Implications of **Policy-Driven Residential Electrification**

An American Gas Association Study
prepared by ICF

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ENERGY

IMPORTANT NOTICE:

This is an American Gas Association (AGA) Study. The analysis was prepared for AGA by ICF. AGA defined the cases to be evaluated, and vetted the overall methodology and major assumptions. The EIA 2017 AEO Reference Case, including energy prices, energy consumption trends, energy emissions, and power generation capacity and dispatch projections, was used as the starting point for this analysis.

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Implications of Policy-Driven Residential Electrification

As states and local municipalities pursue "deep decarbonization" of their economies and as the electric grid becomes less carbon-intensive some policy-makers and environmental advocates are looking at mandated residential electrification as one option for reducing residential greenhouse gas (GHG) emissions. This AGA study sets out to answer several key questions regarding potential costs and benefits of these residential electrification policies.[1] These questions include:

- Will policy-driven residential electrification actually reduce emissions?
- How will policy-driven residential electrification impact natural gas utility customers?
- What will be the impacts on the power sector and on electric transmission infrastructure requirements?
- What will be the overall cost of policy-driven residential electrification?
- How do the costs of policy-driven residential electrification compare to the costs of other approaches to reducing GHG emissions?

This AGA Study of residential electrification is based on a policy case that requires the halt of sales of furnaces and water heaters fueled by natural gas, fuel oil, and propane, starting in 2023. As existing equipment is replaced and new construction built, the analysis assumes the associated space and water heating requirements would be met solely with electric based technologies. The analysis then estimates the impact of such a policy on annual energy costs for residential end-users, as well as the associated impact on emissions generated by the residential end-use and power generation sectors through 2050.

Key Study Conclusions

- The U.S. Energy Information Administration (EIA) projects that by 2035, direct residential natural gas use will account for less than 4 percent of total GHG emissions, and the sum of natural gas, propane, and fuel oil used in the residential sector accounts for less than 6 percent of total GHG emissions. Reductions from policy-driven residential electrification would reduce GHG emissions by 1 to 1.5 percent of U.S. GHG emissions in 2035. The potential reduction in emissions from the residential sector is partially offset by an increase in emissions from the power generation sector, even in a case where all incremental generating capacity is renewable.

- Based on the 2017 EIA AEO, by 2035 direct residential natural gas use will account for about 4 percent of total GHG emissions, and the sum of natural gas, propane, and fuel oil used in the residential sector will account for about 5 percent of total GHG emissions. The EIA 2017 AEO projects emissions from the generation of electricity supplied to the residential sector to account for about 10 percent of total GHG emissions in 2035, or more than twice the GHG emissions from the direct use of natural gas in the residential sector.

[1] The electric grid is becoming cleaner due to a variety of factors, including low cost natural gas displacing coal, penetration of renewable generating capacity, and retirement of existing lower efficiency fossil fuel units due to changes in regulation and market forces.

- In the policy case, where about 60 percent of the natural gas, fuel oil and propane households are converted to electricity by 2035 in the regions where electrification policy is implmeneted, the total economy-wide increase in energy-related costs (residential consumer costs plus incremental power generation and transmission costs) from policy-driven residential electrification ranges from $590 billion to $1.2 trillion (real 2016 $), which is equal to $1,060 to $1,420 per year for each affected household, depending on the power generation scenario. This reflects three components: i) changes in consumer energy costs between 2023 and 2050, ii) changes in consumer space heating and water heating equipment costs between 2023 and 2035, and iii) incremental power generation and transmission infrastructure costs between 2023 and 2035.
    - Policy-driven electrification would increase the average residential household energy-related costs (amortized appliance and electric system upgrade costs and utility bill payments) of affected households by between $750 and $910 per year, or about 38 percent to 46 percent.
    - Widespread policy-driven residential electrification will lead to increases in peak electric demand, and could shift the U.S. electric grid from summer peaking to winter peaking in every region of the country, resulting in the need for new investments in the electric grid including generation capacity, transmission capacity, and distribution capacity.
- The average cost of U.S. GHG emissions reductions achieved by policy-driven residential electrification would range between $572 and $806 per metric ton of CO_2 reduced, which is significantly higher than the estimated cost of other GHG reduction options.
- The costs and impacts from the residential electrification policy modelled in the study vary widely by region. based on differences in weather, which impacts both the demand for space heating, and the efficiency of the electric heat pumps. There also can be dramatic differences in costs and emissions benefits within a given region or state based on that local unique circumstances and dynamics. Criteria that can influence the results for a city or local region include differences in natural gas and electricity prices, differences in the housing stock, cleanliness of the electric grid, impacts on the local distribution systems.

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Executive Summary

ES-1 Introduction

In recent years there has been a shift in the types of policies that are being proposed to reduce greenhouse gas (GHG) emissions. The first wave of GHG policy initiatives focused primarily on regulation of GHG emissions in the power sector, as well as direct fuel efficiency targets in the transportation sector and appliance efficiency standards in the residential and commercial sectors. However, reducing GHG emissions by 80 percent by 2050, relative to 1990 levels, consistent with the Paris Agreement, has become a stated environmental goal in many states and localities. The initial set of environmental policies is expected to be insufficient to meet these deep decarbonization goals.

As states and local municipalities consider deep decarbonization of their economies and as the electric grid becomes less carbon-intensive policy-makers and environmental advocates are looking at mandated residential electrification as one option for additional reductions in residential GHG emissions.

Underlying these residential electrification proposals is the assumption that once the electric grid becomes sufficiently low-carbon emitting, conversion of fossil-fuel based residential heating loads and other appliances to electricity can further reduce CO_2 emissions.

Proponents have also suggested that this policy would provide a benefit to the electric grid by taking advantage of under-utilized power generation capacity during winter months and would allow for new electric load growth profiles to match with expected renewable generation profiles.

Some stakeholders also view residential electrification as a means of reversing the impact of declining power usage trends on electric utilities and electric utility rates by increasing the number of appliances that run on electricity in residential households.

ES-2 Potential Impacts of Residential Electrification

While policy-driven residential electrification has been discussed in multiple venues, there has been little or no analysis of the overall costs, benefits, and implications of such policies. The AGA engaged ICF to assess the costs and benefits of alternative policy-driven residential electrification cases developed by AGA.

The study addresses a series of fundamental questions including:

- Will policy-driven residential electrification actually reduce emissions and if so, by how much?
- How will policy-driven residential electrification impact natural gas utility customers?
- What will be the impacts on the power sector and on electric transmission infrastructure requirements?
- What will be the overall cost of policy-driven residential electrification?
- How do the costs of policy-driven residential electrification compare to the costs of other approaches to reducing GHG emissions?

The primary rationale for policies requiring electrification of residential space heating and other loads is the potential for reducing overall GHG emissions. However, the resulting increase in electricity demand can lead to increases in GHG emissions from the power sector. Hence, to be successful, the decrease in residential sector GHG emissions resulting from policy-driven residential electrification must be greater than any potential increase in GHG emissions from the incremental electricity generation required to meet the resulting growth in electric loads. This requires both a high efficiency alternative to natural gas and other fuels used in the residential sector, and a low-emitting electric grid.

Emissions from direct-use of fossil fuels that would be displaced by residential electrification are already small relative to total GHG emissions. In 2016, natural gas use in the residential sector contributed less than 4 percent of total U.S. GHG emissions, and total direct fuel consumption by the residential sector contributed less than 5 percent of total U.S. GHG emissions. This limits the total GHG benefit that could theoretically be realized from reducing residential use of fossil fuel technologies.

At the same time, emissions from electric generation needed to meet electric load in the residential sector are already nearly twice as large as direct end use sources in this sector. In 2016 emissions from the electric grid attributable to residential sector demands contributed 10.5 percent of the total U.S. GHG emissions. And while the electric grid is expected to become less CO_2 intensive overtime, much of the country will continue to rely on coal and natural gas generation to some degree.

The EIA 2017 AEO Reference Case (which was used as the baseline for this analysis) projects renewable power generation to increase from 14 percent of total power generation in 2016 to 23 percent by 2035, and for coal power generation to decrease from 32 percent of total power generation in 2016 to 23 percent by 2035. Based on the EIA forecast, the power grid will continue to become less CO_2 intensive over time.

However, the EIA 2017 AEO also projects that the power grid in much of the country will continue to rely on coal and natural gas generation. As a result, in most regions, increased electricity demand due to policy-driven residential electrification through 2035 would lead to an increase in emissions from the electric sector. This highlights the need to consider the trade-off between reduced GHG emissions from direct residential end-uses of fossil fuels and increased emissions from replacement power sources.

Finally, meeting the incremental electric demand resulting from policy-driven residential electrification will potentially require incremental investment in the power generation infrastructure throughout the U.S. On an annual basis, natural gas delivers almost as much energy as electricity to the residential sector, while accounting for fewer GHG emissions. Electrifying the entire residential sector by 2035 would increase peak electric system demand and could require the size of the entire U.S. power generation sector to almost double by 2035.

Insight: Impact of Location

The costs and impacts from the residential electrification policy modelled in the study differ based on location and there can be dramatic differences in costs and emissions benefits within a given region or state based on that local unique circumstances and dynamics. Criteria that can influence the results for a city or local region include differences in weather and climate, natural gas and electricity prices, differences in the housing stock, cleanliness of the electric grid, and the local impacts to the distribution systems or other factors.

The costs and impacts of residential electrification would also differ based on the specifics of the implemented residential electrification policy. Policies that would result in a slower rate of electrification, or include measures designed to reduce the impacts of electrification on peak demand could have smaller impacts on the electric grid and lower overall costs, while more aggressive policies that would force early retirement of non-electric furnaces and water heaters would increase the impacts of electrification on peak demand and increase overall costs.

ES-3 Analysis Approach

The residential electrification policy scenarios evaluated in this study impact both new construction and appliance replacement. Overall, the policy case evaluated would result in the conversion of roughly 60 percent of fossil-fueled housing stock to electricity by 2035 in the regions where the policy is implemented. Although focused on natural gas, the analysis also includes conversion of oil and propane-fueled households, which are assumed to be included in any future policy.

For each new and existing household converted from one of the fossil fuels to electricity, the analysis includes a projection of the life-cycle differences in equipment costs, the costs of electrical upgrades in existing homes, the changes in annual fossil fuel and electricity consumption and energy costs, and the changes in annual and peak period electricity required. The analysis does not include the impact to natural gas or electric rates, nor the cost of local electricity distribution system upgrades that might be necessary to meet the growth in electricity demand, due to the very site-specific nature of such upgrades.

Energy prices, equipment conversion costs, and energy consumption are based on regional data from the EIA AEO 2017 and other public sources.

The heat pump efficiency used in this study is well above what is currently considered a high-efficiency system and assumes a further progression in electric heat pump technology over the life of the study period. The space heating conversions are based on high efficiency air source heat pumps (ASHP) with an average heating seasonal performance factor (HSPF) of 11.5 over the conversion time period (2023-2035). The HSPF rating for the heat pump reflects a design efficiency. Actual space heating efficiency varies based on winter temperatures, with efficiency declining as the temperature becomes colder. For the study, temperature data from 220 different points is used to estimate effective heat pump efficiency at different locations across the country on both an annual and peak period basis.

The water heater conversions from natural gas to electric demand are based on a heat pump water heater with an average efficiency of 200 percent.

The impact on CO_2 emissions at the household level was estimated based on changes in energy consumption and standard emissions factors. However, the increase in electricity demand due to the electrification policy also leads to potential increases in emissions from the electric generation sector. The impact of the growth in electricity demand on the power grid depends on how the electric grid responds to the increase in electric load. This study evaluated the impacts on electric grid costs and emissions for two different residential electrification cases:

- Renewables-Only Case: In this case, the electric system was constrained from adding new fossil fuel capacity to meet the incremental electricity demand from electrification. The requirement for additional generating capacity was met by a combination of renewable generation and battery storage.
- Market-Based Generation Case: The Market- Based Generation Case was developed in order to evaluate a lower-cost residential electrification case, compared to the Renewables-Only Case. In this case the electric system was allowed to meet the incremental electricity requirements in the most cost-effective way, without limits on fuel choice.

In the Renewables-Only Case, the residential electrification policy was implemented throughout the lower-48 states. In the Market-Based Generation Case, emissions in the Rocky Mountain, Midwest, and Plains states would have increased as the result of policy-driven electrification, hence the residential electrification policy was not implemented in the states in these regions. In both cases, the annual dispatch of the available power capacity was based on the economics of the dispatch, consistent with current regulatory structures.

The analysis of increased electric generation capacity was conducted using an industry recognized power model, ICF's Integrated Planning Model (IPM®), using AGA specified assumptions. The Reference Case reflects the Energy Information Administration (EIA) Annual Energy Outlook (AEO) 2017 forecast.

ES-4 Study Results

Overall, the residential electrification policy assessed in this study would result in the conversion of between 37.3 and 56.3 million households from natural gas, propane, and fuel oil space and water heating to electricity between 2023 and 2035. This represents about 60 percent of the total non-electric households in each region where the policy is implemented. Table ES-1 summarizes the results of the residential electrification cases relative to the Reference Case.

Table ES-1: Summary of Results[2]

	Renewables-Only Case	Market-Based Generation Case
U.S. Greenhouse Gas Emissions	Annual U.S. GHG emissions reduced by 93 million metric tons of CO_2 by 2035 (1.5 percent)	Annual U.S. GHG emissions reduced by 65 million metric tons of CO_2 by 2035 (1 percent)
Residential Households	56.3 million households converted to electricity $760 billion in energy & equipment costs Direct consumer annual cost increase of $910 per household	37.3 million households converted to electricity $415 billion in energy & equipment costs Direct consumer annual cost increase of $750 per household
Power Sector	320 GW of incremental generation capacity required at a cost of $319 billion $107 Billion of associated transmission system upgrades	132 GW of incremental generation capacity required at a cost of $102 billion $53 Billion of associated transmission system upgrades
Total Cost of Policy-Driven Residential Electrification	Total energy costs increase by $1.19 trillion $21,140 average per converted household $1,420 per year per converted household increase in energy costs	Total energy costs increase by $590 billion $15,830 average per converted household $1,060 per year per converted household increase in energy costs
Cost of Emission Reductions	$806 per metric ton of CO_2 reduction	$572 per metric ton of CO_2 reduction

[2]These cost numbers do not include all costs associated with these policies. These costs do not include the cost of local electric distribution system upgrades, do not consider potential natural gas distribution company rate increases on remaining gas customers as the number of natural gas customers declines, or the decrease in natural gas commodity prices that would be expected if total natural gas demand decreases.

At the national level, the analysis of the residential policy-driven electrification cases in this study leads to several important conclusions:

- Policy-driven residential electrification would reduce total U.S. GHG emissions by 1 percent to 1.5 percent in 2035. The potential net reductions in emissions from the residential sector are partially offset by increases in emissions from the power generation sector, even in the case where all incremental generating capacity is renewable.
- Policy-driven residential electrification could increase the national average residential household energy-related costs (amortized appliance and electric system upgrade costs and utility bill payments) by between $750 and $910 per year, or between 38 percent and 46 percent per year.
- Growth in peak winter period electricity demand resulting from policy-driven residential electrification would shift the U.S. electric grid from summer peaking to winter peaking in every region of the country, and would increase the overall electric system peak period requirements, resulting in the need for new investments in the electric grid including generation capacity, transmission capacity, and distribution capacity. Incremental investment in the electric grid could range from $155 billion to $456 billion between 2023 and 2035.
- The total economy-wide increase in energy-related costs (residential consumer costs plus incremental power generation and transmission costs) from policy-driven residential electrification ranges from $590 billion to $1.2 trillion (real 2016 $), which is equal to from $1,060 to $1,420 per year for each affected household, depending on the power generation scenario. This includes changes in consumer energy costs between 2023 and 2050, as well as changes in consumer space heating and water heating equipment costs, and incremental power generation and transmission infrastructure costs between 2023 and 2035.
- The average cost of U.S. GHG emissions reductions achieved by policy-driven residential electrification would range between $572 and $806 per metric ton of CO_2 reduced.

The analysis conducted for this study indicates that significant policy-driven residential electrification efforts would change the overall pattern of electricity demand, and would require major investments in new generating and transmission capacity. Currently, most of the U.S. electric grid is summer peaking, with higher peak demand during the summer than in the winter. As a result, the primary driver of electric grid capacity requirements is peak summer load. The residential electrification policies evaluated in this study do increase summer demand due to conversion of water heaters to electricity. However, natural gas and other fossil fuel space heating load is heavily focused over the winter season, and electrification of space heating would significantly increase electricity demand during the winter, particularly on the coldest winter days when electric heat pump efficiency is lowest, and space heating requirements are the highest.

The increase in peak winter load associated with the electrification of residential space heating cases would convert nearly every region of the U.S. power grid from summer peaking to winter peaking—the incremental generation requirements from electrification policies are typically more pronounced in regions that are already winter peaking.

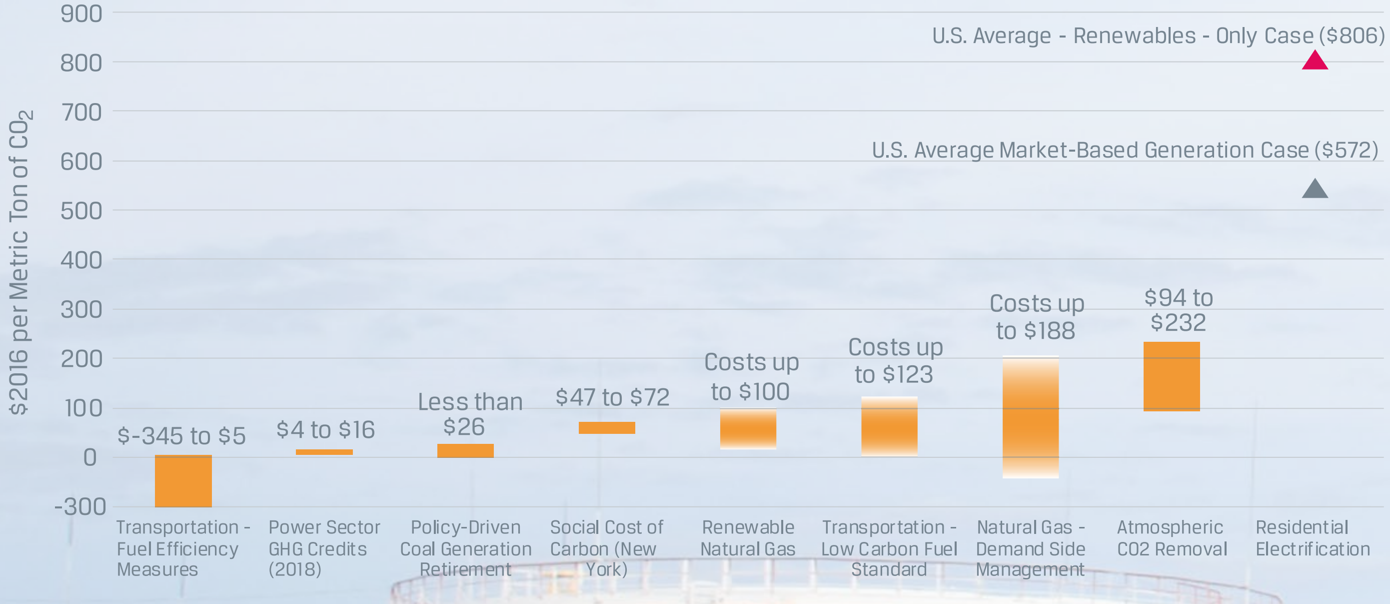
The increase in overall peak electricity demand resulting from the policy-driven residential electrification case would require an increase in total generation capacity in 2035 of between 10 and 28 percent relative to the Reference Case, depending on the power generation case.

The increase in peak demand would also require incremental investments in the transmission and distribution systems. This study includes an estimate for the required incremental investment in transmission capacity. However, it was beyond the scope of the study to assess the potential requirements for additional distribution capacity.

ES-4.1
Cost Effectiveness of Policy-Driven Residential Electrification as a Greenhouse Gas Emissions Reduction Policy

The study of policy-driven electrification of residential fossil fuel heating load (space and water) indicates that residential electrification would be a more expensive approach to greenhouse gas reduction relative to many of the other options being considered—based on considerations related to the emissions reduction potential and the cost competitiveness of this approach relative to other GHG emission reduction options.

Figure ES-1:
Comparison of Cost Ranges for GHG Emissions by Reduction Mechanism



Sources: Energy Innovations, Energy Policy Simulator; GHG emission credits from the most recent auction for the Regional Greenhouse Gas Initiative (RGGI) and California Cap & Trade program; Estimates for GHG reduction costs for the existing coal generation units are based on the Levelized Cost of Energy (LCOE) consistent with the EIA's 2017 AEO Base Case; New York Public Service Commission's (NYPSC's) adoption of the Social Cost of Carbon (SCC); U.C. Davis, The Feasibility of Renewable Natural Gas as a Large-Scale, Low Carbon Substitute, 2016; Comparison of Greenhouse Gas Abatement Costs in California's Transportation Sector presented at the Center for Research in Regulated Industries - 27th Annual Western Conference (2014); The maximum cost of $10 per MMBtu for any Demand Side Management (DSM) program costs is estimated based on an review of public DSM programs; Carbon Engineering, Keith et al., A Process for Capturing CO_2 from the Atmosphere, Joule (2018), https://doi.org/10.1016/j.joule.2018.05.006.

ES-4.2 Overall Conclusions on the Effectiveness of Residential Electrification as a Greenhouse Gas Emissions Reduction Policy

Electrification of direct-use natural gas from the residential sector would result in a significant decrease in the number of residential customers connected to the natural gas distribution system, and a significant decline in natural gas throughput on the system. These changes would result in a material shift in natural gas distribution system costs to the remaining gas utility consumers, including the remaining residential customers, and commercial and industrial sector customers. This study did not include an evaluation of these cost implications to consumers.

This study did not address electrification policies targeted at other sectors of the economy, including the transportation sector, where policy-driven electrification could prove to be a more cost effective approach to reducing GHG emissions. Overall, electrification policy measures aimed at residential natural gas and other non-electric sources of residential energy will be challenged by issues including cost-effectiveness, consumer cost impacts, transmission capacity constraints of the existing electrical system, current and projected electric grid emission levels, and requirements for new investments in the power grid to meet growth in peak generation and transmission requirements .

At the same time, the total GHG emissions reductions available from a policy targeting electrification of residential heating loads represent a small fraction of domestic emissions. Total residential natural gas emissions are expected to account for less than 5 percent of the estimated 6,200 million metric tons of GHG emissions in 2035 in the AEO 2017 Reference Case.[3] Aggressive electrification policies would have the potential to reduce these emissions by up to 1.5 percent of the total U.S. GHG emissions.

[3] The EIA's 2017 AEO Reference Case estimates 4,830 million metric tons of CO2e in 2035 from combustion sources. An additional 1,370 million metric tons of CO2e from both combustion and non-combustion is assumed based on 2016 emission levels from those sources.

1 Policy-Driven Residential Electrification—Introduction and Background

In recent years there has been a shift in the types of policies that are being proposed to reduce GHG emissions. The first wave of GHG policy initiatives focused primarily on regulation of GHG emissions in the power sector, as well as direct fuel efficiency targets and clean fuel standards in the transportation sector and appliance efficiency standards in the residential and commercial sectors. More recently, reducing GHG emissions by 80 percent relative to 1990 levels by 2050, consistent with the Paris Agreement, has become a stated environmental goal in many states and localities. The types of policies implemented in the first wave of GHG policy initiatives are expected to be insufficient to meet these deep decarbonization goals.

A second wave of GHG policy initiatives are being proposed and debated primarily at the local and state level, in order to reach these more aggressive targets. A few examples of jurisdictions discussing or implementing these GHG reduction policies include:

- **Denver:** A city task force has recommended policies to "shift commercial buildings and 200,000 households off natural gas to heat sources that do not lead to carbon pollution."[4]
- **Massachusetts:** Legislation has been proposed to require the conversion of residential fossil fuel use to electricity.[5] The state has also proposed establishing targets for 100 percent renewable generation levels in efforts to decarbonize its economy.
- **Ontario:** Various non-governmental organizations promoted residential electrification, which was then aggressively pursued by the provincial environmental agency.[6]
- **Vancouver, British Columbia:** City council plans to position Vancouver as the greenest city in the world include establishing 100 percent renewable energy targets before 2050 and implementing a phased approach to achieving zero emissions in all new buildings by 2030. Some policies that effectively exclude natural gas have been initiated.[7]
- **California, Oregon, Washington:** Various local and state groups are in active discussion regarding the potential for residential electrification policies to reduce GHG emissions.[8]

While these discussions cover a broad range of initiatives and target markets, many also include discussion of residential electrification as one option for reducing GHG emissions.

[4] https://www.denverpost.com/2017/09/06/denver-greenhouse-gas-emissions-renewable-energy/

[5] Massachusetts Senate Bill 1849 and Massachusetts Bill SD1932 (100 Percent Renewable Energy Act)

[6] It was reported in May 2016 that Ontario was considering policies targeting drastic reductions in GHG emissions, including a new building code rules that would have required all homes and small buildings built in 2030 or later to be heated without using fossil fuels, such as natural gas.

[7] http://vancouver.ca/green-vancouver/renewable-city.aspx

[8] California Energy Commission Report, "GHG Emission Benefits and Air Quality Impacts on California Renewable Integration and Electrification," January 2017; SoCal Edison's, "The Clean Power and Electrification Pathway," November 2017; Evolved Energy Research, "Deep Decarbonization Pathways Analysis for Washington State," April 2017; Energy + Environment Economics, "Pacific Northwest Low Carbon Scenario Analysis," November 2017

While policy-driven residential electrification has been discussed in multiple venues, there has been little or no analysis of the overall costs, benefits, and implications of such policies. AGA engaged ICF to develop this analysis of electrification policies for a set of policy cases specified by AGA. The study addresses a series of fundamental questions including:

- Will policy-driven residential electrification actually reduce emissions?
- How will policy-driven residential electrification impact natural gas utility customers?
- What will be the impacts on the power sector and on electric transmission infrastructure requirements?
- What will be the overall cost of policy-driven residential electrification?
- How do the costs of policy-driven residential electrification compare to the costs of other approaches to reducing GHG emissions?

1.1 What is Policy-Driven Residential Electrification?

Simply stated, policy-driven residential electrification is the required conversion of new and existing residential end-uses supplied by fossil fuel technologies with alternative electric appliances. For this analysis, the incremental electricity is provided by the local electric grid.

The underlying concept driving these proposals is the assumption that when the electric grid becomes sufficiently low-carbon emitting, conversion of fossil-fuel based residential heating loads and other appliances to electricity can reduce CO_2 emissions.

Proponents of policy-driven residential electrification have also suggested that this policy would provide a benefit to the electric grid by taking advantage of under-utilized power generation capacity during winter months and would allow for new electric load growth profiles to match with expected renewable generation profiles.

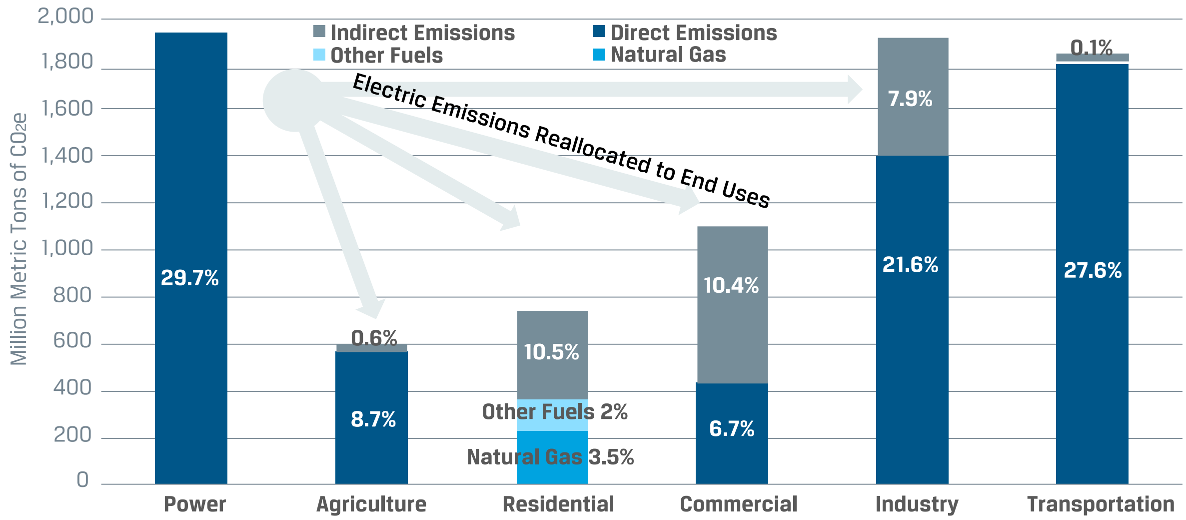
Policy-driven residential electrification also is viewed by some stakeholders as a means of reversing the impact of declining power usage trends on electric utilities and electric utility rates by increasing the number of appliances that run on electricity in residential households.

What are the Potential Environmental Benefits of Residential Electrification?

However, given the complicated interactions of this type of policy proposal, the potential for GHG emission reductions is not always clear and will depend on the relationship between residential electricity demand and the electric grid, which will differ based on regional and local considerations.

Despite the relatively broad interest in residential electrification, the potential benefits in terms of GHG emissions reductions are limited by the overall contribution of residential sector end-use demand to overall GHG emissions.

Figure 1-1:
U.S. GHG Emissions by Source and Sector 2016



Source: EPA GHG Inventory

As shown in Figure 1-1, direct GHG emissions from the residential sector currently comprise only 6 percent of total U.S. GHG emissions, with less than 4 percent coming from natural gas use, including fugitive methane emissions releases.

The residential sector is also responsible for 10.5 percent of total U.S. GHG emissions from its share of the electric sectors emissions. Hence, the emissions from the generation of the electricity used in the residential sector are almost twice as high as residential emissions from other fuels.

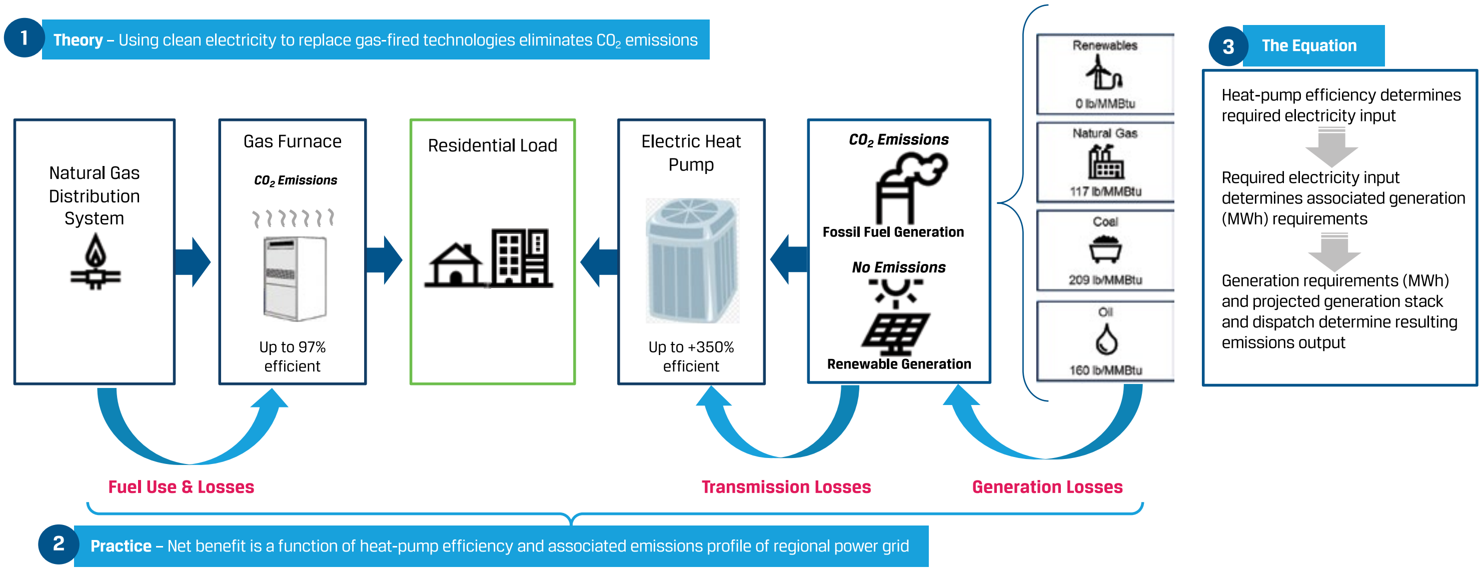
How Would Policy-Driven Residential Electrification Work?

While gas and related fossil fuel residential end-use technologies have achieved high levels of efficiency, their use still involves burning fossil fuels and releasing CO_2 and associated GHG emissions. In contrast, supplying the same MMBtu of heating load with an electric technology, such as a heat pump, results in no direct emissions at the site.

However, to understand the impact of each fuel source on net GHG emissions the full energy-cycle of each fuel path must be considered. This relationship is illustrated in Figure 1-2. In the case of natural gas, this involves the upstream drilling of natural gas, gathering, processing, transmission on interstate pipeline systems, and distribution to residential users. While these are not energy-free activities, they do not add substantially to the net overall energy content of the MMBtu delivered to the residential consumer or impact the residential energy costs significantly.

With the electric system, each Btu of electricity delivered to a residential user must be generated by a power plant, transmitted on high voltage transmission lines, and then across local distribution lines to each individual house. Electric transmission losses alone accounted for a loss of 6 percent of the delivered energy in 2016, compared to a 1 percent loss in natural gas transmission losses. The efficiencies and the GHG emission implications of the upstream generation facilities vary significantly based on the composition of the regional power generation portfolio.

Figure 1-2:
Diagram of Residential Electrification Theory



If all upstream generation resources were renewable or zero-emitting alternatives, displacement of a gas-fired residential technology with an electric technology would result in net emission benefits, regardless of transmission and related losses. However, this does not reflect the current state of the electric grid and/or a realistic expectation in the foreseeable future. As such, to understand the net implications and benefits of residential electrification it is important to place such discussions in the context of the upstream generation portfolio.

What Factors Determine the Net GHG Benefits of Residential Electrification?

The potential environmental benefit of policy-driven residential electrification depends on four critical factors:

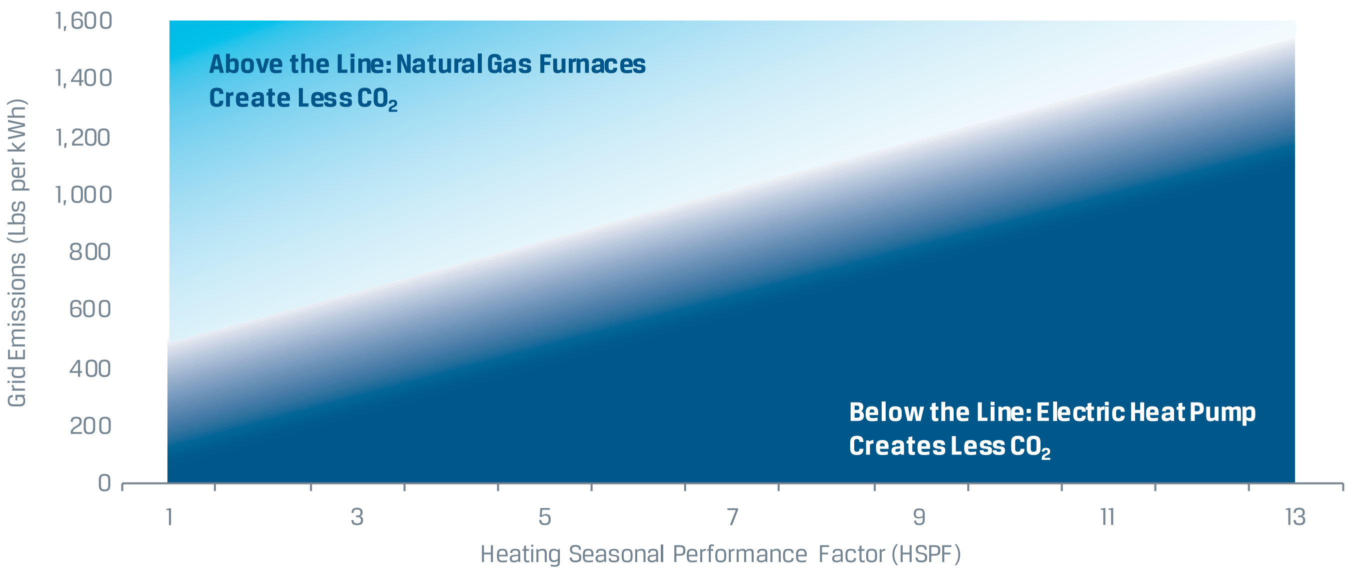
- The heating or water heating load being replaced.
- The efficiency of the appliance facing mandated replacement (e.g., the natural gas furnace and water heaters).
- The seasonal and climate-adjusted efficiency of the replacement electric technology (e.g., heat pump or heat pump water heater).
- The emission rate of the local electric grid used to provide the incremental replacement energy source.

To illustrate this relationship, consider the case of a high efficiency gas furnace being replaced by a heat pump. In warmer regions, the performance of the heat pump relative to the gas-fired furnace will result in greater relative net energy savings.

If this region has a sufficiently low GHG emitting electric grid, transferring energy consumption for the gas-fired technology to the electric technology can reduce net GHG emissions. However, if the same electric grid profile is assumed in a colder region where a heat pump's performance is degraded due to the colder temperatures, the net GHG emission benefits of the policy-driven electrification can be minimal or even negative.

Figure 1-3 shows this relationship. The heat pump performance is shown as actual Heating Seasonal Performance Factor (HSPF)[9], which is a seasonally adjusted efficiency expressed in Btu/Wh and equal to the Coefficient of Performance (COP) factor times 3.4. A gas combined cycle power plant has emissions of approximately 800 pounds of CO_2 per MWh so an electric heat pump needs to operate at an actual HSPF of more than about 7 to have lower emissions than a natural gas furnace.

Figure 1-3: Emissions Reduction For Electric Heat Pumps Based on Weather and Electric Grid Emissions



1.2 Local and Regional Factors

This study's national level impacts were derived from a build-up of more localized analysis. This method was used to capture the unique regional factors for different parts of the country in order to more fully understand the impacts and implications of policy-driven residential electrification policies. The level of detail used in this analysis ranged from city level, to state, to the nine regions used in the study and then aggregated to the national totals.

Due to the complex interaction of the multiple factors involved with modelling the impacts of the residential electrification policy approach used, there are both significant differences in the regional results from the study, as well as significant variations of results within a given region or state based on a wide range of localized issues.

[9]The actual HSPF differs from the nominal HSPF typically used to measure heat pump efficiency. The nominal HSPF is defined for a specific set of climate conditions. Actual HSPF varies with climate and other operational factors. The same heat pump will have a higher actual HSPF in a warmer climate than in a colder climate. In this study, we have defined the heat pump based on nominal HSPF, but have used an estimate of actual HSPF based on Heating Degree Day's (HDDs) on a local level.

Actual emissions from electric generation to meet the growth in electricity demand from policy driven residential electrification for appliances across the U.S. Lower 48 are a result of each region's mix of coal, gas-fired, nuclear, and renewable generation sources, as well as the impact of climate on heat pump efficiency and energy requirements.

These impacts were evaluated on a regional basis to account for differences in both climate (and the relative performance of electric replacement technologies) and regional power grid characteristics. This study presents results using the regions highlighted in Appendix B. The regions were created based on state characteristics, including:

- Electric power pool and grid interconnections
- Natural gas Consumption Profiles
- Regional Climate and Weather Conditions
- Electric Grid Emissions (2035)

1.3 Electric Heat Pump Performance

The residential electrification policies under discussion in different areas generally depend on the replacement of natural gas, propane and fuel oil space heating with electric heat pumps for the majority of the expected environmental benefits. Heat pumps can be very efficient, particularly on an annual basis. However, heat pump performance degrades at lower outdoor temperatures,[10] so heat pump performance must be assessed based on local climatic conditions. In order to assess the overall impacts on the electric grid, the study specifically addressed the question of the impact of the heat pump on peak period electric demand as well as annual electric demand.

Key Factors for Heat Pump Efficiency

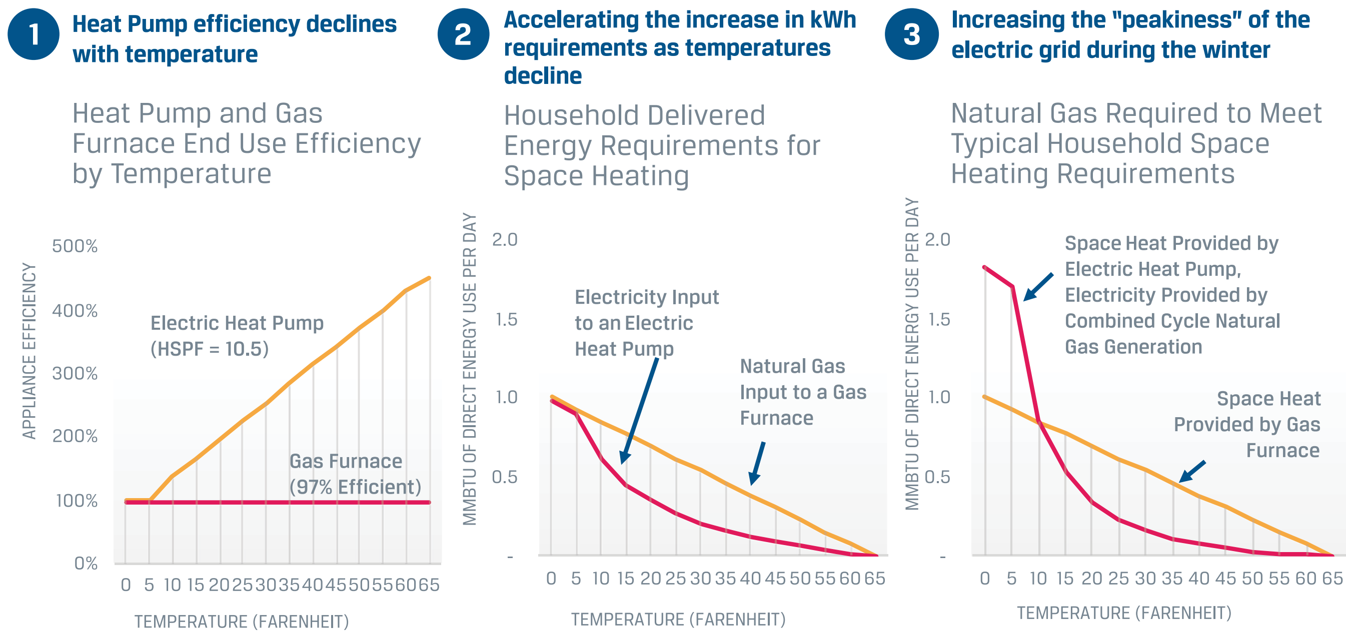
Heat pumps transfer heat rather than transforming chemical energy to heat through combustion. While combustion-based systems can never provide more energy than they consume, i.e., be more than 100 percent efficient, heat pumps can transfer more energy than they consume, i.e., be more than 100 percent efficient. A nominal heat pump efficiency of 300 percent is not unusual under certain operating conditions.

This high efficiency is critical to providing environmental benefits since the higher efficiency of the heat pump offsets the lower efficiency of the electric generating system. However, heat pump performance degrades as the outdoor temperature drops. Falling temperatures affect heat pump performance in three ways:

- The heat pump becomes less efficient.
- The heat pump provides less heat output.
- The discharge air temperature of the heat pump gets lower.

[10]Not all heat pumps degrade at the same rate. The reduction in efficiency for ground source and cold climate heat pumps degrades at a slower rate than conventional heat pumps as outside temperatures decline.

Figure 1-4:
Illustration of Energy Delivery of an Electric Heat Pump and Natural Gas Furnace



In addition, heat pump installations are often sized to meet air conditioning load requirements rather than heating requirements. Oversizing a heat pump to meet peak winter requirements results in more expensive equipment, lower operating efficiency, and additional wear and tear on the equipment during the summer cooling season.

Since peak-day winter requirements occur only a few days each year, and design day conditions occur only every few years, most heat pump installations, including cold climate heat pumps, are designed with electric resistance heat to meet load requirements on the coldest days. The electric resistance heat has an operating efficiency of 100 percent, rather than the average annual operating efficiency of the heat pump which might range from 200 percent to 300 percent (or more).

In addition, at very low temperatures, heat pumps typically cannot provide adequate heat and require some form of back-up energy, typically electric resistance heat. The actual climate-adjusted heat pump performance must be calculated for each region to estimate the consumption and peak demand. This is discussed in Section 2.

Air source heat pumps (ASHP), also referred to as electric heat pumps in this study, have been in commercial use for over 50 years and are a relatively mature technology. Nevertheless, the analysis assumed further performance improvement.

2 Analysis of the Costs and Benefits of Policy-Driven Residential Electrification

In this section, the various cases and assumptions used to evaluate the impact of residential electrification policies are discussed. Descriptions for the following are included:

- **Electrification Policy Definition:** Guidelines for applying a residential electrification program.
- **Analytical Baseline and Alternative Electric Grid Cases:** Key assumptions related to the North American electric grid's response to electrification policies.
- **Impacts on Electricity Consumption and Demand Profiles:** Estimates for the number of households impacted by each policy and the changes in fuel use and electricity demand.
- **Consumer Cost of Electrification:** The development of consumer costs for residential gas-fired and electric appliances.

Though there has been discussion of electrification of residential space and water heating, few specific policies have been proposed by the stakeholders pursuing this agenda. Indeed, public electrification proposals have failed to address many real-world complexities associated with the application of these policies, such as:

- Feasibility of converting the existing household stock, of which a significant number of households would need retrofits to be able to use an electric heat pump.
- Direct consumer costs from the installation of new equipment and any difference in household energy purchases.
- New electric generation requirements and investments to meet new load-growth.
- Impacts on electric transmission networks and implications of a winter-peaking electric system.

2.1 Electrification Policy Definition

In order to perform an analysis of the implications of these policies, the following assumptions were developed for a policy-driven residential electrification policy that could be applied uniformly across the country. For this analysis, it was assumed that an electrification policy would be established in 2020 with the requirements starting in 2023.

Although the primary focus of this analysis is natural gas, it was assumed that the residential electrification policy would also impact fuel oil and propane systems.

The electrification policy included the following key assumptions:

- All new homes after 2023 are built with electric space and water heating appliances only.

- Starting in 2023, any existing direct-fuel use space and water heating systems would be replaced with electric systems at the end of the effective life of the current system. This would result in the conversion of nearly all residential households currently using natural gas, propane, and fuel oil fuels to electricity by 2050 (even households without forced air systems).
- This study does not address market-driven electrification or policy-driven electrification of commercial, industrial, or other sectors.
- The water heater conversions from natural gas to electric demand used a heat pump water heater with an average efficiency of 200 percent.

While the electrification policy was designed to convert all residential households from fossil fuel use to electricity by 2050, the analysis of the impacts of the policy was conducted through 2035, and considered the lifetime costs and benefits through 2050 of all of the households converted to electricity between 2023 and 2035.

2035 represents a point at which significant policy-driven electrification in pursuit of 2050 targets could be assumed to have occurred, but is still near enough that market results could be reasonably analyzed.

Background: Electric Alternatives to Fossil Fuel Space Heating

The analysis of policy-driven residential electrification uses a high efficiency ASHP as the electric alternative fossil fuel space heat throughout the analysis. In the analysis, the efficiency of the average new heat pump is expected to increase by about 1 percent per year, and averages an HSPF of 11.5 (COP of 3.7) over the time period from 2023 through 2035. After accounting for regional differences in weather, and the performance based on the annual temperature load (using the ASHRAE Design Temperature), the heat pumps installed in response to the residential electrification policy are expected to achieve an average winter season COP of 2.6 in the Renewables-Only Case and an average winter season COP of 2.9 in the Market- Based Generation Case. The COPs of the case differ due to the difference in regions covered under each case.

There are also new heat pump technologies that have been proposed as an alternative to the traditional ASHPs for residential electrification purposes. These include:

- **Ground Source Heat Pumps:** Ground source heat pumps use the earth as a heat source and can therefore maintain better cold weather performance. However, they require drilling and placement of underground heat exchangers, which results in much higher costs.
- **Cold Climate Heat Pumps:** Cold-climate heat pumps (ccHP) are still in the development phase but are expected to have better cold weather performance than conventional heat pumps. However, their performance still degrades in cold weather, and many applications will still require back-up heat. The new ccHP's include additional compressors and other equipment, and are expected to be more expensive than the standard high efficiency air source heat pumps.

Many of the current ccHP's are also "mini-split" systems in which the heating unit is a wall-mounted unit similar to a system found in a hotel room, and would not be effective replacements for a central heating system.

- **Heat Pumps with Fossil Fuel Backup:** One potential approach for reducing the impacts of electrification on peak electric grid requirements is to combine a fossil fuel backup (natural gas, propane or fuel oil) with the heat pump to meet space heating requirements on the colder days during the winter. This requires dual space heating systems.

These three systems were not included explicitly in this analysis. GSHP's and ccHP's were not explicitly included due to the incremental costs required for the systems, the general lack of information on the cost and performance of the ccHP's, and the operational challenges and costs associated with retrofitting existing residences with GSHP and ccHP units. However, the average heat pump efficiency used in this study is sufficiently high that it likely would include ccHP's and GSHP's in addition to a mix of medium to high efficiency conventional heat pumps in order to reach the overall average.

Fossil fuel backup was not considered in this study since equipment replacement occurs at the end of the useful life of the existing system, hence would have required the purchase of new fossil fuel equipment as well as the purchase and installation of the heat pump.

Insight: Household Impacts from Electrification Policies Can Vary Significantly

There is a wide range of impacts from policy-driven electrification on consumers based on where the consumer lives, the type of household under consideration, and the age of the household, and the household income.

The per-household cost of residential electrification also can be much greater on consumers in existing homes relative to costs for a newly constructed household. Existing households can often have installation costs more than double the cost difference of a new household, a problem that is particularly acute in older homes that would generally require more extensive retrofit costs and upgrades for electric conversions of heating equipment.

One major concern being raised related to residential electrification proposals is the impact on lower-income consumers. Given the concentration of low income consumers in older homes, the expected cost impacts of policy-driven electrification are expected to fall most heavily on lower income residents.

The relative costs of policy-driven residential electrification would account for a higher share of income for low-income consumers than for the average consumer.

2.2 Alternative Electric Grid Scenarios

A key component of this study was the analysis of the North American electric grid's response to increased electricity consumption and peak demand following the implementation of the residential electrification policy. The study used IPM® to model three separate electrification cases:

- **Reference Case:** For the Reference Case, IPM® was calibrated to reflect the market assumptions from the AEO 2017 Base Case, with no residential electrification policy in place.
- **Renewables-Only Case:** In the Renewables-Only Case, IPM® was constrained so that no new fossil-fueled capacity beyond the capacity built in the reference case would be built to meet the growth in electricity demand resulting from electrification. The only incremental energy generation allowed to meet this new demand was renewable and battery storage—generation from existing fossil-fuel based units was allowed to meet this incremental demand. In this case, electrification policies were applied to all states on the assumption that all new plant construction would be zero-emitting, thus even if the existing emissions were higher than the threshold for environmental benefit in the Reference Case, residential electrification would have the potential for emission reductions. The IPM® model was used to project the changes in generation mix, fuel, and emissions resulting from the policy.
- **Market-Based Generation Case:** In this case, the electric system response to the increase in electricity demand was determined by the market in order to provide a lower cost case than the Renewables-Only Case. The analysis was based on lowest cost mix of generating capacity consistent with environmental and renewable generation policies.

In the Market-Based Generation Case, residential electrification would have increased emissions in certain regions, including the Midwest, Plains and Rocky Mountain regions due to the reliance on incremental natural gas and coal generation to meet the increase in power generation requirements. In these regions, the increase in GHG emissions from the power sector was greater than the reduction in GHG emissions from direct fuel consumption by residential households. In order to avoid a policy that increased net emissions, the residential electrification policy was not implemented in these regions for the Market-Based Generation Case.

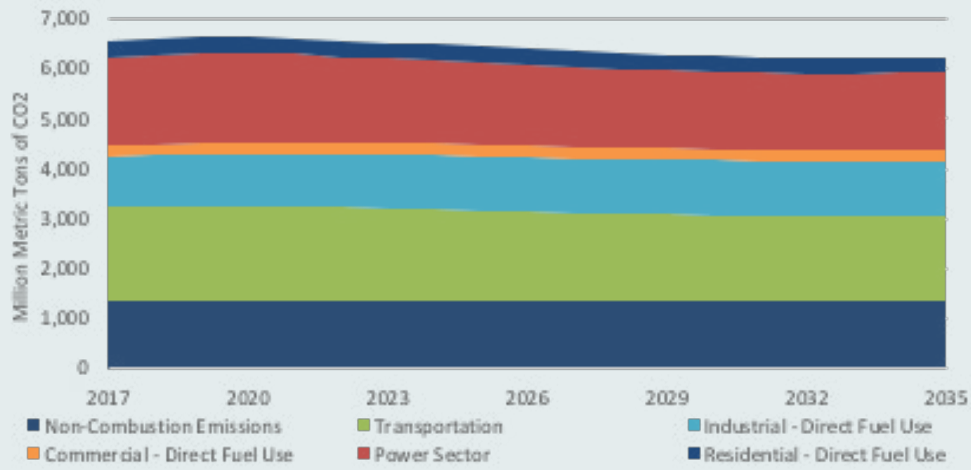
The detailed power sector results of the analysis are presented in Section 3.

Background: Energy Information Agency's 2017 Annual Energy Outlook (AEO)

The EIA's 2017 AEO Base Case forecast is used as the Reference Case for this study. The AEO provides a comprehensive, publicly available forecast of energy consumption, energy prices, and carbon emissions through 2050.

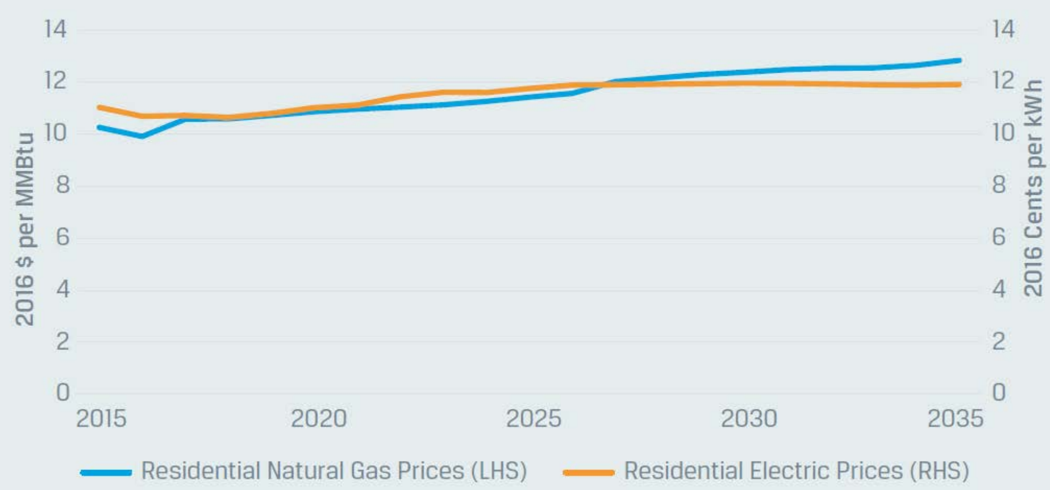
The AEO projects CO_2 emissions from combustion sources to decline from 5,182 million metric tons in 2017 to 4,827 million metric tons in 2035 and 5,084 million metric tons in 2050. Emissions from the power sector decline by 14 percent between 2017 and 2035, primarily due to a 78 percent increase in renewable generation and a decline in coal generation of 22 percent.

Figure 2-1: Total U.S. GHG Emissions (2023 to 2035) in the EIA AEO 2017 Base Case



The relationship between residential electricity and natural gas prices is one of the important determinants of the cost implications of the policy-driven residential electrification analysis. The study used regional AEO price projections to project state-by-state natural gas and electricity prices in the cost analysis. The AEO projects growth in real residential natural gas prices of about 1 percent per year, and real growth in residential electricity prices of about 0.56 percent per year between 2017 and 2035.

Figure 2-2: Average U.S. Residential Prices from EIA's 2017 AEO Base Case (Real 2016 $)



2.3 Household Conversions to Electricity

The Renewables-Only Case, the study assumed that residential electrification policies would be applied in all states. In Figure 2-3, there are 49.8 million natural gas households and 6.4 million oil and propane households converted to electricity by 2035 – representing 60 percent of households using natural gas, propane, and fuel oil under the Reference Case. As a result, there are 36.3 million households that still use fossil-fuels for space and water heating.

In the Market-Based Generation Case, the study assumed that residential electrification policies would only be applied in states where there was a clear emissions benefit based on the state's electric grid emissions profile in 2035 based on the EIA AEO Reference Case (2017). Figure 2-4 shows the conversion impacts for the Market-Based Generation Case. By 2035 this case results in the conversion of 32.4 million natural gas fueled households and 4.8 million oil and propane-fueled households. By 2035 there are 55.3 million households that still use fossil-fuels for space and water heating.

The broader geographic coverage in the Renewables-Only Case results in a greater impact in many aspects of the results and needs to be kept in mind when comparing the results of the two policy cases.

Figure 2-3:
Renewables-Only Case Household Conversions

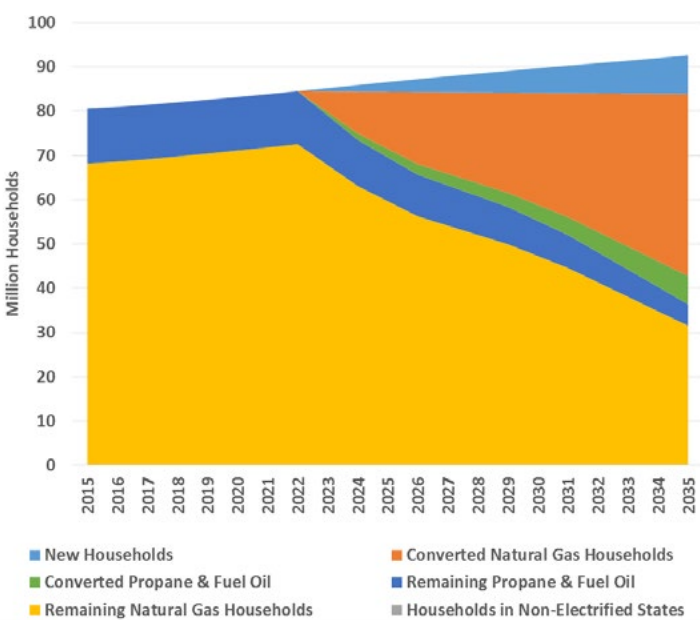
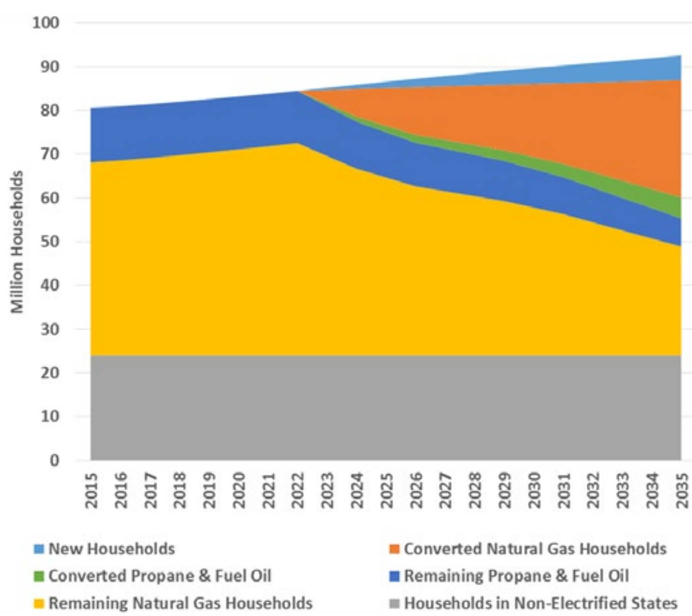


Figure 2-4:
Market-Based Generation Case Household Conversions



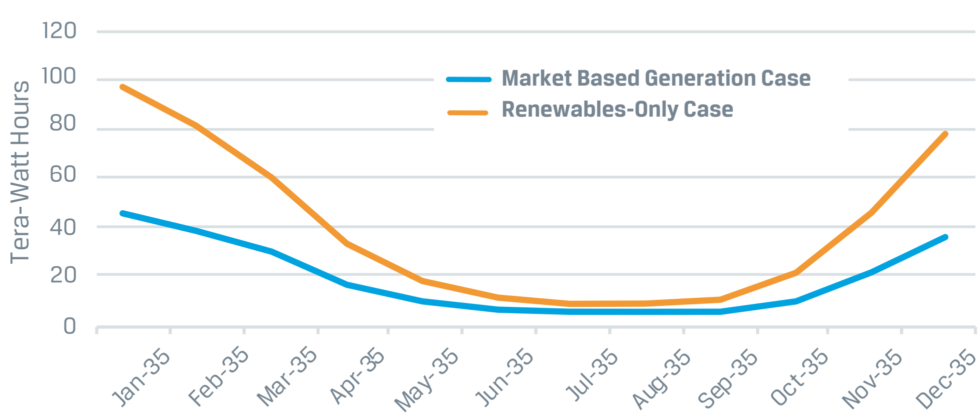
2.4 Impacts on Electricity Consumption and Demand Profiles

For the study, a separate profile was created for the total electricity consumption as well as peak period electric generation requirements in order to fully evaluate the effect of electrification on power system requirements. Electricity consumption is a key variable in understanding the incremental power generation requirements as well as changes in emissions levels and residential energy costs between each case.

Peak electricity demand is a key variable for understanding the impact of electrification policies on electric system capacity requirements. Electric systems must be designed to meet the peak demand at any given time. In many parts of the country the peak demand occurs during summer air conditioning peaks and the system is sized to meet that demand. However the peak in other areas is associated with the peak winter heating load and that peak determines system capacity requirements. As residential space and water heating is electrified in response to the policy-driven electrification mandate, the peak requirements in winter-peaking regions will increase. In regions that are summer peaking in the Reference Case, a certain degree of growth in peak winter demand can occur without significantly impacting the need for electric grid infrastructure. However, when electrification leads to significant growth in space heating demand, regions may switch from summer-peaking to winter-peaking, increasing peak capacity requirements.

- **Incremental Electricity Consumption:** Starting from a baseline natural gas consumption profile for electric generation based on the AEO Reference case, a monthly electric consumption profile was created for use in the electrification cases. This profile includes converted space and water heating demand. To estimate the level of electric demand from space heating conversions, each state's average ASHRAE design temperature and performance characteristics was used for an electric heat pump with an HSPF of 11.5 by 2035, corrected for local climatic conditions.[11] Natural gas water heating usage was converted to an electric water heating system based on current technologies. Water heating demand accounts for the majority of incremental electric demand during the Summer months.

Figure 2-5: 2035 Monthly Electric Consumption by Case



[11] See Appendix A for an explanation of this in the Heating System Efficiency Assumption Section

- **Peak Period Demand:** To determine the impacts of policy-driven residential electrification on peak generation requirements, the first step was to create a peak day sendout for natural gas under the AEO's Reference Case natural gas demand forecast for 2025, 2030 and 2035.[12] Using this peak day demand, an hourly profile of natural gas usage by type (space heating, water heating, and other demand) was developed. The hourly profile was used for estimating the equivalent electric generation requirement based on the heat-pump efficiency at the local design day temperature. Figure 2-6 details the impact of peak period generation on the overall power system capacity requirements for the two cases.

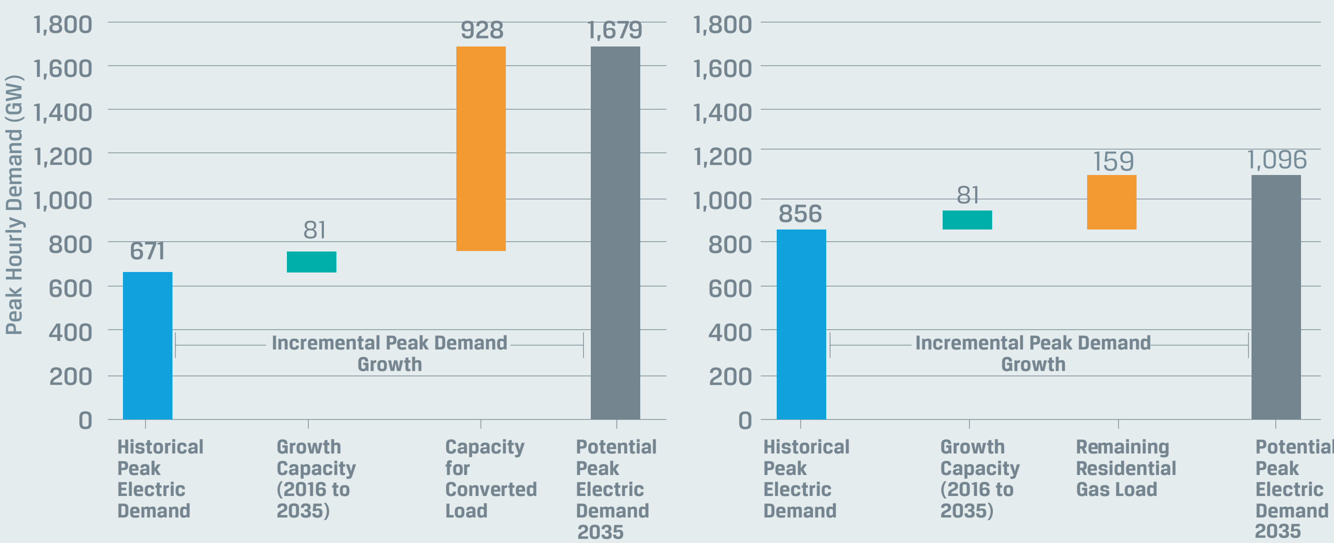
Insight: Impact on Peak-Period Power Demand From 100% Electrification of Residential Natural Gas[13]

Electrifying all direct-use U.S. residential natural gas demand (based on the coincident peak day sendout) would be greater than the highest recorded peak hourly electric generation in the U.S. (July 2011) and 140 percent of highest electric generation ever recorded in the winter (January 2014).[14]

Figure 2-6:

Impact of Residential Electrification on Peak Winter Demand

Impact of Residential Electrification on Peak Summer Demand



2.5 Consumer Cost of Policy-Driven Residential Electrification

New electric heat pump systems typically have a higher lifetime capital cost (equipment cost and installation cost, adjusted for equipment life) than new natural gas systems. In warm regions, this higher cost can be offset by lower energy costs associated with higher efficiency levels (electric heat pump efficiency is directly tied to the ambient temperature), depending on the relative prices of electricity and natural gas.

[12] A detailed description of the Peak Day Methodology is provided in the Appendix.
[13] The AGA scenarios do not assume 100% electrification.
[14] The estimates for the residential natural gas electrification were developed using the same assumptions outlined in Section 3.3 and Appendix 2, with estimates for space and water heating load derived from the EIA's 2009 RECs data. The historic peak-generation levels were sourced from the Form EIA-861.

However, as shown in the previous section, most of the converted households are not new systems but conversions of existing households, which typically incur higher costs for conversions to new heating system types than for a replacement system. The cost of retrofitting a heat pump to natural gas, propane, or fuel oil system can be much higher than replacing the existing system and can include Incremental costs related to the following requirements:

- Upgrades to electrical services and hook-ups.
- Installation and connection of the outdoor portion of the heat pump.
- Resizing ductwork due to different air flow and discharge temperatures.

Moreover, some natural gas systems are not forced air systems but various types of hydronic systems, such as baseboard or radiator heating systems. If the house does not have ductwork for heating or air conditioning then retrofitting to a central heat pump system would be even more expensive and challenging due to the need to install ductwork.[15]

Table 2-1 shows the appliance replacement costs used for the analysis. There are large first-year cost differences between a natural gas and electric heating system based on whether it is new construction or a retrofit to an existing house. For instance, the first-year cost difference between a gas furnace and electric heat pump in a new household indicate an electric system is lower cost, while system retrofit from natural gas to electric heat pumps typically increase first-year costs significantly. Although first-year costs might be lower for an electric heat pump in a new household, the relative cost differences between natural gas and electric heating systems are heavily dependent on the local natural gas and electric prices as well as the heat pump performance in the local climate. These costs were adjusted to account for regional cost variation.

Table 2-1:
National Installation Costs and Annual Fuel Costs (2035) by Household Heating & Cooling System Type (Real 2016 $)

Household Heating & Cooling System Type	New Household Gas Furnace & AC unit	New Household ASHP[1]	Replacement - Gas Furnace & AC unitv	Conversion of Forced Air Furnace		Conversion of Hydronic System	
	Gas Furnace & A/C	ASHP	Gas Furnace & A/C	ASHP (Existing A/C)	ASHP (No Existing A/C)	ASHP (Existing A/C)	ASHP (No Existing A/C)
Purchase Cost (Capital)	$4,495	$3,903	$4,495	$4,065	$4,065	$4,065	$4,065
Total Installation & Upgrade Costs (1-Year Cost)	$6,281	$5,991	$6,858	$6,993	$10,909	$8,637	$11,509
Annual Equipment Costs	$337	$408	$361	$464	$681	$555	$714
Annual Heating Expense	$998	$1,475	$998	$1,475	$1,475	$1,475	$1,475
Total Annualized Costs	**$1,335**	**$1,883**	**$1,359**	**$1,939**	**$2,156**	**$2,030**	**$2,189**

[15] Mini-split systems could be installed without installing ductwork but might not be acceptable for aesthetic reasons and often would require multiple systems in order to serve all the rooms in a typical single-family home.

2.6
Direct Consumer Cost Impacts from Policy-Driven Residential Electrification

The total impact to consumers from potential electrification policies targeting the residential housing sector will depend on the local conditions (relative energy prices, local climate, and the housing stock's heating and cooling systems). For instance, in most areas across the country residential electricity prices are higher than natural gas prices so electrification can result in higher energy costs if the heat pump is not sufficiently efficient.

Insight: Applicability of National and Regional Results to Specific Utility Service Territories

This study is focused on the national level impacts of potential policies requiring electrification of residential energy load. While the analysis conducted for this study was focused on national level impacts, it is not possible to evaluate the impacts of a potential residential electrification policy without looking at the market in a much more disaggregate manner due to the differences in energy demand, energy prices and other factors in different parts of the country. The study used a variety of different data sources, ranging from sub-state level data on heating degree days, housing stock, and changes in electrical and natural gas demand, to state level data on appliance installation costs, regional data on forecasted energy prices, and other inputs. As a result, the analysis is reported at the regional level as well as the national level. The results have been aggregated into nine regions that reflect major regional differences in climate, natural gas use, and power and transmission grid boundaries.

However, the results shown for each region reflect broad averages, and do not include all local cost differences. The study also did not consider the cost impacts on the electric utility distribution system, which are expected to be significant, but are highly utility specific, and difficult to estimate on a national or regional basis. As a result, the regional results reported in this study are unlikely to be representative of individual utility service territories or individual states.

The results of a similar analysis conducted for a specific state or utility service territory within a region may differ significantly from the regional results shown in this report due to:

- Differences in natural gas and electricity prices even within the same region,
- Differences in housing stock,
- Differences in the electric grid, and
- Inclusion of distribution system cost impacts and other factors.

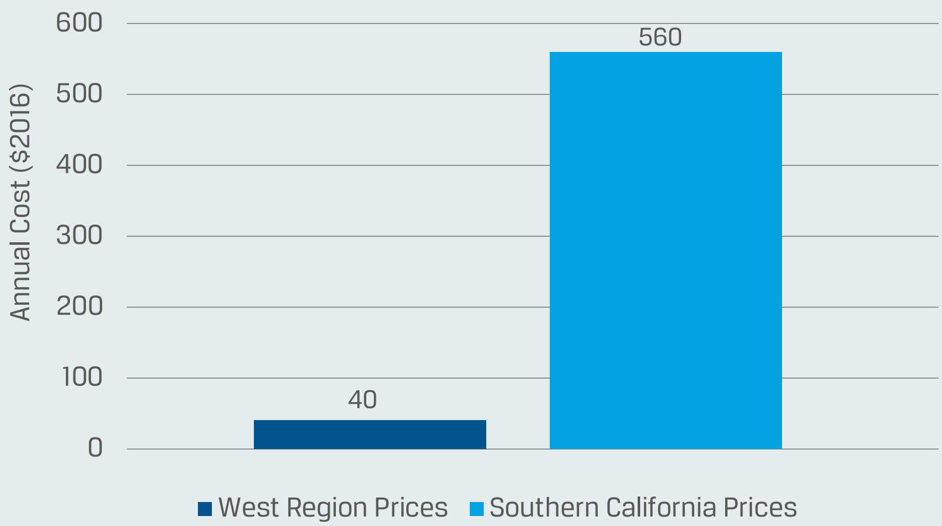
Given the complexity of the issues surrounding residential electrification policies, this study made a number of simplifying assumptions. For instance, this study assumed that all residential households were similar to a national average single-family household, despite the large number of multi-residence households that would be included in these policy proposals. The study found comprehensive data on certain housing characteristics to be limited, and as a result, conservative assumptions for installation and conversion costs were used. In higher cost areas or for households not ideally suited for conversion to electric heating equipment, the actual costs are likely to be understated, particularly for older households and non-single family residential households, which typically are concentrated in lower-income areas.

Case Study: Examining the Impacts of Intra-Regional Residential Prices

In order to illustrate the impact of local conditions relative to the regional averages, we created a simple case study comparing the impact of using Southern California energy prices rather than regional average energy prices on the consumer cost impacts in the Western region.

The projected electricity prices in Southern California (2020) are roughly 37 percent higher than the electricity prices used for the entire West Region, while the local natural gas prices for Southern California were 8.5 percent lower than the regional study price.[16] Using Southern California specific residential rates, when compared to the West's regional average, would result in an incremental increase in consumer's utility bills from $40 per customer reported in the study for the West Region to $560 per year per household, as shown in Figure 2-7.[17]

Figure 2-7: Annual Energy Costs from Electrification Based on Different Residential Rates



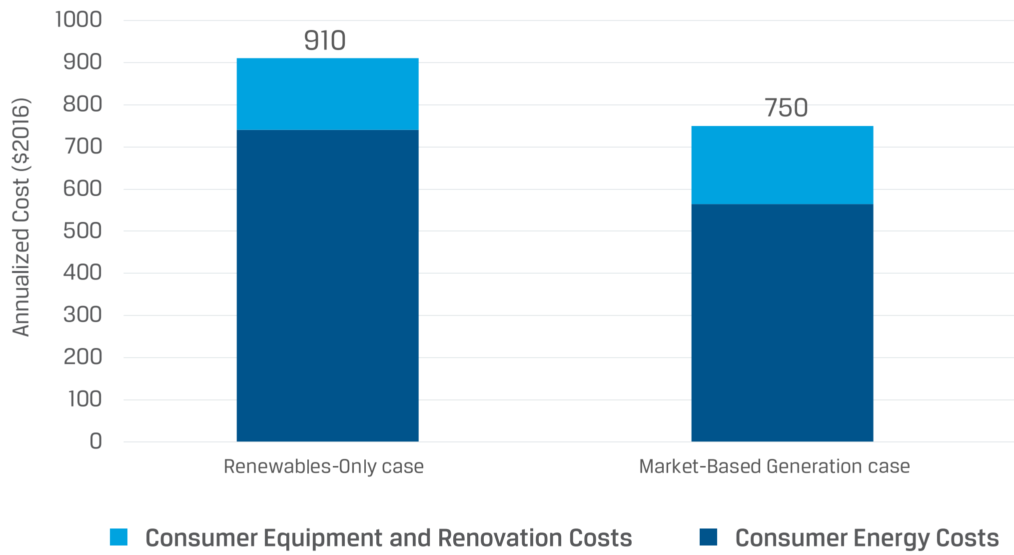
While the study methodology can be applied at the state or utility service territory level, this was beyond the scope of the AGA study. In addition, this type of more localized study approach would also need to consider many costs that were beyond the scope of the study, such as electric distribution costs, natural gas and electric rate impacts and other local considerations not included in this study.

[16] Southern California Rates from California Energy Commission, IEPR Forecasts

[17] Note: It would be inappropriate to use Southern California natural gas and electricity prices for the entire West Region. In addition, if applied only to customers in the Southern California area, the estimated $560 per year would be lower due to lower space heating requirements in this part of the Western Region relative to the overall average.

To capture the differences in the direct costs to consumers[18] from electrification policies, the study considered state level conversion costs for household heating and cooling systems based on state level construction costs, energy usage characteristics, and residential energy rates. These assumptions are more fully documented in Appendix A. These results were then summarized into the nine regions used in this study.

Figure 2-8: Annualized Direct Consumer Costs by Case



Based on this analysis, in the Renewables-Only Case, consumers should expect to see their direct energy expenditures increase by over $760 billion due to higher household fuel purchases and equipment costs. This equates to roughly $910 per converted household per year. (Figure 2-8). In the Market-Based Generation Case, consumers should expect to see their direct energy expenditures increase by about $415 billion. In the Market-Based Generation Case, the average cost per-year nationally would be $750 per converted household.

The reduction in direct energy expenditures in the Market-Based Generation Case relative to the Renewables-Only Case is largely the result of the exclusion of mandated residential electrification policies for the Market-Based Generation Case in the Midwest, Plains, and Rockies regions. These regions have both higher heating loads and are in colder parts of the country, impacting the heat pump performance.

While both cases result in increases in costs to consumers, there is a more nuanced cost impact when evaluating electrification policies in specific regions of the country. Table 2-2 shows the direct consumer costs by each region modelled in this study. One key message from reviewing the regional results is that colder climates with higher heating loads, lower heat pump efficiency, and higher electricity prices relative to natural gas, such as New York and New England, face higher relative costs. Similarly, warm regions with a lower differential in electric and natural gas rates, such as the Southern U.S. can result in lower household fuel purchases and explains why electric heating has made greater inroads in southern cities, even when there are accessible natural gas distribution systems.

[18] Direct costs to consumers include the differences in household capital costs between a natural gas and electric space and water system, and include the differences in household energy purchases over the life of the equipment.

Table 2-2: Annualized Direct Consumer Cost Impacts by Region (Real 2016 $ Per Year Per Household)

The direct consumer costs are derived from households converted from 2023 to 2035. These costs include the installation and equipment costs and the difference in energy purchases for these households from 2023 to 2050 in order to account for future expenditures post-conversions for the natural gas and electric heating systems.

Region	Annual Household Fuel Purchases	Annualized Equipment Conversion Costs	Total Annualized Increase in Consumer Costs per Converted Household
East Coast	770	190	960
Midwest[1]	1,200	150	1,360
New England	1,330	220	1,550
New York	2,630	210	2,840
Plains[1]	910	150	1,070
Rockies[1]	880	140	1,030
South	-330	140	-190
Texas	-120	150	30
West	40	180	230
U.S. Total	**740**	**170**	**910**

[1]These regions were not included in the Market-Based Generation Case since the residential electrification policy would have increased overall GHG emissions.

3 Impact of Policy-Driven Residential Electrification on the Electric Sector

Electrification of residential natural gas and other direct use fuels will increase annual consumption of electricity. It will also increase the demand for electricity during peak periods, including the impact of additional electric space heating on winter peaking, and additional electric water heating on both summer and winter peak periods. Peak period demand is the primary determinant for the overall amount of electrical generation, transmission, and distribution capacity required, and hence determines the overall size of the electrical grid. In most of the country, electricity demand currently peaks during the summer due to air conditioning load. However, some regions of the country experience the electricity demand peak during the winter heating season.

The impact of policy-driven residential electrification depends on the characteristics of the peak electricity demand and the specific region:

- Electrification of residential water heating will have a direct impact on peak electric demand in all regions.
- Electrification of home heating in regions that are already winter peaking will have a direct impact on peak capacity requirements.
- Electrification of home heating in regions that are currently summer peaking will not lead to significant increases in overall peak demand until the conversions create sufficient new winter demand to cause the region to change from summer to winter peaking. Thereafter, additional electrification of space heating will directly contribute to peak period demand.

3.1 Impact on Electric Generation Capacity

The impact of residential electrification on peak electric grid capacity requirements and electric infrastructure is often overlooked in studies of policy-driven residential electrification.[19] This study explicitly projects the potential impact of policy-driven residential electrification on the power grid infrastructure requirements for generation capacity and transmission capacity. Increased demand for electricity is met through the construction of a mix of base load, intermediate load, and peaking generating plants in the Market-Based Generation Case and a combination of renewables and energy storage in the Renewables-Only Case. The need for new plant construction is also affected by retirements of existing plants and environmental and renewable portfolio policies in each region.

For the electric system analysis of the study, the study used IPM® to model the power grid requirements and incremental investments needed to meet electric load growth for each of the three cases described in Section 2. The difference between the Reference Case and each of the two policy cases is used to project the impact of the residential electrification policy on:

- New plant construction by region
- Plant retirements
- Capital expenditure on new plants
- Power plant fuel use and emissions

[19] See, for example: California Energy Commission Report, SoCal Edison's, "The Clean Power and Electrification Pathway," November 2017; Evolved Energy Research, "Deep Decarbonization Pathways Analysis for Washington State," April 2017; Energy + Environment Economics, "Pacific Northwest Low Carbon Scenario Analysis," November 2017

IPM® is a detailed engineering/economic capacity expansion and production-costing model of the power sector supported by an extensive database of every generator in the nation. It is a multi-region model that projects capacity and transmission expansion plans, unit dispatch and compliance decisions, and power and allowance prices, all based on power market fundamentals. IPM® explicitly considers gas, oil, and coal markets, power plant costs and performance characteristics, environmental constraints, and other power market fundamentals. A more detailed description of IPM® is included in Appendix C.

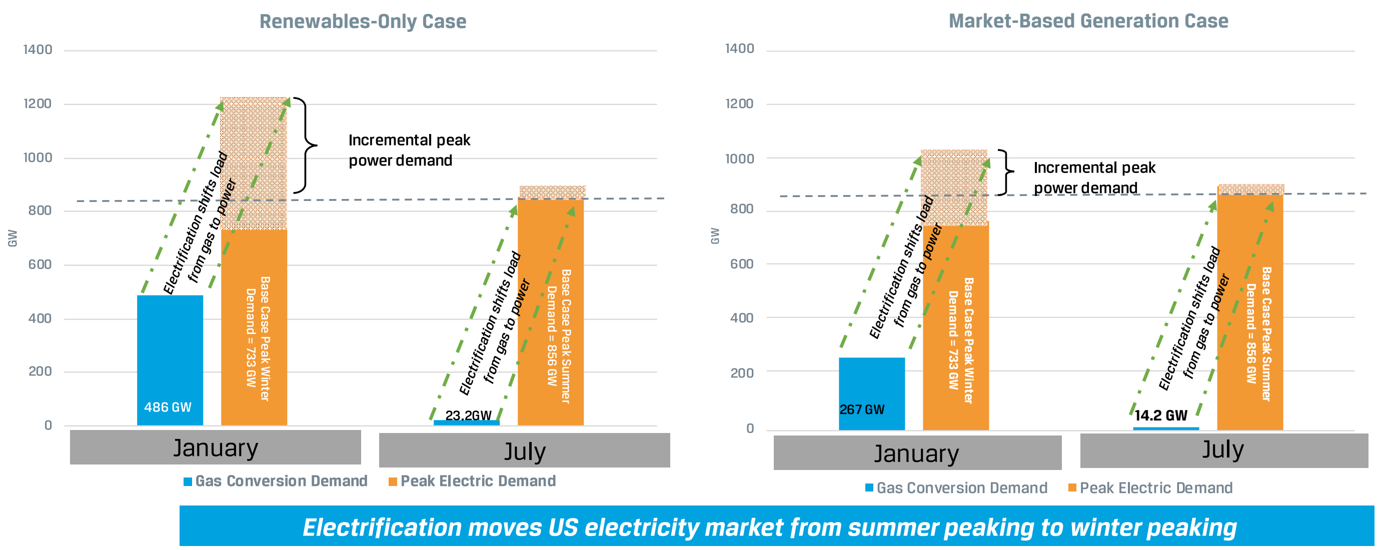
The Reference Case applied the assumptions from the EIA AEO 2017 Reference case, including the Clean Power Plan (CPP).[20] This reference case was calibrated to the EIA results with respect to emissions, total generation mix, levels of total renewable generation, and the mix of newly installed generation capacity. The assumptions were then modified for the policy cases to incorporate the increased electricity consumption and demand from the policy-driven electrification of residential gas use on a regional and seasonal basis.

3.1.1 Impact of Policy-driven Residential Electrification on Peak Period Demand

The effect of electrification on peak electric demand is one of the key drivers of impact on the electricity sector. The impacts are highly dependent on regional weather and generating mix and were modeled on a regional basis. The results also incorporate interactions between generators and transfers between generating regions. Regional results for the power sector analysis are shown in Appendix B, but Figure 3-1 summarizes the national results and illustrates the impact and implications. The figure shows the summer and winter peak demand before and after the policy.

In the AEO 2017 Base Case, or Reference Case, the 2035 peak-hour generation in the winter is 733 GW, 123 GW lower than the summer peak- hour generation of 856 GW. In the Renewables-Only Case, the impacts of electrification increase the winter peak by 486 GW,[21] while the summer peak is increased by only 23 GW (primarily for water heating). The net incremental increase in demand is the winter increase above the pre-existing summer peak capacity or roughly 360 GW.

Figure 3-1: Impact of Residential Electrification on Peak Electric Generation Requirements



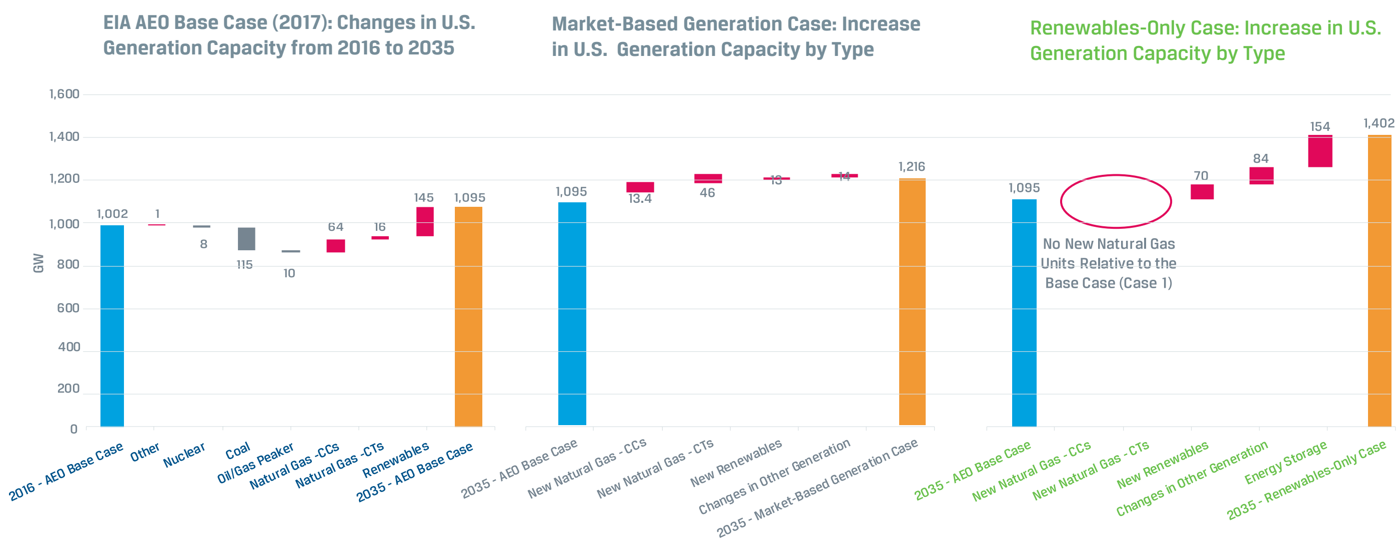
[20] The CPP was put on hold and was not included in the EIA's 2018 AEO Reference Case Assumptions but constitutes a more aggressive environmental case for this analysis.

[21] This is a simplified approach given the differences between coincident and non-coincident peak-hour demand from electrification policies.

In the Market-Based Generation case, the coincident peak-hour increase from electrification is 267 GW and the net incremental generation capacity is 144 GW. The increase for the Renewables-Only case is larger due to the inclusion of electrification in all regions and states within U.S. Lower 48, whereas the Market-Based Generation case excludes several regions. These regions included in the Renewables-Only case have a high penetration of gas heating and are colder, which results in higher demand, exacerbated by lower heat pump efficiency, hence the much higher demand increment.

Figure 3-2 summarizes the projected changes in generating capacity between 2016 and 2035 for the three cases. In the Reference Case, there are 115 GW of retirements of coal-fired plants and 10 GW of retirements for oil/gas steam/peaking units. There are 64 GW of new gas combined-cycle capacity and 145 GW of new renewable capacity.

Figure 3-2:
Changes in U.S. Generating Capacity Due to Residential Electrification



The two policy cases (Renewables-Only and Market-Based Generation) both start from the Reference Case:

- In the Renewables-Only Case, all of the growth in generating capacity needed to meet the electric load growth associated with the policy-driven residential electrification is met with renewable power generation capacity and battery storage capacity. There is no incremental fossil-fuel capacity built in response to the electrification case beyond the capacity built in the Reference Case.
- In the Market-Based Generation Case, the investments in new generating capacity needed to meet the incremental electricity demand associated with the policy-driven residential electrification case are based on the most economic available option, consistent with the environmental regulations (including the CPP) in the 2017 EIA AEO Base Case forecast.

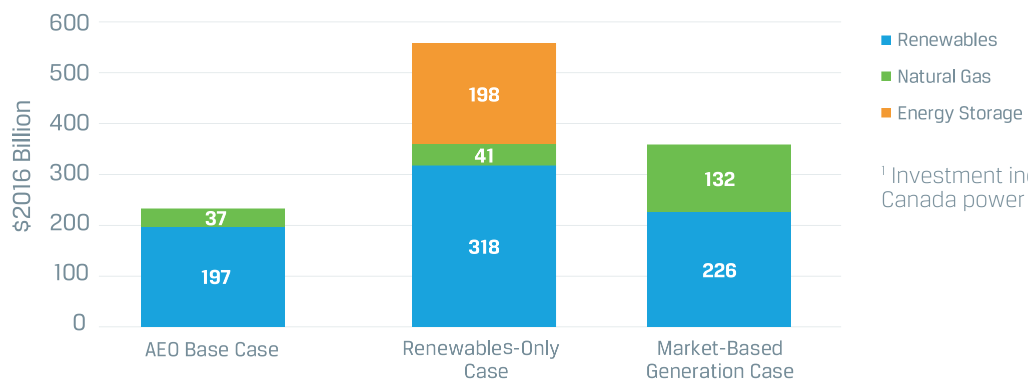
In the Reference Case, the 84 GW of retired capacity was replaced with higher efficiency, lower emitting natural gas combined cycle capacity. In the Renewables-Only Case, we did not allow these units to be replaced with new gas-fired units, which resulted in a delay in the retirement of these units. As a result, the Renewables-Only Case results in higher emissions from existing generation plants than occurs in the Reference Case, which reduces the overall emissions benefits associated with policy-driven electrification.

In the Market-Based Generation Case, the less efficient plants are retired as in the Reference Case and the incremental demand is met primarily with new gas combined cycle (52 GW) and gas combustion turbine peaking units (46 GW), as well as a smaller amount (13 GW) of additional renewable capacity beyond the Reference Case.

3.1.2 Impact of Policy-driven Residential Electrification on Incremental Power Sector Investments

Figure 3-3 shows the cumulative capital investment for generating capacity in North America from 2023 to 2035. The investment in renewable capacity accounts for the majority of the costs in all cases followed by the cost of battery storage in the Renewables-Only Case. The required investment in new generating capacity in the Renewables-Only Case is more than twice as high as the investment in the Reference Case, while electric demand is only 11 percent higher. The increase in investment for the Market-Based Generation Case is about 65 percent of the Renewables-Only Case due to the lower renewable component and lack of battery storage and also because the demand increment is lower for this case.

Figure 3-3: Investment in Generating Capacity by 2035[1]



[1] Investment includes U.S. and Canada power sector costs.

3.1.3 Impact of Policy-driven Residential Electrification on Generation by Source

Figure 3-4 illustrates how the actual generation by fuel changes in the various cases to meet the incremental demand for electricity. The Renewables-Only Case has the highest generation due to the broader geographic coverage of electrification and has the highest renewable generation due to the limitation on construction of new fossil plants. Despite that limitation, fossil generation does not decline significantly in this case due to the delayed retirement of fossil units. Fossil-fueled generation is very similar in the two policy cases.

In the Market-Based Generation Case, much of the gas-based generation is from new, more efficient combined cycle capacity, with implications for gas consumption and emissions.

Figure 3-4: U.S. Electric Generation by Fuel - 2035 (TWh)

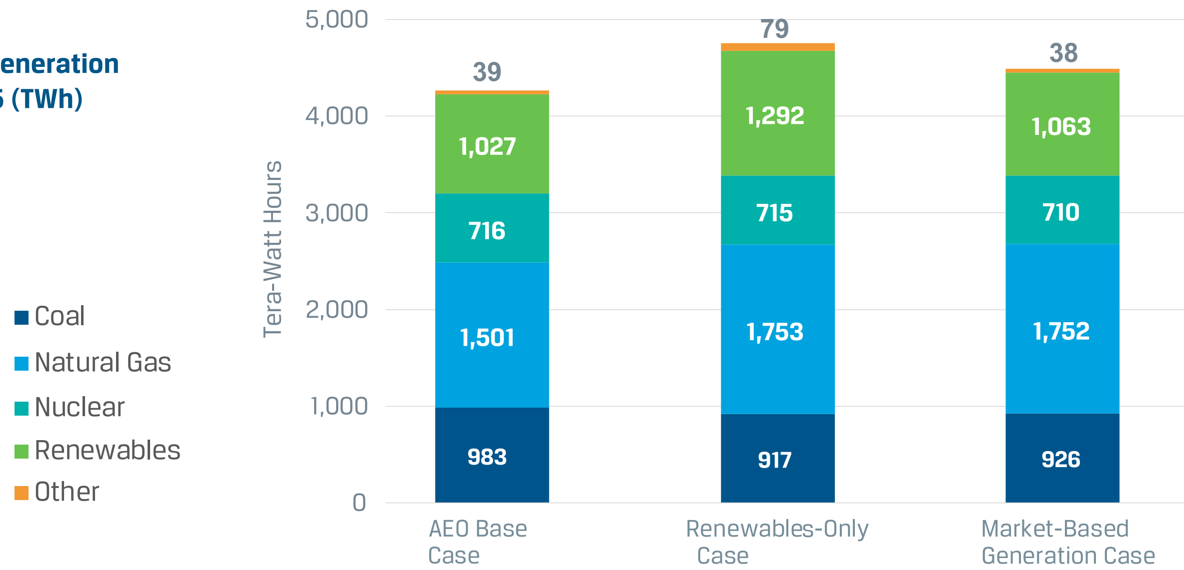
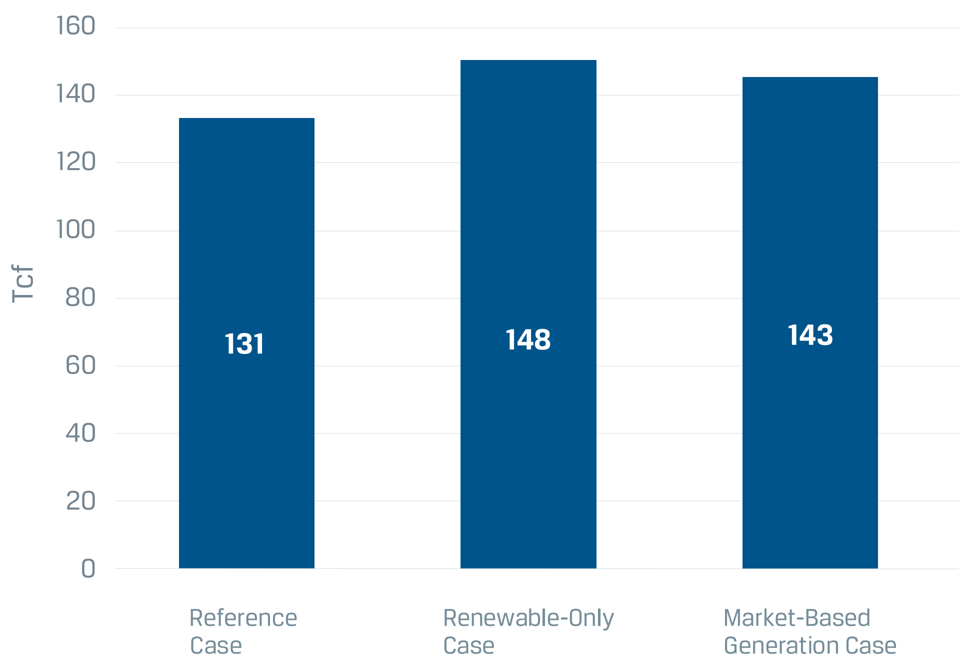


Figure 3-5 shows the gas consumption for power generation in the three cases. Natural gas consumption for electricity production increases in both policy cases as electricity generation increases to meet the increased demand for electric space and water heating loads. This is true even in the Renewables-Only Case as existing gas plants increase their utilization to meet demand and some plants that were retired in the Reference Case remain on line to meet demand. From 2023 to 2035, natural gas consumption for power generation increases by 16.5 Tcf in the Renewables-Only Case and 11.9 Tcf in the Market-Based Generation Case. However, for each case there are offsetting reductions in direct-use natural gas by households from the electrification of space and water heating.

Figure 3-5: Power Sector Natural Gas Consumption for 2023 to 2035

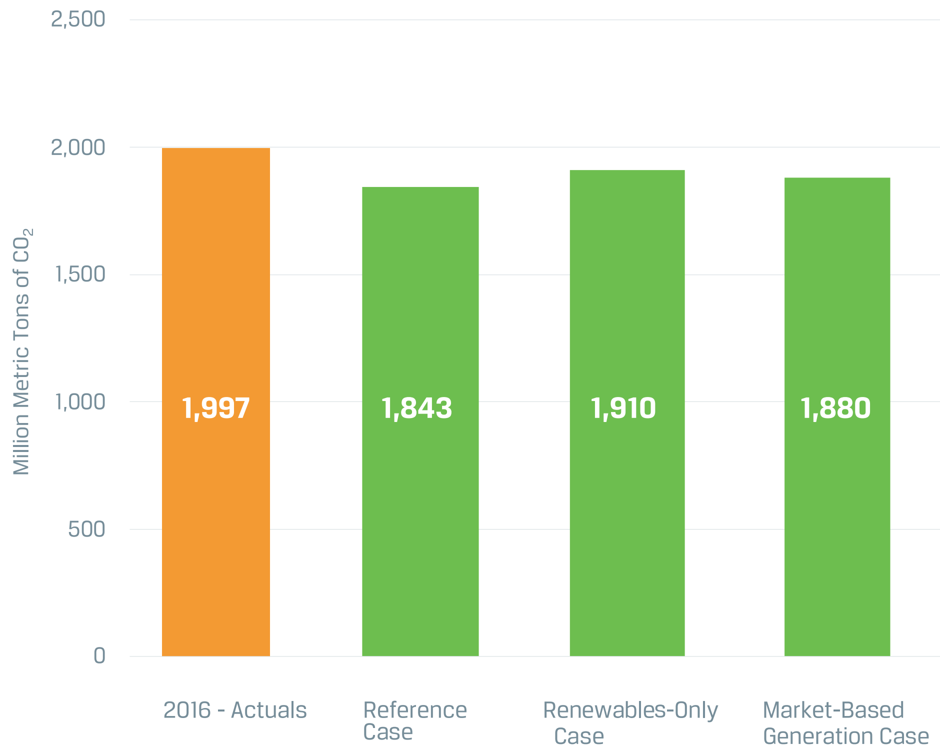


3.1.4 Impact of Policy Driven Residential Electrification on Power Sector CO_2 Emissions

Figure 3-6 shows the power sector emissions of CO_2 for 2016 and the three cases in 2035. In the Reference Case, emissions have declined from 2016 due to coal plant retirements and increased use of gas combined cycles and renewables. Both electrification cases have higher power sector emissions than the Reference Case.

In the Renewables-Only Case, power sector emissions increase due to the increased demand for electricity. In addition, even though no new fossil capacity is allowed, emissions increase due to increased overall generation and greater generation from existing, lower efficiency gas power plants. The Market-Based Generation Case has lower emissions than the Renewables-Only Case because of the lower overall change in generation (due to smaller geographic coverage) and because some older plants are replaced by more efficient/lower-emitting gas combined cycle plants.

Figure 3-6: 2035 U.S. and Canada Power Sector CO_2 Emissions by Case



3.2 Impact on Transmission Requirements

As peak period electricity demand increases and as new electric generating capacity is constructed, the need for additional electric transmission capacity – both local and regional – is also expected to increase. In some cases, generating capacity in one region serves load in an adjacent region, requiring regional transmission. This can be especially important for renewable generation such as wind power, where the potential resources are often in different regions than the demand growth.

This section presents the analysis of electric transmission impacts of the electrification case.[22]

3.2.1 Analytical Approach

The cost of incremental transmission infrastructure that would be needed to meet the higher electric demand levels from the policy-driven electrification was calculated compared to the business-as-usual scenario based on the 2017 EIA AEO Reference Case) for the Market-Based Generation and Renewables-Only cases. To calculate these costs for the study, a detailed review of the transmission network in two of the regions created for this analysis was performed. For these two representative regions, a power flow simulation model was developed that included generation dispatch, regional demand, and net interchange with neighboring regions adjusted to match the peak condition projected by IPM® for the electrification cases.[23] The model simulated the operation of the bulk power system under normal conditions (all assets in service) and contingency conditions (one line or transformer out of service). This identified vulnerable transmission facilities that were likely to be overloaded as a result of the higher demand, and provided estimates for the cost to upgrade these facilities in order to resolve the violations.

Next a detailed model of the East Coast region was created to evaluate the incremental costs from a region that produces a majority of its generation in-region. The Northwestern U.S. in the West region was used to evaluate the transmission costs in a region more reliant on imported electric flows. These two regions were then used as representative regions to extrapolate the transmission costs across all regions.

For each region, the results of the Market-Based Generation and Renewables-Only cases were compared to the Reference Case to identify transmission system overloads unique to the electrification cases. The study also compared the projected inter-regional interchanges to the regional interface transfer limits and estimated the cost of upgrades to increase the limits of interfaces that were found to be deficient.

[22] The transmission infrastructure cost estimates do not include incremental distribution system costs, which vary widely by utility and were beyond the scope of this study.

[23] PowerWorld was licensed to perform the detailed transmission flow modelling.

3.2.2 Impact of Policy-Driven Residential Electrification on Transmission Infrastructure Requirements

Table 3-1 summarizes the results of the transmission analysis.[24] The increased cost for transmission infrastructure in the Renewables-Only Case was estimated at $107.1 billion while the cost in the Market-Based Generation Case was $53.2 billion. The difference is driven in part by the broader geographic coverage and the greater electric demand impact of the Renewables-Only Case. Regional results are presented in Appendix B.

Table 3-1: Total Costs by 2035 of Transmission Investments (Real 2016 $ Billions)[1]

Case	Intra-regional Improvements (Transformers)	Import Facilities (Transmission Lines)	Total Transmission Cost
Renewables-Only Case	91.3	15.8	107.1
Market-Based Generation Case[1]	41.7	11.5	53.2

Note: Transmission costs in the Market-Based Generation case are lower than in the Renewables-Only case in part due to the exclusion of the Plains, Rockies, and Midwest regions from the residential electrification policy in these regions.

Note: The transmission infrastructure cost estimates do not include incremental distribution system costs, which vary widely by utility and were beyond the scope of this study.

The incremental transmission costs vary widely by region, but are dominated in all regions by intra-regional improvements.

The transmission cost analysis should be considered conservative. The analysis did not consider a number of factors that likely would increase the overall transmission cost impacts associated with the electrical load growth driven by mandatory residential electrification policies. These factors include:

- Planning for Stressed Conditions
- Voltage Support
- Zonal Capacity Deliverability
- Permitting challenges, both inter- and intra-state

Additionally, the transmission infrastructure cost estimates do not include incremental distribution system costs, which vary widely by utility.

[24] Two major electric transmissions projects were added in the Renewables-Only case, connecting renewable generation resources in Canada to the Midwest and Northeastern U.S.

4 Overall Impacts of Policy-Driven Residential Electrification

The individual components of the costs and emissions benefits associated with the residential electrification policies evaluated in this study have been reviewed earlier in this report. This section of the report combines these results to assess the overall implications of policy driven residential electrification policies on residential energy costs and the power grid, compared to the potential emissions reductions associated with these policies.

4.1 Overall Cost of Policy-Driven Residential Electrification

The cost impacts from electrification policies include:

Consumer Costs: The direct costs to consumers of policy-driven electrification include.

- The incremental costs for new or replacement electric space and water heating equipment relative to the natural gas or other direct fuel alternative.
- Costs of upgrading or renovating existing home HVAC and electrical systems.
- Difference in energy costs (utility bills) between the electricity options and the natural gas and other direct fuel options.

Most of the affected households will be existing households retrofitting from natural gas and other direct fuel appliances to electric appliances. The costs for these customers typically will be higher than the incremental costs for new households installing the equipment.

Power Generation Costs: The capital cost of new electric generating capacity needed to supply the increased electricity demand.

Transmission Costs: The cost of new electric transmission infrastructure required to serve the increased load and generation.

Figure 4-1 summarizes these costs for the Renewables- Only Case showing that the total cumulative cost increase relative to the Reference Case is nearly $1.2 trillion by 2035. Roughly half of this cost is the increase in consumer energy costs. One third is the cost of new generating capacity and consumer equipment and transmission costs make up the remainder.

The Market-Based Generation Case has a total cumulative cost increase of $590 billion by 2035, shown in Figure 4-2. The consumer energy costs are lower in this case because it does not include electrification of the Midwestern, Plains, and Rockies regions, which have higher heating loads, greater saturation of gas heating equipment, and colder temperatures, which result in lower efficiency for electric heat pumps. The other costs are also somewhat lower, especially the capital cost of new generating capacity. The generating cost is lower because the model is selecting the lowest cost option, rather than being limited to only renewable sources, which increases costs, especially for battery storage, in the Renewables-Only Case.

Figure 4-1:
Total Cost of Renewables-Only Case by Sector

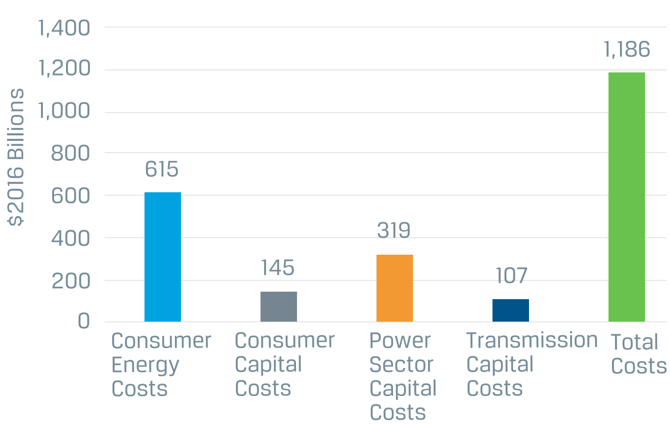
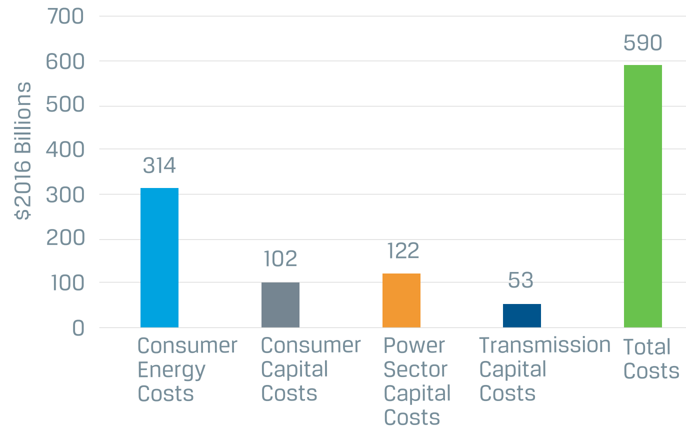


Figure 4-2:
Total Cost of Market-Based Generation Case by Sector



4.2 Cost per Consumer of Policy Driven Residential Electrification

The overall magnitude of the costs of policy-driven residential electrification is expected to place a significant burden on consumers. Table 4-1 shows the cumulative and annualized costs of the conversion to electricity spread out over the total number of converted households. These costs include the direct costs per household, including the direct consumer costs (appliance and energy costs), and an allocation of the capital cost for electric generating plants and electric transmission. The costs are discounted to 2023 and expressed in real 2016 dollars.

One important result from this study was the wide degree of variation in direct consumer costs based on the region of the study.[25]

The cumulative cost per household in the Renewables-Only Case ranged from $1,970 in Texas to over $58,500 in New York, with a national average of $21,140. The annualized cost ranges from $130 to $3,900 per year with a national average of $1,420 per year.

The cumulative cost per household in the Market-Based Generation Case, ranged from $650 in the South region to almost $57,800 in New York, with a national average of $15,830. The annualized cost ranges from $40 per year to nearly $3,880 per year with a national average of over $1,060 per year.

[25]Results within each region can vary significantly based on the local climate and differences in residential energy rates and equipment installation costs.

Table 4-1:
Annual Per Household Total Costs of Electrification Policies (Real 2016 $)[1]

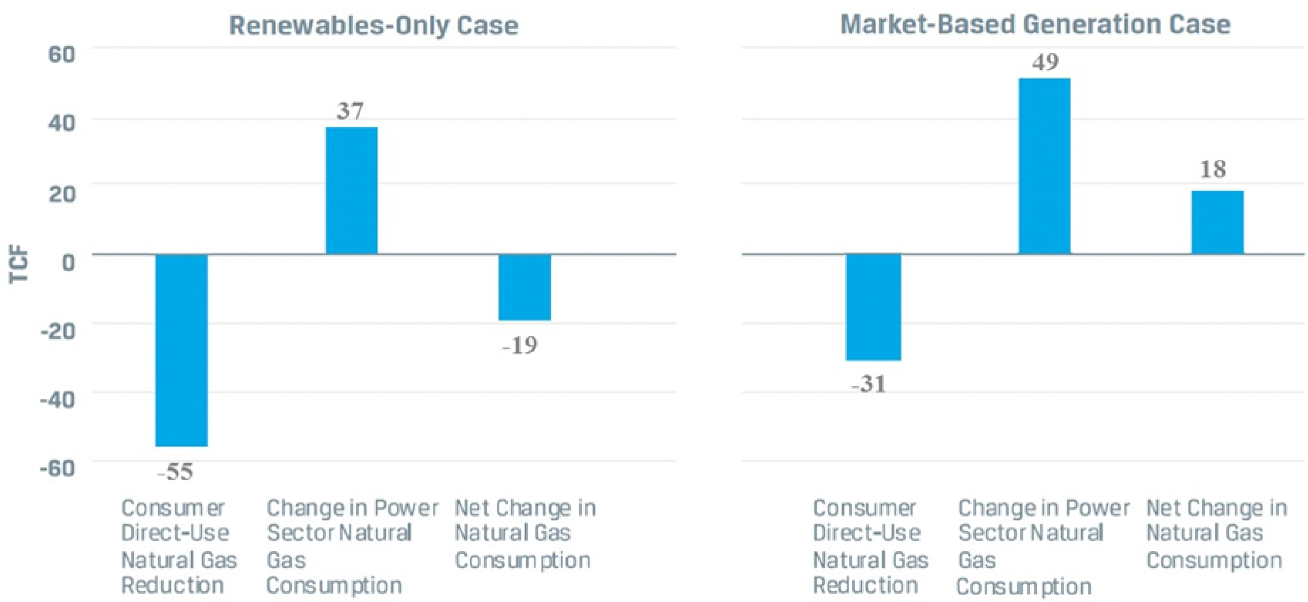
Region	Renewables-Only Case		Market-Based Generation Case	
	Cumulative Change in Costs Per Converted Household	Annualized Change in Costs Per Converted Household	Cumulative Change in Costs Per Converted Household	Annualized Change in Costs Per Converted Household
East Coast	18,440	1,240	16,550	1,110
Midwest	25,920	1,740	Policy Not Implemented	
New York	58,580	3,930	57,770	3,880
New England	41,210	2,770	35,340	2,370
Plains	29,120	1,950	Policy Not Implemented	
Rockies	25,060	1,680	Policy Not Implemented	
South	7,820	520	650	40
Texas	1,970	130	740	50
West	5,880	390	5,140	340
Total U.S.	**21,140**	**1,420**	**15,830**	**1,060**

[1]All costs are discounted in Real 2016 $ to 2023 using a 5 percent discount rate. Costs include direct household conversion costs from 2023 to 2035, power sector and transmission costs from 2023 to 2035 and the cost difference in household energy purchases from 2023 to 2050.

4.3 Net Impacts on Natural Gas Consumption

The residential electrification policies result in a significant reduction in natural gas consumption from home heating and water heating, as well as reductions in fuel oil and propane consumption. However, the growth in electricity demand associated with the residential electrification policies partially offsets the reduction in direct natural gas consumption. Hence the net reduction in natural gas consumption is less than the reduction in direct natural gas use. Figure 4-3 below illustrates the net impact of the residential electrification policy in the two alternative cases.

Figure 4-3:
Change in Cumulative Gas Consumption From – 2023 to 2050



As illustrated in Figure 4-3, the cumulative reduction from 2023 to 2050 in residential natural gas consumption in the Renewables-Only Case is 55 Tcf, or 43 percent of the total residential natural gas consumption in the Reference Case. However, power generation natural gas consumption is projected to increase by 37 Tcf, leading to a net impact on natural gas consumption of 19 Tcf, or about 2.3 percent of total U.S. natural gas consumption over this period.

Natural gas consumption in the power generation sector increases in the Renewables-Only Case due to increased dispatch of the existing natural gas plants, as well as the operation of lower efficiency gas-fired generation capacity that was not retired in this case due to the higher cost of renewable generation capacity.

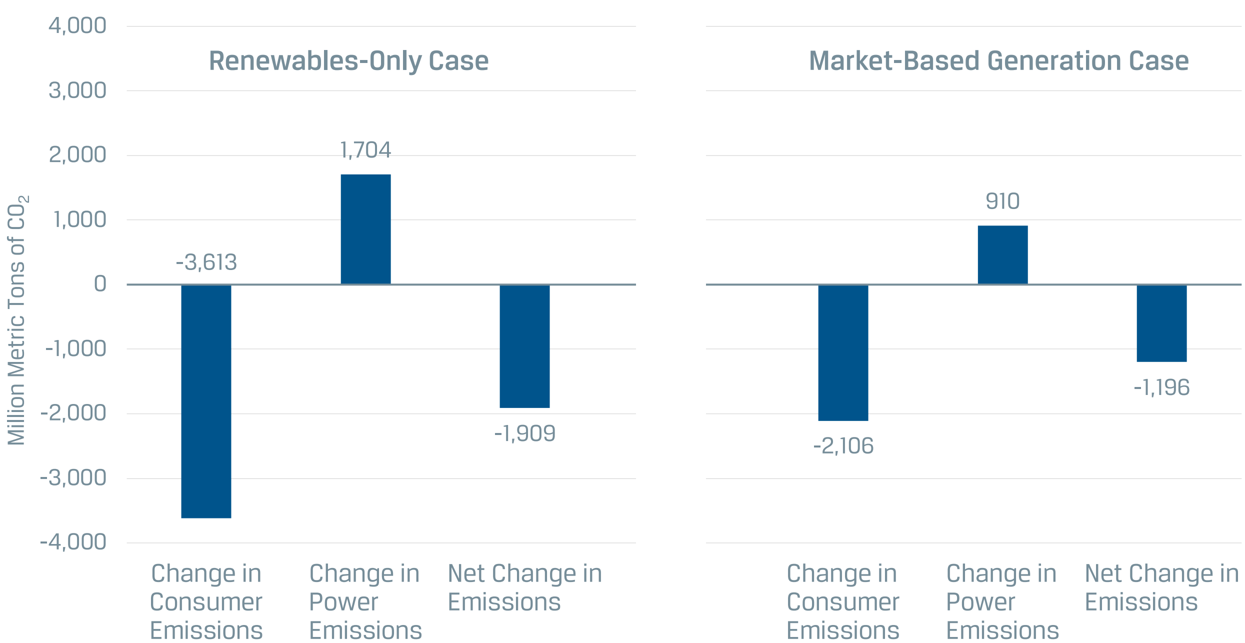
4.4 Net Environmental Impacts

In the Market-Based Generation Case, the reduction in on-site gas consumption is lower than in the All-Renewables Case due to the reduced geographic coverage—a cumulative reduction of Tcf, shown in Figure 4-3. Cumulative gas use for power generation is higher at 49.2 Tcf due to the greater construction

of gas plants to meet the increased electricity demand. As a result, there is a net increase in gas consumption of 18.1 Tcf or about 0.7 Tcf per year. Similar to the impact on natural gas consumption, residential electrification policies are expected to reduce CO_2 emissions from the residential sector, but lead to an increase in emissions from the power generation sector.

Figure 4-4 shows the net change in emissions for the two electrification cases from 2023 to 2050. The Renewables-Only case has the larger on- site reduction due to its larger geographic coverage—a cumulative reduction of 1,909 million metric tons of CO_2 from 2023 to 2050. Despite the prohibition on new fossil fuel

Figure 4-4: Cumulative GHG Emissions Reductions by Electrification Case From - 2023 to 2050



plants to meet the increased demand, CO_2 emissions from the power sector increase by a cumulative total of 1,704 million metric tons of CO_2 (159.7 million metric tons of CO_2 in 2035) due to increased generation from existing fossil-fuel fired generation plants, including natural gas (combined cycles and combustion turbines), coal, and oil-peaking units. This results in a cumulative net emission reduction of 1,909 million metric tons of CO_2, and a total of 96 million metric tons of CO_2 in 2035, which represent about 1 percent of baseline U.S. GHG emissions for that year.

In the Market-Based Generation Case, the cumulative emission reduction is 1,196 million metric tons of CO_2 (65 million metric tons of CO_2 in 2035) due to the exclusion of some regions from the program.

Even though there is more gas generating capacity added than in the Renewables-Only case, the cumulative increase in power sector emissions from the Market-Based Generation case is 910 million metric tons of CO_2 (27.5 million metric tons of CO_2 in 2035). This is lower than in the Renewables-Only Case because the increase in electricity demand is lower and because the new gas plants are more efficient than the older plants that are used in the Renewables-Only Case. Nevertheless, the cumulative total net reduction of emissions is lower, 1,196 Million Metric Tons of CO_2, largely due to the lower geographical application of electrification policies.

Table 4-2: Change in 2035 GHG Emissions by Case (Million Metric Tons of CO_2)

Change in Consumer Emissions	Change in Consumer Emissions	Change in Power Emissions	Net Change in Emissions
Renewables-Only case	-159.7	60.7	-96.3
Market-Based Generation case	-92.7	27.5	-65.2

Even though the Renewables-Only Case prohibits the development of new fossil-fuel generating capacity, and all of the new generating capacity installed in the U.S. in this case is renewable and energy storage, residential electrification still results in higher emissions from the power sector, partially offsetting the larger decline in residential emissions from the expanded application of the electrification policy.

The increase in power sector emissions in the Renewables-Only Case is due to economic market forces in the generation sector and is driven by two factors:

- There are fewer existing natural gas and coal plants retired between 2018 and 2035 than in the Reference Case. In the Reference Case, many of the older existing gas and coal units were driven out of the market by higher efficiency, hence lower cost, new natural gas units. The higher cost of renewable capacity capable of meeting peak winter demands allows these existing units to remain economic longer. These units emit more GHG's than the newer gas units in the baseline.
- The remaining natural gas and coal generating capacity operates at a higher utilization due to the increase in overall electrical load.

4.5 Cost per Ton of CO_2 Emissions Reduced

The primary driver for policy-driven residential electrification is GHG emissions reductions. In order to assess the effectiveness of residential electrification for this purpose, the study calculated the cost implications of the policies based on the cost per metric ton of reduction (Real 2016 $ per metric ton of CO_2 reduced). This is a common figure-of-merit for emission reduction programs and allows comparison of these policies with alternative policies and technologies for GHG reduction.

Table 4-3 shows the emissions cost of reduction from the conversion to electric heating programs and summarizes the cost of emissions reductions for the two policy cases based on the net reductions including increased emissions from the power sector. These costs vary widely among regions based on heating loads, temperature dependent heat pump performance, generating mix, electric transmission capacity, and renewable generation potential among other factors.

For the Renewables-Only Case, the average cost of the net emissions reductions was $806 per metric ton of CO_2. On a regional basis, the costs ranged from $218 per metric ton of CO_2 reduced in the South region to nearly $8,800 per metric ton of CO_2 reduced in New York. The very high cost in New York is due to high costs for the electric generating capacity and infrastructure, high cost of electricity, and cold temperatures reducing heat pump efficiency. Two regions (New England and the Midwest) did not see a reduction in net emissions as growth in power generation emissions more than offset the reduction in residential sector emissions.

Table 4-3: Cost of Emission Reductions (Real 2016 $ Per Metric Ton of CO_2)

Region	Total Cost of Net Emissions Reductions	
	Renewables-Only case	Market-Based Generation case
East Coast	635	391
Midwest[1,2]	N/A	Policy Not Implemented
New York	8,784	6,450
New England[1]	N/A	1,081
Plains[2]	230	Policy Not Implemented
Rockies[2]	794	Policy Not Implemented
South	218	63
Texas	251	54
West	749	485
U.S. Total	**806**	**572**

[1]The Midwest and New England regions show increased total emissions on a Discounted Basis.
[2]In the Market-Based Generation Case, the electrification policy was not implemented in the Midwest, Plains, and Rockies regions due to the lack of potential emissions reductions.

In the Market-Based Generation Case, all regions included in the electrification policy case experienced a net-reduction in GHG emissions. The net cost of emissions reductions by region for the case ranges from $54 to $6,450 per metric ton of CO_2 reduced, with a national average of $572 per metric ton of CO_2. The low cost in the Texas and Southwest regions are due to the mild climate and higher efficiency of heat pumps which result in minimal increases to peak electric generation demand in these summer peaking regions and low incremental energy costs for consumers.

5 Study Conclusions

Overall, the residential electrification policy assessed in this study would convert between 37.3 and 56.3 million households from natural gas, propane, and fuel oil space and water heating to electricity between 2023 and 2035. This represents about 60 percent of the total non-electric households in each region where the policy is implemented. Table 5-1 summarizes the results of the analysis.

5.1 Study Results

Table 5-1: Summary of Results

	Renewables-Only Case	Market-Based Generation Case
U.S. Greenhouse Gas Emissions	Annual U.S. GHG emissions reduced by 93 million metric tons of CO_2 by 2035 (1.5 percent)	Annual U.S. GHG emissions reduced by 65 million metric tons of CO_2 by 2035 (1 percent)
Residential Households	56.3 million households converted to electricity $760 billion in energy & equipment costs Direct consumer annual cost increase of $910 per household	37.3 million households converted to electricity $415 billion in energy & equipment costs Direct consumer annual cost increase of $750 per household
Power Sector	320 GW of incremental generation capacity required at a cost of $319 billion $107 Billion of associated transmission system upgrades	132 GW of incremental generation capacity required at a cost of $102 billion $53 Billion of associated transmission system upgrades
Total Cost of Policy-Driven Residential Electrification	Total energy costs increase by $1.19 trillion $21,140 average per converted household $1,420 per year per converted household increase in energy costs	Total energy costs increase by $590 billion $15,830 average per converted household $1,060 per year per converted household increase in energy costs
Cost of Emission Reductions	$806 per metric ton of CO_2 reduction	$572 per metric ton of CO_2 reduction

Overall, the analysis of the AGA policy-driven residential electrification cases indicates that residential electrification policies would likely result in small reductions in GHG emissions relative to total U.S. emissions, at a cost on a dollar per metric ton basis that would be higher than the cost of other emissions reduction options under consideration, both to individual consumers and society at large.

- Based on the 2017 EIA AEO, by 2035 direct residential natural gas use will account for about 4 percent of total GHG emissions, and the sum of natural gas, propane, and fuel oil used in the residential sector will account for about 5 percent of total GHG emissions. Reductions from policy-driven residential electrification would reduce GHG emissions by 1 percent to 1.5 percent of U.S. GHG emissions in 2035 from the EIA AEO 2017 Baseline emissions.

- GHG emissions from the generation of electricity supplied to the residential sector are expected to account for about 10 percent of total GHG emissions in 2035, or more than twice the GHG emissions from the direct use of natural gas in the residential sector.

- Policy-driven electrification would increase the average residential household energy-related costs (amortized appliance and electric system upgrade costs and utility bill payments) by between $750 and $910 per year, or about 38 to 46 percent above expected energy related costs in the absense of electrification.

- Growth in peak winter period electricity demand resulting from policy-driven residential electrification would shift the U.S. electric grid from summer peaking to winter peaking in every region of the country, and would increase the overall electric system peak period requirements, resulting in the need for major new investments in the electric grid including generation capacity, transmission capacity, and distribution capacity. Incremental investment in the electric grid could range from $155 billion to $456 billion between 2023 and 2035.

- The total economy-wide increase in energy-related costs (residential consumer costs plus incremental power generation and transmission costs) from policy-driven residential electrification ranges from $590 billion to $1.2 trillion (real 2016 $), which is equal to from $1,060 to $1,420 per year for each affected household, depending on the power generation scenario. This reflects changes in consumer energy costs between 2023 and 2050, as well as changes in consumer space heating and water heating equipment costs, and incremental power generation and transmission infrastructure costs between 2023 and 2035.

- The average cost of U.S. GHG emissions reductions achieved by policy-driven residential electrification would be between $572 and $806 per metric ton of CO_2 reduced, well above the costs of other emissions reductions policies under consideration.

5.2 Impact of Policy-Driven Residential Electrification on the Power Grid

The increase in peak winter load associated with the electrification of residential space heating would convert most areas of the U.S. power grid from summer peaking to winter peaking—the incremental generation requirements from electrification policies are typically more pronounced in regions that are already winter peaking.

The analysis conducted for this study indicates that significant residential electrification efforts would change the overall pattern of electricity demand and lead to increases in peak electric demand. Such policies could also shift the U.S. electric grid from summer peaking to winter peaking in most of the country, resulting in the need for major new investments in the electric grid including generation capacity, transmission capacity, and distribution capacity.

Currently, most of the U.S. electric grid is summer peaking, with higher peak demand during the summer than in the winter. As a result, the primary driver of electric grid capacity requirements is peak summer load. The residential electrification policies evaluated in this study do increase summer demand due to conversion of water heaters to electricity. However, natural gas and other fossil fuel space heating load is heavily focused over the winter season, and electrification of space heating will significantly increase electricity demand during the winter, particularly on the coldest winter days when electric heat pump efficiency is lowest, and electricity use for space heating will be the highest.

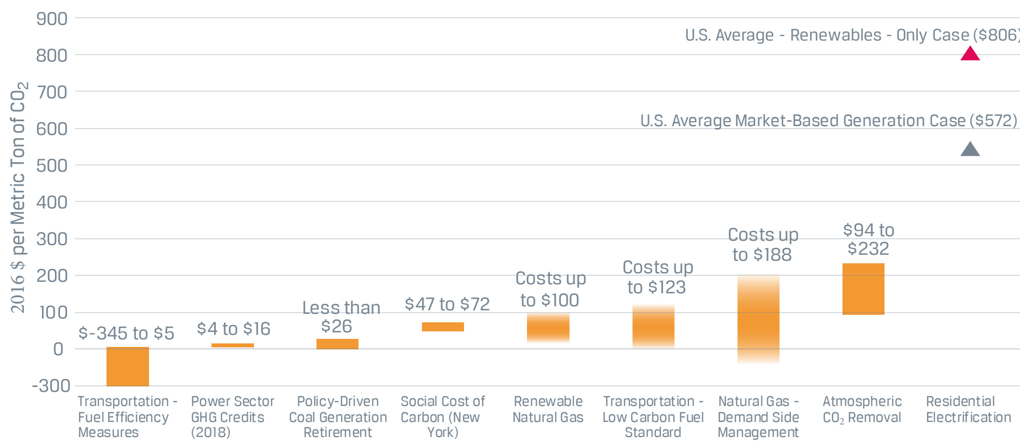
The increase in peak winter demand would lead to an increase in overall peak electric demand, and require an increase in total generation capacity in 2035 of between 10 and 28 percent relative to the reference case, depending on the electrification case.

The growth in peak winter demand will also require incremental investments in the transmission and distribution systems. While this study includes an estimate for the required incremental investment in transmission capacity, it was beyond the scope of the study to assess the potential requirements for additional electric distribution capacity.

5.3 Cost-Effectiveness of Residential Electrification as a Greenhouse Gas Emissions Reduction Policy

The study of policy-driven electrification of residential fossil fuel heating load (space and water) indicates that the national average cost of U.S. GHG emissions reductions achieved would be between $572 and $806 per metric ton of CO_2 reduced, depending on the power generation case considered. These costs indicate that this policy approach would be a more expensive approach to GHG reductions compared to other options being considered. Figure 5-1 provides a comparison of the estimated cost per ton of GHG emissions reductions for a range of alternative policy options and technologies available for reducing carbon emissions.[29]

Figure 5-1: Comparison of Cost Ranges For GHG Emissions by Reduction Mechanism



Sources: Energy Innovations, Energy Policy Simulator; GHG emission credits from the most recent auction for the Regional Greenhouse Gas Initiative (RGGI) and California Cap & Trade program; GHG reduction costs for the existing coal generation units estimated based on the Levelized Cost of Energy (LCOE) consistent with the EIA's 2017 AEO Base Case; New York Public Service Commission's (NYPSC's) adoption of the Social Cost of Carbon (SCC); U.C. Davis, The Feasibility of Renewable Natural Gas as a Large-Scale, Low Carbon Substitute, 2016; Comparison of Greenhouse Gas Abatement Costs in California's Transportation Sector presented at the Center for Research in Regulated Industries - 27th Annual Western Conference (2014); Maximum cost of $10 per MMBtu for any Demand Side Management (DSM) program costs estimated based on an review of public DSM programs; Carbon Engineering, Keith et al., A Process for Capturing CO_2 from the Atmosphere, Joule (2018), https://doi.org/10.1016/j.joule.2018.05

This illustrative comparison to other GHG reduction measures shows the high relative and absolute cost of policy-driven electrification policies at a national level. The other GHG reduction measures shown for comparison include:

- **Fuel Efficiency Improvements (Transportation Sector):** GHG reduction costs from fuel efficiency standards are generally negative, meaning that they generate both cost savings and GHG reductions. Costs range from -$345 to $5 per metric ton of CO_2 reduction.

- **Power Sector GHG Reduction Credits:** Costs range from $4 to $16 per metric ton of CO_2 reduction based on the 2018 GHG reduction credits in the Regional Greenhouse Gas Initiative (RGGI) and the California Cap & Trade programs.

- **Policy-Driven Retirement of Existing Generation:** The EIA 2017 AEO projects GHG emissions from the generation of electricity supplied to the residential sector to account for about 10 percent of total U.S. GHG emissions in 2035, or more than twice the contribution of the CO_2 emissions from natural gas use in the residential sector in the same year.

These emissions could be reduced at a much lower cost than policy-driven residential electrification by replacing coal generation with natural gas generation. Rreducing CO_2 emissions from the power sector by replacing existing coal generation with a new gas generation combined cycle plant would cost up to about $26 per metric ton of CO_2 reduced.

- **Renewable Natural Gas (RNG):** There are broad ranges of estimates for the cost to capture and deliver RNG to consumers. The upper range of these costs has been as high as $100 per metric ton of CO_2 reductions, although there are RNG volumes available at lower costs.

- **Social Cost of Carbon:** Several states are beginning to consider the use of a social cost of carbon as a means to quantifying the comprehensive estimate of climate change damages in future regulatory planning. New York used a social cost of carbon ranging from $47 to $72 per metric ton of CO_2 reduction based on the year of emissions.

- **Low Carbon Fuel Standard (Transportation Sector):** A low carbon fuel standard is a performance-based standard that provides regulated parties an opportunity to find the most cost-effective compliance mechanism to reduce a fuels carbon intensity, which can result in a broad range of costs for these policies. Costs for these policies can be up to $123 per metric ton of CO_2 reduction.

- **Demand Side Management (Natural Gas Use):**
  There are a wide range of DSM measures that natural gas customers can implement to reduce natural gas usage and reduce CO_2 emissions. Many DSM measures can be implemented at below the avoided cost of natural gas, resulting in a negative cost per ton of ton of CO_2 reduction. An upper range on the cost of DSM activity likely to be considered is around $10 per MMBtu above the avoided cost of natural gas, which would correspond to $188 per metric ton of CO_2 reduction.

- **Atmospheric CO_2 Removal:** In June 2018, Joule Magazine published a peer-reviewed study detailing the Carbon Engineering cost estimates for the company's planned large-scale CO_2 removal plant. The company estimates that the costs per metric ton of CO_2 reduction range from $94 to $232 per metric ton of CO_2 reduction, well below prior estimates for this type of technology.

5.4 Applicability of Study Conclusions to Specific Policy Proposals at the State and Local Level

The analysis in this study was focused on broad regional and national markets. However, the residential electrification policy discussion is typically occurring at the state and local level. The study evaluated one set of residential electrification policy options under two alternative approaches to regulating growth in power grid requirements for all states. The policies evaluated here are unlikely to precisely replicate any specific proposed policy option, and there can be a wide variety of permutations of the residential electrification policies under discussion. Different variations of the basic policy will have costs and benefits that are likely to differ from the costs and benefits associated with the scenarios evaluated in this study.

In addition, the costs associated with policy-driven residential electrification can differ widely from the results of this study. For example, the results would differ if the residential electrification policy is implemented on a local or state level rather than the regional and national level as reported in this study.

Natural gas and electricity prices to residential customers, space heating requirements and existing housing stock characteristics can vary widely in different utility service territories even within the same state and region. Hence, the results of this analysis should not be applied or relied on as an indicator of the expected costs and benefits of a specific electrification policy proposal for a specific state or locality. However, the results of the analysis are sufficiently robust to indicate that residential electrification is likely to be a higher cost option for reducing GHG emissions even in areas with stringent renewable power requirements and an expectation of low-emitting future electric grids.

5.5 Other Impacts of Policy Driven Residential Electrification

- **Impact on Natural Gas Distribution System Costs to Other Customers:** Policy-driven electrification of direct-use natural gas from the residential sector would result in a significant decrease in the number of residential customers connected to the natural gas distribution system and in the volume of natural gas throughput on those distribution systems. Payments by residential customers currently support much of the overall natural gas distribution system. While the overall costs incurred by the natural gas distribution system would be expected to decline with the reduction in the number of customers and throughput, the cost reductions would not impact previously incurred costs on the system, which would need to be recovered from the remaining customers. This would result in a material shift in natural gas distribution system costs to the remaining gas utility consumers, including the remaining residential customers, commercial sector, and industrial sector customers. This study did not include an evaluation of these cost implications to consumers.

- **Impact on Electric Distribution System Costs:** While the study includes an assessment of the costs likely to be incurred to meet the growth in electricity demand for generation and transmission assets, the incremental costs not included in current electric rates of expanding the electric distribution system to meeting the increase in load have not been addressed. These costs will differ widely based on the specific locations of the load growth and are difficult to estimate. However, given the estimated increase in peak system requirements nationally, between 10 and 28 percent relative to the Reference Case, these costs are potentially substantial.

- **Impact of Policy-Driven Residential Electrification on Fugitive Methane Emissions:** This study did not include upstream or life-cycle emissions from any of the fuels consumed on site or for electricity generation. Doing so would have required a broader analysis of life-cycle emissions for all fuels through 2050, which was outside the scope of this study. Some studies have included only the upstream emissions of methane associated with on-site gas use. This neglects both the upstream impact on electricity generation and the effect on other fossil fuels. That said, even an assessment of upstream methane emissions has little effect on the net emission reductions calculated in this study. Including upstream methane emissions increases the GHG emissions factor for natural gas for on-site and electricity generation. In the Market-Based Case, net natural gas consumption increases, so including methane emissions reduces the net emissions reductions (including power sector emissions) and increases the cost per ton of reduction.

In the Renewables-Only Case, the emissions reductions would have been roughly 12 percent to 17 percent greater based on GWP100, reducing the cost per ton of emissions reductions by an equivalent amount. Neither change affects the fundamental conclusions or significantly changes the cost-effectiveness relative to other control options.

5.6 Implications for the Policy Debate on Residential Electrification

The study did not address electrification policies targeted at other sectors of the economy, including the transportation sector, where policy-driven electrification could prove to be a more cost-effective approach to reducing GHG emissions, or market-driven electrification where consumers decide to invest in electric technologies rather than natural gas or other fuels. Overall, the results of this study reflect the scenarios evaluated, the costs considered, and the baseline emissions and energy prices from the EIA 2017 AEO. The analysis indicates that electrification policy measures that require the widespread conversion of residential space heating and water heating applications from natural gas and other fuels to electricity in order to reduce GHG emissions will be challenged by issues including the cost-effectiveness, consumer cost impacts, current and projected electric grid emission levels, and requirements for new investments in the power grid to meet growth in peak generation requirements over the winter periods.

At the same time, the total GHG emissions reductions available from a policy targeting electrification of residential heating loads represent a small fraction of domestic emissions. Total residential natural gas emissions are expected to account for less than 4 percent and total residential fossil fuel emissions are expected to account for less than 6 percent of the estimated 6,200 million metric tons of GHG emissions in 2035 in the AEO 2017 Reference Case. Aggressive electrification policies would have the potential to reduce these emissions by up to 1.5 percent of the total U.S. GHG emissions, at a net cost to energy consumers ranging from $590 million to $1.2 trillion (real 2016 $).

As a result, the conversations surrounding residential electrification policies and other approaches toward a low-carbon economy need to be evaluated in an integrated manner that includes not only the potential emissions reductions, but also considers the feasibility and real-world issues of complying with the proposed policies, as well as the potential consequences of the policies, including the economic impacts on consumers, and potential impacts on the power grid.

Appendix A: Study Inputs and Assumptions

A-1 Natural Gas and Electric Rates

The electric and natural gas prices (Real 2016 $) from the EIA 2017 AEO Base Case are used to calculate the difference in the cost of energy between a gas furnace and electric heat pump based on the equipment's regional performance. The residential natural gas and electricity prices from the EIA AEO are summarized in Exhibits A-1 and A-2 below:

Exhibit A-1: Average U.S. Residential Prices from EIA's 2017 AEO Base Case (Real 2016 $)

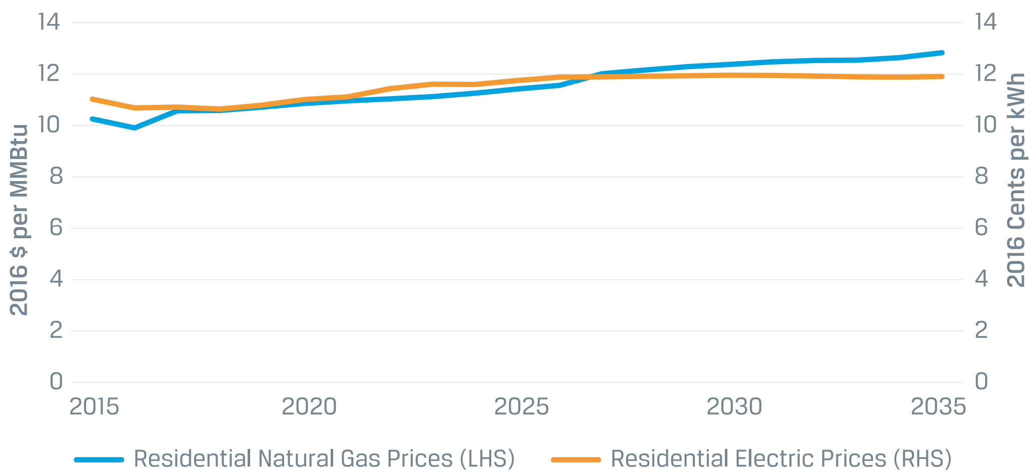


Exhibit A-2: Regional Residential Natural Gas and Electric Rates (Real 2016 $)[1]

	Residential Electric Prices (2016 Cents per kWh)					Residential Natural Gas Prices ($2016 per MMBtu)				
Region	**2016**	**2020**	**2025**	**2030**	**2035**	**2016**	**2020**	**2025**	**2030**	**2035**
East Coast	12.69	14.25	15.89	16.41	16.48	10.15	10.74	11.50	12.12	12.67
Midwest	10.85	11.20	11.98	12.32	12.25	8.46	9.49	9.93	10.62	10.96
New England	15.80	13.61	15.44	16.60	17.27	11.68	12.19	12.91	13.58	14.19
New York	15.90	17.92	20.33	21.16	21.29	11.26	12.06	12.77	13.30	14.08
Plains	10.91	10.47	10.88	10.86	10.85	9.06	10.47	10.77	11.47	11.74
Rockies	9.66	9.46	10.12	10.23	10.62	7.89	8.83	9.39	9.89	10.21
South	9.20	9.90	10.45	10.59	10.49	12.26	13.15	13.95	14.98	15.35
Texas	8.96	9.28	9.80	10.06	9.75	9.47	10.71	10.75	11.48	11.84
West	12.88	12.86	14.22	14.84	15.42	11.01	11.91	12.50	14.84	15.41
U.S. Total	**10.69**	**11.01**	**11.75**	**11.96**	**11.91**	**9.91**	**10.86**	**11.42**	**12.37**	**12.83**

[1] The regional averages are based on a weighted average of the state-level residential prices based on the number of converted natural gas households in each state. The state level residential prices are based on the EIA's 2017 AEO Base Case census division prices, which were used to derive each state's residential rates based on that state's 2016 prices relative to the census division average.

A-2 Impact of Policy-Driven Residential Electrification on Emissions:

Residential and Power Generation Sector Emissions

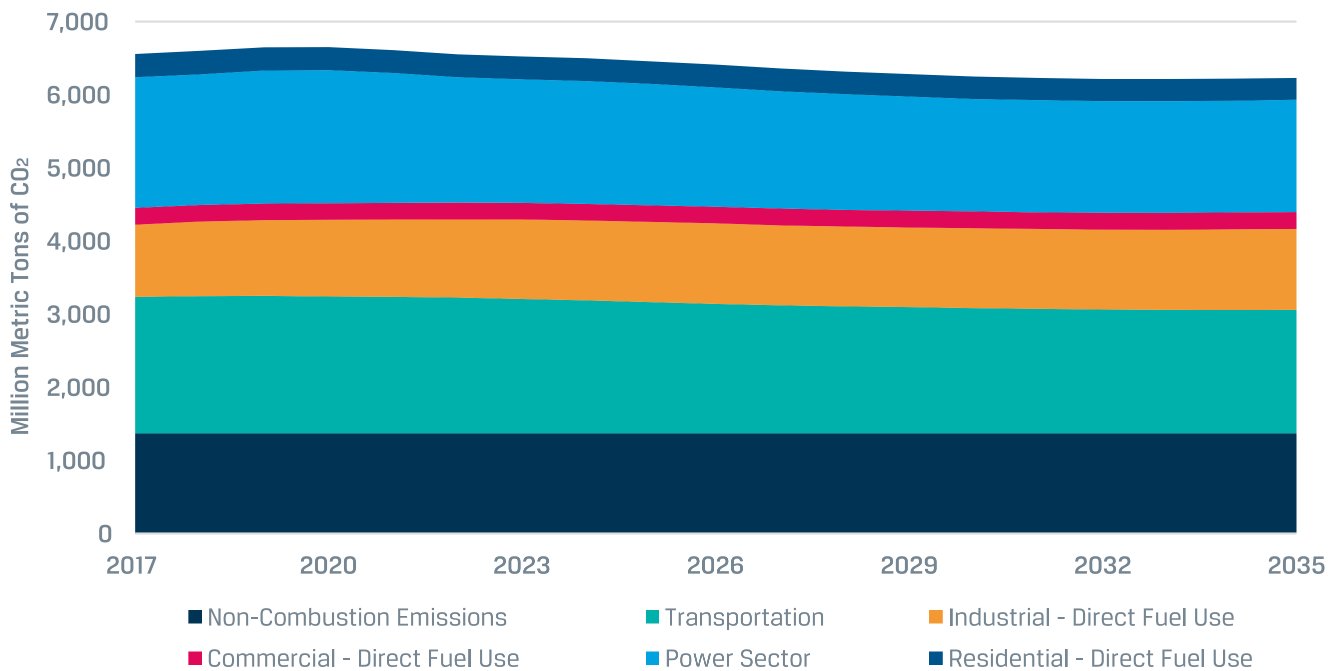
The impact of the residential electrification policies on CO_2 emissions are estimated based on the impact of the residential electrification policies on energy consumption in the residential and power generation sectors relative to the Base Case. The following fuel emissions factors are used to estimate the changes in emissions:[2]

- 117 pounds of CO_2 per Million Btu of natural gas
- 161 pounds of CO_2 per Million Btu of diesel fuel / heating oil
- 139 pounds of CO_2 per Million Btu of propane
- 208 pounds of CO_2 per Million Btu of coal
- 195 pounds of CO_2 per Million Btu of biomass

Other Emission Sources

To estimate the total change in emissions for each region, the study used emissions estimates from the EIA 2017 AEO Base Case for the energy related CO_2 emissions by sector and source and an estimate of 1,370 Million Metric Tons of CO_2 from non-energy related GHG emissions from combustion and non- combustion. This estimate is based on the 2016 reported GHG emission levels from non-combustion sources based on the Environmental Protection Agency's 2016 Inventory of U.S. Greenhouse Gas Emissions and Sinks .[3] Exhibit A-2 shows the total U.S. GHG emissions by emitting sector for the Reference Case from 2017 to 2035.

Exhibit A-3: Reference Case - Total U.S. GHG Emissions by Sector



[2] Source: Energy Information Administration: How much carbon dioxide is produced when different fuels are burned?

[3] https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks-1990-2016

A-3 Residential Household Conversions to Electricity

The policy-driven residential electrification scenario evaluated in this study reflects a policy implemented in 2023 that requires all new homes to be built with electric space and water heating appliances, and requires the conversion of existing homes with natural gas, propane, or fuel oil space and water heating appliances to electricity at the end of the useful life of the space heating appliance.

In order to determine the consumer costs associated with the conversion to electricity, the housing stock is disaggregated by:

- New household construction
- Households with forced-air furnaces and existing air-conditioning
- Households with forced-air furnaces without existing air-conditioning
- Households with hydronic (Radiator) heating systems – Both with and without existing air-conditioning systems

The number of space heating households converted to electricity between 2023 and 2035 by type of household is shown in Exhibit A-4. The number of space heating households converted to electricity between 2023 and 2035 by region for the Renewables Only Case is shown in Exhibit A-5.

Exhibit A-4: Number of Natural Gas, Fuel Oil, and Propane Households Converted to Electricity from 2023 to 2035 by Type of Heating System (Million Households)

Household Fuel Type	New Households	Forced Air Furnace with A/C	Forced Air Furnace without A/C	Hydronic Heating with A/C	Hydronic Heating without A/C	U.S. Lower 48 Total
Natural Gas	8.6	33.3	1.0	5.5	1.3	49.7
Propane/Fuel Oil	0.0	3.9	0.7	1.6	0.3	6.4
Total Fossil/Fuel Households Subject to Electrification Policy	**8.6**	**37.1**	**1.7**	**7.1**	**1.6**	**56.1**

Exhibit A-5: Number of Natural Gas, Fuel Oil, and Propane Households Converted to Electricity in the "Renewable Generation Only" Case from 2023 to 2035 by Region (Million Households)

Household Fuel Type	East Coast	Midwest	New England	New York	Plains	Rockies	Texas	South	West	U.S. Lower 48
Natural Gas	6.4	10.0	2.0	3.7	5.1	2.2	5.0	3.0	12.3	49.7
Propane/Fuel Oil	1.1	0.8	1.4	1.0	0.7	0.1	0.7	0.2	0.5	6.4
Total Households Converted (2023 to 2035)	**7.5**	**10.8**	**3.3**	**4.8**	**5.8**	**2.3**	**5.7**	**3.2**	**12.8**	**56.1**

A-4 Residential Energy Efficiency and Cost Analysis Assumptions[4]

The number of households converted shown in Exhibits A-4 and A-5 are for the Renewables-Only Case. In the Renewables-Only Case, the residential electrification policy is applied in all regions. In the Market-Based Generation Case, the policy is applied only in regions where the electric grid is expected to be sufficiently clean to reduce overall CO_2 emissions, based on the EIA AEO 2017 Base Case projection of the electric grid. Hence, in this scenario, conversions in the Midwest, Plains, and Rockies are zero due to the lack of emissions reductions. The number of conversions in the other regions is the same in both scenarios.

Different conversion costs are estimated for each of the following household heating types:

- New household construction
- Households with forced-air furnaces and existing air-conditioning
- Households with forced-air furnaces without existing air-conditioning
- Households with hydronic (radiator) heating systems – Both with and without existing air-conditioning systems

A typical 2,250 square foot household is used as the baseline for estimating the conversion cost differences between a fossil-fuel heated and electric-heated households. All households are assumed to be single-family households. Other types of residential housing (duplexes, manufactured homes, and large residential housing, etc.) are treated as single-family homes to simplify the analysis, given the wide range of cost uncertainties in converting non-single family homes.

- The equipment and energy cost comparisons for all new construction households and existing households converting to electricity include a fossil-fuel furnace and an electric air conditioning system.
- A real discount rate of 5 percent is used in the economic analysis between systems.

Existing natural gas, propane and fuel oil space heating systems:

- The average efficiency of the existing furnaces being replaced: 80%

New natural gas, propane, and fuel oil space heating systems:

- New furnace costs are based on a 90,000 BTU per Hour High-Efficiency Energy Star® rated system.

[4] All costs are presented in real 2016 $, unless otherwise specified.

- New furnace efficiency – Same as existing furnace efficiency to ensure that the analysis does not overstate potential gas furnace efficiency, or understate furnace installation costs.
- Expected equipment life of 24 years
- Annual non-energy operating costs of $75 (Real 2016 $)
- A/C System - Seasonal Energy Efficiency Ratio (SEER) = 15

New electric space heating system:

- Average HSPF of 11.5 for all new systems installed between 2023 and 2035.
- Heat Pump equipment prices are based on the cost of a typical 3 Ton 9.5 HSPF System in 2016 – We assume that average efficiency improves without increasing system costs in real 2016$ through 2035. The increase in costs associated with higher efficiency units is offset by improvements in technology and economies to scale. The full impact of improvements in technology and economies to scale are assumed to be reflected in improvements in efficiency, rather than reductions in costs.
- Expected equipment life of 18 years.
- Annual non-energy operating costs of $75 (real 2016 $).

Exhibit A-6: National Installation Costs and Annual Fuel Costs (2035) by Household Heating & Cooling System Type

Household Heating & Cooling System Type	New Household		Replacement - Gas Furnace & A/C unit	Conversion of Forced Air Furnace		Conversion of Hydronic System	
	Gas Furnace & A/C	ASHP	Gas Furnace & A/C	ASHP (Existing A/C)	ASHP (No Existing A/C)	ASHP (Existing A/C)	ASHP (No Existing A/C)
Purchase Cost (Capital)	$4,495	$3,903	$4,495	$4,065	$4,065	$4,065	$4,065
Total Installation & Upgrade Costs (1-Year Cost)	$6,281	$5,991	$6,858	$6,993	$10,909	$8,637	$11,509
Annual Equipment Costs[1]	$337	$408	$361	$464	$681	$555	$714
Annual Heating Expense[1]	$998	$1,475	$998	$1,475	$1,475	$1,475	$1,475
Total Annualized Costs	**$1,335**	**$1,883**	**$1,359**	**$1,939**	**$2,156**	**$2,030**	**$2,189**

Source: Derived from national level and state level estimates for installation costs from a variety of sources, including homewyse. com, homeadvisor.com, energyhomes.org, HomeDepot.com, homesteady.com, and manufacture reported retail sales prices for home heating equipment.

[1] Equipment costs are annualized over the expected life of the equipment, using a real discount rate of 5%.

The study uses the household capital cost differences in Exhibit A-6 in the calculation of each region's consumer capital and investment cost impacts. These costs are based on the national average household costs for each system type and heating fuel (Natural Gas & Electric) with a regional cost factor to capture differences in installation and equipment costs between regions.

Water Heating Equipment

The study uses average costs for currently available high efficiency water heating equipment with a 50-gallon tank storage, placed indoors, with no regional variation in water heater efficiency factors. Fuel oil and propane water heating households are treated as if natural gas households.

Natural gas water heating system:

- The replacement natural gas water heater is sized at 42,000 Btu output with an energy efficiency rating of 80 percent.
- Natural gas water heater equipment cost is $1,392, with an expected life of 10 years, with installation costs of $540.

Electric heat pump water heating system:

- Electric heat pump water heater equipment cost is $1,651, with an expected life of 10 years, and installation costs of $520.

A-5 Heating and Cooling System Efficiency Assumptions

Space Heating Efficiency

The study uses a high-efficiency conventional air source heat pump as the electric alternative to fossil fuel space heating equipment throughout the analysis. Heating efficiency for air-source electric heat pumps is indicated by the HSPF, which is the total space heating required during the heating season, expressed in Btu, divided by the total electrical energy consumed by the heat pump system during the same season, expressed in watt-hours.

Electric Heat Pump Heating Efficiency Assumptions

This analysis starts with an Air Source Heat Pump with a reported HSPF of 11.0 in 2023. The efficiency of the average newly installed heat pump is assumed to increase by about 1 percent per year, reaching an HSPF of 12.5 by 2035. This results in an average reported HSPF of 11.5 (COP of 3.4) for the heat pumps used to replace the furnaces converted to electricity due to the residential electrification policy over the time period from 2023 through 2035.

Impact of Weather on Heating System Efficiencies

Actual heat pump performance is highly dependent on the weather conditions (temperature) when the heat pump is operating. To account for the variations in effective performance of electric ASHPs across the different regions, this study adjusts efficiency ratings for the newly installed electric heat pumps for each state based on actual temperature data.

The study uses weather data from 220 different regional weather stations to estimate the weighted average ASHRAE heating season Design Temperature for each state. The seasonal design temperature, based on a consumption weighted annual temperature average for each state, is used to estimate the actual average heating season efficiency of the ASHP for each state.

The study's effective performance ratings for the electric ASHPs are derived based on research from the Florida Solar Energy Center.[5] In addition, the study bases the heat pump performance on manufacturer's performance ratings at select temperature ranges.[6]

The average weather-adjusted effective COP is based on local winter weather conditions from 220 weather reporting regions aggregated to the state level. When adjusted for actual expected weather conditions, the heat pumps installed between 2023 and 2035 are expected to achieve an average weather-adjusted effective COP of 2.6 in the Renewables-Only Case and 2.9 in the Market-Based Generation Case.[7]

At temperatures below 4 degrees Fahrenheit, the study assumes that ASHPs switch-over to electric resistance heating, which has an efficiency of 100 percent, or a COP of 1.

Electric Water Heater Efficiency

The water heater conversions from natural gas to electric demand are based on an electric heat pump water heater with an average efficiency of 200 percent, applied in a uniform manner across all regions.

Air Conditioning

Installation of a heat pump provides both heating and air conditioning. In this study, all gas furnace replacements are paired with an air conditioner when evaluating equipment and operating costs between the different equipment options. The efficiency of the air conditioner used is assumed to be equivalent to the efficiency of the heat pump for cooling load, hence air conditioning load did not impact the incremental operating costs between the different equipment options.

[5] Fairey, P., D.S. Parker, B. Wilcox and M. Lombardi, "Climate Impacts on Heating Seasonal Performance Factor (HSPF) and Seasonal Energy Efficiency Ratio (SEER) for Air Source Heat Pumps." ASHRAE Transactions, American Society of Heating, Refrigerating and Air Conditioning Engineers, Inc., Atlanta, GA, June 2004.

[6] These performance profiles for ASHPs were selected from currently available electric ASHPs on the market rated with performance rating of 10.5 HSPF

[7] The Market-Based case excludes regions where electrification would increase GHG emissions based on the expected grid emissions. This included the Plains and Rockies regions where colder temperatures reduce the effective efficiency of the heat pumps.

A-6 Impact of Conversion to Electricity on Peak and Annual Electricity Demand

The impact on peak and heating season electricity demand resulting from the conversion of residential fossil-fuel space and water heating consumption of natural gas, fuel oil and propane to electricity is estimated by converting the fossil fuel consumption from the converted households to the electricity demand based on the electricity that would be needed to replace the end-use energy provided by the existing space and water heating applications, accounting for the differences in efficiency of the different applications, and the difference in heating season efficiency and peak period efficiency for the ASHPs.

- Residential household energy consumption information from the 2015 EIA Residential Energy Consumption Survey (RECS) is used to segment household usage between space heating, water heating and other use. This is done for each census region and allocated to each state based on 2016 state data.

- 2015 RECS data is used to determine residential fossil fuel consumption by fuel type and end-use demand type.
  (Space Water, Water Heating, and Other). A monthly consumption profile is created using RECs information and monthly natural gas deliveries to residential consumers by state from the EIA.

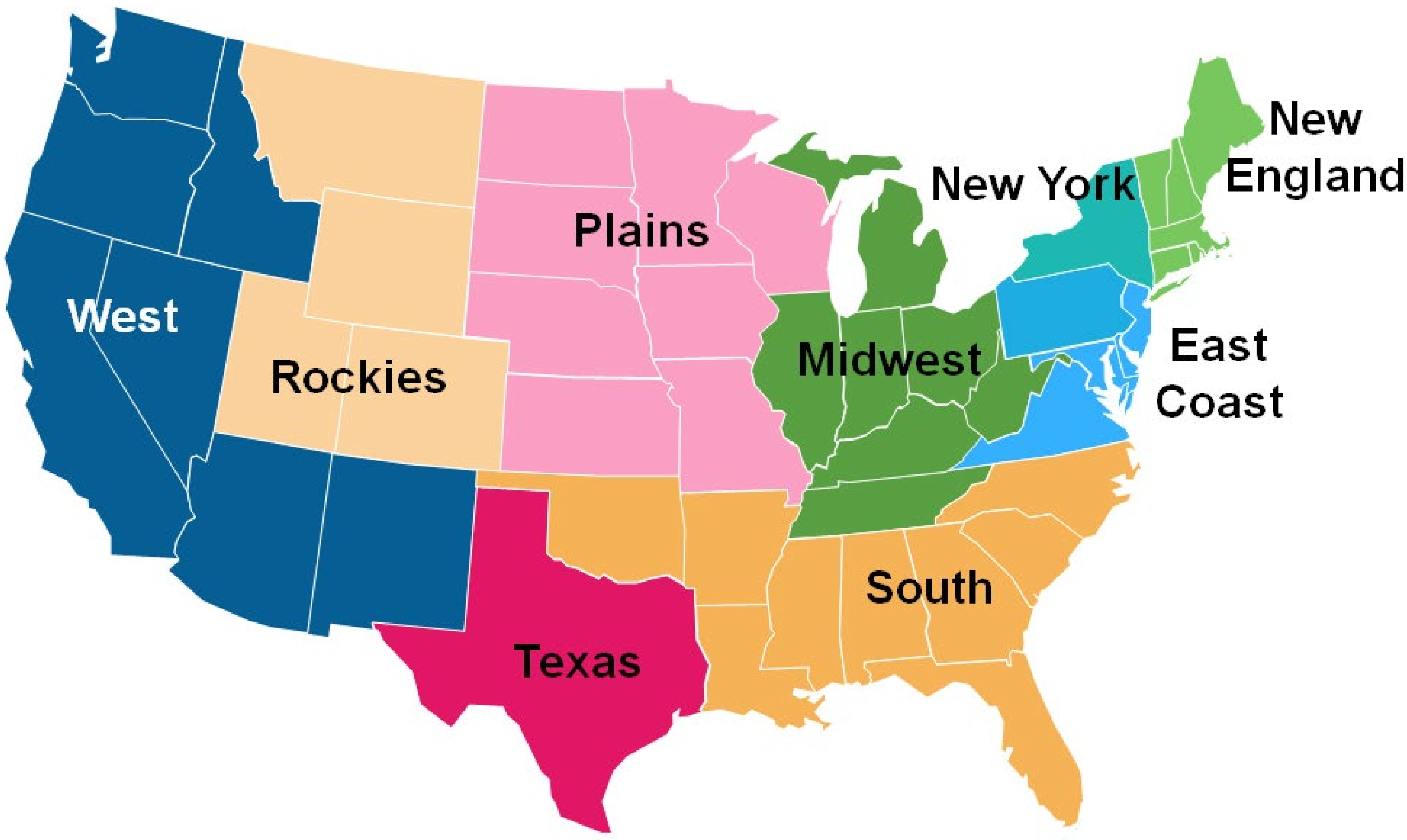
- The peak day design sendout for water and gas heating load is created in order to estimate peak winter period electric demand impacts of converting residential households to electricity. To calculate the peak day natural gas demand levels, the study uses Heating Degree Days (HDDs) from the coldest day from 1986 to 2016 from 220 locations to estimate the HDDs for each state based on weighted state-wide average of the number of natural gas households.

- The average space heating consumption (BTU) per Household and per HDD is calculated for the winter months (December to February) for the past 10-years. The study then uses this ratio to calculate the 2035 residential space heating sendout based on the HDDs from the coldest day from 1986 to 2016 and the number of natural gas households.

- The average monthly consumption per household is then calculated for water heating and other demand for natural gas. This ratio is used to create the 2035 residential water heating and other demand projections based on the number of natural gas households and consumption patterns by region sourced from the EIA RECS.

Appendix B: Regional Results

Exhibit B-1 Study Regions



B-1 East Coast

Exhibit B-2 East Coast Regional Generation and Capacity

Generation Type	2016	2035 Generation (GWh)				2016	2035 Capacity (MW)		
		Reference Case	Renewables-Only	Market-Based Generation			Reference Case	Renewables-Only	Market-Based Generation
Existing Units	**423,159**	**446,559**	**486,686**	**434,777**		**101,927**	**93,818**	**106,800**	**98,096**
Coal	76,433	52,589	34,761	38,436		21,755	8,987	13,258	10,275
Nuclear	151,839	129,846	129,846	129,846		19,189	16,409	16,409	16,409
Natural Gas	162,332	238,560	295,657	241,035		39,663	54,611	54,611	54,611
Wind & Solar	4,906	5,683	5,683	5,683		2,310	2,678	2,678	2,678
Other Renewables	13,819	14,922	13,161	14,781		7,949	8,119	8,120	8,119
Oil/Gas & Other	13,829	4,960	7,579	4,997		11,060	3,013	11,724	6,003
New Units	**0**	**30,197**	**43,980**	**71,653**		**0**	**9,132**	**28,252**	**21,042**
Natural Gas	0	16,536	19,409	57,721		0	2,994	2,994	14,741
Wind & Solar	0	13,661	20,679	13,933		0	6,139	9,328	6,302
Energy Storage	0	0	3,892	0		0	0	15930.0503	0
East Coast Total	**423,159**	**476,756**	**530,666**	**506,431**		**101,927**	**102,950**	**135,053**	**119,138**

Exhibit B-3. East Coast Regional Results

Region	Consumer Direct-Use Natural Gas Use	Power Sector Natural Gas Use	Change in Natural Gas Use	Cumulative Household CO_2 Emissions (Natural Gas, Propane, and Fuel Oil)	Cumulative Power Sector CO_2 Emissions	Cumulative Total Change in CO_2 Emissions	Cost of Emissions Reduction (Discounted to 2023)
Units	Tcf from 2023 to 2050 (Not Discounted)			Million Metric Tons of CO_2 from 2023 to 2050 (Non-Discounted)			2016 $ per Metric Ton of CO_2
Reference Case	17.3	50.2	N/A	1,253.7	4,786	N/A	N/A
Renewables-Only Case	9.7	56.3	-1.5	715.6	5,091	-223	635
Market-Based Generation Case	9.7	62.5	4.7	715.6	4,840	-380	391

Region	Coincident Peak Electric Generation Requirement in 2035 (Space & Water Heating)	Incremental Electric Consumption Levels in 2035 (Space & Water Heating)				
	Maximum Hourly Peak Generation (GW)	Average Winter Day (November - April) (GW)	Normal Day June 2035 (GW)	2035 Annual Electric Consumption (GWh)	January 2035 Electric Consumption (GWh)	June 2035 Electric Consumption (GWh)
Renewables-Only Case	86.1	15.1	2.8	61,899	13,629	1,058
Market-Based Generation Case	86.1	15.1	2.8	61,899	13,629	1,058

Sector Description	Units	Base Case	Change from Base Case	
			Renewables-Only	Market-Based Generation
Consumer Energy Purchases	2016 $ Billions	148.2	86.1	86.1
Consumer Capital Costs		475.2	21.7	21.7
Power Sector Capital Costs		16.4	22.5	12.2
Transmission Capital Costs		N/A	8.7	4.7
Total Costs		639.8	138.9	124.7
Pre-Electrification: Average Household Annual Household Energy Costs	2016 $ per Household	2,178	N/A	N/A
Cumulative Change in Costs Per Converted Household		N/A	17,600	16,550
Annualized Change in Costs Per Converted Household		N/A	1,200	1,110

B-2 Midwest

Exhibit B-4. Midwest Regional Generation and Capacity

Generation Type	2016	2035 Generation (GWh)				2016	2035 Capacity (MW)		
		Reference Case	Renewables-Only	Market-Based Generation			Reference Case	Renewables-Only	Market-Based Generation
Existing Units	**730,975**	**698,035**	**755,301**	**690,846**		**184,214**	**153,361**	**174,483**	**152,879**
Coal	420,221	356,793	355,665	350,739		87,560	50,951	66,726	50,772
Nuclear	168,344	147,173	147,173	147,173		22,210	18,599	18,599	18,599
Natural Gas	95,416	136,081	187,934	136,431		51,633	59,471	59,816	59,334
Wind & Solar	21,650	27,086	27,086	27,086		8,679	10,800	10,800	10,800
Other Renewables*	22,775	27,585	32,277	26,099		8,815	9,481	10,664	9,315
Oil/Gas & Other	2,569	3,317	5,166	3,317		5,317	4,060	7,878	4,060
New Units	**0**	**55,050**	**73,215**	**77,658**		**0**	**21,247**	**53,772**	**24,858**
Natural Gas	0	9,561	10,255	32,169		0	1,389	1,389	5,001
Wind & Solar	0	45,489	56,495	45,489		0	19,857	23,661	19,857
Energy Storage	0	0	6,465	0		0	0	28,721	0
Midwest Total	**730,975**	**753,085**	**828,516**	**768,504**		**184,214**	**174,608**	**228,255**	**177,737**

Exhibit B-5 Midwest Regional Results

Region	Consumer Direct-Use Natural Gas Use	Power Sector Natural Gas Use	Change in Natural Gas Use	Cumulative Household CO_2 Emissions (Natural Gas, Propane, and Fuel Oil)	Cumulative Power Sector CO_2 Emissions	Cumulative Total Change in CO_2 Emissions	Cost of Emissions Reduction (Discounted to 2023)
Units	Tcf from 2023 to 2050 (Non-Discounted)			Million Metric Tons of CO_2 from 2023 to 2050 (Non-Discounted)			2016 $ per Metric Ton of CO_2
Reference Case	32.3	28.8	N/A	1,962	12,278	N/A	N/A
Renewables-Only Case	17.9	32.1	-11.2	1,091	13,090	-38	N/A
Market-Based Generation Case	32.3	40.0	11.1	1,962	12,379	Not Modelled	Not Modelled

Region	Coincident Peak Electric Generation Requirement in 2035 (Space & Water Heating)			Incremental Electric Consumption Levels in 2035 (Space & Water Heating)		
	Maximum Hourly Peak Generation (GW)	Average Winter Day (November - April) (GW)	Normal Day June 2035 (GW)	2035 Annual Electric Consumption (GWh)	January 2035 Electric Consumption (GWh)	June 2035 Electric Consumption (GWh)
Renewables-Only Case	133.5	32.9	4.8	132,856	29,400	1,425
Market-Based Generation Case	N/A	N/A	N/A	N/A	N/A	N/A

Sector Description	Units	Base Case	Change from Base Case	
			Renewables-Only	Market-Based Generation
Consumer Energy Purchases	2016 $ Billions	207.9	193	N/A
Consumer Capital Costs		215.6	24.8	N/A
Power Sector Capital Costs		7.8	47.5	N/A
Transmission Capital Costs		N/A	13.5	N/A
Total Costs		865.9	278.8	N/A
Pre-Electrification: Average Household Annual Household Energy Costs	2016 $ per Household	1,997	N/A	N/A
Cumulative Change in Costs Per Converted Household		N/A	25,920	N/A
Annualized Change in Costs Per Converted Household		N/A	1,740	N/A

B-3 New England

Exhibit B-6 New England Regional Generation and Capacity

Generation Type	2016	2035 Generation (GWh)				2016	2035 Capacity (MW)		
		Reference Case	Renewables-Only	Market-Based Generation			Reference Case	Renewables-Only	Market-Based Generation
Existing Units	**104,928**	**87,114**	**119,073**	**85,039**		**32,344**	**28,769**	**33,779**	**33,345**
Coal	864	0	0	0		1,986	0	0	0
Nuclear	31,795	26,870	26,870	26,870		4,018	3,396	3,396	3,396
Natural Gas	55,127	38,246	69,451	34,423		14,871	17,946	17,946	17,946
Wind & Solar	2,927	4,603	4,603	4,603		1,355	2,181	2,181	2,181
Other Renewables	13,234	17,007	17,759	18,754		4,767	5,162	5,323	5,446
Oil/Gas & Other	982	389	389	389		5,347	84	4,933	4,376
New Units	**0**	**12,912**	**24,616**	**45,192**		**0**	**3,512**	**36,909**	**34,651**
Natural Gas	0	0	0	29,035		0	0	0	30,075
Wind & Solar	0	12,912	21,835	16,157		0	3,512	6,531	4,576
Energy Storage	0	0	2,781	0		0	0	30,378	0
New England Total	**104,928**	**100,026**	**143,689**	**130,230**		**32,344**	**32,281**	**70,688**	**67,996**

Exhibit B-7 New England Regional Results

Region	Consumer Direct-Use Natural Gas Use	Power Sector Natural Gas Use	Change in Natural Gas Use	Cumulative Household CO_2 Emissions (Natural Gas, Propane, and Fuel Oil)	Cumulative Power Sector CO_2 Emissions	Cumulative Total Change in CO_2 Emissions	Cost of Emissions Reduction (Discounted to 2023)
Units	Tcf from 2023 to 2050 (Non-Discounted)			Million Metric Tons of CO_2 from 2023 to 2050 (Non-Discounted)			2016 $ per Metric Ton of CO_2
Reference Case	5.7	8.2	N/A	652.7	702	N/A	N/A
Renewables-Only Case	3.1	12.0	12.5	367.3	1,023	57	N/A
Market-Based Generation Case	3.1	13.7	14.3	367.3	926	-56	1,081

Region	Coincident Peak Electric Generation Requirement in 2035 (Space & Water Heating)			Incremental Electric Consumption Levels in 2035 (Space & Water Heating)		
	Maximum Hourly Peak Generation (GW)	Average Winter Day (November - April) (GW)	Normal Day June 2035 (GW)	2035 Annual Electric Consumption (GWh)	January 2035 Electric Consumption (GWh)	June 2035 Electric Consumption (GWh)
Renewables-Only Case	52.5	13.6	2.7	55,811	11,290	789
Market-Based Generation Case	52.5	13.6	2.7	55,811	11,290	789

Sector Description	Units	Base Case	Change from Base Case	
			Renewables-Only	Market-Based Generation
Consumer Energy Purchases	2016 $ Billions	80.9	66.2	66.2
Consumer Capital Costs		200.2	11	11
Power Sector Capital Costs		22.6	48.6	29.9
Transmission Capital Costs		N/A	11.8	10.9
Total Costs		303.7	137.7	118.1
Pre-Electrification: Average Household Annual Household Energy Costs	2016 $ per Household	2,373	N/A	N/A
Cumulative Change in Costs Per Converted Household		N/A	41,210	35,340
Annualized Change in Costs Per Converted Household		N/A	2,770	2,370

B-4 New York

Exhibit B-8 New York Regional Generation and Capacity

Generation Type	2016	2035 Generation (GWh)				2016	2035 Capacity (MW)		
		Reference Case	Renewables-Only	Market-Based Generation			Reference Case	Renewables-Only	Market-Based Generation
Existing Units	**128,091**	**109,245**	**130,810**	**96,334**		**39,570**	**35,861**	**41,019**	**40,714**
Coal	449	2,657	3,031	1,203		2,246	897	1,562	1,260
Nuclear	42,711	38,844	37,095	32,662		5,398	4,909	4,909	4,909
Natural Gas	40,907	29,711	48,838	23,144		13,213	14,959	14,992	14,992
Wind & Solar	4,046	4,624	4,624	4,624		1,978	2,260	2,260	2,260
Other Renewables	28,583	29,939	32,415	31,231		6,251	6,411	6,803	6,623
Oil/Gas & Other	11,395	3,470	4,807	3,470		10,484	6,425	10,494	10,671
New Units	**0**	**35,601**	**60,937**	**106,526**		**0**	**12,149**	**46,712**	**49,458**
Natural Gas	0	0	1	47,007		0	0	0	28,990
Wind & Solar	0	35,601	58,208	59,519		0	12,149	20,500	20,468
Energy Storage	0	0	2,728	0		0	0	26,212	0
New York Total	**128,091**	**144,846**	**191,747**	**202,860**		**39,570**	**48,010**	**87,732**	**90,173**

Exhibit B-9 New York Regional Results

Region	Consumer Direct-Use Natural Gas Use	Power Sector Natural Gas Use	Change in Natural Gas Use	Cumulative Household CO_2 Emissions (Natural Gas, Propane, and Fuel Oil)	Cumulative Power Sector CO_2 Emissions	Cumulative Total Change in CO_2 Emissions	Cost of Emissions Reduction (Discounted to 2023)
Units	Tcf from 2023 to 2050 (Non-Discounted)			Million Metric Tons of CO_2 from 2023 to 2050 (Non-Discounted)			2016 $ per Metric Ton of CO_2
Reference Case	11.2	7.3	N/A	796.2	567	N/A	N/A
Renewables-Only Case	6.1	13.3	0.9	445.2	869	-23	8,784
Market-Based Generation Case	6.1	11.3	-1.2	445.2	902	-31	6,450

Region	Coincident Peak Electric Generation Requirement in 2035 (Space & Water Heating)			Incremental Electric Consumption Levels in 2035 (Space & Water Heating)		
	Maximum Hourly Peak Generation (GW)	Average Winter Day (November – April) (GW)	Normal Day June 2035 (GW)	2035 Annual Electric Consumption (GWh)	January 2035 Electric Consumption (GWh)	June 2035 Electric Consumption (GWh)
Renewables-Only Case	45.4	8.0	1.9	34,118	6,662	663
Market-Based Generation Case	45.4	8.0	1.9	34,118	6,662	663

Sector Description	Units	Base Case	Change from Base Case	
			Renewables-Only	Market-Based Generation
Consumer Energy Purchases	2016 $ Billions	105.4	186.7	186.7
Consumer Capital Costs		307.3	15.2	15.2
Power Sector Capital Costs		3.5	59.5	56.3
Transmission Capital Costs		N/A	18.3	17.6
Total Costs		416.2	279.6	275.7
Pre-Electrification: Average Household Annual Household Energy Costs	2016 $ per Household	2,252	N/A	N/A
Cumulative Change in Costs Per Converted Household		N/A	58,580	57,770
Annualized Change in Costs Per Converted Household		N/A	3,930	3,880

B-5 Plains

Exhibit B-10 Plains Regional Generation and Capacity

Generation Type	2016	2035 Generation (GWh)				2016	2035 Capacity (MW)		
		Reference Case	Renewables-Only	Market-Based Generation			Reference Case	Renewables-Only	Market-Based Generation
Existing Units	**378,755**	**349,520**	**336,415**	**346,296**		**107,212**	**94,203**	**104,650**	**93,884**
Coal	194,284	156,029	133,210	153,405		41,690	25,665	31,448	25,371
Nuclear	51,906	41,077	41,077	41,077		6,560	5,191	5,191	5,191
Natural Gas	52,528	56,431	62,558	56,073		29,476	31,529	31,529	31,529
Wind & Solar	61,867	75,913	75,913	75,913		20,200	24,245	24,245	24,245
Other Renewables	15,273	18,217	21,674	17,976		4,983	5,551	5,965	5,472
Oil/Gas & Other	2,897	1,853	1,982	1,853		4,303	2,023	6,272	2,076
New Units	**0**	**36,823**	**112,398**	**44,859**		**0**	**8,259**	**54,763**	**9,932**
Natural Gas	0	9,506	10,193	13,512		0	1,425	1,425	2,151
Wind & Solar	0	27,317	98,450	31,347		0	6,834	23,614	7,781
Energy Storage	0	0	3,755	0		0	0	29,724	0
Plains Total	**378,755**	**386,343**	**448,813**	**391,155**		**107,212**	**102,461**	**159,412**	**103,815**

Exhibit B-11 Plains Regional Results

Region	Consumer Direct-Use Natural Gas Use	Power Sector Natural Gas Use	Change in Natural Gas Use	Cumulative Household CO_2 Emissions (Natural Gas, Propane, and Fuel Oil)	Cumulative Power Sector CO_2 Emissions	Cumulative Total Change in CO_2 Emissions	Cost of Emissions Reduction (Discounted to 2023)
Units	Tcf from 2023 to 2050 (Non-Discounted)			Million Metric Tons of CO_2 from 2023 to 2050 (Non-Discounted)			2016 $ per Metric Ton of CO_2
Reference Case	15.0	12.3	N/A	1,011	5,856	N/A	N/A
Renewables-Only Case	8.0	12.8	-6.5	548.6	5,367	-951	230
Market-Based Generation Case	15.0	13.7	1.4	1,011	5,826	Not Modelled	Not Modelled

Region	Coincident Peak Electric Generation Requirement in 2035 (Space & Water Heating)			Incremental Electric Consumption Levels in 2035 (Space & Water Heating)		
	Maximum Hourly Peak Generation (GW)	Average Winter Day (November - April) (GW)	Normal Day June 2035 (GW)	2035 Annual Electric Consumption (GWh)	January 2035 Electric Consumption (GWh)	June 2035 Electric Consumption (GWh)
Renewables-Only Case	60.7	16.9	2.6	68,594	15,331	831
Market-Based Generation Case	N/A	N/A	N/A	N/A	N/A	N/A

Sector Description	Units	Base Case	Change from Base Case	
			Renewables-Only	Market-Based Generation
Consumer Energy Purchases	2016 $ Billions	112.0	29,120	N/A
Consumer Capital Costs		334	1,950	N/A
Power Sector Capital Costs		0.7	29,120	N/A
Transmission Capital Costs		N/A	1,950	N/A
Total Costs		446.7	29,120	N/A
Pre-Electrification: Average Household Annual Household Energy Costs	2016 $ per Household	1,867	N/A	N/A
Cumulative Change in Costs Per Converted Household		N/A	29,120	N/A
Annualized Change in Costs Per Converted Household		N/A	1,950	N/A

B-6 Rockies

Exhibit B-12 Rockies Regional Generation and Capacity

Generation Type	2016	2035 Generation (GWh)				2016	2035 Capacity (MW)		
		Reference Case	Renewables-Only	Market-Based Generation			Reference Case	Renewables-Only	Market-Based Generation
Existing Units	**423,159**	**446,559**	**486,686**	**434,777**		**38,881**	**35,254**	**38,311**	**35,259**
Coal	76,433	52,589	34,761	38,436		18,444	12,764	15,069	12,742
Nuclear	151,839	129,846	129,846	129,846		0	0	0	0
Natural Gas	162,332	238,560	295,657	241,035		9,481	9,551	9,551	9,551
Wind & Solar	4,906	5,683	5,683	5,683		5,930	8,109	8,109	8,109
Other Renewables	13,819	14,922	13,161	14,781		4,698	4,824	4,851	4,851
Oil/Gas & Other	13,829	4,960	7,579	4,997		328	6	731	6
New Units	**0**	**30,197**	**43,980**	**71,653**		**0**	**3,490**	**17,182**	**3,445**
Natural Gas	0	16,536	19,409	57,721		0	0	0	48
Wind & Solar	0	13,661	20,679	13,933		0	3,490	7,489	3,396
Energy Storage	0	0	3,892	0		0	0	9,694	0
Rockies Total	**423,159**	**476,756**	**530,666**	**506,431**		**38,881**	**38,744**	**55,494**	**38,704**

Exhibit B-13 Rockies Regional Results

Region	Consumer Direct-Use Natural Gas Use	Power Sector Natural Gas Use	Change in Natural Gas Use	Cumulative Household CO_2 Emissions (Natural Gas, Propane, and Fuel Oil)	Cumulative Power Sector CO_2 Emissions	Cumulative Total Change in CO_2 Emissions	Cost of Emissions Reduction (Discounted to 2023)
Units	Tcf from 2023 to 2050 (Non-Discounted)			Million Metric Tons of CO_2 from 2023 to 2050 (Non-Discounted)			2016 $ per Metric Ton of CO_2
Reference Case	7.2	3.7	N/A	434.3	3,009	N/A	N/A
Renewables-Only Case	4.3	3.9	-2.7	261.3	3,063	-119	794
Market-Based Generation Case	7.2	4.1	0.4	434.3	2,982	Not Modelled	Not Modelled

Region	Coincident Peak Electric Generation Requirement in 2035 (Space & Water Heating)			Incremental Electric Consumption Levels in 2035 (Space & Water Heating)		
	Maximum Hourly Peak Generation (GW)	Average Winter Day (November - April) (GW)	Normal Day June 2035 (GW)	2035 Annual Electric Consumption (GWh)	January 2035 Electric Consumption (GWh)	June 2035 Electric Consumption (GWh)
Renewables-Only Case	25.8	7.2	1.4	30,840	5,926	430
Market-Based Generation Case	N/A	N/A	N/A	N/A	N/A	N/A

Sector Description	Units	Base Case	Change from Base Case	
			Renewables-Only	Market-Based Generation
Consumer Energy Purchases	2016 $ Billions	42.7	30.1	N/A
Consumer Capital Costs		117.5	4.9	N/A
Power Sector Capital Costs		26.6	18.3	N/A
Transmission Capital Costs		N/A	4	N/A
Total Costs		186.8	57.3	N/A
Pre-Electrification: Average Household Annual Household Energy Costs	2016 $ per Household	1,577	N/A	N/A
Cumulative Change in Costs Per Converted Household		N/A	25,060	N/A
Annualized Change in Costs Per Converted Household		N/A	1,680	N/A

B-7 South

Exhibit B-14 South Regional Generation

Generation Type	2016	2035 Generation (GWh)				2016	2035 Capacity (MW)		
		Reference Case	Renewables-Only	Market-Based Generation			Reference Case	Renewables-Only	Market-Based Generation
Existing Units	**1,021,072**	**996,577**	**1,012,688**	**943,877**		**249,599**	**228,274**	**248,598**	**229,662**
Coal	208,336	187,857	165,784	158,801		59,150	31,382	37,191	30,273
Nuclear	232,893	250,839	250,839	250,839		29,432	31,755	31,755	31,755
Natural Gas	490,144	466,048	506,168	443,383		114,184	119,539	119,539	119,539
Wind & Solar	22,424	42,630	42,630	42,630		8,777	17,196	17,196	17,196
Other Renewables	36,617	37,422	35,525	36,643		17,066	17,328	17,588	17,328
Oil/Gas & Other	30,658	11,782	11,743	11,581		20,991	11,074	25,330	13,571
New Units	**0**	**155,836**	**278,687**	**243,009**		**0**	**40,049**	**77,286**	**54,478**
Natural Gas	0	85,886	88,012	173,060		0	13,830	13,830	28,259
Wind & Solar	0	69,950	180,400	69,950		0	26,219	53,422	26,219
Energy Storage	0	0	10,275	0		0	0	10,034	0
South Total	**1,021,072**	**1,152,413**	**1,291,375**	**1,186,886**		**249,599**	**268,322**	**325,884**	**284,140**

Exhibit B-15 South Regional Results

Region	Consumer Direct-Use Natural Gas Use	Power Sector Natural Gas Use	Change in Natural Gas Use	Cumulative Household CO_2 Emissions (Natural Gas, Propane, and Fuel Oil)	Cumulative Power Sector CO_2 Emissions	Cumulative Total Change in CO_2 Emissions	Cost of Emissions Reduction (Discounted to 2023)
Units	Tcf from 2023 to 2050 (Non-Discounted)			Million Metric Tons of CO_2 from 2023 to 2050 (Non-Discounted)			2016 $ per Metric Ton of CO_2
Reference Case	12.2	106.8	N/A	752.9	12,341	N/A	N/A
Renewables-Only Case	7.3	115.9	4.3	450.0	12,320	-324	218
Market-Based Generation Case	7.3	114.8	3.1	450.0	12,233	-431	63

Region	Coincident Peak Electric Generation Requirement in 2035 (Space & Water Heating)			Incremental Electric Consumption Levels in 2035 (Space & Water Heating)		
	Maximum Hourly Peak Generation (GW)	Average Winter Day (November - April) (GW)	Normal Day June 2035 (GW)	2035 Annual Electric Consumption (GWh)	January 2035 Electric Consumption (GWh)	June 2035 Electric Consumption (GWh)
Renewables-Only Case	24.5	4.3	1.4	18,815	4,039	529
Market-Based Generation Case	24.5	4.3	1.4	18,815	4,039	529

Sector Description	Units	Base Case	Change from Base Case	
			Renewables-Only	Market-Based Generation
Consumer Energy Purchases	2016 $ Billions	110.6	-28.2	-28.2
Consumer Capital Costs		322.4	12.3	12.3
Power Sector Capital Costs		9.5	46.4	14.9
Transmission Capital Costs		N/A	14.1	4.7
Total Costs		442.4	44.6	3.7
Pre-Electrification: Average Household Annual Household Energy Costs	2016 $ per Household	2,116	N/A	N/A
Cumulative Change in Costs Per Converted Household		N/A	7,820	650
Annualized Change in Costs Per Converted Household		N/A	520	40

B-8 Texas

Exhibit B-16 Texas Regional Generation and Capacity

Generation Type	2016	2035 Generation (GWh)				2016	2035 Capacity (MW)		
		Reference Case	Renewables-Only	Market-Based Generation			Reference Case	Renewables-Only	Market-Based Generation
Existing Units	**397,338**	**421,880**	**422,276**	**425,839**		**111,309**	**118,662**	**118,663**	**118,755**
Coal	77,212	88,965	84,860	87,209		22,998	18,531	18,638	18,319
Nuclear	39,249	41,369	41,369	41,369		4,960	5,228	5,228	5,228
Natural Gas	199,368	196,711	202,186	202,929		43,772	47,247	47,247	47,247
Wind & Solar	58,503	83,382	83,382	83,382		21,272	29,321	29,321	29,321
Other Renewables	2,289	3,140	3,130	3,142		1,043	1,091	1,091	1,091
Oil/Gas & Other	20,718	8,313	7,348	7,808		17,263	17,243	17,137	17,548
New Units	**0**	**45,484**	**46,994**	**47,725**		**0**	**17,391**	**17,999**	**17,459**
Natural Gas	0	39,465	40,122	41,707		0	16,018	16,018	16,086
Wind & Solar	0	6,018	5,968	6,018		0	1,373	1,362	1,373
Energy Storage	0	0	905	0		0	0	620	0
Texas Total	**397,338**	**467,364**	**469,270**	**473,564**		**111,309**	**136,053**	**136,662**	**136,215**

Exhibit B-17 Texas Regional Results

Region	Consumer Direct-Use Natural Gas Use	Power Sector Natural Gas Use	Change in Natural Gas Use	Cumulative Household CO_2 Emissions (Natural Gas, Propane, and Fuel Oil)	Cumulative Power Sector CO_2 Emissions	Cumulative Total Change in CO_2 Emissions	Cost of Emissions Reduction (Discounted to 2023)
Units	Tcf from 2023 to 2050 (Non-Discounted)			Million Metric Tons of CO_2 from 2023 to 2050 (Non-Discounted)			2016 $ per Metric Ton of CO_2
Reference Case	6.0	48.6	N/A	334.7	5,865	N/A	N/A
Renewables-Only Case	3.6	50.1	-0.9	200.7	5,832	-167	251
Market-Based Generation Case	3.6	49.7	-1.4	200.7	5,888	-136	54

Region	Coincident Peak Electric Generation Requirement in 2035 (Space & Water Heating)			Incremental Electric Consumption Levels in 2035 (Space & Water Heating)		
	Maximum Hourly Peak Generation (GW)	Average Winter Day (November - April) (GW)	Normal Day June 2035 (GW)	2035 Annual Electric Consumption (GWh)	January 2035 Electric Consumption (GWh)	June 2035 Electric Consumption (GWh)
Renewables-Only Case	13.5	2.6	0.9	11,293	2,523	340
Market-Based Generation Case	13.5	2.6	0.9	11,293	2,523	340

Sector Description	Units	Base Case	Change from Base Case	
			Renewables-Only	Market-Based Generation
Consumer Energy Purchases	2016 $ Billions	38.6	-5.6	-5.6
Consumer Capital Costs		193.0	7.2	7.2
Power Sector Capital Costs		20.0	0.7	0.8
Transmission Capital Costs		N/A	4	0
Total Costs		251.6	6.3	2.3
Pre-Electrification: Average Household Annual Household Energy Costs	2016 $ per Household	1,975	N/A	N/A
Cumulative Change in Costs Per Converted Household		N/A	1,970	740
Annualized Change in Costs Per Converted Household		N/A	130	50

B-9 West

Exhibit B-18 West Regional Generation and Capacity

Generation Type	2016	2035 Generation (GWh)				2035 Capacity (MW)		
		Reference Case	Renewables-Only	Market-Based Generation	2016	Reference Case	Renewables-Only	Market-Based Generation
Existing Units	**567,251**	**541,800**	**587,577**	**571,951**	**170,002**	**168,265**	**177,505**	**172,537**
Coal	66,504	51,140	52,062	49,870	12,324	7,036	7,206	6,902
Nuclear	58,042	40,475	40,475	40,475	7,335	5,115	5,115	5,115
Natural Gas	197,704	148,572	183,836	176,260	60,162	59,935	64,439	63,782
Wind & Solar	56,664	82,151	82,151	82,151	28,117	38,258	38,258	38,258
Other Renewables	183,105	214,687	224,609	218,490	52,661	57,042	58,356	57,532
Oil/Gas & Other	5,230	4,775	4,444	4,704	9,403	880	4,130	948
New Units	**0**	**82,632**	**79,597**	**97,154**	**0**	**23,479**	**25,800**	**25,746**
Natural Gas	0	9,156	5,496	22,535	0	1,261	1,261	3,071
Wind & Solar	0	73,476	73,868	74,619	0	22,218	22,196	22,675
Energy Storage	0	0	233	0	0	0	2,343	0
West Total	**567,251**	**624,432**	**667,174**	**669,105**	**170,002**	**191,744**	**203,305**	**198,283**

Exhibit B-19 West Regional Results

Region	Consumer Direct-Use Natural Gas Use	Power Sector Natural Gas Use	Change in Natural Gas Use	Cumulative Household CO_2 Emissions (Natural Gas, Propane, and Fuel Oil)	Cumulative Power Sector CO_2 Emissions	Cumulative Total Change in CO_2 Emissions	Cost of Emissions Reduction (Discounted to 2023)
Units	Tcf from 2023 to 2050 (Non-Discounted)			Million Metric Tons of CO_2 from 2023 to 2050 (Non-Discounted)			2016$ per Metric Ton of CO_2
Reference Case	20.2	31.4	N/A	1,183	3,692	N/A	N/A
Renewables-Only Case	11.7	37.9	-2.0	689	4,039	-147	749
Market-Based Generation Case	11.7	36.9	-3.0	689	4,032	-155	485

Region	Coincident Peak Electric Generation Requirement in 2035 (Space & Water Heating)			Incremental Electric Consumption Levels in 2035 (Space & Water Heating)		
	Maximum Hourly Peak Generation (GW)	Average Winter Day (November - April) (GW)	Normal Day June 2035 (GW)	2035 Annual Electric Consumption (GWh)	January 2035 Electric Consumption (GWh)	June 2035 Electric Consumption (GWh)
Renewables-Only Case	44.7	8.8	4.4	41,892	7,088	1,552
Market-Based Generation Case	44.7	8.8	4.4	41,892	7,088	1,552

Sector Description	Units	Base Case	Change from Base Case	
			Renewables-Only	Market-Based Generation
Consumer Energy Purchases	2016$ Billions	171.9	8.3	8.3
Consumer Capital Costs	2016$ Billions	742.5	34.5	34.5
Power Sector Capital Costs	2016$ Billions	115.6	10.7	7.4
Transmission Capital Costs	2016$ Billions	N/A	21.5	15.3
Total Costs	2016$ Billions	1030.0	75	65.5
Pre-Electrification: Average Household Annual Household Energy Costs	2016 $ per Household	1,653	N/A	N/A
Cumulative Change in Costs Per Converted Household	2016 $ per Household	N/A	5,880	5,140
Annualized Change in Costs Per Converted Household	2016 $ per Household	N/A	390	340

B-10 U.S. Lower 48

Exhibit B-20 U.S. Lower 48 Regional Generation and Capacity

Generation Type	2016	2035 Generation (GWh)				2016	2035 Capacity (MW)		
		Reference Case	Renewables-Only	Market-Based Generation			Reference Case	Renewables-Only	Market-Based Generation
Existing Units	**3,898,887**	**3,797,327**	**3,999,903**	**3,740,849**		**1,035,057**	**956,466**	**1,043,809**	**975,131**
Coal	1,142,790	983,392	917,032	925,989		268,153	156,212	191,098	155,915
Nuclear	776,778	716,492	714,743	710,311		99,100	90,601	90,601	90,601
Natural Gas	1,311,444	1,331,115	1,579,671	1,334,573		376,457	414,787	419,669	418,530
Wind & Solar	249,072	348,535	348,535	348,535		98,619	135,049	135,049	135,049
Other Renewables	330,482	378,891	396,420	383,278		108,233	115,007	118,763	115,777
Oil/Gas & Other	88,321	38,902	43,501	38,163		84,496	44,809	88,629	59,259
New Units	**0**	**469,374**	**756,150**	**748,626**		**0**	**138,707**	**358,676**	**241,070**
Natural Gas	0	170,110	173,489	417,076		0	36,917	36,917	128,422
Wind & Solar	0	299,263	547,043	331,550		0	101,791	168,102	112,648
Energy Storage	0	0	35,619	0		0	0	153,657	0
U.S. Lower 48 Total	**3,898,887**	**4,266,700**	**4,756,054**	**4,489,474**		**1,035,057**	**1,095,174**	**1,402,484**	**1,216,201**

Exhibit B-21 U.S. Lower 48 Regional Results

Region	Consumer Direct-Use Natural Gas Use	Power Sector Natural Gas Use	Change in Natural Gas Use	Cumulative Household CO_2 Emissions (Natural Gas, Propane, and Fuel Oil)	Cumulative Power Sector CO_2 Emissions	Cumulative Total Change in CO_2 Emissions	Cost of Emissions Reduction (Discounted to 2023)
Units	Tcf from 2023 to 2050 (Non-Discounted)			Million Metric Tons of CO_2 from 2023 to 2050 (Non-Discounted)			2016 per Metric Ton of CO_2
Reference Case	127.1	297.5	N/A	8,382.2	49,097	N/A	N/A
Renewables-Only Case	71.8	334.3	-18.6	4,769.4	50,694	-1,909	806
Market-Based Generation Case	95.2	346.7	18.1	6,276.3	50,007	-1,196	572

Region	Coincident Peak Electric Generation Requirement in 2035 (Space & Water Heating)			Incremental Electric Consumption Levels in 2035 (Space & Water Heating)		
	Maximum Hourly Peak Generation (GW)	Average Winter Day (November - April) (GW)	Normal Day June 2035 (GW)	2035 Annual Electric Consumption (GWh)	January 2035 Electric Consumption (GWh)	June 2035 Electric Consumption (GWh)
Renewables-Only Case	486.7	109.1	22.9	456,118	95,887	7,617
Market-Based Generation Case	266.7	52.2	14.2	223,825	45,231	5,840

Sector Description	Units	Base Case	Change from Base Case	
			Renewables-Only	Market-Based Generation
Consumer Energy Purchases	2016 $ Billions	1,018	615.1	313.5
Consumer Capital Costs		3,342	144.6	101.8
Power Sector Capital Costs		223	318.9	121.6
Transmission Capital Costs		N/A	107.1	53.2
Total Costs		4,583	1,185.6	590.1
Pre-Electrification: Average Household Annual Household Energy Costs	2016 $ per Household	1,990	N/A	N/A
Cumulative Change in Costs Per Converted Household		N/A	21,140	15,830
Annualized Change in Costs Per Converted Household		N/A	1,420	1,060

Exhibit B-22 North America Regional Generation and Capacity

Generation Type	2016	2035 Generation (GWh)				2016	2035 Capacity (MW)		
		Reference Case	Renewables-Only	Market-Based Generation			Reference Case	Renewables-Only	Market-Based Generation
Existing Units	**4,511,467**	**4,404,042**	**4,619,157**	**4,344,442**		**1,175,935**	**1,097,072**	**1,189,379**	**1,118,713**
Coal	1,203,359	1,040,841	974,315	983,416		277,673	164,867	199,753	164,570
Nuclear	873,198	789,568	785,444	782,166		112,465	100,912	100,912	100,912
Natural Gas	1,350,699	1,376,059	1,628,495	1,377,768		394,133	434,852	439,734	438,595
Wind & Solar	271,561	373,089	373,089	373,089		110,593	147,742	147,742	147,742
Other Renewables	717,710	776,980	805,379	781,236		190,656	201,025	206,768	201,795
Oil/Gas & Other	94,941	47,505	52,434	46,766		90,416	47,673	94,470	65,099
New Units	**0**	**543,889**	**840,328**	**835,447**		**0**	**159,452**	**387,108**	**269,912**
Natural Gas	0	173,739	183,851	421,443		0	42,756	49,789	139,810
Wind & Solar	0	370,149	620,859	414,004		0	116,696	183,663	130,102
Energy Storage	0	0	35,619	0		0	0	153,657	0
North America Total	**4,511,467**	**4,947,930**	**5,459,486**	**5,179,887**		**1,175,935**	**1,256,525**	**1,576,487**	**1,388,625**

Appendix C: ICF IPM® Model Description

IPM® is a detailed engineering/economic capacity expansion and production-costing model of the power and industrial sectors supported by an extensive database of every boiler and generator in the nation. It is a multi-region model that provides capacity and transmission expansion plans, unit dispatch and compliance decisions, and power and allowance price forecasts, all based on power market fundamentals.

IPM® explicitly considers gas, oil, and coal markets, power plant costs and performance characteristics, environmental constraints, and other power market fundamentals. Figure C-1 illustrates the key components of IPM®.

Figure C-1: IPM® Schematic

IPM® uses a dynamic linear programming model the electric demand, generation, and transmission within each region as well as the transmission grid that connects the regions.

All existing utility-owned boilers and generators are modeled, as well as independent power producers and cogeneration facilities that sell firm capacity into the wholesale market. IPM® also is capable of explicitly modeling individual (or aggregated) end-use energy efficiency investments. Each technology (e.g., compact fluorescent lighting) or general program (e.g., load control) is characterized in terms of its load shape impacts and costs. Costs can be characterized simply as total costs or more accurately according to its components (e.g., equipment or measure costs, program or equipment costs, and administrative costs), and penetration curves reflecting the market potential for a technology or program. End-use energy efficiency investments compete on a level playing field with traditional electric supply options to meet future demands. As supply side resources become more constrained or expensive (e.g., due to environmental regulation) more energy efficiency resources are used.

IPM® has been used in support of numerous project assignments including:

- Valuation studies for generation and transmission assets
- Forecasting of regional forward energy and capacity prices
- Air emissions compliance strategies and pollution allowances
- Impact assessments of alternate environmental regulatory standards
- Impact assessments of changes in fuel pricing
- Economic or electricity demand growth analysis
- Assessment of power plant retirement decisions
- Combined heat and power (CHP) analysis
- Pricing impact of demand responsiveness
- Determination of probability and cost of lost or unserved load

Outputs of IPM® include estimates of regional energy and capacity prices, optimal build patterns based on timing of need and available technology, unit dispatch, air emission changes, retrofit decisions, incremental electric power system costs (capital, FOM VOM), allowance prices for controlled pollutants, changes in fuel use, and fuel price impacts. Results can be directly reported at the national and power market region levels. ICF can readily develop individual state or regional impacts aggregating unit plant information to those levels. IPM® analyzes wholesale power markets and assesses competitive market prices of electrical energy, based on an analysis of supply and demand fundamentals. IPM® projects zonal wholesale market power prices, power plant dispatch, fuel consumption and prices, interregional transmission flows, environmental emissions and associated costs, capacity expansion and retirements, and retrofits based on an analysis of the engineering economic fundamentals. The model does not extrapolate from historical conditions but rather for a given set of future conditions which determine how the industry will function (i.e., new demand, new power plant costs, new fuel market conditions, new environmental regulations, etc.), provides a least cost optimization projection. The optimization routine has dynamic effects (i.e., it looks ahead at future years and simultaneously evaluates decisions over a specified time horizon). All major factors affecting wholesale electricity prices are explicitly modeled, including detailed modeling of existing and planned units, with careful consideration of fuel prices, environmental allowance and compliance costs, transmission constraints and operating constraints. Based on looking at the supply/demand balance in the context of the various factors discussed above, IPM® projects hourly spot prices of electric energy within a larger wholesale power market. IPM® also projects an annual "pure" capacity price.

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100 YEARS

Implications of **Policy-Driven Residential Electrification**

An American Gas Association Study
prepared by ICF