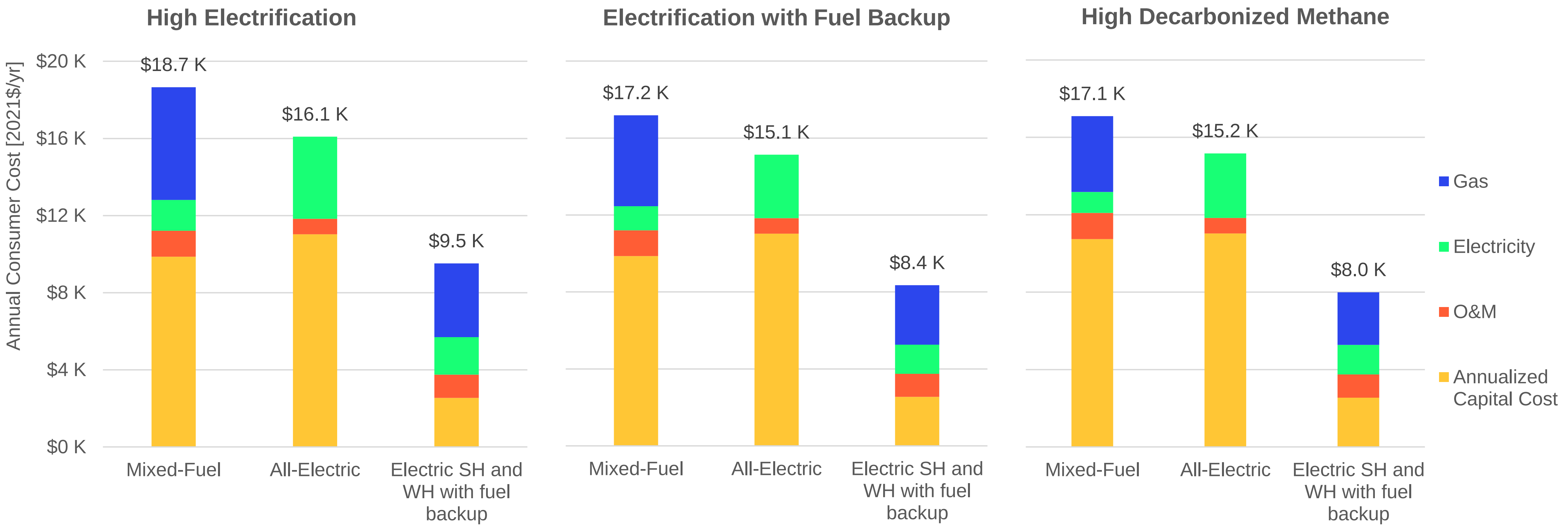
+ **All-electric new construction is cheaper than mixed-fuel new construction for multifamily residential homes across all decarbonization scenarios due to both lower capital (with avoided gas connection) and operating costs**



* Gas costs, electricity costs, and equipment costs are based on 2035 rates; Gas costs represent “optimistic” rate scenario (“conservative” gas scenario has 5% higher total cost for mixed-fuel)

Small commercial retrofit consumer cost impact

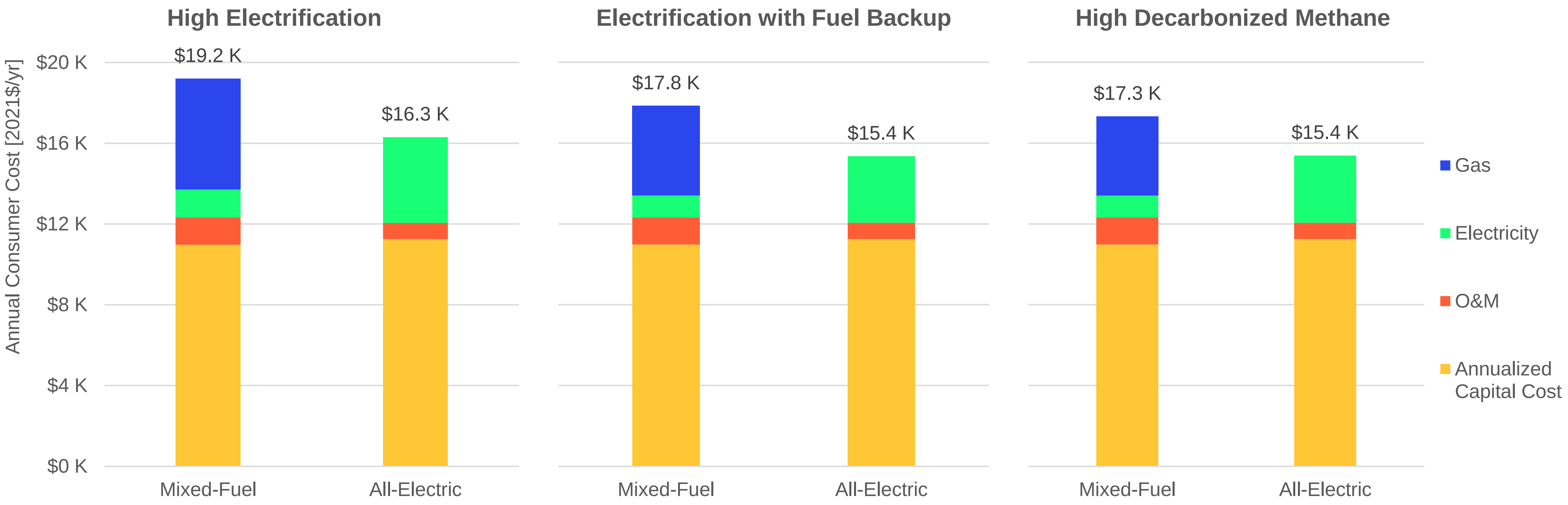
- "Hybrid" customers can save money by utilizing their existing fuel-based heating equipment to provide backup heating during coldest hours of a year, and by not having to upgrade building shells



* Gas costs, electricity costs, and equipment costs are based on 2035 rates; Gas costs represent "optimistic" rate scenario ("conservative" gas scenario has 7% higher total cost for mixed-fuel)

Small commercial new construction consumer cost impact

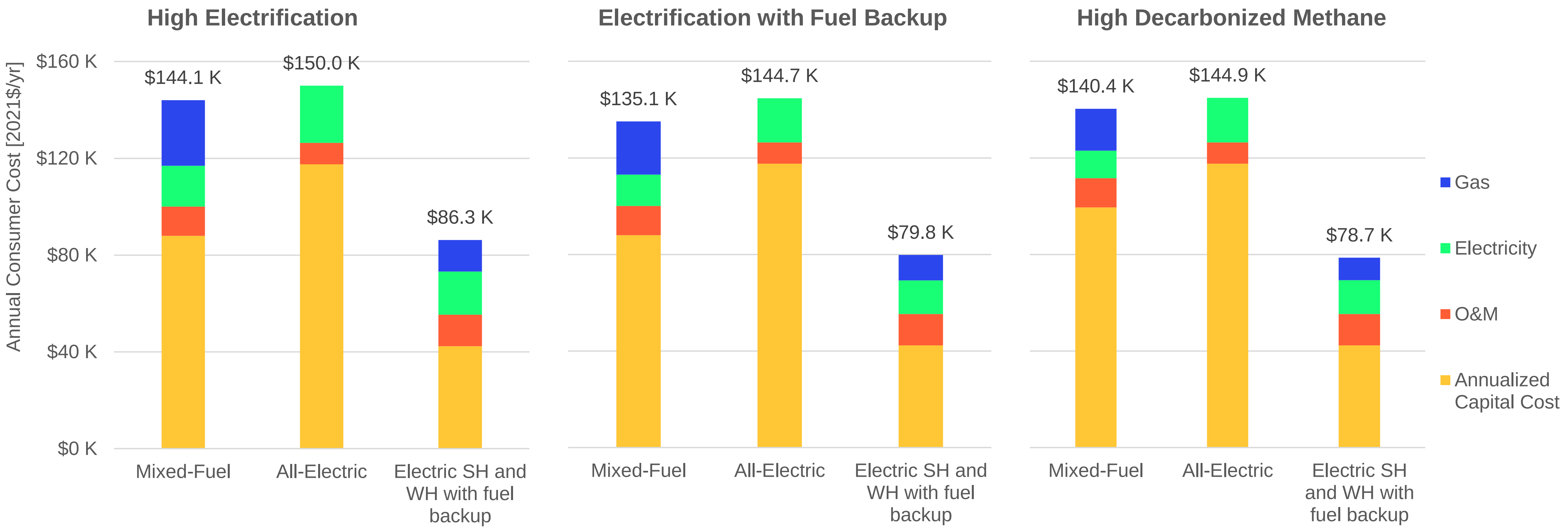
+ **All-electric new construction is cheaper than mixed-fuel new construction for small commercial buildings across all decarbonization scenarios due to both lower capital (with avoided gas connection) and operating costs**



* Gas costs, electricity costs, and equipment costs are based on 2035 rates; Gas costs represent "optimistic" rate scenario ("conservative" gas scenario has 6% higher total cost for mixed-fuel)

Large commercial retrofit consumer cost impact

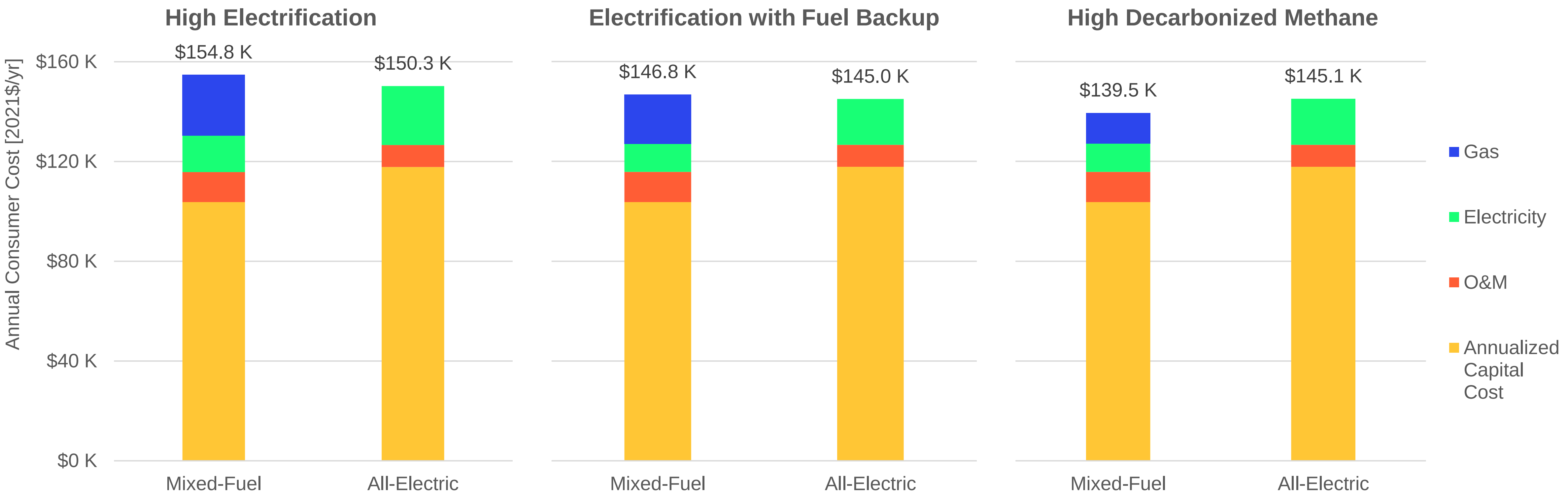
+ **"Hybrid" customers can save money by utilizing their existing fuel-based heating equipment to provide backup heating during coldest hours of a year, and by not having to upgrade building shells**



* Gas costs, electricity costs, and equipment costs are based on 2035 rates; Gas costs represent "optimistic" rate scenario ("conservative" gas scenario has 6% higher total cost for mixed-fuel)

Large commercial new construction consumer cost impact

+ **All-electric new construction is cheaper than mixed-fuel new construction for large commercial buildings in a high electrification scenario and roughly cost neutral in all other decarbonization scenarios; By 2045, all-electric new construction is cheaper in every scenario**



* Gas costs, electricity costs, and equipment costs are based on 2035 rates; Gas costs represent “optimistic” rate scenario (“conservative” gas scenario has 4% higher total cost for mixed-fuel)