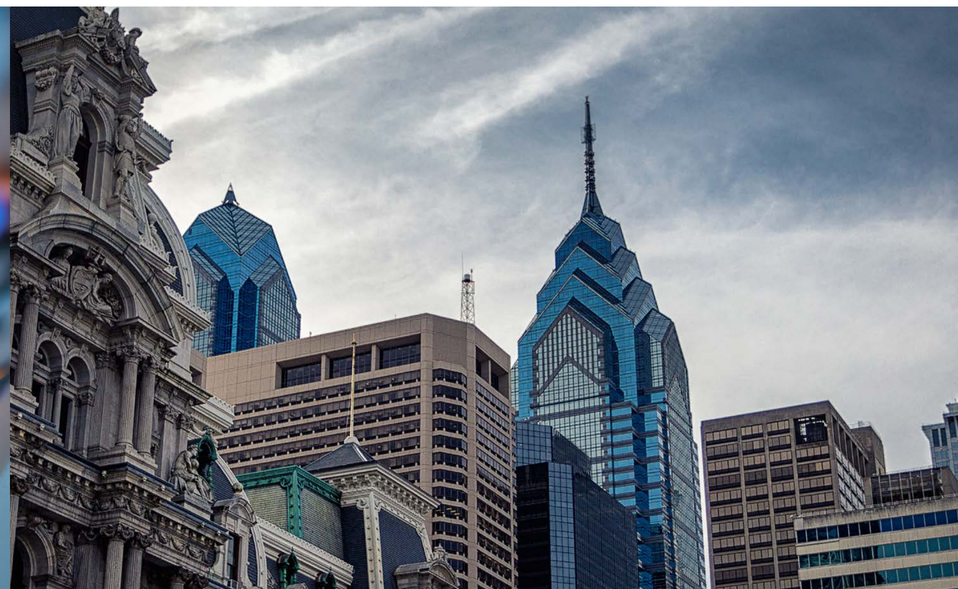
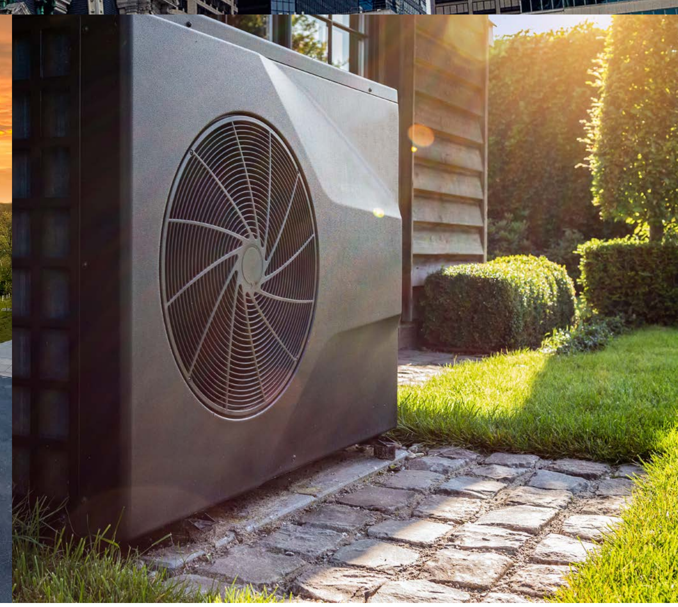
ERM REPORT

Long-Term Vision Analysis: Mid-Atlantic





Contents

List of Tables

List of Figures

Acronyms and Abbreviations

ASHP	Air source heat pump
ASHP+NG	Air source heat pump and natural gas; dual fuel
CO_2	Carbon dioxide
CO_2e	Carbon dioxide equivalent
COP	Coefficient of performance
Dth	Dekatherm
Gas HP	Gas heat pump
GHG	Greenhouse Gas
GSHP	Ground source heat pump
GW	Gigawatt
H_2	Hydrogen
IRA	Inflation Reduction Act
LDC	Local distribution company
M-H_2	Methanated Hydrogen
MMBtu	Million British thermal units
MT	Metric tons
mtCO_2e	Metric ton of carbon dioxide equivalent
MW	Megawatt
MWh	Megawatt hour
NG	Natural gas
NYISO	New York ISO
PJM	Pennsylvania-New Jersey-Maryland Interconnection
RNG	Renewable natural gas
T&D	Transmission and distribution
TBtu	Trillion British thermal units
^oC	Degrees Celsius
^oF	Degrees Fahrenheit

About this Paper

This paper was prepared based on engagement with the Downstream Natural Gas Initiative members and external advisors. It reflects the analysis and judgement of the ERM authors alone.

Brian Jones, Emily O'Connell, James Saeger, Kevin Davis, and Rachel MacIntosh of ERM made important contributions to this paper.

About the Downstream Natural Gas Initiative

The Downstream Natural Gas Initiative (DSI) is a group of leading natural gas utilities collaborating to build a shared vision for the role of utilities and the gas distribution network in the transition to a low-carbon future. DSI is facilitated and managed by ERM.[1]

DSI is focused on opportunities to leverage the existing gas infrastructure to support near- and long-term environmental and economic goals and to address key technical and regulatory challenges related to these goals and opportunities.

Through this collaboration, DSI is advancing a Long-Term Vision and related strategies for natural gas utilities to reduce greenhouse gas emissions and support economy-wide emission reductions.

For more information on DSI and its members, please visit https://www.erm.com/coalitions/downstream-natural-gas-initiative/.

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DSI's Long-Term Vision

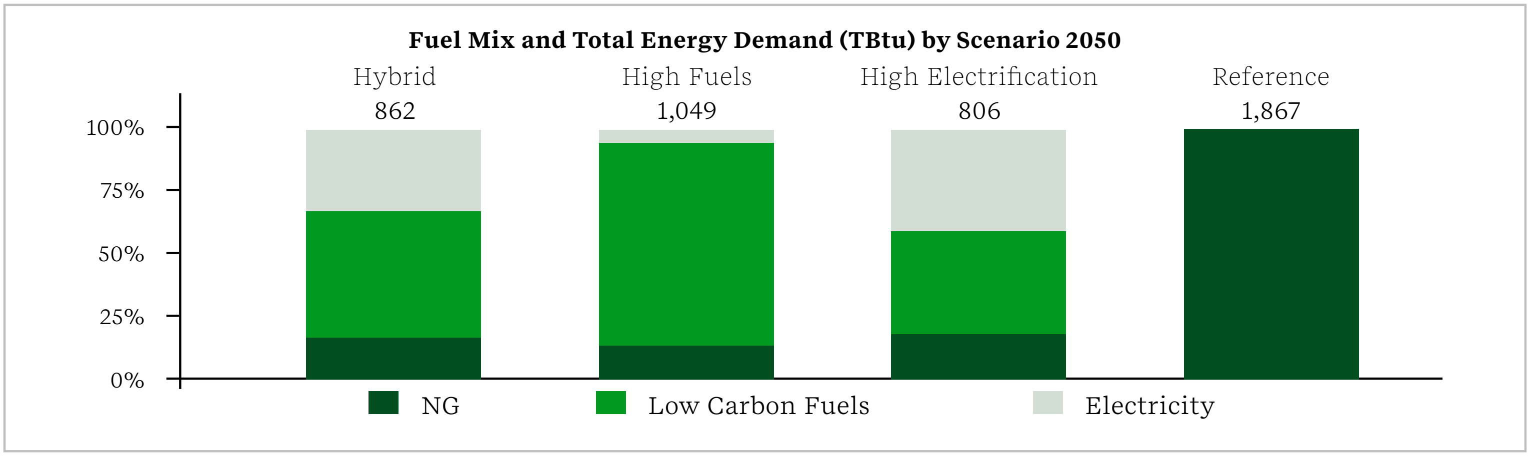
Local distribution companies (LDCs) have a critical role to play in helping local, state, and federal governments meet greenhouse gas (GHG) emissions targets while maintaining safe, reliable and cost-effective energy service.[2] This analysis takes a closer look at how building decarbonization targets can be achieved through different emission reduction scenarios and finds that strategies that pair gas and electric system decarbonization solutions offer the most cost-effective pathway. Specific focus is directed at the energy requirements needed to meet winter heating demand, which vary drastically across the country, and can have consequential impacts on a region's emission abatement opportunities and associated costs. This analysis underscores how important regional considerations are in designing and implementing climate policies and offers utilities and policymakers greater insight into localized costs associated with different building decarbonization solutions.

[1] M.J. Bradley & Associates (MJB&A) was acquired by ERM in March 2020.
[2] M.J. Bradley & Associates, an ERM Group Company, The Role of Gas Networks in a Low-Carbon Future, December 2020. Available at https://mjbradley.com/reports/role-natural-gas-networks-low-carbon-future.

Summary of Findings

This study provides an in-depth analysis of system-wide cost impacts for decarbonizing natural gas end-uses in the three states of the US Census Middle Atlantic division (New Jersey, New York, and Pennsylvania). The study explores three Long-Term Vision (LTV) scenarios — Hybrid, High Fuels, and High Electrification—that achieve emission reductions of just over 90% by 2050 using a mix of decarbonization strategies. This report summarizes the results of the analysis for the three scenarios, detailing energy system impacts, infrastructure requirements, and associated costs for utilities and their customers in the Mid-Atlantic region. This is the second regional analysis released as part of DSI's LTV series.[3]

Figure 1: Scenario Modeling Results Summary



Scenario Results Summary, 2050	Hyrbid	High Fuels	High Electrification	Reference
Change in CO_2e Emissions by 2050 *(% from 2020 base)*	-92%	-92%	-92%	+3%
Total Energy Demand in 2050 *(TBtu)*	862	1,049	806	1,867
Customers on Gas System in 2050 *(in millions)*	9.9	10.9	2.7	11.8
New Electric System Capacity Required by 2050 *(GW)*	21	NA	56	NA
Annualized Cost in 2050 *(2022$ billions)*	$54	$73	$66	$33
Cost premium percentage over Reference	62%	119%	98%	NA

Key finding:
This study finds that the most achievable, cost-effective, and reliable paths to decarbonize natural gas end-uses in the Mid-Atlantic region are those that optimize the range of available strategies, including energy efficiency, decarbonized fuels, and electrification. The Hybrid Scenario, which leverages decarbonization solutions across gas and electric systems, is the least costly path examined to decarbonize natural gas end-uses.

[3] The first regional analysis on New England can be found here: https://www.erm.com/contentassets/65dcaedb758f44358d835eeb4152ada4/dsi-long-term-vision-new-england-report.pdf

The study's scope covers emission reductions associated with fossil natural gas consumption in the residential, commercial, and industrial sectors. As discussed in the DSI LTV regional analysis for New England, decarbonizing natural gas end-uses is highly dependent upon regional conditions. The interplay of factors such as customer mix and demand, climate, building stock, electric grid capacity mix, and seasonal heating demand create unique needs that require regionally-specific approaches to achieve reliable and cost-effective emissions reductions. The three distinct scenarios envision a range of fuel mixes and equipment deployments to test the impact of different technology options on energy consumption, emissions reductions, and system costs. A reference case, following historical trends of steady growth in conventional gas use and associated emissions provides a baseline for comparison.

Additional findings:

- Employing a portfolio of decarbonization strategies can lower the costs of achieving climate goals and can reduce the risks to achieving them, including over-reliance on a single strategy or energy system.
- Energy efficiency is among the most cost-effective decarbonization measures available today.
- Dual-fuel (electric and gas) heating strategies are a cost-effective method to achieve significant building sector emissions reductions in the Mid-Atlantic.
- Decarbonized fuels are an effective and scalable strategy when used in buildings for meeting winter peak heating demand in cold weather climates and for other difficult-to-electrify uses like industrial processes.

Each of the decarbonization scenarios incurs higher total costs than the Reference scenario, which is projected to have $33 billion in annualized costs in 2050. The Hybrid scenario is projected to be the least-cost decarbonization path, at $54 billion in annualized costs in 2050, 62 percent higher than those projected for the Reference scenario in that year. The High Fuels scenario is projected to cost $73 billion annually by 2050, a cost premium to the Reference scenario of 119 percent, and the High Electrification scenario is projected to cost $66 billion in annualized costs, 98 percent greater than the Reference scenario.[4] While some of these costs may be socialized with tax and other federal incentives, most of the costs would ultimately be passed on to ratepayers in the form of higher bills.

Across all scenarios, building energy efficiency (weatherization) improvements lead to declines of just over 20 percent, relative to the Reference case, in customer energy demand and the associated emissions. Additional energy demand reductions are driven by improvements to end-use equipment efficiency.[5] Conversion of end-use customers from conventional gas-fired heating appliances to high-efficiency electric and gas appliances is a primary mechanism by which each scenario achieves emission reductions by 2050.

All of the decarbonization scenarios rely on some level of low-carbon fuels to drive emission reductions by displacing fossil natural gas. The volume of fossil natural gas declines to 145 TBtu across all scenarios, representing between 14% percent and 16% percent of total 2050 energy demand. Low-carbon fuels make up the remainder of gases delivered to customers through the gas distribution systems., and electricity makes up the rest of total energy consumed. The low-carbon fuels include renewable natural gas (RNG), hydrogen (H2), and methanated hydrogen[6] (M-H2). The mix depends on a given scenario's demand for fuels, the projected cost and availability of the fuel types, and expected ability to blend into a gas distribution system. The actual future cost-effectiveness and use of low-carbon fuels will depend on several variables such as feedstock availability and pace of technological development.

[4] Total costs represent all costs to decarbonize current natural gas end use, excluding gas used by electric generators. Costs include gas cost of service, energy efficiency, customer equipment, low carbon fuels, electricity, and electric system.

[5] Most of the equipment efficiency gains are the result of replacing traditional gas-fired furnaces with highly efficient air source heat pumps (ASHPs) and ground source heat pumps (GSHPs). Depending on the scenario, there are additional efficiency gains from deployment of gas heat pumps replacing older, less efficient equipment.

[6] Methanated hydrogen, also known as power to gas, is a process of converting renewable energy into hydrogen then processing it with CO_2 to create a syngas of primarily hydrogen and carbon monoxide, which can be processed over a catalyst to make CH4 to be used directly in existing conventional natural gas pipeline infrastructure.

In the moderately cold-weather climate of the Mid-Atlantic, the winter peak electric demand created by the electrification of building space heating on the coldest days of the heating season can be a significant driver of costs. These electric system costs include investment in new generation capacity as well as transmission and distribution (T&D) upgrades to serve the increasing electric demand. The analysis shows that decarbonization approaches which avoid rapid increases in the electric winter peak demand over the medium- to long-term are more cost-effective. Such strategies include building sector heating that relies on a dual-fuel or hybrid model: electrified heating with highly efficient air source heat pumps (ASHP) is deployed when most efficient, while decarbonized gas-fired space heating, using low-carbon fuel blends, serves customers during the coldest temperatures of the winter heating season. In the Hybrid scenario, dual-fuel buildings shift from their electrified heating to gas-fueled heating when the outdoor air temperature drops to a 20 degrees Fahrenheit (ºF) crossover point.

Comparing the costs and use of ASHPs between the Hybrid and the High Electrification scenarios on a per metric ton of reduction basis highlights one of the key findings of this analysis: air source heat pumps can be among the most cost-effective strategies for the decarbonization of natural gas end-uses. ASHP's cost-effectiveness, however, depends on limiting their impact on the electric grid: equipment efficiency (and cost-effectiveness) declines as temperatures drop, driving winter peak electric demand on the grid to exceed projected peak summer demand. The transition from summer peaking to winter peaking would thus create the need for significant and costly new electric resources.

Customer impacts vary across scenarios. In the High Fuels scenario, 10.9 million customers are served by the gas network in 2050, compared to the 10.6 million customers served today, while the High Electrification scenario shifts 77 percent of these customers to the electric network. The Hybrid scenario retains 9.9 million customers.

All-customer average utility rates in the decarbonization scenarios would need to increase substantially by 2050, relative to the Reference scenario, due to a combination of decreased gas throughput and higher commodity costs for low-carbon fuels. Rapid migration of customers away from the gas system creates a risk of burdening remaining customers who are slower to convert, or who cannot, including many economically vulnerable residential customers. The energy transition is likely to require a thorough redesign of rate structures to moderate impacts and distribute system costs differently across customers and customer classes. Decarbonizing natural gas end-uses in the building sector will incur costs regardless of the pathway chosen. However, pathways that leverage existing gas networks to deliver decarbonized fuels in combination with electrification solutions represent the least costly pathways to achieving building sector decarbonization.

Background and Mid-Atlantic Regional Overview

Local, state, provincial, and federal levels of government across North America have set aggressive economy-wide climate and clean energy goals. Most of these targets are economy-wide, focusing not only on the power sector, but on emissions from the industrial sector, building sector (spanning both residential and commercial), and transportation sector.[7] Within the U.S., 24 states have set these economy-wide targets where each target and emissions baseline year are specific to the needs of each state.[8] The relevant policies in New Jersey, New York, and Pennsylvania are listed in Table 1.

As a step toward implementing these policies, several state and local governments have undertaken economy-wide decarbonization pathway studies. Most of these studies have explored the role of both electricity and gas systems in achieving net-zero emissions targets.[9] Table 1 also summarizes these planning studies. In two of the Mid-Atlantic states, New York and New Jersey, decarbonization discussions have focused particularly on whether to transition the building

[7] Center for Climate and Energy Solutions, State Climate Policy Maps, Available at https://www.c2es.org/content/state-climate-policy/.
[8] Ibid.
[9] The New York State Public Service Commission adopted gas planning procedures requiring natural gas utilities to submit plans that comply with the State's greenhouse gas emission reduction goals.

and industrial sectors to electrified solutions with a limited role for the gas networks. While many of these policy and planning efforts are in the early stages, the need to evaluate the role of existing electricity and gas networks in transitioning toward net-zero climate goals will be critical in developing a safe, reliable, equitable and cost-effective energy future.

Table 1: Key Climate and Energy Policies in Mid-Atlantic

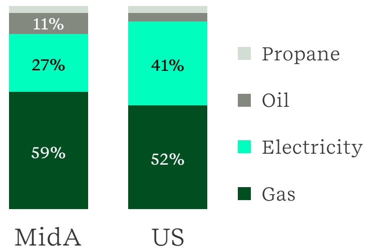
State	GHG Emissions Reduction Targets	Renewable Portfolio Standards (% of electricity sales)	Key Policies
New Jersey	80% below 2006 levels by 2050.	35% by 2025 and 50% renewable energy by 2030.	Global Warming Response Act (GWRA) (2007): set GHG emission targets. Clean Energy Act (2018): Expanded renewable energy targets. Executive Order No. 100 (2020): Regulatory changes to facilitate GHG emission reductions. Executive Order No. 316 (2023): Electrifying 400,000 residential and 20,000 commercial buildings by 2030. Executive Order No. 317 (2023): Directs the New Jersey Board of Public Utilities (BPU) to plan for the future of natural gas utilities in the state. Member of Regional Greenhouse Gas Initiative (RGGI)
New York	40% below 1990 levels by 2040 and 85% by 2050.	70% renewable electricity by 2030 and 100% zero-emission by 2040.	Climate Leadership and Community Protection Act (CLCPA) (2019): GHG emission and clean energy targets. Member of Regional Greenhouse Gas Initiative (RGGI)
Pennsylvania	26% below 2005 levels by 2025 and 80% by 2050.	8% Tier I renewables and 10% Tier II by 2021.	Climate Change Act (2008): Compile state GHG inventory and other activities, no targets. Executive Order 2019-01 (2019): Set GHG reduction targets for 2025 and 2050 (see at left) Member of Regional Greenhouse Gas Initiative (RGGI): Participation stalled by litigation.

Relative to national averages, the Mid-Atlantic has characteristics that present important considerations for rapid decarbonization:

Building Stock[a]: Older than National Average

Approximately 60 percent of residential and commercial buildings were built before 1970 with a third constructed prior to 1950. An older building stock provides opportunities to improve building envelope energy efficiency, however, deep energy efficiency retrofits may not be technologically feasible or cost effective.

Building Space and Water Heater Fuel



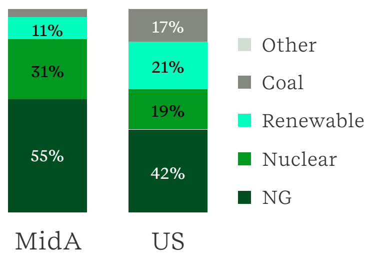
Building Sector[a]: Low Reliance on Electricity for Heat

The Mid-Atlantic is a moderately cold climate region where natural gas is the dominant energy source for residential and commercial space and water heating, accounting for 59 percent of energy consumption. Electricity accounts for 27 percent of residential and commercial space and water heating energy consumption.

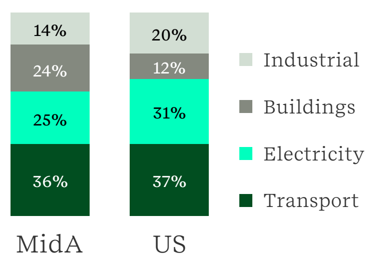
Power Sector[b]: High reliance on natural gas and nuclear

The Mid-Atlantic electricity generation mix is predominantly natural gas and nuclear (55 percent and 31 percent, respectively) and renewables (11 percent). Coal dropped to 3% of the generation mix in 2023. In recent years, electricity demand is met with increased generation from natural gas-fired plants and growth in new renewable generation. A low carbon transition will require emissions reductions from the current electricity mix, while adding more zero-emitting capacity to the system as demand increases due to electrification of end-uses.

Electric Generation Mix



Total CO_2 Emissions from Fuel Consumption



CO_2 Emissions by Sector[c]: Higher emissions from buildings

Fuel use in residential and commercial buildings result in a greater share of emissions in the MidAtlantic compared to the U.S. overall, largely because of cold weather heating. Fossil natural gas accounts for nearly all emissions from the MidAtlantic power sector, while combusting this fuel accounts for roughly 24 percent of emissions from use in buildings.

Data Sources

a. EIA Residential Energy Consumption Survey, 2020 Survey Data.; EIA Commercial Building Energy Consumption Survery, 2018 Survey data.
b. EIA Electricity Data Browser, Net Generation for All Sectors, 2023 data.
c. EIA Energy-Related State CO_2 Emissions, 2021 data.

Analysis Methodology

Analysis Scope

A central feature of this study is the focus on how emission reduction strategies associated with existing natural gas end-use impacts the wider energy system. This focus drives the scenario design to include a range of fuels and end-use equipment deployments to analyze the impacts on energy demand, emission reductions, and electric and gas network costs in 2050.

Reducing end-use emissions from the combustion of fossil natural gas relies on several strategies[10], including:

- Reducing energy demand,
- Meeting energy demand with low- and zero-carbon alternatives, and
- Switching demand to other low-carbon energy sources.

The resulting scenarios for the Mid-Atlantic region—Hybrid, High Fuels, and High Electrification—deploy these strategies in different configurations while exploring a range of challenges and costs posed by each path.

DSI members recognize that the efforts of LDCs to decarbonize are necessarily utility-specific, differing from the illustrative paths discussed here, and are part of a wider decarbonization effort across the economy.

Scenarios Analyzed

The analysis develops three decarbonization scenarios and a reference scenario described in Table 2. The Reference scenario represents business as usual fossil natural gas usage, while the three decarbonization scenarios achieve carbon-neutrality with greater than 90 percent reductions in carbon dioxide (CO_2) emissions from 2020 levels.[11]

Table 2: Modeled Scenarios

Scenario	Description
Hyrbid	**Hybrid or dual-fuel approach;** Building energy efficiency, electrification, and decarbonized fuels together reduce GHGs. Most building heating is served with a dual-fuel strategy of ASHPs and gas-fired furnaces with some GSHPs and gas heat pumps (GHPs). ASHPs operate during most of the heating season while heating switches to gas on the coldest days. The gas distribution network meets peak energy demand on those coldest days.
High Fuels	**High levels of decarbonized fuels;** Low-carbon fuels such as renewable natural gas (RNG) and hydrogen blends drive this approach with efficient GHPs serving as the primary building heating strategy. Existing gas distribution networks play a larger role in delivering decarbonized fuels. This scenario includes building energy efficiency but has minimal electrification of current gas end-use.
High Electrification	**High levels of electrification;** Most buildings electrify with ASHPS and GSHPs, significantly increasing demand on the region's electric grids. Building energy efficiency helps reduce demand; decarbonized fuels play a minimal role except in industrial applications. Use of gas distribution networks decline heavily as most residential and commercial customers convert from gas to electricity.
Reference	**Business as usual projection of current energy system;** Does not achieve economy-wide carbon neutrality by 2050.

[10] Carbon capture, utilization, and storage (CCUS) is a potentially viable strategy that is not analyzed as part of this study. Deployment and cost data are less well understood than those of the other strategies. As data improve, this strategy will warrant further study.

[11] The scope of this study is focused on the reduction of current emissions associated with consumption of fossil natural gas, excluding gas used to power large electric generating facilities. To achieve carbon neutrality in 2050 for this scope, remaining emissions are assumed to be addressed through carbon removal and/or carbon capture.

The High Electrification and High Fuels scenarios examine decarbonization paths that rely heavily on a single strategy: fuel switching in the case of High Electrification and low-carbon gas alternatives in High Fuels. The Hybrid scenario balances the two strategies.

Modeling Approach

These scenarios were developed and analyzed using ERM's proprietary Downstream Natural Gas Decarbonization Scenario model (DNG-Decarb). The set of tools comprising the integrated model consider the impact of different reduction strategies on current gas customers and on the utility business model.

Below is a brief overview of the analytical approach. A separately issued report will provide a more detailed discussion of the analytical assumptions and methodology. Table 3 illustrates the key inputs and outputs of the scenario modeling.

Table 3. Scenario Modeling - Key Inputs and Outputs

Key Inputs	Key Outputs
■ Regional customer natural gas demand. ■ Heating equipment costs and efficiency improvements. ■ Fuel commodity costs for conventional natural gas, renewable natural gas, clean hydrogen, and methanated hydrogen (synthetic natural gas). ■ Electric generation capacity costs and transmission & distribution costs for incremental capacity additions.	■ Carbon dioxide emissions associated with building sector natural gas use. ■ Energy demand and customer counts by type: fossil natural gas, alternative fuels, and electricity. ■ Total costs for decarbonizing buildings sector natural gas use (costs for natural gas service, energy efficiency, end-use appliances, fuels, electric system, and electricity).

Inflation Reduction Act Considerations

On August 16, 2022, President Biden signed into law the Inflation Reduction Act (IRA), a legislative package with key provisions focused on reducing energy costs and addressing climate change. This study works to incorporate economic impacts from relevant changes from this Act, though actual implementation of the IRA in the future may differ from the assumptions outlined here. The resulting effect of this legislation in reducing costs for clean energy projects and new technologies will be an important driver for decarbonizing gas networks.

Key IRA provisions incorporated into this scenario analysis include supply-side credits for zero-emitting renewable electricity as well as for renewable natural gas and hydrogen. Demand-side incentives are also captured as reducing the costs of heat pumps.

Analysis Results

Key Findings

The Mid-Atlantic region presents a range of challenges for decarbonizing natural gas end-uses in the residential, commercial, and industrial sectors, such as a relatively vintage building stock, significant energy system impacts of building space heating during the region's moderately cold-weather climate, and a variety of hard-to-electrify industrial uses. Most of the following findings are related to strategies for addressing these challenges:

- Energy efficiency (building e can be achieved,[12]
- Low-carbon fuels are an effective and scalable strategy when employed for hard-to-electrify uses like winter peak

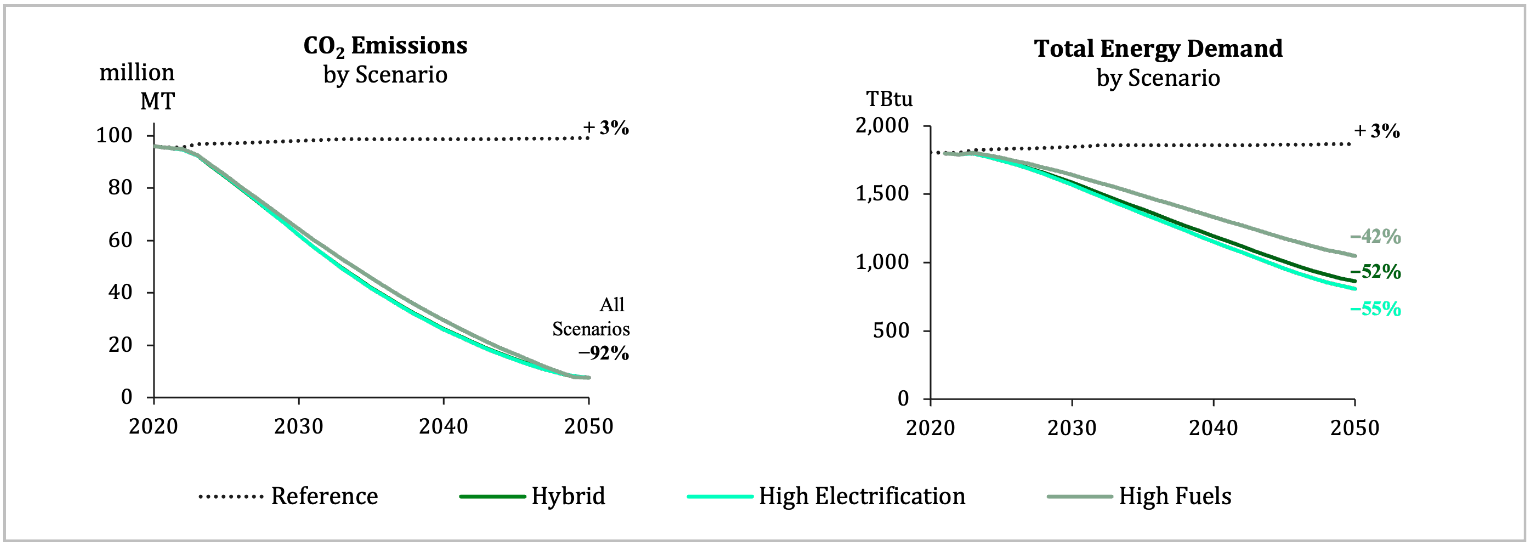
[12] The study distinguishes buildings from appliances, and not all appliance efficiency can be said to be "highly cost-effective."

heating demand and industrial processes,

- The cost of meeting winter heating peak is a significant cost differentiator between a full electrification path and one that uses a hybrid (dual fuel) strategy for building heat, and
- Decarbonization paths that rapidly migrate customers from LDC systems pose significant cost risks to customers who might be slower to convert or who cannot covert.

Considering these key findings, the analysis suggests that a balance of strategies represents a middle ground of cost, feasibility, and emission reductions. The Hybrid scenario emerges as DSI's recommended path for the Mid-Atlantic region as it brings a greater likelihood of success, fewer implementation challenges, and can be deployed with lower overall costs than the other two scenarios.

Figure 2. Total CO_2 Emissions and Energy Demand by Scenario, 2020-2050



Emissions and Total Energy

Each scenario is constructed to follow a similar emissions reduction trajectory. All the scenarios exceed 90 percent emissions reduction by 2050 (Figure 2, left), a target that is roughly consistent with a 1.5º Celsius path in which less than 10% of reductions need to reach net zero could come from carbon removals. The emission reduction in each scenario results from a decrease in delivered fossil natural gas. Each scenario has approximately the same amount of residual fossil gas delivered in 2050. By contrast, the Reference scenario that includes no GHG mitigation efforts grow end-use emissions with gas demand, increasing 3 percent by 2050.

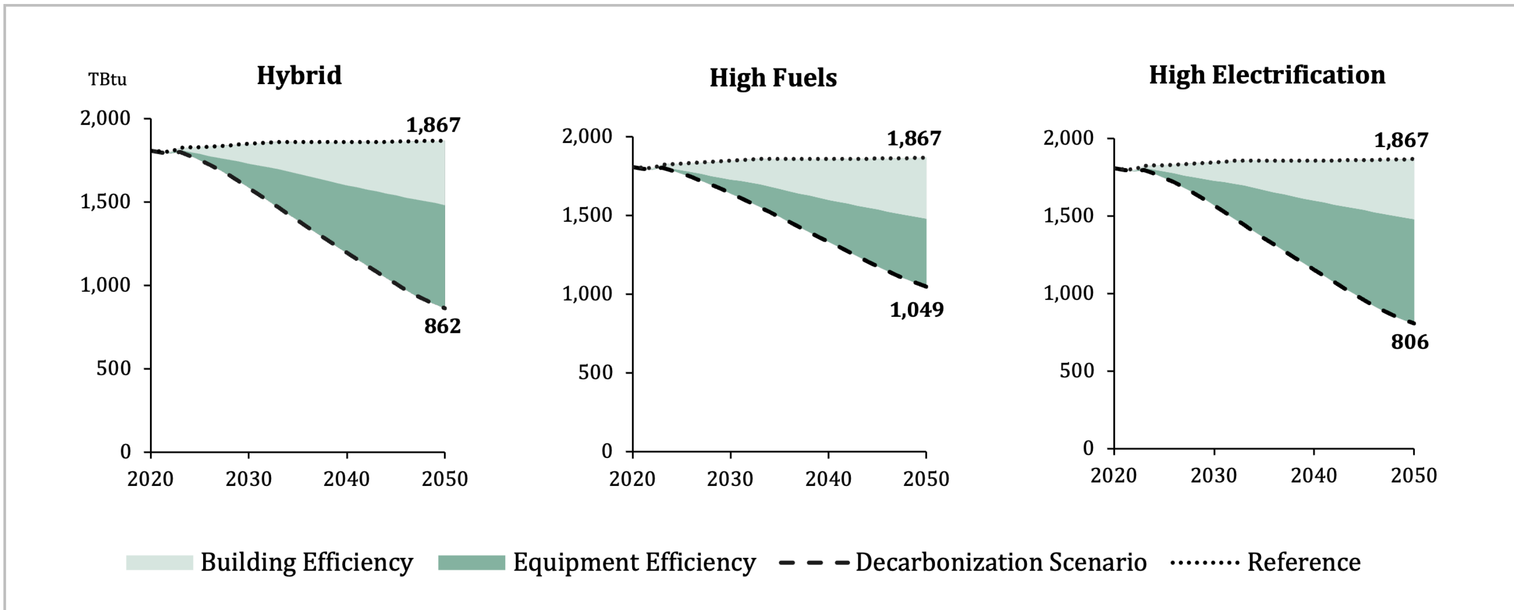
Although the emissions trajectory is the same for each scenario, the total energy demand varies across each path (Figure 2, right). The variation depends on the type of end-use equipment that is part of a scenario's decarbonization approach (see Change in Energy Demand below).

Change in Energy Demand

Energy demand reduction in each scenario is driven by two main elements: building efficiency measures and end-use appliance efficiency. Figure 3 and its accompanying chart show the contribution of each element across the decarbonization scenarios.

Building efficiency, which includes a range of measures that decrease building energy use for both heating and cooling, is a foundational strategy. Building efficiency, however, is constrained by the building stock itself and by feasibility, practicality, and cost issues that limit how much can be deployed. All scenarios incorporate the same level of building efficiency.

Figure 3: Change in Energy Demand by Scenario, 2020-2050



Change in Energy Demand by 2050

TBtu	Hybrid	High Fuels	High Electrification	Reference
Building Efficiency Reductions	-386	-386	-386	NA
Equipment Efficiency Reductions	-619	-432	-674	NA
Total Energy Demand in 2050	**862**	**1,049**	**806**	**1,867**
Percentage Change in Energy Demand *(from 2020)*	-52%	-42%	-55%	3%

End-use appliance efficiency yields energy demand reductions through the conversion from conventional gas-fired heating equipment to a range of heat pump technologies, including air source heat pumps, ground source heat pumps (GSHP), and gas heat pumps (GHPs), that have significantly higher efficiencies. The differences among the scenarios in the energy demand reduction from equipment efficiency depends on the mix of conversion technologies applied.[13]

In Figure 3, change in energy demand for each scenario is compared to the demand for fossil natural gas in the Reference scenario (dotted line at the top). In the figures for each of the scenarios, the black dotted line represents the Reference scenario energy demand, which increases from 1,807 TBtu in 2020 to 1,867 in 2050.[14] The black dashed line represents the energy demand trajectory for each decarbonization scenario. In the Hybrid scenario, energy demand declines to 862 TBtu; High Fuels demand declines to 1,049 TBtu; and High Electrification declines to 806 TBtu. The High Electrification scenario, because it replaces a larger portion of demand with high efficiency electrical appliances, achieves the greatest reduction in energy demand (approximately 55 percent compared to 2020 levels). The High Fuels scenario reduces demand the least, about 42 percent, while the Hybrid scenario reduces demand 52 percent.

[13] The current fleet-wide efficiency of conventional gas-fired heating units in the MidAtlantic region is estimated at 82% and is the baseline for the analysis. New high-efficiency conventional gas-fired heating equipment is roughly 95% efficient (in the analysis this efficiency grows over time to 98%). The heat pump technologies to which gas customers are converted over time in each scenario range from starting values of 130% for gas heat pumps, 300% for air-source heat pumps , and 450% for ground-source heat pumps. (Useful thermal output from heat pump technologies can exceed the energy input because the delivered heat is not directly supplied by the fuel, but rather the fuel is used to extract heat from an environmental source, either air or water.)

[14] Growth in Reference reflects current historical trend through 2030, then slows to a long-run growth rate tied to historical population and housing trends.

Energy Supply by Fuel Type

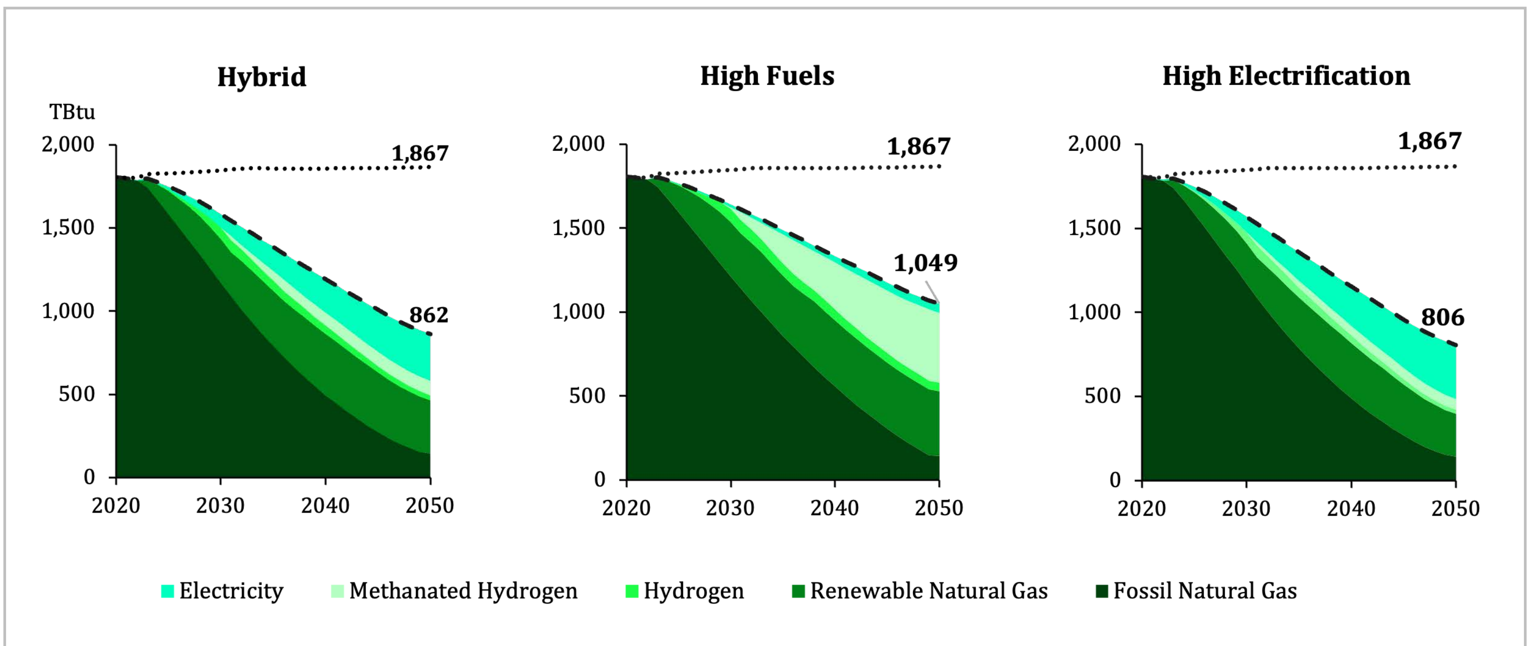
Once reduction in energy demand has been accounted for, the next component of each scenario is the energy mix to meet demand, Figure 4. The mix in each scenario is comprised of electricity, RNG, two forms of green-hydrogen-based gases, and a residual amount of fossil natural gas.

The hydrogen-based gases are pure hydrogen (H2) and methanated hydrogen (M-H2) and the analysis limits the amount of pure hydrogen blending in each scenario to 16 percent.[15] Methanated hydrogen is green hydrogen that has been converted to methane through the addition of CO_2. Since it behaves like fossil natural gas, P2G can be blended into LDC distribution systems without the restrictions that are associated with pure hydrogen. As equipment and demand change over time, fuels are added to the energy supply in the model based on relative price, available supply, and blending restrictions.

As shown in Figure 4, the Hybrid scenario spreads usage across the mix of fuels more than the other scenarios. This fuel diversity is among the many elements making the Hybrid scenario attractive. A diverse approach to decarbonized fuels achieves several desirable ends. First, it can encourage the parallel development of a range of decarbonized fuels over time. Second, it can adapt to a range of outcomes in the evolutionary path of those decarbonized fuels. Third, the strategy can use those decarbonized fuels at levels which may pose fewer stresses on all sources of supply. The High Fuels scenario, for instance, exhausts the estimated available RNG supply to Mid-Atlantic (based on proportional demand from Eastern U.S. sources) and must add greater amounts of hydrogen-based fuels.

The High Fuels scenario uses the largest amount of gases to fulfill demand at 995 TBtu in 2050, a reduction of 45 percent from 2020 throughput levels. The Hybrid scenario reduces gas throughput by 68 percent to 582 million Dth and High Electrification's gas throughput is reduced 73 percent to 483 TBtu.

Figure 4: Energy Supply by Fuel



[15] 16% volumetric basis, which is equivalent to 5% on a heat content basis.

Energy Supply by Fuel, 2050

TBtu	Hybrid	High Fuels	High Electrification	Reference
Fossil Natural Gas (NG)	145 (17%)	145 (14%)	145 (18%)	1,867 (100%)
Renewable Natural Gas (RNG)	321 (37%)	384 (37%)	252 (31%)	- (0%)
Hydrogen (H_2)	29 (3%)	50 (5%)	24 (3%)	- (0%)
Methanated Hydrogen (P2G)	87 (10%)	415 (40%)	62 (8%)	- (0%)
Total Gases (Throughput)	**582** (67%)	**995** (95%)	**483** (60%)	**1,867** (100%)
Electricity (Btu basis)	280 (33%)	54 (5%)	323 (40%)	- (0%)
Total Energy Demand, 2050 (Btu basis)	**862** (100%)	**1,049** (100%)	**806** (100%)	**1,867** (100%)
Electricity (TWh)	82	16	95	NA

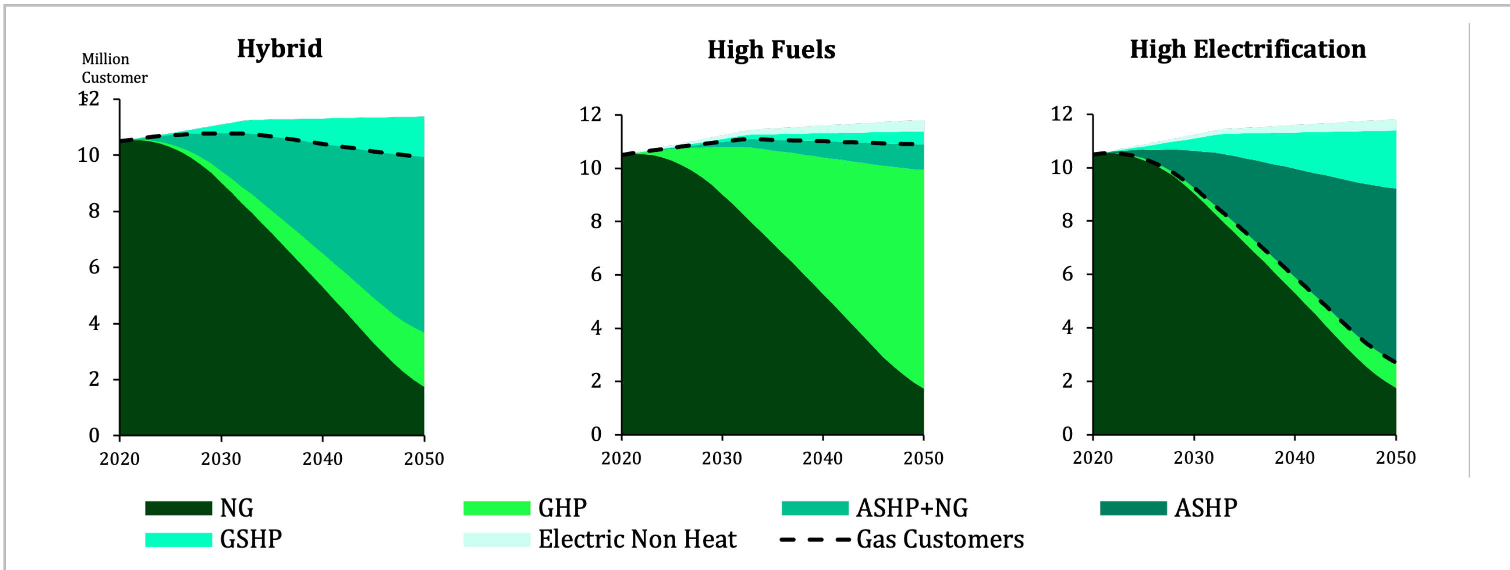
Heating Equipment Evolution

In each of the decarbonization scenarios, the addition of new conventional gas-fired heating appliances is slowly phased out through 2030. From 2030 onward, only new high-efficiency electric and gas heat pumps are added at the natural replacement cycle of the existing gas furnaces, assuming an average 25-year useful life.[16] The exception is that of ASHPs in the Hybrid scenario, which are added as part of a dual-fuel system in combination with the existing conventional gas-fired appliances remaining in operation.

Figure 5 shows the evolution of heating equipment across scenarios. The dark green color (NG) represents the fleet of fossil natural gas-fired equipment; its trajectory is the same in each scenario as it is driven by the natural replacement cycle. Each decarbonization scenario employs a different mix of equipment types. The type of equipment to which customers are converted and how it is used in the case of dual-fuel heating in the Hybrid scenario, determines whether they remain as gas customers of the LDC or migrate fully away from gas use.

[16] New heat pump (ASHP, GSHP, GHP) are replaced over time assuming an average useful life of 15 years.

Figure 5: Customer Counts by Heating Equipment Type, 2020-2050



Customer Counts by Heating Equipment Type in 2050

Million Customers	Hybrid	High Fuels	High Electrification	Reference
Conventional Natural Gas (NG)	1.7 (15%)	1.7 (15%)	1.7 (15%)	11.8 (100%)
Gas Heat Pump (GHP)	1.9 (16%)	8.2 (69%)	1.0 (8%)	NA (0%)
Hybrid Heating (ASHP+NG)	6.3 (53%)	1.0 (8%)	NA (0%)	NA (0%)
Total Gas Customers	**9.9** (84%)	**10.9** (92%)	**2.7** (23%)	**11.8** (100%)
Non-Heating Electric	0.4 (4%)	0.4 (4%)	0.4 (4%)	NA (0%)
Air Source Heat Pump (ASHP)	0.0 (0%)	0.0 (0%)	6.5 (55%)	NA (0%)
Ground Source Heat Pump (GSHP)	1.4 (12%)	0.5 (4%)	2.2 (18%)	NA (0%)
Total Customers (including migrated)	**11.8** (100%)	**11.8** (100%)	**11.8** (100%)	**11.8** (100%)

The Mid-Atlantic residential and commercial gas customer base in the Reference scenario grows from 10.5 million customers to 11.8 million customers (12 percent by 2050 or 0.4 percent per year). The High Fuels scenario converts most customers to gas heat pumps and retains 92 percent of the customers projected in the Reference scenario as gas customers. In the Hybrid scenario, the gas customer base declines modestly (-5 percent from 2020 to 2050, -0.2 percent per year); 16 percent of 2050's projected customers have migrated away from the gas system. In High Electrification, the customer base has declined 77 percent by 2050, leaving only a small residual number of customers, mainly industrial, on the system. The High Electrification scenario converts only a small number of customers to gas heat pumps, 10 percent of new equipment conversions. Most customers in the High Electrification scenario convert to fully electrified heating, approximately 75 percent of which to ASHP (55% of total customers) and approximately 25 percent to GSHP (18% of total). These fully electrified customers migrate completely away from the gas system on conversion.

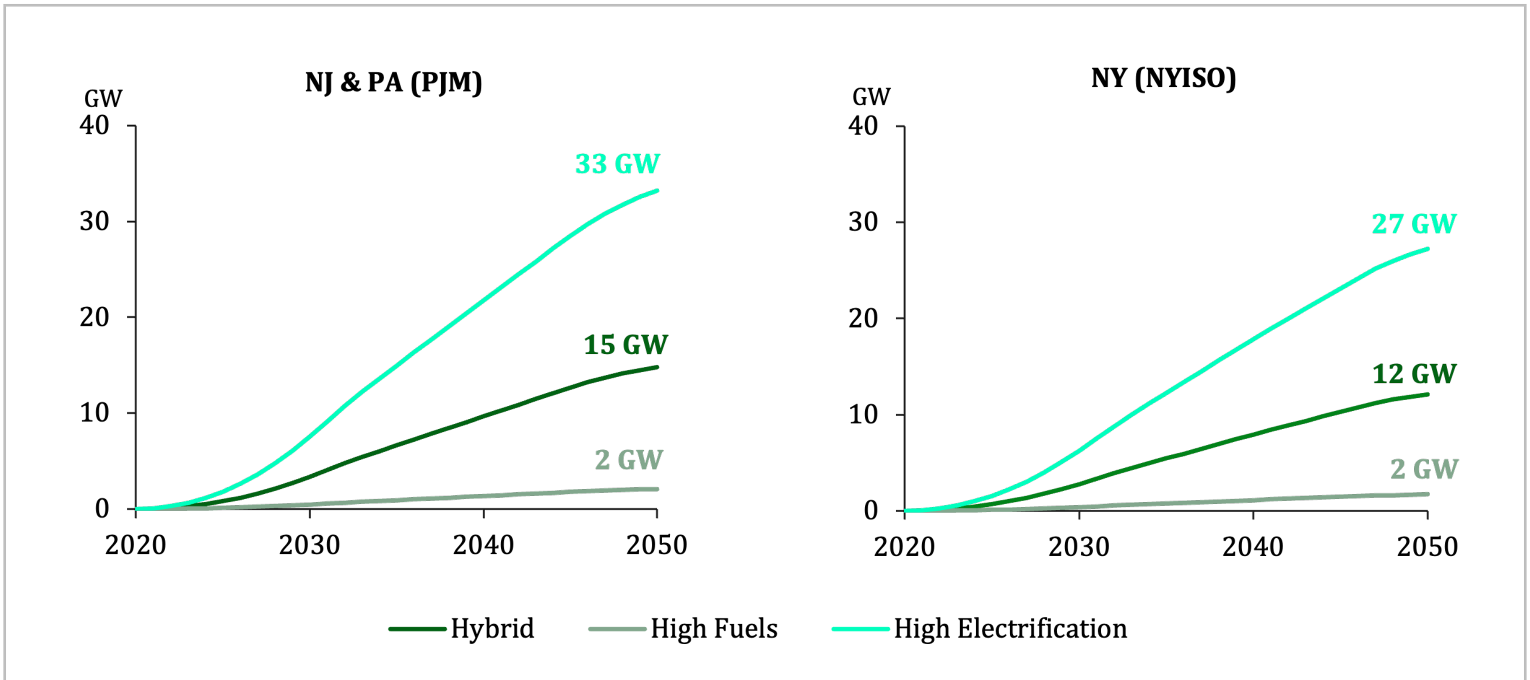
Considering that the Hybrid scenario's primary conversion strategy is dual-fuel—adding ASHPs to existing gas-fired heating—all customers who adopt the dual fuel (ASHP+NG) remain as gas customers, though with significantly reduced demand. In a dual-fuel configuration, the ASHP is used when outdoor temperatures are above 20ºF and the gas-fired conventional heating is used at 20ºF and below. A dual-fuel strategy uses electrified heating in its most efficient range and relies on the gas-fired heating at temperatures in which air-source heat pumps rapidly lose efficiency.

Electric Peak Demand from Building Heat

The high-efficiency of electricity-based heat pumps can significantly reduce energy demand while also converting the demand for fossil natural gas to electricity that steadily decarbonizes with growth in renewable energy sources. In cold-weather climates, however, ASHPs can create significant peak demand for electricity during the coldest days of the heating season. The efficiency of air source heat pumps, even those designed for cold climates, lose efficiency as temperatures decline below freezing. To fully electrify a home or business might require significant oversizing of the system and/or a reliance on an electric resistance back-up heating system to ensure sufficient space heating output in the coldest temperatures.[17]

Figure 6 shows the total estimated peak demand from electrified heating through 2050. Peak demand steadily rises over time in all decarbonizations scenarios as the number of electricity-based heat pumps increases. In the High Electrification scenario, the peak demand for electricity is estimated to reach 33 GW in New Jersey and Pennsylvania (PJM) by 2050, and 27 GW in New York (NYISO). The Hybrid scenario, however, creates less peak demand by 2050, estimated to reach 15 GW in New Jersey and Pennsylvania and 12 GW in New York.

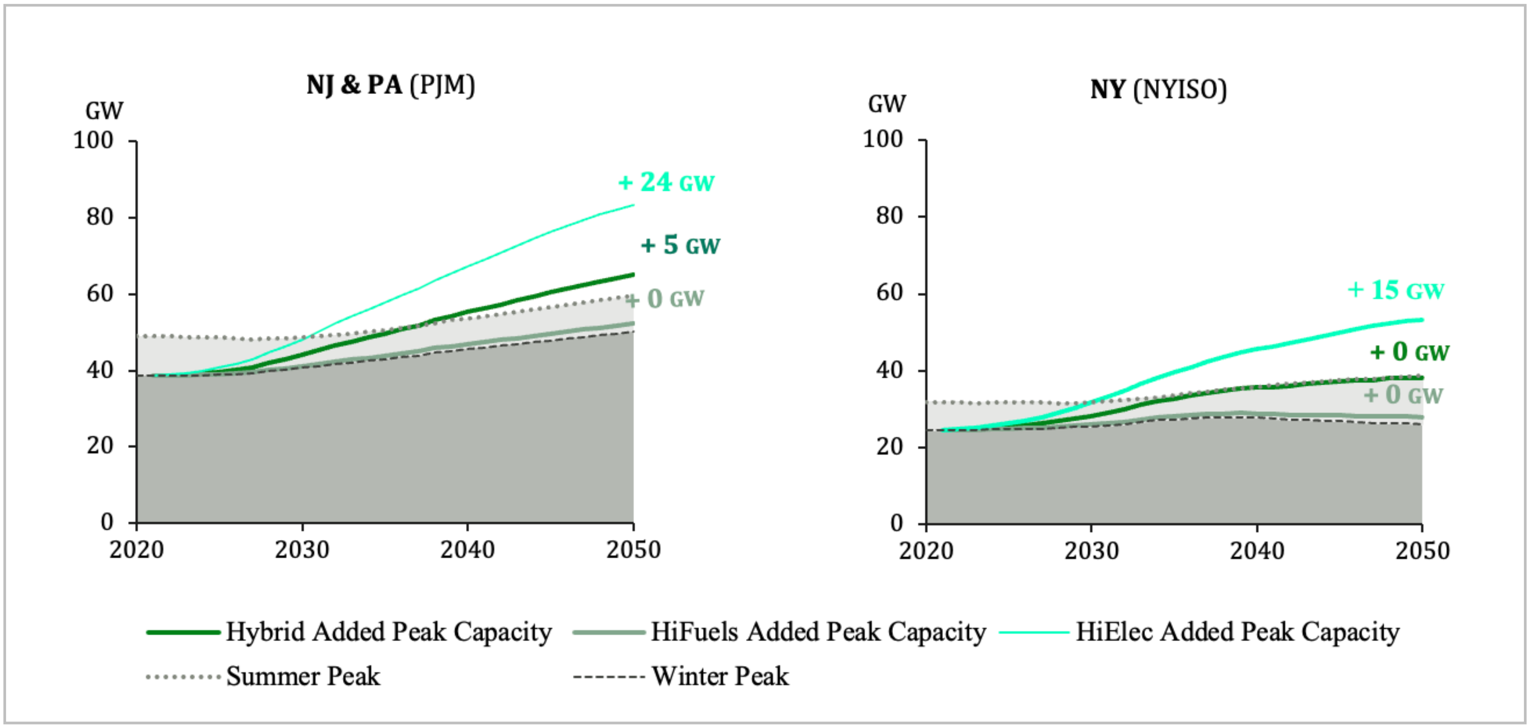
Figure 6: Winter Peaking Demand from Building Heat Electrification



While the High Electrification scenario has a slightly larger fleet of ASHPs than the Hybrid scenario, the conditions under which they are used in each scenario creates the difference in their impact on the grid. Two main factors drive this difference between the scenarios. The first factor is the temperature at which the air source heat pumps operate. In the High Electrification scenario, the ASHPs supply space heating through the entire winter season and need to provide heat for customers even on the coldest days. In the Hybrid scenario, by contrast, ASHPs operate only down to 20ºF, and gas-fired heating operates at temperatures below 20ºF. The second factor is the declining efficiencies of ASHPs in the coldest of weather means that in High Electrification, ASHPs have their highest Btu per hour output when they are operating at their lowest efficiency. These two factors drive the winter peak demand for electricity in the High Electrification scenario to be 63 percent more than that of the Hybrid scenario.

[17] Because ground source heat pumps work from a constant-temperature liquid, they operate at much higher efficiencies across the heating and cooling seasons and do not have the same cold temperature efficiency decline as air source heat pumps.

Figure 7: Impact of Electrified Heating Demand on Winter Peak for Regional Grids



Impact of Electrified Heating Demand on Regional Grids, 2050

		NJ & PA (PJM)[18]			NY (NYISO)[19]		
	GW	Hybrid	High Fuels	High Electrification	Hybrid	High Fuels	High Electrification
Winter Peak Demand (before heating electrification peak demand)		50.2	50.2	50.2	26.1	26.1	26.1
Summer Peak Demand (adjusted for solar capacity availability)		59.6	59.6	59.6	38.6	38.6	38.6
Summer Peak Capacity Available for Winter Peaking		9.4	9.4	9.4	12.5	12.5	12.5
Peak Demand from Electrification		14.8	2.1	33.2	12.1	1.7	27.2
Winter Peak Capacity Required		**+5.4**	**+0.0**	**28**	**+0.0**	**+0.0**	**+14.7**
Hydrogen Production and Associated Generation Capacity[20]: Electric Generation Capacity from Hydrogen Production (available for winter peak demand)	GW	4	0	3	2	0	2
Hydrogen (H_2)	TBtu	17	27	14	12	23	10
Methanated Hydrogen (P_2G)	TBtu	59	237	38	28	178	24

[18] PJM peak demand projections for New Jersey and Pennsylvania come from the PJM Load Forecast Report (2024). PJM projections are for 15 years (to 2039) and have been extended to 2050 by ERM based on PJM's forecast trend.

[19] NYISO peak demand projections come from the NYISO Gold Book (2023) which extend to 2053. NYISO's projections of winter peak demand from building electrification reach 25 GW by 2050, slightly below this study's High Electrification scenario of 29 GW of added winter peak. The winter peak demand shown in the chart and table reflect winter peak before electrification.

[20] The capacity used for hydrogen production in each scenario becomes part of the capacity that serves the peak demand required in that scenario.

To accommodate the increase in peak electric demand, the electric grid will require investment in new generation capacity, additional transmission to interconnect generation capacity, and upgrades to the distribution system to deliver increased electricity to end-use customers during periods of peak demand. All of this required new infrastructure investment increases costs in the form of higher electricity utility rates to energy customers.

The portion of the PJM grid serving New Jersey and Pennsylvania is a summer peaking system currently designed for 48 GW of peak demand; summer peak demand is largely driven by air conditioning load in the hottest of summer days. Winter peak for those two states is currently 38 GW. This gap between projected winter and summer peak demand allows for additional winter peak demand to be absorbed before the grid requires additional resources. In the High Electrification scenario, that gap is exceeded by new heating peak demand in 2030 and grows to 24 GW of new peak demand for the grid by 2050 (Figure 7). In the Hybrid scenario, the gap is not exceeded until 2038 and grows more slowly, reaching only 5 GW of additional peak demand for the grid in New Jersey and Pennsylvania by 2050. The minimal amount of electrification in the High Fuels scenario never exceeds the gap between summer and winter peaks, so creates no new peak demand requirements.

The New York ISO (NYISO) grid, which entirely serves New York State, is also a summer peaking system, also largely air-conditioning driven and is currently designed for nearly 32 gigawatts (GW) of summer peak demand. Winter peak on the NYISO grid is currently 24 GW. For the New York grid, the High Electrification scenario's heating electrification peak demand surpasses the gap between summer and winter peaks in 2030 as well and grows to 15 GW of added peak demand for the grid by 2050. The Hybrid scenario nearly closes the gap between winter and summer peak but does not by 2050, though it likely would in subsequent years. The High Fuels scenario in New York, as with New Jersey and Pennsylvania, creates no new peak demand for the NYISO grid.

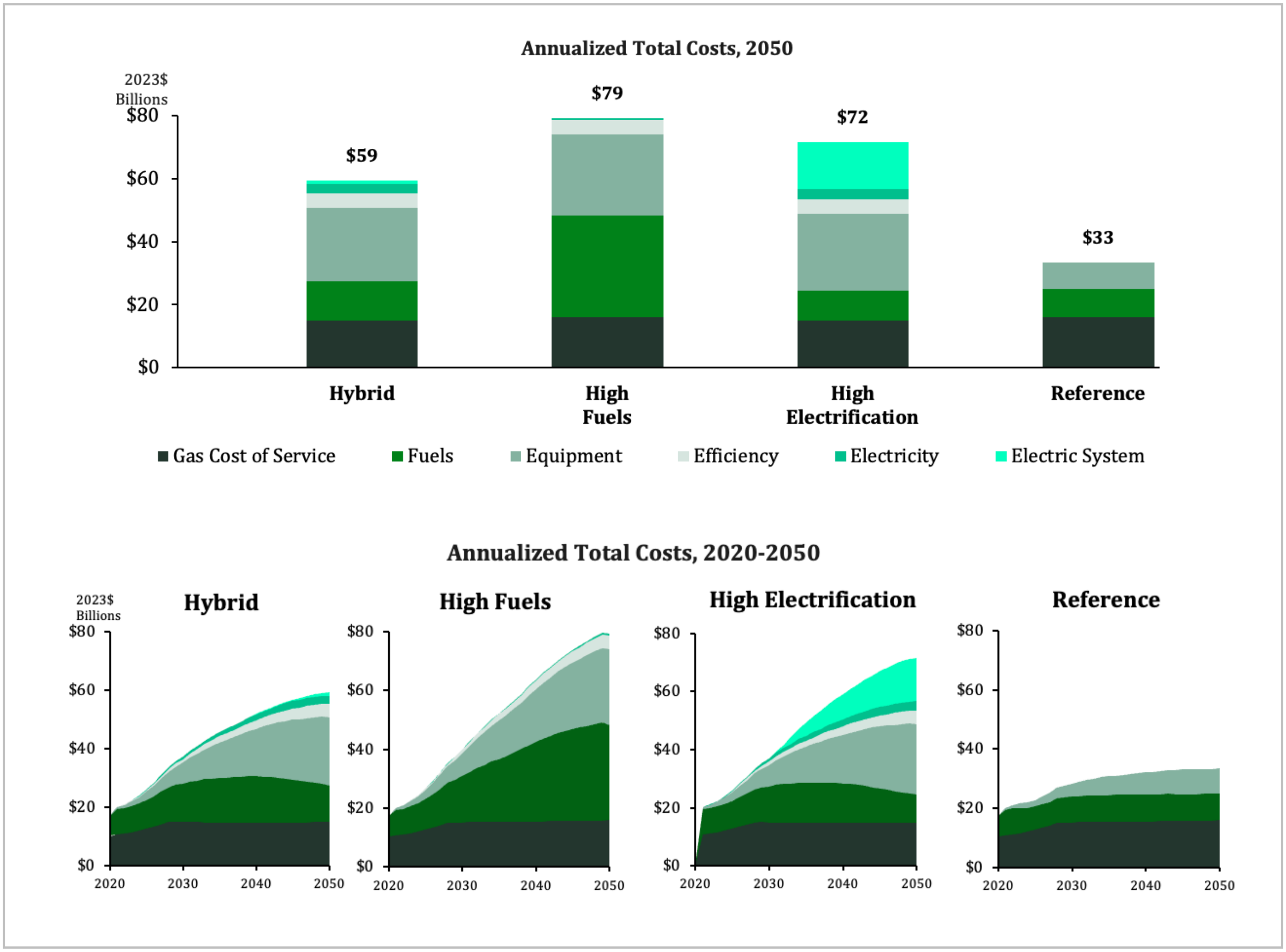
Comparison of Cost by Scenario

Costs for each of the scenarios are presented on an annualized basis, similar to the annual revenue requirement utilities establish in a regulated rate case. In addition to aligning with ratemaking processes, the annualization of the analysis's projected costs also allows costs to be associated with the energy delivered and the energy and emissions reduced each year. Although the direct effect of each scenario's costs may not fully be borne by individual rate payers, as incentives and other mechanisms could spread costs more broadly, the cost projections in this analysis are designed to represent the full economic impact of each scenario. Figure 8 compares each of the scenarios' annual costs in 2050 and the annualized costs for each of the scenarios from 2020 to 2050.

Cost projections in the analysis are divided into the following categories:

- **Cost of Service:** the cost to operate and maintain the gas distribution systems of Mid-Atlantic LDCs.
- **Fuels (commodity):** the total cost of all gases supplied to customers, including RNG, hydrogen, methanated hydrogen, and residual fossil natural gas.
- **Customer Equipment:** the costs for new heating equipment added in each scenario as existing heating equipment is retired and replaced.
- **Efficiency (Building):** the cost of efficiency measures (building envelope, etc.) that reduce the heating and cooling energy needs of a building.
- **Electricity (commodity):** the cost of renewable electricity used by electric heat pumps.
- **Electric System:** the costs associated with the electric generation capacity and T&D upgrades required to meet the winter peak demand for electricity from electrified heating.

Figure 8: Annualized Total Costs



Total Annualized Costs in 2050 *2023$, Billions*	**Hybrid**	**High Fuels**	**High Electrification**	**Reference**
Gas Cost of Service	$15.0	$15.9	$15.0	$15.9
Fuels (Commodity)	$12.5	$32.3	$9.5	$9.0
Customer Equipment	$23.3	$25.8	$24.4	$8.5
Efficiency (Building)	$4.6	$4.6	$4.6	$0.0
Efficiency (Commodity)	$2.8	$0.5	$3.2	$0.0
Electric System (Generation/T&D Capacity)	$1.1	$0.0	$14.9	$0.0
Total Annualized Cost, 2050	**$59.3**	**$79.2**	**$71.6**	**$33.4**
Cost premium percentage over Reference	78%	137%	114%	NA

Each of the decarbonization scenarios costs more than the Reference scenario, which has a projected cost of just over $33 billion in annualized costs (in 2023 dollars). The Hybrid scenario is projected to be the least-cost decarbonization path, with $59 billion in annualized costs by 2050, 78 percent higher than those projected for the Reference scenario in that year. The High Fuels scenario is projected to cost $79 billion annually by 2050, a cost premium to the Reference scenario of 137 percent, and the High Electrification scenario is projected to cost $72 billion annually, 114 percent more than the Reference scenario.

Part of the cost gap between the Reference scenario and the decarbonization scenarios is the higher cost of high efficiency heat pumps, with the variation among scenarios driven by the mix of equipment in each. The three decarbonization scenarios employ the same level of energy efficiency at the same cost. Efficiency and customer equipment account for $20 to $22 billion of annual cost over the Reference scenario.

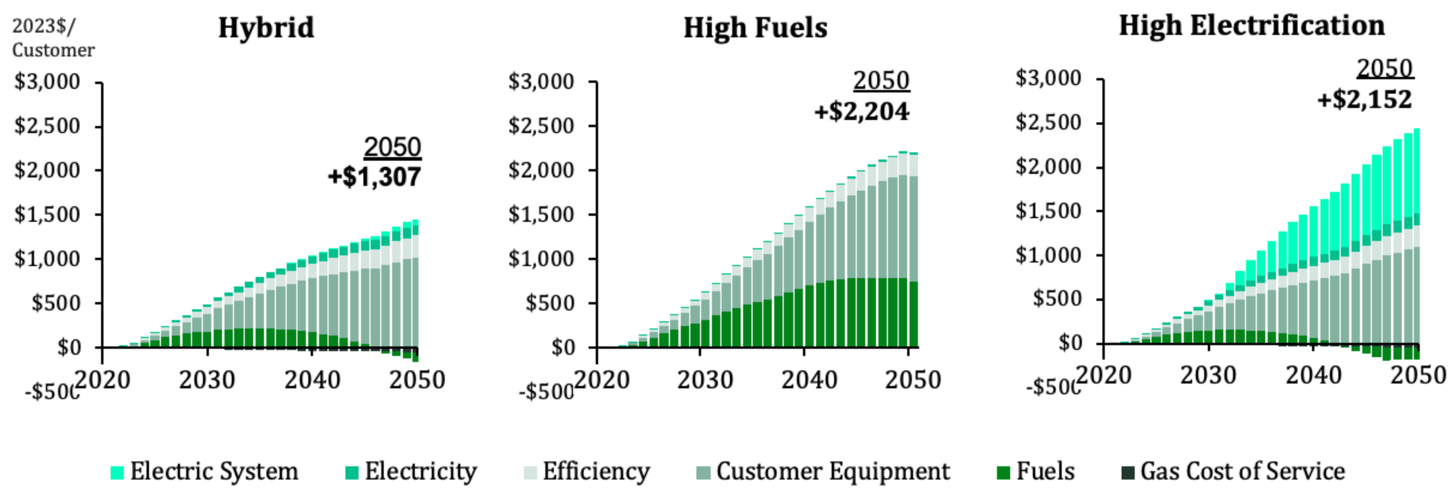
The cost of the energy sources and the infrastructure to deliver it account for the rest of the gap, between $10 and $24 billion in annual costs, from Reference to the decarbonization scenarios. In the High Electrification scenario, these costs are driven primarily by the build out of the electric generating capacity and the grid needed to serve new winter electric peak demand. The cost of meeting winter electric peak in the Hybrid scenario, by comparison, is far lower because it is borne by the existing gas distribution system which is already designed to serve the load. While the High Fuels scenario has no costs associated with winter electric peak, its high level of demand for decarbonized fuels requires using reaching to more expensive resources, such RNG from costlier processes and feedstocks, and higher levels of green hydrogen-based fuels. These fuels, incentivized by the IRA through the 2030s, are a cost-effective solution during that time period, but continued use after that period pushes the scenarios fuels costs up.

Costs per Average Residential Customer

Examining the total costs in terms of an average residential customer's share can provide some perspective on the potential impact each scenario might have on customers. As noted earlier, many of these costs will ultimately pass to customers in the form of higher energy bills. Some costs, like those created by IRA provisions or other tax incentives, may be broadly socialized. The cost of utility-sponsored incentives for space heating equipment or energy efficiency, however, would benefit individual customers while their costs would likely be spread across the whole customer base. Figure 9 shows the scale of incremental costs per scenario relative to an average residential customer. While many of these costs would likely be borne by individual customers either directly (e.g., for customer equipment) or through energy bills, the costs identified here would flow to customers in a range of ways not considered in this analysis. Costs could vary widely for customers who have done energy efficiency upgrades or converted to new technology compared with those who have not.

In 2050, an average residential customer's share of the Reference scenario costs is projected to be $1,656 per year, which includes annualized equipment costs, fuel costs, and gas cost of service. The Hybrid scenario would add $1,307 in net incremental costs, a 79% increase over Reference. In High Fuels and High Electrification, incremental costs in 2050 reach $2,204 and $2,152 annually per customer for increases of 133% and 130%, respectively, over the Reference scenario.

Figure 9: Indicative Share of Incremental Costs per Average Residential Customer



Notes on Incremental Share of Costs for Residential Customers: *The above charts show the estimated share of total annualized costs over the Reference scenario for an average residential customer. For each of the cost categories, the amounts depicted represent the residential share of incremental costs by category divided by the number of residential gas and converted customers in a given year. These charts are designed to show the scale of costs accounted for in the study relative to an average residential customer, but they are not meant to represent bills or rates. The totals shown in the charts (+$1,307 for Hybrid, +$2,204 for High Fuels, and +$2,252 for High Electrification) are net incremental costs: in both the Hybrid and High Electrification scenarios, savings for Fuels and Gas Cost of Service appear as negative numbers in later years, and these reduce the amount depicted at the top of the bars.*

2023$ / Customer / Year	**Hybrid**	**High Fuels**	**High Electrification**
Gas Cost of Service	($44)	$0	($44)
Fuels (Commodity)	($108)	$746	($242)
Customer Equipment	$1,026	$1,188	$1,093
Efficiency (Building)	$248	$248	$248
Efficiency (Commodity)	$115	$22	$135
Electric System (Generation/T&D Capacity)	$70	$0	$961
Total Incremental Cost (over Reference), 2050	**$1,307**	**$2,204**	**$2,152**
Reference Total Cost, 2050	$1,656	$1,656	$1,656
Total Cost, 2050	**$2,963**	**$3,861**	**$3,431**
Cost premium percentage over Reference	79%	133%	130%

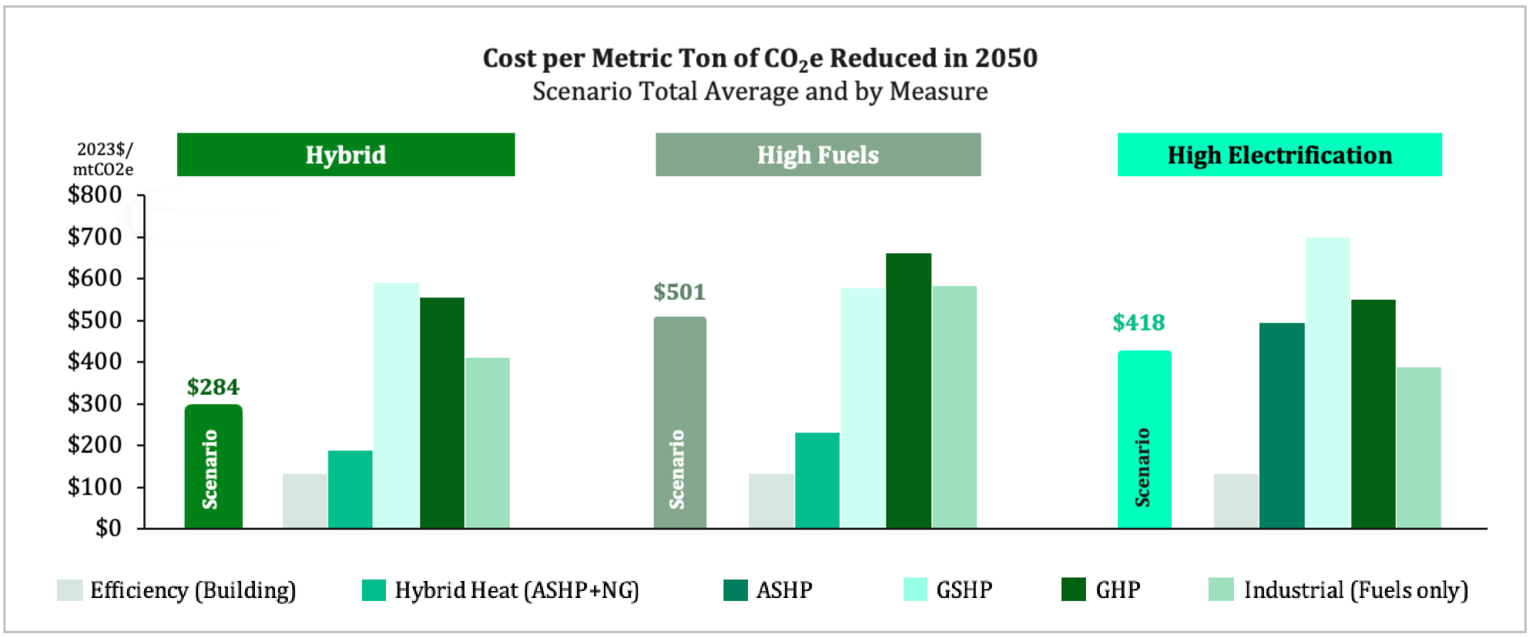
[21] Cost of reductions per metric ton of CO_2e reduced = (Total Decarbonization Scenario Costs – Total Reference Scenario Costs) / Total Metric Tons of CO_2e reduced. Costs of reductions per measure are similarly calculated using the incremental cost over Reference and the reductions attributable to that measure.

Cost per Metric Ton of Emissions Reduction

Figure 10 shows each decarbonization scenario's costs on a per metric ton of CO_2 equivalent (mtCO_2e) reduced.[21] On this basis, the full Hybrid scenario is $284 per mt$CO_2$e reduced, High Fuels is $501, and High Electrification is $418.

The costs per measure include all net incremental costs associated with the strategy or equipment type.[22] In each of the decarbonization scenarios, the cost of building efficiency (weatherization) is the same since each scenario employs the same level of efficiency across the Mid-Atlantic building stock, at $134 per mt$CO_2$e. Building efficiency is the most cost-effective measure across all scenarios. The use of AHSPs in the Hybrid and High Fuels (both in hybrid or dual-fuel) is the next-most cost-effective measure at $188 and $233, respectively, compared with $495 in the High Electrification scenario. In the High Electrification scenario, the cost of generation, transmission and distribution capacity required to meet peak winter heating demand drives most of the difference between it and the other two scenarios' costs of abatement for ASHPs. The cost of GSHPs is also higher in High Electrification ($701 per metric ton of CO_2e reduced) than in the other two scenarios ($591 for Hybrid and $579 for High Fuels), also because of the cost to meet winter peak demand. The fuel-based measures in High Fuels—GHPs and Industrial, $662 and $583, respectively—are higher than those in Hybrid and High Electrification owing to the higher cost of low-carbon fuels in that scenario.

Figure 10: Cost of Abatement ($/metric ton of CO_2e reduced)



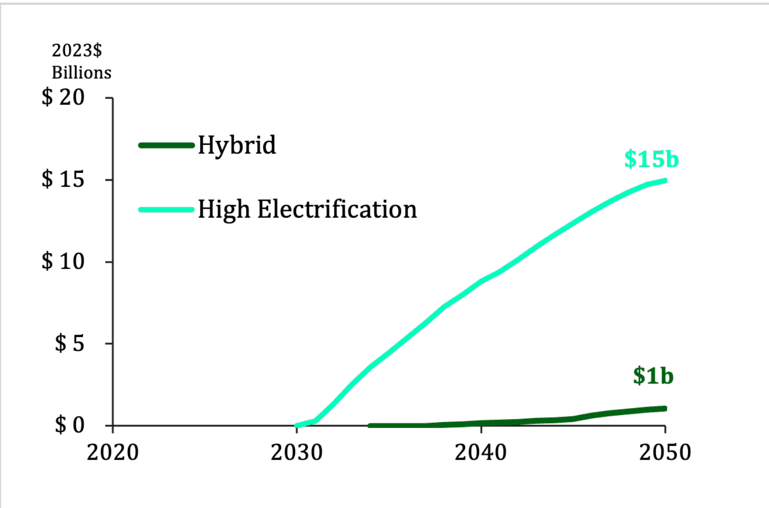
Cost of Abatement in 2050 ($/Metric Ton of CO_2e)

2023$ / mtCO_2e	Hybrid	High Fuels	High Electrification
Weighted Average for Scenario	**$284**	**$501**	**$418**
Efficiency (Building)	$134	$134	$134
	ASHP+NG	*ASHP+NG*	*ASHP only*
ASHP	$188	$233	$495
GSHP	$591	$579	$701
GHP	$556	$662	$551
Industrial (Fuels Only)	$412	$583	$390

[22] These include the cost of equipment, fuels or electricity, and electric infrastructure less the comparable costs of equipment and fuels from the Reference scenario.

In all scenarios, industrial demand is held constant across the timeframe of the study and is deemed, for the purposes of the analysis, a "hard-to electrify" source of gas demand. All carbon reductions of industrial usage are achieved exclusively by using low carbon fuels, and thus the cost per metric ton of CO_2e reduction for the industrial sector represents the incremental costs of the fuels relative to the cost of fossil natural gas in the Reference scenario.

Figure 11: Annualized Costs of Required Peak Capacity



Required Peak Capacity and Annualized Costs (select years)

	Capacity and Costs for Years:	**2030**	**2035**	**2040**	**2045**	**2050**
Hybrid						
Total Peak Demand from Electrified Heating	GW	6	12	18	23	27
New Peak Capacity Required for Grid	GW	-	-	2	4	5
Annualized Cost of Required Capacity	2023$ Billions	-	-	**$0.2**	**$0.4**	**$1.1**
High Fuels						
Total Peak Demand from Electrified Heating	GW	1	2	2	3	4
New Peak Capacity Required for Grid	GW	-	-	-	-	-
Annualized Cost of Required Capacity	2023$ Billions	-	-	-	-	-
High Electrification						
Total Peak Demand from Electrified Heating	GW	14	27	40	52	60
New Peak Capacity Required for Grid	GW	0	13	23	32	39
Annualized Cost of Required Capacity	2023$ Billions	**$0.0**	**$4.5**	**$8.8**	**$12.4**	**$14.9**

Cost to Meet Electric Peak Capacity

The cost to meet winter peak demand from electrified heating closely follows the curve of peak demand once it exceeds the respective summer peaks of the region's grids (Figure 11). To assess the potential costs of the decarbonization scenarios, this analysis assumes that the new generation capacity used to meet demand is comprised of a mix of the best available clean energy resources for the Mid-Atlantic, largely offshore wind with storage to help balance those resources.[23,24]

In the High Electrification scenario, the costs for new generation capacity and T&D upgrades begins after 2030 and total $15 billion in annualized costs by 2050. Since the Hybrid scenario limits the impact on winter peak electric demand, incremental costs for generation and T&D do not begin to accumulate until 2034 and reach a much more modest $4 billion by 2050. As noted earlier, the cost of peak capacity is one of the largest cost differentiators between the High Electrification scenario and the Hybrid scenario. With minimal electrification, the High Fuels scenario requires no new electric system infrastructure to meet its peak demand.

Cost of Service

Cost of Service in the near-term (through the mid- to late-2020s) grows rapidly, driven by current large-scale investment programs (primarily pipe replacement).[25] Over the longer term, the Cost of Service moderates to a level of investment that allows rates in real terms to stabilize (Figure 12). For the Reference scenario, this means that investment is aligned with the growth in customers and demand. For the Hybrid and High Electrification scenarios, total Cost of Service is held roughly constant, to approximate a condition of maintaining the system reliably but with no growth.[26] Holding Cost of Service at a static, maintenance level, for the Hybrid and High Electrification scenarios assumes that new investment in the system would be challenged by the goals of decarbonization efforts. It also assumes that the safety and the reliability of the system would need to be maintained over the entire study period and that the ability to reduce the size and cost of the system may be limited.

A path of rapid decarbonization poses several important risks to gas utility Cost of Service revenue and with it, the ability of the region's LDCs to maintain the reliability and safety of their systems. The central risk is the cost to maintain the system as gas throughput declines. In this situation, either Cost of Service rates will need to increase rapidly or, if regulators hold rates steady, growing revenue gaps could be created between Cost of Service revenue and the total cost to maintain the gas network. Figure 12 compares the total Cost of Service projected for the decarbonization scenario to the implied Cost of Service revenue if rates were held constant in real terms. Using this lens, the High Electrification scenario creates the largest potential gap and poses the greatest risks to customers and to the LDCs. As customers and throughput decline under rapid electrification, the cost to maintain the system must be spread over fewer customers and lower demand. Affected customers are likely to be those who are unable to take advantage of energy efficiency programs or replace their heating equipment with high efficiency appliances. Since the High Fuels scenario uses the largest amount of gases and retains all projected customers, its potential for a revenue gap is lower than the other scenarios, but is nonetheless a significant one. With the complex interaction between maintaining the gas system and the potential trajectory of customer rates under rapid decarbonization paths, the risks to and from the Cost of Service are among the most difficult problems to address for gas LDCs in their efforts to reduce theirs and their customers' carbon emissions.

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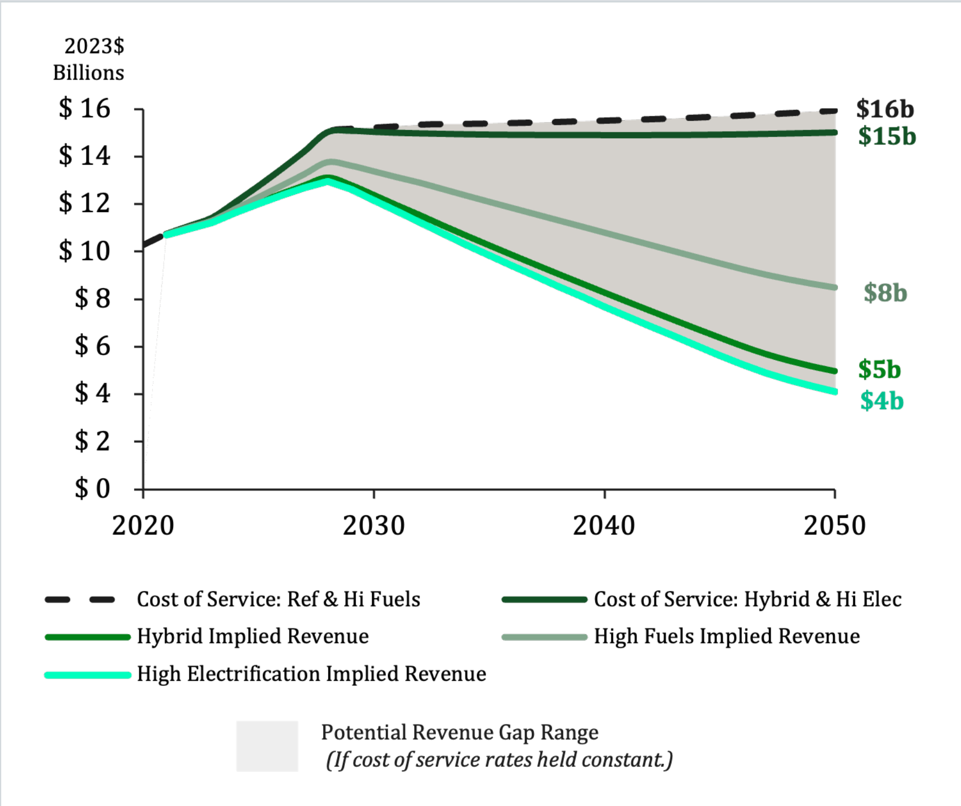
[23] A full economic dispatch optimization analysis of the Mid-Atlantic grids was outside the scope of the analysis. This study assumes that all electrified demand from gas end-uses is served by incremental new clean electricity resources, with offshore wind and batteries as the best proxy for associated costs. Costs could vary depending on the clean energy resources used; dispatchable clean energy resources (e.g., hydrogen) would likely provide the most reliable way to ensure peak demand is met.

[24] Many electric grids assess the ability of variable (renewable) resource availability for peak demand, assigning them a capacity rating. The regional capacity ratings are considered when assessing the capacity required to meet peak demand.

[25] The Cost of Service for MidAtlantic LDCs has been estimated using an aggregated regulatory financial model that projects the primary elements driving a utility Cost of Service revenue requirement (capital investment, depreciation, taxes, and operations & maintenance).

[26] This study assumes that the ability to reduce the size and cost of gas distribution systems will be limited, even under the aggressive conversion assumptions of the High Electrification scenario, since reductions to the gas system can occur only when all customers served by a given section of the system have been disconnected. Conversions and migration are assumed to be spread across systems creating limitations on reductions.

Figure 12: Cost of Service and Potential Revenue Gap



Cost of Service and Potential Revenue Gap in 2050

2023$, Billions (except where noted)		Hybrid	High Fuels	High Electrification	Reference
Cost of Service (Decarbonization Scenarios)	*2023$, Billions*	$15.0	$15.9	$15.0	$15.9
Reference All-Customer Average Rate	*2023$, Dth*	$8.50	$8.50	$8.50	$8.50
Total Scenario Gas Throughput	*TBtu*	603	95	501	1,867
Implied Revenue at Reference Rate	*2023$, Billions*	$5.0	$8.5	$4.2	$15.9
Implied Potential for Revenue Gap	*2023$, Billions*	$10.0	-$7.5	-$10.9	NA

Conclusion

This report summarized three decarbonization scenarios and the associated costs of decarbonizing natural gas use in the building sector in the Mid-Atlantic region by 2050. Changes to demand are projected forward with modeling of different pathway scenarios of fuel mixes and equipment deployments to test the impact of different technology options on energy consumption, emissions reductions, and system costs.

The analysis considered three decarbonization scenarios that assessed the GHG emission trajectories of the residential, commercial, and industrial sectors for natural gas demand. The High Electrification and High Fuels scenarios examine decarbonization paths that rely heavily on a single strategy: fuel switching in the case of High Electrification and low-carbon alternatives in High Fuels. **The Hybrid scenario, DSI's recommended path for the Mid-Atlantic region, balances the two strategies.** This balancing of strategies represents an optimization of cost, feasibility, and results: a strategy that could have greater success, fewer implementation challenges, and be deployed with lower overall costs than the other two scenarios.

After assessing the peak demand from electrified heating in the two scenarios (Hybrid and High Electrification) that employ electricity-based heat pumps, peak demand steadily rises over time as the number of electricity-based heat pumps increases. In the High Electrification scenario, the peak demand for electricity is estimated to reach 60 GW across the three states of the region by 2050. The Hybrid scenario, however, creates less peak demand by 2050, projected to reach 27 GW. Both scenarios have comparable levels of air source heat pumps, with the number of ASHPs in High Electrification only 4% percent higher than that in Hybrid scenario.

Although the direct effect of each scenario's costs may not fully be borne by individual rate payers, as incentives and other mechanisms could spread costs more broadly, the cost projections in this analysis are designed to represent the full economic impact of each scenario. Each of the decarbonization scenarios costs more than the Reference scenario, which has a projected cost of just over $33 billion in annualized costs. **The Hybrid scenario is projected to be the least-cost decarbonization path, with $54 billion in annualized costs in 2050, 62 percent higher than those projected for the Reference scenario in that year.** The High Fuels scenario is projected to cost $66 billion annually by 2050, a cost premium to the Reference scenario of 98 percent, and the High Electrification scenario is projected to cost over $73 billion in annualized costs, 119 percent greater than the Reference scenario.

Additional findings include:

- Energy efficiency is among the most cost-effective decarbonization measures available today.
- Dual-fuel (electric and gas), or hybrid heating strategies are a key and cost-effective strategy that can achieve significant emissions reductions from current conventional natural gas consumption in the Mid-Atlantic.
- Decarbonized fuels are an effective and scalable strategy when used in buildings for meeting winter peak heating demand in cold weather climates and difficult-to-electrify uses like industrial processes.
- To decarbonize the building sector's natural gas end-uses is highly dependent upon regional conditions which creates unique needs that require Mid-Atlantic-specific approaches to achieve reliable and cost-effective emissions reductions.

About ERM

Sustainability is our business.
As the largest global pure play sustainability consultancy, ERM partners with the world's leading organizations, creating innovative solutions to sustainability challenges and unlocking commercial opportunities that meet the needs of today while preserving opportunity for future generations.

ERM's diverse team of 8,000+ world-class experts in over 150 offices in 40 countries and territories combine strategic transformation and technical delivery to help clients operationalize sustainability at pace and scale. ERM calls this capability its "boots to boardroom" approach - a comprehensive service model that helps organizations to accelerate the integration of sustainability into their strategy and operations.