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California Energy Commission

FINAL COMMISSION REPORT

California Building Decarbonization Assessment

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California Energy Commission

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ABSTRACT

The *California Building Decarbonization Assessment* is the initial report addressing the mandates from Assembly Bill 3232 (Friedman, Chapter 373, Statutes of 2018). The report analyzes scenarios to reduce greenhouse gas emissions by at least 40 percent by 2030 and identifies several strategies that will lead to significant emission reductions. The analysis includes emissions attributed to electricity and gas use in buildings, and from refrigerants. The strategies include electrification, electricity generation decarbonization, energy efficiency, refrigerant leakage reduction, distributed energy resources, decarbonizing the gas system, and demand flexibility. The assessment shows that California can achieve significantly more than a 40 percent reduction by 2030 through these strategies. Efficient electrification of space and water heating in California's buildings combined with refrigerant leakage reduction presents the most readily achievable pathway to a greater than 40 percent reduction in greenhouse gas emissions by 2030. Challenges exist to accomplishing these emission reductions, from consumer awareness to financing availability, but can be overcome and implemented equitably with collaboration and planning among state and local officials, utilities, environmental justice organizations, equipment manufacturers and distributors, financiers, and community leaders.

Keywords: Decarbonization, buildings, equity, electrification, efficiency

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GLOSSARY AND ACRONYMS

Term	Acronym (if applicable) and Definition
Additional achievable energy efficiency	AAEE. Incremental savings from the future market potential identified in utility potential studies not included in the baseline demand forecast, but reasonably expected to occur, including updates to building codes, appliance regulations, and new or expanded utility efficiency programs.
Assembly Bill 32 (Núñez, Chapter 488, Statutes of 2006)	AB 32. Global Warming Solutions Act of 2006. The bill required California to reduce its greenhouse gas emissions to 1990 levels by 2020.
Assembly Bill 3232 (Friedman, Chapter 373, Statutes of 2018)	AB 3232. This bill requires the CEC to assess the potential to reduce greenhouse gas emissions from residential and commercial buildings by 40 percent of 1990 levels by 2030.
American Council for an Energy-Efficient Economy	ACEEE. A nonprofit energy efficiency organization that researches energy efficiency issues, reports on local, state, and federal government energy efficiency activity, and hosts workshops on several energy efficiency topics each year.
Building Energy Efficiency Standards	Energy Code (present and past standards) or Energy Standards (future cycles). California's building energy standards (Title 24, Part 6).
Behind the meter	BTM. Encompasses energy resources that are located on the customer side of a utility electricity or gas meter. This includes equipment such as rooftop solar systems and on-site batteries.
2020–2030 Baseline Case	An analytical reference scenario covering 2020 to 2030 based on existing norms, policies, and activities continuing throughout this period and used as point of comparison for impacts from new decarbonization activities.
California Air Resources Board	CARB. State board tasked with protecting the public from air pollution and developing programs and policies to fight climate change.
California Department of Community Services & Development	CSD. State department that is tasked with reducing poverty for Californians by leading the development and coordination of effective and innovative programs for low-income individuals, families, and their communities. CSD implements the Low-Income Weatherization Program.

California Energy Commission	CEC. California's primary energy policy and planning agency.
California Independent System Operator	California ISO. Independent organization that maintains electricity reliability on the majority of California's electrical grid and operates a wholesale energy market.
California Public Utilities Commission	CPUC. State agency responsible for regulating services and utilities, protecting consumers, safeguarding the environment, and assuring access to safe and reliable utility infrastructure and services.
California Solar Initiative	CSI. State program that promoted the production and sales of solar photovoltaic systems.
Carbon neutrality	Refers to achieving net-zero emissions of carbon dioxide.
Combined heat and power	CHP. System that uses waste heat energy to generate electricity.
Commercial buildings	Building sector that includes a wide variety of nonresidential building types such as high-rise multifamily, offices, retail, restaurants, campuses, and hospitals.
Community choice aggregators	Electricity provider run by a single or partnership of local governments.
Decarbonization	Activities that reduce greenhouse gas emissions such as reducing or removing fossil gas use in buildings or replacing fossil fuel generated electricity with renewable sources like solar or wind.
Demand response	Changes in electric usage by demand-side resources from normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized.
Distributed energy resource	DER. Electricity-producing or controllable loads that are directly connected to a local distribution system. It includes, but is not limited to, demand response, rooftop solar, energy efficiency, and battery storage.
Early retirement	RET. Retirement of equipment before the end of useful life.
Electrification	Converting end uses from a combustible fuel source (typically a fossil gas) to electricity.
Electric vehicle	EV. Vehicle powered by electricity.

Fossil gas	Primarily methane derived from nonrenewable sources. This is commonly referred to as "natural gas".
Fuel substitution	Replacement of one utility fuel type with another fuel type.
Fuel Substitution Scenario Analysis Tool	FSSAT. CEC analytical tool used to assess fuel substitution of electric and gas measures.
Global warming potential	GWP. The relative global warming intensity of an emission relative to the same weight of carbon dioxide. The global warming potential of carbon dioxide is 1.
Greenhouse gas	GHG. Gases in Earth's atmosphere that trap heat.
Green lease	Commercial building lease that helps to align tenant and landlord interests for investments in energy efficiency.
Heating, ventilation, and air conditioning	HVAC. Mechanical systems that provide thermal comfort and air quality to indoor spaces.
Hydrofluorocarbon	HFC. Man-made organic compounds that contain fluorine and hydrogen atoms and are a potent greenhouse gas.
Integrated Energy Policy Report	IEPR. CEC biennial report on major energy trends and issues facing California's electricity, gas, and transportation fuel sectors. It contains policy recommendations to address issues.
Investor-owned utility	IOU. Privately owned electricity and gas providers.
Joint Appendix	JA. Reference appendices that provide qualification requirements for the Energy Code.
Low-Income Weatherization Program	LIWP. State program run by CSD that helps low-income families reduce their energy bills by making their homes more energy-efficient. The program reduces greenhouse gas emissions and household energy costs by saving energy and generating clean renewable power.
Load flexibility	A strategy of enabling automation of building and appliance loads to continuously adapt the timing of electricity use in response to frequent and ongoing signals. Like energy efficiency, load flexibility is intended to be invisible: acting to reduce GHG emissions without reducing the quality of customer service.
Load management	Adjustments in utility rate structure, programs for energy storage, or programs for demand response automation to encourage use of electrical energy at off-peak hours or to

	encourage control of daily electrical load. (CA Pub. Res. Code §25403.5)
Load shift	The process of moving electricity loads from one time of the day to another.
Load shed	Partial reduction or complete curtailment of an electrical load in response to an economic or reliability signal.
Marginal abatement cost curve	MAC Curve. An estimate of the volume and costs of an action to reduce GHG emissions rate.
Million metric tons of carbon dioxide equivalent	$MMTCO_2e$. Unit of measurement for the amount of greenhouse gas emissions produced by an activity.
New construction	NC.
On-bill financing	OBF. Alternative energy financing tool that allows a utility to recover the cost of an upgrade on the utility bill.
Onsite emissions	GHG emissions emitted from a building site, including combustion products, methane leakage behind the meter, and refrigerant leakage. These emissions can also be described as direct emissions.
Property assessed clean energy	PACE. Private financing program for home and business owners, which is repaid through a special assessment on their property tax over years.
Photovoltaic	PV. Solar panels use photovoltaic technology to generate electricity.
Renewable gas	A combustible fuel, such as methane or hydrogen, from a renewable resource.
Residential	In this assessment, building sector that includes single-family homes, multifamily units, townhouses, and condominiums.
Renewables Portfolio Standard	RPS. Regulation that requires increases procurement of electricity from renewable sources.
Replace on burnout	ROB. Installing a new end-use when the prior one fails.
Retrocommissioning	Tuning the energy consuming systems in an existing building to operate more efficiently.
Senate Bill 100 (De León, Chapter 312, Statutes of 2018)	SB 100. This bill requires that by 2045 renewable and zero-carbon energy sources must supply 100 percent of electric retail sales to end-use customers.

Senate Bill 1383 (Lara, Chapter 395, Statutes of 2016)	SB 1383. This bill set targets to reduce emission from short-lived climate pollutants like methane by 2030.
Senate Bill 350 (De León, Chapter 547, Statutes of 2015)	SB 350. This bill set 2030 targets for energy efficiency and renewable electricity generation to reduce greenhouse gas emissions and fossil energy use.
Scenario	In this assessment, a scenario refers to a distinct set of input assumptions that when run through a model, result in a unique solution.
Self-Generation Incentive Program	SGIP. CPUC program that provides incentives from the installation of self-generation and storage technologies.
Split incentive	Split incentive is a term used to indicate a barrier between owners and tenants of buildings when deciding if an energy upgrade should be done.
Synthetic gas	SNG. Gaseous fuel alternative to fossil gas when produced using renewable resources.
Systemwide emissions	GHG emissions emitted from sources beyond the building location such as from electricity generation, yet attributable to energy consumption at the building. This can also be described as "indirect emissions" or "offsite emissions."
Time-of-use	TOU. Electricity rate that varies by the time of day and season.
Zero-emission vehicle	ZEV. Vehicle that generates no greenhouse gas emissions during operation.

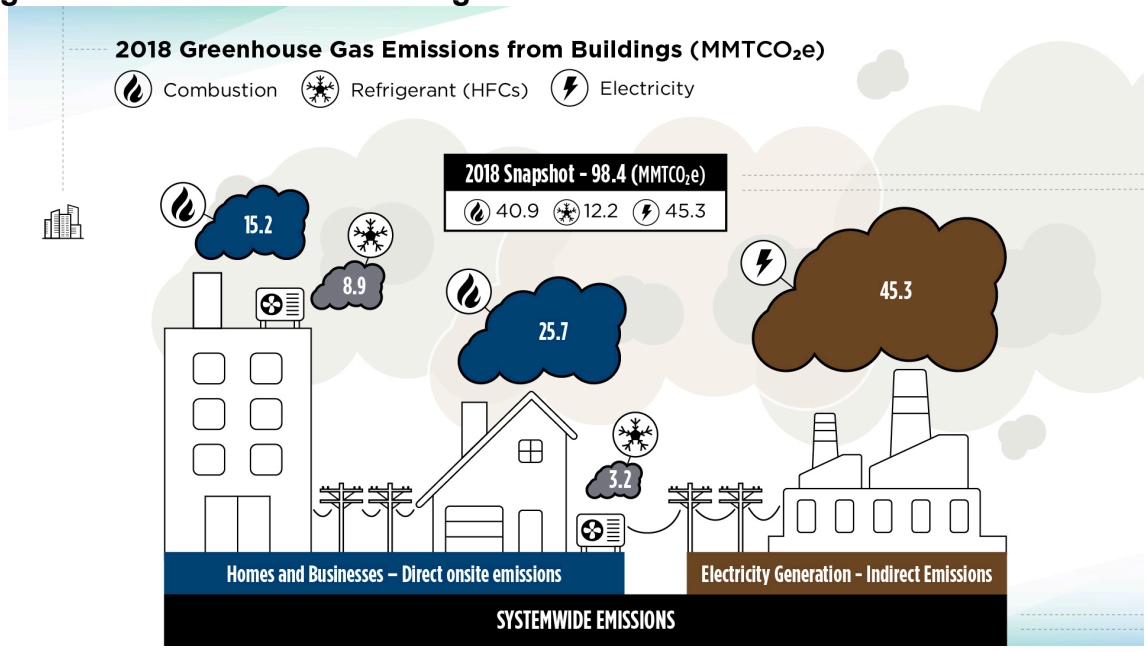
EXECUTIVE SUMMARY

Introduction

Residential and commercial buildings jointly account for 25 percent of greenhouse gas (GHG) emissions in the state when accounting for both fossil fuels consumed onsite and those used to generate electricity for buildings. Reducing these emissions in a timely and cost-effective manner, by using energy more efficiently and employing fuels with a lower GHG content, is essential to meeting California's ambitious GHG reduction and climate goals. Recognizing this, the California Legislature passed Assembly Bill 3232 (Friedman, Chapter 373, Statutes of 2018) (AB 3232), directing the California Energy Commission (CEC) to "assess the potential … to reduce the emissions of greenhouse gases in … residential and commercial building stock by at least 40 percent below 1990 levels by January 1, 2030." As directed by AB 3232, this assessment evaluates the possibilities, costs, impacts, and barriers of reducing GHG emissions in residential and commercial buildings by 2030.

This report presents an initial assessment of how buildings can reduce onsite and systemwide GHG emissions. For this assessment, onsite emissions include the combustion of fuels, gas leakage on the customer side of the meter, and hydrofluorocarbon (HFC) refrigerants. The system emissions are those from the electricity system supplying residential and commercial buildings. A breakdown of these emissions sources and their values is shown in **Figure ES-1**.

Figure ES-1: Sources of Building GHG Emissions and Potential 2030 Emissions



Note: Behind-the-meter gas leakage in the residential (0.7 $MMTCO_2e$) and commercial (1.0 $MMTCO_2e$) sectors are represented in the "Combustion" emissions bubble of each sector.

Source: CEC staff

Buildings-related emissions are best understood within the broader context of California's efforts to reduce GHG emissions across the state's diverse and dynamic economy. While the

electric sector is perhaps the most successful to date in the pace of decarbonization, major reductions will also come from the transportation sector; from manufacturing, industry, and agriculture; and from natural lands. No one sector is independent of the others. Progress must be monitored and efforts coordinated across all the relevant agencies via the California Air Resources Board (CARB) scoping plan, CEC's *Integrated Energy Policy Report (IEPR)*, and other formal platforms.

Building Greenhouse Gas Emissions

Buildings in California are served primarily by electricity and fossil gas, each responsible for about one-half of energy use. Most GHG emissions from buildings come from onsite use of electricity, gas space-conditioning and water-heating equipment, and gas plug-in appliances. A much smaller amount comes from the use of propane, kerosene, diesel, and wood, mostly in rural areas with limited or no electric or gas distribution systems, with the remainder coming from hydrofluorocarbons (HFCs) leaked from primarily refrigeration and space-conditioning equipment.

The electricity sector is a major component of building emissions but is rapidly decarbonizing as increasing amounts of renewable resources are brought on-line. In fact, the *2021 SB 100 Joint Agency Report* provides direction toward achieving 100 percent renewable and carbon-free resources by 2045. In some evaluations of building emissions, emissions from electricity generation are treated separately from buildings-related emissions. However, a significant portion of California's electricity demand is directly driven by building usage and occupant behavior. The GHG emissions intensity of the electricity system changes throughout the day and across seasons with the mix of different energy resources called on at any given time. Therefore, it is important to consider electricity emissions within the context of buildings, as there are specific strategies, such as electric appliance efficiency and load flexibility, that can significantly reduce system emissions.

Onsite combustion, particularly fossil gas combustion, forms the next largest component of emissions. Replacing gas equipment in residential and commercial buildings with electric equipment is one strategy to reduce onsite emissions. From a system view, the pathway to a clean gas system is less understood than that for a clean energy electricity system and has large cost barriers. Assessing the ability of the gas system to decarbonize will require further research and development, as well as coordination among stakeholders.

Lastly, HFC refrigerants form a significant source of building GHG emissions. HFC refrigerants emerged in the 1990s as a replacement for refrigerants containing ozone-depleting gases, which were eliminated because of the 1987 Montreal Protocol, a United Nations-led effort to get nations to ban ozone-depleting gases. However, HFCs are GHGs with a global warming potential (GWP) that can be hundreds to thousands of times more potent than carbon dioxide in contributing to climate change. The use of refrigerants containing HFCs is commonplace in refrigeration and air-conditioning equipment in buildings. Some equipment, particularly larger refrigeration systems, develop leaks that release HFCs into the atmosphere during operation. Other leakage occurs at the end of life for common appliances that are scrapped without capturing the refrigerant gases. While the quantity of HFCs leaked for equipment units may be

relatively small, the high global warming potential of HFCs makes them important sources of GHG that must be addressed.

Building Characteristics

As an emissions category, buildings are unique. Buildings can be segmented by residential, commercial, and other categories such as vintages and climate zones. Even within these broad categories, important subcategories exist, such as single-family homes versus multifamily and low-rise versus high-rise. They also vary with the type of commercial process occurring and the specific activities performed in buildings, whether schools, retail outlets, or warehouses.

The approach to building decarbonization will be different for existing versus new buildings. The cost of decarbonizing newly constructed buildings is low when compared to existing buildings because there are no old appliances and infrastructure to remove, and designs are integrated into a larger construction project.

The bulk of building GHG emissions in 2030 are from today's existing buildings. California has almost 14 million existing single-family homes and multifamily units. Combustion of gas and related methane leaks contribute more than one-half of all emissions from single-family homes, with space and water heating accounting for more than 90 percent of the gas usage. In single-family homes, space heating accounts for most emissions, while in multifamily housing, it is water heating although there some regional variation due to climate.

Commercial buildings occupy more than 7.5 billion square feet and include restaurants, offices, warehouses, schools, and any nonresidential space excluding industry and agriculture **(Figure ES- 2**). Electricity is used predominantly for lighting, space conditioning (cooling and ventilation), and refrigeration. Most fossil gas is used for space heating, water heating, and cooking.

Figure ES- 2: California Residential and Commercial Buildings

Source: CEC 2019 Energy Demand Forecast

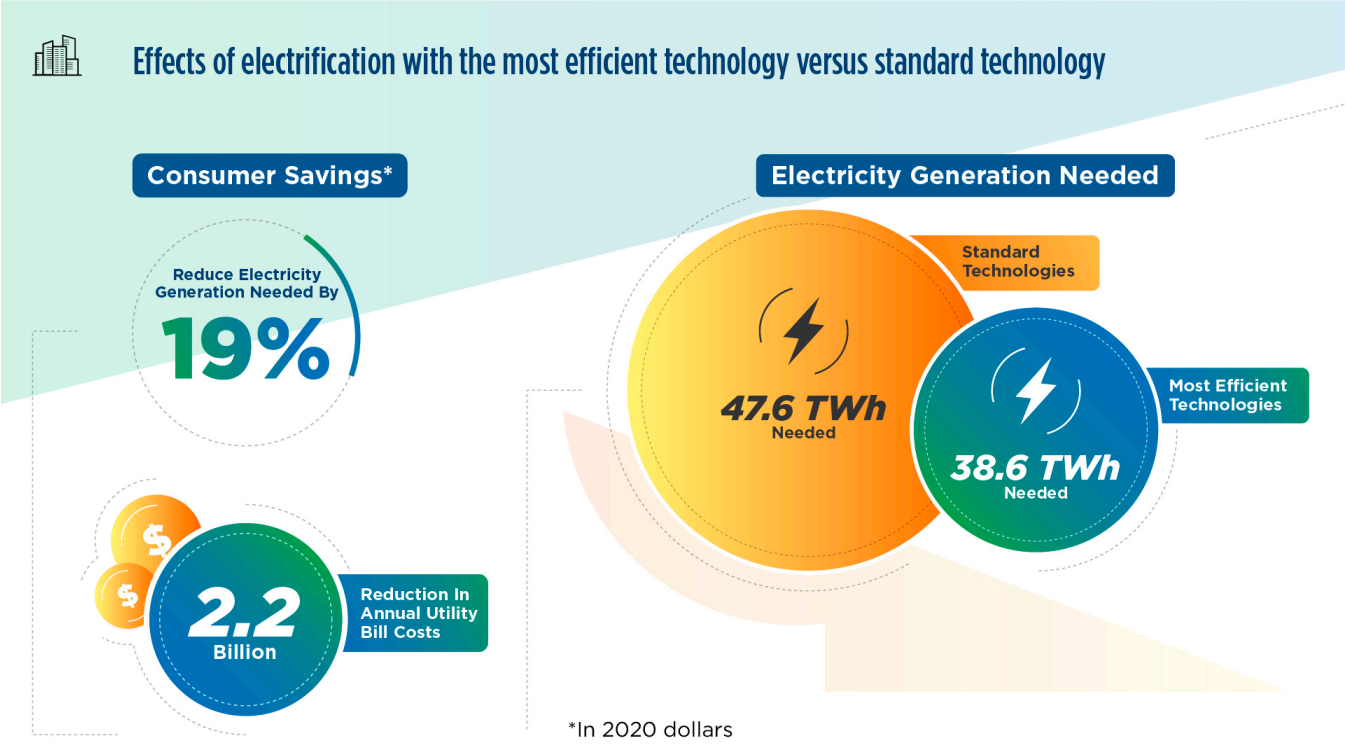
Building GHG Emission Reduction Strategies

This report defines and analyzes seven GHG emission strategies within seven high-level categories. These broad decarbonization strategies, described in Chapters 1 and 5, can be components of a decarbonization pathway and be used alone or in combination to achieve the state's goals. CEC plans to assess further the effect of combining strategies in subsequent iterations of this analysis.

The seven strategies, listed broadly in order of feasibility and potential, are:

1. **Building end-use electrification.** Substituting energy-efficient electric appliances for gas appliances and equipment in buildings can offer efficiency savings and GHG reductions, as well as air quality co-benefits. These benefits are particularly pronounced when efficient electric heat pump technologies are used. **Figure ES-3** summarizes the consumer savings and reduced electricity generation needed when electrifying with highly efficient rather than minimum efficiency equipment. For this reason, the assessment limited the analyses to "efficient electrification," as discussed more fully later in this report.

Figure ES-3: Selection of Efficient Equipment Is Key Within Electrification Strategies



Note: "Standard Technologies" and "Most Efficient Technologies" represent a comparison of the "aggressive electrification" and "efficient aggressive electrification" scenarios examined by CEC staff.

Source: CEC staff

While heat-pump appliances as a class are inherently more efficient than combustion and electric-resistance appliances, they also have varying levels of efficiency. There is a significant performance gap between standard-performance heat pumps and best-in-class units. Emission-reduction potential, electricity demand, and operational costs will depend on the heat pump market, including which refrigerant is used, and technology development.

2. **Decarbonizing the Electricity Generation System.** California residential and commercial buildings demand the most energy from the electricity generation system compared to other building sectors. The mix of generation resources needed to meet this demand has different GHG content, or GHG emission intensity, across years, and the hours within a year, as the mix of available resources evolves. CEC staff analysis, relying on CARB's official GHG emission inventory, indicates that the electric grid has already seen significant improvements in GHG emission intensity in recent years. This trend is expected to continue as California's Renewables Portfolio Standard (RPS) requirements increase from 33 percent in 2020 to 60 percent in 2030, and target 100 percent renewable and zero-carbon resources by 2045 as required by SB 100.
3. **Energy Efficiency**
    a. **Electricity Efficiency.** California has pursued electricity energy efficiency through voluntary utility programs, appliance standards, building standards, research, and a range of deployment programs for more than 40 years. Most programs and all

standards apply cost-effectiveness criteria to assure that participating customers receive a benefit from reduced energy costs that exceed their investment costs.

b. **Gas Efficiency.** Similar to electricity efficiency, California has pursued gas energy efficiency for more than 40 years through various programs and standards.

c. **Building Energy Efficiency Standards.** California has pursued building energy efficiency standards for newly constructed buildings and alterations and additions to existing buildings for more than 40 years through the CEC's Building Energy Efficiency Standards (Energy Code). The Energy Code pursues incremental efficiency gains through a triennial update. In alignment with GHG reduction as a primary policy driver, the 2022 Energy Code development aims to further address building decarbonization through a focus on efficient heat-pump technologies and a range of other elements.

4. **Refrigerant Leakage Reduction.** Senate Bill 1383 established economywide goals to reduce HFC emissions by 40 percent from 2013 levels by 2030, which if successful, would eliminate 7.5 million metric tons of carbon dioxide equivalent ($MMTCO_2e$) from residential and commercial buildings in 2030. CARB has adopted regulations to require HFCs producing equipment to have a GWP no higher than 750, but how much HFC emission reduction will occur as a result is subject to many factors. Although reduction in HFC emissions will be an important building decarbonization strategy, potential GHG reductions and the costs of specific leakage mitigation, recapture programs, or regulations are beyond the scope of this assessment.

5. **Distributed Energy Resources.** California has seen a growing number of rooftop solar PV systems and, more recently, onsite battery storage installations. Over the past decade more than 1 million rooftop solar PV systems have been installed on commercial, industrial, and residential buildings. Much of the initial impetus for this technology stems from favorable electricity rates that enable excess power generated to be "sold" to the utility at retail rates, along with direct incentive programs under the California Solar Initiative and New Solar Homes Partnership. The 2019 Energy Code furthered the role of distributed solar by requiring the installation of rooftop PV panels or enrollment in community solar programs for new low-rise homes.

   This assessment includes a specific scenario that analyzes the additional electricity savings from increased rooftop PV penetration in homes and businesses. The amount of GHG emission reductions in 2030 produced by these savings do not by themselves achieve the 40 percent below 1990 target. Future work will incorporate other distributed energy resources such as lithium-ion and thermal batteries.

6. **Decarbonizing the Gas System.** Until recently, all gas extracted from the ground, sent across the country, and distributed to customers in California through the gas system was fossil gas. Gas utilities have proposed replacing a portion of fossil gas with renewable gas such as biomethane. The California Public Utilities Commission (CPUC) has recently approved investor-owned gas utilities' biomethane feed-in tariffs that enable facilities to sell captured methane from dairy cow manure, landfills, municipal solid waste, food waste, and wastewater treatment plants to gas utilities. Other decarbonization strategies include

injecting renewable hydrogen into the gas system or creating synthetic gas using chemical production plants.

Based on current information, the maximum penetration of biomethane is likely to be constrained to about 15 percent of total pipeline gas composition by converting all available biomass resources to biomethane. Higher quantities of renewable gas would require use of synthetic gas. Both these sources for renewable gas are significantly more expensive than fossil gas. This topic will be further analyzed and discussed in the 2021 IEPR development process and CPUC proceedings.

7. **Demand Flexibility.** Demand flexibility is the ability of customers to reduce or increase load in response to grid conditions, usually through a proxy price signal or system operator or utility signal and facilitated by automation. Demand response is an umbrella term that covers policies and programs that induce electricity demand to shift or be shed in response to economic, or electricity grid reliability signals. The primary benefits of demand flexibility derive from giving utility customers more control over their electricity usage; the ability to use technology to respond to rate, GHG intensity, or other signals; the ability to use excess renewable generation; the potential to increase the reliability of variable renewable generation without additional GHG emissions; and the potential to enhance electric system reliability while providing cost savings to customers. To evaluate demand flexibility for this initial assessment, the CEC analyzed hourly electric load for heat pump water heaters. The analysis looked at shifting building loads into hours when renewables are expected to be available and therefore avoid curtailment and new energy storage.

Two Methods of Evaluating Building GHG Emissions

AB 3232 states that 25 percent of the state's overall GHG emissions come from the building sector and that direct emissions from buildings account for 10 percent of total emissions. Accordingly, this assessment presents two baselines of 1990 emissions, summarized in **Table ES-1**. Ongoing policies and efforts to reduce GHG emissions across the energy system are likely to reduce systemwide building emissions by almost 40 percent by 2030 without additional effort to improve building performance in that time frame. However, reducing direct emissions in buildings — especially existing buildings — by 40 percent is more challenging. Given California's overall goal of full carbon neutrality by 2045, it is necessary to seek viable pathways for reductions in direct and systemwide emissions.

Table ES-1: Summary of the Two Baselines Considered in the Assessment ($MMTCO_2e$)

Baselines	1990 Emissions	2020-30 Baseline Case (SB 100 trajectory the status quo)	2030 GHG Emissions Target (40% below 1990)	Annual GHG Emissions Reduction Needed in 2030
Baseline 1: Systemwide Emissions	124.1	79.9	74.4	5.5
Baseline 2: Direct Emissions	54.4	54.7	32.6	22.1

Note: See Chapter 2 and Appendix B for how CEC staff estimated 1990 GHG emissions.

Source: CEC staff

Baseline 1: Systemwide Emissions

The systemwide emissions baseline includes on-site combustion from gas; combustion from other fuels (such as propane); behind-the-meter (BTM) gas leakage; HFC leakage from air conditioning, heat pumps, and refrigeration; and electricity generation emissions attributable to residential and commercial buildings. This assessment finds overall building sector emissions were 124.1 million metric tons carbon dioxide equivalent ($MMTCO_2e$) per year in 1990, and that on the current trajectory those emissions will decrease to 80 $MMTCO_2e$ in 2030, a reduction of 36 percent. In other words, California residential and commercial buildings will come close to achieving 40 percent GHG emission reduction by 2030 by simply assuming SB 100-compliant progress to net-zero-carbon electricity sales and current projections for the use of rooftop solar photovoltaic (PV) and energy efficiency. Moreover, GHG emissions from buildings will decline by more than 40 percent if the SB 1383 HFC reduction goals are also achieved. While the feasibility of achieving a 40 percent reduction is surprising and perhaps reassuring, the ongoing efforts outlined above come with many assumptions.

Baseline 2: Direct Emissions

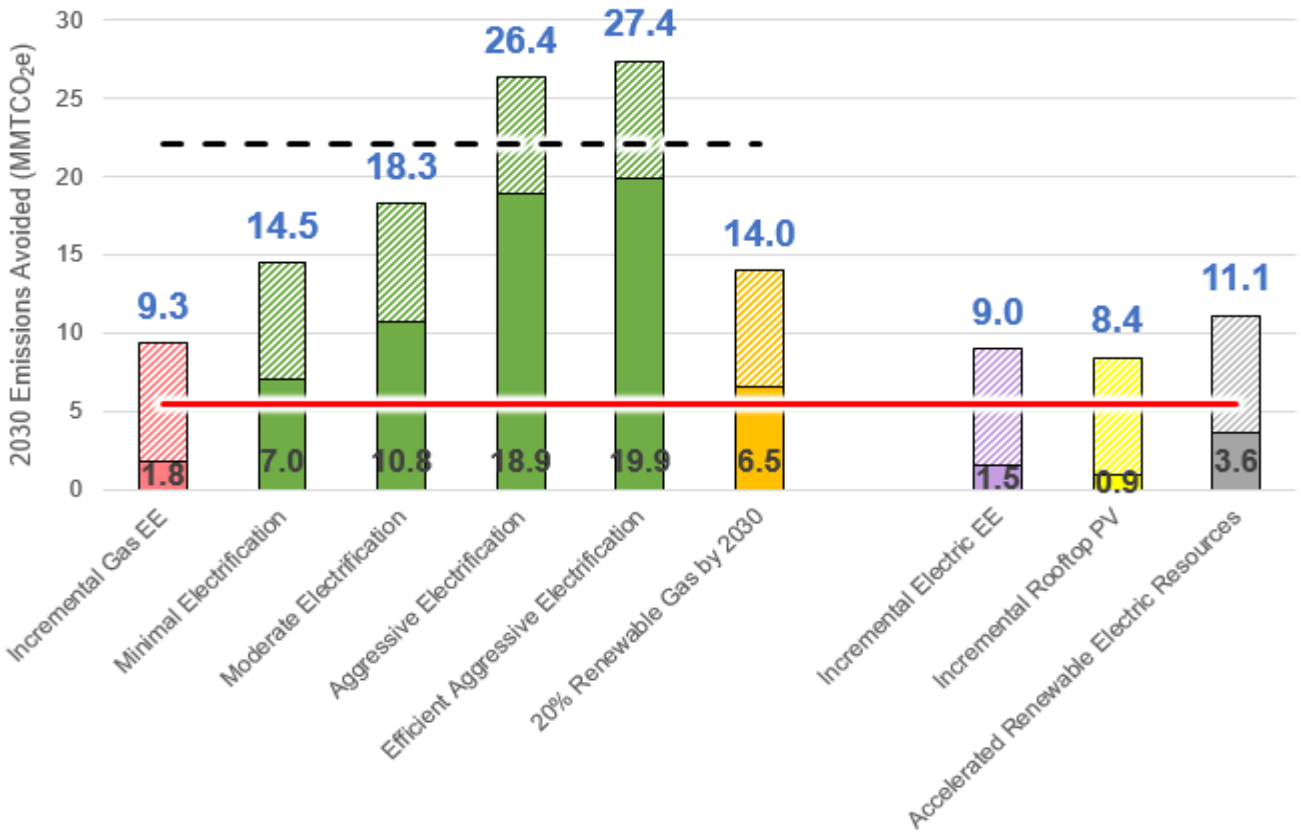
A direct emissions baseline excludes the 1990 electricity generation emissions attributable to residential and commercial buildings. This baseline includes emissions from onsite end uses in a building plus new incremental electricity system emissions due to electrification of appliances and yields a different result. Fifty-four $MMTCO_2e$ of the 124 $MMTCO_2e$ systemwide 1990 emissions were direct emissions — primarily from fossil gas combustion. Under this framing, reductions from that 54 $MMTCO_2e$ baseline depends on limiting onsite use of fossil gas by substituting either electricity or nonfossil gas in its place; electricity generation emissions reductions due to growing zero-carbon electricity sources no longer applies except when

accounting for the GHG intensity of new electricity demand due to electrification. Thus, this direct emissions baseline forces more aggressive reductions in buildings to achieve a 40 percent reduction by 2030.

To settle on a set of potential trajectories for a 40 percent reduction relative to 1990, it is useful to compare these two baseline approaches. As noted in the Baseline 1 discussion, the broad decarbonization of the electric grid will reduce the 124 $MMTCO_2e$ overall buildings-related emissions by 36 percent without additional efforts. However, as shown in the Baseline 2 discussion, the 54 $MMTCO_2e$ of direct emissions would remain relatively static, with expected energy efficiency improvements roughly offsetting new energy demands from a steady expansion of the building stock to 2030.

Figure ES-4 shows the results for several reduction scenarios against the two baselines. The analysis here shows that traditional fuel-specific efficiency and behind-the-meter renewable energy efforts alone do not achieve the major reductions needed in absolute emissions; in contrast, electrification approaches can achieve much more significant reductions. Further, substitution of renewable gas for fossil gas holds potential for GHG emission reductions.

Figure ES-4: Annual GHG Reduction for 2030 Relative to the Direct and Systemwide 40 Percent Emission Targets



Note: Solid regions in the electrification scenarios include the added HFC emissions from heat pumps.

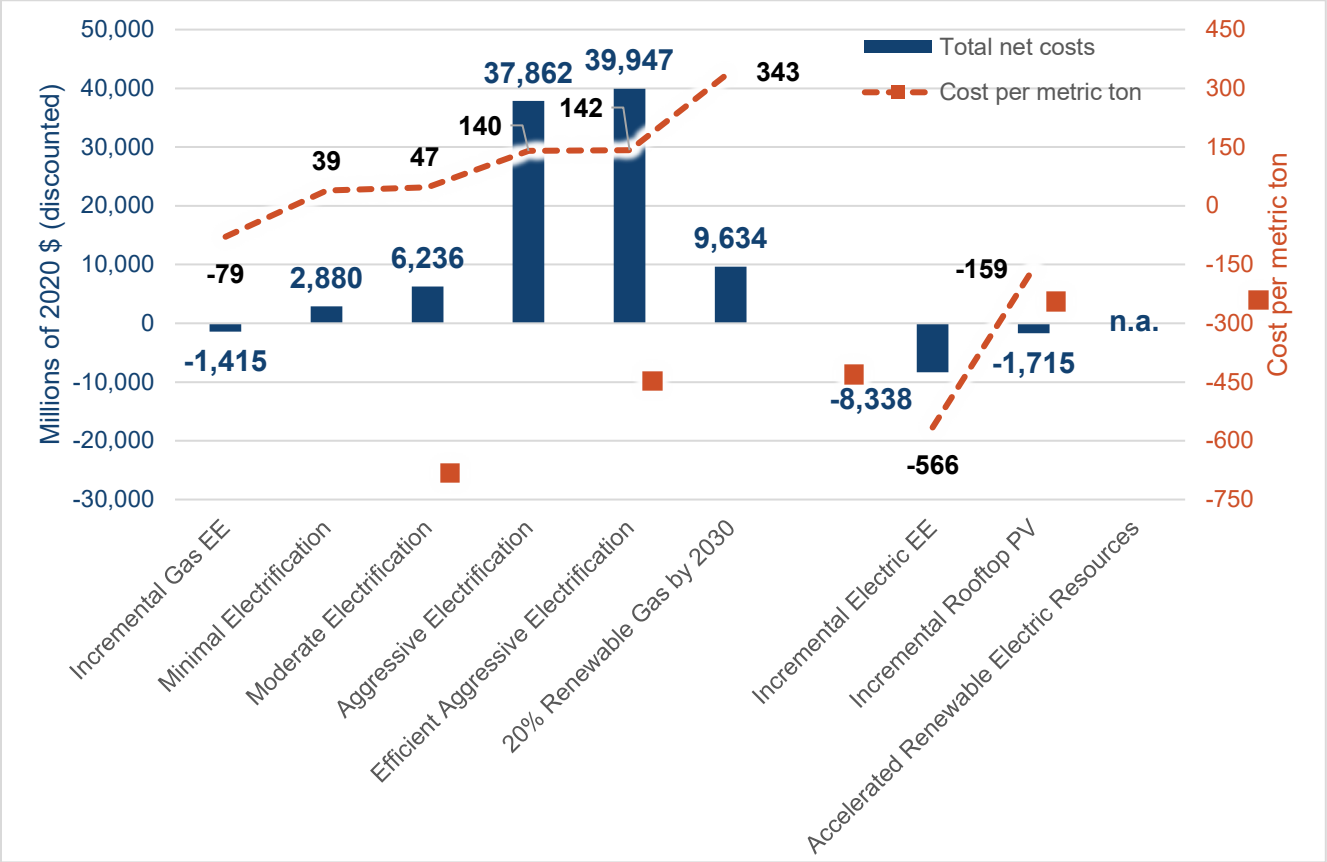
EE is energy efficiency

Source: CEC staff

Decarbonization Costs

The costs of the analyzed approaches vary greatly, as shown in **Figure ES- 5**. Improving electric and gas efficiencies are highly cost-effective — in fact, showing negative cost — while renewable gas implementation is the most expensive building decarbonization option. Electrification scenarios for new and existing buildings show modest positive cost per ton of CO_2 reduction. Whether evaluating based on a systemwide or direct emissions focus as a marker to 2045 climate goals, the analysis indicates a shift to electric end uses would need to be a major component of any plan.

Figure ES-5: Cost Summary of the Assessed GHG Emission Reduction Strategies



Note: Costs and emissions reductions are assessed over a 2020–2045 time horizon.

Source: CEC staff

These findings can be viewed as a foundation of progress to build upon toward the state's 2045 carbon-neutrality goal. One scenario of particular note, the "moderate electrification" scenario, would achieve a 50 and 33 percent reduction of emissions, from Baselines 1 and 2 respectively, from the building sector by 2030. The "moderate electrification" scenario accomplishes this reduction at a net cost of $47 per ton CO_2e. This scenario assumes the SB 1383 HFC reduction goals are met and additional savings would be realized through electrification of space and water heating and other end uses in newly constructed buildings. The scenario also assumes that by 2030, 50 percent of existing gas appliances would be replaced upon burnout, and 5 percent of current gas appliances would be replaced before burnout, with efficient heat pump technologies. This scenario is one-sixth the costs of the aggressive electrification scenarios, which have higher costs primarily because the respective higher penetration of gas appliances replaced before burnout significantly increases electrification costs.

Decarbonization Grid Impacts

AB 3232 requires consideration of the impact of emission reduction strategies on grid reliability. The combined impact of increased electric demand from recent and projected building electrification, a growing market for electric vehicles, and electric generation system

decarbonization requires the analysis to accommodate changes to the historical patterns of electric demand to ensure reliability. This initial analysis uses a simple planning reserve margin requirement to ensure that sufficient grid resources are added to balance increased electric loads; however, that method has shortcomings, especially in its consideration of demand-side approaches. Accordingly, this report also assesses how load flexibility from traditional building electricity uses, with emphasis on electrified space and water heating through the use of efficient heat-pump technologies, could contribute to increased energy system reliability at a lower cost than new carbon-free generation or storage.

As directed by AB 3232, the CEC will conduct additional analysis on strategies and update progress on reducing GHG emissions from residential and commercial buildings in the 2021 and future *IEPRs*.

Barriers to Decarbonization Strategies

Decarbonization of buildings will require major financial investments in upgrading existing buildings, for efficiency and in efficient electrification. Barriers to achieving these savings include:

- Project financing.
- Program design.
- Building age.
- Scheduling retrofits.
- New construction practices and costs.
- Retrofit costs.
- Available low-GWP refrigerants and heat pumps.
- Electric system and panel upgrades.
- Gas cooking preferences.
- Utility bill changes.
- Renewable gas supply and cost.
- Existing programmatic and regulatory restrictions.
- Affordable internet access.
- Workforce training regarding installation and maintenance practices.
- Landlord/tenant responsibilities in rental buildings.

Low-income and disadvantaged communities may face additional unique barriers because of systemic inequality, a history of lower access to capital and financing, greater energy burden, and lower rates of home or business ownership. Rural regions and Native American tribes also require careful consideration for decarbonization solutions.

Decarbonization of the electricity system and related barriers are being addressed primarily through joint agency efforts under SB 100. The initial joint agency report found that California may need record-setting build-out of renewable energy sources and grid infrastructure to

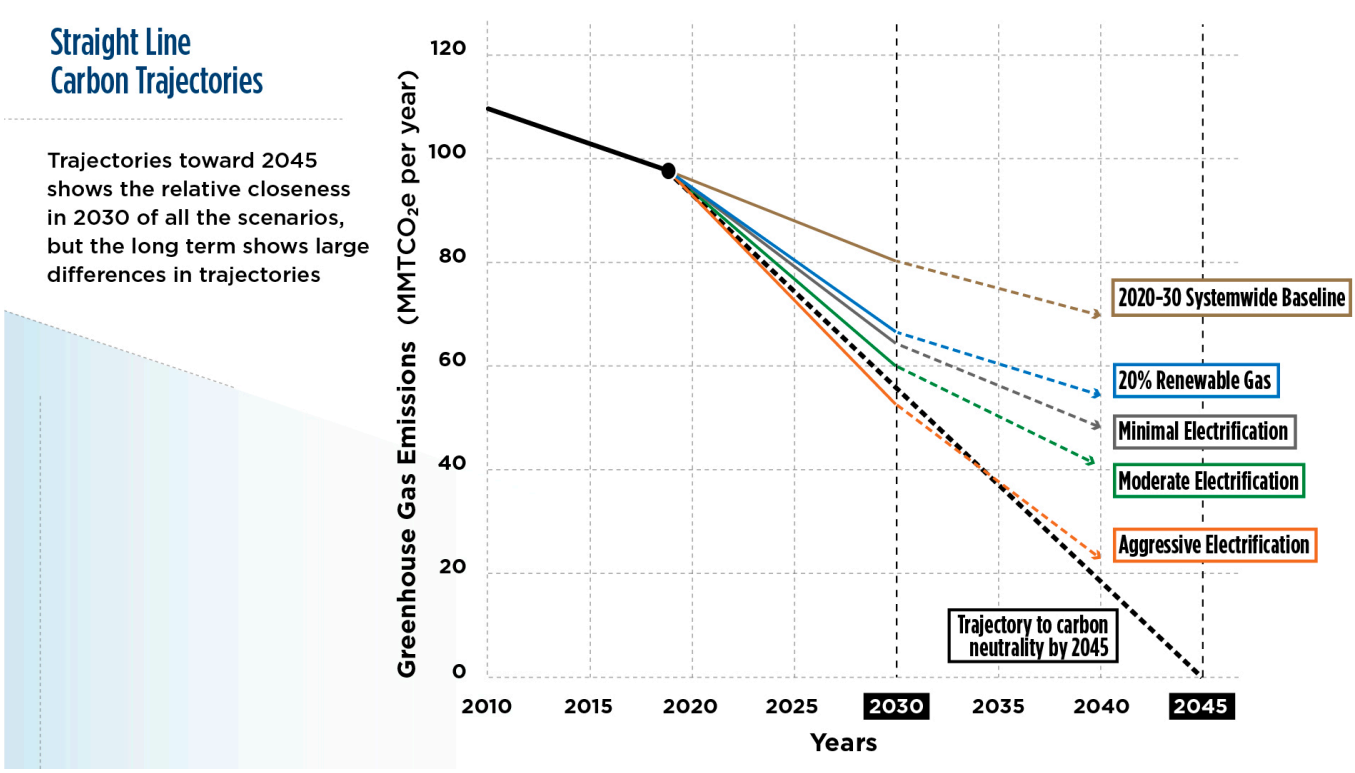
achieve the SB 100 target and the need for a reliability assessment. The decarbonization potential of the gas system hinges on cost reduction and availability of renewable gases.

Conclusion

This analysis shows that, as of 2018, systemwide GHG emissions in residential and commercial buildings are 26 percent below 1990 levels and with current policies and activities are on a trajectory to reach 36 percent below 1990 levels by 2030. Assuming SB 1383 HFC reduction targets are also met, buildings would achieve a 40 percent reduction by 2030. However, when examining a direct emission baseline, which excludes electric generation GHG emissions in the 1990 base year, buildings would require aggressive decarbonization efforts to achieve a 40 percent reduction by 2030.

AB 3232 required the CEC to assess the potential of *at least* a 40 percent reduction in GHG emissions by 2030. Given California's 2045 carbon-neutrality goal, it is useful to understand how each of the scenarios comports with that longer-term trajectory. **Figure ES-6** shows each of the main scenarios relative to a straight-line path to zero carbon by 2045, where the straight-line trajectory of each scenario is based on the annual incremental emissions reduction between 2029 and 2030. All scenarios achieve at least 40 percent reduction in systemwide GHG emissions from buildings by 2030 assuming SB 1383 is met, including the "moderate electrification" scenario, which achieves a greater than 40 percent reduction at roughly one-sixth the cost of the aggressive electrification scenarios (**Figure ES-5**).

Figure ES-6: Systemwide Straight-Line Building Emission Trajectories of Scenarios Compared to 2045 Carbon Neutrality

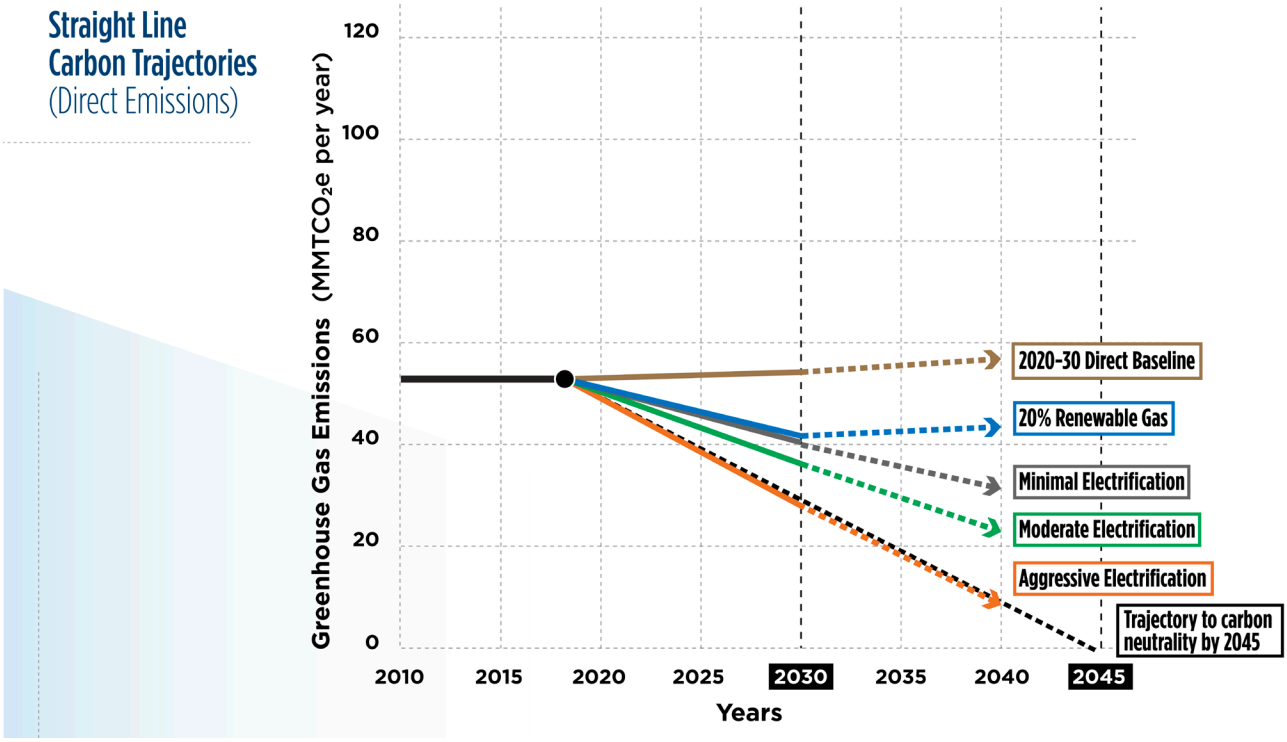


Note: All reported scenarios in the figure achieve the 40 percent systemwide emissions reduction target of 74.4 $MMTCO_2e$ by 2030 and assume that the SB 1383 HFC reduction targets are met.

Source: CEC staff

When examining these same emissions trajectories using the direct emissions baseline, as seen in **Figure ES-7**, the burden on the residential and commercial buildings sector to reduce GHG emissions is significantly greater: aggressive decarbonization action is required for the buildings sector to achieve 40 percent reduction of onsite GHG emissions.

Figure ES-7: Direct Straight-Line Building Emission Trajectories of Scenarios Compared to 2045 Carbon Neutrality



Note: All reported scenarios assume that the SB 1383 HFC reduction targets are met. Only the "aggressive electrification" in the figure achieves the 40 percent direct emissions reduction target of 32.6 $MMTCO_2e$ by 2030.

Source: CEC staff

Following the results of the AB 3232 assessment and comments from stakeholders, the CEC makes several conclusions to help guide the California's building decarbonization policy. Detailed descriptions can be found in Chapter 7 of this report.

Assessment Conclusions

1. AB 3232 suggests two baseline approaches from which California can track building decarbonization: systemwide and direct emissions. From a systemwide perspective, ongoing decarbonization of the electric system itself is steadily reducing overall building-related emissions. However, this framing understates the need and opportunity for reductions of onsite emissions.

2. Reducing direct emissions – which are largely due to onsite use of fossil gas – will require large-scale deployment of electric heat pumps.
3. Newly constructed buildings have the lowest decarbonization costs. The Energy Code will continue to advance efficiency in newly constructed buildings in each successive code cycle, including increasing emphasis on the use of heat pumps.
4. Reducing building-sector GHG emissions will require large investments in existing buildings.
5. Equity considerations are paramount and require collaboration among agencies, local governments, utilities, tribal governments, and local community organizations. Decarbonization initiatives should involve environmental justice communities throughout the effort and reflect their needs and priorities.
6. Traditional energy efficiency — gas and electric — can continue to provide emissions reductions cost-effectively.
7. Accelerating efficient electrification of building end uses in new and existing buildings represents the most predictable pathway to achieve deep reductions in building emissions. An information campaign could familiarize consumers with high-efficiency electric appliances.
8. Additional analysis of the reliability impacts of increased electrification is needed, including the role of load flexibility as a building decarbonization and reliability resource.
9. The CARB effort to reduce refrigerant emissions to comply with SB 1383 is an important component of building decarbonization.
10. The role of the gas system in achieving building decarbonization needs further assessment, including the roles of renewable gas, hydrogen, and engineered carbon removal. Gas system planning itself must optimize across transportation, industry, power sector, land use, and air quality elements.
11. The CPUC may wish to review the role incentives play in adding new gas infrastructure for buildings.
12. California must expand and train its clean energy construction workforce.
13. Building decarbonization efforts should work in harmony with the state's response to the housing crisis.

CHAPTER 1: Introduction

In August 2020, as firefighters battled wildfires burning more than a million acres across the state, Governor Gavin Newsom tweeted, "If you don't believe in climate change, come to California." Climate change is no longer a theory up for debate; it is an active threat impacting California's 40 million residents and its unique and varied environment. The severity of the impacts — more regular and severe wildfires, heat waves, ocean acidification, reduced or shifting habitats, worsening air quality — will continue to grow unless global greenhouse gas (GHG) emissions are dramatically reduced in short order.

In response to the threat of climate change, California has focused aggressively on reducing GHG emissions since the passage of the landmark Global Warming Solutions Act in 2006 (Assembly Bill 32, Núñez, Chapter 488, Statutes of 2006) (AB 32). The state has applied a comprehensive suite of measures to address climate change that include establishing ambitious GHG reduction targets, implementing programs and policies to reduce GHG emissions in all sectors of the economy, and developing a portfolio of mitigation strategies and activities. To date, reducing GHG emissions from the electricity generation system has been a primary focus of these efforts.

A primary mission of the California Energy Commission (CEC) since its inception has been to conserve resources and minimize the environmental impacts of energy use from buildings and California's energy infrastructure. The state's leadership in energy efficiency has already strongly improved its GHG intensity. California has focused on reducing GHG emissions since the passage of AB 32.[1] This work is implemented in a staged and coordinated approach, with the establishment of GHG reduction targets to keep future global temperature increases within an acceptable range and a portfolio of activities to address impacts. California has surpassed its first climate target of reducing emissions to 1990 levels by 2020.

The next GHG reduction targets call for an additional 40 percent decrease by 2030 and carbon neutrality by 2045. This report describes the buildings-related initiatives that will be required to meet these deeper goals. Development and implementation of specific plans will require policy makers, federal, state and local agencies, tribes, academia, private businesses, and other stakeholders (interested parties) to continue to study, collaborate, develop, and advance strategies to reduce emissions now and into the future.

Buildings are responsible for 10 percent of direct emissions (from on-site fuel combustion and leakage) and 25 percent of systemwide emissions (including direct and electricity generation emissions). Reducing these emissions is essential to meeting the state's GHG reduction goals.

1 See Appendix A for a list of related legislation to building decarbonization.

Assembly Bill 3232 (Friedman, Chapter 373, Statutes of 2018) (AB 3232) calls upon the CEC to assess the potential for residential and commercial buildings to achieve at least a 40 percent reduction in GHG emissions by 2030.[2] This report builds on energy efficiency, renewable energy, and other GHG-reducing efforts previously undertaken and underway in the state.[3] As GHG emissions associated with building energy use come from diverse sources — electricity, gas, and refrigerants — the analysis presented in this report includes all these sources.

California Electricity Generation System GHG Reductions

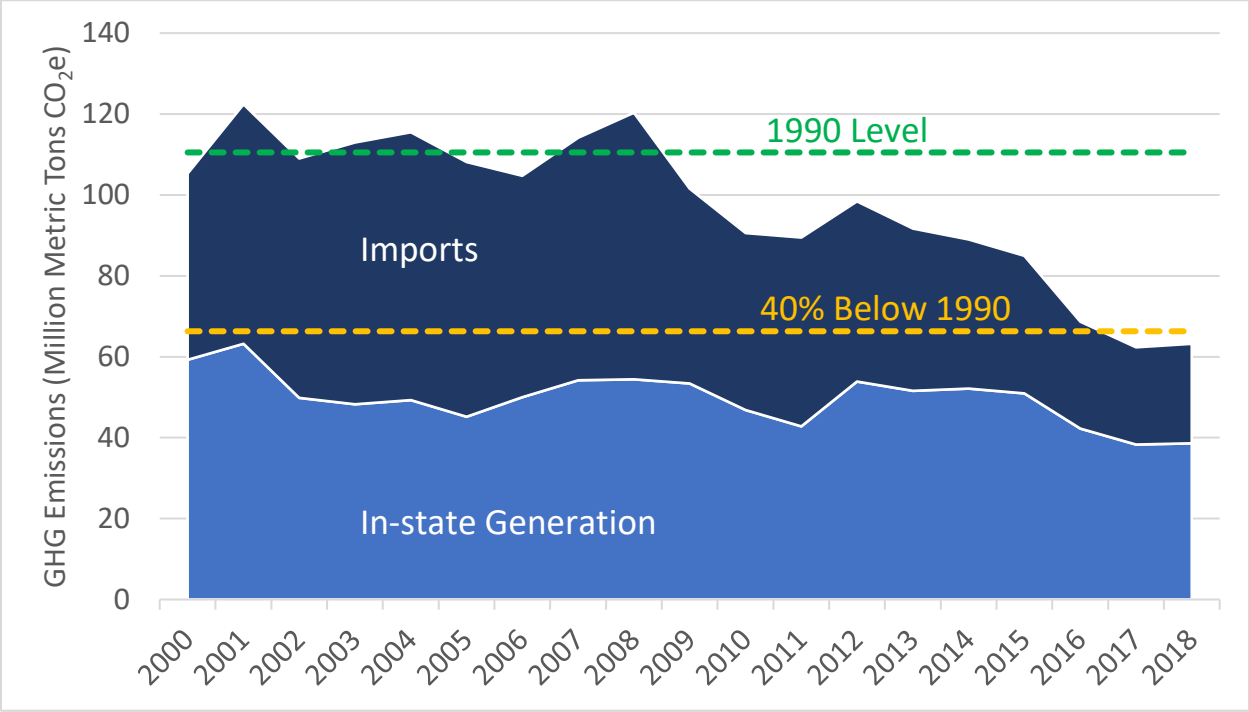
California's electricity generation system has experienced rapid progress toward achieving GHG reduction targets. California is beginning a transition away from fossil energy as a primary fuel source for electric generation. To meet air quality, climate, and other environmental goals, fossil gas generation is being replaced by renewable energy, energy efficiency, energy storage and demand response. This replacement will lead to retiring some fossil gas-fired power plants as they are called on less frequently. However, for the near future fossil gas-fired generation will continue to play a key role in integrating renewable resources and ensuring reliability.

As the mix of resources has changed, so have GHG emissions from the electricity generation system. The electricity generation system led the way in California achieving its first climate target of reducing GHG emissions to 1990 levels by 2020 across all sectors of the economy; electricity sector GHG emissions were 40 percent below 1990 levels in 2016, as shown in **Figure 1**.

Figure 1: California Electricity Generation System GHG Reduction Targets

2 CARB, GHG Emissions Inventory 2000-2018, https://ww2.arb.ca.gov/ghg-inventory-data.

3 These efforts include the Building Energy Efficiency Standards, Appliance Energy Efficiency Standards, Energy Efficiency Action Plans, New Solar Homes Partnership, siting of utility-scale renewable energy facilities, Renewables Portfolio Standard, funding EV charging stations, supporting alternative fuels in transportation, and ongoing energy research.



Source: CEC with CARB data

California's Renewables Portfolio Standard (RPS) is a major factor in driving these GHG emission reductions. California's RPS target called for 33 percent of retail sales to be served with renewable energy resources by 2020. In 2018, the state achieved an estimated 34 percent of retail sales met with renewable resources, two years ahead of schedule. Senate Bill 350 (De León, Chapter 547, Statutes of 2015) (SB 350) increased the target to a 50 percent RPS. In 2019, it is estimated that renewable resources increased to 36 percent of retail sales and carbon-free resources increased to 63 percent of retail sales.[4] Most recently, the state's path to deeper GHG reductions in the electricity sector was delineated in Senate Bill 100 (De León, Chapter 312, Statutes of 2018) (SB 100), which calls for 100 percent of retail electricity sales to be served by renewable or zero-carbon resources by 2045. SB 100 also establishes an ambitious 60 percent RPS by 2030.

Assessing Building Decarbonization Strategies

AB 3232 identifies that "buildings are responsible for 25 percent of all emissions of greenhouse gases"[5] and "direct emissions from the combustion of fossil fuels in buildings … accounts for 10 percent of all emissions of greenhouse gases in California."[6] The CEC began its assessment

4 California Energy Commission, Tracking Progress, https://www.energy.ca.gov/sites/default/files/2019-12/renewable_ada.pdf.

5 California Assembly Bill 3232, Friedman, Chapter 373, Statutes of 2018, section 1(a)(2).

6 Ibid., section 1(a)(3).

by identifying the underlying GHG emission components and then evaluating strategies to reduce emissions. Taking a comprehensive view of potential GHG reductions and costs is critical to developing an implementable and economical building decarbonization strategy. The CEC has also examined the impact of the strategies on the electricity generation and gas systems, allowing the CEC to identify interactions between these systems and the effects strategies have on each other.

As discussed in the executive summary and Chapter 3, CEC staff developed scenarios characterizing broad building decarbonization strategies for analysis. These broad building decarbonization strategies addressed in this report include:

1. **Building end-use electrification**: Replacement of high-carbon, fossil gas-powered appliances with more efficient, low- or zero-carbon-powered appliances. Two common examples are replacing the gas water heating of a home with an electric heat pump or swapping a gas range with an electric induction range.
2. **Decarbonizing the electricity generation system:** The state's electricity generation system, as discussed above, has led the way in decarbonizing the state. Adding renewable resources to the system, as well as energy storage and demand flexibility to help manage intermittent renewables, is key to the success of other building decarbonization strategies. SB 100 charts the state's path to a 60 percent RPS by 2030 and 100 percent renewable and zero-carbon resources by 2045.
3. **Energy efficiency:**
    a. **Electric energy efficiency:** Electric energy efficiency include measures such as retrofits in insulation and air sealing, home lighting, heating, ventilation, and air conditioning (HVAC) through whole-home retrofits and small commercial programs. This strategy drives a direct reduction in electricity demand, which then reduces carbon produced by electricity generation. Energy efficiency also represents the most powerful tool for cost containment in decarbonization by making the overall system sizes in buildings and on the electrical grid smaller and, therefore, less expensive. Highly efficient electric appliances are essential to building decarbonization.
    b. **Gas energy efficiency:** Similar to electricity energy efficiency, gas energy efficiency savings include measures such as insulation and air sealing, home space and water heating, whole-home retrofits, and small commercial programs. Gas energy efficiency can similarly reduce costs, building equipment size, and the need for gas infrastructure. However, unlike electric energy efficiency, gas efficiency investments may be left unrecouped by new electrification investments.
    c. **Building Energy Efficiency Standards:** Building energy efficiency standards (Energy Code) are an important component of building decarbonization. These standards allow a strong transition to decarbonization of new buildings and can help drive technological and market readiness changes that can also benefit the retrofit market. The Energy Code has significantly reduced the GHG emissions associated with newly constructed, low-rise single-family homes in California; the 2022 and

2025 and subsequent standards cycles will provide a pathway to make heat pump space- and water-heating technologies commonplace in the state's newly constructed buildings, across many building categories. Appliance standards, both mandatory and voluntary such as ENERGY STAR®, also play a key role in transforming the appliance market toward building decarbonization.

4. **Refrigerant leakage reduction:** As an important complement to the strategies that emphasize electric heat-pump technologies, this report addresses low-global warming potential (GWP) refrigerants as replacements for refrigerants using hydrofluorocarbons (HFC). CEC staff evaluated this strategy in the context of meeting state's goals set by Senate Bill 1383 (Lara, Chapter 395, Statutes of 2016) (SB 1383). Because the pathway to lowering the GWP of refrigerants is less clear than the decarbonization of the electricity grid, CEC staff added sensitivity scenarios where HFC reduction strategies are still being developed.
5. **Distributed energy resources:** Numerous distributed energy strategies exist to support building decarbonization including rooftop solar photovoltaic (PV) systems, solar thermal systems, thermal batteries, and lithium-ion batteries. California has had great success supporting the solar PV market through incentives, beneficial rate designs, and research to drive down the cost of installing, owning, and operating a solar-powered system. These same approaches can increase the deployment of rooftop solar and batteries.
6. **Decarbonizing the gas system:** While the electricity generation system is rapidly decarbonizing, the state's gas system delivers, almost exclusively, fossil gas, and the development of strategies to decarbonize the gas system are less developed. Low-carbon fuel substitutes for fossil gas such as renewable gas and synthetic gas into the gas pipeline system are emerging as decarbonization strategies. In contrast to the electricity sector, retail renewable gas is not competitive with fossil gas on a cost basis. The potential for these alternatives to fossil gas is briefly discussed in this report and will be examined in more detail in the *2021 Integrated Energy Policy Report (IEPR)*.
7. **Demand flexibility:** Demand flexibility is an emerging approach that relies upon the capability of modern communication and internet-of-things to enable end-use devices to respond automatically to a GHG, rate, or grid shortage signal from the electric system operator. This ability to respond automatically can enable the alignment of building electricity demand with offering available supply, reducing costs of decarbonization by offering economic benefit to participants, decreasing the cost to build a decarbonized electric system, and increasing reliability.

As required by AB 3232, the CEC will conduct additional analysis of building decarbonization strategies in the 2021 and future IEPRs.

The Context for Building Decarbonization Strategies

The history and thus the context of each of these broad building decarbonization strategies underpin the design of the scenarios staff developed. There have been extensive efforts by the CEC and other entities to support ever-increasing levels of energy efficiency and more recently in rooftop PV installation, behind-the-meter battery storage, and an increased RPS

requirement. Furthermore, the implications from well-established strategies are included in the managed statewide electricity and gas demand forecast published biennially in the *IEPR* and tightly integrated in statewide interagency resource planning and procurements efforts. To date, there has been less work focused on emerging building decarbonization strategies.

Energy efficiency for electric and gas end uses has been a major emphasis of the state's mandatory appliance standards and Energy Codes since the CEC's inception in 1975. Additional local ordinances or "reach codes" going beyond the Energy Code have been adopted by some local jurisdictions through Title 24, Part 11, since 2005. Utility and other incentive programs have a more than 30-year history with renewed efforts spurred by SB 350 energy efficiency doubling initiatives set in 2015. The result of these sustained efforts in energy efficiency is that there is less potential for low-cost, cost-effective energy efficiency savings available to consumers.

Rooftop PV systems have enjoyed promotion through net metering and new construction programs, including property assessed clean energy financing for solar and efficiency, New Solar Homes Partnership, and the 30 percent federal investment tax credit. Most recently, 2019 Title 24, Part 6, has made a modest PV system mandatory on most new home construction.[7] However, the rapid growth of solar PV has created equity concerns as nonsolar PV customers incur a greater share of the overall electricity system costs. There are also system reliability and benefit valuation concerns that arise as net peak loads shift and require steeper ramping rates by electricity providers.

Demand flexibility has been promoted mostly through the lens of peak-load reduction and emergency response, less as a specific decarbonization strategy. There are promising reliability benefits from demand flexibility being pursued in the CEC's Load Management Standards and Flexible Demand Appliance Standards under development and compliance approaches in the Energy Code. This report points toward the decarbonization benefits from expanding these flexible-demand strategies.

The potential for decarbonizing pipeline gas is being explored by the California Public Utilities Commission (CPUC) and CEC. Preliminary estimates indicate that biomethane is limited in quantity, and that synthetic gas, while not subject to the same source-related volume limitations, is more expensive than standard pipeline gas. The constraint on lower-cost renewable gases also necessitates the conversation of where it can be most effectively used. The CPUC has just recently adopted its initial biomethane feed-in tariffs.

The electricity generation system has had an RPS in place since 2002, which has significantly contributed to increasing the penetration of renewables statewide. To date, this effort has been highly successful, as gas power plants and non-RPS imports are phased out and

7 The CEC has authorized builders to rely upon PV production from specific resources developed by the Sacramento Municipal Utility District to substitute for residential rooftop PV systems in Sacramento County.

renewables with storage are added. Further decarbonization of the electricity generation system is accelerating as a result of the passage of SB 100.

Building electrification, also referred to as fuel substitution, is a quickly emerging decarbonization strategy that takes advantage of the evolution of the electric grid. The 2019 Energy Code removed barriers for all-electric new construction and substitution of efficient heat pump technologies for current gas end uses by establishing separate baselines for mixed fuel and electric construction. Implementing a dual baseline in the Energy Code has also enabled electrification efforts by local jurisdictions as well as electrification program development by utilities. In 2019, the CPUC opened a new building decarbonization proceeding[8] to craft a policy framework surrounding building decarbonization and updated its energy efficiency three-prong test to permit and fund certain electrification measures.[9] Other programs supporting electric technologies are being implemented, such as those described under Senate Bill 1477 (Stern, Chapter 378, Statutes of 2018) (SB 1477). In addition, the CEC's SB 350 analysis included electrification pathways within its portfolio of efficiency measures. The *2018 IEPR Update* also sets a baseline for the discussion of electrification, including the associated potential and barriers. A significant portion of the analysis presented in this chapter focuses on the large and mostly untapped potential for electrification in existing buildings.

Development Process of AB 3232 Assessment

CEC staff developed its building decarbonization assessment framework and analysis between June 2019 and December 2020. The CEC collaborated with the California Air Resources Board (CARB), California Independent System Operator (California ISO), and CPUC, as well as with numerous stakeholders through public workshops. In total, the CEC held five workshops on the assessment from December 2019 to December 2020.[10] These workshops gave stakeholders an opportunity to provide input to the baseline, modeled scenarios, and benefits and challenges of decarbonization. CEC staff considered all oral and written comments received and addressed them herein as appropriate. The CEC conducted a workshop on the draft assessment in May 2021. In addition to the workshops, CEC plans to continue evaluating strategies and challenges to decarbonizing buildings in the *2021 IEPR*.

Organization of the AB 3232 Assessment

Chapter 1 introduces building decarbonization, discusses GHG emission reduction goals and progress in meeting them, describes the broad strategies to decarbonize buildings, and

8 CPUC, Rulemaking 19-01-011, January 2019, https://apps.cpuc.ca.gov/apex/f?p=401:56:0::NO:RP,57,RIR:P5_PROCEEDING_SELECT:R1901011.

9 CPUC, Rulemaking 13-11-005, Decision Modifying the Energy Efficiency Three-Prong Test Related to Fuel Substitution, August 2019, https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M310/K053/310053527.PDF.

10 CEC, Building Decarbonization Docket, 19-DECARB-01, https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=19-DECARB-01.

provides context for these strategies. It also discusses the development process for the AB 3232 report.

Chapter 2 provides an overview of the state's residential and commercial buildings, including building energy use and sources of GHG emissions. This chapter also addresses the two baseline approaches from which California can track building decarbonization.[11] It also explains the greenhouse gas emission baselines for 1990 and the boundary of decarbonization cost, feasibility, and potential assessment.

Chapter 3 addresses the scenario analysis staff performed for the report, including a description of the specific building decarbonization scenarios, an overview of the method, and presents the results of the analysis.

Chapter 4 analyzes the impacts the decarbonization scenarios on the electricity generation and gas systems, including an overview of the method; presents the results of the analysis of demand flexibility; and discusses opportunities to reduce HFC in refrigerants.

Chapter 5 addresses the known barriers to reducing GHG emissions in buildings such as high retrofit costs, unavailable low-cost financing, building age, low customer awareness, and consumer preferences.

Chapter 6 discusses impacts to environmental justice and disadvantaged communities and, more broadly, pathways to advance energy equity. It also addresses workforce issues.

Chapter 7 provides conclusions from the initial decarbonization assessment.

Addressing Elements of AB 3232

AB 3232 requires the consideration of five elements:

1. An evaluation, based on the best available data and existing analyses, of the cost per metric ton of carbon dioxide equivalent of the potential reduction from residential and commercial building stock relative to other statewide greenhouse gas emissions reduction strategies.[12]

This element is addressed in Chapter 3, which reports the cost-per-metric-ton estimates of the different building decarbonization strategies considered in this assessment (**Table 3**). These cost estimates are compared to other statewide GHG reduction measures estimated in the *2017 Climate Change Scoping Plan*.[13] Appendix C summarizes the input assumptions used in this assessment.

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11 California Assembly Bill 3232, Friedman, Chapter 373, Statutes of 2018. Section 1(a)(2-3). https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201720180AB3232

12 California Assembly Bill 3232, Friedman, Chapter 373, Statutes of 2018, section 2(a)(1).

13 *California's 2017 Climate Change Scoping Plan*. California Air Resources Board. November 2017. https://ww2.arb.ca.gov/sites/default/files/classic//cc/scopingplan/scoping_plan_2017.pdf.

2. The cost-effectiveness of strategies to reduce emissions of greenhouse gases from space heating and water heating in new and existing residential and commercial buildings.[14]

Chapters 3 and 5 address this element. Chapter 3 considers cost-effectiveness as the relative cost per metric ton of various GHG reduction strategies. The data reported in Chapter 3, particularly the marginal abatement cost curve broken down by end use (**Figure 17**), illustrate the cost-effectiveness of a moderate electrification strategy for space and water heating occurring in new and existing buildings by sector. Appendix C reports similar marginal abatement curves for the other electrification scenarios considered.

3. The challenges associated with reducing emissions of greenhouse gases from low-income housing, multifamily housing, and high-rise buildings.[15]

Chapters 5 and 6 address this element. Chapter 5 discusses the decarbonization strategies and associated challenges for residential and commercial buildings including financing, addressing existing building conditions, program designs, equipment costs, internet access, and more. Chapter 6 focuses on the equity issues surrounding decarbonization, including low-income household challenges affording new equipment, relieving energy burden, financing access, and more.

4. Load-management strategies to optimize building energy use in a manner that reduces the emissions of greenhouse gases.[16]

Chapters 4 and 5 address this element. Chapter 4 reports the potential impacts from a demand-flexibility scenario in the form of "load shift" as defined according to the CPUC. Chapter 5 discusses the current research on load management as an important decarbonization strategy.

5. The potential impacts of emission reduction strategies on ratepayers, construction costs, and grid reliability. In assessing the impact on grid reliability, the Commission shall account for both of the following:
    - The Commission's 2019 Building Energy Efficiency Standards, effective January 1, 2020, that propose to require solar energy systems on all new single-family and low-rise residential dwellings.
    - The increased load and impact on electrical infrastructure due to transportation electrification.[17]

Chapter 4 and 5 addressed the potential impacts to ratepayers. Impacts to construction costs are qualitatively assessed in Chapter 5 and will be further explored in the *2021 IEPR*. In assessing the impacts of scenarios (Chapter 4), staff's analysis added or subtracted electric

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14 California Assembly Bill 3232, Friedman, Chapter 373, Statutes of 2018, section 2(a)(2).

15 California Assembly Bill 3232, Friedman, Chapter 373, Statutes of 2018, section 2(a)(3).

16 Ibid., section 2(a)(4).

17 Ibid., section 2(a)(5).

generation of storage resources as electric load changed while satisfying a 15 percent planning reserve margin. The *2021 IEPR* will explore topics concerning grid reliability. For example, the electric load impacts reported in this assessment will inform the development of a building electrification load modifier and the additional achievable energy efficiency (AAEE) load modifier as part of the managed electricity demand forecast for the *2021 IEPR*. Therefore, the electricity demand forecast will have to consider the combined effects of these and the load impacts from other sources such as rooftop solar and transportation electrification when considering grid reliability issues as part of the forecast.

All elements will continue to be assessed in updates in the *IEPR* as new information and analysis are available.

CHAPTER 2:
Residential and Commercial Buildings and GHG Baseline

This chapter provides an overview of building energy use and sources of GHG emissions. It also presents a 1990 GHG emission baseline to which future GHG emissions from buildings can be compared. The decarbonization of residential and commercial buildings in California will include clean energy resources, electrification, increased energy efficiency, and demand flexibility. It will also require the balance of other state goals and challenges, such as advancing energy equity, reducing costs, and managing increased levels of electricity demand with clean electricity sources.

Residential Buildings

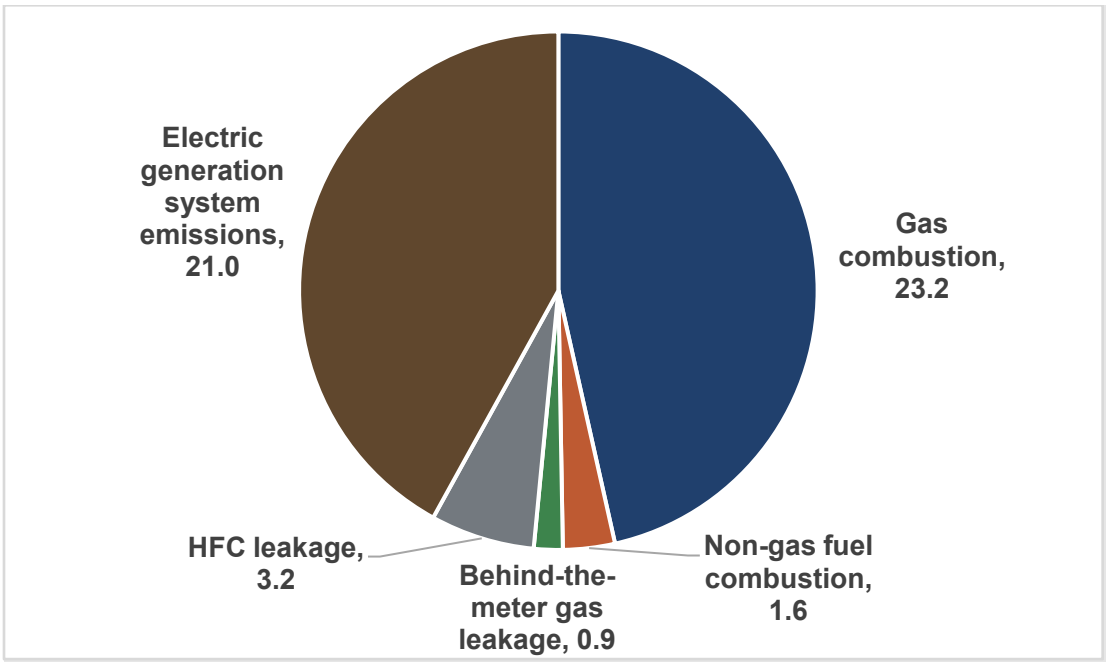
The California Department of Finance estimates that there are more than 9.2 million single-family homes and more than 4.5 million multifamily units, such as apartments, condominiums, in California.[18] California will need hundreds of thousands of new housing units in the near term to meet demand.[19] Most households in California use both gas and electricity, and in 2018, the residential sector was responsible for about 49.5 $MTTCO_2e$ of emissions, as shown in **Figure 2**.[20]

Figure 2: 2018 Residential Building GHG Emissions ($MMTCO_2e$)

18 California Department of Finance, E-5 File, May 2020, http://www.dof.ca.gov/Forecasting/Demographics/Estimates/e-5/.

19 California Department of Housing and Community Development, California's Housing Future: Challenges and Opportunities, 2018, page 7, https://hcd.ca.gov/policy-research/plans-reports/docs/sha_final_combined.pdf.

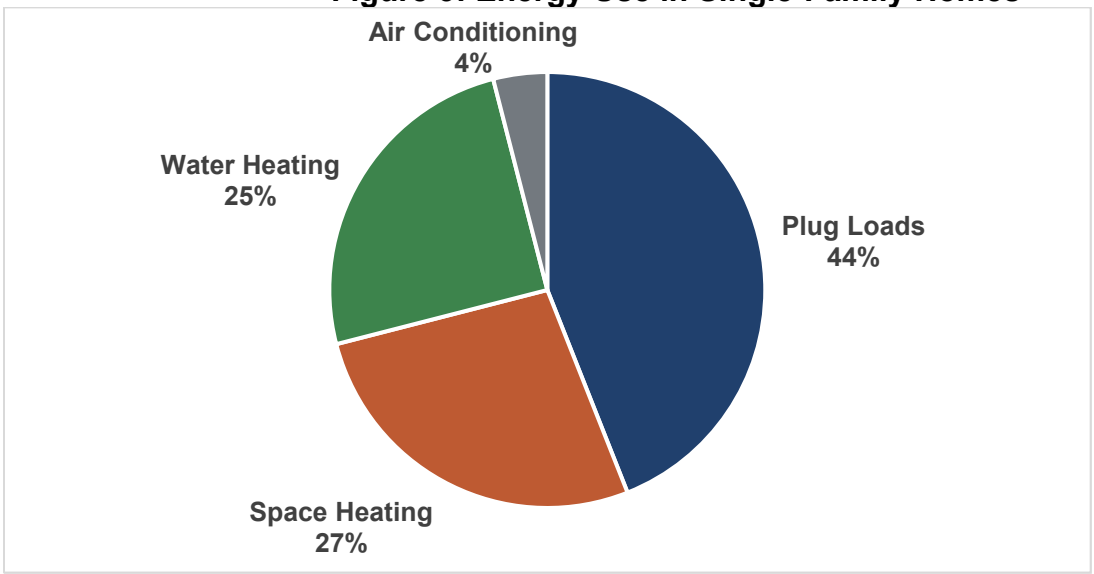
20 CARB, GHG Emissions Inventory 2000-2018, https://ww2.arb.ca.gov/ghg-inventory-data.



Source: CEC staff and CARB 2018 GHG Inventory

Combustion of gas and related leaks contribute nearly one-half of all residential emissions. **Figure 3** illustrates that residential buildings consume a significant amount of energy for space and water heating, accounting for a little more than 50 percent of energy use. Plug loads (for example, appliances, lighting, and small electronics) make up around 44 percent, and air conditioning is only 4 percent of annual usage. However, air conditioning use may increase with installation of combined space conditioning heat pumps and as residents install air conditioners in response to heat waves and sustained higher temperatures from climate change.

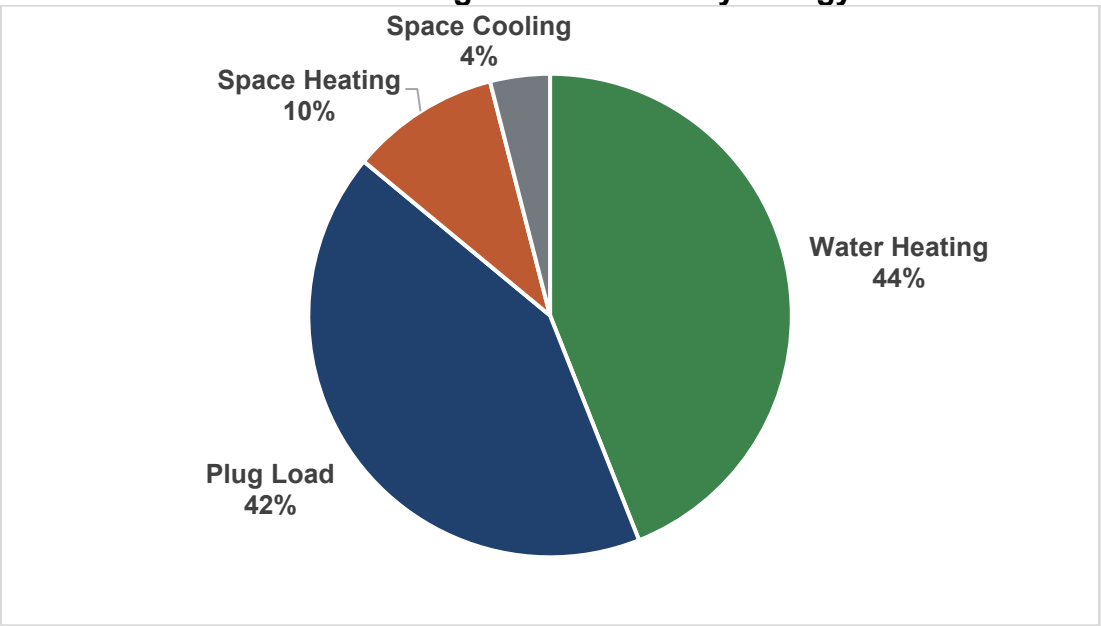
Figure 3: Energy Use in Single-Family Homes



Source: Energy Information Agency, Residential Energy Consumption Survey, 2009

Figure 4 shows that energy use in multifamily buildings is distinct from single-family households, although this comparison has regional variation. Space heating is a much smaller share of the overall energy consumption, whereas water heating is greater compared to single-family homes.

Figure 4: Multifamily Energy Use



Source: Energy Information Agency, Residential Energy Consumption Survey, 2009

Commercial Buildings

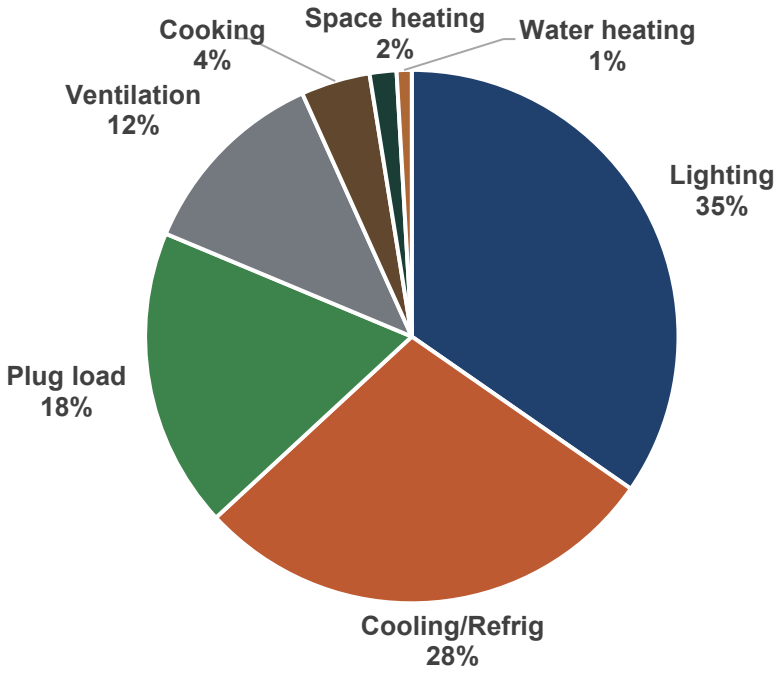
Commercial buildings include restaurants, offices, warehouses, schools, and any nonresidential space outside industry and agriculture. Together, California commercial spaces occupy more than 7.5 billion square feet.[21] This sector uses energy for a variety of purposes, and energy consumption is dominated by offices, retail, and warehouses.[22] Commercial buildings have significant gas use and high electricity consumption.[23] Electricity is used in numerous ways, but predominantly for lighting, space conditioning (cooling and ventilation), and refrigeration, as shown in **Figure 5**.

Figure 5: Electricity Consumption in Commercial Buildings by End Use

21 California Energy Commission, *2019 Integrated Energy Policy Report, Demand Forecast*, https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report/2019-integrated-energy-policy-report#accordion-3707.

22 CEC, prepared by Itron. *2006 Commercial End-Use Survey,* https://www.energy.ca.gov/data-reports/surveys/california-commercial-end-use-survey/2006-california-commercial-end-use-survey.

23 Ibid.

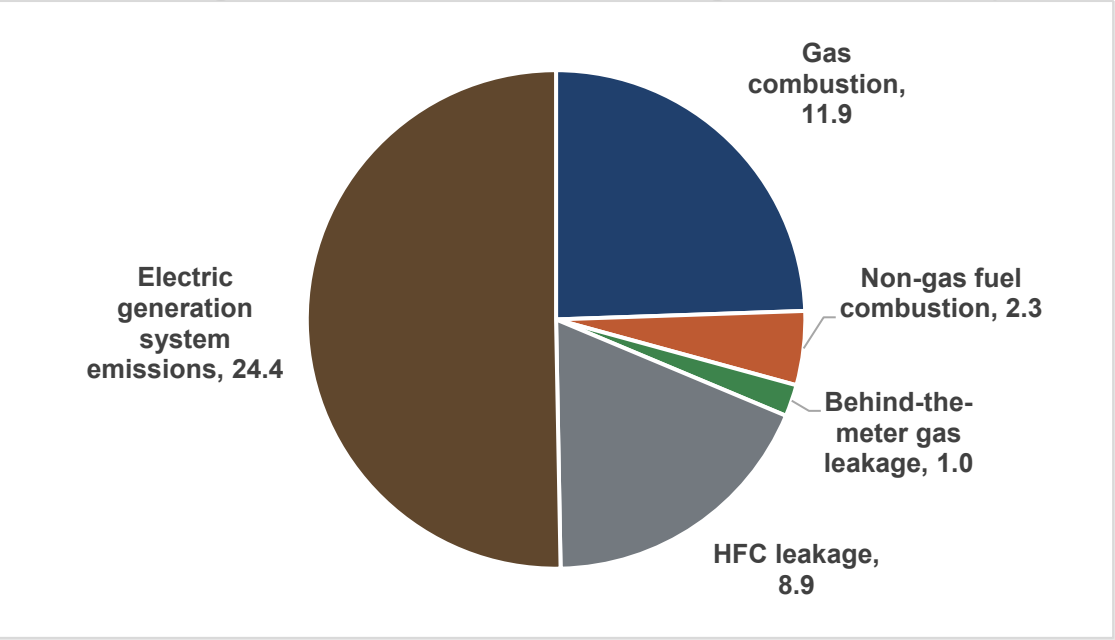


Source: California Commercial End-Use Survey

Most emissions in the commercial sector are from electricity generation, but these emissions are expected to decrease as the state approaches its zero-net-carbon electricity target by 2045 shown in **Figure** 6.[24]

24 CARB, GHG Emissions Inventory 2000-2018, https://ww2.arb.ca.gov/ghg-inventory-data.

Figure 6: 2018 Commercial Building GHG Emissions ($MMTCO_2e$)



Note: Commercial behind-the-meter gas leakage is not reported in the CARB 2018 GHG Emissions Inventory. CEC staff assumed a non-zero value of this emission source. (Refer to Appendix B for explanation.)

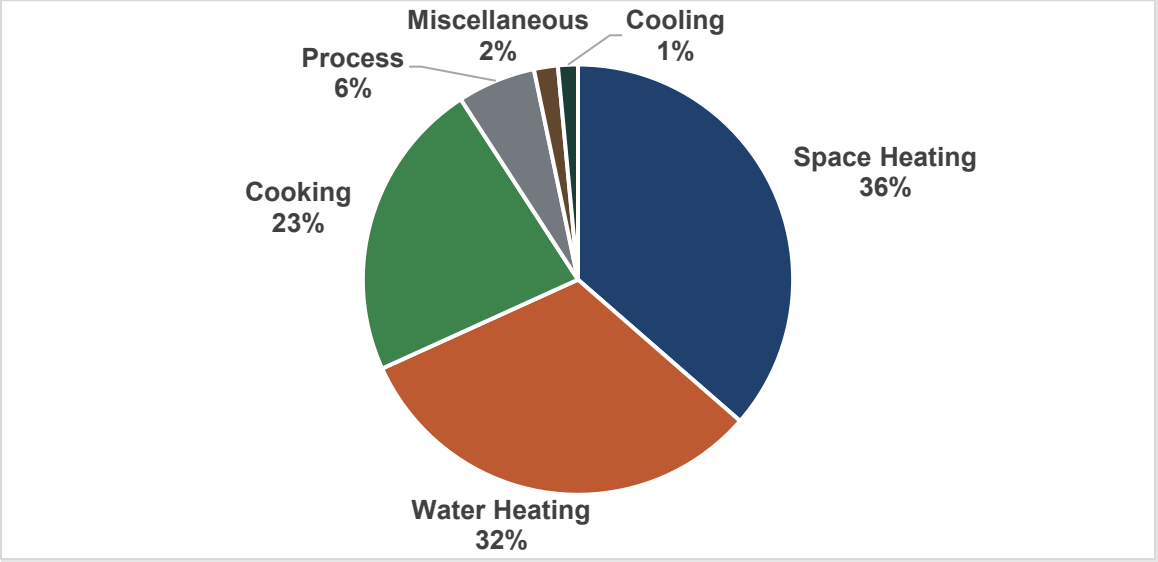
Source: CEC staff and CARB 2018 GHG Emissions Inventory

Similar to residential buildings, space conditioning in commercial buildings is expected to increase as daily temperatures increase statewide because of climate change.[25] Businesses or warehouses that previously lacked cooling would likely adopt space cooling via air conditioners or heat pumps. Moreover, more refrigerants would be needed to operate these systems, increasing potential HFC emissions.

Commercial building gas demand is driven primarily by space heating, water heating, and cooking, shown in **Figure 7**. Decarbonization strategies that focus on those end uses will be most effective in reducing GHG emissions from the commercial sector.

Figure 7: Gas Consumption in Commercial Buildings by End Use

25 California's Fourth Climate Change Assessment. August 2018. Page 23. https://www.energy.ca.gov/sites/default/files/2019-11/Statewide_Reports-SUM-CCCA4-2018-013_Statewide_Summary_Report_ADA.pdf.



Source: California Commercial End-Use Survey

In addition to building sector, type, and usage, a successful statewide building decarbonization policy must account for the ongoing challenges facing California. Specifically, it must chart a path to achieving significant GHG reductions in buildings at least cost, advance energy equity, ensure reliability, and reduce ratepayer costs associated with changing energy systems while not exacerbating California's housing crisis.

GHG Emissions Baseline

To meet the requirements of AB 3232, CEC identified a 1990 GHG emission baseline to which future GHG emissions are either added or subtracted. The 1990 GHG baseline includes on-site combustion from gas; combustion from other fuels (such as propane); behind-the-meter (BTM) gas leakage; HFC leakage from air conditioning, heat pumps, and refrigeration; and electricity generation emissions attributable to residential and commercial buildings. This assessment compares all emissions to the carbon dioxide (CO_2) equivalence using a 100-year GWP consistent with the CARB GHG inventory and the International Panel on Climate Change guidelines.[26] To determine a 1990 baseline for GHG emissions, the CEC studied possible emission sources and vetted potential approaches through a public process and with the CARB and CPUC.

Values are detailed for the residential and commercial sectors in Table 1.[27] The emission sources are separated by onsite and offsite of the building. Onsite emissions include fuel combustion, BTM gas leakage, and HFC leakage. Upstream emissions include electric generation. Emissions from methane leakage outside the building are not considered in the

26 For more information on GWP, see Appendix B.

27 Values in Table 1 are rounded.

baseline. The total 1990 emissions are 124.1 $MMTCO_2e$, which equates to a 2030 goal of 74.4 $MMTCO_2e$.

Table 1: 1990 Baseline Emissions by Building Sector ($MMTCO_2e$)

Source #	GHG Emission Category	Residential 1990	Commercial 1990	Total 1990
1	Gas combustion	27.7	11.1	38.8
2	Non-gas fuel combustion ("other fuels")*	2.0	3.4	5.4
3	Behind-the-meter gas leakage	0.7	1.0	1.7
4	HFC leakage**	1.6	6.9	8.5
	Total on-site emissions ("direct emissions")	32.0	22.4	54.4
5	Electric generation system emissions	33.8	35.9	69.7
-	Total on-site and electric generation system emissions ("systemwide emissions")	65.8	58.3	124.1

*Nongas fuel combustion in 1990 includes the following fuels: coal, digester gas, distillate, gasoline, jet fuel, kerosene, landfill gas, LPG, propane, refinery gas, residual fuel oil, waste oil, and wood (wet).

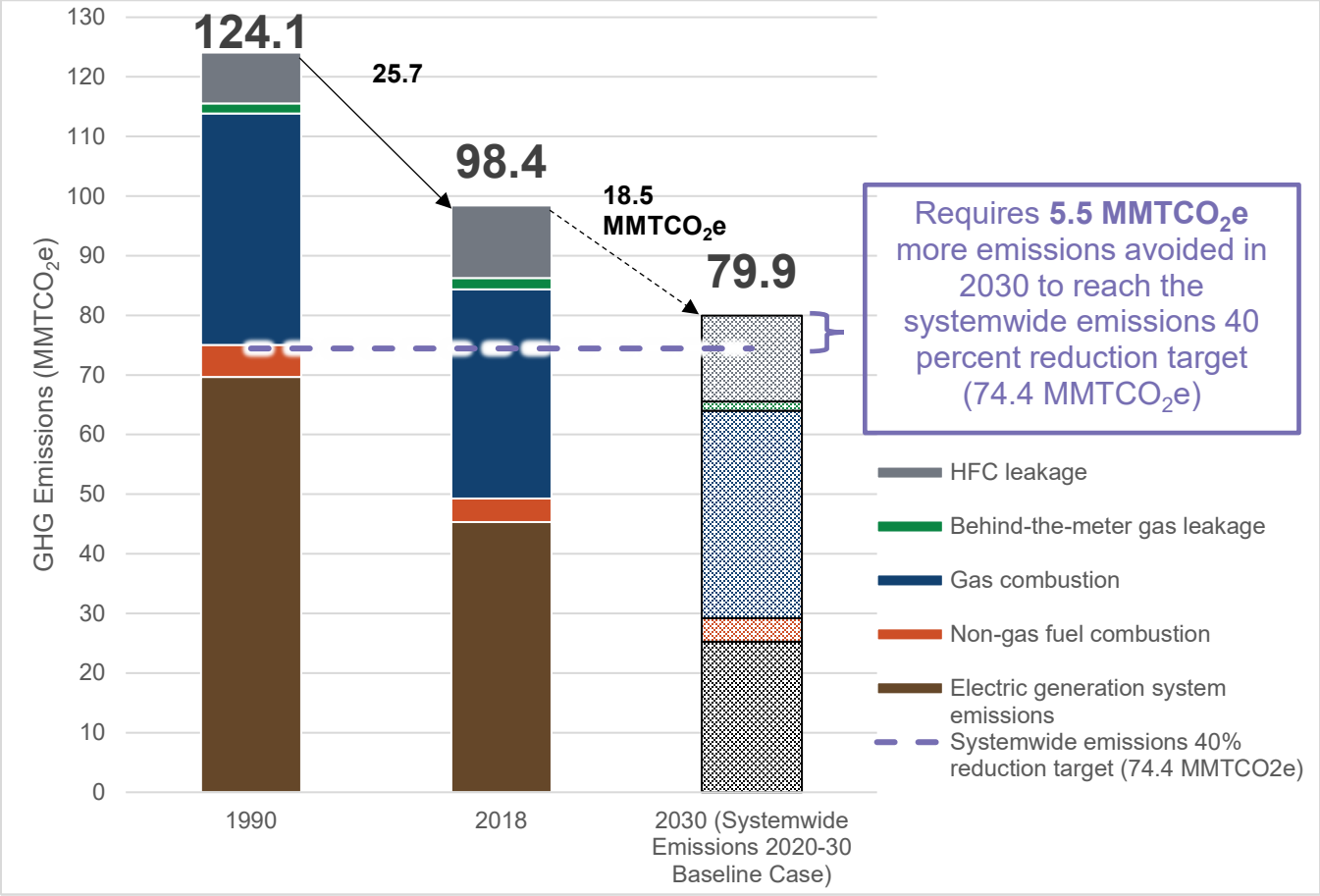
** HFC leakage from refrigeration and air conditioning. As described in this chapter and Appendix B, staff used 2013 levels for the 1990 base year to align with SB 1383 and best portray the level of these refrigerant emissions in the 1990 base year.

Source: CEC staff and CARB GHG Emissions Inventory

As shown in **Figure 8**, the AB 3232 1990 baseline requires emissions to be reduced to 74.5 $MMTCO_2e$, roughly a 50 $MMTCO_2e$ curtailment, to reach the 40 percent reduction by 2030. In 2018, emissions were already 25.7 $MMTCO_2e$ below 1990 levels, and the estimated 2030 emissions in the 2020–30 Baseline Case suggests that emissions would reduce by another 18.5 $MMTCO_2e$ to 79.9 $MMTCO_2e$, which is 89 percent of the way to the AB 3232 goal.[28] The CEC assessed how various decarbonization strategies can achieve at least the additional emissions reduction relative to the 2020–30 Baseline Case required to meet the AB 3232 goal. See Chapter 3 for how the 2020–30 Baseline Case was estimated.

Figure 8: Reductions From a 1990 Baseline to the Systemwide Emissions 2020–30 Baseline Case

28 As reported in Appendix B, CEC staff's estimates of emissions may not align completely with the emissions or categories reported in the most recent CARB GHG Emissions Inventory.



Source: CEC staff and CARB GHG Emission Inventory

Alternative 1990 Baseline

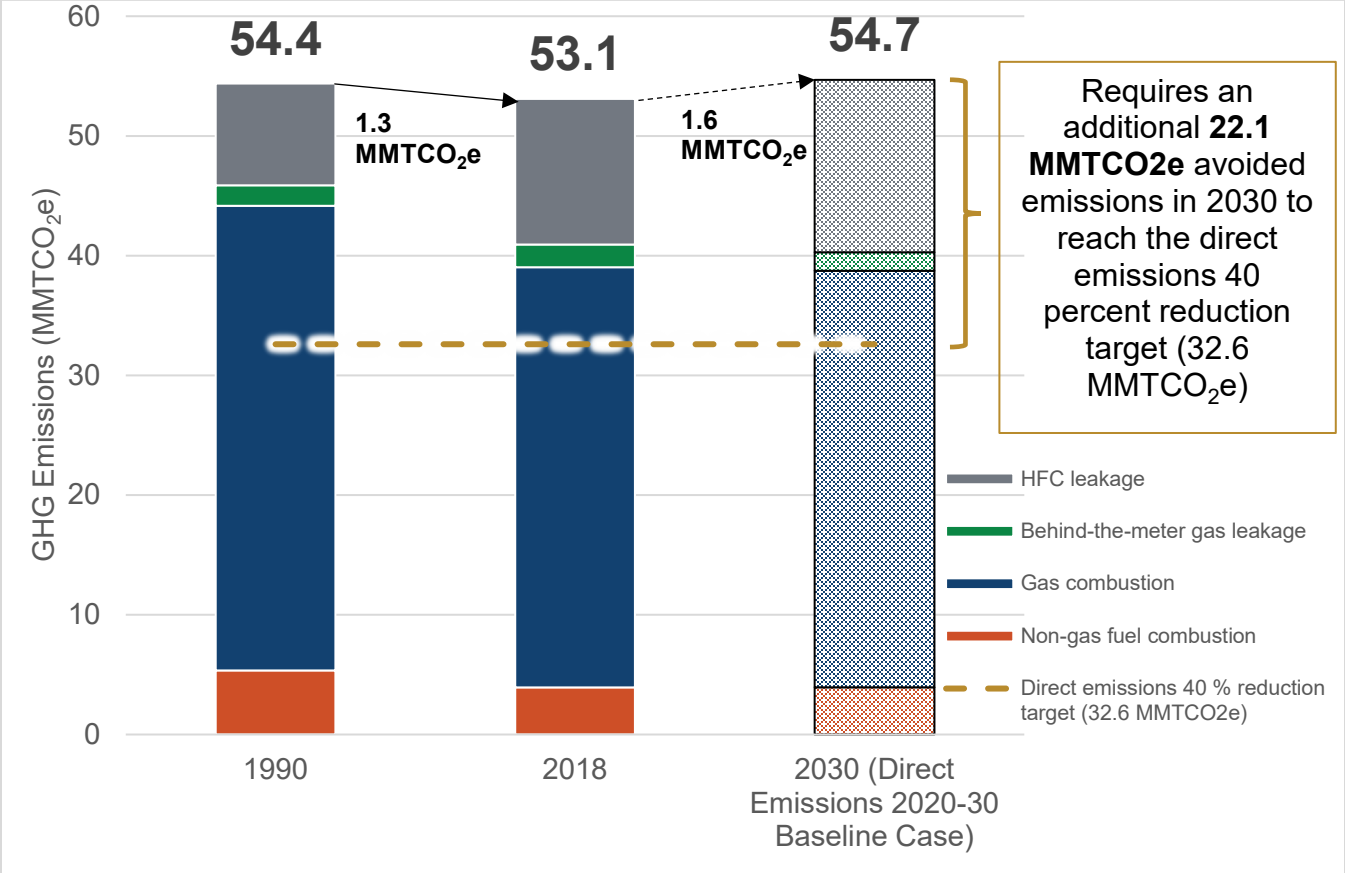
In addition to the systemwide baseline presented in **Table 1** and **Figure 8**, the CEC explored an onsite-only emissions baseline. The onsite-only baseline examined the direct emissions from the scenarios and any incremental electric generation emissions resulting from building electrification. The AB 3232 legislation cites 25 percent of emissions come from the building sector, including onsite and offsite emissions, and that around 40 percent of buildings-related emissions — 10 percent of the state total — are due to onsite combustion, primarily of fossil gas.[29] CEC interpreted the citation of energy emissions from buildings as a suggestion to also examine a baseline of onsite emissions (or "direct emissions") generated from the buildings sector.

29 California Assembly Bill 3232, Friedman, Chapter 373, Statutes of 2018, section 1(a)(2-3).

According to CEC staff analysis, based on the 2020 CARB GHG inventory, which reports emissions for 2018, the building sector contributed to roughly 22 percent of total statewide emissions. About 43 percent of building-related emissions, or roughly 10 percent of the statewide total, are due to onsite combustion, primarily fossil gas.

Figure 9 illustrates the direct emissions baseline where the electric generation system emissions in 1990 are removed compared to **Figure 8**. The omission of electricity generation emissions in 1990 increases the emission reductions needed to meet the alternative 40 percent target by 16.6 $MMTCO_2e$, from 5.5 $MMTCO_2e$ using the systemwide emissions baseline to 22.1 $MMTCO_2e$. The direct emission baseline also cuts the electric-based building decarbonization strategies that could count against this more aggressive target. The report presents the assessment for both baselines. The set of strategies and the percentage reduction vary across baselines, but the cost of a scenario and the GHG impacts to the electric generation system do not vary across the two baselines.[30]

Figure 9: More Emissions Reduction Required When Considering a Direct Emissions 2020–30 Baseline Case



Source: CEC staff and CARB GHG Emission Inventory

2030 Relative to 2045 Climate Goals

30 Not including the incremental electric generation system emissions would make achieving the direct emissions baseline target more achievable, but such an omission would ignore the crucial impacts occurring in the electric generation system.

AB 3232 directs the CEC to assess the potential of reaching at least 40 percent GHG reduction by 2030. However, this assessment does not mean that the state should limit itself to this 40-percent level of reduction in future years. The 2045 targets set out in SB 100 and Executive Order B-55-18 clearly indicate that market transformation should be completed by 2045. To reach the state's 2045 economywide carbon neutrality goal, it will be necessary to remove or offset all remaining building emissions not addressed by 2030.[31] This means even when the AB 3232 goal is achieved, there will still be close to 80 $MMTCO_2e$ remaining to remove and offset by 2045, as shown in **Figure 8**. About 25 $MMTCO_2e$ of emissions will remain in the electricity sector attributable to buildings, most which will be offset by decarbonization of electric generation sources from 2030 to 2045; the remaining emissions will be reduced or offset using a mix of other decarbonization strategies. The costs to achieve the remaining reduction should drop as markets become streamlined, advanced technologies become commercially viable, and greater market awareness and program availability encourages broader customer participation.

It is also important to consider how various 2030 scenarios create momentum and position California to achieve economywide decarbonization in 2045. For example, this report shows that compressing the timeline for appliance upgrades, particularly moving from replacement on burnout (ROB) to early retirement (RET), leads to significant incremental cost. This means that moving quickly toward appliance replacement by 2030 increases cost per ton of GHG reduction. It also means that making too little progress by 2030 forces early retirement in later years and significantly increases the pathway cost to achieving 2045 goals.

The need to achieve deeper levels of decarbonization in the period following 2030 also complicates gas energy efficiency as a medium- and long-term strategy. The overall cost of investing in upgrading the efficiency of a gas appliance to achieve 2030 goals, and then later upgrading that gas appliance to a high-efficiency electric one later, is greater than the cost of upgrading to a high-efficiency electric appliance in the first place, although both are likely better than inaction. Care must be taken to avoid early retirement leading to higher associated costs. In the nearer term, gas efficiency can make sense as an interim strategy until a subsequent replacement, with the caveat that long-lived equipment may be replaced only once more between now and 2045.

Similarly, integrating renewable gas into the system may provide significant GHG reductions needed to reach the 2030 goals. Greater volumes of nonfossil gas would be required to reach the deeper decarbonization targeted for 2045. While synthetic gas from renewable sources can be used for further decarbonization, the associated costs are high. Further, there is competition for RNG from sectors such as industrial and heavy-duty vehicles, limiting the availability of this gas to the building sector. Thus, gas efficiency and decarbonization may provide a near-term bridge to subsequent, deeper reductions heading to 2045.

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31 California, Executive Order B-55-18, https://www.ca.gov/archive/gov39/wp-content/uploads/2018/09/9.10.18-Executive-Order.pdf.

Sources of GHG Emissions in Buildings

As stated above, buildings contribute to GHG emissions via several sources: onsite fuel combustion, leakage of gas and HFCs, and offsite through the use of electricity.[32] These data were incorporated into the GHG baseline computation.

Fuel Combustion

A significant portion of building emissions are a result of onsite combustion of fuels for cooking and space and water heating (Table 1; Source 1 and 2). Most of the fuel combustion emissions come from the residential sector, about 2.5 times more than emissions from the commercial sector (Table 1). Gas is the primary source of fuel combustion emissions, while other fuels like propane, heating oil, and distillate comprise the remainder (Table 1).[33] While nongas fuels are included in the baseline, technologies using them are not considered for fuel substitution such as in a fuel oil furnace. The amount of emissions coming from these other fuels is assumed to be fixed from 2017 to 2030.

Behind-the-Meter Gas Leakage

BTM gas leaks are another important emission source. The 1990 baseline includes 1.7 $MMTCO_2e$ of BTM gas leakage (Table 1). BTM leaks occur from stoves, furnaces, water heaters, or other gas-using appliances when gas leaks from the appliance as opposed to burning. The leaked gas not only contributes to climate change, but also negatively impacts the indoor air quality for inhabitants. A recent study found that residential buildings leak about 0.5 percent of the gas they register at the meter.[34] The leaked gas is also a potent short-lived climate pollutant with a high short-term GWP, which requires immediate action to avoid climate and public health impacts.[35] Additional avoidable leakage occurs at the meter itself.[36]

HFC Leakage (Refrigerant Leakage)

While the transition to nonozone-depleting refrigerants is providing significant improvement to the environment caused by avoiding the potency of HFC leakage, HFC refrigerants now make up a significant contribution of building sector emissions. HFCs are the most common type of

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32 Appendix B details the methods CEC staff used to approximate the level of emissions for homes and businesses of the various sources using the CARB GHG inventory.

33 CARB, GHG Emissions Inventory 2000–2018, https://ww2.arb.ca.gov/ghg-inventory-data.

34 Fischer, Marc L., Wanyu Chan, Seongeun Jeong, and Zhimin Zhu. Lawrence Berkeley National Laboratory. 2018. Natural Gas Methane Emissions From California Homes. California Energy Commission. Publication Number: CEC-500-2018-021., page 38, https://ww2.energy.ca.gov/2018publications/CEC-500-2018-021/CEC-500-2018-021.pdf.

35 CARB, Short Lived Climate Pollutant Reduction Strategy, page 42, March 2017, https://ww2.arb.ca.gov/sites/default/files/2020-07/final_SLCP_strategy.pdf.

36 These emissions are smaller than BTM Gas Leakage and staff did not have time to include these emissions in the analysis. See CARB, Quantifying Methane Emissions from Natural Gas Residential Customer Meters in California, May 2020, https://ww2.arb.ca.gov/resources/documents/quantifying-methane-emissions-natural-gas-residential-customer-meters.

refrigerants and are commonly used in air-conditioning, heat pump space conditioning, heat pump water heaters, and refrigerators. The GWP of HFCs today may be hundreds of thousands of times more potent than CO_2. When refrigerant-using equipment is retired, the refrigerant may not be properly collected and disposed and instead allowed to release into the atmosphere.[37] In addition, significant HFC emissions occur from leaks, particularly in commercial refrigeration systems.

The amount of HFCs in use in 1990 was low but its use grew quickly over the next decade.[38] This was because the Montreal Protocol required nations to transition from ozone-depleting substances to substitutes, such as HFCs.[39] In 2016, through the Kigali Amendment to the Montreal Protocol, the United States and 196 other countries were signatories and agreed to phase down HFC usage by more than 80 percent over the next 30 years starting in 2019, although the United States has yet to ratify the Kigali Amendment.[40] In December 2020, the federal American Innovation and Manufacturing Act was enacted.[41] This law grants the United States Environmental Protection Agency the authority to regulate HFCs. This law will lead to a national phasedown on HFCs that mimics the global phasedown.

HFCs and other high GWP gases grew significantly relative to 1990 and will be a major GHG emission source by 2030.[42] The 1990 baseline has been adjusted to use a 2013 value of HFC emissions following consultation with CARB. This adjustment enables the assessment to capture strategies that use lower GWP refrigerants. CARB is also working on new programs and regulations for refrigerants that have lower GWP.[43] CARB also notes in its comments to the CEC that the HFC reductions called for by Senate Bill 1383 (Lara, Chapter 395, Statutes of 2016) do not address increased usage from moving to new electric heat pumps.[44] The incremental growth of HFCs over what was anticipated must be dealt with through different programs or regulations. The CEC continues to study low-GWP refrigerants in research pilots and will coordinate with CARB on its efforts to reduce HFC emissions as required by SB 1383.

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37 CARB, Short Lived Climate Pollutant Reduction Strategy, page 83, March 2017, https://ww2.arb.ca.gov/sites/default/files/2020-07/final_SLCP_strategy.pdf.

38 CARB, 1990 to 2004 GHG Inventory, https://ww2.arb.ca.gov/ghg-1990-to-2004.

39 Montreal Protocol, 1991, https://www.unenvironment.org/ozonaction/who-we-are/about-montreal-protocol.

40 Kigali Amendment to the Montreal Protocol, 2016, https://treaties.un.org/Pages/ViewDetails.aspx?src=IND&mtdsg_no=XXVII-2-f&chapter=27&clang=_en.

41 United States 116th Congress, Consolidated Appropriations Act, Section 103, "American Innovation and Manufacturing Act of 2020," December 2020, https://rules.house.gov/sites/democrats.rules.house.gov/files/BILLS-116HR133SA-RCP-116-68.pdf.

42 CARB, GHG Emissions Inventory 2000-2018, https://ww2.arb.ca.gov/ghg-inventory-data.

43 CARB, Refrigerant Management Program, https://ww2.arb.ca.gov/our-work/programs/refrigerant-management-program.

44 CARB comments to CEC Building Decarbonization Docket, https://efiling.energy.ca.gov/GetDocument.aspx?tn=233127&DocumentContentId=65605.

Research is ongoing to identify alternatives to potent HFCs, examples of which are described in Appendix A.

Electricity Generation System Emissions

The largest contributor to building emissions is the electricity generation system. From 1990 to 2030, it is estimated that the electric emissions associated with powering buildings will drop from about 70 $MMTCO_2e$ to around 25 $MMTCO_2e$ in a baseline case shown in **Figure 8**. Building emissions from the electricity generation system will decrease over time as the grid shifts to 60 percent renewable energy in 2030 and 100 percent net zero-carbon resources by 2045, as called for in SB 100.

Upstream Methane Emissions

Methane emissions from extraction, processing, transmission, and distribution of gas are a significant contributor to global GHG emissions. Current research suggests that the gas system leaks around 2.3 percent of gross gas production.[45] However, these upstream emissions are not included in the 1990 baseline as they are not considered a part of the building emissions inventory at CARB.[46] In addition, there is uncertainty on upstream methane leakage rates and ways that methane leakage from out-of-state gas facilities should be counted toward in-state emissions. More research is also needed on the causality of building fossil gas usage on upstream methane leakage. As more information on upstream methane emissions becomes available, the CEC may address impacts that may be avoided by reductions in building gas use in future iterations of this assessment. Additional information on upstream methane emissions is available in Appendix B.

California has limited ability to control out-of-state emission abatement. In state, there are existing efforts underway to reduce emissions from infrastructure leaks. For example, the Natural Gas Leak Abatement Program is charged with reducing fugitive and vented emissions from the transmission and distribution of gas in California. Efforts to reduce gas use in buildings may not impact fugitive and vented upstream emissions unless gas transmission and distribution infrastructure are removed entirely.[47] The leaks from the gas system are controlled by several factors, such as pipeline pressure, and are only partially correlated to throughput. In addition, leakage in the gas sector is dominated by a relatively small number of large leaks at oil/gas wells and storage facilities.

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45 Alvarez et al. 2018. "Assessment of Methane Emissions From the U.S. Oil and Gas Supply Chain." *Science* https://science.sciencemag.org/content/361/6398/186.

46 CARB, GHG Emissions Inventory 2000-2018, https://ww2.arb.ca.gov/ghg-inventory-data.

47 Recent research suggests that probably some emissions would be abated from gas use reductions without infrastructure removal, but not all. See Mac Kinnon, M., Heydarzadeh, Z., Doan, Q., Ngo, C., Reed, J., & Brouwer, J. (2018). "*Need for a Marginal Methodology in Assessing Natural Gas System Methane Emissions in Response to Incremental Consumption*." *Journal of the Air & Waste Management Association*, 68(11), 1139-1147. https://www.tandfonline.com/doi/full/10.1080/10962247.2018.1476274.

CHAPTER 3:
Analysis of Building Decarbonization Scenarios

This chapter describes the analysis to assess building decarbonization scenarios performed by the CEC in support of AB 3232 policy objectives. Specifically, AB 3232 directs the CEC to assess the potential for the state to reduce GHG emissions in the state's residential and commercial buildings by *at least* 40 percent by 2030. The CEC staff identified specific scenarios based on the broad decarbonization strategies discussed in other sections of the report. The staff then analyzed the scenarios for GHG emission reductions, costs, and impacts on the electric and gas systems. The chapter summarizes a subset of the scenarios that staff analyzed. Appendix C presents the full set of scenarios, including details on method, inputs and assumptions, and results. The assessment of impacts of decarbonization strategies on the electricity generation and gas systems, along with a discussion of demand flexibility impacts and opportunities to reduce HFC emissions from building, is presented in Chapter 4.

Building Decarbonization Scenarios

CEC developed a series of scenarios based on the seven broad decarbonization strategies, briefly described in **Table 2** below. The nonelectrification scenarios are referred to as "impact scenarios"; all scenarios are compared to an estimated 2020–30 Baseline Case described in this chapter. Additional details on how the scenarios were constructed and future planned refinements, including inclusion of strategies not analyzed in this process, are presented in Appendix C.

Table 2: Summary of the Decarbonization Scenarios Analyzed

Building Decarbonization Strategy	Decarbonization Scenario(s) Analyzed	Used in the 2020–30 Baseline Case	Used in Decarbonization Scenarios
1. Building End-Use Electrification	Four building end-use electrification scenarios (minimal, moderate, aggressive, efficient aggressive)	AAEE Scenario 3 includes low penetration of all-electric new construction in residential and commercial building sectors	A broad range and combination of electrification through new construction, appliance burnouts, and early appliance replacements.
2. Decarbonizing the Electricity Generation System	Accelerated Renewable Electric Generation Resources	60% RPS by 2030	65–70% RPS by 2030

Building Decarbonization Strategy	Decarbonization Scenario(s) Analyzed	Used in the 2020–30 Baseline Case	Used in Decarbonization Scenarios
3. Energy Efficiency	Incremental Electric Energy Efficiency	AAEE business as usual	AAEE optimistic (Scen. 5)
	Incremental Gas Energy Efficiency	AAEE business as usual	AAEE optimistic (Scen. 5)
4. Refrigerant Leakage Reduction	Not assessed	None	None
5. Distributed Energy Resources	Incremental rooftop solar PV systems	AAPV business as usual	IEPR High penetration
6. Decarbonizing the Gas System	Decarbonizing gas system with renewable gas	None	Substitution of 20 percent of total system fossil gas throughput with renewable gas by 2030
7. Demand Flexibility	Demand flexibility	Traditional non-event-based load management programs business as usual	Automated systems that take advantage of curtailment and avoid net-peak consumption

Source: CEC staff

The impacts of some building decarbonization strategies are better understood than others. Staff incorporated the best available data and existing analysis of the potential GHG reduction strategies. However, there is considerable uncertainty associated with analytical inputs and assumptions used in this preliminary analysis due to a lack of experience with technologies and limited data with some of the newer strategies. As the knowledge base and experience with the newer building decarbonization strategies grow, these initial estimates can be improved upon as part of the IEPR process, as envisioned in AB 3232.

Analytical Approaches and Methods

Some of the building decarbonization strategies analyzed have been pursued for more than a decade, and in some cases much longer, although not explicitly for GHG emission reduction. For example, the state has considerable experience with strategies involving energy efficiency, rooftop PV, and decarbonizing the electricity generation system with higher levels of renewable resources. Electrification and renewable gas have surfaced as strategies only recently, in part because of the focus that AB 3232 has brought to building decarbonization. Existing tools and techniques were used to examine traditional resources like energy efficiency to assess the building decarbonization potential. New analytical techniques were needed to

assess newer strategies, such as electrification and use of renewable gas, and assess electric and gas system impacts.

Staff used a new tool for some of this analysis — the Fuel Substitution Scenario Analysis Tool (FSSAT) — that was developed under a technical-support contract with Guidehouse Inc. with the primary objective of determining the change in GHG emissions from electrification efforts from 2020 through 2030.[48] Staff also used production cost-simulation modeling to determine changes in electricity generation system GHG emission from the various strategies. Appendix C shows a simplified flow diagram showing the steps in the analysis and iterations between the steps needed to account for electricity generation system emissions. Appendix C also provides a detailed description of the method, inputs, assumptions, and results.

Staff devised a series of electrification scenarios that specify increasingly large displacement of projected 2030 gas consumption and quantified these in terms of gas displaced, incremental electric energy added, capital and operating costs, and GHG emission reductions.[49] As research on consumer behavior is collected and implementation data from pilot programs become available, more capabilities including these aspects of a predictive behavior can be incorporated in the model to transform the FSSAT into a genuine forecasting tool.

Additional details on the method and assumptions used to assess the scenarios designed for each strategy can be found in Appendix C.

2020–30 Baseline Case

With 1990 base year GHG emissions already established, as discussed in Chapter 2, the staff developed a 2020–30 Baseline Case based on existing policies from which to measure the impacts of various decarbonization strategies. This case uses the *2019 IEPR* managed demand forecasts for electricity and gas and the implications of these gas and electric supplies. These managed demand forecasts incorporate the load-reducing impacts of continued aggressive efforts using existing statutory authority (spending on utility programs, triennial updates of the Energy Code, some additional state and federal appliance standards, and limited impacts from other programs). These resulting managed demand forecasts are the basis for supply-side assessments that also address unique requirements for the supply of electricity or gas.

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48 Sathe, Amul Sathe (Guidehouse), Karen Maoz (Guidehouse), John Aquino (Guidehouse), Abhijeet Pande (TRC), and Floyd Keneipp (Tierra Resource Consultants). 2020. Fuel Substitution Reporting Tools. California Energy Commission. Publication Number: CEC-200-2020-001. https://efiling.energy.ca.gov/GetDocument.aspx?tn=233241&DocumentContentId=65725

GHG emissions sources included gas consumption (including behind the meter leakage), nongas consumption, incremental HFC leakage, stock refrigerant HFC leakages, and incremental electric generation. Staff used annual CARB projections with or without "success" of SB 1383 as defined in each scenario.

49 FSSAT is not a forecasting tool because it lacks a predictive framework to enable a full forecast of technology-level electrification on the basis of consumer education, technology-specific incentives through programs, and the wide range of consumer behavior embedded in a true forecast model.

On the building-energy-demand side, well-established decarbonization strategies of energy efficiency and rooftop PV are included in the statewide electricity and gas demand forecast published biennially in the *IEPR*. The CEC examines a wide range of potential programs and standards but includes in its baseline demand forecast only those considered to be committed. The additional energy savings from potential future updates of building standards, appliance regulations, and new or expanded energy efficiency programs are referred to as "AAEE." For this analysis, staff uses a mid-demand case, meant to represent neither an optimistic nor pessimistic view, which serves as the basis of statewide planning and resource procurements activities. Like energy efficiency, behind-the-meter rooftop PV in the residential and commercial sectors are included in the mid-mid IEPR forecast used here as the business-as-usual projection against which various decarbonization strategies are compared.

On the electric supply side, staff developed resource plans of in-state and out-of-state resources using production cost modeling that incorporate RPS procurement requirements and simultaneously satisfy basic reliability criteria. For this initial round of building decarbonization analysis, staff added or subtracted renewable resources consistent with changes in total electric energy consumed to satisfy RPS requirements. Staff then added or subtracted storage capacity as needed to satisfy changes in annual peak demand plus the 15 percent annual planning reserve margin reliability criteria. The impact of electric load reductions due to a wide range of energy efficiency standards is built into the adopted managed demand forecast used for the 2020–2030 Base Case. The GHG emissions for the 2020–2030 Base Case and each scenario are computed using a supply-side assessment of necessary resource build-out to satisfy demand and assessing GHG emission impacts using production simulation modeling. Renewables are not included in the baseline demand forecast, though the business-as-usual case does include a modest amount of behind-the-meter PV. Demand flexibility is considered in nonemergency program impacts included in *2019 IEPR* forecast. Coordination issues between CPUC and California ISO are ongoing but are not integrated into the business-as-usual demand forecast beyond the traditional nonevent-based load management programs. Renewable gas is not included in the baseline nor the business-as-usual assumptions for the gas supply system to date. As a result, the emission characteristics of gas supplied to customers is constant through time.

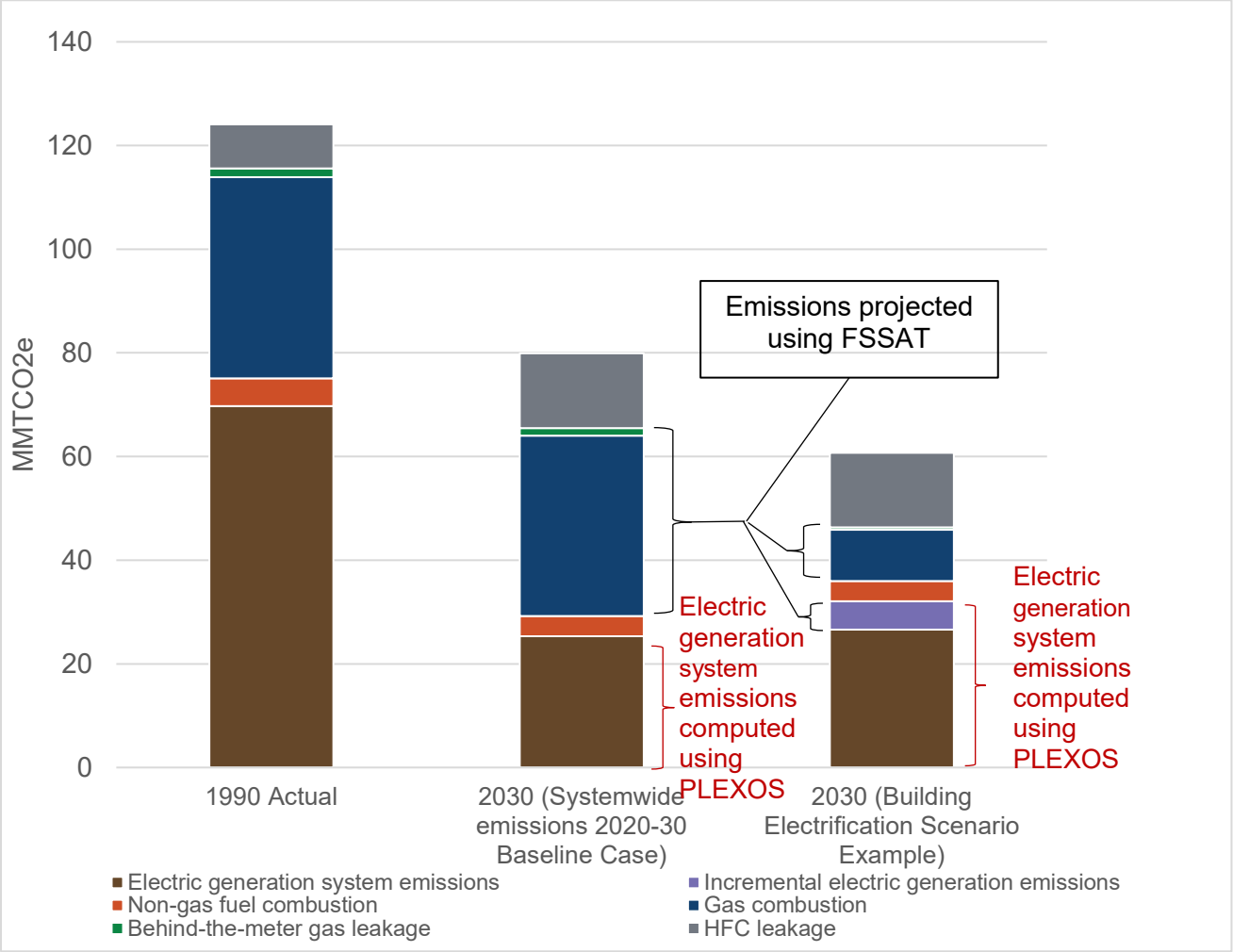
Interactions Between Strategies and Electricity Generation System

In most cases, each scenario was assessed independently; thus, the impacts are not additive. However, analysis of GHG emission reductions in the electricity generation system is more complex than the other strategies in two ways. First, decarbonizing the electric generation system constitutes its own strategy for achieving emission reductions that can be assessed separately. For example, adding higher levels of renewable resources to the generation mix is a strategy to reduce electricity generation system GHG emissions. Second, building decarbonization strategies can increase or decrease electricity sales, which in turn can affect the amount of GHG emissions from the electricity generation system. Since nearly all the scenarios described later in this chapter change electricity sales, devising a method that can determine these impacts was essential.

Figure 10 illustrates the interactions that can occur between strategies and the electricity generation system. Staff compared a 2030 Baseline Case based on existing policies to a 2030 "efficient aggressive electrification" scenario that combines electrification with high-efficiency equipment to serve as an example. **Figure 10** uses stacked bars to show the GHG emissions from the two 2030 cases, along with the 1990 Base Year. It demonstrates that the shift from gas to electricity in appliance and equipment at the end-user level can result in increased GHG emissions from the electricity generation system. While the building electrification scenario reduces gas consumption, it increases the total expected 2030 electricity sales and thereby increases the GHG emissions from the electricity generation system.[50] Including the impacts on the electricity generation system in the scope of assessment of AB 3232 does make GHG emission analysis more complex but enables a more complete and accurate assessment of building decarbonization strategies that affect electricity sales.

Figure 10: Interaction Between Electrification and Electricity Generation System Emissions

50 A detailed description of the modeling of the electric generation system can be found in Appendix C.



Source: CEC staff and Guidehouse

Overview of Scenario Assessment Results

The scope of the building decarbonization assessment includes four building electrification scenarios (minimal, moderate, aggressive, efficient aggressive), accelerated renewable development, rooftop PV, incremental energy efficiency, and renewable gas, all with and without the success of SB 1383 reducing hydrofluorocarbon (HFC) emissions from buildings. All scenarios examine the effects from implementing activities occurring from 2020 to 2030. However, since implementing most of these strategies have effects beyond 2030, the life-cycle impacts of costs and GHG abatement used a 2045 time horizon. Please refer to Appendix C for a complete summary of the scenarios examined in this assessment.

Table 3 provides an overview of the avoided annual GHG emissions for 2030, the percentage reduction in 2030 compared to the 1990 direct and systemwide emission baselines, cumulative avoided GHG emissions from 2020 to 2045, net cost to implement the strategy, and the metric cost per ton. The avoided annual GHG emissions for 2030 are reflected in **Figure 11**, **Figure 12**, and **Figure 13** and demonstrate the effectiveness of building electrification. The "minimal electrification" depicts a scenario that meets the 40-percent-reduction target. In the "moderate

electrification" scenario, new construction will be fully electrified by 2030; 50 percent of burned-out space and water heating and other gas appliances in existing buildings will be replaced and electrified by 2030 (in other words, 35 percent more compared to the "minimal electrification" scenario); and 5 percent of space and water heating and other gas appliances in existing buildings will be replaced and electrified before they are burned out.

The aggressive scenarios have higher penetrations of electrification. The "efficient aggressive electrification" scenario depicts an extreme case of the "aggressive electrification" scenario where each replaced electric technology is assumed to be the most efficient technology out of the mix of technologies that could be used for replacement. It can be seen in **Table 3** that this additional assumption for this particular scenario increases GHG reduction impact in 2030 by 1.0 $MMTCO_2e$ and 2045 cumulative GHG reductions by 10.9 $MMTCO_2e$.

The last column in **Table 3** reports the estimates of the cost per metric ton of estimates reductions for each scenario to 2045. The incremental electric energy efficiency scenario has the lowest cost per metric ton, exemplifying the potential operational savings from energy efficiency. The renewable gas scenario has the highest cost per metric ton estimates. The electrification scenarios have estimated costs per metric ton ranging from $39 to $142. As expected, the deeper the penetration of electrification, the more GHG emissions avoidance.

Table 3: Costs and Avoided Emissions by Selected Scenario

Scenario	**Annual avoided GHG emissions in 2030 ($MMTCO_2e$)***	**% reduction in 2030 compared to a systemwide 1990 baseline***	**% reduction in 2030 compared to a direct emission 1990 baseline***	**Cumulative avoided GHG emissions 2020-2045 ($MMTCO_2e$)**	**Total discounted net costs (Mil. $)**	**Discounted costs per avoided GHG emissions ($/tonne)**
Building Electrification Scenarios						
Minimal: 100% New Construction, 15% Replace on Burnout, 5% Early Retirement, no panel upgrades	7.0 (14.5)	41.2% 47.2%	12.3% (26.1%)	74.2	2,880	$39
Moderate: 100% New Construction, 50% Replace on Burnout, 5% Early Retirement	10.8 (18.3)	44.2% (50.3%)	19.2% (33.0%)	133.5	6,236	$47
Aggressive: 100% New Construction,	18.9	50.8%	34.2%	270.4	37,862	$140

Scenario	Annual avoided GHG emissions in 2030 ($MMTCO_2e$)*	% reduction in 2030 compared to a systemwide 1990 baseline*	% reduction in 2030 compared to a direct emission 1990 baseline*	Cumulative avoided GHG emissions 2020-2045 ($MMTCO_2e$)	Total discounted net costs (Mil. $)	Discounted costs per avoided GHG emissions ($/tonne)
90% Replace on Burnout, 70% Early Retirement	(26.4)	(56.8%)	(48.0%)			
Efficient Aggressive: 100% New Construction, 90% Replace on Burnout, 70% Early Retirement (single-best efficient technology)	19.9 (27.4)	51.6% (57.6%)	36.0% (49.8%)	281.2	39,947	$142
Impact Scenarios						
Accelerated Renewable Electric Generation Resources	3.6 (11.1)	38.5% (44.5%)	--	n.a.	n.a.	n.a.
Electricity Energy Efficiency	1.8 (9.3)	37.5% (43.5%)	--	14.7	-8,338	-$566
Gas Energy Efficiency^	1.5 (9.0)	36.8% (42.8%)	2.2% (16.0%)	17.8	-1,415	-$79
Rooftop Solar PV Systems	0.9 (8.4)	36.3% (42.4%)	--	10.8	-1,715	-$159
Decarbonizing the Gas System: 20% Renewable Gas by 2030 - Low Cost Synthetic Gas starting in 2026#	6.5 (14.0)	40.8% (46.9%)	11.4% (25.2%)	28.1	9,634	$343

* Values in parentheses include the additional annual HFC emissions from buildings mitigated from meeting SB 1383 goals.

^ Assumes the gas equipment is not replaced before the associated useful life has concluded.

Low cost synthetic gas refers to terms used in the CEC report *The Challenges of Retail Gas in California's Low-Carbon Future*, CEC-500-02019-055-F, April 2020.

Source: CEC staff

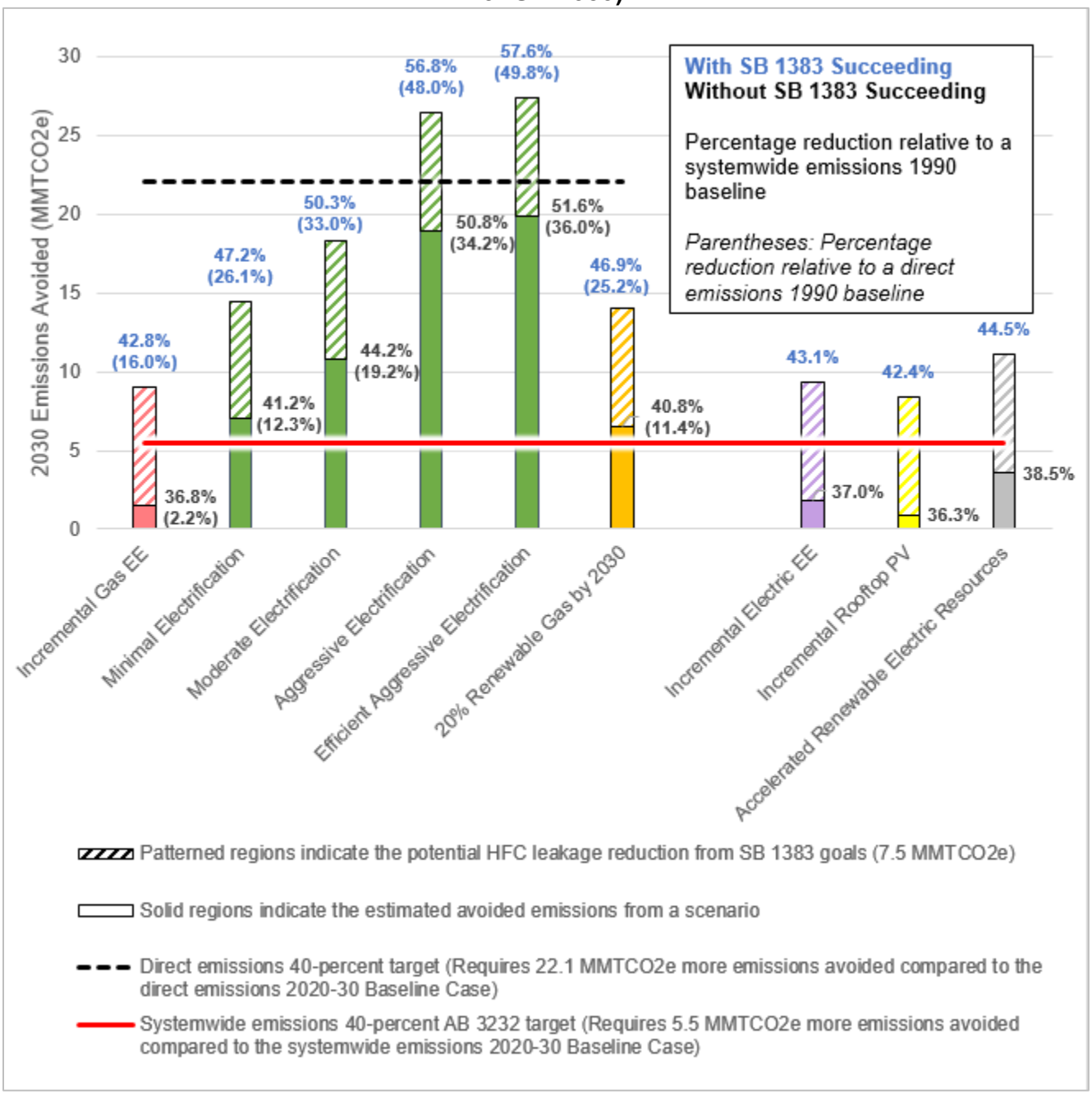
GHG Emission Reductions

Figure 11 illustrates the independent potential impact of each scenario relative to achieving the 2030 40-percent reduction target. **Figure 11** depicts the potential GHG emissions avoided in 2030 in $MMTCO_2e$ and translates the potential impacts in terms of overall percentage reduction relative to the two 1990 GHG emission baselines with and without the success of SB 1383.[51] Since the current analysis examines each strategy independently, the results are not additive. As can be seen in the figure, the four electrification scenarios (represented in green on the far left) have the most potential for not only achieving the 40 percent systemwide emission reduction by 2030 target, but the additional building GHG reduction needed from the residential and commercial sectors to achieve the state's 2045 economywide carbon-neutrality goals. As such, this evaluation places more focus on the electrification scenarios compared to the impact scenarios since they have the clearest pathway in achieving the 40-percent systemwide emission target and California's 2045 climate goals.

51 SB 1383 encompasses many sectors and emission sources. As such, "SB 1383 success" in this report refers to a narrow situation of refrigerant and air-conditioning HFC emissions in residential and commercial buildings declining 40 percent based on 2013 levels, which is different than the legally binding SB 1383 economywide reduction goals in 2030.

Staff estimated this all-or-nothing case of SB 1383 compliance using FSSAT based on data provided by CARB staff. This case reflects the GHG reduction potential in residential and commercial buildings based on policy goals. The FSSAT has a toggle that assumes whether SB 1383 goals are achieved and adjusts the level HFC emissions in buildings but does not model a pathway of achieving that goal.

Figure 11: Annual GHG Reduction for 2030 by Scenario (With and Without the Success of SB 1383)



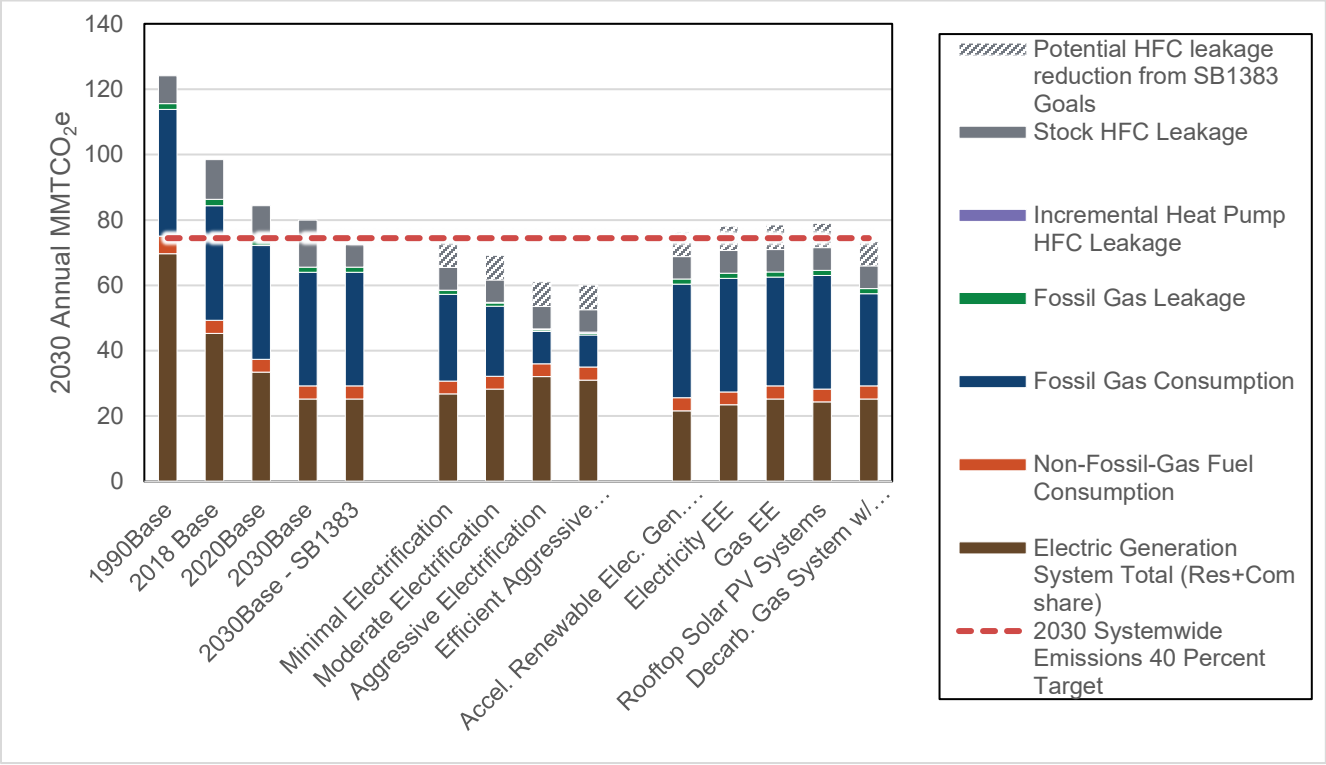
Based on data reported in Table 3 (page 46). Note: Load management strategies can amplify each of these scenarios. Source: CEC staff

The absolute emissions reductions for each scenario are valid independent of the baseline used, though the percentage reduction for a given baseline varies for a given scenario. **Figure 11** makes clear that using the direct (onsite-only) emission baseline, only the two aggressive electrification scenarios when assuming SB 1383 compliance achieve the 40 percent reduction target.

Figure 12 shows the estimated statewide GHG emission impacts in 2030 for the scenarios, relative to the 40 percent systemwide emission reduction target (horizontal line), the 1990 base-year emissions, and the 2030 Baseline Case. The first bar on the left in **Figure 12** illustrates the 1990 GHG systemwide emission base year of 124 $MMTCO_2e$ and implies a 40 percent reduction target of 74 $MMTCO_2e$ for 2030. The next set of four bars shows the historical emission values for 2017 and the 2030 Baseline Case (2030Base) with and without achieving the state goal to reduce HFCs under Senate Bill 1383 (Lara, Chapter 395, Statutes of 2016).

As described in Chapter 2 and shown in **Figure 12**, GHG emissions have decreased from 1990 levels, but additional GHG reduction needs remain when observing the 2030 Baseline Case without SB 1383 succeeding (2030Base). However, as seen with the "2030Base-SB1383" scenario, the state would meet the 2030 building decarbonization goal if SB 1383 goals are achieved independent of other building decarbonization strategies. As seen in **Figure 12,** many of the considered building decarbonization scenarios reduce GHG emissions beyond the 2030 40 percent systemwide emission target, setting California on a pathway to achieve its 2045 climate GHG reduction and zero-carbon system goals.

Figure 12: 2030 Statewide GHG Emissions for Building Decarbonization Scenarios Using a Systemwide Emissions Baseline



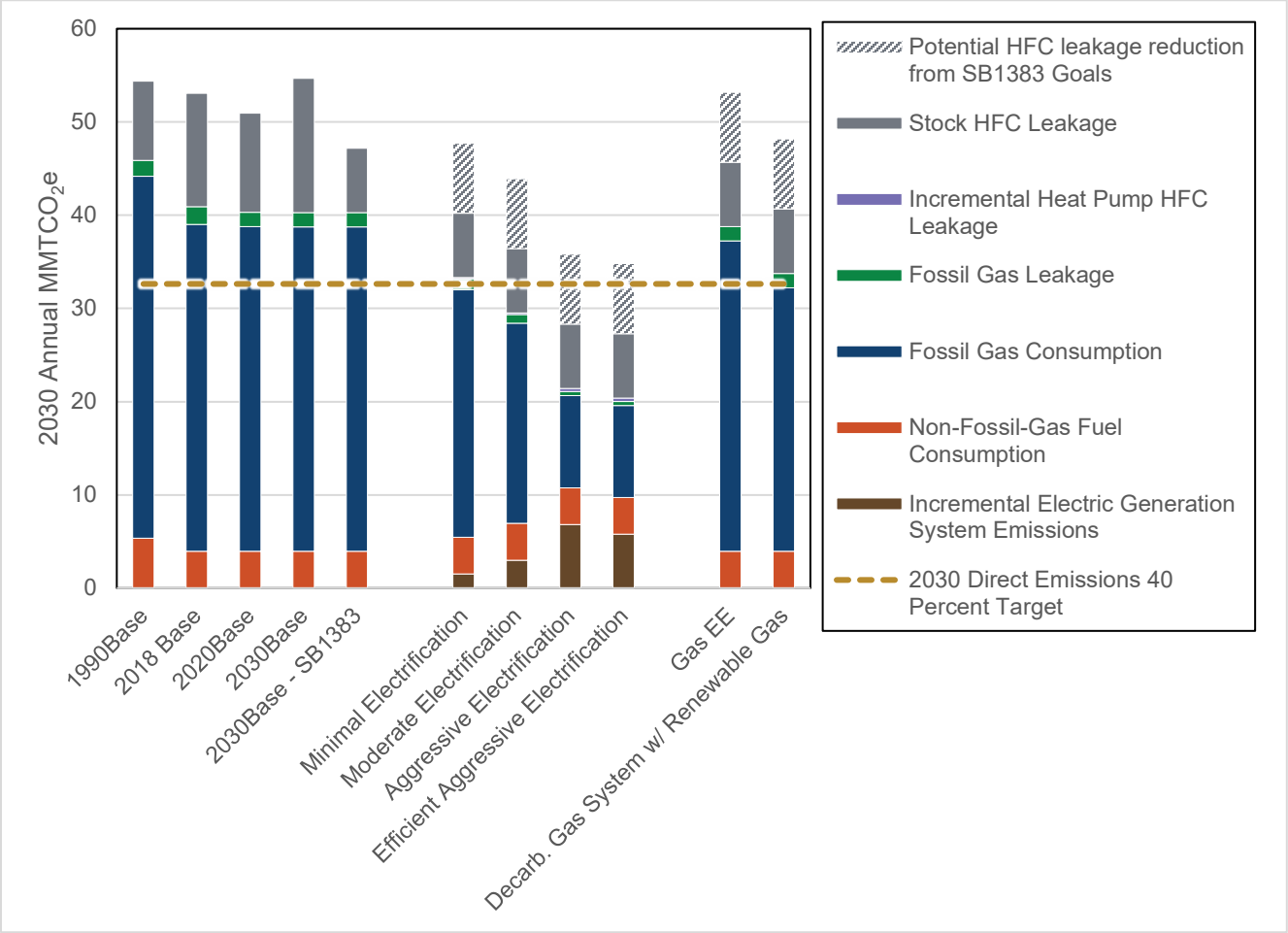
Source: CEC staff using CARB GHG inventory

In addition to the additional impact of meeting SB 1383 goals, **Figure 12** illustrates the potential GHG emission reduction from the impact scenarios compared to electrification

strategies (minimal, moderate, aggressive, and efficient aggressive).[52] The impact scenarios approach the 40 percent target while keeping gas fuel combustion relatively the same, with the exception of the incremental gas energy efficiency scenario. All electrification scenarios (minimal, moderate, aggressive, and efficient aggressive) exceed the 40 percent reduction target while reducing gas fuel combustion. The "minimal electrification" scenario would result in 41.2 percent GHG emission reduction (or 47.4 percent if SB 1383 succeeds), while the "aggressive electrification" scenario would achieve a 50.8 percent GHG emission reduction (or 56.8 percent if SB 1383 succeeds). Between those two scenarios, the "moderate electrification" scenario achieves 44.2 percent GHG emission reduction (or 50.3 percent if SB 1383 succeeds). CEC staff considered modifications to the "aggressive electrification" scenario such as the type of technology replacement and the success of SB 1383 and found that the "efficient aggressive electrification" scenario could achieve a reduction of 57.6 percent compared to 1990 levels. However, as seen in **Figure 13**, which depicts the same impacts relevant for those scenarios using the direct emissions baseline, it is only with the success of SB 1383 that the "aggressive electrification" and "efficient aggressive electrification" scenarios achieve the more aggressive 40 percent direct emissions target.

Figure 13: Building Decarbonization Scenario Results Using a Direct Emissions Baseline

52 Appendix C contains a table with the numerical values underlying **Figure 11**.



Source: CEC staff using CARB GHG inventory

Costs and Cost-Effectiveness

AB 3232 directs the CEC to evaluate the cost per metric ton of CO_2 equivalent of the potential building decarbonization strategies relative to other statewide GHG reduction strategies. It also directs the CEC to consider the cost-effectiveness of strategies to reduce GHGs from space and water heating. This assessment applies a similar definition of cost-effectiveness as the CARB *2017 Climate Change Scoping Plan Update*, which is based on AB 32 and Assembly Bill 197 (E. Garcia, Chapter 250, Statutes of 2016). Unlike common energy efficiency cost-effectiveness tests, cost-effectiveness defined in this assessment "means the relative cost per metric ton of various GHG reduction strategies, which is the traditional cost metric associated with emission control."[53] This evaluation excludes any additional estimations of the benefits (that is, the

53 *California's 2017 Climate Change Scoping Plan.* California Air Resources Board. November 2017. Page 44 https://ww2.arb.ca.gov/sites/default/files/classic//cc/scopingplan/scoping_plan_2017.pdf.

valuation of the social cost of carbon, as well as health and other benefits) from potential emission and pollution abatement.

The approach of this assessment of examining the costs and cost-effectiveness of emission abatement contrasts with the CPUC's approach of assessing its demand-side management programs. The CPUC's cost-effectiveness analysis estimates the costs and benefits and uses tests based on the *California Standard Practice Manual*.[54] This assessment does not evaluate any benefits from pollution abatement and does not use any such cost-effectiveness tests. Instead, it applies a more basic approach of comparing the relative cost per metric ton of the various decarbonization strategies.

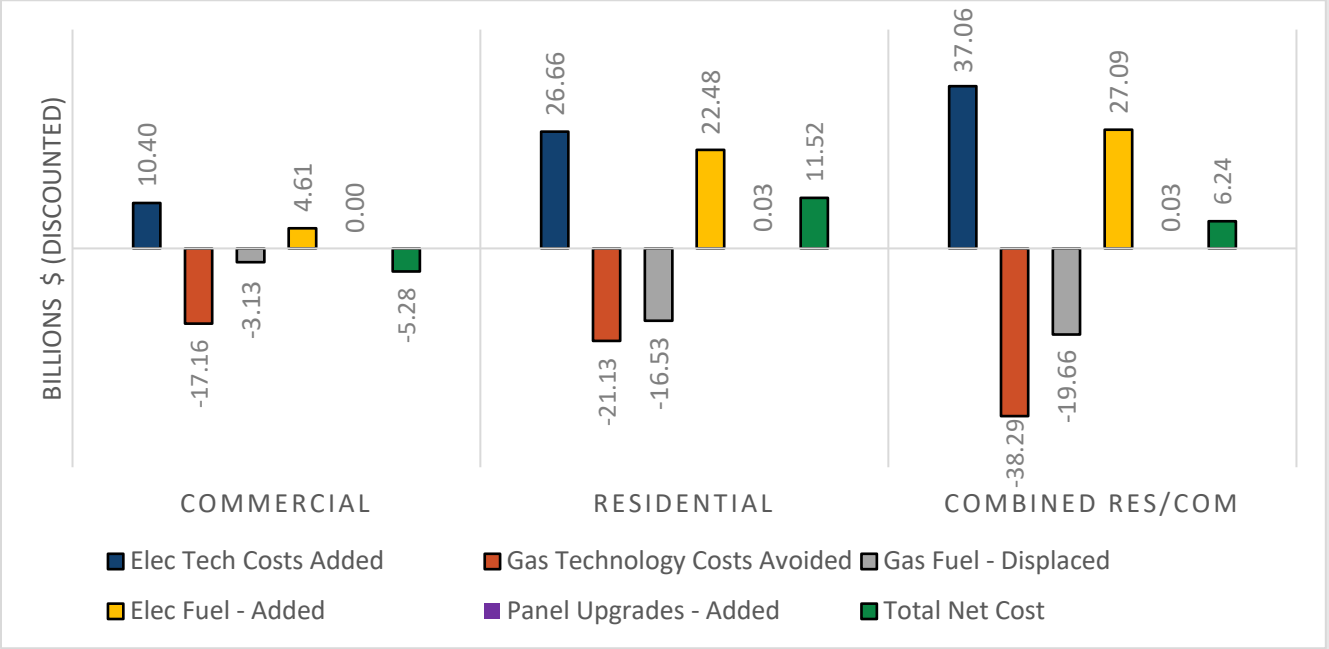
Costs

The analysis evaluated electric technology costs added and gas technology costs avoided. For technology cost, this analysis includes three elements — the equipment, the labor cost to install it, and the profit required by the installing contractor. Gas technologies consume gas, so there are avoided gas operating costs quantified using average gas prices by customer class for each utility service area from the *2019 IEPR* demand forecast. For electric technologies added, there are annual electric consumption costs quantified using *2019 IEPR* average electricity prices by customer class for each utility service area. Some residential sector electric technology installations impose an electric service panel upgrade, so there are panel upgrade costs just for the residential sector. All these cost elements add up to a total net cost or a total net savings depending upon many detailed assumptions.

Figure 14 illustrates the cumulative total net cost, split up by incremental technology and net fuel cost, and sector for the "moderate electrification" scenario. Ancillary costs, like electrical panel upgrades, are shown for the residential sector. The incremental technology costs are represented by the first two bars for a sector, where the blue bar represents the electric technology cost added, and the orange bar represents the avoided gas technology costs. The equipment, installation, and contractor overhead and profit costs represent the total added electric technology costs. Avoided gas technology costs are broken down by labor and technology costs, which also include avoided air-conditioner costs for certain types of replacements. These costs exclude any avoided infrastructure costs.

Figure 14: Moderate Electrification Scenario Cumulative Costs by Category and Customer Sector for 2020 Through 2030

54 See the CPUC's cost-effectiveness analysis webpage for more information on how they evaluate their demand-side management programs: https://www.cpuc.ca.gov/general.aspx?id=5267.



Source: CEC staff

As can be seen for the combined residential and commercial sector bars on the right in **Figure 14**, the incremental technology costs for this scenario are negative $1.23 billion. The grey and gold bars represent the displaced gas fuel costs and the electric fuel costs of using the added equipment. Together, they represent the net operational fuel costs, which depend on the efficiency of the equipment and the input forecast of rates for electricity and gas.[55] For the "moderate electrification" scenario, the net operational costs total $7.44 billion. Taken together, along with the electric panel upgrade costs of $30 million, the net total costs for the "moderate electrification" scenario are $6.24 billion. No electric panel upgrade costs occur in the "minimal electrification" scenario. Of the additional electrification scenarios CEC staff explored in the appendix beyond the set of four electrification scenarios, electric panel upgrade costs range from $30 million to $2.3 billion, which adds roughly $1 to $9 to the cost per metric ton for an entire scenario. Additional details on panel upgrades are provided in Appendix C.

In September 2020, the Sacramento Municipal Utility District (SMUD) submitted to the docket its programwide aggregated average costs for its heat pump water heater and space heating heat pump programs that the utility has been running since 2018 and 2019. These costs are comparable to what CEC staff is assuming for retrofit costs in the FSSAT. For example, the

55 When comparing the costs of the "aggressive electrification" and "efficient aggressive electrification" scenarios, the efficiency gains from the "efficient aggressive electrification" scenario yielded net operational fuel costs decreasing by $11.6 billion (discounted 2020 $).

average gas-to-electric 50-gallon heat pump water heater project costs is $4,155 per unit, which is comparable to what to the input assumptions for the FSSAT analysis.[56]

Comments from stakeholders received following the June 9, 2020, CEC workshop discussed how market transformation efforts could influence total net costs and how the collective effects from electrification can influence electric and gas rates.[57] Comments from the Natural Resources Defense Council argue for the strong need to incorporate market transformation of clean energy technologies into the cost estimation. The FSSAT currently cannot model such transformation, but using **Figure 14** and other scenarios, staff estimated in Appendix C equipment cost-reduction impacts by 20 and 30 percent when modeling electric technology costs. By decreasing the added electric technology costs, the incremental technology costs drop lower, driving total net costs and dollar-per-ton estimates down.

Marginal Abatement Costs of Carbon Reductions

Marginal abatement cost curves (MAC curves) plot the marginal costs of achieving a cumulative amount of emission abatement in order from the least- to most-expensive scenario, measure, or technology. MAC curves show emission abatement potential and associated abatement costs but should be considered alongside other evidence when weighing the merits of numerous climate change mitigation strategies. Interpreting decarbonization MAC curves can be challenging because measures should interact with each other and the reported costs are likely not fixed over time. As such, since all scenarios were derived independently, aggregating the costs and impacts of selected scenarios to derive a unique new strategy is analytically challenging and would require a great deal of caution and consideration.

Estimates of the cost per metric ton must be interpreted carefully, particularly when comparing to other studies, since different assumptions can change the scope and magnitude of the evaluation. For example, the costs-per-metric-ton estimates here *exclude* upstream methane abatement and avoided infrastructure costs upstream from a building. Most of the building decarbonization scenarios assume activities and technology replacement happening until 2030, while the GHG emission and cost impacts accrue beyond 2030 to 2045. As such, the dollar-per-ton cost estimates are reported and compared to a 2045 time horizon. These costs include the annualized incremental technology costs over the life of the equipment and the operational fuel costs (or savings) of using the equipment. The total costs are discounted using a 10 percent discount rate, which is the same rate used in the *2017 Scoping Plan Update* and reflects the opportunity cost of capital to firms and households. Since costs occur across the

56 Sacramento Municipal Utility District Comments – SMUD Residential Electrification Project Costs (September 22, 2020). Docket Number 19-DECARB-01, September 22, 2020. https://efiling.energy.ca.gov/GetDocument.aspx?tn=234862&DocumentContentId=67717.

57 September NRDC comment submitted to the docket: https://efiling.energy.ca.gov/GetDocument.aspx?tn=234687&DocumentContentId=67539.

2045 time frame, this discounting of costs allows a common apples-to-apples metric, the present value, which is used to compare costs across measures.

Another reason for interpreting cost per metric ton estimates carefully is when inferring the implications of negative abatement costs. Economists are typically skeptical of such "free lunch" estimates since they suggest poor decision-making by firms and individuals. However, these estimates, like those in this assessment, do not include behavioral considerations of individuals and that these savings may be potentially valid but may be difficult to realize out in the field.[58]

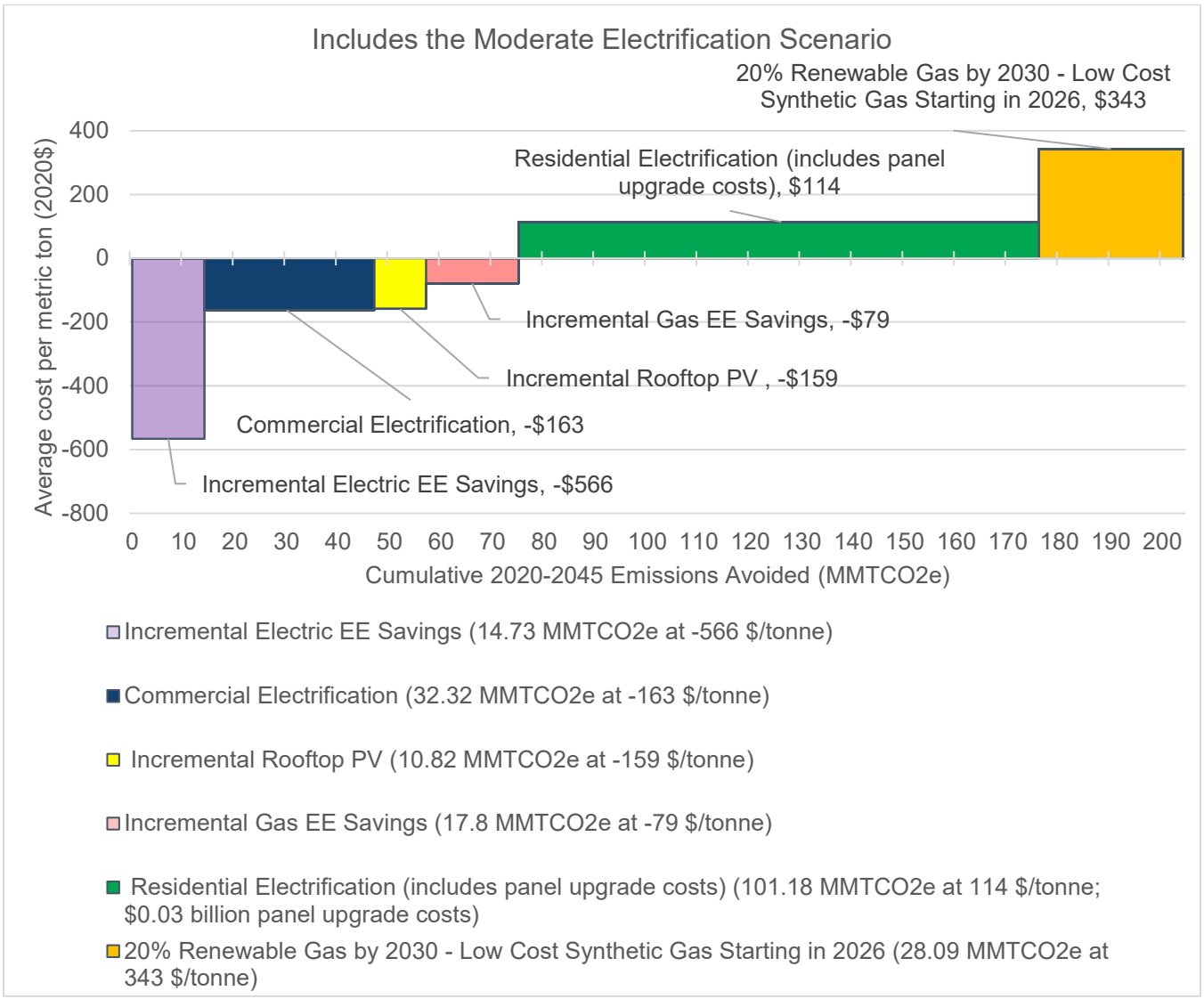
Figure 15 and **Figure 16** report the aggregated MAC curves for the "moderate electrification" and "aggressive electrification" scenarios, respectively. They also include the other building decarbonization scenarios and provide several insights:

- The combined GHG reduction potential of electrification from both sectors is either competitive or significantly outweighs the combined GHG reduction potential from all but the electrification scenarios.
- The highest GHG reduction potential is electrification occurring in the residential sector.
- The abatement costs for electrification in the commercial sector are negative and are even more negative than the incremental gas energy efficiency scenario and incremental rooftop PV systems for the "moderate electrification" scenario.
- The marginal abatement costs for each sector increase as electrification penetration increases.
- Incremental electric energy efficiency is the most cost-effective scenario, while the renewable gas scenario is the least cost-effective scenario.

The insights from these MAC curves demonstrate the cost-effectiveness and potential GHG reduction of strategies relative to GHG reduction strategies examined in this report. Additional details on marginal abatement cost results, along with electrification abatement potential and relative cost-effectiveness by sector and end use, are explored.

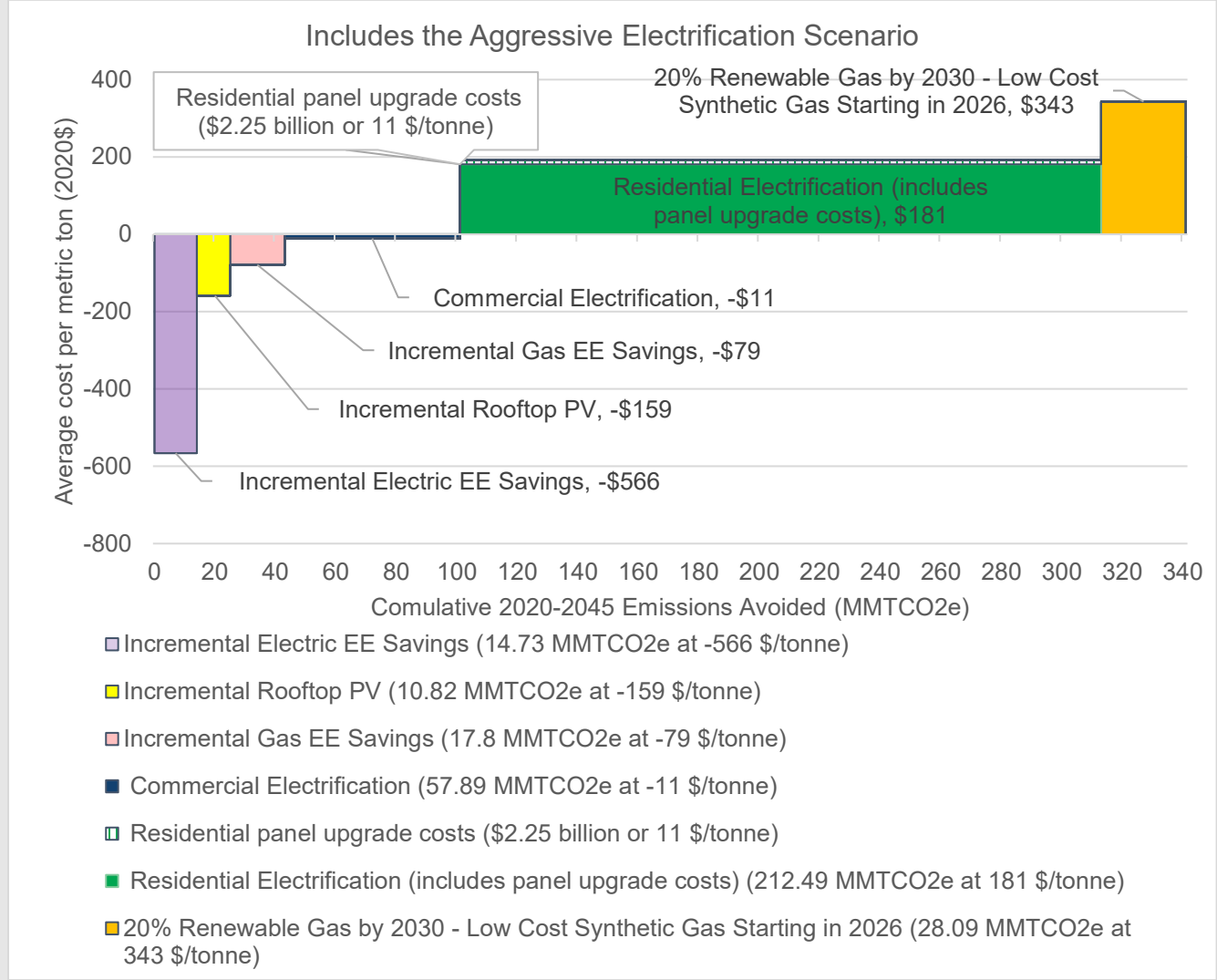
Figure 15: Aggregated MAC Curve Using Moderate Electrification Scenario (100 Percent NC, 50 Percent ROB, 5 Percent RET)

58 See pp 55-57 in Gillingham and Stock (2018) for how economists view negative abatement costs estimates. Gillingham, K., & Stock, J. H. (2018). "The Cost of Reducing Greenhouse Gas Emissions." *Journal of Economic Perspectives*, 32(4), 53-72.



Source: CEC staff

Figure 16: Aggregated MAC Curve Using Aggressive Electrification Scenario (100 Percent NC, 90 Percent ROB, 70 Percent RET)



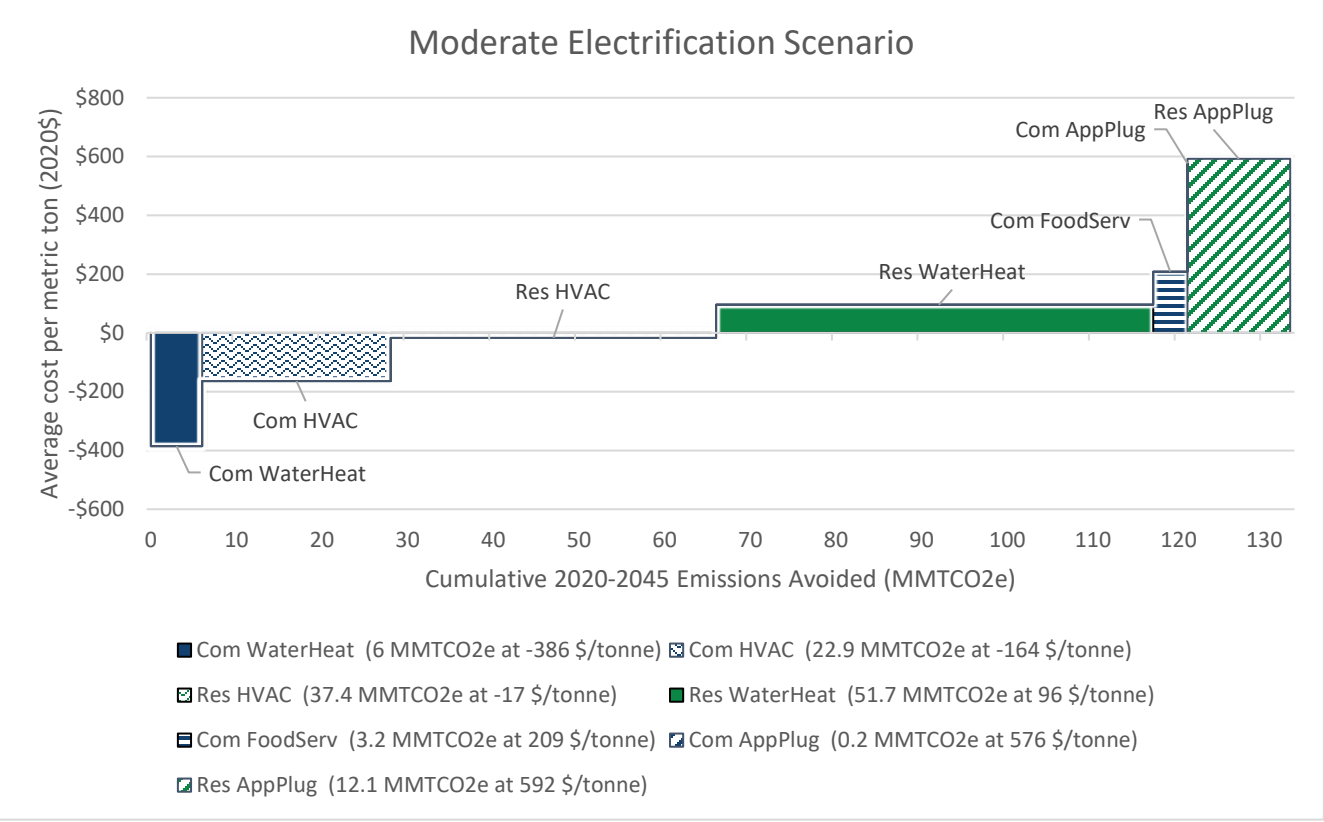
Source: CEC staff

Figure 17 further breaks down the electrification abatement potential by end use and shows the relative cost-effectiveness of electrification by sector and end use for the "moderate electrification" scenario.[59] Since these costs include new and existing residential and commercial buildings, they can help assess the cost-effectiveness of strategies that target

59 Electrical panel upgrade costs are estimated to not occur in the "minimal electrification" scenario and do not affect dollar-per-ton estimates. However, since electric panel upgrade costs cannot be reported at the technology or end-use level, any dollar-per-ton estimates at this level of disaggregation would underreport the costs for scenarios that require electrical panel upgrades. (Please refer to the appendix for MAC curves by end-use for other electrification scenarios.)

space and water heating. As reported earlier in **Table 3**, the estimated dollar-per-ton value for the "moderate electrification" scenario is $47 per ton (that is, the weighted average of dollar-per-ton estimates by end use, including electrical panel upgrade costs). Seeing the breakdown of the GHG abatement potential of a sector by end use, as seen in **Figure 17,** provides several observations. First, commercial water heating is the most cost-effective, and the associated large negative dollar-per-ton estimate (-$386 per ton) helps explain why the entire commercial sector reported has a negative abatement cost estimate. Second, residential HVAC and water heating potentials have the largest potential of GHG emission reduction and have costs below $100 per ton, negative $17 for residential HVAC and $96 per ton for residential water heating. Third, electrification of residential and commercial appliance end uses (such as laundry and cooking) are estimated to be the least cost-effective where the dollar-per-ton estimates are greater than $575 dollars per ton, which is an order of magnitude greater than other end-use estimates. CEC staff believes that the present technology replacement assumptions for the laundry and cooking end uses are aggressive and are likely driving up these costs.

Figure 17: MAC Curve by End Use for Moderate Electrification Scenario (100 Percent NC, 50 Percent ROB, 5 Percent RET)



Source: CEC staff

Taken together, the summary of costs for each scenario in **Table 3**, the aggregated MAC curves in **Figure 15** and **Figure 16**, and the MAC curve by sector and end use in **Figure 17** provide the tools needed to help evaluate the cost-effectiveness of building decarbonization.

Many of the scenarios along with the "minimal electrification" and "moderate electrification" scenarios have cost-per-metric-ton estimates of less than $50 per ton. The renewable gas impact scenario has a higher estimate, almost $350 per ton. Understanding the disaggregated cost per metric ton estimates at the end-use or technology level can help state policy makers prioritize where to target electrification efforts and which pathways need more research and development to improve cost-effectiveness.

Building Decarbonization Versus Other GHG Reduction Strategies

CEC staff used the CARB *2017 Climate Change Scoping Plan* to evaluate and compare the cost-per-metric-ton estimates of the AB 3232 analysis to other statewide GHG reduction strategies.[60] The estimates appear similar across studies. For example, CARB reports negative abatement costs (-$300 to -$200 per ton) for energy efficiency measures. It also reports that combined energy efficiency and building electrification measures have negative abatement costs (-$120 to -$70 per ton). Likely examining the building electrification cost-effectiveness independent of energy efficiency would reveal comparable results as reported for AB 3232.

Some of the other statewide GHG reduction measures estimated in the *2017 Climate Change Scoping Plan* were mobile sources clean fuels technology and freight, liquid biofuels (18 percent carbon-intensity reduction target for the Low Carbon Fuels Standard), and a short-lived climate pollutant strategy measure. No estimates from agricultural or soil management measures were reported. The cost-per-metric-ton estimates for these measures are less than $50 per ton for the clean fuels technology measure, $100 to $200 per ton for the liquid biofuels measure, and $25 per ton for the short-lived climate pollutant strategy. CARB's building decarbonization abatement estimates are similar or more cost-effective than some of these statewide measures. The cost per ton assessed for the "moderate electrification" scenario is cost-effective relative to measures outside the buildings sector domain.[61]

The CEC will be providing an expanded analysis of the potential impact of emission reduction — strategies on new construction costs in the *2021 IEPR*. This analysis will be consistent and align with the analysis being developed as part of the 2022 Energy Code.

60 See Table 10 in *California's 2017 Climate Change Scoping Plan*. California Air Resources Board. November 2017. Pages 44–46. https://ww2.arb.ca.gov/sites/default/files/classic//cc/scopingplan/scoping_plan_2017.pdf.

61 Comparing across studies may not provide a direct comparison. These other studies may have different cost and discounting assumptions and may be examining different scopes of potential total emission abatement.

CHAPTER 4:
Electricity Generation and Gas System Impacts

This chapter presents the results of analysis to determine how the various building decarbonization strategies impact the electricity generation and gas system. Since decarbonizing the electricity generation systems is needed to enable building decarbonization pathways, analyzing the impact of building decarbonization strategies on the electricity generation and gas system is critical to the AB 3232 assessment.

Electricity Generation System Impacts

Building decarbonization scenarios that change electric loads also result in changes in GHG emissions from the electricity generation system. To analyze these changes, staff developed an appropriate business-as-usual electric generation resource mix through 2030 based on the *2019 IEPR* mid-mid demand case. CEC staff then used a production cost model with an hourly resolution to simulate the operation of that resource mix on an hourly basis to determine fuel combustion and resulting GHG emissions. This modeling was done on a statewide basis rather than satisfying load and resource balances and planning reserve margin criteria by utility service area.

CEC built a modified resource mix for each scenario for electrification, increased energy efficiency, PV, and renewable resources by adding necessary renewable generating resources to satisfy the RPS requirements of SB 100, and then adding battery capacity to generally satisfy planning reserve margins on a statewide basis.[62] For each scenario analyzed, changes to the electricity generation system were limited to those for different levels of load, renewable resource capacities, and battery storage capacities. All other inputs and assumptions remained unchanged, which allowed comparison of building decarbonization impacts on electric generation fuel use and GHG emissions for each scenario relative to the business-as-usual case.

GHG emission projections are calculated hourly for the base case and each scenario. An average annual emission intensity is calculated for each scenario, taking hourly load changes into account. The metric is based on in-state generation from GHG-emitting generators and imported energy. The GHG emission calculation is based on the CO_2e content of each fuel, while the import calculation is based on the assumed emission intensity of the energy imported from each region. Additional details on the production cost simulation modeling method used for the analysis along with the inputs and assumptions used in analyses are provided in Appendix C.

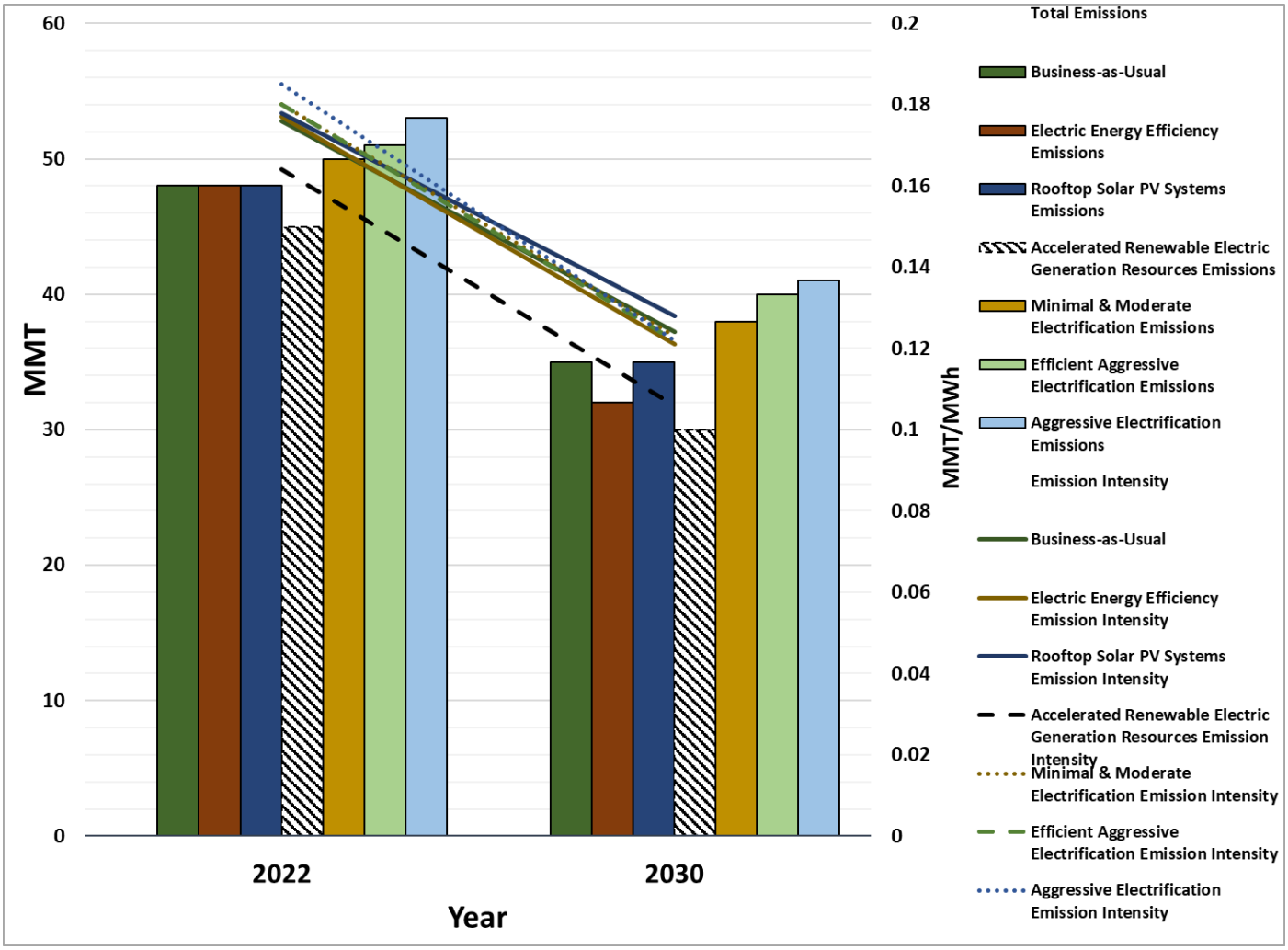
62 Since RPS requirements are based on a percentage of retail sales, the amount of renewable resources to meet the requirement change in the different scenario analyzed.

Since AB 3232 focuses on the GHG emissions associated with residential and commercial buildings, staff identified the subset of emissions attributed to this load from the total electric generation system emissions. CEC computed the scenario-specific residential and commercial share of total annual electric energy to determine GHG emissions from the residential and commercial sectors applicable to any desired scenario. As electrification scenarios add increasing amounts of electric load, all this load is attributed to residential and commercial buildings, and the share of this load increases through time. The additional postprocessing to assess the changes to residential and commercial building GHG emissions is described in Appendix C.

Electric Generation System GHG Emissions

Figure 18 shows the change in projected annual electric generation system emissions for each building decarbonization scenario. Even with the total annual emissions increase caused by the additional demand, the system average emission intensity projections are similar except for the accelerated renewable electric generation resources scenario. That input assumption alone significantly lowers the annual and system average emission intensity.

Figure 18: Projected Electric Generation Sector California GHG Emissions and Emission Intensity



Source: CEC staff

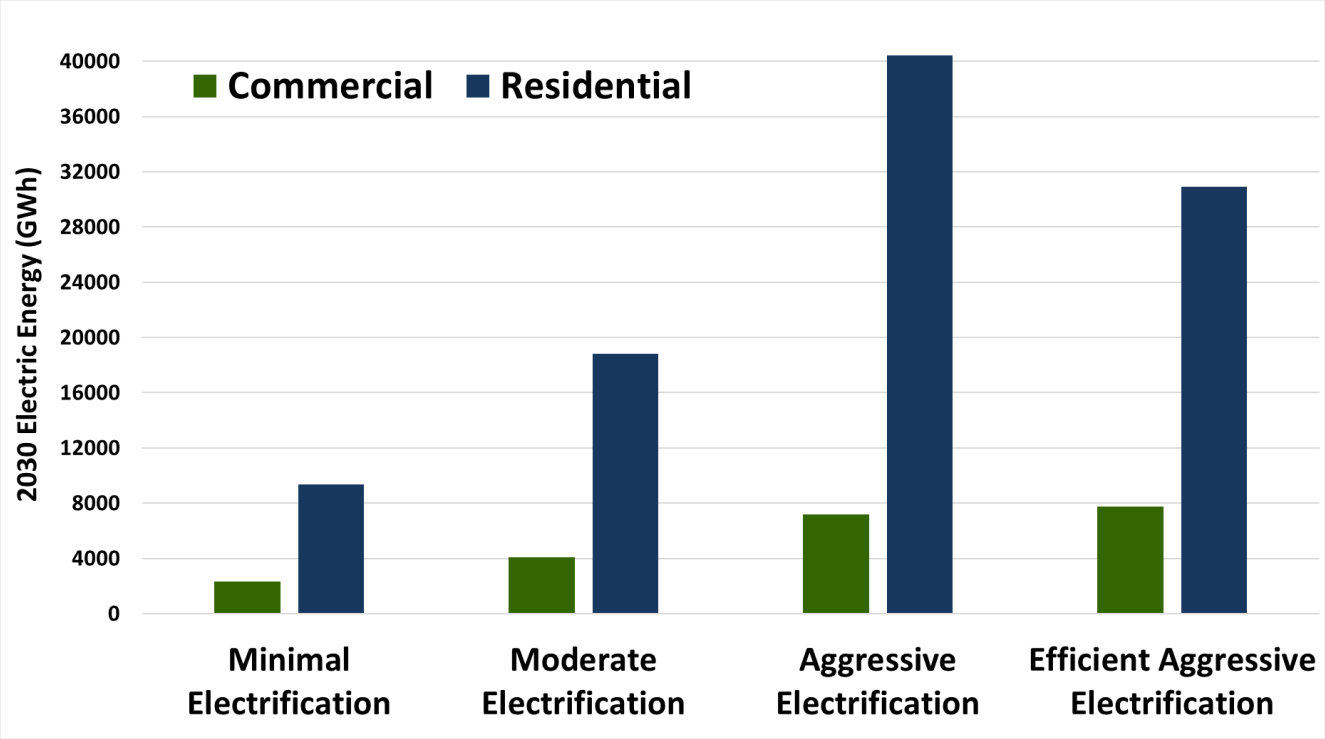
Annual Electricity Impacts

For the electrification scenarios, staff used FSSAT tool described in Chapter 3 to determine the incremental electric energy added as a result of the technology substitutions specified in the scenarios. The output is generated with the granularity of utility, sector, end use, and technology. As shown in **Figure 19**, it is apparent that all electrification scenarios, from low to high penetration, result in the addition of substantial incremental electric energy; generally, the more gas displaced, the more incremental electricity additions.

The "minimal electrification" scenario is shown in the leftmost column of **Figure 19**. It adds 3 to 9 percent of the baseline electricity consumption forecast in 2030 for the commercial and residential sectors, respectively, while in the "moderate electrification" scenario, left center, 5 to 19 percent are added. In the "aggressive electrification" scenario, shown in the right center column of **Figure 19**, electrification efforts add 8 to 40 percent of the baseline electricity consumption forecast in 2030 for the commercial and residential sectors, respectively. The rightmost column of **Figure 19** portrays the incremental electricity added in 2030 because of "efficient aggressive electrification" scenario. For this case, less incremental electricity is added

as compared to the "aggressive electrification" scenario, even though the amounts of gas displaced are identical; only 8 to 31 percent of the baseline electricity consumption forecast in 2030 for the commercial and residential sectors is added, respectively.

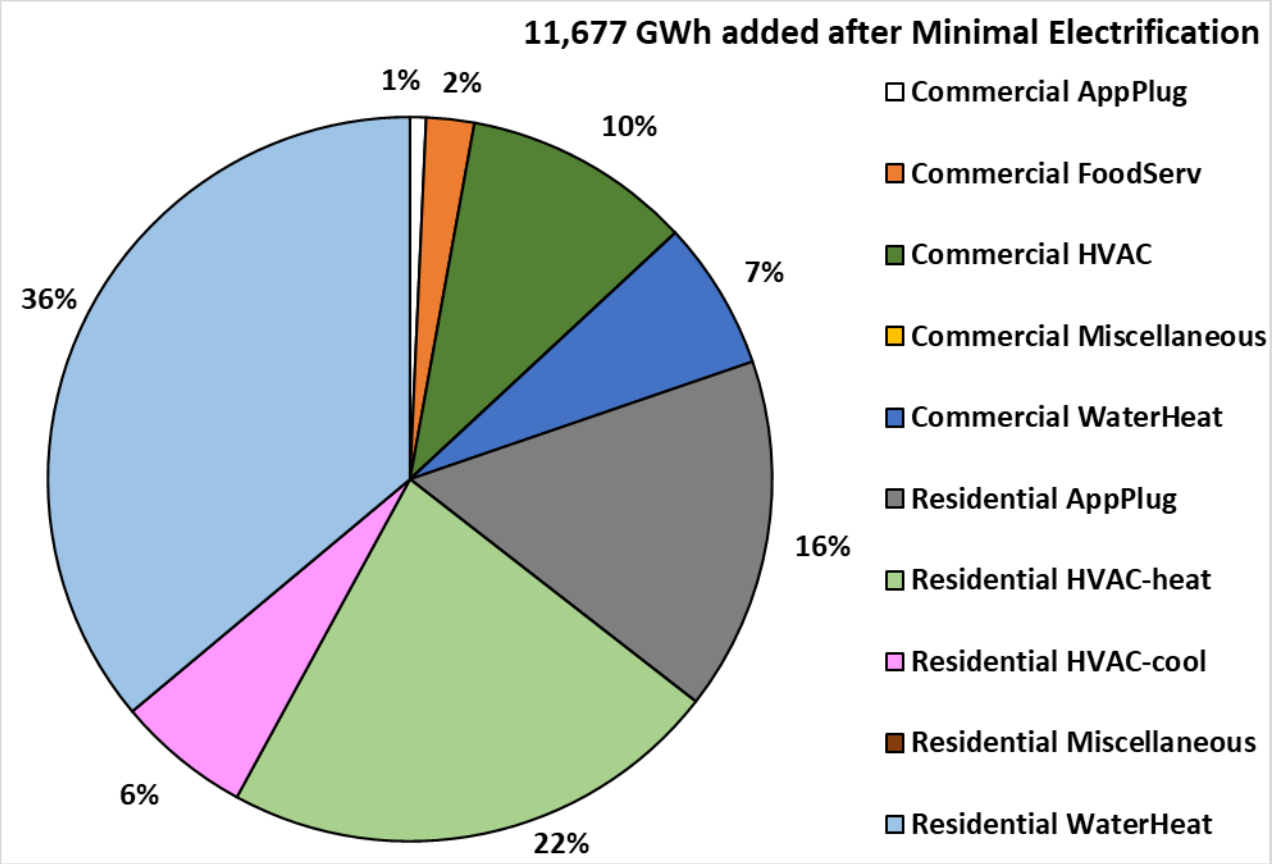
Figure 19: Statewide Annual Incremental Electricity Demand Added by Scenario-Specific Electrification in 2030



Source: CEC staff

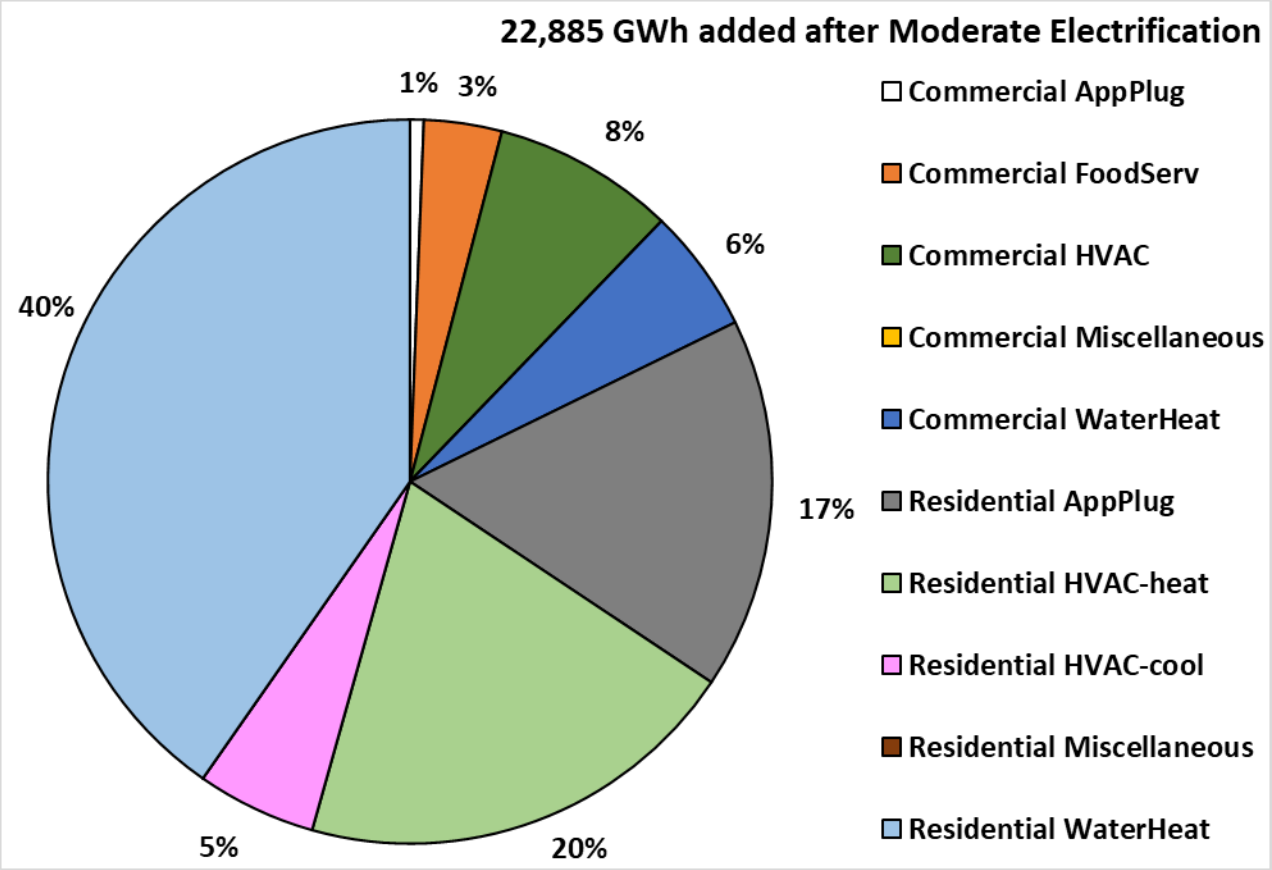
The incremental added electricity consumption after the "minimal electrification" scenario is 11,677 GWh in 2030, and the end-use breakdown is shown in **Figure 20**. Similarly, the end-use breakdown for the "moderate electrification" scenario is shown in **Figure 21.**

Figure 20: 2030 Incremental Electricity Added in the Minimal Electrification Scenario



Source: CEC staff

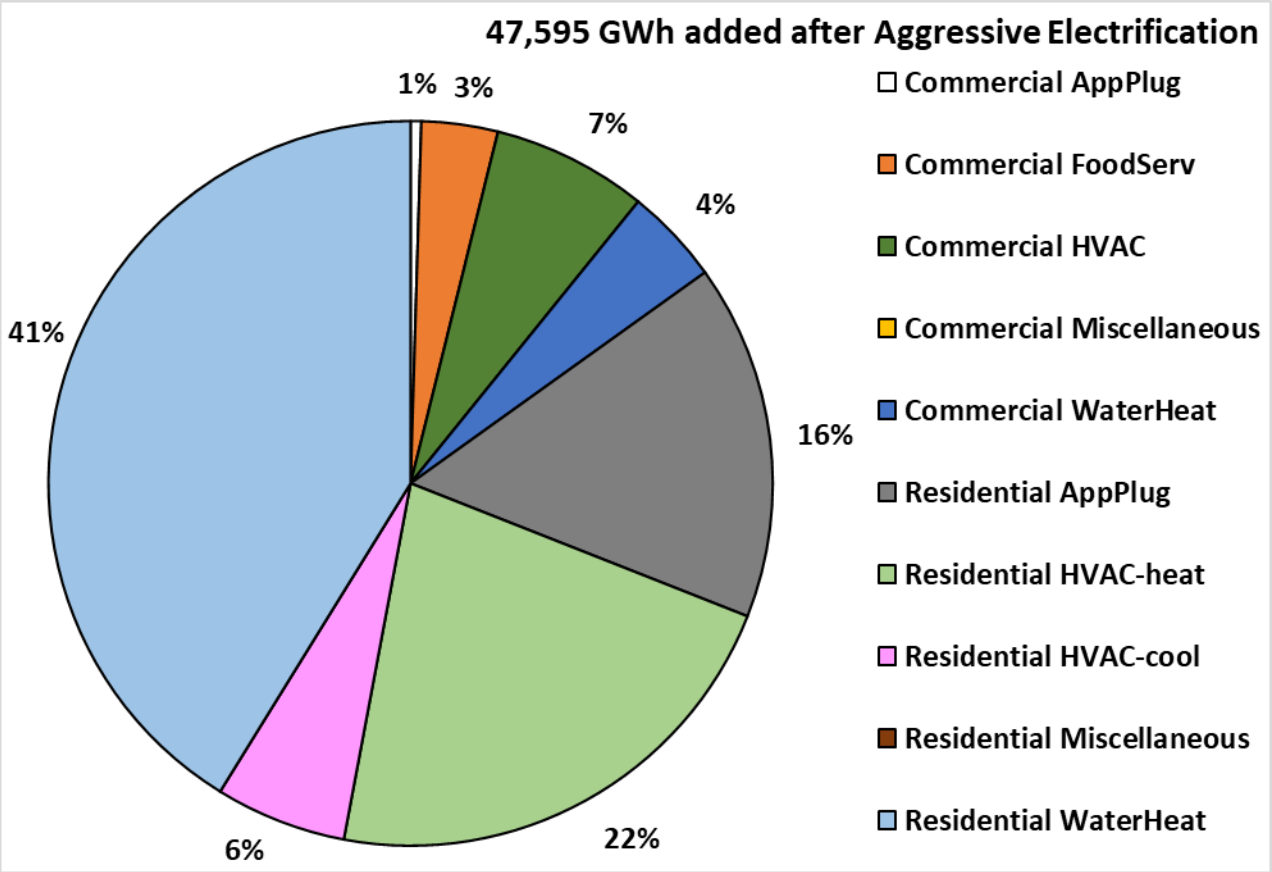
Figure 21: 2030 Incremental Electricity Added in the Moderate Electrification Scenario



Source: CEC staff

The incremental added electricity consumption after the "aggressive electrification" scenario is 47,595 GWh in 2030, and the end-use breakdown is shown in **Figure 22**. In the commercial sector, 74 percent of the incremental electricity added is from water heating and space conditioning and similarly 81 percent of the incremental electricity added in the residential sector is in the same end uses.

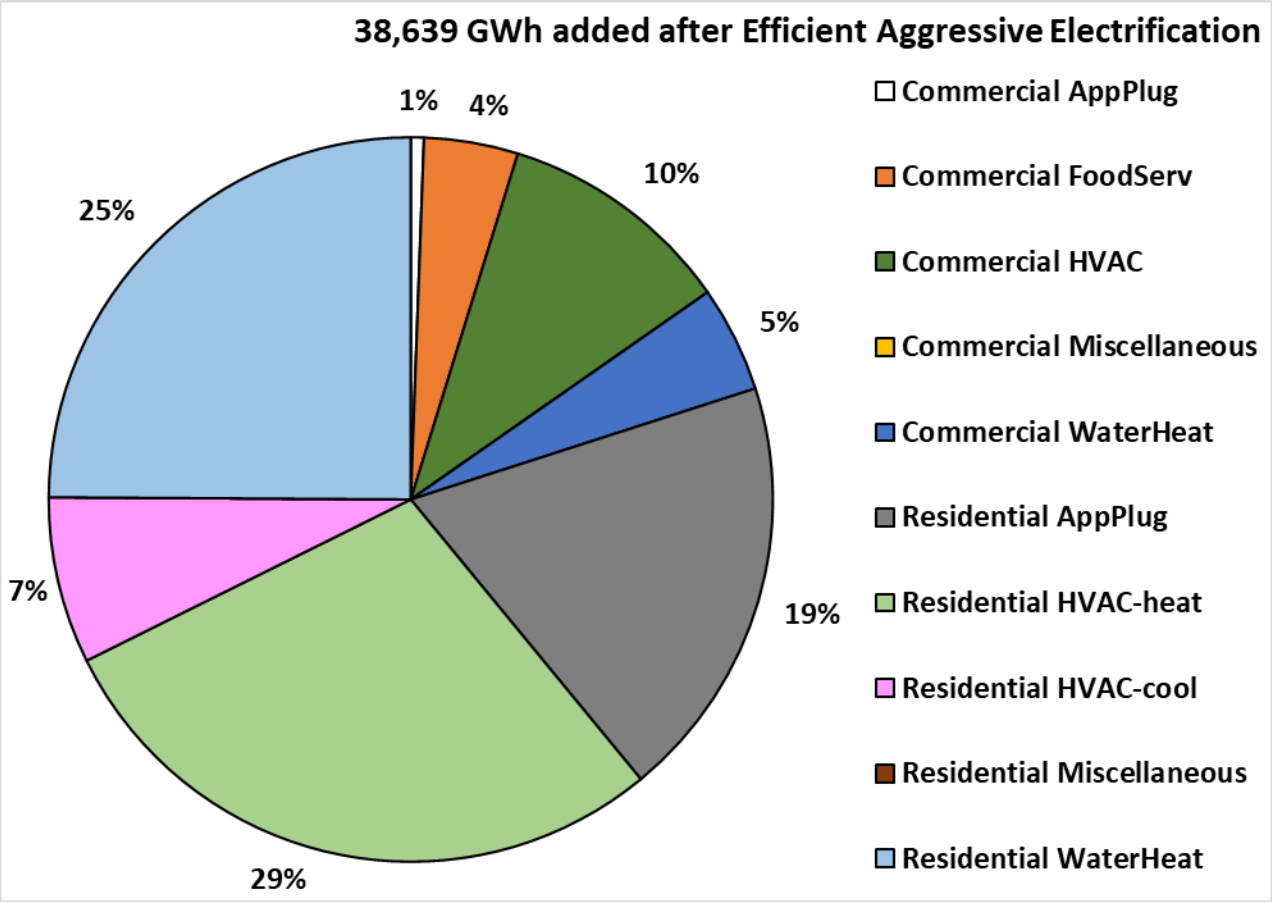
Figure 22: 2030 Incremental Electricity Added in the Aggressive Electrification Scenario



Source: CEC staff

An efficient variation of the "aggressive electrification" scenario, in which only the best technology from the high-efficiency technology mix is installed, is broken down in **Figure 23**. The residential sector constitutes slightly less of the incremental electric added at 75 percent, and the total is also less at 38,639 GWh. The distribution from water heating and space conditioning stays steady at 87 percent for the commercial sector and 78 percent for the residential sector, but the amount of incremental electricity added by water heating relative to space conditioning is less for both. All the effects described for the "efficient aggressive" and the "aggressive electrification" scenarios above are apparent but less pronounced for the "minimal electrification" and "moderate electrification" scenarios. These scenarios are explored in detail in Appendix C.

Figure 23: Incremental Electricity Added in Efficient Aggressive Electrification Scenario



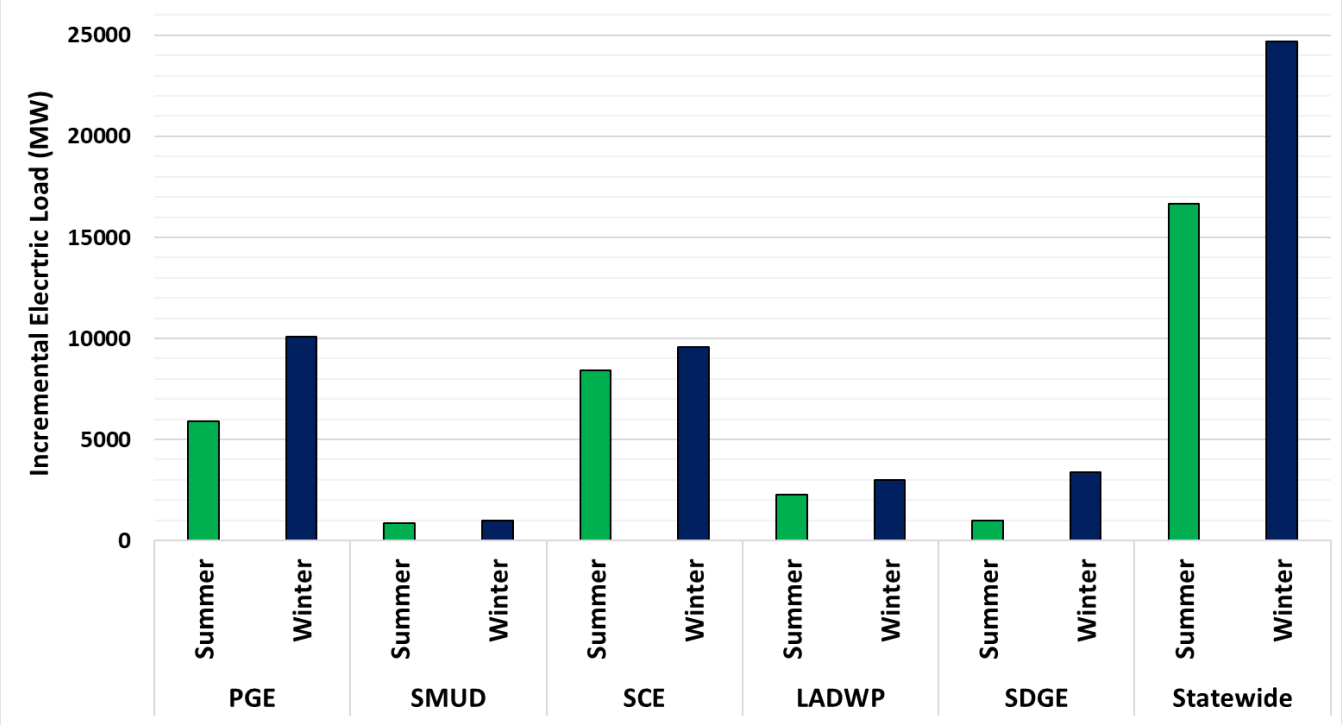
Source: CEC staff

Hourly Electricity Impacts

In addition to reporting annual incremental electricity impacts due to electrification, the FSSAT includes an optional hourly load-impact module that combines annual incremental electric energy at the sector, end-use, and technology levels with an hourly load profile to develop hourly loads at the same level of granularity for each major electric utility. These disaggregated hourly impacts are summed across each sector, end use, and technology level to develop combined load impacts for each major electric utility.

The tool estimates incremental space-conditioning load for existing homes that did not have air conditioning but will gain this capability when a heat pump replaces the gas space-heating equipment. Both summer and winter incremental loads grow for all electrification scenarios studied. The impacts vary from being small in the "minimal electrification" and "moderate electrification" scenarios to visible in the "aggressive electrification" scenario. Winter loads continue to increase more than summer loads in all scenarios and over all utilities. The latter is demonstrated explicitly in **Figure 24** for the "aggressive electrification" scenario with a mix of technologies in 2030.

Figure 24: 2030 Seasonal Maximum Incremental Load for the Aggressive Electrification Scenario by Utility and Statewide



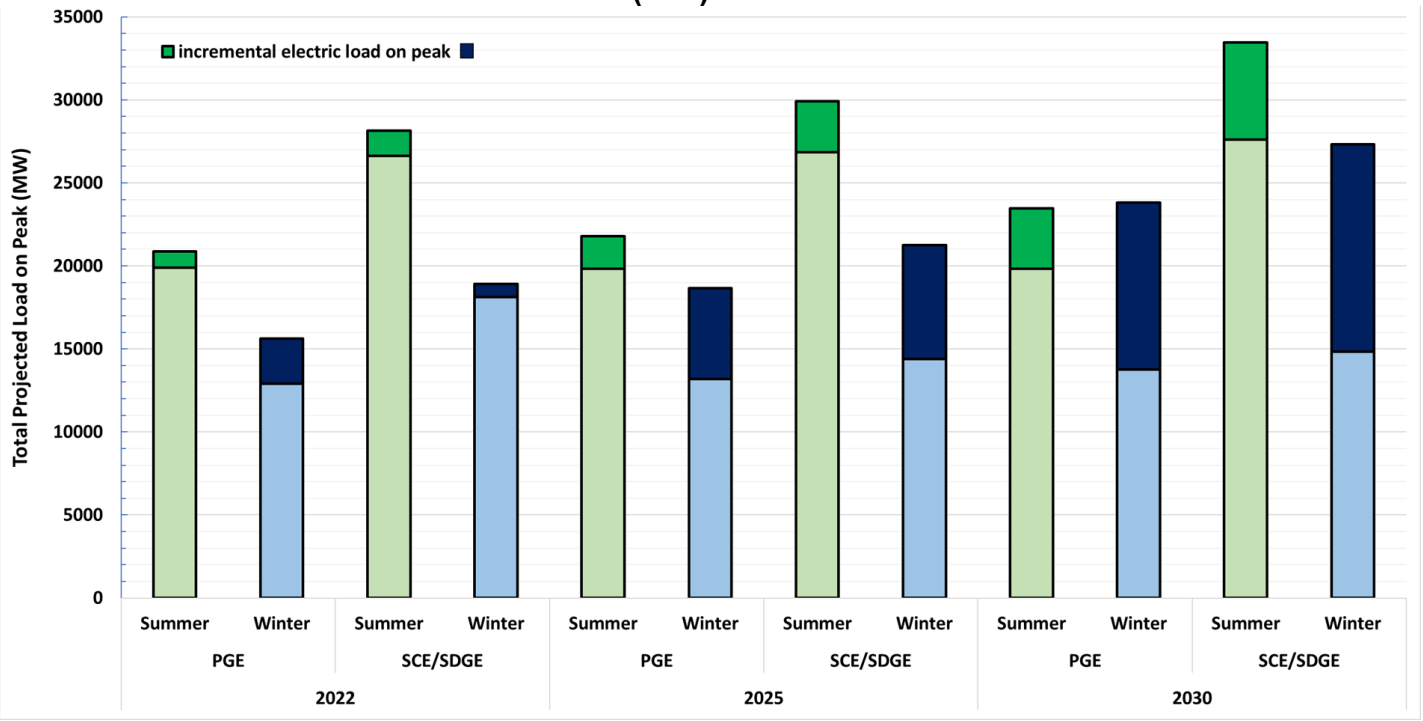
Source: CEC staff

The full impact of added electricity from electrification can be assessed only when measured against the baseline loads. This assessment is necessary when considering grid-reliability in an electrified future. Like the "business-as-usual" case, where various load modifiers are incorporated with the baseline consumption forecast to create a managed forecast, this assessment can be accomplished annually, as well as hourly. In the annual case, the percentage of baseline load added by electrification was reported in **Figure 19.** For the hourly impacts, CEC modified the baseline load forecast and analyzed the peak-load dates, hours, and magnitudes by season.

Electrification results in increased peak loads and increases the magnitude of the peaks across the period, as shown in **Figure 25**. While winter loads are affected more than summer loads, the baseline peak loads are not coincident with the incremental electrification peaks. This finding results in a 6 percent addition to the new IOU winter peak load and an 8 percent addition to the new IOU summer peak load for the "aggressive electrification" scenario. Impacts from the "minimal" or "moderate" electrification scenarios are difficult to show because they are less than 2 percent statewide.

The seasonal concentration of winter space heating loads resulting from electrification added to little electric space heating in the baseline demand forecast can shift peak dates and hours for utilities in the winter. Electrification of water heating yields a more uniform impact across the seasons and thus has limited impact on summer or winter peak loads. Electrification efforts cause impacts to managed peak loads at a scale that shift the dates and hours of these peak loads in the winter season for utilities, as further described in Appendix C, but does not have this effect statewide.

Figure 25: Aggressive Electrification Scenario Winter and Summer Peak Load Impacts (MW)



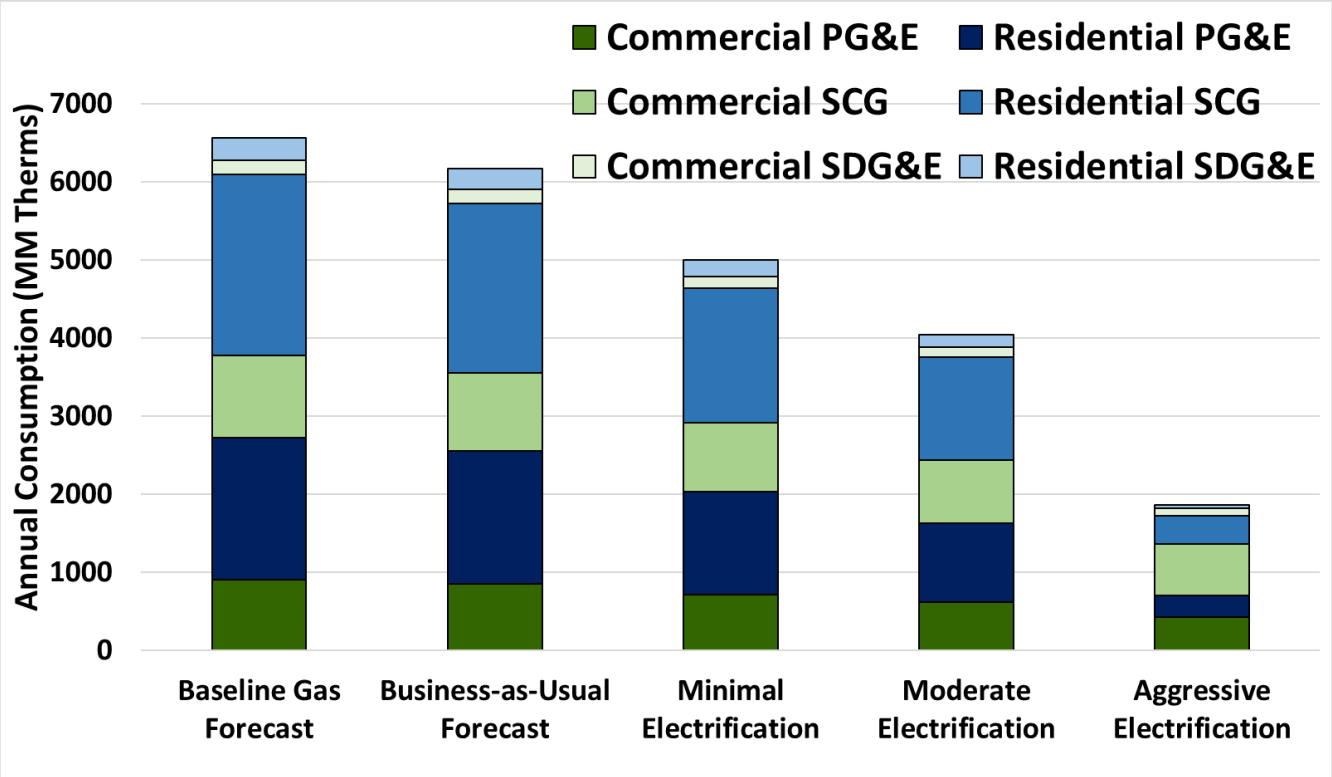
Source: CEC staff

Gas System Impacts

For each of the four electrification scenarios, the 2019 gas efficiency savings from AAEE Scenario 3 were used to adjust the gas forecast from the "business-as-usual" case before any electrification was applied. The adjustment has a small effect, retaining 94 percent of the baseline consumption in 2030, as shown in **Figure 26**. The FSSAT computes remaining gas consumption after each electrification scenario effort is applied, with granularity of utility, sector, end use, and technology.

Electrification is possible for 87 percent of residential and commercial gas consumption, as this portion of gas end-use consumption can be disaggregated to gas technologies for which a suitable electric technology exists. Thus, these gas technologies may be substituted for an electric technology while providing equivalent service to the end-use consumer. Of that, the residential sector accounts for 77 percent of the gas consumption considered for electrification. Further refinement of the miscellaneous share of commercial building consumption may be possible in future updates and lower the 38 percent of gas consumption attributed to uncategorized end uses in commercial buildings. The 87 percent of residential consumption evaluated for electrification is split between space and water heating, whereas the commercial sector has 84 percent of gas consumption eligible for electrification in the same two end uses.

Figure 26: Statewide Annual Gas Demand by 2030

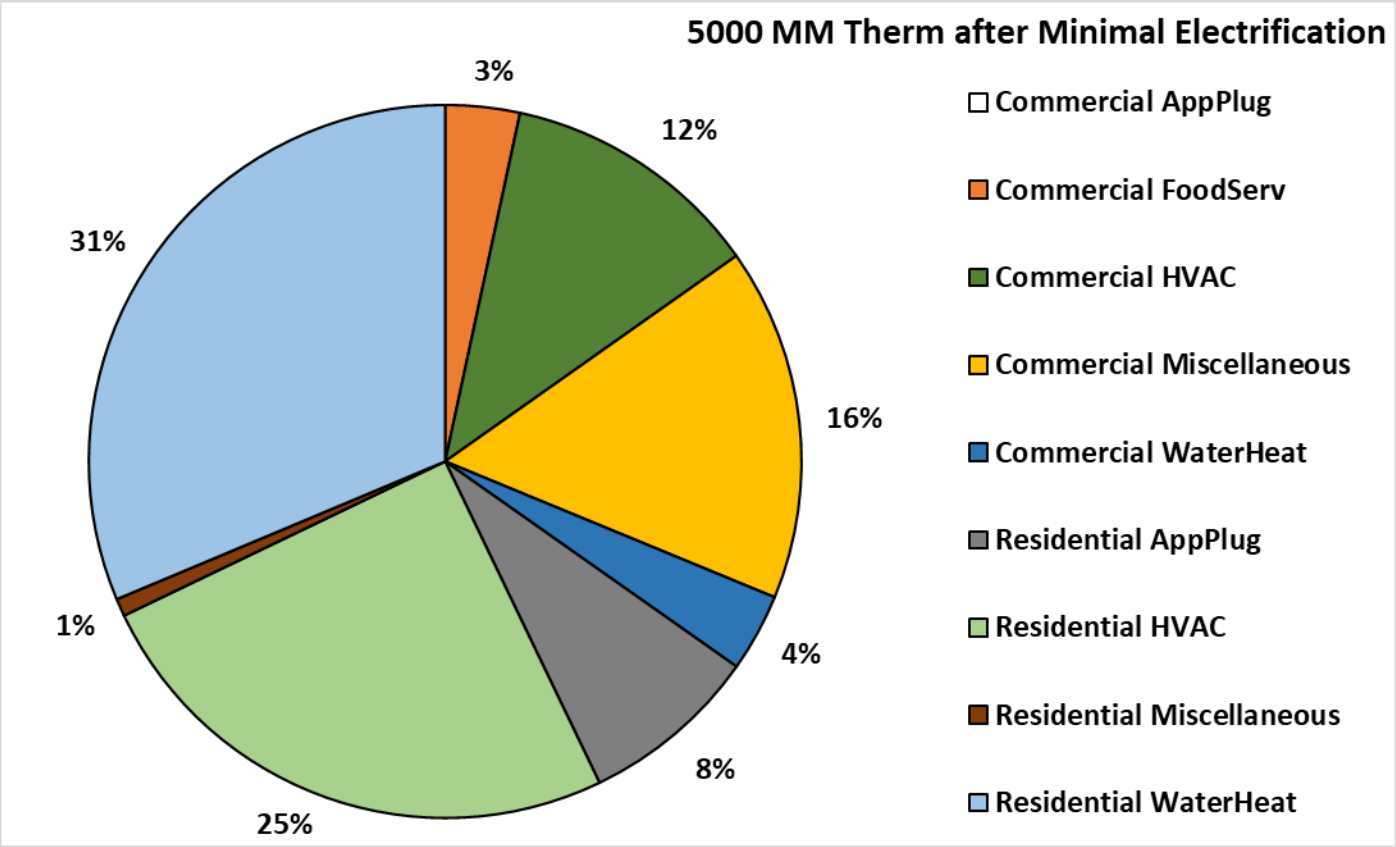


Source: CEC staff

In the "minimal electrification" scenario, gas consumption is reduced to 76 percent of the "business-as-usual" case in 2030, while the "moderate electrification" scenario reduces it to 62 percent. In the "aggressive electrification" scenarios, electrification efforts reduce gas consumption to 28 percent of the baseline forecast in 2030. Figure 27 shows these changes in gas consumption.

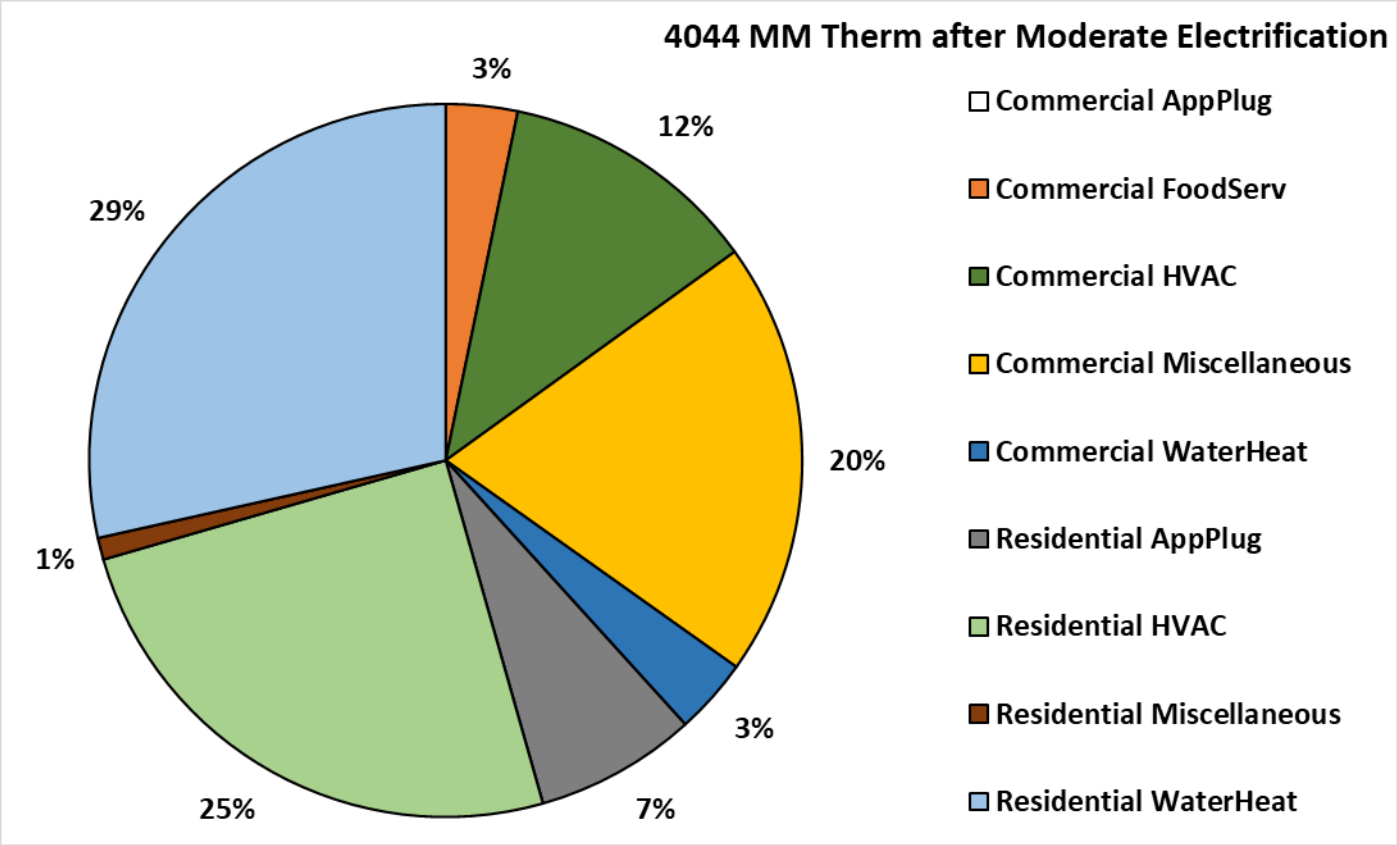
The "business-as-usual" case gas consumption in 2030 is 6,159 MM therms. The gas consumption remaining after minimal electrification is 5,000 MM therms in 2030. The end-use distribution of remaining gas consumption does not appear markedly different than before electrification; it simply diminished in magnitude to 81 percent of gas consumption before electrification.

Figure 27: Gas Consumption Remaining After the Minimal Electrification Scenario



Source: CEC Staff

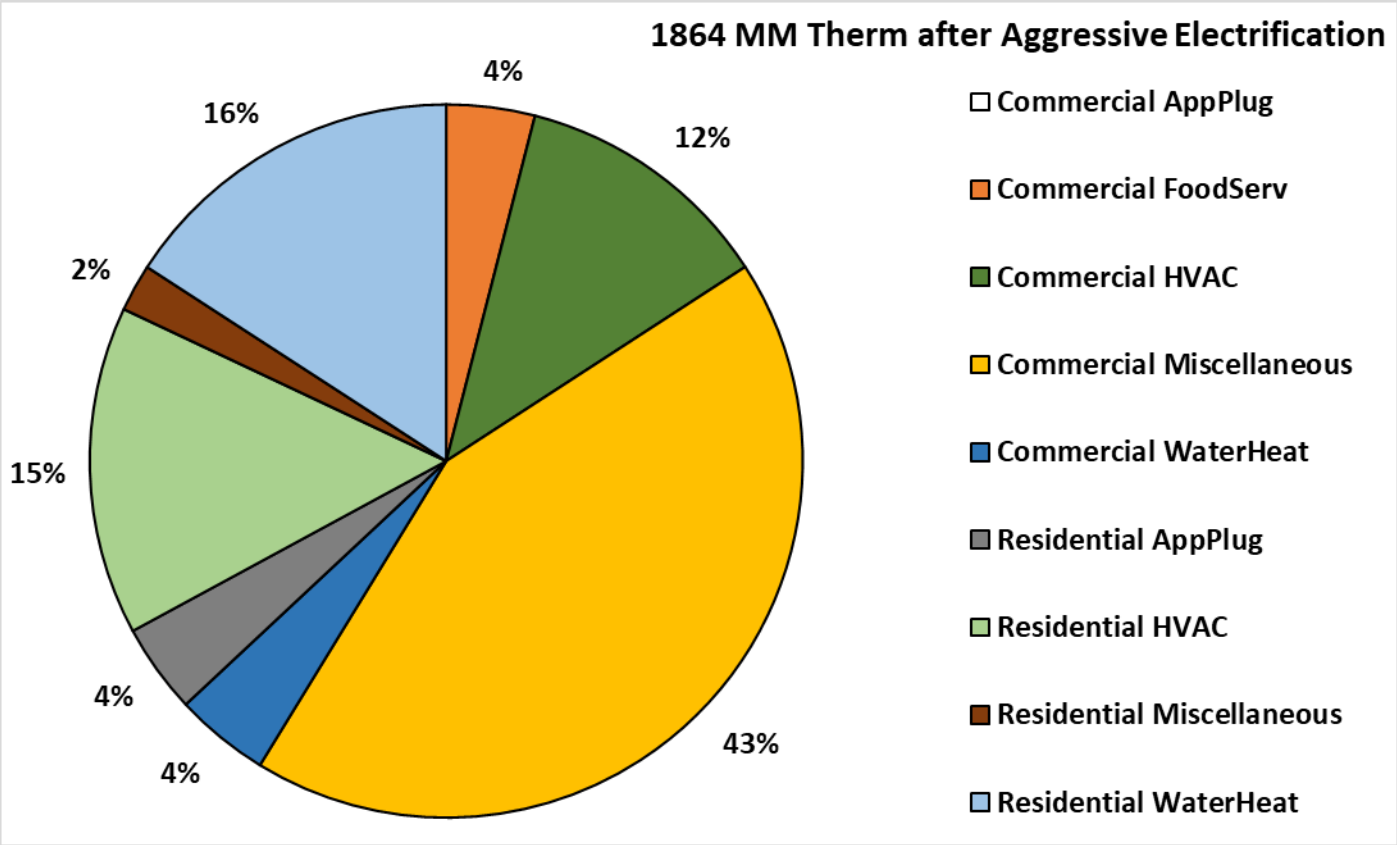
Figure 28: Gas Consumption Remaining After the Moderate Electrification Scenario



Source: CEC staff

Figure 28 shows the end-use breakdown of the remaining 4,044 MM therms of gas consumption in 2030 after the "moderate electrification" effort. There is an increased reduction from the "business-as-usual" case, leaving only two-thirds of the gas consumption. The end-use breakdown after this electrification effort is similar to the "minimal electrification" case.

Figure 29: Gas Consumption Remaining After the Aggressive Electrification Scenarios



Source: CEC staff

Figure 29 shows the end-use breakdown of the remaining 1,874 MM therms of gas consumption in 2030 after either the "aggressive" or the "efficient aggressive electrification" scenarios. There is a marked reduction from the "business-as-usual" case, leaving only 30 percent of gas consumption, and the end-use breakdown after electrification efforts is very different.

Issues and Insights

The electrification scenarios reveal the GHG and cost implications of successively greater shifts from gas to electricity. CEC staff conducted several sensitivity studies to explore some key details worth highlighting.

Efficiency of Electric Technologies

The "minimal," "moderate," and "aggressive" electrification scenarios assume there is a range of alternative electric technologies available to replace a specific gas technology. These electric technologies differ by efficiency and cost. The FSSAT selects across these technology options with a mix that produces collective incremental electric load and costs to end users. As depicted in "efficient aggressive," CEC prepared two alternative electric technology sets that allowed only a single electric technology. The "best" set picks an electric technology option for each corresponding gas technology displaced that was the upper end of the distribution of options in the "mix" cases. This "best" electric technology sensitivity produces both lower

incremental electric load and in the aggregate. Lower incremental electrical load results in fewer GHG emissions from the electricity generation system. The opposite was noted by allowing only the "worst" technology option from among those included in the "mix" set.

Table 4 provides the differences in total incremental electricity consumption of the "aggressive electrification" scenario ("mix" electric technologies) versus sensitivity cases using "best" electric technologies ("efficient aggressive electrification" scenario) that reduce incremental added electricity and "worst" electric technologies that increase collective incremental electric load. Staff developed estimated GHG emissions for the "best" and "mix" cases using production simulation modeling, but "worst" emissions are assumed to vary from "best" by the ratio of total additional electric energy. While the reduction in 2030 GHG emissions (assuming SB 100 requirements are in place) is significant, the reduction in GHG emissions, if there is no improvement in the electricity generation system emission factor to the SB 100 case, is larger. This finding reflects the dramatic improvement overall in the electricity generation system emission factor applied to the entire electric load, not just the increment switched from gas to electric technologies.

Table 4 makes clear that programs and standards to encourage use of more efficient electric appliances would be able to reduce incremental load growth from electrification, thus reducing additions of resources and operation of more GHG-intensive resources in nondaytime hours. Since federal appliance standards preclude California's development of Title 20 appliance efficiency standards for water heating and space heating, some form of incentive program may be needed to induce end uses to make more efficient choices.

Table 4: Differences in Incremental Electric Load and Overall Building Share of Electric Generation System GHG Emissions from Alternative Electric Technology Sets

Electric Tech Options	Sector	Incremental Electric Energy Impact in Year 2030 (GWh) Added From New A/C	Incremental Electric Energy Impact in Year 2030 (GWh) Added From Building Electrification	Total Incremental Electric Energy Impact in Year 2030 (GWh) Added	Projected GHG Impact ($MMTCO_2e$) Using Electric Generation System Emission Factor Reductions per SB 100	Projected GHG Impact ($MMTCO_2e$) Using Electric Generation Emission Factor Frozen at 2020 Value[63]
worst	Commercial	0	7,101	7,101	--	
worst	Residential	3,097	49,655	52,751	--	
worst	Grand Total	3,097	56,756	59,852	33.5	50.8
mix	Commercial	0	7,192	7,192	--	
mix	Residential	2,791	37,612	40,403	--	
mix	Grand Total	2,791	44,804	47,595	32.1	48.2
best	Commercial	0	7,744	7,744	--	
best	Residential	2,876	28,020	30,896	--	
best	Grand Total	2,876	35,764	38,639	31.0	46.3

Source: CEC staff

HFC Emission Reductions

CARB is working to achieve HFC emission reductions in parallel to the AB 3232 assessment.[64] The FSSAT was designed to include historical and projected HFC emissions, but not to examine specific mechanisms that might accomplish the HFC emission reduction goal set by SB 1383. The FSSAT was also designed to compute the incremental HFC emissions from the

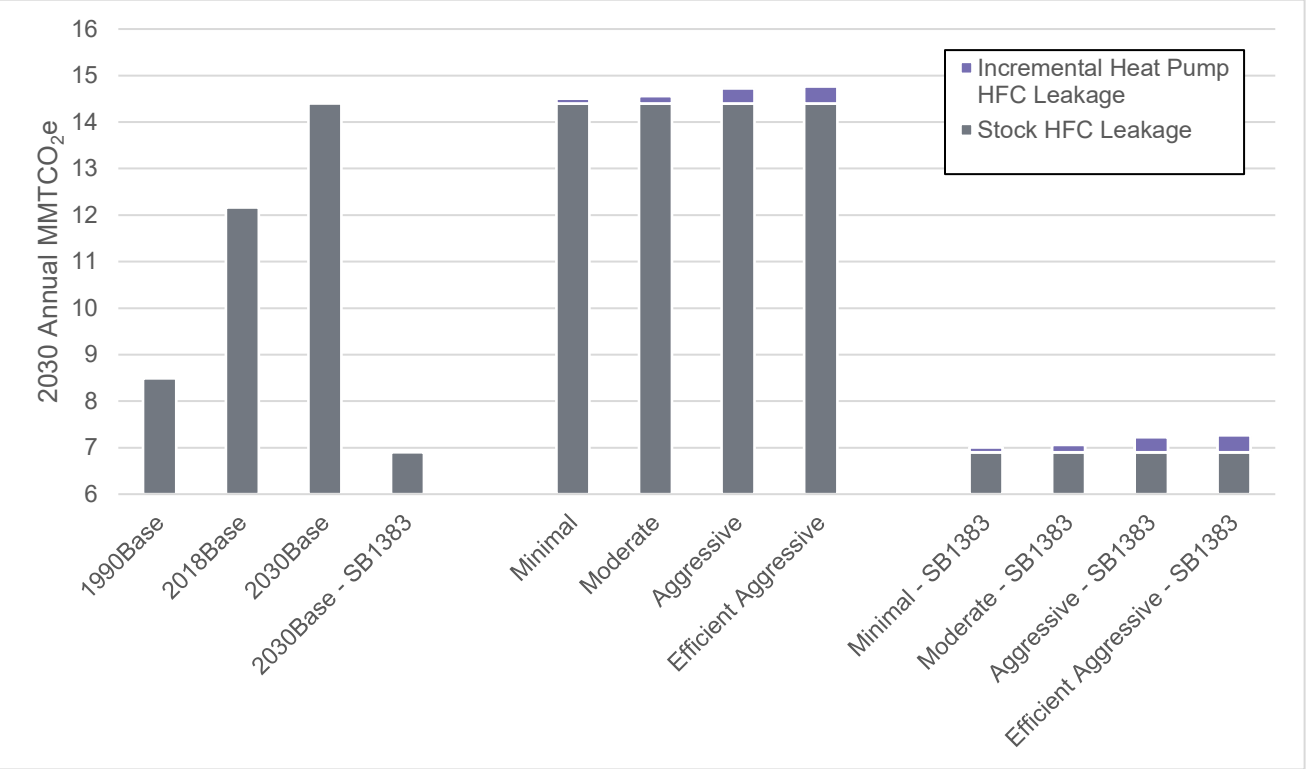
63 Electric generation sector emissions calculated at the estimated 2020 value of 0.18933 tonnes/MWh times the entire energy for load (*2019 IEPR* mid-mid managed load forecast plus incremental load calculated by FSSAT) then shared to the residential and commercial sectors using the residential plus commercial load growth from the FSSAT to determine the overall residential and commercial share of aggregated electric generation system GHG emissions.

64 CARB. 2020. Prohibitions on Use of Certain Hydrofluorocarbons in Stationary Refrigeration, Chillers, Aerosols-Propellants, and Foam End-Uses Regulation. https://ww2.arb.ca.gov/rulemaking/2020/hfc2020.

use of heat-pump technologies, which use HFC refrigerants to achieve the heat transfer required in water heating and space conditioning.

Figure 30 shows the HFC emissions included in **Figure 12** and **Figure 13** (in Chapter 3) and earlier GHG emission charts, so that the relative scale of HFC GHG emissions can be better appreciated. It also isolates the potential impacts for each electrification scenario of SB 1383 succeeding.[65] "Stock HFC emissions" refers to the many existing sources of HFC emissions that are within the scope of the SB 1383 reduction target of 10 $MMTCO_2e$. The residential and commercial building portion of this goal is estimated to be 6.9 $MMTCO_2e$ in 2030. The uncontrolled HFC emissions in the residential and commercial building sectors are estimated to grow from about 11.7 $MMTCO_2e$ in 2017 to 14.4 $MMTCO_2e$ in 2030. The uncontrolled HFC emissions constitute about 20 percent of the AB 3232 target of 74.4 $MMTCO_2e$.

Figure 30: Statewide HFC-Based GHG Emissions in 2030



Source: CEC staff

The incremental HFC emissions from new heat-pump sources, not included in the SB 1383 target of 6.9 $MMTCO_2e$, are low in 2030 compared to the other principal sources of GHG

65 Where "- SB 1383" assumes SB 1383 succeeding. For example, "aggressive – SB 1383" is the "aggressive electrification" scenario, assuming SB 1383 succeeding, and "efficient aggressive – SB 1383" is the "efficient aggressive electrification" scenario, which includes a "single-best" replacement technology mix and assumes SB 1383 succeeding.

emissions, although issues remain to be explored about relative charge rates, the GWP of new refrigerants, and the full life-cycle impacts of refrigerant leakage.[66] Therefore, the focus of HFC emissions is on the traditional sources in residential and commercial buildings. Closer coordination between the CEC and CARB will be needed in future cycles of the building decarbonization analyses in the IEPR proceedings.

Demand Flexibility Potential Estimates

Building end uses that already use electricity will play the largest role in building demand flexibility over the next decade, with commercial air conditioning having the most near-term potential.[67] But new electric demands resulting from electrification of water heating and space heating will also add to the potential for building-demand flexibility, depending on the costs of load shift-enabling technologies. For this analysis, CEC staff has investigated only demand flexibility in the form of "load shift" as established in the Lawrence Berkeley National Lab report prepared for the CPUC.[68]

CEC estimates the potential energy that could be reallocated over a typical day, applying the constraint that only 20 percent of hourly demands could be shifted, as follows in **Table 5**.

Table 5: Load Shift in 2030 by End Use

Load Shift End Use	2030 GWh per Shift Event
LBNL Com HVAC	2.5*
FS Com Space Heating	0.9**
FS Res Water Heating	4.0**
FS Res Space HVAC	2.9**

*At the midrange of the cost thresholds LBNL studied

**No cost constraints applied

Source: CEC staff

The potential electricity generation system impacts of shifting hourly electricity use of new demands are also significant. Although the AB 3232 GHG reduction target can be met with

66 The FSSAT assumes an annual and end-of-life leakage rate for each technology. Since 2030 is a short time horizon, none of the installed heat pump technologies in the electrification scenarios have any end-of-life leakage, which can be relatively large. As such, a full life-cycle analysis of refrigerant emissions beyond 2030 can reveal that the unregulated growth of these emissions can be significant.

67 Gerke et al. July 2020. *The California Demand Response Potential Study Phase 3: Final Report on the Shift Resource Through 2030.* pg. xvi. DOI: 10.20357/B7MS40. pg. xvi. https://eta-publications.lbl.gov/sites/default/files/ca_dr_potential_study_-_phase_3_-_shift_-_final_report.pdf.

68 Ibid.

only 20 percent of existing gas-fueled space and water equipment being replaced with electric alternatives by 2030, even this modest level of demand flexibility could reduce the need for electricity generation system storage and renewable curtailment required for grid reliability by nearly 20 percent in 2030.

Electricity Price Impacts

Building decarbonization is likely to increase some elements of utility costs and revenue requirements, but those rate impacts will be offset by the increasing volume of sales. CEC staff developed electricity rate estimates for scenarios consistent with the "minimal electrification" and "aggressive electrification" scenarios explored, which as bookends could indicate the possible direction and magnitude of impacts. Further development of implementation plans and associated costs are needed to quantify these impacts more accurately.

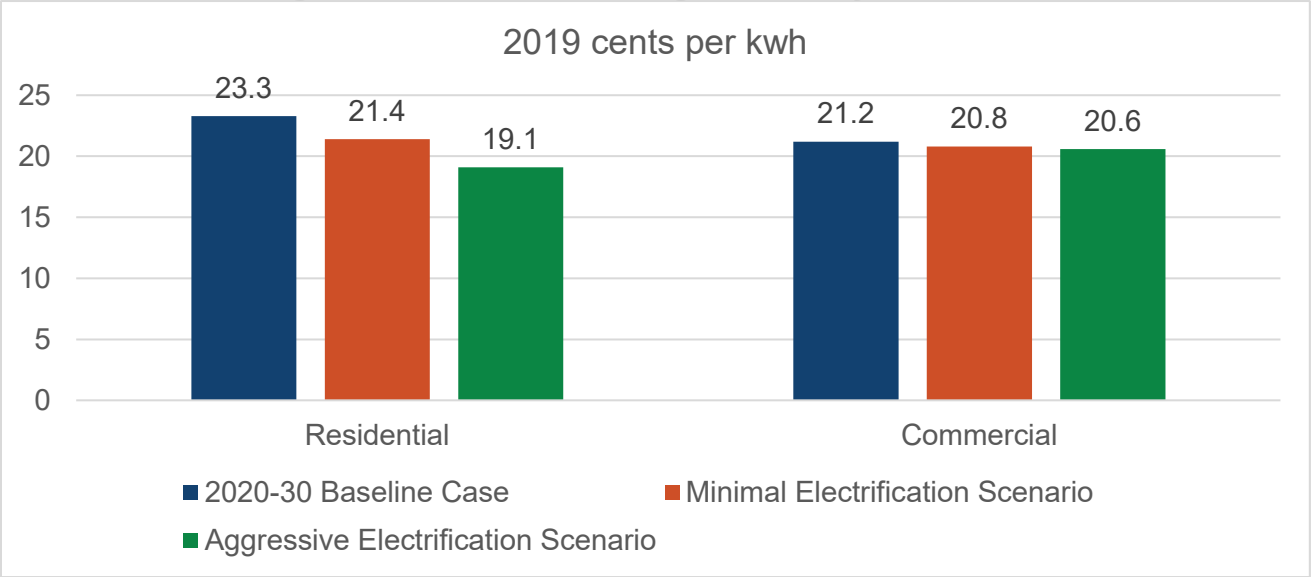
Based on the PLEXOS simulation results, the 2030 cost per MWh of energy served, including energy and ancillary services, increases 2 percent in a low-electrification scenario such as the "minimal" or "moderate" electrification scenarios and 4.5 percent in the "aggressive electrification" scenarios compared to the base case, reflecting the addition of relatively low-cost renewables and batteries. For some utilities, the addition of these new resources can dilute the cost of more expensive legacy contracts, lowering the average cost to customers. Utilities with lower cost portfolios may see a slight increase in energy procurement rates. Future capacity prices are uncertain. Analysis of marginal generation capacity costs for the CPUC Avoided Cost Calculator indicates that capacity prices will decline long term, based on the declining net cost of new 4-hour storage. However, recent capacity prices have been increasing and could continue to increase to retain needed gas-fired resources. For this analysis, staff assumed 2020 prices escalated 2.5 percent in all cases.

The significant increases in demand caused by building decarbonization will likely necessitate additional investment in distribution and transmission infrastructure compared to what is already planned for the base load forecast. To estimate these additional revenue requirements, staff used marginal distribution capacity costs from utility cost of service studies. For IOUs, these are part of their General Rate Case Phase II applications. For transmission costs, avoided capacity costs developed for the avoided cost calculator were used. These provide a cost per kW of load growth that can be applied to demand forecast scenarios to estimate incremental revenue requirements.

Offsetting the rate impact of new transmission and distribution infrastructure, other costs such as customer access costs, wildfire risk mitigation, and infrastructure maintenance and replacement do not increase proportionately with load, so load growth reduces the associated per-kWh rate impact.

Figure 31 shows the estimated sector rates compared to the mid-case electric rate scenario developed for the *2019 IEPR*. In the low-electrification scenario, the statewide average residential rate is 2 percent lower. In the "aggressive electrification" scenario, residential rates are 18 percent lower than previously projected, and commercial rates are 3 percent lower.

Figure 31: Statewide Average Electricity Rates in 2030



Source: CEC staff

These scenarios indicate the magnitude of effects on rates. Distribution and transmission planning studies can quantify more accurately the necessary grid investment needed. Also, these scenarios do not include the effect of demand flexibility, which could reduce generation and grid capacity costs. Based on recent studies of TOU rates, well-designed time-variant rates could be expected to reduce capacity needs.

These rates represent the average annual rate required to collect the utility revenue requirement. As the load of a decarbonized customer increases and the load shape changes, an important consideration for achieving the targeted benefits is the availability of rate designs that encourage technology adoption and that encourage use during low-cost and low-emission hours. Many standard residential rates collect all or most costs volumetrically and were designed based on the current average household use and load profile. These rates would collect excess revenues from households whose use is substantially higher, and those customers will pay more than their cost of service. Utilities would refund this surplus through balancing accounts but would not fairly reimburse the customers who were overcharged. Offering rates that use a fixed charge to collect those costs that do not increase with demand can better align rates with cost of service and encourage customer adoption of electric technologies. Second, rate designs should allocate costs by time of day to encourage customers to shift load to hours when costs and GHG emissions are lowest.

Uncertainties

The analyses presented here result from a series of "what if" scenario analyses and are not a forecast of expected outcomes. There are no specific policies and programs in place that would accomplish the estimated GHG reduction and costs. As explained at the beginning of Chapter 3, each of the scenarios was assessed independently, and the impacts of the scenarios cannot be added together. It is possible that a combination of strategies could be

the best approach meet a 2030 goal as the state works toward the more ambitious 2045 economywide decarbonization goals.

The most important element missing from these analyses is the role that energy consumers will play in making choices for electric appliances rather than gas ones, adopting energy efficiency measures, and heeding the warning of climate scientists to reduce GHG emissions across the board. Better understanding of consumer behavior is essential but will require substantial time and effort to collect the appropriate data and understand how to best guide California's residents toward the state's climate and energy goals.

CHAPTER 5:
Pathways to Decarbonizing Buildings

This chapter describes broad decarbonization strategies that were analyzed as part of this assessment. These strategies require decision makers to consider and address the possible barriers, especially those that would leave low-income or disadvantaged communities worse off relative to other communities. Barriers such as high costs, unavailable financing, building age, low customer awareness, and consumer preferences must be addressed for the decarbonization strategies to succeed.

The variability of building design, location, use, and owner's or occupants' access to retrofit capital requires state decarbonization policy to be flexible with multiple strategies. The seven key strategies for decarbonizing residential and commercial buildings are:

1. Building end-use electrification.
2. Decarbonizing the electricity generation system.
3. Energy efficiency.
4. Refrigerant leakage reduction.
5. Distributed energy resources.
6. Decarbonizing the gas system.
7. Demand flexibility.

Strategy 1 – Building End-Use Electrification

Electrification replaces gas use in appliances and equipment in residential and commercial buildings with efficient heat-pump technologies. As a decarbonization strategy, electrification would replace high-GHG emitting appliances with more efficient, low- or zero-GHG-emitting appliances. Two common examples are replacing the gas water heater of a home with an electric heat pump or swapping a gas range with an electric induction range.

Building Electrification

Electrification is the replacement of one gas fuel end-use device for an electric one within a building. This process may significantly reduce overall GHG emissions but may result in additional HFC emissions. Electrification can also result in increased electricity demand because of the new electric appliances to the building. As California moves to provide 100 percent net-zero-carbon retail electricity sales, additional electricity demand will have reduced GHG emissions over time.

Electrification Barriers

Home and business owners may experience several barriers to decarbonizing their buildings through electrification. Some barriers are common to all strategies, such as affordability, program design, and the age of existing buildings.[69] Specific to electrification, some technologies available today have premium prices due to the associated smaller market share. Thus, market transformation activities that can lower technology prices are critical. Also, given the older age of most of California's existing buildings, it is reasonable to assume that some portion will require electric panel upgrades from 100 amps to 200 amps or larger to support new electric loads or, conversely, require the installation of low-amperage alternative technologies, such as low-amperage heat pump water heaters.

Of all the appliance electrification measures in homes, consumer preference for gas cooking presents challenges to the broad adoption of electric cooking. The cost of induction cooking technology is an additional barrier. All these barriers can be solved but will require extensive coordination among state agencies, utilities, manufacturers, local communities, and consumers.

New Building Construction Practices and Costs

California will need to build hundreds of thousands of new homes over the next decade to meet population growth and increased demand. The construction industry will need to shift purchasing and planning practices quickly if these new homes will be all-electric. Current building practices allow builders to receive rebates that cover the cost of gas infrastructure installation.[70] In the absence of these rebates, all-electric construction is more cost-effective in several climate zones.

The cost of new single-family homes is lower if built all-electric across most climate zones in California, according to research by Frontier Energy.[71] The study found incremental costs could be $30,000 less to $3,000 more than a mixed-fuel home.[72] Homes would be more expensive if equipment and installation costs are greater. Most of the savings is due to the avoided costs of gas infrastructure.[73]

Evaluating the costs and savings in mid-rise, all-electric new construction is more complex. Incremental first costs of an all-electric multifamily unit are up to $20,000 less to $4,500 more

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69 See "Cross-Cutting Barriers" on page 103.

70 CPUC, Rule 20, Gas Main Extensions.

71 Prepared by Frontier Energy for the PG&E Codes and Standards Program. *2019 Energy Efficiency Ordinance Cost-Effectiveness Study: Low-Rise Residential*, page 33, August 2019, https://efiling.energy.ca.gov/GetDocument.aspx?tn=234020-6&DocumentContentId=66846.

72 Ibid., page 15-16.

73 Ibid., page 33.

than a mixed-fuel unit, depending on the final costs of equipment. The lifetime costs for these units are negative, meaning that they will have lower operating costs than mixed-fuel ones.[74] Additional research by Redwood Energy found that all-electric, multifamily construction costs less than mixed-fuel units. The cost savings are achieved by avoiding gas piping, venting, and trenching.[75] An average reduction of $3,300 per unit was found by avoiding a gas system. The reductions increased with the size and location of buildings.[76] Other work by Energy and Environmental Economics (E3) found similar results: all-electric, new, low-rise multifamily buildings were thousands of dollars cheaper to build.[77] Some cities, as highlighted in the "Local Ordinances" section, now require new multifamily buildings to be all-electric or all-electric-ready.

All-electric new commercial buildings can see similar cost reductions. A study by TRC and Energy Soft modeled the costs to build a medium-sized office, retail space, and small hotel.[78] Cost reductions from avoided gas infrastructure exceeded $18,000 in the medium office, $28,000 in the medium retail, and $50,000 in the small hotel.[79] Additional wiring and panel capacity to meet the demand of electricity will add more than $25,000 to the construction costs.[80] The incremental cost savings for new retail, all-electric, standard, and above-code energy efficiency are negative. In all climate zones, the upfront costs are lower to build an all-electric retail building.[81] Small hotels see similar negative incremental costs across all climate zones, even when adding measures like solar PV and battery storage. A medium office has negative incremental costs in all climate zone when building to code minimum and in most climate zones when adding more efficiency measures.[82] Altogether, this analysis indicates that nonresidential all-electric construction can be cost-effective using available technology.

As shown in previous chapters, new buildings that are constructed with efficient electrification as an integrated principle offer some of the lowest cost GHG reductions of all measures

74 Ibid., page 16.

75 Redwood Energy. 2019. A Zero-Emissions All-Electric Multifamily Construction Guide, https://www.redwoodenergy.tech/wp-content/uploads/2019/11/Multifamily-ZNC-Guide-7-10-19-sa-clean.pdf. Page 9.

76 Ibid, pg. 2.

77 E3, Residential Building Electrification, Page 56. 2019. https://www.ethree.com/wp-content/uploads/2019/04/E3_Residential_Building_Electrification_in_California_April_2019.pdf.

78 Prepared by TRC and Energy Soft for PG&E Codes and Standards Program, 2019 Non-residential New Construction, page 1, https://localenergycodes.com/download/74/file_path/fieldList/2019%20NR%20NC%20Cost%20Effectiveness%20Report.

79 Ibid., page 22.

80 Ibid., page 21.

81 Ibid., page 37.

82 Ibid., page 30-31.

studied. While the potential value of all-electric construction founded on efficient electrification is clear, the pathway to get there is challenging. The Energy Code represents one important tool that can foster a strong transition toward efficient heat-pump technologies, consistent with state and federal laws concerning energy efficiency, demand flexibility, and distributed resources.

Existing Building Retrofit Costs

Retrofit costs to decarbonize existing homes vary by size, number of appliances to replace, age of equipment and building, and climate zone. Some homes can expect more efficient equipment to return the investment during the useful life, but other homes will see added operation costs. As discussed below, older homes may have the added expense of upgrading an electric panel, which can cost a few thousand dollars. Research by E3 found that homes with an existing air-conditioning and furnace system can see savings when replacing those units at burnout with a heat-pump system.[83] Other research found potential costs to upgrade residential units ranging between $10,000 to nearly $40,000.[84] In some homes, the cost may be lower if they already have electric appliances, or be lower in multifamily units that receive space heating and water heating from a central boiler. The same study reported incremental costs since people will commonly only replace appliances at or near the end of the useful life.

The cost to upgrade existing commercial buildings varies as well. Small and medium commercial spaces can anticipate costs to decarbonize ranging from a few thousand dollars to well over $40,000.[85] There is strong variability in costs depending on the building square footage, age of equipment, electric panel size, and type of equipment needed to decarbonize. Large commercial and campus-style buildings face variable costs as well.[86] Water heating and space conditioning represent the most significant investments. In campus-type settings, buildings could share those costs by using district energy systems.[87]

Electric Panel Upgrades

The size of electric panels varies with the age and size of the building. Today's new homes are built with electric service panels capable of handling larger electric loads such as electric vehicle (EVs), rooftop solar, and heat pumps. However, by 2030, only about 10 percent of homes will have been built in compliance with the 2019 or later Energy Code. One main

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83 E3. April 2019. *Residential Building Electrification in California*, page viii, https://www.ethree.com/wp-content/uploads/2019/04/E3_Residential_Building_Electrification_in_California_April_2019.pdf.

84 Jones, Betony, Jason Karpman, Molly Chlebnikow, and Alexis Goggans. UCLA Luskin Center. *California Building Decarbonization: Workforce Needs and Recommendations.* Page ES-vii. https://innovation.luskin.ucla.edu/wpcontent/uploads/2019/11/California_Building_Decarbonization.pdf.

85 Ibid., page 17.

86 Ibid., page 18.

87 Energy Futures Initiative, *Pathways for Deep Decarbonization in California*, 2019, page 182, https://energyfuturesinitiative.org/s/EFI_CA_Decarbonization_Full-b3at.pdf.

barrier to electrifying existing homes (and promoting access to EV charging) will be upgrading electric service panels that may not be adequately sized to allow new electric equipment safely and reliably. Based on available data, costs to upgrade a panel vary from $2,500 to $4,000,[88] including equipment, installation, permitting, and labor. Additional costs may be necessary for rewiring, providing clearance for an expanded panel, or relocating the panel.

District and Shared Heating

Commercial and multifamily buildings may use large-scale, central space- and water-heating systems. Many multifamily buildings have central boilers that provide hot water and space heating. The average boiler age in the IOU territories is between 9 and 10 years, which is about 50 percent of the useful life.[89] While most other appliances in multifamily units are electric, the central system may be the only appliance using gas. However, recent developments in heat-pump technology allows them to replace gas boilers.[90] Even without substituting fuels, a recent assessment of boiler equipment potential found close to 5 MM therms of savings over a 10-year period through inclusion of pump controls, pipe insulation, flue dampers, improved economizer, and retrocommissioning.[91]

Multifamily building owners will need to replace many of these boilers in the coming decade, so having an electric option that is market-ready and cost-competitive is critical. Should owners install a new gas boiler, it locks the building to the gas system for another 20 years unless there are incentives to retire early.[92] Moreover, in new buildings, once the pipes and gas network are installed for the boiler, they must be maintained.

Like multifamily buildings, commercial buildings with large gas-fired boilers now have low- or carbon-free alternatives with electric heat pumps. Heat recovery chillers are a type of heat pump designed for large and shared commercial buildings with a central cooling system. A heat pump water heater can fit in most mechanical spaces to provide water heating and, in some sectors, use waste heat from cooking, steam, or other sources to lower the operating costs. Commercial building complexes, such as universities, may use a combined-heat-and power (CHP) system or central boilers for water heating and interior spaces. These systems

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88 Gridworks and Building Decarbonization Coalition. *Decoding Grid Integrated Building Reports.* January 2020. page 7. https://gridworks.org/wp-content/uploads/2020/02/Decoding-Grid-Integrated-Buildings_WEB.pdf.

89 *California Statewide Multifamily Boiler Market Assessment*, Prepared by Benningfield Group for Southern California Gas, 2019. Page 65. www.calmac.org/publications/CA_Statewide_MF_Boiler_Market_Assessment_Cadmus.pdf,.

90 Redwood Energy. *A Zero-Emissions All-Electric Multifamily Construction Guide*. 2019, https://www.redwoodenergy.tech/wp-content/uploads/2019/11/Multifamily-ZNC-Guide-7-10-19-sa-clean.pdf. Page 9.

91 *California Statewide Multifamily Boiler Market Assessment*, Prepared by Benningfield Group for Southern California Gas, 2019. Page 6. www.calmac.org/publications/CA_Statewide_MF_Boiler_Market_Assessment_Cadmus.pdf,.

92 Ibid., page 32.

often use gas; CHP systems account for more than 60 percent of University of California campus' gas usage.[93] Replacing the gas-fired boiler with a heat recovery chiller or heat pump water heater may not entirely decarbonize the building (or campus); however, it can greatly reduce the need to use combustible fuels for heating.

Alternatively, expanding and converting central systems to electric geothermal or water-source heat pumps offer several commercial subsectors a pathway to full decarbonization.[94] The costs to perform such upgrades vary between $5 to $39 per square foot.[95] Upfront costs to decarbonize may be higher than not switching the systems, but the lifetime savings and flexibility to use waste heat for additional purposes may make the switch economical.

Cooking

While most occupants have little regard for how their home or water is heated, some individuals have a strong preference for gas cooking.[96] Even though gas cooking is only the third largest contributor to GHGs from homes, it contributes to the need to extend gas lines to new homes and the reason why some homeowners are reluctant to go all-electric. However, gas stoves can contribute to indoor air pollution, which can result in air quality worse than outdoor air. Food cooked on a stove, regardless of fuel type, will emit particulate matter, but only gas stoves result in nitrogen oxides (NO_x), carbon monoxide, and formaldehyde emissions.[97] Nitrogen dioxide (NO_2) levels are 50 to 400 percent higher in homes with gas versus electric stoves.[98] These levels can have negative health impacts on residents, especially children, the elderly, and those with preexisting conditions. For children, long-term NO_x exposure can lead to learning deficiencies, asthma, cardiovascular issues, and other aggravated respiratory symptoms. Electrification of cooking is the only way to eliminate this danger and lower the risk of developing respiratory and cardiovascular issues.

The 2022 Energy Code proposes new requirements for kitchen ventilation capture efficiency or increasing ventilation rates with a goal of reducing pollution from cooking and kitchen appliances and primarily providing indoor air quality benefits.[99] Separate requirements will be

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93 Jones, Betony, Jason Karpman, Molly Chlebnikow, and Alexis Goggans. UCLA Luskin Center. *California Building Decarbonization: Workforce Needs and Recommendations*, page 16. https://innovation.luskin.ucla.edu/wp-content/uploads/2019/11/California_Building_Decarbonization.pdf.

94 Ibid., page 16-17.

95 Ibid, page 18.

96 "Visions Home Preference Survey," Administered by Southern California Gas, July 2014, https://www.socalgas.com/for-your-business/builder-services/visions-home-preference-survey.

97 Seals, Brady and Andee Krasner. *Health Effects From Gas Stove Pollution.* Page 8. 2020. https://www.psr.org/wp-content/uploads/2020/05/health-effects-from-gas-stove-pollution.pdf.

98 Ibid page 11.

99 Prepared by TRC for the California Statewide Codes and Standards Enhancement Program, "Multifamily Indoor Air Quality," October 2020, https://title24stakeholders.com/measures/cycle-2022/multifamily-indoor-air-quality/.

established to address NO_2 impacts from gas cooking versus particulate pollution from electric cooking.

Induction cooking offers a cooking experience with no open flame, quick heating, and easy cleaning from a flat cooking surface that is not hot.[100] Even with these benefits, changing to induction cooking requires purchasing of new, dedicated pots and pans and changing of cooking habits. The awareness of the effectiveness and safety of induction cooking remains low, but utility-sponsored take-home tests and live demonstrations are ways the public can become familiar with the technology and use the appliance firsthand. Such programs are being sponsored by the Sacramento Public Library, Sonoma Clean Power, the City of San José, the City of Palo Alto, Peninsula Clean Energy, and others.

The restaurant industry faces similar behavior and cultural hurdles to decarbonize. Cooks and chefs have been trained in and are familiar with gas cooking, with some believing it is required to prepare certain types of food.[101] Like residential loan programs, Southern California Edison is piloting a commercial restaurant induction cooking loan program.[102] This program gives cooks an opportunity to try induction cooking without spending any money on appliances. Similarly, the Food Service Technology Center in San Ramon (Contra Costa County) allows cooks and chefs to try induction and other all-electric cooking options while learning about additional energy-saving strategies.[103]

Induction cooking also offers a safer environment for restaurant workers. Since cooking surfaces do not stay hot the same way as gas or electric resistance surfaces, burning accidents are expected to decline.[104]

It is important to recognize that restaurants will also need to upgrade other gas cooking equipment. These upgrades may include fryers, skillets, grills, and ovens. Electric options exist for all equipment but may require changes in cooking technique and kitchen layout. In a business where profit margins are small and possibly seasonal, it is unlikely owners will have the upfront capital to retrofit their equipment and space, and others may be unable to take on

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100 Lynch, Tyler Wells. June 25, 2019. "If Induction Cooktops Are So Great, Why Does Hardly Anyone Use Them?" *The New York Times,* https://www.nytimes.com/wirecutter/blog/why-dont-people-use-induction-cooktops/.

101 California Hispanic Chamber of Commerce. Comments to the CEC in Docket 19-IEPR-06. December 2019. https://efiling.energy.ca.gov/GetDocument.aspx?tn=231155&DocumentContentId=62797.

102 "Foodservice Technology Center," Southern California Edison, https://www.sce.com/residential/energy-education-centers/Foodservice-Technology-Center?from=ftc.

103 "Food Service Technology Center," https://fishnick.com/fstc/.

104 Sweeney, Micah, Jeff Dols, Brian Fortenbery, and Frank Sharp. "Induction Cooking Technology Design and Assessment." EPRI, presented at the 2014 ACEEE Summer Study, https://www.aceee.org/files/proceedings/2014/data/papers/9-702.pdf.

new debts. The restaurant industry will need pathways to low- to no-cost financing options, education, and strong incentives to decarbonize.

Utility Bill Changes

A recent study by the CPUC found that utility rates have been growing since 2013, and monthly bills in each electric IOU territory are rising.[105] The study estimates that in these regions rates will increase annually by between 3.5 and 4.7 percent in the next 10 years.[106] This increase may result in bills rising at an annual rate of 4.5 percent compared to the anticipated 1.9 percent inflation rate.[107] The study also notes, however, that a well-managed effort to move customers to all-electric homes and electric vehicles could lower energy bills by more than $100 a month.[108]

In any electrification scenario, the effects to customers' bills will vary because of building operation, end use, rate changes, building type, building age, climate zone, or packaging with other technology like rooftop PV, battery storage, or electric vehicles. Rate changes from decarbonization may be layered onto predicted increases in the price of electricity and gas by 2030. Recent research indicates that in all modeled low-carbon future scenarios, maintaining the electric grid, including for wildfire upgrades, will increase rates.[109] Electricity rate increases may be partially offset by increasing sales volume, but there may also be increased energy burden and more customers enrolled in rate assistance. Gas rates are also expected to increase, independently of building decarbonization strategies, as utilities further invest in maintenance and upgrades of existing infrastructure; but as more customers leave the gas system, gas rates may rise further to cover the fixed rate of returns to the gas utilities over a smaller customer base. The possibility to increase the ongoing equity issue around rate increases and utility costs coverage needs to be addressed.

Strategy 2 — Decarbonizing the Electricity Generation System

SB 100 requires an increase in the RPS to 60 percent by 2030, meaning that renewables will continue to be one of the main driving forces in reducing GHG emissions from the electricity generation system. SB 100 also calls for a joint report by the CEC, CPUC, and CARB on the

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105 CPUC. "Utility Costs and Affordability of the Grid of the Future." May 2021. Page 8. https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy_-_Electricity_and_Natural_Gas/Senate%20Bill%20695%20Report%202021_En%20Banc%20White%20Paper.pdf.

106 Ibid.

107 Ibid.

108 Ibid.

109 Aas, Dan, Amber Mahone, Zack Subin, Michael Mac Kinnon, Blake Lane, and Snuller Price. 2020. *The Challenge of Retail Gas in California's Low-Carbon Future: Technology Options, Customer Costs and Public Health Benefits of Reducing Natural Gas Use.* California Energy Commission. Publication Number: CEC-500-2019-055-F page 52-53, April 2020, https://ww2.energy.ca.gov/2019publications/CEC-500-2019-055/CEC-500-2019-055-F.pdf.

potential benefits and impacts on system and local reliability associated with achieving the policy. The *SB 100 Joint Agency Report* assesses barriers and opportunities to implementing the 100 percent clean energy policy. As such, this section will provide only a high-level summary of issues being addressed in the *SB 100 Joint Agency Report*.[110] It also discusses the electricity generation system and GHG emission reduction to date, as well as some of the benefits of achieving the SB 100 goals.

Changing Electricity Resource Mix

The electricity generation system has led the way in California meeting the 2020 goal to reduce GHG emissions to 1990 levels, four years ahead of schedule, as discussed in Chapter 1. As the electricity resource mix has moved away from fossil resources to clean energy sources, GHG emissions from electricity generation have substantially declined. In 2017, GHG emissions from the electricity generation system were 40 percent below 1990 levels. California's electric system has reduced its GHG intensity by rapidly increasing the amount of renewable resources in the electricity mix. Other factors include the sharp decline in the import of coal-fired electricity over the last decade, which is expected to drop to zero by 2025, and the beginning of a reduced reliance on gas for electricity generation.

Since the inception of the Renewables Portfolio Standard (RPS) program in 2002, there has been an intense focus on increasing renewable energy resources in California. Renewable resources, including rooftop solar, have more than doubled in the last decade in response to the RPS.[111] This doubling has been accomplished through major investments in utility-scale renewable generating facilities, programs that have encouraged homeowners and businesses with incentives to install rooftop solar, and local leadership promoting clean energy communities that feature local renewable resources.[112] California's RPS called for 33 percent of the retail sales to be served with renewable resources by 2020. In 2019, renewable resources provided an estimated 36 percent of electricity generation in the state.

The GHG content of the existing electricity generating system changes throughout the day and across seasons because of the differing generation profiles of energy resources and consumer demand patterns. As noted, *when* a building draws energy from the electricity generation system affects the GHG emissions associated with that energy use, which makes automated shifting of energy key to decarbonizing buildings in the short term, and a long-term grid reliability strategy.

The electricity system is operated by the California ISO and other balancing authorities in the state. Many load-serving entities provide for the electricity needs of California's customers,

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110 *2021 SB 100 Joint Agency Report*, March 2021, https://efiling.energy.ca.gov/EFiling/GetFile.aspx?tn=237167&DocumentContentId=70349.

111 CEC, Renewable Portfolio Standard, https://www.energy.ca.gov/programs-and-topics/programs/renewables-portfolio-standard.

112 Ibid.

including investor-owned and publicly owned utilities, community choice aggregators, energy service providers, and other retail sellers. Decarbonizing the electricity system requires coordination among all the energy system operators and retail providers in the state.

Pathway to a Clean Electricity Generation System

SB 100 charts the path for California's electricity generation system to transform to a clean energy grid. The goal is to cut emissions from the electricity generation system to zero while meeting an increasing demand and maintaining energy reliability, controlling costs, and ensuring benefits reach all Californians.

Among the possible benefits for California's residents in achieving the SB 100 goals are improving public health by limiting the need to use fossil fuels to generate electricity and advancing energy equity by ensuring low-income and disadvantaged communities, along with tribes and rural communities, enjoy the benefits of the clean energy future. In addition, achieving the SB 100 goals of a 100-percent carbon-free future supports a clean energy economy by stimulating continued innovations and markets for renewable energy, energy efficiency, energy storage, low-carbon fuels, and zero-emission vehicles.

Strategy 3 – Energy Efficiency

Energy efficiency is the first action and lowest-cost strategy for building decarbonization since it can impact both residential and commercial buildings and electric and gas end uses. A 2019 study of the benefits of energy efficiency programs showed that electricity efficiency programs are a low-cost opportunity for utilities to reduce peak demand.[113] Highly cost-effective measures included residential lighting; heating, ventilation, and air conditioning (HVAC); whole-home retrofits; and small commercial programs. Residents and building owners directly benefit when efficiency reduces energy demand and subsequent utility bills. The state's electricity and gas systems also benefit from measures that reduce electricity demands, delay costly infrastructure upgrades, and offset new electric loads that will be added from increasing levels of EVs and electrification projects.

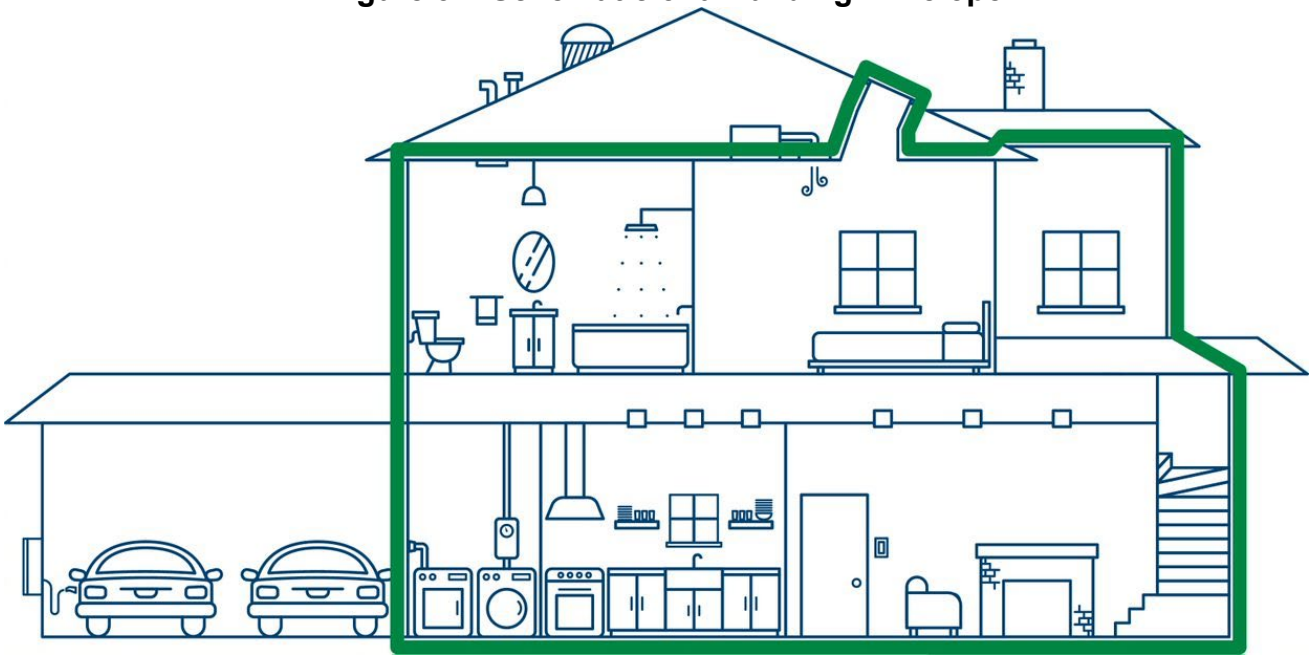
Highly efficient gas and electric appliances are essential to short- and long-term decarbonization efforts. Converting gas and electric appliances to highly efficient electric alternatives (such as heat-pump alternatives) offers significant efficiency improvements that reduce demand and lower GHG emissions regardless of which energy source was used beforehand. While most energy efficiency activities reduce use of an energy source, improvements to the envelope of an existing building can save gas and electricity and provide improved comfort to the occupant.

More than 50 percent of the existing housing stock was built before state energy codes took effect in 1978. CEC staff assumes that many homes lack proper envelope insulation and

113 Frick et al. *Peak Demand Impacts From Electricity Efficiency Programs*. November 2019. https://emp.lbl.gov/publications/peak-demand-impacts-electricity.

infiltration air gap sealing. Improving the envelope and ventilation of a building, illustrated in **Figure 32**, has the potential for significant energy and GHG emission savings by limiting heat gain or loss and preventing moisture buildup and accumulated airborne toxins. Also, improving the building envelope can provide a more comfortable space for occupants, may reduce the size of the space-conditioning system, and allow optimization of other decarbonization strategies. A well-sealed and ventilated building can precool or preheat more effectively, thus reducing peak loads and reducing the size of a potential PV system. Similar potential exists in the commercial sector.

Figure 32: Schematic of a Building Envelope



Green outline the envelope of a building. Source: CEC

Electricity Efficiency

Residential and commercial buildings predominately use electricity to operate plug loads, lighting, cooling, and refrigeration. California's Energy Code and appliance efficiency standards establish minimum efficiency requirements for buildings and appliances. Incentives for upgrading efficient plug-load devices and lighting fixtures are implemented through a variety of utility or local retrofit programs. Efficiency standards for cooling and refrigeration end uses are under the jurisdiction of the federal government, so California can develop programs and offer incentives for but not require advanced high-efficiency technologies. The GHG emission impact of electric end uses will improve as the state electricity grids transition to carbon-free generating resources.

Gas Efficiency

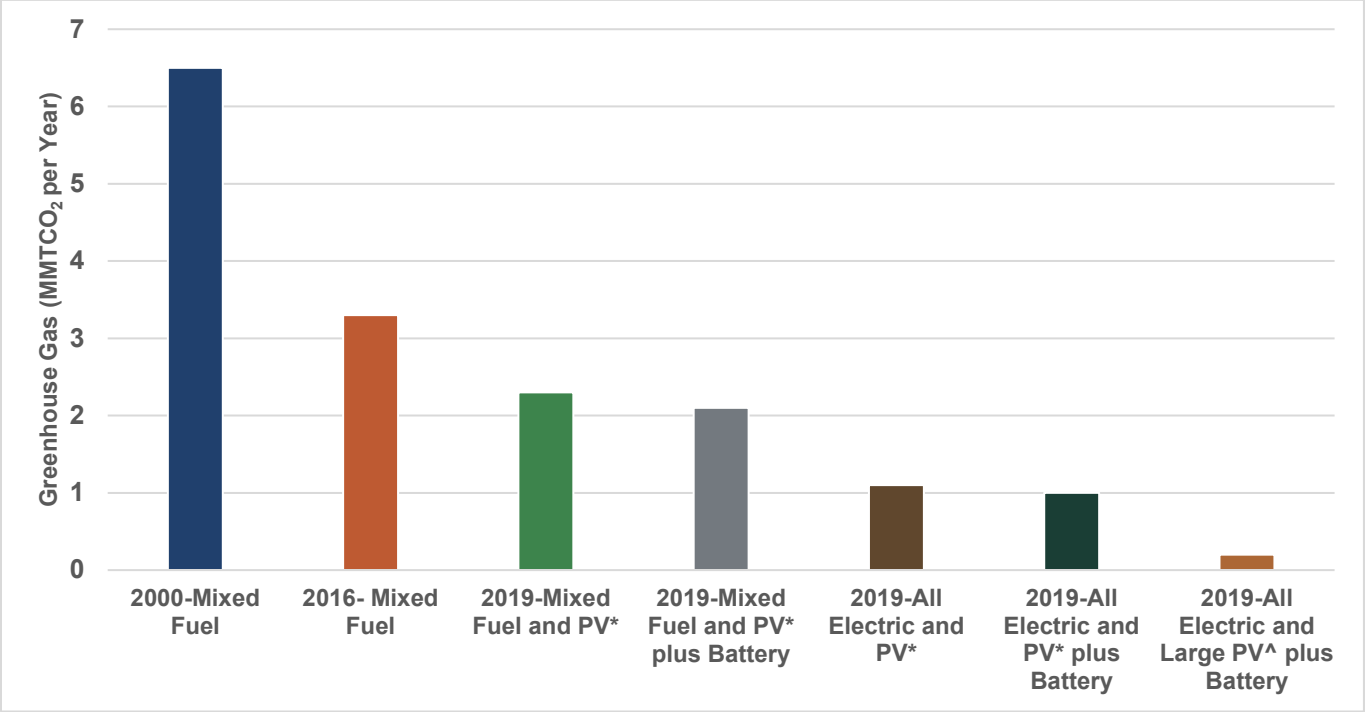
In the near term, gas efficiency can play a role in reducing GHG emissions from buildings. However, when a gas appliance reaches the end of useful life, if building owners choose to replace it with a similar gas appliance, the building likely relies on the gas system through the

useful lifetime of that appliance. Policy makers must determine the appropriate circumstances under which building owners must replace the gas appliance with an electric appliance.

Energy Efficiency Codes and Standards

California sets minimum levels of efficiency for new residential and commercial buildings, for major equipment or building projects in existing buildings, and for non-federally preempted appliances. California can rely on Energy Codes and appliance efficiency standards to deliver more efficient technologies and greater cost savings. These standard-making processes are critical to decarbonizing buildings and shifting markets to support decarbonization. The GHG emissions of single-family homes have been reduced dramatically by the Energy Code. **Figure 33** shows the GHG emission trajectory of a standard single-family home in the Sacramento area (Climate Zone 12) over the last 20 years under the Energy Code and further decarbonization potential from electrification and distributed generation improvements.

Figure 33: Climate Zone 12 Newly Constructed Single-Family Home Emissions



*3.1 kW PV system. ^6 kW PV system. Source: CEC

Building Energy Efficiency Standards

The California Energy Code establishes cost-effective energy performance standards that foster energy efficiency, demand flexibility, and distributed energy resources in the design and construction of residential and commercial buildings, consistent with state and federal laws. The CEC also provides voluntary standards through the California Green Building Standards

that local governments can adopt through local ordinances.[114] The 2022 Energy Code is investigating the transformation of these performance standards to promote building decarbonization by establishing new baselines, where cost-effective, on efficient heat-pump technologies for either space heating or water heating. In the 2025 Energy Standards and subsequent update cycles, the CEC intends to expand further, where cost-effective, by establishing baselines for space and water heating simultaneously. This process will establish a feasible but aggressive pathway to transition the state's newly constructed buildings, across many building categories, from the very low current market share for efficient heat pump space and water heating technologies that exists now to a large majority market share.

Appliance Energy Efficiency Standards

California's appliance efficiency standards are cost-effective efficiency requirements for appliances, which are not preempted by federal law. California's appliance efficiency standards have been an effective tool for reducing energy consumption for decades. Continued expansion and compliance with appliance standards will lead to more energy savings and emission reductions. The appliance standards include permanently installed equipment, as well as portable device plug loads, such as lighting, pool pumps, computers, and televisions.

The CEC will include analysis of the GHG intensity of appliances and consideration of GHG emissions when determining the cost-effectiveness of new regulations. More information on the appliance standards is available at the Title 20 CEC website[115] and in the recently published *2019 California Energy Efficiency Action Plan*.[116]

Local Efficiency Ordinances

More than 30 cities and counties in California have adopted local building energy codes that exceed the statewide minimum 2019 Energy Code requirements. Most of these new local ordinances are based on local climate action plans and include measures to reduce carbon emissions from buildings, require all-electric new construction, or establish minimum efficiency, or design ratings for mixed-use buildings, or limit the installation of new gas infrastructure, or some combination of these actions. **Table 6** presents a list of current (as of January 2021) decarbonization policies adopted by local jurisdictions.[117]

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114 Prepared by Frontier Energy for the PG&E Codes and Standards Program. August 2019. *2019 Energy Efficiency Ordinance Cost-Effectiveness Study: Low-Rise Residential,* page 16, https://efiling.energy.ca.gov/GetDocument.aspx?tn=234020-6&DocumentContentId=66846.

115 CEC, "Appliance Efficiency Regulations – Title 20," https://www.energy.ca.gov/rules-and-regulations/appliance-efficiency-regulations-title-20.

116 Kenney, Michael, Heather Bird, and Heriberto Rosales. *2019 California Energy Efficiency Action Plan*. California Energy Commission. 2019. CMF, https://efiling.energy.ca.gov/GetDocument.aspx?tn=231261&DocumentContentId=62916. Appendix A-16, A-17.

117 More information on Reach Code adoption can be found at the California Energy Code Ace site. Similar information is gathered on the Building Decarbonization Coalition webpage.

Table 6: California Local Jurisdiction Decarbonization Reach Codes

Jurisdiction	All-Electric Build	Electric-Ready	Gas Infrastructure Limitations
Alameda			X
Berkeley		X	X
Brisbane	X		
Burlingame	X		
Campbell	X		
Chula Vista		X	
Cupertino	X		
Davis		X	
East Palo Alto	X		
Hayward	X	X	
Healdsburg		X	
Los Altos Hills	X		
Los Gatos	X		
Marin County		X	
Menlo Park		X	
Millbrae	X		
Mill Valley		X	
Milpitas		X	
Morgan Hill			X
Mountain View	X		
Pacifica	X	X	
Palo Alto		X	
Redwood City	X		
Richmond	X	X	
San Anselmo		X	
San Francisco		X	X

Jurisdiction	All-Electric Build	Electric-Ready	Gas Infrastructure Limitations
San Jose		X	X
San Luis Obispo		X	
San Mateo	X		
San Mateo County		X	
Santa Cruz			X
Santa Monica		X	
Santa Rosa	X		
Saratoga		X	
Sunnyvale	X		
Windsor	X		

Source: CEC, California Building Code Ace, Building Decarbonization Coalition. The "All-Electric Build" category includes some ordinances that do not allow homes or other specified buildings to use gas, as well as other ordinances that allow gas to be installed, but with higher stringency requirements.

Operational Performance Standards

California will need to retrofit its existing residential and commercial building stock to meet climate and energy goals. Mandatory operational performance standards can accelerate the rate of retrofits and send a signal to the market to invest in support systems like manufacturing, technical assistance, auditing, and so forth. A recent report by American Council for an Energy-Efficient Economy (ACEEE) suggests that the United States needs about a twofold increase in the rate of commercial building retrofits.[118]

California's energy benchmarking program requires large commercial and multifamily properties to report annual energy consumption, with some local jurisdictions requiring expanded reporting, auditing, and efficiency improvements.[119] For example, the City of Brisbane requires commercial building owners to verify satisfactory energy and water

118 Nadel, Steven, and Adam Hinge, ACEEE, Mandatory Building Performance Standards: A Key Policy for Achieving Climate Goals, https://www.aceee.org/white-paper/2020/06/mandatory-building-performance-standards-key-policy-achieving-climate-goals. page 3.

119 Brisbane, Los Angeles, San Diego, San Francisco, and San Jose have approved local energy benchmarking programs.

performance.[120] If a building with more than 40,000 square feet does not meet satisfactory performance, the owner must conduct an audit and perform retrocommissioning, adopt efficiency or distributed energy resources measures, or adopt a green lease. The City of Los Angeles similarly requires an energy audit and retrocommissioning measures in the operation of buildings.[121] Building owners can also achieve compliance by receiving ENERGY STAR certification for the compliance year, receiving the certification for two of the three years preceding the compliance date, or documenting a 15 percent reduction in energy-use intensity over the prior five years.

National and global approaches to encourage improved building operational performance include the following:

- New York City recently passed a law requiring buildings with more than 25,000 square feet to meet GHG emissions limits by 2024. Building owners can comply with energy efficiency upgrades by purchasing renewable energy credits or installing a renewable energy system. Building owners must comply over a five-year period.[122]
- In Tokyo, Japan, nearly 1,400 commercial buildings over a certain size have required GHG targets. Building owners must develop a carbon-reduction plan for submittal to the city and then reduce emissions over two consecutive five-year compliance periods.[123]
- Across Europe, countries require commercial buildings to meet certain levels on an energy performance scale. Buildings must meet a C (on a scale between A and G) on the Netherlands Energy Performance Certificate scale, with those failing to comply at risk of losing their license to operate. The Netherlands offers property owners technical assistance and a list of technologies with short payback periods. These are also paired with a tax incentive where owners can deduct up to 45 percent of the energy equipment costs from their taxable profit.[124]

Energy Efficiency Barriers and Challenges

Energy efficiency has well-known barriers to adoption, including financing, program design, and the age of the building.[125] Low Energy Code permitting compliance is one barrier that is

120 City of Brisbane, Building Efficiency Program, https://www.brisbaneca.org/bbep.

121 City of Los Angeles, Existing Buildings Energy and Water Efficiency Ordinance, https://www.betterbuildingsla.com/.

122 Ibid, page 20.

123 Nadel, Steve and Adam Hinge, ACEEE, Mandatory Building Performance Standards: A Key Policy for Achieving Climate Goals, page 5, June 2020, https://www.aceee.org/white-paper/2020/06/mandatory-building-performance-standards-key-policy-achieving-climate-goals.

124 Ibid., page 11.

125 Kenney, Michael, Heather Bird, and Heriberto Rosales. December 2019. *2019 California Energy Efficiency Action Plan.* California Energy Commission. 2019. CMF, https://efiling.energy.ca.gov/GetDocument.aspx?tn=231261&DocumentContentId=62916.

crucial to overcoming the ability to track the success of building decarbonization. Recent studies indicate that between 8 and 29 percent of space conditioning projects had a permit pulled.[126] More information about addressing Energy Code compliance will be included in the *2021 IEPR*.

Cross-cutting barriers constrain implementing all the strategies and are covered in more detail later in the chapter.

Strategy 4 – Refrigerant Leakage Reduction

As the climate in California warms, more residents and businesses will install and use air-conditioning systems, either separate from or inclusive with heat pumps. These installations will increase HFC leakage potential as most HFC emissions come from leakage of refrigeration and air-conditioning systems, mostly in the commercial and industrial sectors.[127]

CARB, CPUC, and CEC are working on policies and programs that require or offer incentives for the use of low-GWP refrigerants or both. CARB runs the state's Refrigerant Management Program, which requires refrigeration system owners and operators to inspect and repair leaks, keep records of service, and report refrigerant use. The service industry is required to capture and properly dispose of HFCs.[128] In 2018, CARB adopted partially vacated federal HFC rules in California, prohibiting high-GWP HFCs in a wide range of end uses, including aerosol propellants, foams, chillers, retail food refrigeration, and residential refrigeration.[129] CARB also adopted regulations requiring new HVAC equipment to have a GWP less than 750 by 2025 and for companies with refrigeration equipment containing more than 50 pounds of refrigerant to reduce their GHG emissions by 55 percent by 2030 or reduce companywide average GWP to less than 1,400 GWP by 2030.[130] Senate Bill 1013 also requires the CPUC, CEC, and the California Department of Housing and Community Development to consider offering incentives for low-GWP refrigerants in their existing energy efficiency programs.[131] The CPUC is

126 DNV-GL, Final Report: 2014-2016 HVAC Permit and Code Compliance Market Assessment Volume I, Prepared for the CPUC, September 2017, calmac.org/publications/HVAC_WO6_FINAL_REPORT_VolumeI_22Sept2017.pdf.

127 CARB. March 2017. *Short-Lived Climate Pollutant Reduction Strategy*, https://ww2.arb.ca.gov/resources/documents/slcp-strategy-final, page 84.

128 CARB. "Refrigerant Management Program," https://ww2.arb.ca.gov/our-work/programs/refrigerant-management-program.

129 CARB. 2018. "Prohibitions on Use of Certain Hydrofluorocarbons in Stationary Refrigeration and Foam End-Uses." https://ww2.arb.ca.gov/rulemaking/2018/high-global-warming-potential-refrigerant-emissions-reductions-regulation.

130 CARB. December 2020. Proposed Amendments to Prohibitions on Use of Certain Hydrofluorocarbons in Stationary Refrigeration, Chillers, Aerosols-Propellants, and Foam End-Uses Regulation. Resolution 20-37. https://ww3.arb.ca.gov/board/res/2020/res20-37.pdf.

131 Senate Bill 1013, Chapter 375, Statutes of 2018. Public Resources Code Section 76002, 76004, and 76006. https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201720180SB1013.

simultaneously establishing low-GWP refrigerants in energy programs to limit the GHG emissions from new projects.[132] The implementation plans for the Building Initiative for Low-Emissions Development (BUILD) and Technology and Equipment for Clean Heating (TECH) programs include extra funds for applicants using low-GWP refrigerants.[133]

CARB and CEC are funding research on low-GWP alternatives to current refrigerants since most common refrigerants have GWPs thousands of times higher than CO_2, as shown in **Table 7**.

Table 7: GWP of Common Refrigerants

Refrigerant	100-Year GWP	Common Use
R-410A	2,088	New heat pumps and air conditioners
R-134A	1,430	New heat pump water heaters
R-22*	1,810	Existing air conditioners, supermarkets
R-404A	3922	Existing supermarkets

Source: CPUC, D. 20-04-010 Appendix A

*R-22 is a HFC and ozone-depleting substance

California utilities through their energy efficiency programs may offer additional funds for low-GWP refrigerants. For example, SMUD is running a pilot program, the Natural Refrigerant Incentive Program, which provides incentives for the use of low-GWP refrigerant technology.[134] As electrification programs expand and the amount of refrigerants increase, other utilities should offer incentives for the use of low-GWP refrigerants.

Barriers to HFC Leakage Mitigation and Low-GWP Refrigerants

Low-GWP refrigerants have barriers associated with higher incremental cost, lack of commercially available equipment, lack of building code updates and lack of trained technicians. The cost premium for low-GWP technologies is a major barrier that prevents the

132 CPUC. April 2020. Building Decarbonization Pilot Programs, Decision 20-03-027, https://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=331772660.

133 Ibid.

134 SMUD. "Pilot Refrigeration Program," https://www.smud.org/en/Business-Solutions-and-Rebates/Business-Rebates/Advanced-Tech-Solutions.

retrofit or replacement of existing HFC systems, which can last 15–20 years or even longer. Some technologies may require special installation and maintenance practices that make them uneconomical, while others have flammability concerns, and some may result in lower operating efficiency if not appropriately designed.[135] Moreover, in spite of existing regulations that prohibit intentional venting of refrigerants, there is little incentive to capture end-of-life refrigerant emissions from millions of units of equipment. Researchers, policy makers, and manufacturers must weigh the options of continued use of high-GWP refrigerants against the concerns related to low-GWP refrigerants. Some low-GWP refrigerants are shown in **Table 8**.

Table 8: Low-Global-Warming-Potential Refrigerants

Refrigerant	100-Year GWP	Common Uses
R-32, R-452B, R-454B, R-466A*	450-750	Replacement for R-410A. Not currently allowed in building codes for most types of HVAC applications. *R-466A is allowed per existing building codes but is not commercially viable.
R-1234yf	<1	Replacement for R-134A. Not currently allowed in building codes for most types of applications Permitted for use in chillers. Already widely used in vehicle air conditioners.
Propane (R-290)[136]	3	Replacement for some types of heat pumps. Not widely adopted in the United States and not currently allowed in building codes. Widely used in residential and commercial refrigeration elsewhere.
CO_2 (R-744)	1	Used in supermarket refrigeration, vehicle air conditioners, and heat pump water heaters. Not widely adopted in United States.
Ammonia (R-717)	0	Commercial and industrial refrigeration systems, and cold storage warehouses.
R-450A, R-448A, R-449A, R-513A	~600-1400	Used in supermarket refrigeration, chillers, and industrial process refrigeration.

135 CPUC. D. 20-04-010 Appendix A, page 45, https://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=334734544.

136 Due to high flammability, special installation and maintenance are required.

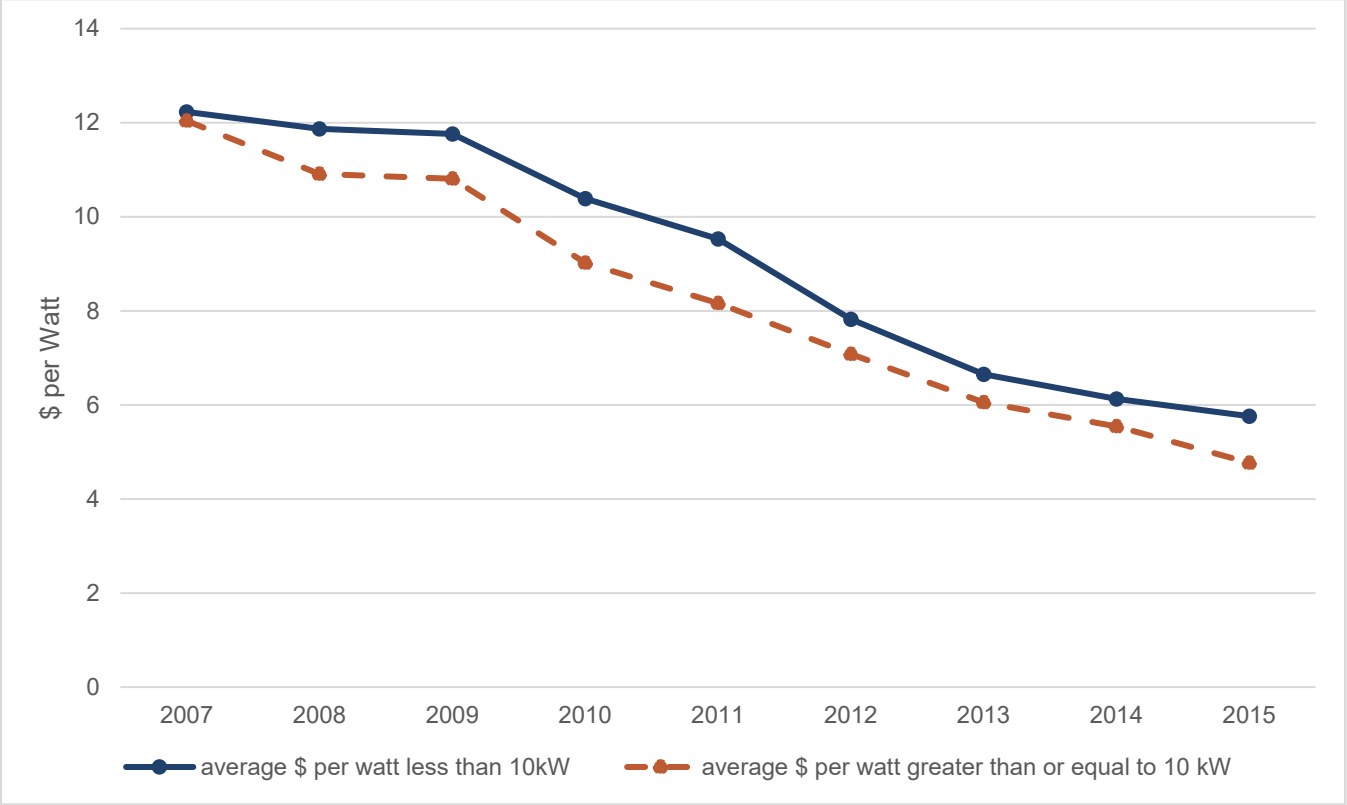
Source: CPUC, D. 20-04-010 Appendix A

Some low-GWP alternatives still have warming impacts up to hundreds of times greater than CO_2, so continued leakage at the end of life will continue to result in major GHG emissions.

Strategy 5 – Distributed Energy Resources

Expansion of distributed renewable energy and storage is critical to California meeting its clean energy goals and grid reliability. California has had great success supporting the solar PV market, which it will need to do for other decarbonization technologies like heat pumps and batteries. In 2005, then-Governor Arnold Schwarzenegger set the goal to have 1 million solar roofs installed, and the state launched the California Solar Initiative (CSI) in 2006. This program led to incentives, beneficial rate designs, and research to drive down the cost of installing, owning, and operating a solar-powered system, as shown in **Figure 34**. California achieved this goal set more than a decade ago and will see thousands more installations now that all new homes must install solar PV systems to meet electric needs.[137]

Figure 34: Average Cost per Watt of Rooftop Solar



Source: California Distributed Generation Statistics

137 CEC. December 2018. *2019 Building Energy Efficiency Standards*, Section 110.10, page 127, CEC-400-2018-020-CMF https://ww2.energy.ca.gov/2018publications/CEC-400-2018-020/CEC-400-2018-020-CMF.pdf.

The CSI created a self-sustaining solar market by rebating solar power installations on residential and commercial buildings.[138] CSI succeeded by creating economies of scale, which drove down costs of solar energy and generated new jobs in the solar industry. Throughout its life, the CSI provided more than $2.9 billion in rebates to California customers.[139] However, the program also created inequality. As wealthier customers moved to favorable rooftop PV rates, the burden of paying back utility investment increased on lower-income customers.[140]

The Self Generation Incentive Program (SGIP) is a CPUC-administered program focused on reducing emissions and increased system reliability by offering incentives for distributed generation.[141] The program has been operating since 2001 in response to the 2000–2001 energy crisis. Funding for SGIP primarily goes to energy storage, but about a fifth is reserved for other projects like wind turbines, combined heat and power, and fuel cells. About 25 percent of the SGIP budget is reserved for disadvantaged and low-income communities.[142] The program also offers incentives through the equity budget to customers impacted by two or more public power shutoff events to install on-site batteries.[143]

Most recently, the program expanded to fund heat pump water heaters as a form of thermal storage.[144] In January 2020, the CPUC set aside $40.67 million in the SGIP to fund installation of general market heat pump water heaters between 2020 and 2024.[145] This allocation is in addition to the $4 million set aside in a September 2019 decision for customers in disadvantaged and low-income communities.[146]

Distributed Energy Strategies for Building Decarbonization

Numerous distributed energy strategies exist to support building decarbonization. They commonly include rooftop solar, thermal batteries, and lithium-ion batteries, as shown in **Figure 35.** These distributed energy resources can support demand flexibility, which eases

138 CPUC. "California Solar Initiative," https://www.cpuc.ca.gov/General.aspx?id=6058.

139 CPUC. June 2020. *California Solar Initiative 2020 Annual Program Assessment,* page 8, CSI Program Results, https://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442465653.

140 Energy Institute at UC Berkeley's Hass School of Business and NEXT 10, Designing Electricity Rates for An Equitable Energy Transition, February 2021. Page 27. Available at https://www.next10.org/sites/default/files/2021-02/Next10-electricity-rates-v2.pdf.

141 CPUC. "Self-Generation Incentive Program," https://www.cpuc.ca.gov/sgip/.

142 CPUC. "Self-Generation Incentive Program, Decision 19-09-027," https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M313/K975/313975481.PDF.

143 CPUC. "Self-Generation Incentive Program, Decision 20-01-021," https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M325/K979/325979689.PDF.

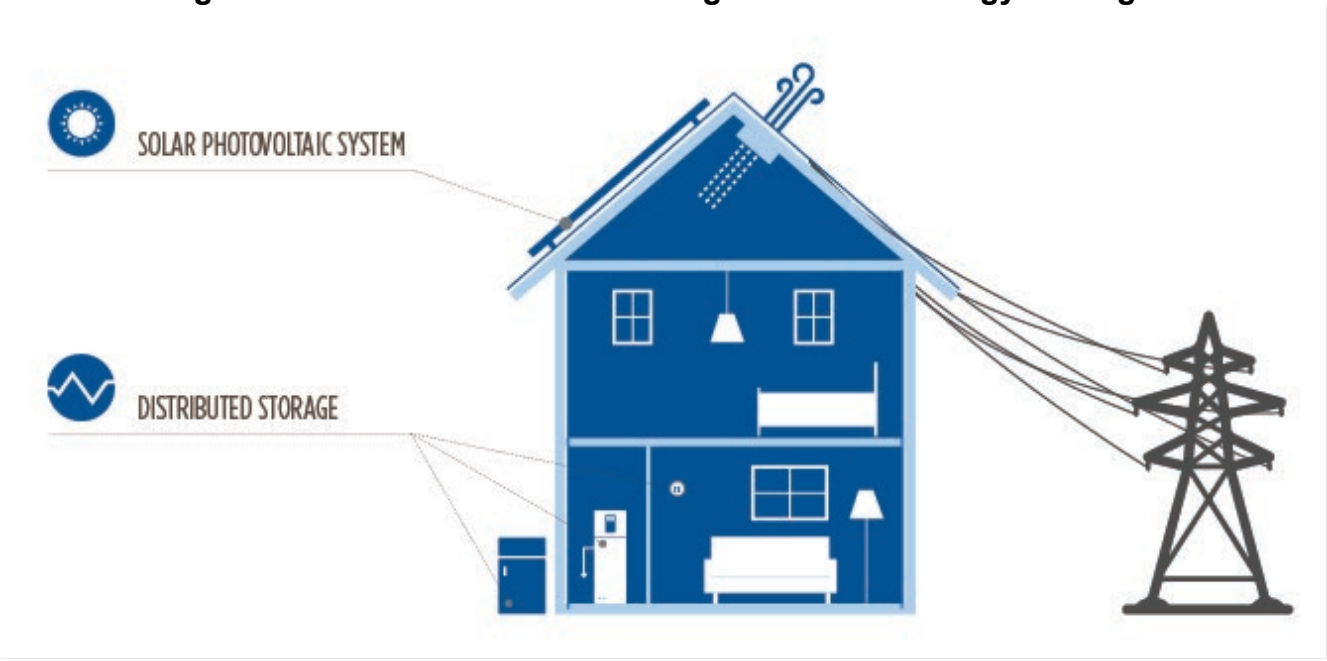
144 Ibid..

145 Ibid.

146 CPUC Decision 19-09-027, http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=313975481.

strain on the electrical grid, may reduce customers' energy bills, and increase the resiliency of buildings to power shutoffs and outages.

Figure 35: Schematic of Home Using Distributed Energy Strategies



Source: CEC

Rooftop Solar PV

Residential and commercial buildings across the state use rooftop solar to generate their own electricity. These customers can offset the cost of running electric end uses and electric vehicle charging. To maximize the solar energy produced and limit the strain on the grid, the electricity that is being generated must be used or stored on-site and not rely on net metering to compensate usage.

Thermal Battery

Water heaters can serve not just as a source of hot water for a home or business, but also as a thermal battery to absorb excess renewable energy during the day. An air-source heat pump water heater can preheat water to high levels during the day so that at night or in the early morning, it can provide all the hot water required of the occupants of a building.[147] The key is for the water heater to be able to communicate with the local utility or third-party provider, so it knows what time of day to operate and absorb excess electricity as hot water. (See "Demand Flexibility" discussion.) This has the potential to save the customer and the utility

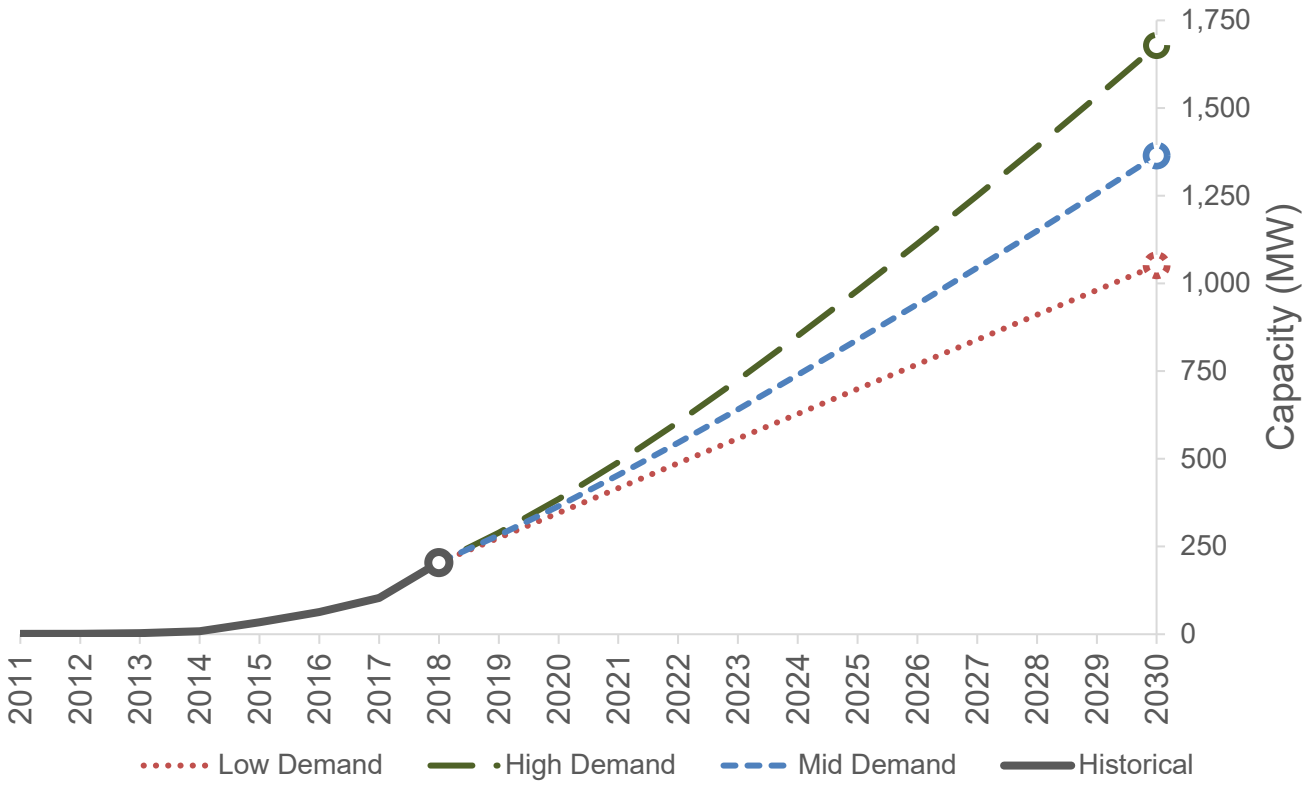
147 Example: Pierre Delforge and Olivia Ashmoore. January 2020. "Heat Pump Water Heater as Clean-Energy Batteries," pg. 4, https://www.nrdc.org/experts/pierre-delforge/heat-pump-water-heaters-clean-energy-batteries.

money. The Energy Code has established a set of requirements for demand-responsive water heaters to earn compliance credit in Joint Appendix (JA) 13.

Lithium-Ion Battery

The cost of short-duration batteries continues to drop. The capacity of behind-the-meter storage has grown more than 200 percent in the last decade and is expected to grow substantially by 2030 in all scenarios studied by the CEC shown in **Figure 36**.[148]

Figure 36: Energy Storage Capacity Forecast



Source: CEC, 2019 Integrated Energy Policy Report

Solar PV systems can be paired more affordably with a battery system so that excess solar energy is not sent back into the grid but saved for future use on site. According to a 2019 National Renewable Energy Laboratory report, the cost of a 4-hour lithium-ion battery is expected to drop from 20 to 70 percent by 2030.[149] Recent changes to SGIP may make

148 California Energy Commission staff. 2020. *Electricity Demand Forecast*, https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report/2019-integrated-energy-policy-report/2019-iepr#accordion-4131.

149 Cole, W., and A. W. Frazier. 2019. *Cost Projections for Utility-Scale Battery Storage*. NREL/TP-6A20-73222. Available at https://www.nrel.gov/docs/fy19osti/73222.pdf.

behind-the-meter storage more cost-effective, especially for rural and low-income households affected by public safety power shutoffs.

Distributed Generation and Storage Barriers

The primary barriers to distributed generation and storage are covered in the "Cross-Cutting Barriers" section. Many home or business owners lack the upfront capital to install these technologies and may not have adequate roof strength or space for installation.

While the GHG intensity of the electricity generation system decreases, rooftop solar and batteries are zero-carbon options building owners can install now. When paired together, solar-plus-storage can carry excess zero-carbon electricity into the evening and night hours. This solution lessens peak demand from buildings, which in turn lowers the need for GHG-intensive electricity sources being used.

Strategy 6 – Decarbonizing the Gas System

Combustion of gas results in the emission of several types of GHGs and air pollutants. The state's gas system is operated predominately by two IOUs, with the Pacific Gas and Electric Company serving the northern portions of the state and the Southern California Gas Company, which also operates San Diego Gas & Electric Company's gas system, serving the southern portions of the state. These utilities, along with gas utilities across the country, are pursuing opportunities to decarbonize the gas system with renewable gas and other low-carbon fuels. For the immediate future, these opportunities are more limited and costly than building electrification.

Alternative methods exist to create renewable gas from agriculture waste, municipal solid waste, landfills, dairy digesters, and forest biomass, thus reducing the climate impacts by displacing fossil gas and recycling GHGs in other sectors of the economy. Biogas can be harvested from municipal waste and manure, agricultural and forest waste can be converted into methane through a process called "gasification," and electrolysis converts excess renewable electricity into hydrogen. Another possible renewable gas is synthetic gas if it is developed from renewable hydrogen and carbon dioxide. By using the existing gas infrastructure to deliver fuel to buildings and substituting gas with renewable gas, California can reduce the GHG emissions from sectors or industries that cannot functionally electrify. It may be necessary to treat renewable gas to remove impurities that could damage pipelines, thus raising the cost of the use of this gas.[150]

By keeping components of the gas system in use, the state can save on decommissioning costs. The SB 100 analysis indicates that most of the gas-fired power plants will remain

150 For example, Kleeman, Michael J., Thomas M. Young, Peter G. Green, and Stefan Wuertz. 2020. *Evaluation and Identification of Constituents in Pipeline Natural Gas, Biogas, and Upgraded Biomethane in California*. California Energy Commission. Publication Number: CEC-500-2020-031.

operational through 2045, potentially allowing renewable gas to play a role in reducing the GHG intensity of electricity even further.[151]

Renewable Gas Barriers

The key barriers to renewable gas are supply and costs. The amount of renewable gas available has been studied by several sources with an estimate that 9 percent of existing gas use in California could be replaced by renewable gas using both in-state and out-of-state sources.[152] Others have estimated the technical potential of renewable gas as 90.6 billion cubic feet annually, which would be around 18 percent of the state's annual gas use.[153] CEC analyzed a 20 percent substitution of renewable gas for fossil gas in this assessment based on findings in a 2018 study on renewable gas potential.[154]

The costs to produce renewable gas vary by supply source and the distance to the gas pipeline. Forest waste may be available for use in the northwest and mountainous regions, whereas potential agricultural waste is mostly in the Central Valley, and potential municipal and gaseous wastes are primarily within urban areas.[155] The distribution of resources means that all parts of the state could generate renewable gas, but some of those areas will have greater barriers than others because of a lack of existing facilities, large distances to a gas system interconnection, costs and land impacts of new pipelines, and the costs to prepare gas for interconnection. Once the amount of biomass available for conversion to biogas or biomethane is reached, then much more expensive synthetic gas sources would have to be used for any further displacement of fossil gas.

It is not clear that the most economical GHG-reducing strategy is to send that cleaner gas to residential and commercial buildings via the gas distribution system. Overall, researchers have estimated that renewable gas has the lowest cost per metric ton of CO_2 in transportation and carbon-capture power plants, not buildings.[156] The use of these fuels in the residential and

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151 Joint Agencies. March 2021. 2021 SB 100 Joint Agency Report. page 103. https://efiling.energy.ca.gov/EFiling/GetFile.aspx?tn=237167&DocumentContentId=70349.

152 Energy Futures Initiative. May 2019, *Pathways for Deep Decarbonization in California*, pg. 215, https://energyfuturesinitiative.org/s/EFI_CA_Decarbonization_Full-b3at.pdf.

153 Jaffe, Amy & Dominguez-Faus, Rosa & Parker, Nathan & Scheitrum, Daniel & Wilcock, Justin & Miller, Marshall. (2016). The Feasibility of Renewable Natural Gas as a Large-Scale, Low Carbon Substitute. Page 75. California Air Resources Board Final Draft Report Contract. https://www.researchgate.net/publication/320215969_The_Feasibility_of_Renewable_Natural_Gas_as_a_Large-Scale_Low_Carbon_Substitute.

154 Guidehouse (Formerly Navigant), Prepared for Southern California Gas Company. 2018. Analysis of the Role of Gas for a Low-Carbon California Future. https://www.socalgas.com/1443741887279/SoCalGas_Renewable_Gas_Final-Report.pdf.

155 Ibid., page 33.

156 Baker et al. January 2020. *Getting to Neutral: Options for Negative Carbon Emissions in California,* Lawrence Livermore National Laboratory, LLNL-TR-796100. pages 63-68, https://www-gs.llnl.gov/content/assets/docs/energy/Getting_to_Neutral.pdf.

commercial sectors still results in significant air quality issues from indoor combustion and leakage. Also, California has worked for years to establish the Low Carbon Fuel Standard, which offers incentives for the displacement of high-carbon-intensity fuels for lower ones in the transportation sector.[157] The replacement of high-carbon-intensity fossil fuels with renewable gas in the transportation sector may be impeded if more renewable gas is slated for injection in the pipeline for building use. Renewable gas may be best suited for consumption in sectors least able to electrify, such as certain heavy industries, long-haul transportation, or electricity power generation.

Strategy 7 – Demand Flexibility

Demand flexibility will be critical for supporting the grid and transitioning to a carbon-free energy system in the short term and mid-term. Demand flexibility is a particularly promising strategy for reducing GHG emissions in buildings, with the potential to reduce GHG emissions significantly hour to hour, or even minute to minute. Such flexibility requires the presence of automated control technologies for quick reactions to incoming utility signals. End-use technologies that control thermal, chemical, and potential energy storage are especially good candidates for demand flexibility. These include technologies that manage battery charging, space and water heating, and space cooling. Common examples include home battery systems, electric vehicle supply equipment, thermostats, pool and spa controls, and water heaters.

In 2019, the CEC instituted a rulemaking to update the existing load management standards with a goal to promote the automation of flexible demand resources on a statewide, mass-market scale.[158] The proceeding is focused on developing a statewide system for gathering and publishing time-varying prices and 5-minute GHG emission profiles to support demand flexibility. The CEC is simultaneously developing appliance standards for flexible-demand technologies.[159] Senate Bill 49 (Skinner, Chapter 697, Statutes of 2019) expanded the CEC's authority to set load-shifting standards for appliances and consider the avoided GHG impacts of flexible-demand technologies.[160] Taken together, these two proceedings have the potential to revamp the traditional utility load-control paradigm, replacing it with a more organic, customer-centric system for modifying load. This effort is expected to reduce GHG emissions, improve grid reliability, reduce the need to curtail renewable resources, simplify utility demand flexibility programs, and lower system and ratepayer costs.

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157 CARB. Low Carbon Fuel Standard. https://ww2.arb.ca.gov/our-work/programs/low-carbon-fuel-standard.

158 CEC Load Management Standards Rulemaking: https://www.energy.ca.gov/proceedings/energy-commission-proceedings/2020-load-management-rulemaking. See also California Code of Regulations Title 20 §1621-25.

159 California Public Resources Code 25402 (f).

160 Ibid.

The CEC is initiating a new research project that will create the California Load Flexibility Hub.[161] The hub will advance load-flexible technologies and strategies to further the state's clean energy goals and support other CEC efforts, including the SB 49 and load management standards rulemakings. The primary goals of the California Load Flexibility Hub are to enhance grid reliability in a cost-effective and equitable manner.

As shared in the "Efficiency Strategy" above, efficiency programs targeted at reducing peak demand are a low-cost opportunity for utilities.[162] A recent study commissioned by the CPUC indicates that the total potential for cost-effective load shifting in California is about 2 GW, with an expectation for this potential to increase to 2.5 GW by 2030. The vast majority of this potential capacity is expected to be derived from commercial and residential HVAC systems, followed by electric vehicles, residential water heaters, and pool pumps.[163] To date, the potential for granular demand flexibility in California has not been well studied. The CEC's pending load-management standards and flexible demand appliance standards rulemakings supporting analyses will shine more light on this complex topic.[164]

Today, California maintains 1.8 GW of supply-side demand response and nearly 1 GW of response to critical peak pricing.[165] As a practical and policy matter, this potential is used for system resiliency, not GHG reductions. Future policy decisions can create programs that encourage response to high GHG emissions as well.

Demand Flexibility Barriers

Demand flexibility can play an important role in building decarbonization. A principal barrier to widespread demand flexibility is the propensity of utilities and state agencies to segregate, or "silo," the four demand flexibility strategies — energy efficiency, load shifting, demand response, and demand flexibility — in field studies, research, policy, and funding. Rules tethering certain silos of funding to strict program definitions hamstring efforts to advance demand flexibility strategies needed to address objectives that can have synergistic effects. For example, a single program that offers improved insulation and a time-of-use (TOU)

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161 CEC. 2020. California Flexible Load Research and Deployment Hub. GFO-19-309. https://www.energy.ca.gov/solicitations/2020-09/gfo-19-309-california-flexible-load-research-and-deployment-hub

162 Frick et al. November 2019. *Peak Demand Impacts From Electricity Efficiency Programs.* LNBNL. https://emp.lbl.gov/publications/peak-demand-impacts-electricity

163 Gerke et al. July 2020. *The California Demand Response Potential Study Phase 3: Final Report on the Shift Resource through 2030.* DOI: 10.20357/B7MS40.

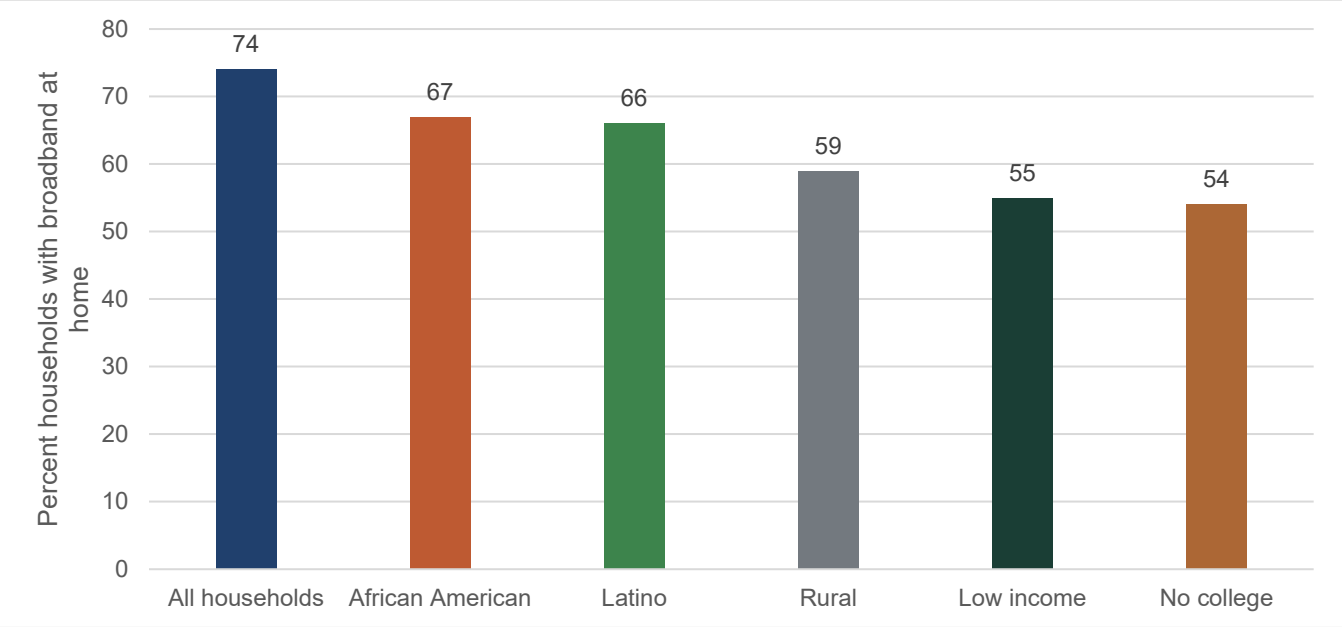
164 See CEC Flexible Demand Appliances rulemakings: https://www.energy.ca.gov/proceedings/energy-commission-proceedings/flexible-demand-appliances.

165 CPUC Energy Division. September 2020. "Demand Response Achievements in California – Fact Sheet."

responsive precooling thermostat will enhance efficiency and load shifting, while the insulation improves the effects of load shifting. Widespread market adoption will be necessary for demand flexibility to play a sizeable role in building decarbonization.

There are also concerns about the cost of buying and installing demand-flexibility technologies, including access by low- and moderate-income households to appliances and financing. Most demand-responsive and demand-flexible controls require broadband internet access, in addition to controllable loads such as heat pump water heaters, EVs, pools and spas, and battery systems — items not yet typically found in low-income homes. As **Figure 37** shows, 74 percent of California households have broadband, with those numbers dropping to 59 and 54 percent for rural and low-income, respectively.

Figure 37: California Household Access to Broadband Internet



Source: American Community Survey, 2017

According to Broadband Now, 889,000 residents do not have a wired internet provider, and 1.3 million people in California without access to a wired connection capable of 25 Mbps download speeds. Another 1.5 million have access to only one wired provider, leaving them no options to switch.[166]

Broadband Now's latest affordability data show that 70 percent (about 28 million) of California residents have access to a standalone broadband internet plan costing less than $60 per

166 Broadband Now. "Best States WITH Internet Coverage and Speed," https://broadbandnow.com/research/best-states-with-internet-coverage-and-speed.

month as of the fourth quarter of, 2019. This percentage is significantly higher than the 51.5 percent of consumers that have access to the same at the national level.[167]

Demand flexibility derived from customer response to TOU or dynamic rates requires interval meters or "smart" meters, which collect and store energy-use metrics at least every hour to send to the utility for billing. While the IOUs and Sacramento Municipal Utility District (SMUD) have rolled out smart meters to all sectors in their service territories, there are many publicly owned utilities, such as the Los Angeles Department of Water and Power (LADWP), that have very few installed. In the absence of smart meters, utilities can still offer demand-flexibility programs that reduce GHG emissions. For example, SGIP offers equipment rebates in return for GHG-response or utility control of battery charging. Similar programs offering technology or cash incentives in exchange for GHG response can be offered at any utility, regardless of metering infrastructure.

Cross-Cutting Barriers

The primary building decarbonization strategies have common barriers. All barriers must be analyzed at state, regional, and local levels to evaluate solutions. The following sections discuss the common barriers to implementing decarbonization strategies that decision-makers must consider.

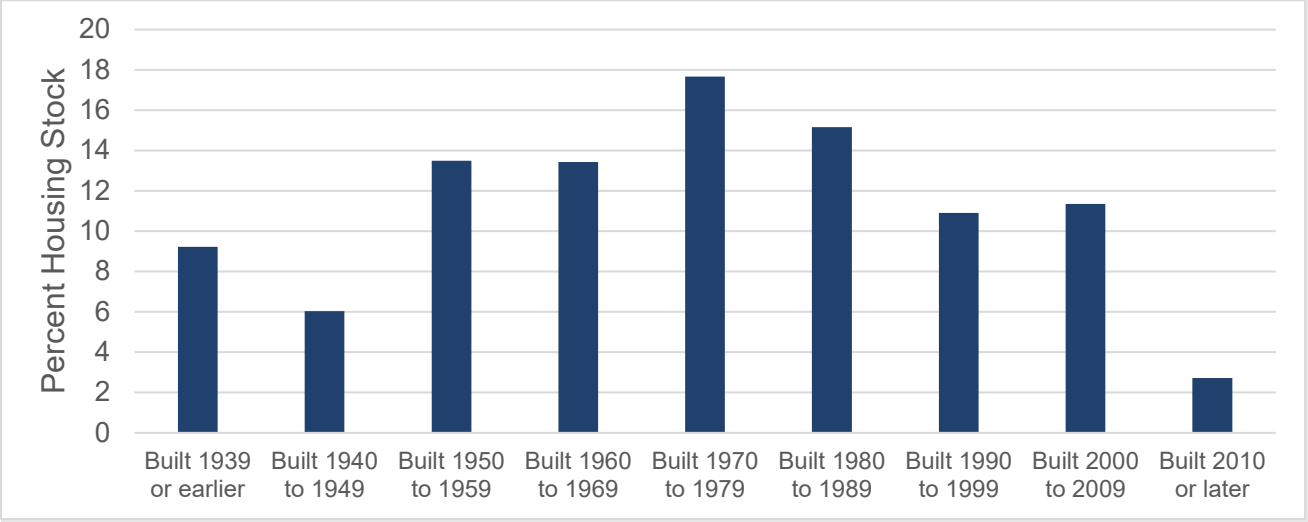
Age of Building Stock

About 75 percent of California's residential buildings, or about 9.75 million units, were built before 1990, as shown in **Figure 38**.[168] Older homes have significant barriers to decarbonization and are less likely to have adequately sized electric panels for new electric loads, appropriate levels of insulation for holding cooling or heating effects, proper ventilation, and roofs with the structural integrity or space capable to support the necessary number of solar panels. In addition, older buildings may have structural or design issues that may require structural retrofits or that make decarbonization retrofits more challenging.

Figure 38: Age of California Housing Stock

167 Ibid.

168 California Department of Housing and Community Development. February 2018. *California Housing Future: Challenges and Opportunities*, page 17, https://hcd.ca.gov/policy-research/plans-reports/docs/sha_final_combined.pdf.



Source: U.S. Census Bureau, 2018 American Community Survey 5-year estimates, DP04

Older homes are also more likely to contain unhealthy construction materials and older equipment. Low-income occupants in older, unhealthy homes have a higher risk of chronic disease like asthma, heart attack, stroke, and high blood pressure.[169] Structural issues may also disqualify households from energy program participation, further disenfranchising them from clean energy benefits. These issues add to the costs of upgrades (either in piecemeal or comprehensive fashion) and can prevent lower- and middle-income residents from participating.

By 2030, fewer than 10 percent of residential buildings will have been built following 2019 or later Energy Codes unless measures are taken to ramp up new construction. To achieve the 40 percent GHG reduction in residential and commercial buildings, the state will need to accelerate the number of retrofits done each year. The state's existing building stock has the potential to either set California on the road to decarbonization or be a roadblock to achieving climate goals.

Scheduling Retrofits

Most upgrades to water and space heating systems are not planned. Heat pump technology is not as widely available as gas water heaters or furnaces, and in emergency or unplanned situations, the building owner or occupant may be restricted to what new equipment can be installed quickly. To achieve greater rates of heat pump penetration, either installers need to be educated and trained in heat pumps with ready access to heat pumps, or consumers need to anticipate an appliance reaching the end of useful life and proactively retiring it to a related schedule before it is nonoperative.

169 Hayes et al. May 2020. *Making Health Count: Monetizing the Health Benefits of In-Home Services Delivered by Energy Efficiency Programs,* pg. 1, ACEEE, https://www.aceee.org/research-report/h2001.

Owners and operators of multifamily and commercial properties seeking to perform decarbonization retrofits must plan well in advance to make it happen. Given competing needs in a building or the lack of awareness or benefits from energy programs, energy retrofits may be overlooked or determined to be too time-consuming. Moreover, building owners need assurances that financial incentives will be available to reimburse upgrade expenses before committing to move forward.

In low-income developments, "resyndication" is a process that requires owners of affordable housing properties to reapply for tax credits after an initial 15-year period. It affords owners an opportunity to make many building upgrades. According to a recent Energy Efficiency for All study, building owners need one to two years of planning and preparation for building upgrades before resyndication.[170] Since taking on debt is often not possible for these owners, debt-free options must be on the table, or the owner may continue to delay improvements.[171] Setting up a program or resource through local or state offices, a one-stop shop, for building owners to use for scheduling upgrades, layering incentives, or arranging audits would streamline the process for residential and commercial building owners and tenants.[172]

Project Financing

Retrofit rates for residential and commercial buildings are constrained by the lack of upfront capital available to most businesses and households to finance a major energy retrofit, and retroactive rebates do not offset enough of the costs to increase customer participation. Low- and moderate-income households need access to zero-to-low upfront cost programs and technical assistance to participate in retrofits. Commercial building owners also need zero- to low-debt options with longer-term payback periods. All programs must be offered in multiple languages so that all Californians have access to programs and can easily participate.

Work by the Building Decarbonization Coalition estimates that the investment needed to decarbonize the residential sector is about $5 billion annually just for low- to moderate-income households.[173] Unlocking more capital to support implementing decarbonization strategies is critical. In August 2020, the CPUC initiated a new rulemaking, R.20-08-022, to investigate and

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170 Energy Efficiency for All. 2019. *Advancing a Green New Deal for Los Angeles Renters,* page 18, https://www.energyefficiencyforall.org/resources/advancing-a-green-new-deal-for-los-angeles-renters/.

171 Henderson, Philip. 2015. *Program Design Guide: Energy Efficiency Programs in Multifamily Affordable Housing.* http://www.energyefficiencyforall.org/sites/default/files/Full%20Program%20Design%20Guide.pdf.

172 Ibid., page 25.

173 Mast, Bruce, Holmes Hummel, and Jeanne Clinton. June 2020. *Towards an Accessible Financing Solution, Building Decarbonization Coalition,* page 16, http://www.buildingdecarb.org/uploads/3/0/7/3/30734489/bdc_junewhitepaper_designdraft.pdf.

design clean energy financing options for electricity and gas customers.[174] Below are some options policy makers can consider:

- Residential property assessed clean energy (PACE) provides a pathway for households to finance upgrades but is limited to property-affixed measures and only to property owners.[175] In addition, the financing terms may not be affordable to low- and middle-income households.
- The CEC offers Energy Conservation Assistance Act loans to schools and local jurisdictions.[176] The zero- and low-interest loans are used for energy- and demand-reduction measures. These loans could be used to further decarbonize schools and government buildings, but there is limited annual funding available.
- The California Alternative Energy and Advanced Transportation Financing Authority administers the Affordable Multifamily Energy Efficiency Financing Program, which leverages existing efforts to finance affordable multifamily energy efficiency retrofits and provides a credit enhancement to reduce financing entity risk. An on-bill repayment option is scheduled at this time.
- The California Tax Credit Allocation Committee administers the federal and state Low-Income Housing Tax Credit Programs, which provide private investment in affordable multifamily construction and rehabilitation.
- Current incentives from utilities offset a portion of upfront costs either directly or indirectly. Covering a greater percentage of upfront costs is needed to increase customer participation. SMUD recently offered significant cost recovery incentives for building decarbonization retrofits, which provides a pilot example for decision makers and other utilities.[177]
- Stakeholders have also pushed California to consider methods that require no upfront payment by the customer, such as tariff on-bill financing (OBF), which qualifies homes for direct installation of cost-effective measures in **Figure 39**.[178] OBF leverages funds from capital providers loaned to the utility company, which is used to upgrade a building, with repayment collected through a tariff tied to the building meter. The *2019 California Energy Efficiency Action Plan* calls for statewide implementation of tariff OBF

174 CPUC. August 2020. https://www.cpuc.ca.gov/General.aspx?id=6442467601.

175 Property-affixed measures include heating, cooling, ventilation, and envelope changes.

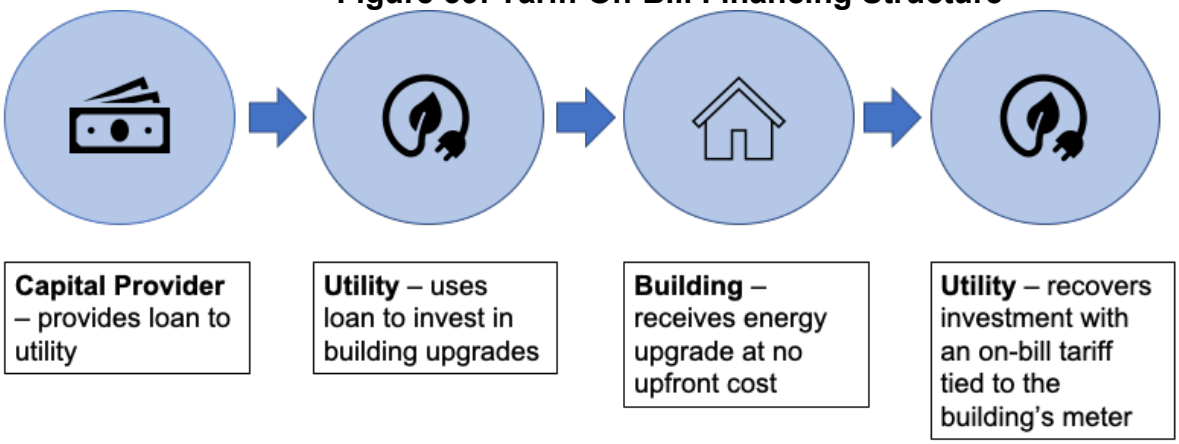
176 CEC. "Energy Savings Assistance Act Loan," https://www.energy.ca.gov/programs-and-topics/programs/energy-conservation-assistance-act/low-interest-loans.

177 SMUD. "Go Electric," https://www.smud.org/en/Rebates-and-Savings-Tips/Go-electric.

178 Mast, Bruce, Holmes Hummel, and Jeanne Clinton. June 2020. *Towards an Accessible Financing Solution, Building Decarbonization Coalition,* page 22, http://www.buildingdecarb.org/uploads/3/0/7/3/30734489/bdc_junewhitepaper_designdraft.pdf.

to provide pathways to energy efficiency and decarbonization.[179] This method can be applied to occupant-owned and rented units.

Figure 39: Tariff On-Bill Financing Structure



Source: Southeast Energy Efficiency Alliance, Utility Guide to Tariffed On-Bill Programs, February 2020

Considerations for setting up residential tariff OBF in California include:

- Setting up a loan loss reserve to avoid disconnections.
- Allowing partial payments to preserve electric service.
- Developing strong consumer protection guidelines.
- Permitting energy and emission reducing measures.
- Requiring contractor standards.
- Requiring cash-positive projects to reduce energy burden.
- Having tariff OBF, which allows the completion of a commercial building retrofit without the owner taking on new debt and can be made available to specific tenants in a building responsible for the energy bills. The qualification for the business is based on the payment of their utility bill. Changes to current on-bill program rules are needed.[180] They include:
    - Expanding the payback period from 5 years to up to 15 years.
    - Increasing the maximum capital limit available for a project from $250,000.
    - Performing meter-based verification of savings.

179 Kenney, Michael, Heather Bird, and Heriberto Rosales. December 2019. *2019 California Energy Efficiency Action Plan.* California Energy Commission. Page 95. CMF, https://efiling.energy.ca.gov/GetDocument.aspx?tn=231261&DocumentContentId=62916.

180 Shahinian, Mark. July 2020. "Setting Free the Dancing Bear: A Practitioner's View of How to Break Open Energy Efficiency." *Utility Dive*, https://www.utilitydive.com/news/setting-free-the-dancing-bear-a-practitioners-view-of-how-to-break-open-e/581862/.

With longer investment periods and avoided debt to the building owner, the sale of buildings is not hindered, but deep retrofits are implemented, and the value of the property increases. These actions are interrelated, and each transaction becomes smoother to the benefit of every involved market actor.

Program Design

Implementation of wide-scale building decarbonization in California should look to recent, successful programs for guidance. The CSI used incentives, policy goals, and research to drive the installation and cost reduction of PV panels.[181] Residential and commercial building decarbonization can follow a similar program design however it would need to avoid exacerbating equity issues by pushing costs to non-participants. A concerted effort is needed to spread program benefits to disadvantaged and low-income communities and households and avoid directing resources primarily to higher-income households. California must fund research program designs, offer incentives for appropriate technologies, use regulations to guide the market, and adopt responsible policies.

- A statewide on-bill program could generate tens of thousands of new projects, remove upfront costs to participants, support the growing clean energy workforce, provide health and energy benefits regardless of income or rental status, and drive building decarbonization.
- Direct-installation programs, like the California Department of Community Services and Development-run Low-Income Weatherization Program (LIWP), are successful at achieving significant energy and GHG savings, raising awareness of customers, and installing several measures.[182] LIWP is underfunded with a waitlist of more than 10,000 homes.
- California can also look to the American Recovery and Reinvestment Act-era programs as prime examples, including the California Comprehensive Residential Retrofit program, which funded retrofits using local governments and utilities as administrators, and the Municipal and Commercial Building Targeted Measure Retrofit program, which completed retrofits and audits and trained hundreds of personnel. Expanded funding would boost local economies as California recovers from the COVID-19 pandemic-induced recession and moves closer to its clean energy goals. Direct-install programs are also more convenient and preferred over upfront capital programs, according to surveyed Los Angeles multifamily building owners.[183] Mid- and upstream-incentive programs reduce costs further up the supply chain. By

181 CPUC. June 2020. *2020 California Solar Initiative Annual Program Assessment,* pages 12-14, https://www.cpuc.ca.gov/General.aspx?id=6043.

182 California Department of Community Services and Development. "Low-Income Weatherization Program," https://csd.ca.gov/Pages/Low-Income-Weatherization-Program.aspx.

183 *Advancing a Green New Deal for Los Angeles Renters*, Energy Efficiency for All, page 19, 2019, https://www.energyefficiencyforall.org/resources/advancing-a-green-new-deal-for-los-angeles-renters/.

lowering the cost to manufacturers and distributors, preferred technologies are cost-competitive in the market.

New programs should also layer funding from decarbonization and health care sources. ACEEE has estimated annual health care savings from energy-related interventions at more than $228,000,000 nationally.[184] There is potential to address other goals — remediate mold, improve indoor air quality, remove asbestos — when performing energy retrofits. To address this challenge, the California Department of Community Services and Development, in consultation with California Department of Public Health's Office of Health Equity and CEC, developed an action plan identifying best practices from programs and funding mechanisms.[185] The intent of the underlying legislation is to improve cross-referral among agencies and promote projects that provide net financial benefits, provide health benefits, increase indoor air quality, and address asthma or respiratory issues triggered by mold and moisture.[186]

California also needs to promote and fund programs aimed at low-income households. These homes will require the most upfront capital and assistance to upgrade.

184 Hayes, Sara, Cassandra Kubes, and Christine Gerbode. May 2020 *Making Health Count,* ACEEE, pg. 15-18, https://www.aceee.org/research-report/h2001.

185 California Department of Community Services and Development*, Assembly Bill 1232 Report & Action Plan*, January 2021, https://www.csd.ca.gov/Shared%20Documents/AB1232-Report.pdf.

186 Under Assembly Bill 1232 (Gloria, Chapter 754, Statutes of 2019). https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201920200AB1232

CHAPTER 6:
Energy Equity and Other Impacts

This chapter addresses barriers to decarbonization that prevent communities and households from participating in and benefitting from decarbonization programs. It includes discussions of energy equity considerations associated with building decarbonization strategies including energy burden, housing stock affordability, split incentives, reaching rural areas, and engaging with California tribal governments. This chapter also discusses workforce impacts and the need for a just energy transition.

Energy Equity

There are complex barriers to decarbonization for disadvantaged and environmental justice communities, as well as low-income households that have limited disposable income and are disproportionally burdened by environmental pollutants. The demographics of such communities and households are primarily Hispanic, Black, Native American, and other people of color.[187] It is in these communities and households where systemic discrimination, environmental hazards, and poverty cycles intersect. Decarbonization programs can begin to address these cycles by working with local communities and directly investing in them. Programs need to overcome issues such as the upfront costs of upgrades, the age of existing buildings, the possible effect of energy upgrades on tenant rents, unstable project cashflow, current and future maintenance costs, availability of local experienced contractors, renter status, and proximity to and availability of resources. The issues under consideration are exacerbated by the current global pandemic.

California is facing an unprecedented recession driven by the spread of COVID-19. The spread of COVID-19 resulted in millions of people across the nation and world sheltering in place. For many, this pandemic put a lens on the housing crisis in California and, for some, continued subjugation to unhealthy living conditions. More than one-half of renters in the state are housing burdened, meaning more than 30 percent of their monthly income goes toward rent.[188] Many end up living in units with lead paint, water leaks, mold, and other health issues because of the lack of affordable housing options.

Policy makers will need to consider the following barriers and challenges when designing a decarbonization plan that benefits low-income and disadvantaged communities. As with all

187 Drehobl, Ariel, Lauren Ross, and Roxana Ayala. ACEEE. September 2020. *How High Are Household Energy Burdens?* Page 3. https://www.aceee.org/sites/default/files/pdfs/u2006.pdf.

188 California Department of Housing and Community Development. February 2018. *California's Housing Future: Challenges and Opportunities,* page 27, https://hcd.ca.gov/policy-research/plans-reports/docs/sha_final_combined.pdf.

barriers and challenges, this plan should be viewed as preliminary; this information will likely expand as unique and geographic-focused issues are gathered and researched. Additional barriers and strategies for addressing low-income, multifamily, and disadvantaged communities are presented in the *2019 IEPR*,[189] the *Clean Energy in Low-Income Multifamily Buildings Action Plan,*[190] and the *2019 California Energy Efficiency Action Plan,* which are actively being researched and addressed by state agencies.[191]

Energy Burden

The energy costs to operate a home can be a significant portion of a household's income; this situation is referred to as "energy burden." The greater the percentage of total income devoted to energy costs, the higher the energy burden of the household. Higher energy burden leads households to conservation measures that may not be healthy or safe for the occupants. Moreover, the increased burden can prevent occupants from moving out of the unhealthy conditions, furthering their hardship. Low-income households pay more than three times their household income on energy consumption than non-low-income households; and the median energy burden of renters is more than 10 percent higher than owners.[192] This means it is harder for renters to save money to move into less energy-intensive housing or purchase a home. Energy burden is also more likely to impact Native American, Black, and Hispanic households, regardless of income, compared to the national median household.[193]

Figure 40 shows the average energy burden across California counties. While this does not show the impacts to low-income communities within a given county, it is clear the inland and mountainous portions of the state have higher energy burden than the coastal regions. Even within coastal communities, the energy burden experienced by low-income households is often three times greater than non-low-income households.[194] Therefore, decarbonization strategies must prioritize and proactively address energy burden to reduce the energy costs low-income and disadvantaged communities experience. Decarbonization programs must avoid increasing energy burden and furthering poverty in communities across the state.

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189 California Energy Commission staff. February 2020. *Final 2019 Integrated Energy Policy Report*. California Energy Commission. Publication Number: CEC-100-2019-001-CMF. https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report/2019-integrated-energy-policy-report.

190 Haramati, Mikhail, Eugene Lee, Tiffany Mateo, Brian McCollough, Shaun Ransom, Robert Ridgley, and Joseph Sit. August 2018. *Clean Energy in Low-Income Multifamily Buildings Action Plan.* California Energy Commission. Publication Number: CEC-300-2018-005-SF. https://efiling.energy.ca.gov/getdocument.aspx?tn=224513.

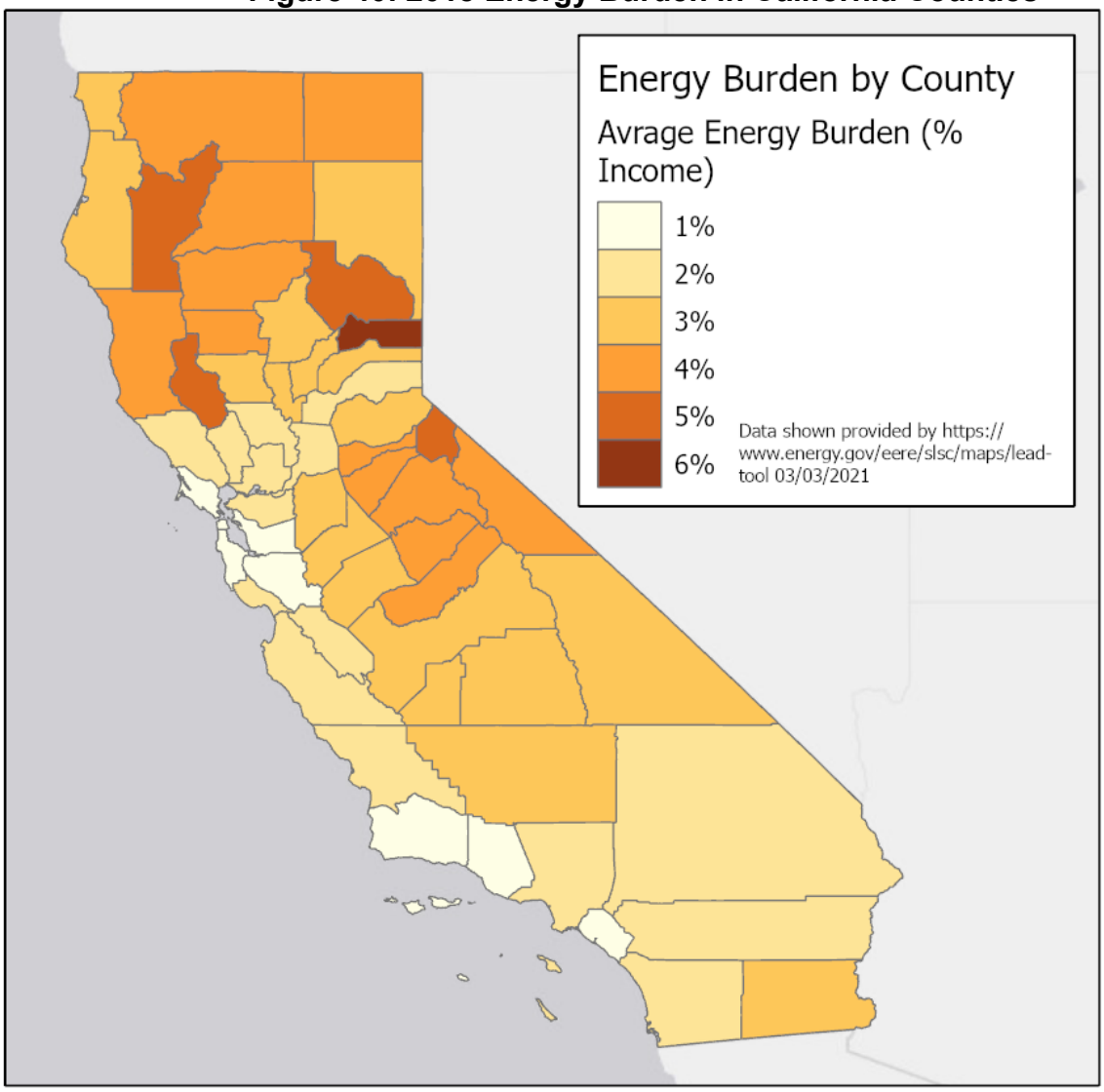
191 Kenney, Michael, Heather Bird, and Heriberto Rosales. December 2019. *2019 California Energy Efficiency Action Plan.* California Energy Commission. CMF, https://efiling.energy.ca.gov/GetDocument.aspx?tn=231261&DocumentContentId=62916.

192 Drehobl, Ariel, Lauren Ross, and Roxana Ayala. ACEEE. September 2020. *How High Are Household Energy Burdens?* Page iii. https://www.aceee.org/sites/default/files/pdfs/u2006.pdf.

193 Ibid.

194 Ibid, page 16.

Figure 40: 2018 Energy Burden in California Counties



Source: Low-Income Energy Affordability Data Tool Map Export (https://www.energy.gov/eere/slsc/maps/lead-tool)

Split Incentive

Split incentives are the most significant barrier to energy retrofits in multifamily housing units. This issue affects 45 percent of renter households in California.[195] Tenants often pay for the operation of major energy-consuming equipment. Because the building owner often does not pay the energy costs of the home, they typically have no incentive to replace inefficient

195 Greenlining. 2019. *Equitable Building Electrification*. page 18, https://greenlining.org/publications/reports/2019/equitable-building-electrification-a-framework-for-powering-resilient-communities/.

equipment before burnout. This issue furthers energy burden in low-income households, 60 percent of which are renters.[196]

Data from the last Residential Energy Consumptions Survey showed that renters often rely on water heating and space heating equipment beyond the useful life, likely as a result of this split incentive.[197] Thirty-eight percent of renters use a water heater that is more than 10 years old compared to 36 percent of homeowners, and 56 percent use space heating equipment that is more than 10 years old compared to 49 percent of homeowners.[198] There are significant efficiency gains and emission reductions to realize by retiring older equipment and replacing it with heat pump water heaters and heat pump space conditioning.

Rural Areas

In rural areas of the state with low-population density, program and financing options may be limited. These areas may not connect to the state's electric grid and may also be geographically distant from training centers, distribution centers, or other resources to participate in decarbonization activities. As the San Joaquin Valley Proceeding at the CPUC highlighted, many rural communities, especially farming ones, do not have gas heating, and instead, rely on propane, fuel oil, or wood burning. Rural households often experience greater energy burden because of the higher costs for those fuels and health impacts given the increased pollution produced by these sources.

California Native American Tribes

Specific challenges exist for California Native American Tribes (Tribes). California is home to approximately 170 tribes; 109 are federally recognized, the most in the nation.[199] Furthermore, many Native Americans are from tribes outside the state borders and also California residents making California the state with the highest population of Native Americans. At the 2019 California Tribal Energy Summit, representatives from more than 30 tribes gathered with state representatives to initiate government-to-government dialogue, educate each other on clean energy initiatives, and discuss unique challenges and opportunities of tribes. While some tribes can rapidly demonstrate and adopt energy

196 Evergreen Economics. December 2016. *Needs Assessment for the Energy Savings Assistance and the California Alternate Rates for Energy Programs,* page 43, https://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442452159.

197 United States Energy Information Administration. "2009 Residential Energy Consumption Survey," Table HC6.2 and HC8.2, https://www.eia.gov/consumption/residential/data/2009/#sh.

198 Ibid.

199 2010 U.S. Census. "American Indian and Alaska Native Tribes in the United States and Puerto Rico: 2010," https://www.census.gov/data/tables/time-series/dec/cph-series/cph-t/cph-t-6.html.

technologies because of quick decision-making processes, many tribes in rural areas have unreliable or complete lack of access to electricity or gas lines.[200]

Native Americans also experience nearly twice the poverty rates of the general population, which limits opportunities to invest in energy upgrades or move out of substandard housing.[201] In a 2018 California Department of Housing and Community Development report on California's housing future, between 15 to 20 percent of tribal homes need major rehabilitation, if not complete replacement.[202] As noted in the "Age of Housing" challenge discussion earlier in this report, non-energy housing issues, such as mold, wood rot, asbestos, and water damage, can prevent homeowners from participating in energy programs. Exacerbating the challenge is the limited federal funding from community development block grants available to tribes interested in retrofitting residential and commercial buildings for a low-carbon future. This means that in the short term, state and local governments must increase partnerships to support tribes in shifting to a clean energy future, as the CEC has done through microgrid projects at the Blue Lake Rancheria and Chemehuevi Indian Tribe,[203] energy and battery storage projects at the Viejas, Rincon, Soboba and Pechanga tribes, and energy planning grants for the Karuk, Pitt River, Big Valley, Scotts Valley, Kashia Pomo, Middletown, Tule River, and Pala tribes.[204]

Housing Stock and Affordability

California is experiencing a housing crisis. For the last decade, the state has not had sufficient new housing to meet population growth, and as a result, the cost of housing has increased dramatically. California has underproduced around 100,000 new homes annually and will need hundreds of thousands of new housing units in the next decade to meet demand.[205] If current rates do not change, by 2030, the housing gap could reach more than a million homes and put added pressure on the cost of housing. The California Department of Housing and Community

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200 Gates, Thomas, and Jessica Bonitz. May 2019. *Tribal Energy Summit November 26-28 2018 Summary Report.* California Energy Commission. Publication Number: CEC-700-2019-001, https://ww2.energy.ca.gov/2019publications/CEC-700-2019-001/CEC-700-2019-001.pdf.

201 California Department of Housing and Community Development. February 2018. *California's Housing Future: Challenges and Opportunities*, Appendix A-25, https://hcd.ca.gov/policy-research/plans-reports/docs/sha_final_combined.pdf.

202 Ibid., Appendix A-26.

203 Carter, David, Jim Zoellick and Marc Marshall. Schatz Energy Research Center, Humboldt State University. 2019. *Demonstrating a Secure, Reliable, Low-Carbon Community Microgrid at the Blue Lake Rancheria.* California Energy Commission. Publication Number: CEC-500-2019–011.

204 California Energy Commission. 2021. "Tribal Government Challenge Awardees." https://www.energy.ca.gov/news/2021-01/state-awards-2-million-10-california-native-american-tribes-climate-and-clean.

205 California Department of Housing and Community Development, California's Housing Future: Challenges and Opportunities, 2018, page 6-7, https://hcd.ca.gov/policy-research/plans-reports/docs/sha_final_combined.pdf.

Development forecasts new housing will keep up only with the growing population of the state, but the state also needs to address the thousands of residents who are homeless, which is about 25 percent of the nation's homeless population.[206] Moreover, California's aging population will require different types of housing, such as smaller, handicap-accessible apartments.

Affordable housing is an important component of single and multifamily housing. However, California lacks more than a million affordable homes to meet the needs of low-income residents.[207] Thus, the competition for existing affordable housing is significant. Furthermore, owners of existing affordable housing are often prevented from taking on new debts to finance upgrades, making improvements inaccessible.

A recent study by Energy Efficiency for All[208] found numerous benefits would result from all low-income housing receiving complete, cost-effective energy efficiency upgrades through the Energy Savings Assistance Program.[209] Benefits include between $136 million to $200 million in bill savings for tenants, nearly 1 terawatt-hour (TWh) of electric savings, 37 million therms of gas savings, and thousands of long-term jobs created.[210] These building upgrades can be combined with building decarbonization measures to create holistic programs.

Workforce Impacts and Needs

California has a growing clean energy workforce supported by aggressive clean energy goals that simultaneously spur job growth and lower energy consumption. The clean energy workforce covers renewable energy installation, building construction and retrofits, manufacturing of appliances and batteries, and numerous trades. In 2019, the United States Energy Employment Report detailed the employment across California's clean energy fields. At the time, California employed more than 950,000 people across energy sectors.[211] This includes more than 97,000 in gas-related industries, more than 136,000 in renewable electricity generation, more than 152,000 in transmission and distribution, and more than

206 Ibid., page 10.

207 Ibid., page 28.

208 *Plugging Into Savings: California's Huge Potential for Cost-Effective Energy Savings in Low-Income Multifamily Housing, Energy Efficiency for All*, page 4, 2017, https://www.energyefficiencyforall.org/resources/plugging-into-savings-californias-huge-potential-for-cost-effective-energy/.

209 The "Energy Savings Assistance Program" is a low-income-qualified program operated by the IOUs and overseen by the CPUC. More information is available here: https://www.cpuc.ca.gov/esap/.

210 Energy Efficiency for All. 2017. *Plugging Into Savings: California's Huge Potential for Cost-Effective Energy Savings in Low-Income Multifamily Housing*, page 6, https://www.energyefficiencyforall.org/resources/plugging-into-savings-californias-huge-potential-for-cost-effective-energy/.

211 BW Research. *2020 California Energy and Employment Report,* Prepared for CEC and CPUC, page 3 https://www.energy.ca.gov/filebrowser/download/2272.

323,000 in energy efficiency.[212] However, these numbers reflect a pre-COVID-19 world. The estimated energy sector job losses in the first half of 2020 have wiped out years of growth. The energy efficiency field has been hit particularly hard because so much of the work involves close contact with others.

Before the COVID-19-induced recession, the California Employment Development Department found that there was a growing annual demand for first-line construction supervisors, carpenters, construction laborers, equipment operators, drywall and ceiling tile installers, electricians, painters, plumbers, pipefitters, roofers, sheet metal workers, and inspectors — all critical professions in the clean energy sector. In 2018, it was estimated that these professions sought more than 72,000 workers statewide. These jobs are accessible, requiring at most a high school diploma, or equivalent, to enter the workforce. Median wages in these fields range from about $40,000 up to $80,000.[213]

While California has set the bar for economic growth while cutting GHG emissions, the job study found that the energy-sector workforce lags behind the rest of the state when it comes to employing women and people of color (**Table 9**).[214] The energy-sector workforce also has a below average rate of unionized workers. Thus, the energy workforce may not represent the communities in which it operates, and many workers may not have the bargaining power unions provide to receive family-supporting, livable wages.

Table 9: California Energy Efficiency Workforce Demographics

Demographic	California Energy Efficiency Sector	California Workforce Average	National Energy Efficiency Average
Male	74%	55%	75%
Female	26%	45%	25%
Hispanic or Latino	25%	37%	15%
Not Hispanic or Latino	75%	63%	85%
American Indian or Alaska Native	1%	<1%	1%
Asian	9%	16%	6%

212 Ibid., page 3-4.

213 Wages and Employment data from California Employment Development Department, Labor Market Information Division Found through Centers of Excellence, 2019, Supply and Demand http://coeccc.net/Supply-and-Demand.aspx, Labor Market.

214 BW Research. 2020. *2020 California Energy and Employment Report,* Prepared for CEC and CPUC, California Energy Employment Report, page 43-44, https://www.energy.ca.gov/filebrowser/download/2272.

Demographic	California Energy Efficiency Sector	California Workforce Average	National Energy Efficiency Average
Black or African American	6%	6%	8%
Native Hawaiian or other Pacific Islander	1%	<1%	1%
White	70%	72%	77%
Two or more races	12%	2%	7%
Veterans	7%	4%	9%
55 or over	11%	21%	13%
Unionized	8%	15%	10%

Source: BW Research

There are also differences in how the workforce is organized between residential and commercial sectors. The single-family and small multifamily new construction and retrofit sectors have low barriers to entry; high labor turnover; unorganized labor, both locally and across the state; and price-driven competition. In contrast, the large multifamily and commercial sectors are made up of a well-trained, unionized, stable workforce, and there is performance-driven competition between firms. A just transition requires building decarbonization programs and policies that address these realities and generate high-quality job opportunities.

Workforce Impacts

Research into workforce impacts from building decarbonization have found both job gains and losses. Building decarbonization may lead to job gains in the construction, trades, and electric utility sector yet lead to job losses in the gas utility and gas infrastructure sector. The massive number of home retrofits, additional generation capacity, and associated electric infrastructure would be a boost to the clean energy sector. Research by UCLA's Luskin Center estimates that the state would need between 20,000 and 23,000 new full-time construction workers to build new generation sites and infrastructure.[215] The increased revenue to electric utilities would support about another 10,000 to 12,000 workers in electric generation, transmission and distribution, and other utility jobs.[216] Gas employment would likely be affected proportional to the reduction in gas sales. Gas extraction jobs are likely unaffected since California imports

215 Jones, Betony, Jason Karpman, Molly Chlebnikow, and Alexis Goggans. 2019. UCLA Luskin Center. *California Building Decarbonization: Workforce Needs and Recommendations.* page 22. https://innovation.luskin.ucla.edu/wpcontent/uploads/2019/11/California_Building_Decarbonization.pdf.

216 Ibid, page 23.

most of its gas. Any in-state extraction jobs can continue exporting gas to other regions of the country and, therefore, are not necessarily at risk of loss. Changes in employment in the gas sector are estimated to be from 0 to -6,600 in extraction, -5,400 to -7,200 in transmission, distribution, and storage, and -1,500 for gas programs.[217] This is up to 25 percent of the extraction and 20 percent of the transmission, distribution, and storage workforce. Gas program workers, typically based in offices, could be shifted to operating other energy efficiency efforts.[218]

Workforce Needs

California needs to increase the number of workers involved in the clean energy workforce to achieve the building and construction rates necessary to reach 2030 and 2045 climate goals. To meet the goals, the rate of solar, wind, and battery installation must dramatically increase over both historical averages and peaks.[219] The average build rates for solar, wind, and batteries must increase by 50, 100, and 1,000 percent, respectively, between 2020 and 2030.[220] The anticipated rates increase even more to reach a 2045 zero-net carbon future. The current rate of commercial building retrofits is also inadequate to meet climate goals, as mentioned in the "Mandatory Performance Standards" section. Meanwhile, there are millions of single-family and multifamily units that would need to be retrofitted with decarbonization measures in the next two decades to meet the 2030 and 2045 goals. Overall, the construction, manufacturing, and trades workforce must be expanded to meet 2030 and 2045 climate goals.

Clean Energy Workforce Program

Successfully decarbonizing California's building sector requires ramping up the clean energy workforce and enabling workers to transition away from the gas sector while maintaining wages, promotional opportunity, health coverage, and retirement plans. The market for workers involved in single-family projects is different than that in multifamily or commercial projects. The former is price-driven and has high labor turnover, whereas the latter two are typically unionized, well-trained, and stable.[221]

The gas sector provides good paying jobs and supports tens of thousands of Californians. The Greenlining Institute recommends that workers in this field must not face a choice between a

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217 Ibid., page 24.

218 Ibid., page 25.

219 Joint Agencies. March 2021. 2021 SB 100 Joint Agency Report., page 102, https://efiling.energy.ca.gov/EFiling/GetFile.aspx?tn=237167&DocumentContentId=70349.

220 Ibid., page 105.

221 Jones, Betony, Jason Karpman, Molly Chlebnikow, and Alexis Goggans. 2019. UCLA Luskin Center. *California Building Decarbonization: Workforce Needs and Recommendations*. page 16. https://innovation.luskin.ucla.edu/wpcontent/uploads/2019/11/California_Building_Decarbonization. pdf.

good job and a clean energy job.[222] It finds that any program or policy to move existing gas jobs to new sectors must pay family-sustaining wages.[223] Moreover, any job transition should keep workers local and offer benefits to disadvantaged communities. Laura Ettenson with the Natural Resources Defense Council echoed this sentiment: "But there are a few things that are needed in every situation: diverse local representation to ensure the transition plan is equitably designed by and for the community, accessible job training with connections to high-quality jobs, and sufficient funding to make the transition plan possible."[224]

222 Greenlining, *Equitable Building Electrification,* page 25, https://greenlining.org/publications/reports/2019/equitable-building-electrification-a-framework-for-powering-resilient-communities/.

223 Ibid., page 25.

224 Natural Resources Defense Council. March 2020. "This is What a Just Transition Looks Like," https://www.nrdc.org/stories/what-just-transition-looks.

CHAPTER 7: Conclusion

The CEC analyzed multiple scenarios to understand the potential to reduce GHG emissions from residential and commercial buildings by 40 percent by 2030. This analysis included cost-effective strategies to reduce GHG emissions from space and water heating. Staff also researched challenges residents and building owners may face as a result of decarbonization. Included in the analysis of GHG reduction scenarios were considerations for load management strategies, which will be expanded in the future. Based upon the analysis, staff also estimated the possible impacts to ratepayers and the electric grid. Potential impacts to construction costs are discussed qualitatively but are still under investigation. The interaction of additional rooftop PV and transportation electrification with greater building electrification is also part of CEC's ongoing research.

Any successful building decarbonization plan will rely on a collaborative effort between state agencies. An interagency approach opens up more avenues to achieve GHG reductions than would be possible through one agency. The CEC, CARB, CPUC, and many more agencies will need to work in tandem to reduce GHG emissions from buildings.

GHG Reduction Potential

The results of the analysis show that, as of 2018, GHG emissions in residential and commercial buildings are 26 percent below 1990 levels and are on a trajectory to reach 36 percent below 1990 levels by 2030. In addition, if the state meets the HFC reduction goals laid out in SB 1383, buildings would be on track to meet about a 40 percent reduction by 2030.

AB 3232 required the CEC to assess the potential of *at least* a 40 percent reduction in GHG emissions by 2030. Given California's 2045 carbon-neutrality goal in combination with the long life of many fossil fuel-based appliances, it is vital that the building sector be on a trajectory to achieve deep decarbonization and, therefore, that additional progress be made toward electrification by 2030. While aggressive electrification scenarios show the state would meet its goals sooner, it is also estimated to cost six times the total cost of the "moderate electrification" scenario.

Assessment Conclusions

Following the results of the AB 3232 assessment and comments from stakeholders, the CEC makes several conclusions to help guide the California's building decarbonization policy. Analytical next steps to strengthen future building decarbonization assessments can be found in Appendix C.

1. AB 3232 suggests two baseline approaches from which California can track building decarbonization: systemwide and direct emissions. From a systemwide perspective, ongoing decarbonization of the electric system itself is steadily reducing overall

building-related emissions. However, this framing understates the need and opportunity for reductions of onsite emissions.

2. Reducing direct emissions – which are largely due to onsite use of fossil gas – will require large-scale deployment of electric heat pumps.
3. Newly constructed buildings have the lowest decarbonization costs. The Energy Code will continue to advance efficiency in newly constructed buildings in each successive code cycle, including increasing emphasis on the use of heat pumps.
4. Reducing building-sector GHG emission will require large investments in existing buildings.
5. Equity considerations are paramount and require collaboration amongst agencies, local governments, utilities, and community groups. Decarbonization initiatives should involve environmental justice communities throughout the effort and reflect their needs and priorities.
6. Traditional energy efficiency — gas and electric — can continue to provide emissions reductions very cost-effectively, but the potential for gas energy efficiency will decline if building electrification becomes a major strategy.
7. Accelerating efficient electrification of building end uses in new and existing buildings represents the most predictable pathway to achieve deep reductions in building emissions. An information campaign could familiarize consumers with high-efficiency electric appliances.
8. Additional analysis of reliability impacts of increased electrification is needed, including the role of load flexibility as both a building decarbonization and reliability resource.
9. The CARB-led effort to reduce refrigerant emissions to comply with SB 1383 is an important component of building decarbonization.
10. The role of the gas system in achieving building decarbonization needs further assessment, including the roles of renewable gas, hydrogen, and engineered carbon removal. Gas system planning itself must optimize across transportation, industry, power sector, land use, and air quality elements.
11. The CPUC may wish to review the role incentives play in adding new gas infrastructure for buildings.
12. California must expand and train its clean energy construction workforce.
13. Building decarbonization efforts should work in harmony with the state's response to the housing crisis.

APPENDIX A:
Decarbonization Programs and Policies

Active Building Decarbonization Programs

While this assessment focuses on the feasibility of achieving a specific level of building decarbonization, there are already many programs ongoing in the state aimed at this goal. These programs are operated by a variety of entities, including state agencies, local districts, community choice aggregators (CCAs), and utilities. Table A-1 outlines these early building decarbonization efforts.

Table A-1: California Building Decarbonization Programs

Program Name	Administrator	Sector	Description
Home Performance Program	Sacramento Municipal Utility District	Residential	Whole-house energy retrofit.[225]
FutureFit	Silicon Valley Clean Energy	Residential	Rebate for single-family and multifamily customers to switch to a heat pump water heater. Includes funds to upgrade electric panel.[226]
Clean Energy Optimization Pilot	Southern California Edison	Commercial	University buildings piloting GHG-based pay for performance program design.[227]
Advanced Energy Rebuild	PG&E/Marin Clean Energy/ Sonoma Clean Power	Residential	Funds to rebuild homes lost in recent wildfires. Extra incentive for all-electric rebuild.[228]

225 SMUD. "Home Performance Program." https://www.smud.org/en/Rebates-and-Savings-Tips/Improve-Home-Efficiency.

226 Silicon Valley Clean Energy, "FutureFit," https://www.svcleanenergy.org/water-heating/.

227 CPUC. http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M287/K454/287454189.PDF.

228 For example, Marin Clean Energy. Advanced Home Rebuild. https://www.mcecleanenergy.org/rebuildnapa/.

Program Name	Administrator	Sector	Description
Self-Generation Incentive Program	CPUC	Residential	Expanded program to fund heat pump water heaters.[229]

Source: CEC staff

CEC Decarbonization Research Pilots and Demonstrations

The CEC funds decarbonization-related research projects. These include projects focused on energy efficiency, low-GWP refrigerants, and electrification.

Building Envelope Research Projects

The CEC is funding new research into advanced envelope measures to minimize technology and implementation costs, while reducing heating and cooling energy use and costs for building occupants. Through these research projects, the CEC strives to overcome the technological and cost challenges, while documenting energy performance and cost savings and introducing new technologies into the marketplace. Below are some current CEC-funded projects that are improving building envelope technology (Table A-2).

Table A-2: Select Building Envelope Projects

Project Name	Description
Advancing Energy Efficiency in Manufactured Homes Through High Performance Envelope[230]	The project will build and test advanced manufactured home designs that promote energy efficiency advancements in building envelope.
Advanced Energy-efficient and Fire-Resistive Envelope Systems Utilizing Vacuum Insulation for Manufactured Homes[231]	This project will design, build, and install three proto-type manufactured, single-family homes. The homes will be built using a vacuum insulation panel based prefabricated envelope systems and state-of-the-art air sealing methods.
Demonstrating Benefits of Highly Insulating Thin-Triple Window Retrofits in California[232]	The demonstration project includes the installation of thin-glass triple-pane windows in at least 16 multifamily and 30 single-family housing units located in low-income or disadvantaged communities.

229 CPUC, Self-Generation Incentive Program Revisions Pursuant to Senate Bill 700 and Other Program Changes, Decision 20-01-021.

230 CEC, EPIC Program, EPC-19-035, 2019.

231 CEC, EPIC Program , EPC-19-043, 2019.

232 CEC, EPIC Program, EPC-19-033, 2019.

Source: CEC staff

Electric Efficiency Research Projects

The CEC is funding several electric efficiency projects that advance the understanding of zero-net energy technologies, identify the most cost-effective combination of technologies in buildings to reduce demand, and reduce the GHG emissions from electric technologies (Table A-3).

Table A-3: Select Electric Efficiency Projects

Project Name	Description
California Homebuilding Foundation's Zero Energy Residential Optimization – Community Achievement Project [233]	The project funds a community-scale demonstration of zero-net-energy (ZNE) single-family homes in the City of Clovis.
Pathways to More Cost-Effective ZNE Homes[234]	The project provides detailed cost-effectiveness modeling of all-electric versus mixed fuel ZNE homes with gas-based heating.
Integrated Whole-Building ZNE Retrofits for Small Commercial Offices[235]	The project develops and evaluates cost-effective packages of precommercial integrated energy efficiency measures and controls to achieve ZNE performance for multi-story small commercial offices in San Francisco and Southern California.
Measure Results from Affordable ZNE Homes[236]	The project demonstrates that affordable ZNE houses are readily achievable using low-cost construction techniques and on-site renewable energy in combination with high performance housing approaches.
San Diego Libraries ZNE and Integrated Demand-Side Management Demonstration Project[237]	The project integrates pre-commercial energy efficiency measures, building automation and controls system, behind-the-meter solar photovoltaic and energy storage in three existing public libraries in the City of San Diego
Customer-Centric Approach to Scaling Integrating Demand Side	The project develops and demonstrates an approach to scale residential retrofits for

233 CEC, EPIC Program, EPC-15-042, 2015.

234 CEC, EPIC Program, EPC-16-002, 2016.

235 CEC, EPIC Program, EPC-16-004, 2016.

236 CEC, EPIC Program, EPC-16-001, 2016.

237 CEC, EPIC Program, EPC-15-085, 2015.

Project Name	Description
Management Retrofits[238]	disadvantaged communities that minimizes disruptions to building owners and tenants.
Mass Deployment of Energy Efficiency Retrofits in Disadvantaged Communities[239]	The project develops and demonstrates standardized energy efficiency retrofit packages, specifically geared towards the low-income multifamily housing market, and that can be scaled to drive down costs.
Lead Locally[240]	The project develops and demonstrates a program that evaluates energy savings, cost-effectiveness, and training requirements for innovative retrofit technologies and promotes the most promising technologies through multiple channels in existing residential and commercial buildings.
Bundle-Based Energy Efficiency Technology Solutions for California ("BEETS for California")[241]	The project demonstrates a suite of pre-commercial energy-efficiency technologies to be installed in an existing office and laboratory building in Southern California.
Integrating Smart Ceiling Fans and Communicating Thermostats to Provide Energy-Efficient Comfort[242]	The project integrates smart ceiling fans and smart thermostats in low-income multifamily properties to reduce air-conditioning cost while increasing comfort and control flexibility to residents and building owners.
Development and Testing of the Next Generation Residential Space Conditioning System for California[243]	The project developed a next-generation residential space-conditioning system optimized for California climates.

Source: CEC staff

238 CEC, EPIC Program, EPC-15-053, 2015.

239 CEC, EPIC Program, EPC-17-040, 2017.

240 CEC, EPIC Program, EPC-17-041, 2017.

241 CEC, EPIC Program, EPC-17-009, 2017.

242 CEC, EPIC Program, EPC-16-013 Integrated Smart Ceiling Fans and Communicating Thermostats to Provide Energy Efficient Comfort.

243 EPC-14-021 Development and Testing of the Next Generation Residential Space Conditioning System for California.

Gas Research Projects

Among other efforts, the CEC is also funding projects to reduce gas use in buildings (Table A-4). These projects are focused on achieving decarbonization in buildings that are reliant on gas, such as healthcare facilities, and commercial and multifamily buildings.

Table A-4: Select Gas Research Projects

Project Name	Description
Comprehensive, High-Efficiency Solution for Water Heating in Multifamily Buildings[244]	The project demonstrates the integration of a high efficiency gas engine heat pump with a high efficiency solar thermal evacuated tube collector that could reduce domestic hot water energy use in existing multifamily buildings in Los Angeles County. It will also demonstrate a hot water controller that could reduce distribution line losses.
The Decarbonizing Healthcare Guidebook[245]	The project develops a comprehensive and interactive guidebook that focuses on existing and emerging energy efficiency equipment and systems and design improvements to reduce gas use, increase efficiency, and provide a plan for decarbonizing the healthcare industry.
Decarbonizing Healthcare with Zero-Carbon Reheat Systems[246]	The project will demonstrate a high-efficiency dehumidification system integrated with air handling units that will reduce or eliminate energy consumption associated with reheating supply air, in a healthcare facility.
Westin High Efficiency Gas Heat Pump Project[247]	The project will demonstrate an emerging and replicable gas heat pump technology that can reduce gas consumption for hot water heating by at least 35 percent in large commercial buildings.

Source: CEC staff

Electrification Research Projects

The goal to reduce emissions in residential and commercial buildings 40 percent by 2030 cannot be reached without electrification. Therefore, electrification research that results in cost reductions, greater GHG reductions, or greater market awareness is important. The CEC is

244 CEC, Natural Gas Program, PIR-16-005, 2016.

245 CEC, Natural Gas Program, PIR-19-016, 2019.

246 CEC, Natural Gas Program, PIR-19-012, 2019.

247 CEC, Natural Gas Program, PIR-19-014, 2019.

funding several projects to this end highlighted in Table A-5.

Table A-5: Select Electrification Projects

Project Name	Description
Low-Global Warming Potential Mechanical Modules for Rapid Deployment Project[248]	The project will develop, test, and demonstrate a prefabricated, scalable central mechanical system module to provide space conditioning and hot water to multifamily buildings.
Large Capacity CO_2 Central Heat Pump Water Heating Technology Evaluation and Demonstration[249]	The project will install and test the performance of low-GWP central heat pump water heating systems at five multifamily buildings located in disadvantaged or low-income communities.
Affordable Near- and Medium-Term Solutions for Integration of Low GWP Heat Pumps in Residential Buildings[250]	The project will develop and demonstrate next generation air to air heat pumps and microchannel polymer heat exchanger in single-family and multifamily residential buildings that utilize low global warming potential refrigerants.
Low Cost, Large Diameter, Shallow Ground Loops for Ground-Coupled Heat Pumps[251]	The project addresses the high cost of ground heat exchangers for water-to-water and water-to-air heat pumps to facilitate the application of efficient ground-coupled heat pumps in California.

Source: CEC staff

Refrigerant Research Projects

Critically important to reaching the goal of the AB 3232 assessment is to reduce the emissions from HFCs. To this end, there is ongoing research in the next generation of low-GWP refrigerants funded through the CEC (Table A-6).

248 CEC, EPIC Program, EPC-19-032, 2019.

249 CEC, EPIC Program, EPC-19-030, 2019.

250 CEC, EPIC Program, EPC-19-016, 2019.

251 CEC, EPIC Program, EPC-15-019, 2019.

Table A-6: Select Refrigerant Projects

Project Name	Description
Benefits and Challenges in Deployment of Low Global Warming Potential A3 Refrigerants in Residential and Commercial Cooling Equipment[252]	The project will develop test procedures for alternative refrigerants for flammability and energy savings characterization and to develop a "favorability" index of end-use market segments and equipment types based on potential GHG savings impact and commercial feasibility and adoption.
A Zero Global Warming Potential Heat Pump and Distribution System for All-Electric Heating and Cooling in California[253]	The project will develop, test, and demonstrate ammonia- and carbon dioxide-based heat pumps in multifamily and small commercial applications to improve heating and cooling efficiencies while advancing a low global warming potential refrigerant solution.

Source: CEC staff

In a recent study, the UC Davis Western Cooling Efficiency Center analyzed a refrigerant replacement for R-410A. The alternative, R-466, performed slightly less efficiently than equipment operating R-410A, but the marginal efficiency is compensated by the drastically lower GWP (733 compared to 2,088). Further research is needed to understand the long-term viability.[254]

Load Flexibility

Important to reaching the goal of the AB 3232 assessment is for residential and commercial buildings to be grid flexible. To this end, there is research in assessing the potential and expansion of the use of load-flexible technologies and strategies (Table A-7).

Table A-7: Select Load-Flexible Projects

Project Name	Description
Residential Intelligent Energy Management Solution: Advanced Intelligence to Enable	This project tests and validates an intelligent residential energy management system that is capable of communicating with a variety of distributed energy resources.

252 CEC, EPIC Program, EPC-16-041, 2016.

253 CEC, EPIC Program, EPC-19-014, 2019.

254 UC Davis Western Cooling Efficiency Center. *Case Study 2019, Performance Testing of R-466A: A Low Global Warming Potential Alternative Refrigerant,* https://wcec.ucdavis.edu/wp-content/uploads/Case-Study_Refrigerant_R466A_10_30_2019.pdf.

Project Name	Description
Integration of Distributed Energy Resources[255]	
Complete and Low Cost Retail Automated Transactive Energy System (RATES)[256]	This project develops and pilot-tests a standards-based Retail Automated Transactive Energy System to minimize the cost and complexity of customer participation in energy efficiency programs, maximize the potential of small loads to improve system load factor, integrate renewable generation, and provide resources to the grid.
Customer-controlled, Price-mediated, Automated Demand Response for Commercial Buildings[257]	This project improves small and large commercial customer participation in demand response programs by providing a cost-effective energy management system that provides a wide range of service offerings and effective and automated price-based management.
Customer-centric Demand Management using Load Aggregation and Data Analytics[258]	This project demonstrates how a large number of small loads, each impacted by and tuned to individual customer preferences can provide load management for both utilities and the ISO in California.
Empowering Proactive Consumers to Participate in Demand Response Program [259]	This project determines prosumer (producer/consumer) interest in a third-party demand response market by testing user acquisition via direct and non-direct engagement strategies, informs how much energy load shifting can be expected and creates a novel solution for using residential telemetry to connect prosumers and their Internet of Things devices to the markets.
Flexibility for Cost, Comfort, and Carbon Emissions [260]	This project develops and tests an advanced control system that optimizes heat pump operation based on building owner/occupant preferences, comfort and use

255 CEC, EPIC Program, EPC-16-041, 2016.

256 CEC, EPIC Program, EPC-19-014, 2019.

257 CEC, EPIC Program, EPC-19-014, 2019.

258 CEC, EPIC Program, EPC-19-014, 2019.

259 CEC, EPIC Program, EPC-19-014, 2019.

260 CEC, EPIC Program, EPC-19-014, 2019.

Project Name	Description
	patterns, electricity pricing, electricity grid needs, real-time carbon emission rates, and weather data.
Achieving Integrated and Equitable Decarbonized Loads with CalFlex Hub [261]	CalFlexHub will develop and test a Load Management Standards Prototype (LMS-P) with the capability of communicating price, GHG and dispatch signals to up to 99 percent of California consumers. CalFlexHub will research pre-selected, pre-commercial innovations to support the deployment of new, commercially-available, signal-responsive products to support load-flexibility and provide a clear value proposition.

Global Decarbonization Efforts

California is not alone in its quest for a low carbon future. As a member of the Pacific Coast Collaborative, there is a shared interest among the various member jurisdictions to lower the entire regions GHG emissions by at least 80 percent by 2050.[262] Members includes the governments of British Columbia (Canada), Washington (state), Oregon, and cities like Portland (OR), Vancouver (British Columbia), Seattle (WA), Los Angeles (CA), Oakland (CA), and San Francisco (CA). The World Green Building Council has also set out a Net Zero Carbon Buildings Commitment, of which California is a signatory.[263] California is learning and sharing from other signatories, including the regions of Catalonia and Navarra (Spain), Scotland (UK), Yucatan (Mexico), Baden-Württemberg (Germany), as well as more than 25 cities around the world.

Policy and Legislative History

California has passed numerous pieces of legislation to guide local and state policy toward a clean energy future. Initial efforts focused on transitions in the electric and transportation sectors. This section summarizes the major pieces of legislation and executive direction to address GHG emissions across the economy with a particular focus on buildings.

Executive Order S-3-05 (2005)

This executive order was signed by then-Governor Schwarzenegger in 2005 to move the state to combat GHG emissions. It set targets for California to reduce GHG emissions to 2000 levels

261 CEC, EPIC Program, EPC-19-014, 2019.

262 Pacific Coast Collaborative. "*How Will the West Coast Reduce Greenhouse Gases From Building Heating and Cooling*." https://46h83069gmc37jdhm425hbh3-wpengine.netdna-ssl.com/wp-content/uploads/2021/02/PCC_ThermalDecarbonization_Paper.pdf

263 World Green Building Council. *"Net Zero Carbon Buildings Commitment,"* https://worldgbc.org/thecommitment.

by 2010, 1990 levels by 2020, and 80 percent below 1990 levels by 2050. These targets were subsequently adopted in future legislation.

Assembly Bill 32 (2006)

AB 32 (Núñez, Chapter 488, Statutes of 2006), known as the Global Warming Solutions Act of 2006, established a goal of to reduce statewide greenhouse gas emissions to 1990 levels by 2020.

Assembly Bill 758 (2009)

AB 758 (Skinner, Chapter 470, Statutes of 2009) required the development of the Existing Buildings Program, which resulted in the triennial *Existing Buildings Energy Efficiency Action Plan*, now incorporated into the biennial *California Energy Efficiency Action Plan.*[264]

Executive Order B-18-12 (2012)

In 2012, then-Governor Edmund G. Brown Jr. directed all state of California agencies, departments, and other entities under direct executive authority to reduce GHG emissions. The Governor specifically directed state entities to exceed energy code requirements for new buildings, reduce grid-based energy purchases, participate in demand response programs, reduce water use, develop on-site renewable resources, and prioritize many other sustainable and green building measures.

Senate Bill 1371 (2014)

SB 1371 (Leno, Chapter 525, Statutes of 2014) directs the CPUC to adopt rules and procedures governing the operation, maintenance, repair, and replacement of intrastate gas pipelines to minimize leaks.

Executive Order B-30-15 (2015)

Governor Brown signed this executive order in 2015 to establish an interim GHG emission reduction target. The interim goal is to achieve reach 40 percent below 1990 GHG emissions by 2030 to keep the state on track for an 80 percent below 1990 levels by 2050 goal.

Senate Bill 350 (2015)

SB 350 (De León, Chapter 547, Statutes of 2015) codified California's goals of 50 percent procured renewable energy sources, double energy efficiency savings in electricity and gas end uses by 2030, and study barriers to energy efficiency and clean energy for low-income customers and disadvantaged communities.

Senate Bill 32 (2016)

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264 Kenney, Michael, Heather Bird, and Heriberto Rosales. 2019. *2019 California Energy Efficiency Action Plan*. California Energy Commission. Publication Number: CEC-400-2019-010-CMF. https://efiling.energy.ca.gov/GetDocument.aspx?tn=231261&DocumentContentId=62916

SB 32 (Pavley, Chapter 249, Statutes of 2016) amended the Global Warming Solutions Act of 2006. It called for a statewide reduction of greenhouse gas emissions of 40 percent below 1990 levels by 2030. The bill codified the goal initially set in Governor Brown's Executive Order B-30-15.

Assembly Bill 197 (2016)

AB 197 (Garcia, Chapter 250, Statutes of 2016) was a companion bill to Senate Bill 32 (2016). The bill emphasized the need to equitably implement all climate change policy so that benefits reach all Californians, including those in disadvantaged communities.

Senate Bill 1383 (2016)

SB 1383 (Lara, Chapter 395, Statutes of 2016) directs CARB, CEC, and California Department of Food and Agriculture to implement various strategies and regulations to reduce short-lived climate pollutant emissions. It called for a strategy to reduce methane emissions by 40 percent, hydrofluorocarbon (HFC) gases by 40 percent, and anthropogenic black carbon by 50 percent below 2013 levels by 2030.

Executive Order B-55-18 (2018)

Governor Brown's 2018 executive order took the additional step to push California to a carbon-neutral future. The order set a new statewide goal to achieve carbon neutrality as soon as possible, and no later than 2045, as well as maintain net negative emissions thereafter.

Senate Bill 100 (2018)

SB 100 (De León, Chapter 312, Statutes of 2018) increases the Renewables Portfolio Standard (RPS) to 50 percent by 2025 and 60 percent by 2030. Moreover, the bill sets a policy that eligible renewable resources and zero-carbon resources supply 100 percent of retail sales of electricity to end-use customers and 100 percent of electricity procured to serve all state agencies by December 31, 2045. Also, the CEC, CPUC, and CARB are required to prepare a joint report addressing the implementation of the policy focused on technologies, forecasts, existing transmission, maintaining safety, environmental protection, affordability, and system and local reliability to the Legislature in 2021 and every four years thereafter.

Senate Bill 1013 (2018)

SB 1013 (Lara, Chapter 375, Statutes of 2018) directs the CPUC to develop a strategy for increasing the use of low-global-warming potential refrigerants as part of the energy efficiency portfolio. This bill requires the CEC to "identify opportunities to assess" the energy efficiency of low-global warming potential alternatives that could be used in fluorine-based appliances and equipment.

Senate Bill 1477 (2018)

SB 1477 (Stern, Chapter 378, Statutes of 2018) requires the CPUC to develop two new incentive programs. These programs will provide incentives for low-emission space- and water-heating equipment for new homes and for near-zero-emission building technologies in new and existing homes to reduce GHG emissions.

Senate Bill 49 (2019)

SB 49 (Skinner, Chapter 697, Statutes of 2019) expands the authority of the CEC to set appliance energy efficiency standards to include cost-effective flexibility that supports electrical grid reliability and existing demand response programs and policies. The CEC is required to adopt, by regulation, and periodically update standards for appliances to expedite the development of flexible-demand technologies. The CEC must consult with the CPUC and load-serving entities to align the demand flexibility standards with demand response programs administered by the state and load-serving entities, as well as offer incentives for demand-flexible appliances. The CEC may also use GHG emissions when determining the cost-effectiveness of the flexible demand appliance.

APPENDIX B:
Buildings and GHG Baseline

The following summarizes how CEC staff approximated the direct and systemwide 1990 GHG emission baselines used for this report. CEC staff received stakeholder feedback on a white paper[265] that recommended a GHG emission baseline for AB 3232 at a December 4, 2019, Commissioner Workshop. Staff from the CPUC and CARB consulted with CEC staff while CEC staff developed this baseline recommendation. The white paper summarized the scope of emissions and reported the method of how CEC staff used the CARB GHG inventory to estimate the various GHG emission sources used in the 1990 baseline. Several of the data and methodological assumptions have been updated since the posting of the white paper, which did change the 1990 level and the resulting 40 percent reduction target. CEC staff presented both the direct emissions and systemwide emissions baselines at the June 9, 2021 workshop.

Overview of AB 3232 Building Decarbonization Baseline Method

Chapter 2 reports the five emission sources used in the 1990 GHG systemwide emission baseline for the residential and commercial sectors:

- Gas fuel combustion
- Non-gas fuel combustion
- Behind-the-meter (BTM) gas leakage
- Refrigerant leakage
- Electric generation system emissions (not included in direct emissions baseline; only incremental electric generation system emissions from electrification are accounted for using the direct emissions approach)

As discussed in Chapter 2, any emission leakage occurring at or upstream from the gas meter of a building was not included in the 1990 baseline. The magnitude of the scope and the potential abatement of these emissions from electrification activities are highly uncertain. The methods of estimating the 1990 magnitude of these five sources GHG emissions rely on

265 "CEC Staff Recommended 1990 Greenhouse Gas Emission Baseline for Building Decarbonization Assessment." Docket number 19-DECARB-01. November 22, 2019. https://efiling.energy.ca.gov/GetDocument.aspx?tn=230833&DocumentContentId=62450.

CARB's two GHG emissions inventory series: 1990 to 2004[266] and 2000 to 2018[267] series. These two series have differing assumptions in which emissions are included or have different taxonomies in how they label GHG emission sources. For example, HFC Leakage or BTM Gas Leakage are not reported the same or are not included at all in the 1990–2004 series. CEC staff had to bridge these two inventories to complete a full time series so to make any target setting out to 2030 and beyond consistent. All emissions (CO_2, CH_4, N_2O, and so forth) are reported in millions of tonnes carbon dioxide equivalent.

Table B-1 reports how CEC staff bridged the two inventories for the different emission sources. The value of fuel combustion emission sources came directly from the CARB inventories (labels of "CARB Inventory" indicates values straight from the inventory). However, CEC staff had to approximate the level of HFC Leakage, BTM Gas Leakage, and the share of electricity generation system emissions for the residential and commercial sectors (Labels of "CEC Staff Approximation" or "2013 SB 1383 Baseline" indicate where CEC staff had to develop a method for approximating the amount of emissions). Columns 1 and 2 in Table B-1 were used to calculate the 1990 baseline, while Columns 3 and 4 are used to help track emissions. As discussed below, CEC staff did not approximate but used the SB 1383 2013 baseline for HFC Leakage emissions for 1990.

266 California Air Resources Board. 2007. "1990 to 2004 California's Greenhouse Gas Inventory by Sector & Activity." (Version 1 – Last updated on 11/19/2007). Available at https://ww3.arb.ca.gov/cc/inventory/archive/tables/ghg_inventory_by_sector_all_90-04_ar4.xlsx. Accessed 6/24/2019.

267 California Air Resources Board. 2020. "California's Greenhouse Gas Inventory by Sector & Activity" (Thirteenth Edition: 2000 to 2018 – Last updated on 10/15/2020). Available at https://ww3.arb.ca.gov/cc/inventory/data/tables/ghg_inventory_by_sector_all_00-18.xlsx. Accessed 11/4/2020.

Table B-1: CEC Staff Estimation Approaches by GHG Emission Source and CARB Inventory Series

Category	1990-2004 CARB Inventory Residential (1)	1990-2004 CARB Inventory Commercial (2)	2000-2018 CARB Inventory Residential (3)	2000-2018 CARB Inventory Commercial (4)
Gas Fuel Combustion	CARB Inventory	CARB Inventory	CARB Inventory	CARB Inventory
Non-Gas Fuel Combustion	CARB Inventory	CARB Inventory	CARB Inventory	CARB Inventory
Behind-The-Meter (BTM) Gas Leakage	CEC Staff Approximation	CEC Staff Approximation	CARB Inventory	CEC Staff Approximation
Hydrofluorocarbon (HFC) Leakage	2013 SB 1383 Baseline / CEC Staff Approximation	2013 SB 1383 Baseline / CEC Staff Approximation	CARB Inventory	CARB Inventory
Residential and Commercial Sector Share of Electric Generation System Emissions	CEC Staff Approximation	CEC Staff Approximation	CEC Staff Approximation	CEC Staff Approximation

Source: CEC staff

Table B-2 provides a table of nomenclature and the filtered query definition when using the two inventories. The next section provides the details for the methods CEC staff used for approximating the amount of emissions as reported by Table B-1.

Table B-2: Table of Nomenclature and CARB GHG Inventory Filtered Query Definition

AB 3232 Report Nomenclature	CARB GHG Inventory Filtered Query Definition
Gas Fuel Combustion	1990 and 2020 Inventories: Sector Level 1: Residential / Commercial Activity Level 1: Fuel Combustion Activity Level 2: Natural Gas
Non-Gas Fuel Combustion	1990 and 2020 Inventories: Sector Level 1: Residential/Commercial Activity Level 1: Fuel Combustion Activity Level 2: All Except Natural Gas
Behind-The-Meter Gas Leakage	1990 Inventory: See text 2020 Inventory (Commercial): See text 2020 Inventory (Residential): Sector Level 1: Residential/Commercial Sector Level 2: Transmission and Distribution Sector Level 3: Natural Gas Pipeline Sector Level 4: Fugitive Emissions Activity Level 1: Fugitive Emissions
HFC Leakage	1990 Inventory: See text 2020 Inventory: Sector Level 1: Residential/Commercial Activity Level 1: Use of substitutes for ozone-depleting substances Activity Level 2: Refrigeration and Air Conditioning
Total Electric Generation System Emissions	<u>1990 and 2020 Inventory:</u> approximation based on: Sector level 1: Electricity Generation (Imports) and Electricity Generation (In-State) (See text for how residential and commercial sectors were approximated)

Source: CEC staff

Methodology by GHG Emission Source

Gas Fuel Combustion

Values are taken directly from CARB inventories. See Table B-2 for details of the query.

Non-Gas Fuel Combustion

Values are taken directly from CARB inventories. See Table B-2 for details of the query.

Behind-the-Meter Gas Leakage

Residential

CARB first started reporting residential BTM gas leakage in its inventory in 2019. The estimates for these emissions are based on a 2018 CEC study, which investigated the magnitude of gas methane emissions in California homes.[268] As shown in Table B-1, CEC staff needed to approximate the amount of these emissions in 1990. CEC staff consulted with CARB staff to apply the same method[269] using the most recent Department of Finance housing estimates.[270] Residential BTM gas leakage is a function of the number of buildings and not the consumption of gas.[271] CEC staff did notice a difference in its 2000–2017 estimates compared to the CARB inventory but learned that the reported inventory relied on an older vintage of Department of Finance data. CEC staff expects these emissions, particularly the 1990 estimation, to be updated as more information becomes available and CARB's methodical approach evolves.

Commercial

No current estimate of BTM gas leakage exists for the commercial sector in the CARB inventory (See Table B-1). As a placeholder, CEC staff assumes 1.0 $MMTCO_2e$ for all years, including 1990.

This 1.0 $MMTCO_2e$ BTM gas leakage placeholder value will likely be updated if CARB includes these emissions in its next inventory update. In the summer of 2020, CEC published research

268 California Energy Commission. August 2018. *Natural Gas Methane Emissions From California Homes.* CEC-500-2018-021. Available at https://ww2.energy.ca.gov/2018publications/CEC-500-2018-021/CEC-500-2018-021.pdf. Accessed 10/2/2019.

269 California Air Resources Board. 2019. *Inventory Updates Since the 2018 Edition of the Inventory: Supplement to the Technical Support Document.* Pages 5-6. Available at https://ww3.arb.ca.gov/cc/inventory/pubs/reports/2000_2017/ghg_inventory_00-17_method_update_document.pdf. Accessed 10/2/2019.

270 For 1990-2000: California Department of Finance. E-8 Population and Housing Estimates for Cities, Counties, and the State, 1990 - 2000. Available at http://www.dof.ca.gov/Forecasting/Demographics/Estimates/. Accessed 9/26/2019. For 2000-2019: California Department of Finance. E-5 and E-8 Population and Housing Estimates for Cities, Counties, and the State, 2000 - 2019. Available at: http://www.dof.ca.gov/Forecasting/Demographics/Estimates/. Accessed 9/26/2019.

271 The method assumes a constant annual leakage rate, where the number of housing units in California each year is multiplied by the leak estimate of 2,539 grams of CH4 per house.

that investigated the extent of these BTM methane leaks in the commercial sector.[272] CEC staff will follow CARB's lead in developing a method that integrates this recent research when estimating the annual emissions of this new emissions category reported in future updates of the GHG inventory.

Hydrofluorocarbon (HFC) Leakage

The CEC staff handled the 1990 level of HFC leakage emissions differently compared to other emission sources because the scope of which refrigerant emissions pollutants are accounted for in the CARB and international GHG inventories and the magnitude reported for 1990. In consultation with CPUC and CARB, CEC staff used the 2013 values of HFC leakage emissions for the residential and commercial sectors for 1990. See Table B-2 for the filtered query definition in the inventory for obtaining these 2013 values.

Unlike what was reported in the white paper and discussed at the December 2019 workshop, this approach results in a nonzero value of HFC leakage for 1990. CEC staff discussed this change at the June 9 commissioner workshop.

The HFC accounting complication is due to two types of refrigerant emissions present but only one inside the scope of the IPCC accounting framework and AB 32: ozone-depleting substances (ODS) and ODS substitutes. Of these two high-GWP gas emissions, only the emissions from ODS substitutes are tracked. However, emissions of ODS were negligible in 1990 (less than 0.01 $MMTCO_2e$) and have increased and will continue to grow as they replace ODSs banned under the Montreal Protocol.[273] The amount of ODSs in 1990 was significant, and including them in the 1990 baseline would create a meaningless 2030 target since most of the ODS emissions have been removed. As such, CEC staff argues that these two 1990 levels of refrigerant emissions are not realistic for use in the 1990 baseline for AB 3232.

During the December 2019 workshop regarding the baseline, CARB staff recommended that CEC use 2013 as the base year for HFC leakage emissions. But CEC staff argued that having a separate 2013 baseline would be infeasible since the GHG emission baseline and the resulting 2030 target must be based on the 1990 base year.

Instead, staff from CEC and CARB resolved the issue and used the 2013 level of HFC emissions for 1990. This resolution helps provide a nonnegligible value of emissions for 1990 and allows consistency with the SB 1383 proceeding, which requires a reduction of short-lived climate

272 Sweeney, Meredith, Daniel Ersoy, Kristine Wiley, Erin Case, Eric Stubee, and Marc L. Fischer. Gas Technology Institute. 2020. *Assessment of Fugitive Emissions from the Natural Gas System — Commercial Buildings*. California Energy Commission. Publication Number: CEC-500-2020-035. https://ww2.energy.ca.gov/2020publications/CEC-500-2020-035/CEC-500-2020-035.pdf.

273 California Air Resources Board. 2019. *California Greenhouse Gas Emissions for 2000 to 2017: Trends of Emissions and Other Indicators.* Page 16. https://ww3.arb.ca.gov/cc/inventory/pubs/reports/2000_2017/ghg_inventory_trends_00-17.pdf.

pollutants (for example, reduce hydrofluorocarbon gases by 40 percent) from 2013 levels by 2030.

Residential and Commercial Share of Electric Generation System Emissions

Staff applied a simplistic approach for estimating the residential and commercial share of electricity system emissions. For all years in the inventory, CEC staff estimated the GHG emission attribution of the residential and commercial sectors using the annual sum of imports and in-state electricity generation in the CARB GHG inventory. These reported emissions from the GHG inventory include transmission and distribution in the electricity generation sector.

CEC staff used the California Energy Demand Forecast, Form 1.1b, mid-demand case, which reports electricity sales (GWh) by sector beginning in 1990, to calculate percentage attribution shares by sector.[274] Form 1.1b lists the following sectors: residential, commercial, industrial, mining, agriculture and water pumping (AGWP), transportation, communication, and utilities (TCU). These residential and commercial shares are then applied to the total 1990 electric generation system emissions (110.51 $MMTCO_2e$) to get an approximated share of emissions for these sectors.[275] Electricity sales by sector equals consumption minus self-generation.

The direct emissions baseline approach presented in the report accounts for only the incremental electric generation system emissions from building electrification occurring in the residential and commercial sectors.

274 CEC staff used the most recent available Form 1.1.b, which as the preliminary IEPR forecast presented at an August 15th IEPR workshop, when developing the initial baseline estimation for the December 2019 workshop (see https://efiling.energy.ca.gov/GetDocument.aspx?tn=229333&DocumentContentId=60746). The 1990 residential and commercial electricity generation shares used were 0.3055 and 0.3251.

275 For future updates, CEC staff is considering adjusting for 1990 and future years the sector attribution shares by adding TCU and streetlighting as part of the commercial sector. Staff is also considering adjusting the 1990 and future year GHG estimates by accounting for combined heating and power in the industrial and commercial sectors when examining total electric generation emissions.

APPENDIX C: Detailed Analysis of Building Decarbonization Strategies

Building Decarbonization Strategies and Modeling Approaches

Chapters 3 and 4 summarize the analytical work performed by the EAD staff in support of AB 3232 policy objectives. [276] This analysis studied the potential impacts of various strategies that can contribute to residential and commercial building decarbonization. The EAD staff conducted an analysis of each of the following building decarbonization strategies:

- Gas energy efficiency savings
- Electric energy efficiency savings
- Rooftop solar photovoltaic generation
- Electrification from gas appliances to electric appliances (i.e. efficient electrification)
- Renewable gas replacing gas
- Emission reduction in the electric generation system supplying the load in the residential and commercial building sectors
- Demand flexibility to reduce the need to develop generation capacity

Scenarios characterizing each of these strategies were assessed for physical GHG emission reduction, costs, and impacts on the gas system and electric generation system. This appendix provides a more detailed explanation of the analytical methods used and results. The appendix is organized into four sections as follows: (I) modeling framework, (II) modeling approach for assessing each building decarbonization strategy, (III) modeling results in terms of energy system impacts, GHG emission reductions, costs and cost-effectiveness, electricity rate impacts, uncertainties of results and (IV) next steps for future analytic iterations for upcoming IEPR cycles.

Before diving further into the analytical details, it is prudent to understand the context of each of these broad building decarbonization strategies. As described in the main report there have been extensive efforts by both the CEC and other entities to support ever increasing levels of energy efficiency and more recently in PV adoptions and an increased RPS requirement. Less decarbonization focused work has been completed elsewhere. Furthermore, the implications from well-established strategies are currently included in the managed statewide electricity and gas demand forecast published biennially in the IEPR by the CEC and tightly integrated in statewide interagency resource planning and procurements efforts.

276 April 30 2021 Supplementary material for AB 3232 Report Appendix C - Selected Input Data Assumptions used in AB 3232 analysis ("AB 3232 Appendix C"). California Energy Commission. TN# 237504. Docket Number 19-DECARB-01. April 20, 2020. https://efiling.energy.ca.gov/GetDocument.aspx?tn=237504&DocumentContentId=70704.

Energy efficiency, for both gas and electric end uses, has been a major emphasis as incorporated through mandatory Building Energy Efficiency Standards in Title 24 Part 6 (i.e., the 2019 Energy Codes) since the inception of the CEC in 1975. Additional local ordinances or reach codes have been formally implemented by select local jurisdictions through Title 24 Part 11 since 2005. Utility and other incentive programs have a more than 30-year history with renewed efforts spurred onwards by SB 350 energy efficiency doubling initiatives set in 2015. The result of these sustained efforts in energy efficiency is that the remaining potential of additional cost-effective energy efficiency savings available to the consumer is continuously declining.

Rooftop PV has enjoyed moderate promotion through net metering and aggressive new construction programs including PACE Financing for solar and efficiency, New Solar Homes Partnership (NSHP), and the 30 percent Federal Investment Tax Credit. Most recently, the 2019 Energy Codes have made a modest PV system mandatory on all new residential construction. While a sizeable physical potential remains for additional PV installation in existing buildings there are unresolved system reliability issues with excess reliance on PV or supply-side central solar generating facilities without commensurate amounts of new storage installations.

Load flexibility has been promoted mostly through the lens of peak load reduction and emergency response, less as a specific decarbonization strategy. As described in earlier chapters, there are promising reliability benefits in load flexibility being pursued in the CEC load management standards currently under development. These new load management standards could best support building decarbonization efforts by mitigating reliability issues innate to the other building decarbonization strategies.

Pipeline RNG (i.e., renewable gas) may have a large physical potential, which is being explored by both the CPUC and the CEC. Preliminary estimates indicate that biomethane is limited in quantity while synthetic gas (i.e., SNG or synthetic natural gas) which is much more expensive than biomethane can be synthesized in greater quantities. Both forms of renewable gas are more costly than standard pipeline fossil gas, where SNG can be 8 to 17 times more expensive.[277] The CPUC has just recently adopted its initial biomethane tariffs.

In contrast, the electric generation sector has had RPS requirements in place since 2002 which have significantly contributed to increasing the penetration of renewables statewide. This effort has been moderate, as gas power plants and non-RPS imports are phased out and renewables with storage are added but is rapidly accelerating due to passage of SB 100 in 2018.

277 See page 4 and Figure 6 on page 25 in Aas, Dan, Amber Mahone, Zack Subin, Michael Mac Kinnon, Blake Lane, and Snuller Price. 2020. The Challenge of Retail Gas in California's Low-Carbon Future: Technology Options, Customer Costs and Public Health Benefits of Reducing Natural Gas Use. California Energy Commission. Publication Number: CEC-500-2019-055-F. https://ww2.energy.ca.gov/2019publications/CEC-500-2019-055/index.html.

Efforts towards building end-use electrification have been limited to local pilot scale programs just being implemented or statewide programs being currently developed such as BUILD and TECH funded by SB 1477. The 2019 Energy Code has removed barriers for all electric new construction as well as for electric substitution of existing gas end uses by establishing separate baselines for mixed fuel and all electric construction. Implementing a dual baseline in the standards has also facilitated electrification efforts through reach codes by local jurisdictions as well as program development by utilities. The CPUC updated their three-prong energy efficiency test in 2019 to permit certain fuel substitution measures to be included as measures in their energy efficiency potential studies and subsequent IOU portfolios.[278]

(I) Modeling Framework

Five of these seven strategies have been pursued for a decade or more as state energy policy goals, but not explicitly for GHG emission reduction purposes. Building end-use electrification and renewable gas have only surfaced as strategies needing assessment because of the focus that AB 3232 brought to the GHG reduction potential they offer. Thus, new analytic techniques were clearly needed for these two strategies. Even energy efficiency and rooftop PV generation topics - traditionally examined as load modifiers to baseline demand forecasts - EAD staff had no tools to compute incremental GHG emission reductions or net costs to consumers, so even these required new tools to be developed. There are well-developed techniques for assessing the GHG impacts in the electric generation system that merely had to be adapted for the specific purposes of AB 3232. Finally, although load management has also played a role in electricity planning for many years, the related concept of demand flexibility is strongly dependent upon recent advances in wireless communication to reduce implementation costs to the level that make this strategy competitive.

In most cases, the methods used in this first round of analysis assessed each strategy independently, and thus the impacts are not additive. However, analysis of the electric generation system is different in two ways. First, electric generation system emission reductions can be assessed as a strategy on its own; for example, as a result of assuming higher levels of renewable generating resources or other non-carbon emitting sources of supply. Second, GHG emissions from the electric generating sector are impacted by other scenarios that increase or decrease electricity sales. Since nearly all the scenarios described later in this chapter do change electricity sales, devising a methodology that can determine the GHG impacts on the electric generation system was essential.

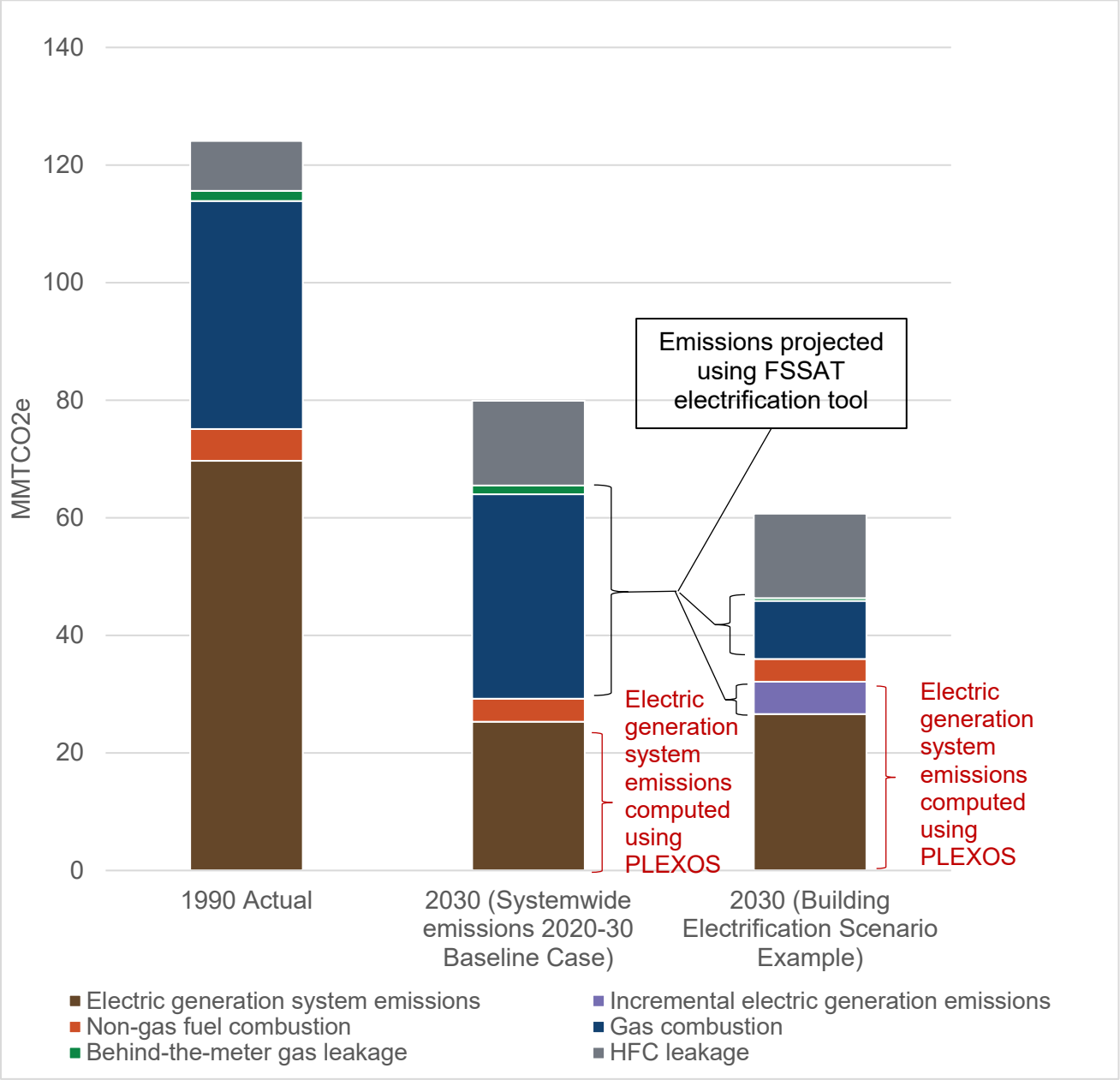
Figure C-1 illustrates three important features of the CEC assessment. First, ongoing implementation of existing policies (continued funding of utility energy efficiency programs, triennial Energy Code updates, periodic tightening of appliance standards by the CEC and US Department of Energy) will make a major reduction in GHG emissions by 2030 without any new policies. For purposes of this appendix, the cumulative impact of the continuation of

278 CPUC, Rulemaking 13-11-005, Decision Modifying the Energy Efficiency Three-Prong Test Related to Fuel Substitution, August 2019, https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M310/K053/310053527.PDF.

existing policies over the 2020 – 2030 period is called 2030 business as usual (i.e., the 2020-30 Baseline Case in the main report). Second, specific strategies can shrink individual segments of the composite of GHG emission sources in the residential and commercial sectors above and beyond what existing policies are expected to accomplish. Finally, the shift from gas to electricity at the end-user level results in increased GHG emissions from the electric generation system, but the extent is affected by the specific type and amount of generating capacity added, and how this added capacity is used in conjunction with all of the other generating sources expected to exist in future years.

Figure C-1 presents the 1990 and 2030 business as usual cases as stacked bars using the same data as used in Chapter 2 describing the baseline GHG emission inventory for 1990. The 1990 values come directly from CARB's GHG emission inventory as adapted by CEC staff. The 2030 business as usual values are projections based on the 2019 IEPR adopted managed demand forecast and the corresponding electric generation system emissions computed by CEC staff while considering 2030 RPS requirements and an hour by hour optimization of resources dispatched to meet those loads. Similarly, an electrification case displaces gas consumption and adds electricity load that alters the total expected 2030 electricity sales. Finally, since the sectors and end-uses where these incremental electrification loads occur are different than the 2019 IEPR demand forecast used for the 2030 business as usual case, **Figure C-1** shows that there is a conceptual difference in GHG emissions from the incremental loads added and the "base" loads (labeled in the figure as "Electric generation system emissions").

Figure C-1: Interaction between FSSAT Modeling for Building End-Use Electrification Impacts and PLEXOS for Electric Generation System Emissions



Source: CEC staff

2030 Business as Usual (i.e. the 2020-30 Baseline Case)

EAD staff made a fundamental assumption that the impacts of proposed building decarbonization strategies should be examined from the perspective of incremental GHG emission reductions compared to those resulting from existing planning processes and assumptions. To do otherwise would improperly discount the contribution to GHG emission reduction that is already underway as a result of existing policies and provide too much benefit to new policies. This presumption has quite different impacts on assessing the seven decarbonization strategies. To illustrate a strategy with heavy prior emphasis, consider that state energy policy has pursued energy efficiency for 40-plus years since the very first HCD (Housing and Community Development) building standards in the 1970s. The impacts of such

energy efficiency standards and utility-sponsored programs have been quantified and included in CEC gas and electricity demand forecasts for many years, and these demand forecasts are the load inputs into electric generation system modeling that determines resulting GHG emissions from this sector. For AB 3232 purposes only incremental electric energy efficiency activity above and beyond "business as usual" levels contribute to further GHG emission reductions from the electric generation system. At the other extreme, there has been limited policy emphasis on electrification until recently, and in fact, the CPUC's three-prong test actively discouraged shifts between gas and electricity until it was changed in 2019.[279] SB 1477 is the first substantive legislation to actively promote shifts from gas to electricity. Thus, there is little electrification to date and many of the elements of an assessment of GHG impacts and costs had to be developed for the AB 3232 project.

As **Figure C-1** depicted visually, CEC staff developed a business as usual scenario for 2020 through 2030 from which to measure the impacts of various new decarbonization strategies. This scenario includes the 2019 IEPR managed demand forecasts for gas and electricity.[280] Energy efficiency and rooftop PV are currently included in the managed statewide gas and electricity demand forecast published biennially in the IEPR. The forecast provides long-term electricity consumptions, sales, and net peak demand and end-use gas consumption and AAEE savings forecasts for the state of California for the years 2020 through 2030.[281]

These managed demand forecasts were adopted by the CEC, at the January 22, 2020 business meeting and specific variants are used in various proceedings including the CPUC Integrated Resource Planning process and the California ISO.

AAEE is the incremental energy savings from the future market potential identified in various data streams not included in the baseline demand forecast but reasonably expected to occur. This includes many future updates of the Energy Code, appliance regulations, and new or expanded energy efficiency programs. A portfolio of AAEE scenarios is designed to condense uncertainty of specific scenario elements into six scenarios ranging from conservative to optimistic. Scenario 3 the Mid-Demand Mid-AAEE Savings scenario is the most probable to occur and is used as the reference case for statewide planning activities. This reference case assumed a small market penetration rate of 1.5 percent all electric new construction per year beginning 2020, with max of 16.5 percent in 2030.

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279 CPUC, Rulemaking 13-11-005, Decision Modifying the Energy Efficiency Three-Prong Test Related to Fuel Substitution, August 2019, https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M310/K053/310053527.PDF.

280 The Energy Commission develops managed demand forecasts in two steps. First, a baseline demand forecast includes the impacts of all energy efficiency and other load modifiers considered to be "committed." Second, a range of additional energy efficiency and other impacts from less certain initiatives are quantified. Combining the baseline demand forecasts with scenarios of additional policy impacts creates a series of "managed" demand forecasts.

281 CEC, 2019 California Energy Demand Forecast 2020-2030, May 2020, https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report/2019-integrated-energy-policy-report/2019-iepr.

Similarly, three scenarios of self-generation by BTM PV in both the residential and commercial sectors is forecast as part of the baseline demand low, mid, and high demand cases. The bookend scenarios are projected using predictive models, based on estimated payback periods and cost-effectiveness, which are determined by upfront costs, electricity rates, and incentive levels. The mid electricity demand case, which takes the average of the high and low scenarios, is the most probable to occur.

On the supply side, statewide integrated resource planning includes both in state electricity production and imports from out of state resources. The development of resource plans using production simulation models for the forecast time-period include RPS requirements as well as system reliability criteria. Although the CEC undertakes extensive analyses of the gas system, its focus has been on projecting expected gas prices in the context of existing gas production and transmission markets. Renewable gas is to date not included in the counterfactual or business-as-usual assumptions. Load management program impacts for non-emergency programs are included in 2019 IEPR forecast, but load flexibility as evaluated for AB 3232 purposes has not yet been addressed in routine CEC planning assessments.

(II) Modeling Approach for Assessing Each Building Decarbonization Strategy

Even though most strategies are already assessed in a limited manner in existing CEC forecasting and assessment proceedings, the requirements of AB 3232 to evaluate costs and GHG emission reduction required a different emphasis. New analytic techniques had to be developed to assess some strategies, while others required adaptation. **Table C- 1** reports the comprehensive list of scenarios examined in the assessment and provides a crosswalk between the scenario numbering nomenclature used in this Appendix compared to the naming conventions used in the main report. **Table C-2** describes the analytic approach used to assess each strategy and the extent to which determining only incremental impacts above and beyond "business as usual" policies had to be considered.

Table C- 1: Mapping of the comprehensive list of scenarios analyzed for AB 3232 based on the seven decarbonization strategies

Building decarbonization strategy	Decarbonization scenario(s) analyzed in the main report	Associated scenario number analyzed in comprehensive analysis and reported in the Appendix
1. Building End-Use Electrification	Four building end-use electrification scenarios (Minimal, Moderate, Aggressive, Efficient Aggressive)	**Scenario 6 or 6.a** ("Minimal electrification"); **Scenario 6.b*;** **Scenario 7**; **Scenario 8** ("Moderate electrification"); **Scenario 9**; **Scenario 10**; **Scenario 11**; **Scenario 12.a** ("Aggressive

Building decarbonization strategy	Decarbonization scenario(s) analyzed in the main report	Associated scenario number analyzed in comprehensive analysis and reported in the Appendix
		electrification"); **Scenario 12.b** ("Efficient aggressive electrification"); **Scenario 12.c;** **Scenario 12.d** (Refer to Table C-10 on page 48 for electrification scenario descriptions)
2. Decarbonizing the Electricity Generation System	Accelerated Renewable Electric Generation Resources	Scenario 5
3. Energy Efficiency	Incremental Electric Energy Efficiency	Scenario 1
	Incremental Gas Energy Efficiency	Scenario 2
4. Refrigerant Leakage Reduction	Not assessed	Not assessed
5. Distributed Energy Resources	Incremental rooftop solar PV systems	Scenario 3
6. Decarbonizing the Gas System	Decarbonizing gas system with renewable gas (Main report reports results from Scenario 4.b.)	**Scenario 4.a**. (15% Renewable Gas by 2030); **Scenario 4.b**. (20% Renewable Gas by 2030 - Low Cost Synthetic Gas Starting in 2026); **Scenario 4.c.** (20% Renewable Gas by 2030 - High Cost Synthetic Gas Starting in 2026)
7. Demand Flexibility	Demand flexibility	Discussed in text

*Note: Scenario 6.b is a sensitivity analysis of Scenario 6.a (i.e., the minimum electrification scenario) that investigates the potential grid impacts from a different type of technology replacement mix. The GHG impacts and costs are not reported for Scenario 6.b.

Source: CEC staff

Table C-2: Analytic Approach Used to Quantify Building Decarbonization Impacts

Decarb Scenario Analyzed	Analytic Approach	Treatment of Business as Usual Policies
Scenario 1: Gas Energy Efficiency	Standalone Excel workbook quantifies savings, GHG and net cost impacts beyond BAU assumptions	Incremental NG EE savings beyond AAEE Scenario 3 used to estimate impacts
Scenario 2: Electric Energy Efficiency	Standalone Excel workbook quantifies savings and net cost impacts beyond BAU assumptions, while GHG impacts assessed using electric generation system techniques	Incremental NG EE savings beyond AAEE Scenario 3 used to determine impacts
Scenario 3: Rooftop Solar PV	Standalone Excel workbook quantifies GHG and net cost impacts beyond BAU assumptions	Incremental PV penetration beyond Mid PV case from 2019 IEPR demand forecast
Scenarios 4a-c: Renewable Gas	Standalone Excel workbook quantifies GHG emission reductions and E3 revenue/rate tool used to compute net costs	Assumed AAEE Scenario 3 reduces gas consumption
Scenario 5: Electric generation system decarbonization through accelerating the introduction of renewable resources into electricity system	EAD/SAO staff manually determine resource buildout and GHG emissions are then quantified using PLEXOS production simulation model	SB100 establishes Renewable Portfolio Standard of 60% of electricity sales by 2030; and projected sales are determined by 2019 IEPR Mid-Mid managed demand forecast
Scenarios 6-12: Building End-use Electrification	FSSAT tool developed by Guidehouse specifically for building end-use electrification analyses	No BAU policy impacts to consider
Demand Flexibility	Standalone analysis drawing upon LBNL demand flexibility analyses for CPUC	Traditional non-event-based load management programs BAU

Source: CEC staff

As **Table C-2** indicates, there are several different approaches needed to evaluate all building decarb strategies. The approach used in each grouping of strategies with similar methods are described below.

Assessing Energy Efficiency Strategies (Scenarios 1 & 2)

For energy efficiency impacts — a topic traditionally examined as a load modifier to baseline demand forecasts — EAD staff had no tools to compute incremental GHG emission reductions or net costs to consumers. The usual focus has been on the likelihood of a program operating in future years, the amount of energy savings and its cost-effectiveness compared to supply-side resources that would otherwise be required to meet consumer demand. As a result, new assessment tools had to be developed for any scenarios involving these energy efficiency strategies.

Several basic steps were followed in developing Excel-based tools:

1. Acquire all of the available energy efficiency results from scenarios of possible energy efficiency from the 2019 IEPR cycle.
2. Compute net incremental savings on an annual and/or hourly basis for the hypothesized scenario definition above and beyond those included in the 2019 IEPR Mid-Mid managed demand forecast adopted by the CEC. In order to evaluate the full energy savings and GHG reduction benefits of 1st year savings in the 2020 to 2030 period, develop decayed savings in years 2030 and beyond using assumed savings mean lifetimes of 15 years for residential savings and 20-year mean lifetime for commercial sector savings.
3. Translate energy savings into GHG emission reductions using an appropriate GHG emission factor.
    a. For gas energy efficiency this is a fixed conversion factor based on gas combustion.
    b. For electric energy efficiency this is an annual emission intensity (metric tonnes GHG per MWh of generation) derived from CEC Supply Analysis office (SAO) analyses of the 2019 IEPR Mid-Mid load forecast case assuming RPS requirements are fully implemented as required by SB 100.
4. Compute gross consumer costs incurred in each year 2020 to 2030, where:
    a. Gross costs for IOU gas energy efficiency programs are taken from the CPUC 2018 Potential and Goals Study[282] using Southern California Gas program costs for all three gas IOUs.
    b. Gross costs for IOU electric energy efficiency programs are taken from the CPUC 2018 Potential and Goals Study using Southern California Edison program costs for all three electric IOUs.
    c. Gross costs for building and appliance standards are assumed to be 95 percent of the gross benefits.

282 Guidehouse provided detailed results from the 2018 Potential and Goals Study that were not published at the level of detailed used in this study.

5. Compute gross consumer benefits incurred in each year 2020 to 2045 as the surviving energy savings after decay times the 2019 IEPR retail average price in each future year by sector.
6. Compute net costs in each year as gross costs minus gross benefits.
7. Compute discounted net costs on a cumulative 2020 to 2045 basis by applying a 10 percent per year discount rate.

Table C-3 provides the aggregate cumulative savings for each year 2020 through 2030 that result from computing the difference between 2019 IEPR AAEE Scenarios 5 and 3 for IOU programs and standards. Other types of program savings included in the 2019 IEPR development of AAEE Scenarios 3 and 5 were omitted since consumer costs were unknown. Once these cumulative annual savings were developed the corresponding 1st year savings were decayed for years 2031 through 2045 with no replacement for lost savings. Residential savings were assumed to have a 15-year mean life, while commercial savings were assumed to have a 20-year mean life. These lifetimes mean that savings that occur in the early years of the 2020 to 2030 period have lost a substantial proportion of their 1st year impact by the mid-2030s and most of their 1st year impact by the 2040s.

Table C-3: Gas and Electricity Program Savings for Scenarios 1 and 2

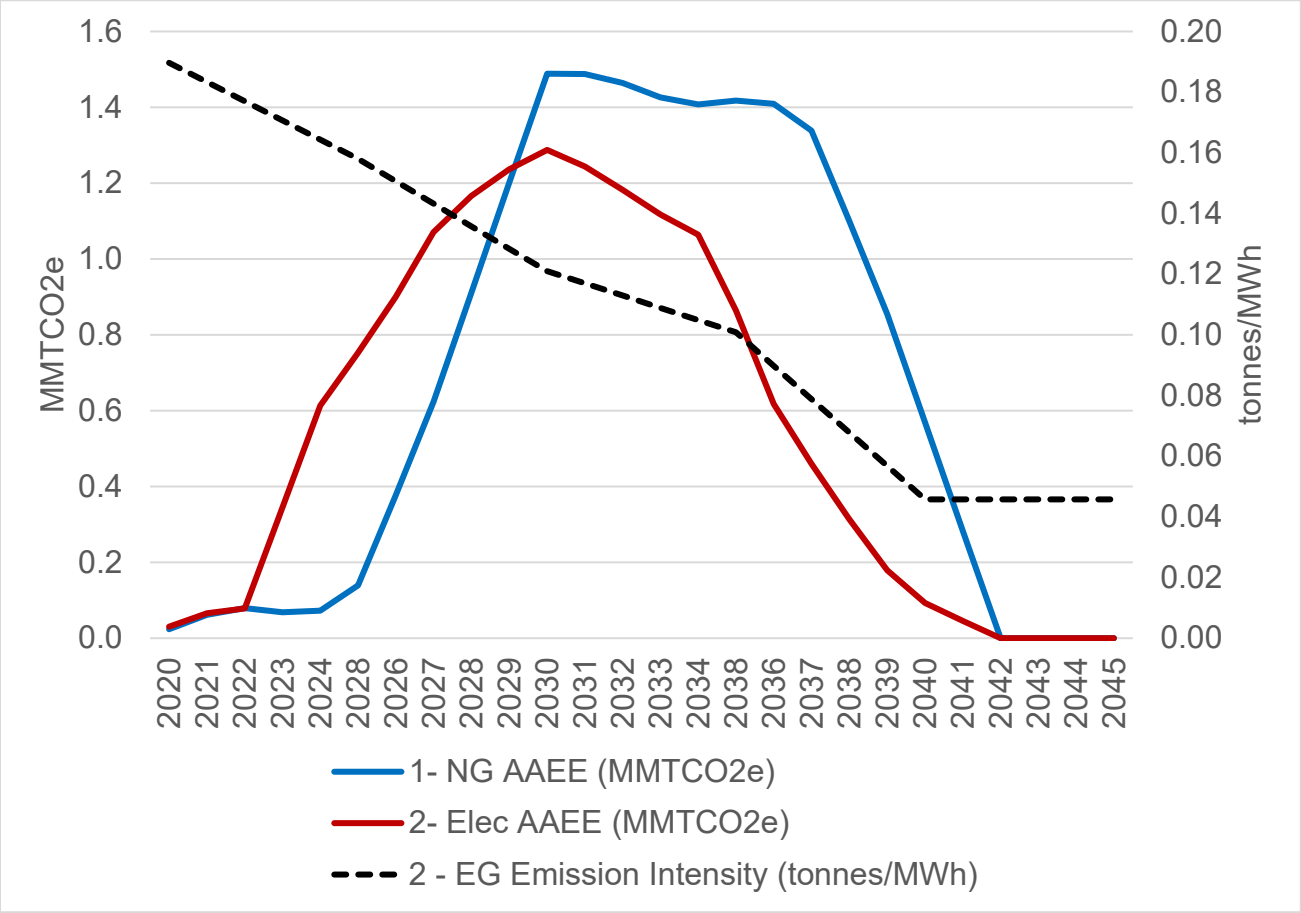
Program Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Gas Savings (MM Therms)											
IOU Program Total	2.8	4.4	5.0	5.5	6.4	7.7	8.2	9.8	13.3	16.7	19.9
Standards Total	0.0	4.0	5.5	3.1	2.8	13.0	56.1	99.6	148.3	197.3	245.9
Res Total	2.8	8.4	10.5	8.6	9.2	20.7	64.3	109.4	161.6	214.0	265.8
IOU Program Total	1.7	3.7	5.1	6.4	8.0	9.6	11.0	12.1	13.5	15.2	17.2
Standards Total	0.0	-0.3	-0.6	-2.1	-3.4	-4.0	-4.0	-3.6	-3.0	-2.4	-1.7
Com Total	1.7	3.3	4.5	4.3	4.6	5.6	7.0	8.5	10.5	12.8	15.5
Res+Com Total	4.5	11.7	15.0	12.9	13.8	26.4	71.3	117.9	172.1	226.8	281.3
Electricity Savings (GWh)											
IOU Program Total	74.9	136.2	120.9	105.1	128.2	152.8	175.7	192.7	213.6	238.0	266.0

Standards Total	0.2	32.7	69.6	1525.4	2845.3	3510.9	4403.3	5269.3	5805.4	6315.8	6831.2
Res Total	75.1	168.9	190.5	1630.5	2973.5	3663.7	4579.0	5462.0	6019.0	6553.8	7097.2
IOU Program Total	85.4	175.7	210.1	240.8	290.4	356.7	373.8	381.6	400.5	415.0	451.0
Standards Total	0.0	13.2	40.4	152.8	468.8	745.0	1028.3	1632.1	2169.8	2659.7	3093.4
Com Total	85.4	188.9	250.5	393.7	759.2	1101.6	1402.1	2013.7	2570.3	3074.6	3544.4
Res+Com Total	160.5	357.9	441.1	2024.2	3732.7	4765.3	5981.2	7475.7	8589.3	9628.4	10641.6

Source: CEC staff

Figure C-2 provides a view of the pattern of aggregate GHG emission reductions for Scenarios 1 and 2. The electric generation system emission factor in each future year declines substantially over time, given the 2019 IEPR managed demand forecast and the requirements that mandate an increase in RPS. As a result, the GHG emission reductions of electricity energy efficiency savings decline faster than do the GHG emissions reductions from gas energy efficiency programs and standards that have a constant factor translating gas combustion into GHG emissions.

Figure C-2: GHG Emission Reductions for Scenarios 1 and 2, Statewide



Source: CEC staff

Table C-4 provides total rolled up energy efficiency costs for IOU gas and electric energy efficiency rebate programs used to compute gross costs for the IOU programs portion of the incremental savings of AAEE Scenarios 1 and 2, respectively. While these values appear large, recall that 15-20 years of energy savings result from a single year's investment in energy efficiency measures.

Table C-4: IOU Program Savings Costs Per Unit for Gas and Electricity

Program Type	Units	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Res IOU Rebate Programs	$/Thm	4.99	4.60	4.60	4.60	4.62	5.90	4.99	6.26	6.39	6.49	6.55
Com IOU Rebate Programs	$/Thm	12.89	12.64	12.95	13.18	13.45	13.48	13.74	13.92	14.08	14.23	14.34

Res IOU Rebate Programs	$/kWh	0.46	0.53	0.60	0.63	0.66	0.75	0.78	0.81	0.84	0.87	0.86
Com IOU Rebate Programs	$/kWh	2.47	2.34	2.37	2.32	2.46	2.63	3.05	3.28	3.51	4.40	4.59

Source: 2018 Potential and Goals Study (courtesy of Guidehouse)

Assessing Rooftop PV Strategies (Scenario 3)

The general approach to developing an Excel-based analysis tool for rooftop PV followed many of the same steps as discussed above for energy efficiency program savings. Assessing strategies that rely upon increased capacity of rooftop solar generation beyond that included in 2019 IEPR managed demand forecasts does not reduce electric energy consumption but increases the share of consumption that comes from non-carbon sources. Even though rooftop PV is not an eligible generating technology to satisfy RPS requirements, a rooftop PV decarb strategy effectively displaces dispatchable supply-side generating sources in much the same way as would supply-side solar generation.

Several basic steps were followed in developing an Excel-based tool:

1. Acquire the available rooftop PV capacity increases, hourly electric energy production, and capacity investment costs from scenarios of possible rooftop PV assessments from the CEC/EAD staff's analysis in the 2019 IEPR cycle.
2. Compute net capacity increases on an annual basis for the hypothesized scenario definition that is above and beyond that included in the 2019 IEPR Mid-Mid managed demand forecast adopted by the CEC. Compute energy production on an annual basis for the correlation of 2022, 2025, and 2030 analyses that report complete results and apply to all years to obtain annual energy production. In order to evaluate the full energy savings and GHG reduction benefits of 1st year savings in the 2020 to 2030 period, develop decayed energy production in years 2031 and beyond using an assumed mean lifetime of 25 years for 1st year energy production.
3. Translate energy production into GHG emission reductions using an appropriate GHG emission factor obtained from SAO's analysis of the response of the electric generation system to the added rooftop PV production built out to satisfy the 2019 IEPR Mid-Mid load forecast case assuming RPS requirements are fully implemented as determined by SB 100.
4. Gross costs for rooftop PV are the cost of the high penetration case multiplied by the incremental capacity additions from mid case to high case.
5. Compute gross benefits incurred in each year 2020 to 2045 as the surviving 1st year energy production after decay times the 2019 IEPR retail average blended electricity price in each future year assuming residential capacity is 75 percent and commercial sector is 25 percent of each year's capacity additions.
6. Compute net costs in each year as gross costs minus gross benefits

7. Compute discounted net costs on a cumulative 2020 to 2045 basis by applying a 10 percent per year discount rate.

Table C-5 summarizes by utility the estimated rooftop PV capacity additions for combined across the residential and commercial sectors.

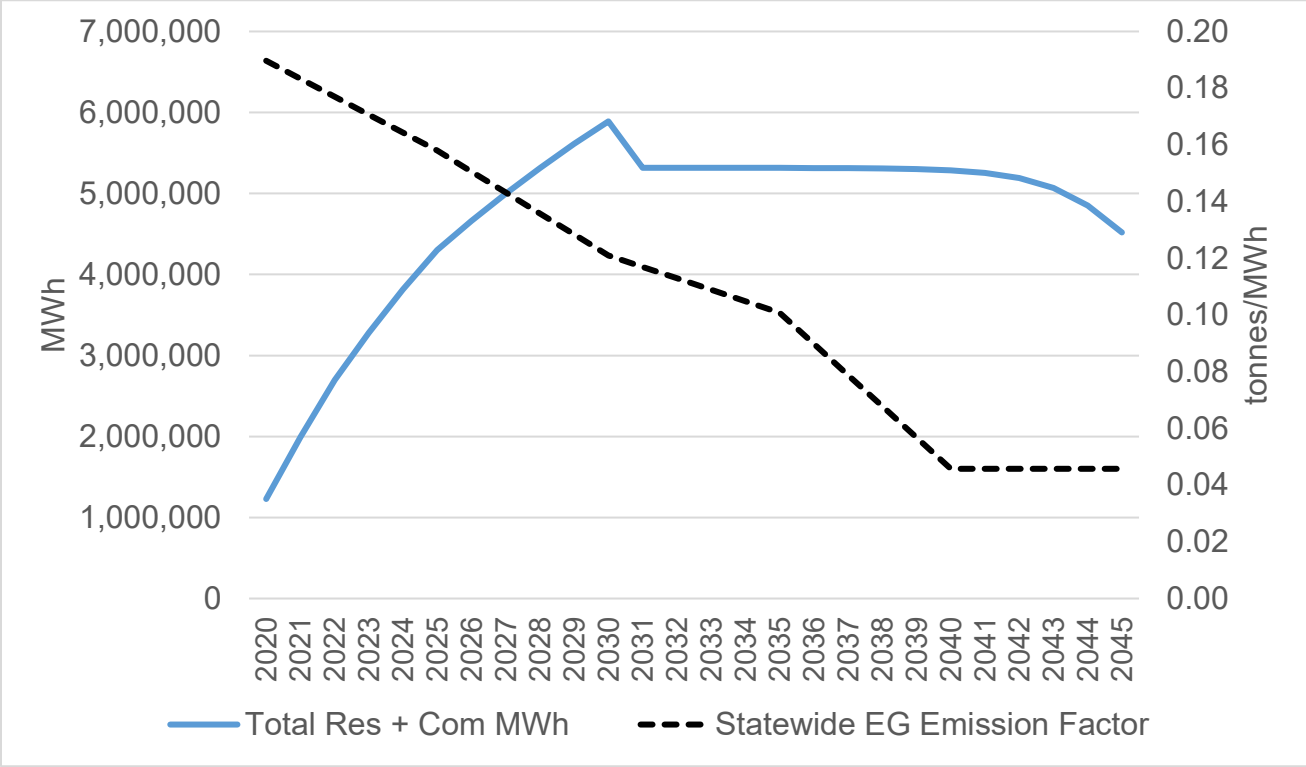
Table C-5: Rooftop PV Capacity Additions for Combined Residential/Commercial Sectors (Megawatts)

Utility	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
PGE	427	737	977	1100	1208	1298	1384	1470	1555	1639	1720
SMUD	31	53	73	94	113	131	147	161	173	183	193
SCE	238	353	506	647	764	859	938	1003	1056	1098	1129
LADWP	4	7	12	21	28	35	45	57	70	85	101
SDGE	54	75	89	100	111	120	129	140	153	167	182
Other	2	6	10	15	20	26	32	40	48	57	68
State	756	1231	1667	1977	2243	2469	2676	2871	3055	3229	3392

Source: CEC staff

Additional capacity produces electric energy on an hourly pattern that varies across the year. To ensure consistency with the energy production assumptions of the 2019 IEPR, annual energy was computed as the sum of the hourly generation for the incremental capacity for each year. Since rooftop PV performance can be assumed to degrade through time, Staff assumed a 25-year mean lifeline for new rooftop arrays. This longer mean life compared to that assumed for energy efficiency savings resulted in relatively little performance degradation until the latter years of the projections. **Figure C-3** illustrates this limited energy production decline. It also shows the electric generation system emission intensity with this increased capacity in place, and the decline through time as 60 percent RPS is accomplished reduces the value of the rooftop PV as a GHG reduction strategy.

Figure C-3: Electric Generation From Rooftop PV Capacity Additions and Electric Generation System Emission Factors — Statewide



Source: CEC staff

Table C-6 reports investment costs on a $/kW basis for the incremental capacity added, for each of the five utility planning areas, which were used in determining the gross costs of investments in the incremental rooftop PV capacity.

Table C-6: Per Unit Investment Costs (2018$) for Incremental Rooftop PV Capacity Additions

Year	PGE	SCE	SDGE	LADWP	SMUD	Other
2019	3.73	3.68	3.77	3.73	3.75	3.41
2020	3.56	3.51	3.51	3.44	3.48	3.18
2021	3.35	3.29	3.27	3.17	3.23	2.94
2022	3.02	3.09	3.03	2.88	3.01	2.73
2023	2.63	2.88	2.78	2.72	2.80	2.59
2024	2.37	2.68	2.50	2.53	2.60	2.44
2025	2.15	2.47	2.24	2.39	2.39	2.31
2026	1.99	2.27	2.01	2.27	2.20	2.19
2027	1.85	2.09	1.87	2.15	2.01	2.08
2028	1.72	1.90	1.74	2.03	1.84	1.97

2029	1.59	1.73	1.63	1.91	1.69	1.87
2030	1.48	1.56	1.52	1.80	1.56	1.77

Source: CEC staff

Assessing Renewable Gas Strategies (Scenarios 4.a, 4.b, 4.c)

Assessing renewable gas as a building decarbonization strategy required the development of new tools and sources of data not generally examined by the CEC until very recently. The CEC operates an extensive research program under an arrangement with the CPUC using funds collected from electric and gas ratepayers known as the Electric Program investment charge (EPIC). The CEC published, "The Challenge of Retail Gas in California's Low-Carbon Future," an EPIC-funded study of the impacts of high electrification levels on the gas system in 2020, which this analysis drew upon for projected costs of various components of renewable gas.[283]

Following the approach that was implemented for the energy efficiency decarbonization strategies, EAD staff developed an Excel-based tool that could assess scenarios in which various proportions of fossil gas were displaced by biomethane, synthetic gas, or hydrogen. The analysis would estimate GHG emission reductions and net costs to end-users. Since the limited previous assessment of renewable gas means that there was no pre-existing body of analysis reviewed within the biennial IEPR process, greater uncertainty about plausible scenarios and needed input assumptions exists for renewable gas than for energy efficiency savings or rooftop PV electricity production.

The following basic steps were implemented:

1. Review the E3 report, "The Challenge of Retail Gas in California's Low-Carbon Future," and the revenue requirements/rate tools developing as part of the project and documented in Appendix G.[284]
2. Assume that engineering practices associated with technologies to create and/or pressurize biomethane and synthetic gas have negligible GHG emissions compared to the GWP of the gas displaced.

283 Aas, Dan, Amber Mahone, Zack Subin, Michael Mac Kinnon, Blake Lane, and Snuller Price. 2020. The Challenge of Retail Gas in California's Low-Carbon Future: Technology Options, Customer Costs and Public Health Benefits of Reducing Natural Gas Use. California Energy Commission. Publication Number: CEC-500-2019-055-F. https://ww2.energy.ca.gov/2019publications/CEC-500-2019-055/index.html.

284 "APPENDIX G: E3 Gas Revenue Requirement Model" in Aas, Dan, Amber Mahone, Zack Subin, Michael Mac Kinnon, Blake Lane, and Snuller Price. 2020. The Challenge of Retail Gas in California's Low-Carbon Future: Technology Options, Customer Costs and Public Health Benefits of Reducing Natural Gas Use. California Energy Commission. Publication Number: CEC-500-2019-055-F. https://ww2.energy.ca.gov/2019publications/CEC-500-2019-055/CEC-500-2019-055-AP-G.pdf.

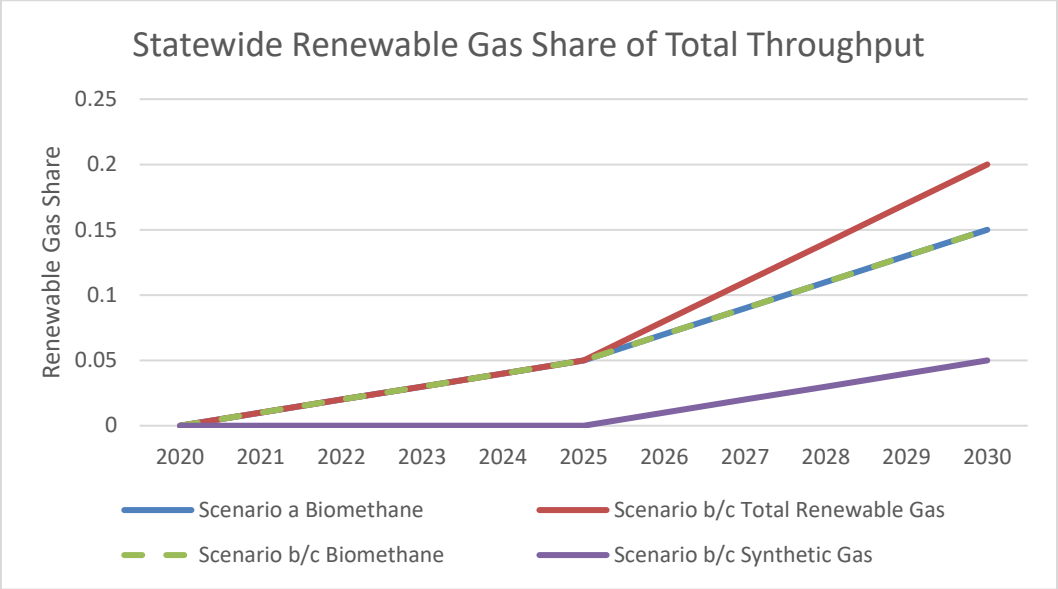
3. Operate the E3 revenue requirements/rate tool for each of Southern California Gas and Pacific Gas & Electric versions for two scenarios: (1) No Electrification, and (2) the CEC-staff defined scenario penetration of biomethane and/or synthetic gas.
4. For each of Southern California Gas and Pacific Gas & Electric variants of the E3 revenue requirements/rate tool, form the ratio of residential and commercial customer rates for the renewable gas scenario divided by the No Electrification case for each year 2020 through 2030 and apply the year-specific ratio to the CEC staff's 2019 IEPR average customer price by customer sector. Assume the ratios formed for Southern California Gas are applicable to San Diego Gas & Electric.
5. For each of residential and commercial sectors, for each year from 2020 through 2030, compute net costs as the difference in scenario-specific annual average sector prices less 2019 IEPR average sector price times the volume of gas projected to be combusted in that sector (less the gas energy efficiency savings of AAEE Scenario 3).
6. Compute discounted net costs by applying a 10 percent per year discount factor.

Given the uncertainty of the penetration of renewable gas into the overall consumption of gas in California, three sub-scenarios were developed to explore the consequences of this uncertainty. Each of these is described below and shown in Figure C-4:

- Sub-scenario 4.a – renewable gas composed entirely of biomethane rising gradually as a share of total gas deliveries from 2020 reaching 15 percent in 2030.
- Sub-scenario 4.b – the same pattern of biomethane displacement as sub-scenario 4a augmented by synthetic gas further displacing gas beginning in 2026 and reaching 5 percent by 2030 for a total renewable gas penetration of 20 percent in 2030.
- Sub-scenario 4.c – the same pattern of biomethane and synthetic gas displacing gas as sub-scenario 4.b, but with synthetic gas approximately twice as expensive on a per therm basis as synthetic gas in sub-scenario 4b.

Sub-scenarios 4.b and 4.c introduce synthetic gas, even though much more expensive than biomethane, because the limit on the biomass that could be converted into either biomethane or bioliquids for transportation fuels is reached at the level of 15 percent of business as usual gas system throughput.

Figure C-4: Penetration of Renewable Gas Components in Each Sub-Scenario



Source: CEC staff

Computing the GHG emission reductions for renewable gas scenarios using the AB 3232 framing is very straightforward with the assumption that renewable gas has no GHG emissions.[285] The GHG emissions reduction is simply the product of one minus the renewable gas share multiplied by the adjusted gas consumption projection for the residential and commercial sectors.[286] **Table C-7** provides a numeric result of these GHG emission reductions for sub-scenario 4.a and for both subs-scenarios b and c.

Table C-7: Statewide GHG Emission Reductions from Renewable Gas Sub-scenarios ($MMTCO_2e$)

Scenario	Sector	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Sub-scenario a	Res+Com	0.00	0.34	0.69	1.02	1.35	1.68	2.33	2.98	3.62	4.26	4.89
-	Com	0.00	0.11	0.22	0.33	0.44	0.55	0.76	0.98	1.19	1.40	1.60

285 Determining the GHG emissions from any of the processes of capturing biomethane from food production waste, biomass crop production, or synthetic gas chemical production facilities is beyond the scope of this assessment. Any of such analyses would reveal some GHG emissions, which would reduce the net GHG benefits compared to the results of using the simplified assumptions of this study.

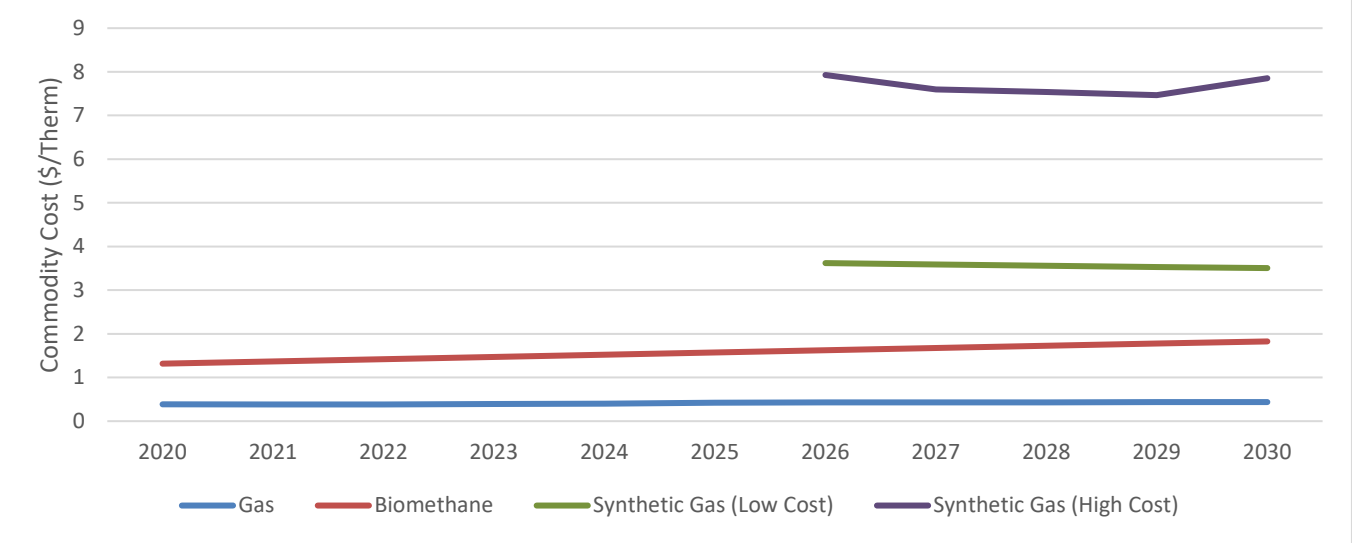
286 The renewable gas (i.e., RNG) penetration assumptions in these scenarios apply to the entire gas system throughput, since virtually all gas customers are connected to a common gas transmission and distribution system. The analysis of GHG emission reductions and costs reported here are those attributable to the residential and commercial building sectors alone. There are further costs and further GHG emission reduction benefits attributable to other end-use sectors that are not included here.

-	Res	0.00	0.23	0.46	0.69	0.91	1.13	1.57	2.00	2.43	2.87	3.29
Sub-scenario b/c	Res+Com	0.00	0.34	0.69	1.02	1.35	1.68	2.67	3.64	4.61	5.57	6.52
-	Com	0.00	0.11	0.22	0.33	0.44	0.55	0.87	1.20	1.51	1.83	2.14
-	Res	0.00	0.23	0.46	0.69	0.91	1.13	1.79	2.45	3.10	3.75	4.38

Source: CEC staff

Figure C-5 provides a visual comparison of the cost per therm of renewable gas components compared to "business as usual" commodity gas costs. **Figure C-5** shows that biomethane is assumed to be three times as expensive as gas, low-priced synthetic gas is about ten times as expensive and high-priced synthetic gas is about 20 times more expensive.

Figure C-5: Assumed Commodity Costs of Renewable Gas Components Compared to Gas



Source: CEC staff

Finally, unlike energy efficiency and rooftop PV scenarios, where a physical change is made to a building that has a stream of impacts through time, albeit with some performance degradation over the years, there is no corresponding physical change to end-user buildings when the mix of gas distributed to end-users shifts from fossil gas to renewable gas. Thus, it is unclear how to treat impacts in years beyond 2030. Would the facilities coming online in 2028 or 2029 have contracts that imply their production would be assured for years to come? How many years? What happens to a facility that, in hindsight, had a high-priced contract when its original contract term expires? Would it cease production? Would the original owners declare bankruptcy and new owners negotiate a lower price for the facility's output? These issues of how to assess costs and GHG emission reductions for the period beyond 2030 are

beyond the scope of this initial assessment and render the costs and efficacy of the renewable gas scenarios very uncertain.

Assessing Building End-Use Electrification Strategies (Scenarios 6-12)

Recognizing a substantial unstudied potential building decarbonization strategy, EAD began developing a fuel substitution capability in the fall of 2018 and staff published an exploratory study highlighted in the December 2019 IEPR demand forecast emerging issues workshop.[287] A much more sophisticated effort to create the Fuel Substitution Scenario Analysis (FSSAT) tool to meet the analytical needs of AB 3232 was subsequently undertaken and presented in the AB 3232 workshop on February 27, 2020.[288]

The FSSAT is useful for development impacts form detailed assumption about the penetration of residential and commercial building electric technologies, but lacks a predictive framework to enable a full forecast of technology-level electrification on the basis of consumer education, technology-specific incentives through programs, and the wide range of consumer behavior embedded in a true forecast model. As research on consumer behavior is collected and implementation data from pilot programs becomes available, more capabilities including these aspects of a predictive behavior can be incorporated in the model to transform the FSSAT into a genuine forecasting tool.

FSSAT Overview: Key Inputs, Processes, and Outputs

The FSSAT was developed by Guidehouse in collaboration with EAD staff with the prime objective of determining the change in GHG emissions in four building sectors: residential, commercial, agricultural, and industrial due to electrification efforts during a given projection period. For the purposes of AB 3232 only the residential and commercial sectors were explored, and the projection period is assumed to be from 2020 through 2030 unless stated otherwise.

The flow chart below in **Figure C-6** provides an overview of the key processes in the model. The FSSAT begins with the mid baseline 2019 IEPR gas forecast for the three IOU gas utilities by sector and end-use which is modified using one of six AAEE gas savings scenarios also disaggregated by utility, sector and end-use. This adjusted gas consumption forecast is subsequently further disaggregated to the technology level within key fuel combustion end-uses. For the residential sector these encompass space and water heating, cooking, and laundry. For the commercial sector space and water heating as well as cooking are considered. A set of electric technologies is characterized providing the same function for the end user and a map created with which to replace specific gas technologies in each sector and end-use combination.

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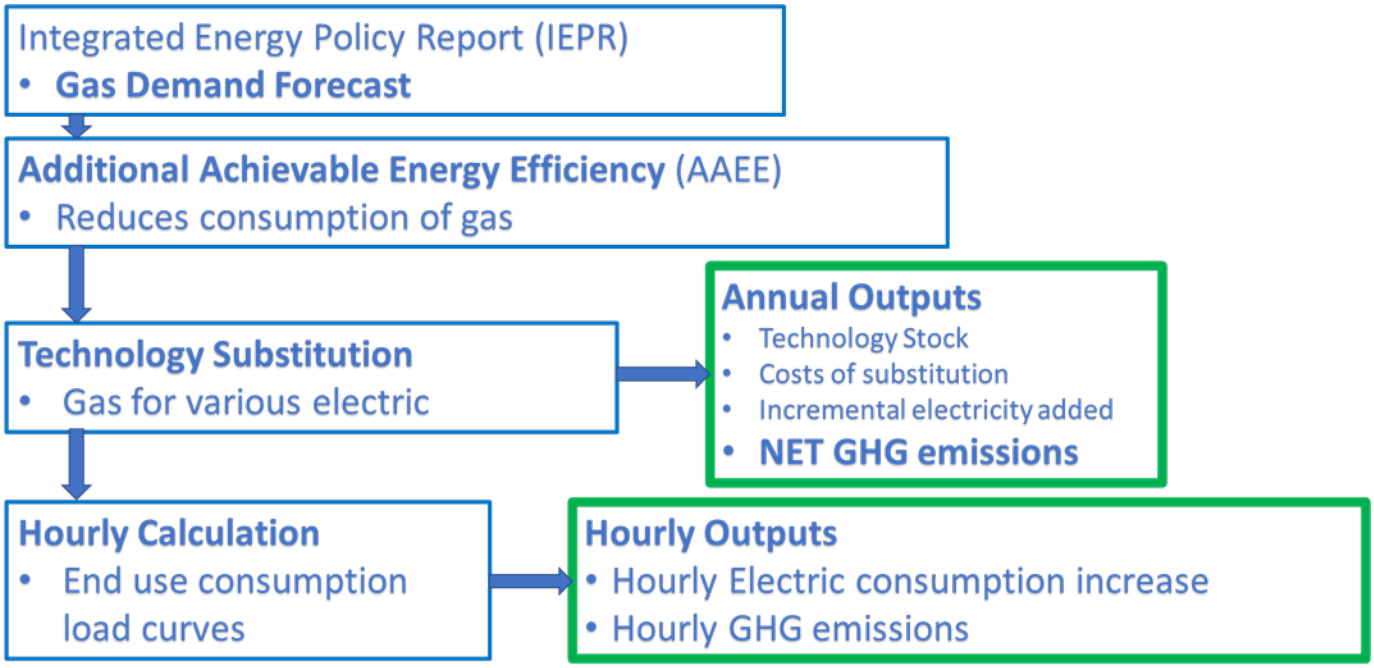
287 Michael R. Jaske, Ph.D. Energy Assessments Division. Fuel Substitution: An Exploratory Assessment of Electric Load Impacts. Publication Number CEC-200-2019-020 November 2019. TN# 232186.

288 Amul Sathe, Karen Maoz, John Aquino, Abhijeet Pande, Floyd Keneipp. Fuel Substitution Forecasting Tools Methods Supporting Senate Bill 350 Analysis. Publication Number CEC-200-2020-001 May 2020 TN# 233241.

Figure C-6: FSSAT Main Processes Flow Chart



Source: CEC staff

The next step is to define one or more scenarios with assumed 2030 penetration shares for each end-use segment: New construction (NC); Replace on burnout (ROB); Early replacement (RET). The electrification penetrations can be interpreted as described in the **Table C-8** below. The penetrations are cumulative percentages for eligible equipment stock to be replaced by 2030 which can vary from zero to one hundred percent. The saturation description refers to the present of installed over the entire projection time-period, here 2020-2030. This means it describes the share of the cumulative stock that is new over this period, not a marginal saturation for technologies added in 2030. The saturation combined with the adoption curve determine the number of units electrified in a given year.

Additional scenario levers include the performance and cost metrics of the set of technologies selected for substitution. GHG emissions factors can also be varied by source category and a toggle for meeting SB 1383 HFC reduction goals can be switched on or off. Each of these are these are hypothetical "what if" scenarios depicting technical rather than economic potential.

All of these levers, with the exception of the GHG emissions, can be assigned a common statewide value or be further refined to vary for each of the five large electric utilities (Pacific Gas & Electric, Southern California Edison, San Diego Gas & Electric, SMUD, and Los Angeles Department of Water and Power) leaving the remaining electric utilities grouped as one. Variation in end-use fuel choice saturations by utility are embedded in the gas demand forecast and the consequences of building electrification by substituting electric technologies for gas ones implies varying levels of gas displacement and added incremental electricity based on electric service area. Fuel saturation data are somewhat dated in the current iteration of the FSSAT tool. Staff plans on updating these with the recently obtained results of the 2019-20 Residential Appliance Saturation Survey (RASS). A similar endeavor may be

undertaken when the results of the Commercial End Use Survey (CEUS) are obtained in 2022-23.

Table C-8: FSSAT Scenario lever descriptions

Scenario Parameter	Definition	Variable Range
New construction (NC)	Percentage of eligible technologies by sector/end-use that will be electric in the last year of the forecast period (2030).	0%—100%
Replace on burnout (ROB)	Percentage of existing gas technologies by sector/end-use that will burn out by the end of the forecast period (2030) and be replaced by an electric technology.	0%—100%
Early replacement (RET)	Percentage of existing gas technologies by sector/end-use that will not burn out by the end of the forecast period (2030) and will be replaced by an electric technology.	0%—100%
Technology Performance	A weighting that determines the distribution among potential electric replacement technologies according to their relative efficiencies.	Low efficiency weighted
		Evenly weighted
		High efficiency weighted
		User defined
Technology Cost	Percentage defining the highest allowable technology cost by end use.	Minimum value: 0%—100%
		Maximum value: 0%—100%
GHG Emissions	emissions factors by source category	user file input
	SB 1383 HFC reduction goals	goal met/not met

Source: CEC staff

After the substitution from gas to electric technologies is complete, annual outputs are created for the remaining technology stock of both fuels, the costs and the incremental added electricity of the substitution effort as well as the net change in GHG emissions. Optional hourly and comparison modules can be run to develop hourly incremental added electric consumption and GHG emissions changes due to fuel substitution efforts, undergone to electrify the existing building stock as well as new construction, or to observe key differences among multiple scenarios respectively.

The goal of AB 3232 is a 40 percent reduction of GHG emissions from a 1990 baseline in 2030. The FSSAT assesses GHG emissions from five sources as delineated in **Table C-9**. The largest source is GHG emissions from gas combustion which is first reduced by an AAEE scenario and then furthermore from the building electrification scenario specific efforts to displace gas consumption. BTM methane leakage is also calculated in the FSSAT as a percentage of gas consumption. The next largest source is stock refrigerant leakage emissions, mostly from HFC's, which uses a constant value from CARB projections with or without "success" of SB 1383 as defined in each scenario. The FSSAT also computes incremental HFC's from heat

pumps added in each electrification scenario but this value is very small.[289] Non-gas combustion emissions are included as a moderate constant value from the 2018 CARB emissions inventory. Lastly, the incremental electric generation emissions due to incremental added electric loads from electrification efforts are converted to GHG emissions using emission factors based on hourly loads developed by EAD staff as illustrated in the "Electric Generation System Greenhouse Gas Emissions" sub-section of the next section "Electric Generation System Modeling Approach". This was an iterative process in which FSSAT hourly electric loads for various building electrification scenarios first using baseline GHG factors were passed to EAD/SAO to develop RPS compliant, reliable resources mixes that were then re-assessed to include the incremental added electric load using the Plexos production simulation model to develop appropriately adjusted GHG emissions factors.

Table C-9: GHG emissions projected in the FSSAT for each scenario

FSSAT GHG Component	Method for Assessing
Gas Combustion	AAEE reduces baseline consumption
	analyze "what if" scenarios of sector/end-use/technology displacement of gas consumption
Non-gas fuel Combustion	Constant 2017 value from CARB emission inventory
Behind-the-meter gas leakage	percentage of gas fuel combustion using appropriate emission factors
Incremental HP HFC's	Computes incremental HFCs from installed heat pumps
HFC leakage	"stock" emissions use CARB projections with or without "success" of SB 1383
Incremental Electric Generation emissions	incremental electric loads are converted to GHG emissions using emission factors based on hourly loads

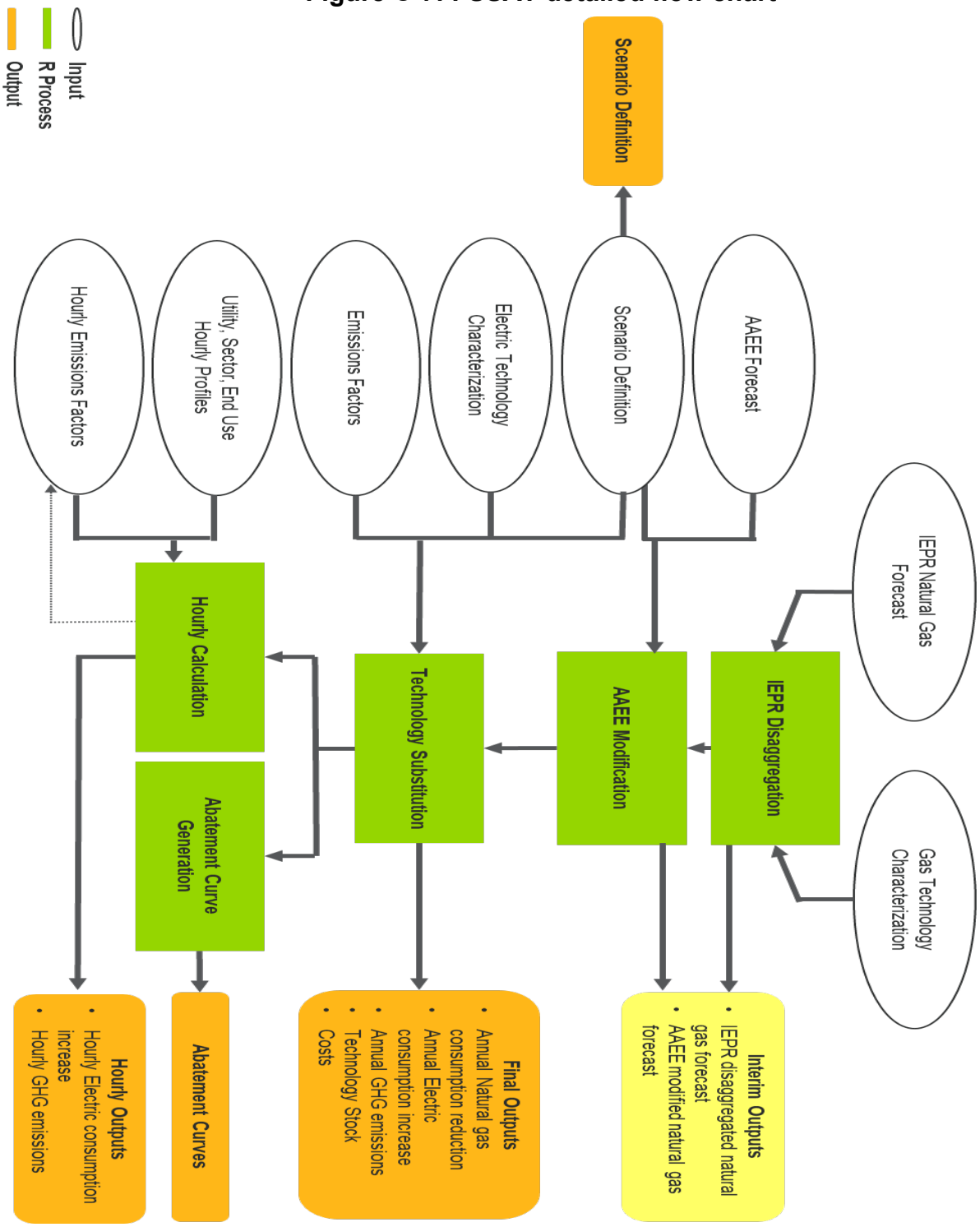
Source: CEC staff

A more detailed flow chart from the Guidehouse methodology report is presented in **Figure C-7**. As indicated in the figure the white ovals are key inputs; these are contained in three different locations from which the R-processes, shown in green rectangles, draw from. The first location is the global inputs workbook containing the (mid) baseline IEPR gas demand forecast as well as the six scenario options for AAEE gas savings. The emissions factors for all emitting point sources (i.e., all sources described in **Table C-9** besides the incremental electric generations emissions utility) to climate zone mappings, as well as utility rates

289 Refer to Figure 12 on page 54 and Figure 13 on page 55.

forecasts and building stock forecasts from the IEPR are also included in the global inputs workbook. This workbook is intended to be updated each full IEPR cycle.

Figure C-7: FSSAT detailed flow chart



Source: Guidehouse, Inc.

The bulk of the remaining inputs are contained in the user inputs workbook which uniquely defines a given electrification scenario. The AAEE scenario to be applied; forecast period; cost metrics such as: the standards dollar year, inflation, and real discount rates, as well as the annual electric energy emission factors specific to the scenario are updated here. This input workbook includes the scenario parameters or levers as described in **Table C-8**, which set the targets for 2030 technology substitution activity required for calculating adoption using the replacement map, efficiency level, sector, and utility. The replacement maps, mapping existing gas technologies to one or more electric replacement technologies, as well as the adoption scheme defined by adoption curves assigned to each technology substitution are defined here. The user input workbook also contains the percent refrigerant leakage and charge size by electric technology, the SB 1383 toggle, the percentage leakage as a function of gas consumption, panel upgrade costs, and the proportion of residential buildings with existing air conditioning units.

Lastly the gas and electric technology characterizations are fully contained in each scenario use input workbook. The gas technology-level consumption, costs, saturation, and density by utility, sector, end-use, building type, building climate zone, and efficiency level are mostly sourced from 2019 Database of Energy Efficiency Resources (DEER) data and the same as those utilized in the 2019 CPUC Potential and Goals Study. Similarly, the electric technologies available to replace gas technologies are characterized by efficiency and cost using the same sources. Each technology is described by the annual gas (therms) or electric consumption (kWh) as appropriate and electric consumption is calculated using the baseline gas technology consumption and the expected coefficient of performance of the electric technology mapped to it for replacement. Technology costs include both equipment and installation costs from a variety and sources and years according to best available data, Costs were scaled to the same year using the Producer Price Index. Market information on density, the quantity of a technology group in a given territory, and saturation, the proportion of technologies and given efficiency levels within a technology group, were pulled directly from the 2019 CPUC Potential and Goals Study. Technology lifetimes are based on DEER data and the current default assumption for electric technology are 15 years. No decay in consumption performance over time is included. Efficiency or performance values such as Coefficients of Performance (i.e., COP's) are based on a sample of manufacturer rating and scaled according to building climate zone.

The third and final input location is a set of workbooks specific only to the hourly R-module. The hourly module was built around the hourly AAEE tool also developed by Guidehouse in conjunction with EAD staff in 2019. It contains a file for hourly emissions factors specific to a given building electrification scenario, an end-use load shape library, and a master map file to assign the load shapes and choose utility based hourly outputs.

The key assumption in the Technology Substitution R-module is that the tool calculates the electric load using the gas consumption of the baseline technology. As seen in **Figure C-8** , Equation 5 in the Guidehouse FSSAT Methodology Report provides the calculation of electric consumption increasing using the baseline technology gas decrease.

Figure C-8: Screenshot of Equation 5 -- Added Electricity Consumption - Electrification of Gas Load

$$Elec\ Consumption_{i,k} = Gas\ Avoided_{i,j,k} * \frac{Gas\ Tech\ Eff_j}{Elec\ Tech\ COP_k} * \frac{29.3\ kWh}{1\ therm}$$

$Where$:
$Elec\ Consumption_{yr=i,electech=k}$ = Electric consumption by electric technology, k, in year, i.
$Gas\ Avoided_{i,j,k}$ = Gas consumption avoided by substituting gas technology, j, with electric technology, k, in year, i.
$Gas\ Tech\ Eff_j$ = Fuel efficiency of gas technology, j.
$Elec\ Tech\ COP_k$ = COP of electric technology, k.

Source: Sathe, Amul Sathe (Guidehouse), Karen Maoz (Guidehouse), John Aquino (Guidehouse), Abhijeet Pande (TRC), and Floyd Keneipp (Tierra Resource Consultants). 2020. Fuel Substitution Reporting Tools. California Energy Commission. Publication Number: CEC-200-2020-001. Page 94

Figure C-9(Table 19 on page 94 in the Guidehouse FSSAT Methodology Report) offers a concrete example of how the FSSAT electrifies gas loads.

Figure C-9: Example---Electrification of Gas Load

Step	Example
1) Identify gas technology	Residential small gas water heater
2) Identify replacement electric technology	Residential heat pump water heater
3) Characterize annual unit energy consumption of replaced gas technology	403 therms
4) Determine COP of electrification technology	COP = 3.0
5) Electrify replaced gas technology based on COP and furnace efficiency	$\text{Unit energy consumption (kWh)} = \frac{\left[(403\ \text{therms})\left(29.3\frac{\text{kWh}}{\text{therms}}\right)(0.8\ \text{EF})\right]}{3.0\ \text{COP}}$ $= 3{,}149\ \text{kWh}$

Source: Table 19 in Sathe, Amul Sathe (Guidehouse), Karen Maoz (Guidehouse), John Aquino (Guidehouse), Abhijeet Pande (TRC), and Floyd Keneipp (Tierra Resource Consultants). 2020. Fuel Substitution Reporting Tools. California Energy Commission. Publication Number: CEC-200-2020-001. Page 94

Scenario Design and Specification

EAD staff designed and implemented a suite of building electrification scenarios to satisfy the AB 3232 GHG reduction goal as described in the subsequent "Modeling Results" sections of this Appendix. Additional scenarios, beyond the three described in main AB 3232 California Building Decarbonization Assessment Chapters 3 and 4, are presented here. Listed in **Table C-10** below are the seven core FSSAT Scenarios studied in detail (Scenarios 6, 7, 8, 9, 10, 11, 12) and illustrated in subsequent sections of this Appendix in order of increasing building

electrification efforts. The two bookend scenarios (Scenarios 6 and 12) also include a particularly consequential variation of the substitution technology mix (Scenarios 6.b and 12.b) that will be described in more detail momentarily. The 12.c. and 12.d. variation of the highest electrification scenario are identical to 12.a. and 12.b. respectively with the exception of setting the SB 1383 goals achieved toggle to "on". Since the impacts of whether SB 1383 achieves its goals have a uniform impact regardless of the building decarbonization scenario, the main report reported both the impacts with and without the emission reduction potential of SB 1383.

Each of the scenarios in the chart used a 0.475 percent BTM gas leakage rate, a AAEE mid-mid planning Scenario 3 utilized 100 percent all electric new construction in both residential & commercial sectors by 2030, and did not impose any cost cap thresholds to electric technologies available for substitution. The standard dollar year for reporting was 2020, and an inflation rate of 2 percent and a real discount rate of 10 percent were used.[290]

The variations shown on the bookend scenarios, Scenarios 6.b and 12.b, compare results between all else equal scenarios using a high efficiency weighted mix of technology efficiencies ("mixMod") and those using only the "realistic best" single most efficient technology available from this same mix ("bestMod"). This original technology mix provided in the FSSAT was modified by EAD staff to exclude extremely inefficient technologies as well as those technologies which are unlikely to perform to listed specs in most installations. The "realistic best" single technology was chosen as the most efficient technology from the aforementioned mix that would also be readily available on the market and satisfy consumer expectations. For example, in the residential HVAC end use split systems while more efficient were not chosen due to prevalent homeowner preferences of not installing units requiring additional wall penetrations. In all end uses other than HVAC the most efficient technology was indeed chosen as the "single best realistic" one. Staff also allowed commercial boilers in the HVAC and water heating end uses to undergo substitution upon burnout or early retrofit but capped that at 50 percent i.e. for scenarios such as Scenario 12.a which are described as having substitution at rates higher than 50 percent substitution in for these particular technologies only, is manually capped at 50 percent in the "fine control" provided in the "R INPUT - Substitution Map" tab. To assist a future user so this those modified lines have been shaded gray rather than green below and green rather than white in the "R INPUT - Substitution Map" tab in the user input workbooks found the second to last two tabs of the docketed workbook. The docketed workbook displays the Tab "FS - Tech Map - Modified Mix" containing the "High Efficiency Weighted Mix" of electric replacement technologies that can be employed for substitution for the existing gas technologies for each sector, end-use, and replacement type. It also shows the Tab "FS - Tech Map – Single Best Realistic" containing the "realistic single

290 Refer to the "Costs and cost effectiveness" section in this appendix for a discussion of the assumptions underlying the costs analysis of this assessment.

best" electric replacement technology chosen from the mix utilized in Scenarios 6.b, 12.b and 12.d.

Table C-10: Building Electrification Scenario Definitions

Appendix Scenario	Scenario Parameters	New Construction	Replace on Burnout	Early Replacement	Technology Efficiency	SB 1383 goals
Scenario 6.a: *Minimal Electrification Scenario in main report*	NC100 ROB35 RET05 mixModEf HFCno	100% by 2030	15%	5%	High Efficiency Weighted Mix	Not met (Toggle Off)
Scenario 6.b:	NC100 ROB35 RET05 bestModEf HFCno				single best	
Scenario 7:	NC100 ROB35 RET05 mixModEf HFCno		35%		High Efficiency Weighted Mix	
Scenario 8: *Moderate Electrification Scenario in main report*	NC100 ROB50 RET05 mixModEf HFCno		50%			
Scenario 9:	NC100 ROB75 RET05 mixModEf HFCno		75%			
Scenario 10:	NC100 ROB90 RET05 mixModEf HFCno		90%			
Scenario 11:	NC100 ROB90 RET35 mixModEf HFCno			35%		
Scenario 12.a: Aggressive Electrification *Scenario in main report*	NC100 ROB90 RET70 mixModEf HFCno			70%		
Scenario 12.b: *Efficient Aggressive Electrification Scenario in main report*	NC100 ROB90 RET70 bestModEf HFCno				single best	
Scenario 12.c:	NC100 ROB90 RET70 mixModEf HFCyes				High Efficiency Weighted Mix	Met (Toggle On)
Scenario 12.d:	NC100 ROB90 RET70 bestModEf HFCyes				single best	

Source: CEC staff

CEC staff updates to FSSAT since the June 9th, 2020 workshop

Table C-11 summarizes several of the changes and updates staff made since the June 9th, 2020 that affected the final estimates for all scenarios presented in the report. Some of the data updates were planned, but as can be seen in the table, many of the changes were needed after staff discovered flaws during their quality control tests with the backend algorithms occurring within FSSAT. In addition to making structural modifications to the modeling tools, including FSSAT, used for building decarbonization analysis in future cycles,

updating and tracking other issues and data updates for the models will affect the estimates of any building decarbonization scenarios examined.

Table C-11: CEC Staff Updates to FSSAT since the June 9th, 2020 workshop

#	Description
1	Updated baseline forecast from 2017 IEPR to 2019 IEPR
2	Updated heat pump load shapes and hourly emission factors
3	Updated building end-use electrification technology replacement mapping assumptions
4	Updated the efficiency values for commercial cooking appliances and repaired a formula error in the FSSAT input workbook
5	Adjusted electric water heating technology costs to make them comparable to the baseline gas technology costs that were used in the 2019 Potential and Goals Study
6	Discovered and repaired a unit conversion coding bug that prevented incremental costs for some technologies to become negative
7	Updated annual emission factors for each FSSAT scenario based on PLEXOS work done by CEC's Supply Analysis Office

Source: CEC staff

Electric Generation System Modeling Approach (Scenario 5 and support for Scenarios 2, 3, 6-12)

The electric generation system is a major component of the 1990 GHG emission inventory and thus merits a substantial effort to assess properly. EAD/SAO staff employed its electric generation system modeling team to conduct an assessment of the electric generation system loads for all sectors and on a statewide basis implied by the scenarios evaluated in Chapters 3 and 4.[291] SAO also assessed an accelerated renewable portfolio standard scenario in which renewable capacity was introduced on a faster schedule than required by SB 100. Due to the large number of scenarios, SAO assessed only years 2022, 2025, and 2030. Since AB 3232 focuses on just GHG emissions associated with the residential and commercial building sectors the total electric generation system emissions must be reduced to the subset that corresponds to the electric load for these two sectors. EAD/DAO staff developed a method that computes the scenario-specific residential and commercial share of total annual electric energy and multiplies this share by the total GHG emissions to get GHG emissions from the residential and

291 Projected loads for the industrial, agricultural, water pumping and other minor sectors remained at the level in the 2019 IEPR Mid-Mid managed demand forecast for all AB 3232 scenarios.

commercial sectors applicable to any desired scenario. As building decarbonization scenarios add increasing amounts of electric load through electrification, all of this load is in the residential and commercial building sectors so that the share of the total of these two sectors is increasing through time. This "post-processing" step scaled the full electric generation system results to those applicable to the residential and commercial building sectors that are the domain of the AB 3232 legislation, and also interpolated between the three assessment years to provide annual values.

EAD/SAO staff assessed electric generation system GHG emissions for each scenario with a change in electric energy demand in five separate steps:

- Calculating resource capacity to satisfy California's Renewable Portfolio Standards (RPS) as required by SB 100
- Adding battery capacity to satisfy planning reserve margin requirement commonly used to guide procurement of resources
- Collect data on capital costs for resource additions
- Adding resource additions into PLEXOS production simulation model to assess fuel use, operating costs, and GHG emissions for each scenario
- Translating aggregate electric generation system emissions into the portion that is attributable to the residential and commercial building sectors and extending SAO's analyses from three key years to each individual year for 2020 through 2030

Resource Additions to Satisfy Planning Reserve Margin and RPS Requirements

For the AB 3232 scenarios involving additional electricity loads, staff calculated additional line losses, or avoided line losses in scenarios 2 and 3, by year and planning area and added those losses to hourly electrification load provided by EAD/DAO. Staff calculated line loss factor to be used for each scenario by subtracting retail sales from net energy for load, then dividing the difference by retail sales to compute a loss factor to be used for each scenario. For each scenario, the incremental loads, scaled up for line losses, were then added to the 2019 IEPR Mid - Mid loads for the generating system simulations.

Satisfying California Planning Reserve Margin Requirements

Entities under CPUC jurisdiction have long been required to satisfying planning reserve margin requirements of 15 percent above summer peak load as a simplified way to acquire sufficient capacity to assure system reliability.[292] SAO does not currently operate a complete reliability assessment methodology, so a simplified approach was used to approximate a full reliability assessment.

Battery resource amounts added to increase system flexibility and to meet reserve margin requirements are depicted in **Table C-12**. Staff placed a maximum cap of 4,500 MW of 4-hour

292 California ISO tariffs and Business Practice Manual sections obligate publicly owned utilities not under CPUC jurisdiction to follow similar practices.

storage in Scenarios 12.a and 12.c and scaled amounts of batteries for scenarios 6 through 11 and 12.b and 12.d according to added scenario load. No battery capacity was added or removed in the scenarios with load reduction due to energy efficiency savings and additional behind the meter PV.

Table C-12: 2030 California Battery Storage – Incremental to Base Case (MW)

2030	Base	Scenario 2	Scenario 3	Scenario 5	Scenarios 6.a, 6.b, 7, 8	Scenario 9	Scenario 10	Scenarios 11, 12.b, 12.d	Scenarios 12.a, 12.c
(MW)	0	0	0	2,208	2,840	3,220	3,748	4,330	4,500

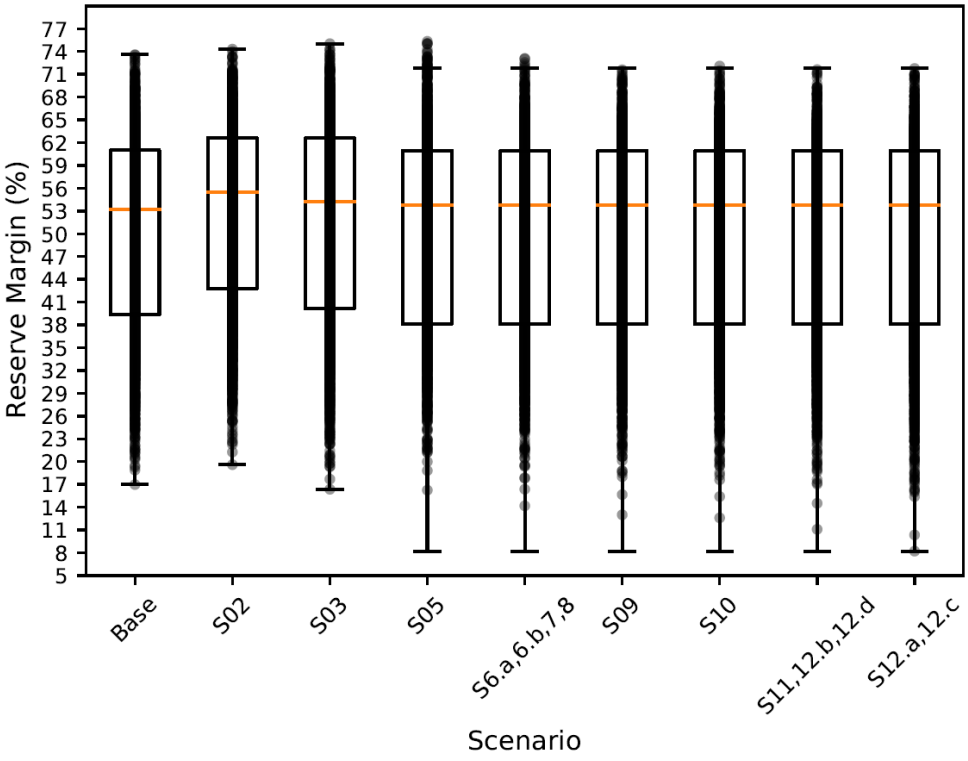
Source: CEC staff

After adding this capacity, SAO staff calculated California 2030 reserve margins for each scenario and found that for most hours the reserve margins are between 40 and 60 percent. The scenarios that increased load from the base case (Scenarios 6 through 12) each had one or two hours where reserve margins dropped below 15 percent, and scenarios 12.a and 12.c dropped below 10 percent for one hour.

Figure C-10 depicts a box and whiskers plot for each scenario that summarizes results.[293] The orange line inside each box is the median reserve margin values. The top border of each box is the 90th percentile (90 percent of data points fall below this line) and the bottom box border is the 10th percentile (10 percent of data points fall below this line). The 'T' shapes at the top of each boxplot (whiskers) represent the point where any larger values are considered outliers, data points that do not follow the trend of the rest of the reserve margin values; the whiskers near the bottom of each plot are defined similarly. The individual reserve margin values are depicted as dots for each scenario, but due to groupings, these dots are largely seen as a dark line. For example, in Scenarios 12.a and 12.c, the bottom two data point shows the two hours the reserve margin fell below 15 percent.

Figure C-10: California 2030 Reserve Margin Comparison, by Scenario

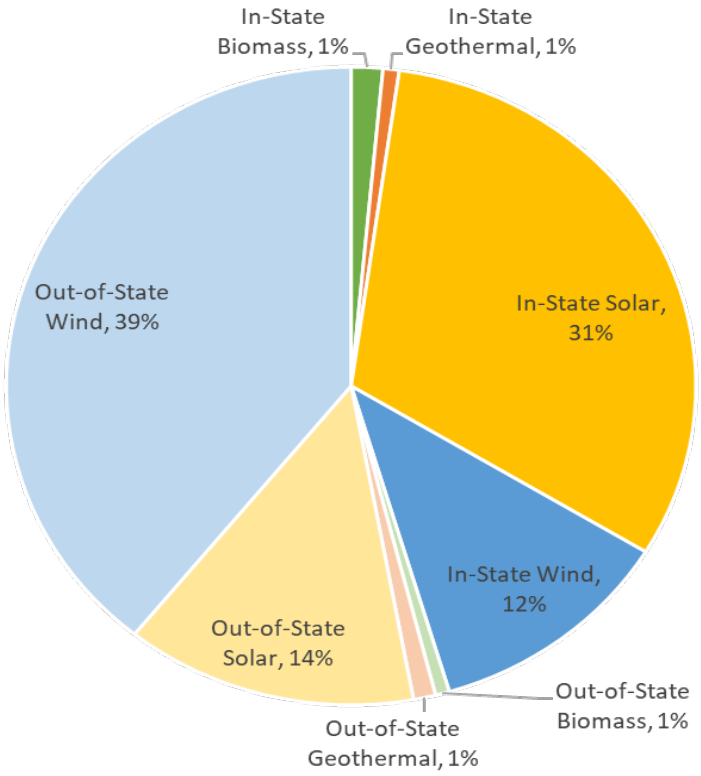
293 https://towardsdatascience.com/understanding-boxplots-5e2df7bcbd51.



Source: CEC staff

For each scenario that either increased or decreased total projected electricity sales relative to the 2019 IEPR Mid-Mid load forecast, Staff added incremental renewable capacity to meet the California RPS mandate. Staff calculated the target amount for each scenario by taking the difference in the RPS target from the renewable generation build out previously developed by staff using the 2019 IEPR Mid – Mid load forecast. The incremental capacity was added so that 75 percent of the total RPS energy target was satisfied by in - state resources with the rest of the requirements imported from out-of-state. **Figure C-11** depicts the distribution ratio of renewables added for 2030 relative to the 2019 IEPR Mid – Mid case model. The ratio of additional renewable capacity in California and from out-of-state remains consistent between all scenarios, except for scenarios 12.a and 12.c. In the case of scenario 2 and 3, the capacity implied by this method was subtracted from the 2019 IEPR Mid – Mid case model since annual energy sold was reduced in those two scenarios.

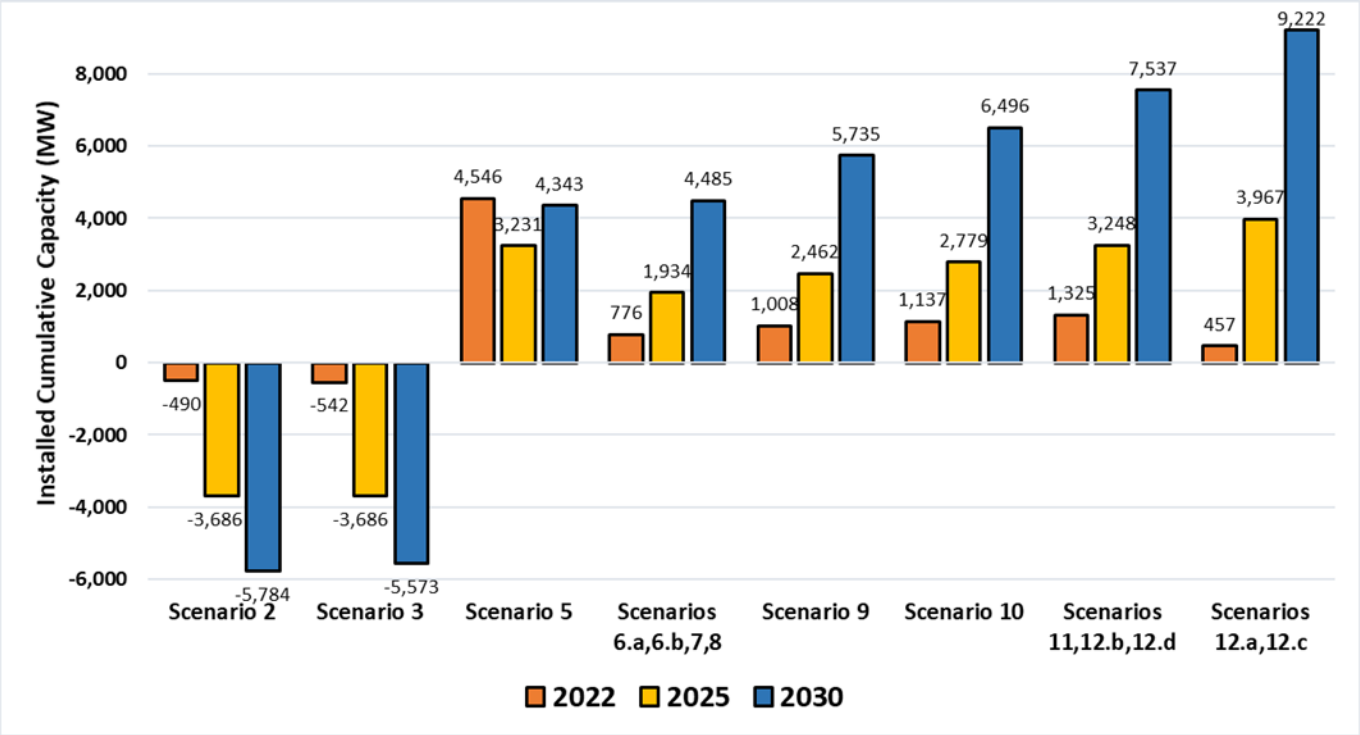
Figure C-11: 2030 Percent Distribution of Incremental Renewable Capacity



Source: CEC staff

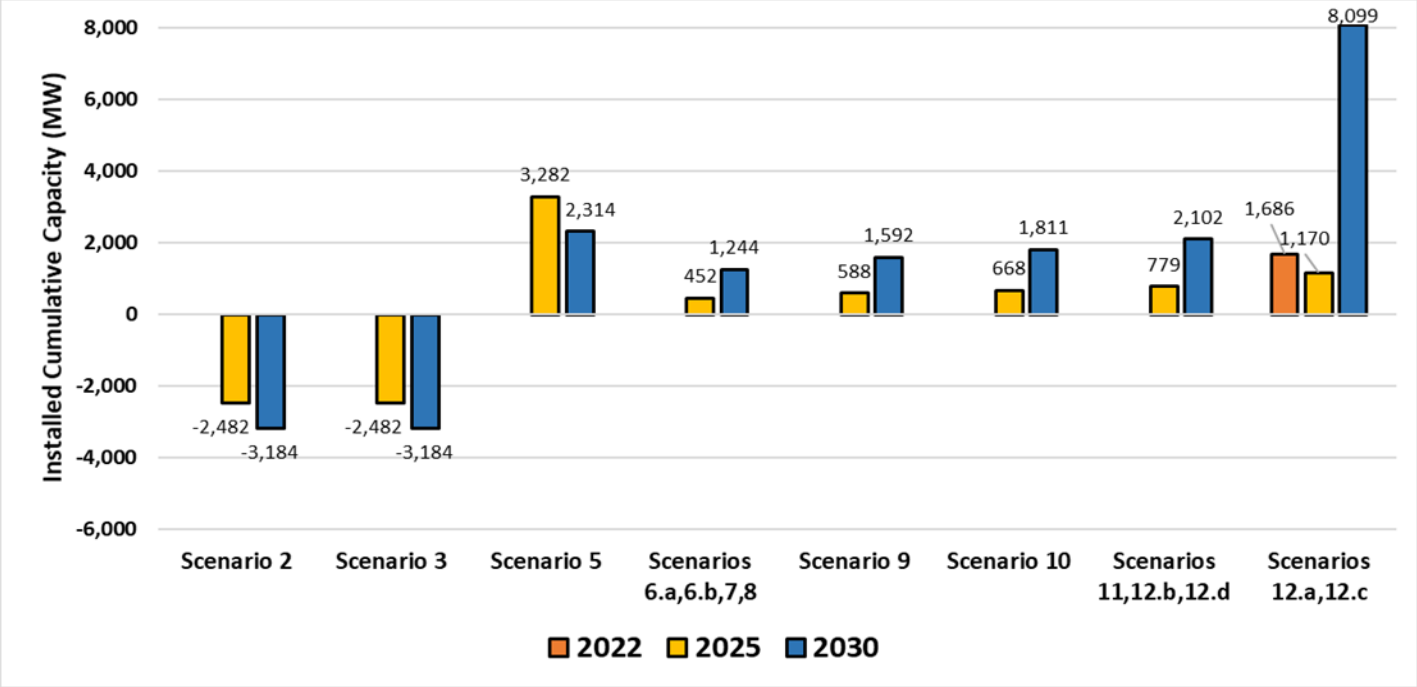
Figure C-12 and **Figure C-13** provide the quantities of renewable capacity added for in-state resources and out of state resources for each of the three key years (2022, 2025, and 2030), respectively.

Figure C-12: In-state incremental renewable installed capacity relative to the base case scenario



Source: CEC staff

Figure C-13: Out-of-state Total Renewable Capacity Relative to the Base Case



Source: CEC staff

Production Simulation Modeling

Electric generation system simulations of various scenarios were run using the PLEXOS production cost model for 2022, 2025, and 2030 using an hourly resolution. PLEXOS is implemented for the entire loads and resources of the Western Grid using data developed through Western Electricity Coordinating Council (WECC) processes.[294] The base case for this study was the 2019 IEPR Mid-Mid managed forecast adopted in January 2020. For each scenario, database changes were limited to California load, renewable resource capacities, and battery storage capacities. All other inputs and assumptions remain unchanged from 2019 IEPR Mid - Mid case simulations. This allows comparison of building decarbonization impacts on electric generation fuel use and emissions for each scenario relative to the 2019 IEPR Mid-Mid case.

Simulation Results

Simulation results for all scenarios indicate stable system conditions: all load was served, hourly price ranges are indicative of normal model operations, and calculated reserve margins are at acceptable levels.

Battery / Storage and Renewable Operations

Table C-13 depicts annual battery and pumped storage load and generation amounts for 2030. Only scenarios 8 through 12, and 14 had additional storage (battery capacity) added.

Table C-13: Total Storage Load and Generation

2030	Base	Scenario 2	Scenario 3	Scenario 5	Scenarios 6.a, 6.b, 7, 8	Scenario 9	Scenario 10	Scenarios 11, 12.b, 12.d	Scenarios 12.a, 12.c
Load (GWh)	10,348	9,417	9,748	10,794	13,940	15,140	15,843	16.87	16.781
Generation (GWh)	8,514	7,843	8,084	8,813	11,026	11,868	12,367	13,095	14,380

Source: CEC staff

In the load reducing scenarios (Scenarios 2 and 3), PLEXOS dispatches storage resources less than in the Base Case. Scenario 5 (increased RPS and same load as Base Case) has similar storage operations as in the Base Case. Load increasing scenarios had more storage activity. All scenario results exhibit a similar pattern of storing energy when solar production is high and discharging during the morning and evening ramp hours.

Curtailment of renewable energy in California occurred in all scenarios, with the majority, roughly two-thirds, occurring in April and May in all scenarios. The significant curtailment in April and May is consistent with information provided by California ISO.[295] During these

294 WECC 2028 Anchor Data Set Public Version can be found at the following link: https://www.wecc.org/SystemStabilityPlanning/Pages/AnchorDataSet.aspx?utm_source=PopularSearches.

The Anchor Data Set (ADS) is a compilation of load, resource and transmission topology information used by the Regional Planning Groups (RPG) in the Western Interconnection as part of their regional transmission plans.

295 http://www.caiso.com/informed/Pages/ManagingOversupply.aspx#dailyCurtailment.

periods, PLEXOS was unable to use, store, or export more renewable energy given lower seasonal loads, limitations on storage capacity, and export limits.

Table C-14 depicts 2030 renewable energy curtailment in California for each scenario. Decreasing load scenarios resulted in significantly less curtailment, while increasing load scenarios 6 through 12 used additional battery storage to reduce curtailment below that of the Base Case. Scenario 5, which increased California's renewable portfolio standard to 70 percent for 2030, had an amount of renewable curtailment slightly above the Base Case.

Table C-14: 2030 Renewable Energy Curtailment from In-state Generators

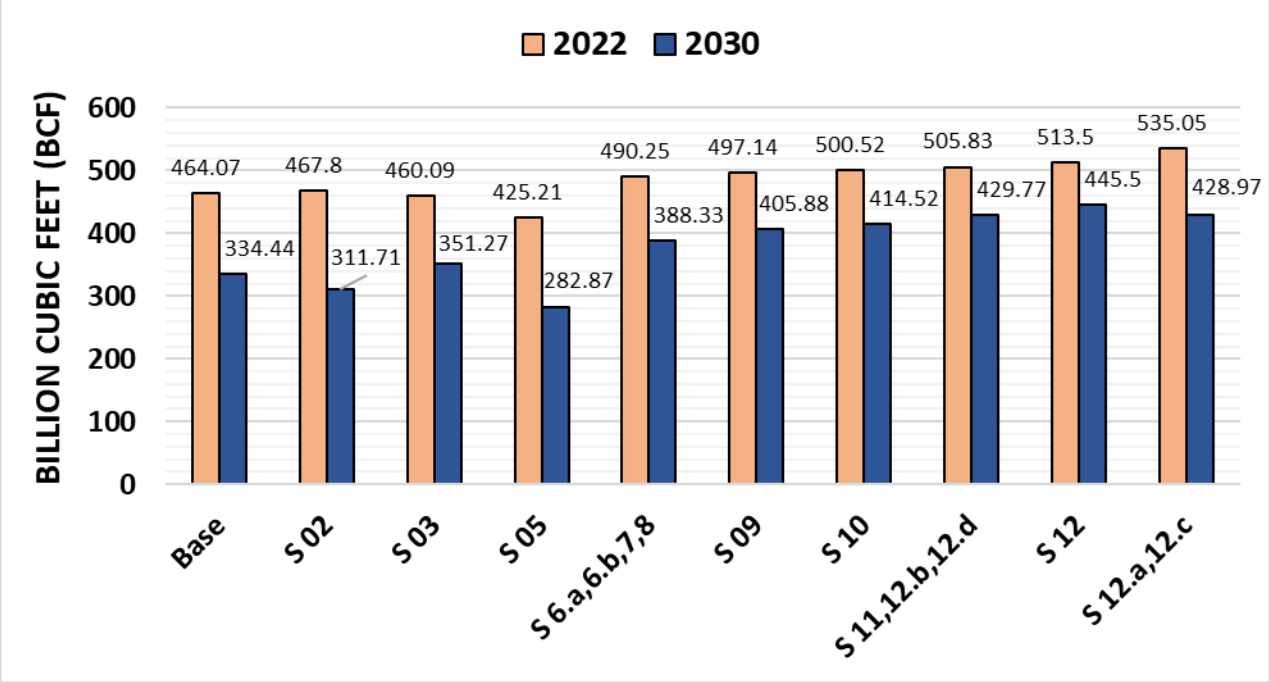
2030	Base	Scenario 2	Scenario 3	Scenario 5	Scenarios 6.a, 6.b, 7, 8	Scenario 9	Scenario 10	Scenarios 11, 12.b, 12.d	Scenarios 12.a, 12.c
GWh	1,977	465	504	2,044	1,701	1,634	1,607	1,554	2,150

Source: CEC staff

Electric Generation System Gas Fuel Use

California uses less gas for electric generation in 2030 compared to 2022 for all scenarios. **Figure C-14** compares the total fuel use in 2022 and in 2030. While scenarios 12.a and 12.c have a higher load than all other cases, it has lower gas burn for electric generation in 2030. This is most likely due to differences in the load profile of these scenarios, specifically, the amount out-of-state renewable generators added to meet renewable requirements and California storage operations.

Figure C-14: California Annual Gas Consumption for Electric Generation

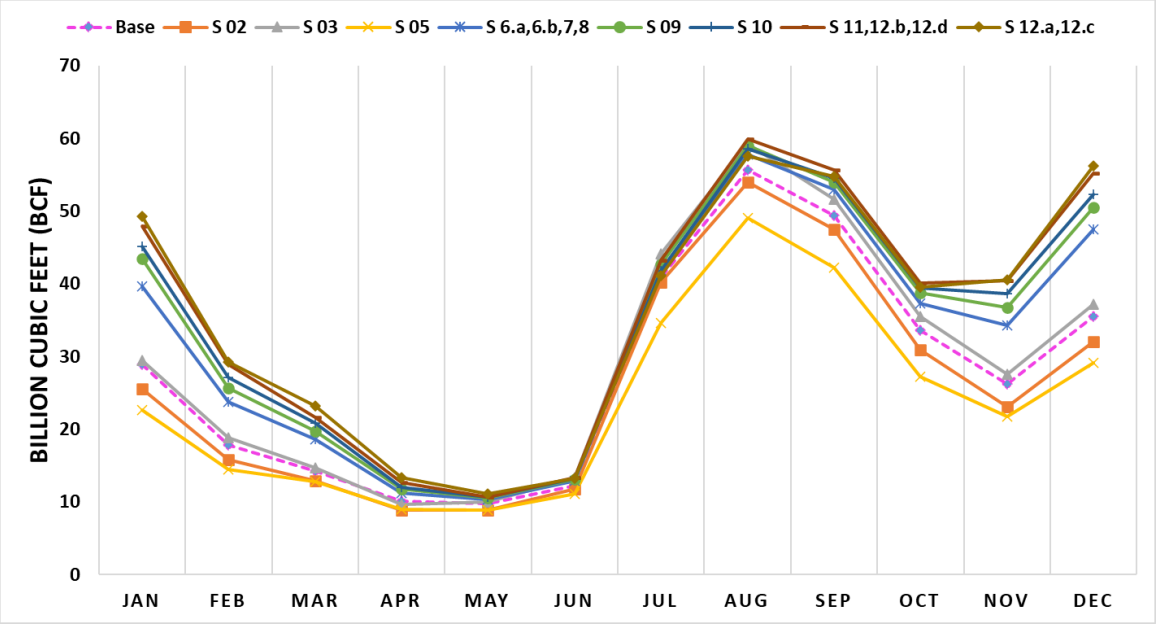


Source: CEC staff

Figure C-15 depicts the monthly California gas consumption for electric generation in 2030 for all scenarios. Since input gas prices remained consistent for all scenarios, the shape

remains relatively the same to the Base Case. Load reducing scenarios are consistently below the Base Case, as is the increased RPS scenario. However, all the electrification scenarios show increased gas consumption in colder months as would be expected by the increased electric consumption for space heating, and the timing of this increased load in night-time hours where solar resources are not available.

Figure C-15: 2030 California Monthly Gas Consumption for Electric Generation



Source: CEC staff

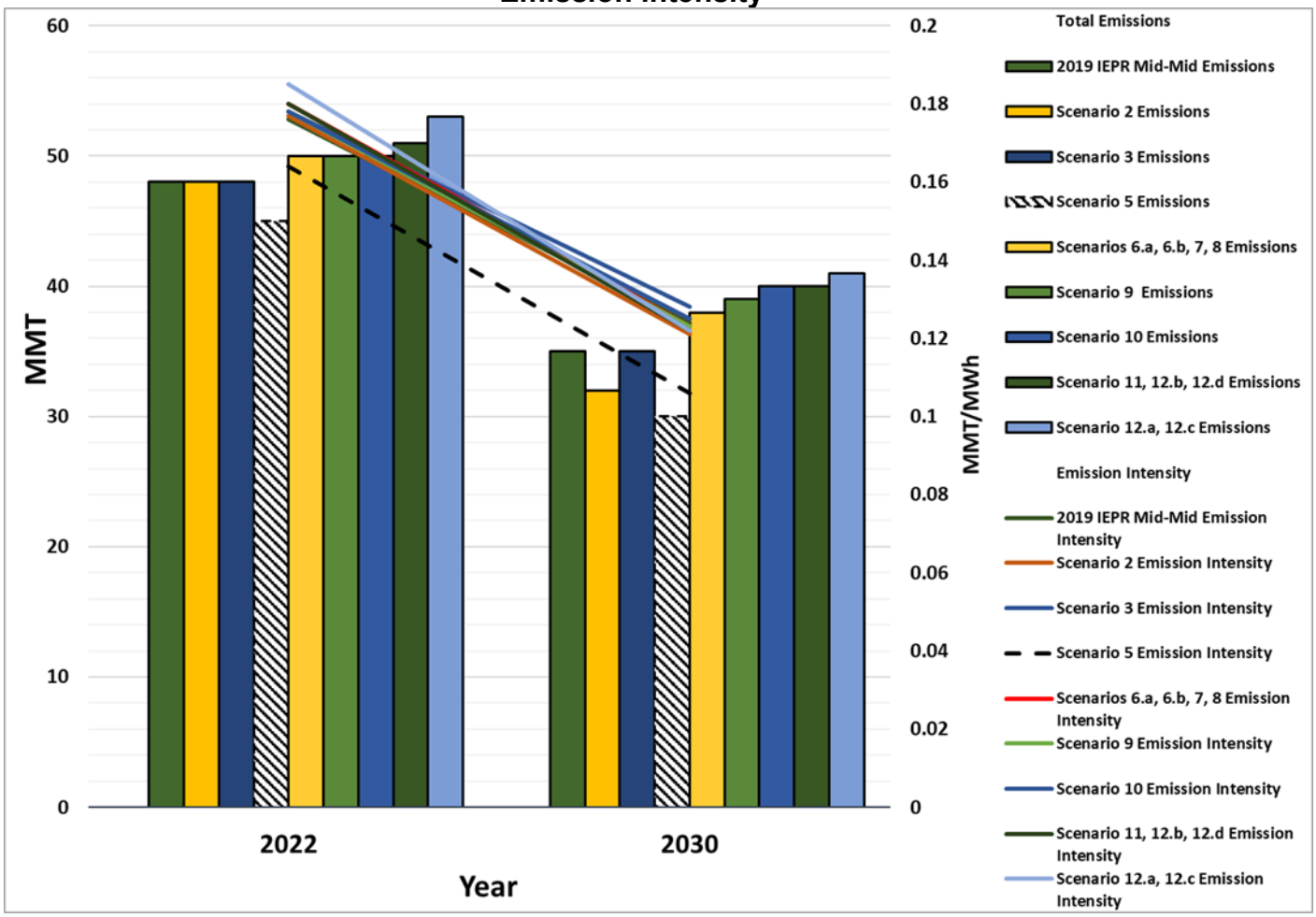
Electric Generation System Greenhouse Gas Emissions

California GHG emission projections were calculated both annually and hourly for the base case and each scenario for years 2022, 2025, and 2030. SAO Staff computed electric generation GHG emissions from both in-state generation from GHG emitting generators and imported energy. CEC staff developed a methodology, using PLEXOS hourly simulation results, to calculate California hourly GHG emissions, and presented this methodology at the 2018 IEPR Update SB 350 workshop.[296] The GHG emission calculation is based on the CO2e content of each fuel while the import calculation is based on the assumed emission intensity of the energy imported from each region. **Figure C-16** shows the change in projected annual electric generation sector emissions for each scenario. Interestingly, even with the total annual emissions increase caused by the additional demand, the system average emission intensity

296 Presentation available at https://efiling.energy.ca.gov/GetDocument.aspx?tn=223684&DocumentContentId=53839.

projections are very similar except for scenario 5, which includes a higher RPS target. That input assumption alone significantly lowers the annual and system average emission intensity.

Figure C-16: Projected Electric Generation Sector California GHG Emissions and Emission Intensity



Source: CEC Staff

Assessing Electric Generation Impacts from Electric Load Changes in the Residential and Commercial Building Sectors

Since AB 3232 focuses on just GHG emissions associated with the residential and commercial building sectors the total electric generation system emissions described previously must be reduced to the subset that represents the electric load for these two sectors. EAD/DAO staff developed a method that computes the scenario-specific residential and commercial share of total annual electric energy and multiplies this share by the total to get GHG emissions from the residential and commercial sectors applicable to any desired scenario. As scenarios add increasing amounts of electric load through electrification, all of this load is in the residential and commercial building sectors so that the share of the total of these two sectors is increasing through time.

Translating EAD/SAO Staff's Electric Generation System Analyses into AB 3232 Requirements

SAO staff assessed electric generation consequences for 2022, 2025, and 2030 and for the entire electric generation system serving all electric load in California. AB 3232 assessments require annual results and for the portion of the electric generation sector attributable to electricity consumption in the residential and commercial building sectors. "Post-processing" was employed to scale the full electric generation system results to those applicable to the residential and commercial building sectors that are the domain of the AB 3232 legislation and to "fill-in" the other years in the range of 2020 through 2030 that SAO did not assess individually. These adjustments to EAD/SAO results are described below.

GHG Emissions Values for Intermediate Years from SAO's Analysis of Key Years

AB 3232 analysis needed values of GHG emissions and electric generation system emission intensities for all years 2020 through 2030, but SAO only had the resources to assess the key years of 2022, 2025, and 2030. Staff used simple interpolation between these three-year years, plus estimated GHG emissions for 2020, to compute GHG emission values at the aggregate electric generation system level. 2020 GHG emissions were estimated by starting CARB's 2017 electric generation system GHG estimate and increasing it by two percent for 2018, and a four percent for 2019.

Due to the timing of this project, SAO assessed scenarios 1-5 and 8-12, before scenarios 6-7 were defined. DAO staff also developed 2020 through 2030 estimates for scenarios 6 and 7, that SAO did not assess, by multiplying Scenario 8 GHG projections for each year by the annual ratio of electric energy of Scenarios 6 and 7 to that of Scenario 8.

Table C-15 provides the annual GHG emissions values for each scenario resulting from this process. The values for the key years of 2022, 2025, and 2030 are the same as shown in **Figure C-16**, while all others are the result of the interpolation and scaling processes described above.

Table C-15: Annual All-Sector Electric Generation System GHG Emissions by Scenario ($MMTCO_2e$)

Scen.	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Base	44.6	45.4	46.3	46.9	47.4	48.0	46.3	44.7	43.0	41.4	39.8	38.2	36.6	35.0
1	44.6	45.4	46.3	46.9	47.4	48.0	46.3	44.7	43.0	41.4	39.8	38.2	36.6	35.0
2	44.6	45.4	46.3	46.9	47.4	48.0	46.0	44.0	42.0	40.0	38.0	36.0	34.0	32.0
3	44.6	45.4	46.3	46.6	46.8	47.0	45.0	43.0	41.0	39.6	38.2	36.8	35.4	34.0
4	44.6	45.4	46.3	46.9	47.4	48.0	46.3	44.7	43.0	41.4	39.8	38.2	36.6	35.0
5	44.6	45.4	46.3	45.9	45.4	45.0	42.7	40.3	38.0	36.4	34.8	33.2	31.6	30.0
6.a&b	44.6	45.4	46.3	47.4	48.4	49.4	47.6	45.8	44.0	42.5	41.0	39.5	38.0	36.5
7	44.6	45.4	46.3	47.5	48.6	49.7	48.0	46.3	44.6	43.1	41.7	40.2	38.8	37.4
8	44.6	45.4	46.3	47.6	48.8	50.0	48.3	46.7	45.0	43.6	42.2	40.8	39.4	38.0

Scen.	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
9	44.6	45.4	46.3	47.6	48.8	50.0	48.7	47.3	46.0	44.6	43.2	41.8	40.4	39.0
10	44.6	45.4	46.3	47.6	48.8	50.0	48.7	47.3	46.0	44.8	43.6	42.4	41.2	40.0
11	44.6	45.4	46.3	47.9	49.4	51.0	49.7	48.3	47.0	45.6	44.2	42.8	41.4	40.0
12.b&d	44.6	45.4	46.3	47.9	49.4	51.0	49.7	48.3	47.0	46.0	45.0	44.0	43.0	42.0
12.a&c	44.6	45.4	46.3	48.6	50.8	53.0	51.0	49.0	47.0	45.8	44.6	43.4	42.2	41.0

Source: CEC staff

Extending Electric Generation System GHG Emission Intensities to 2045

Since most AB 3232 demand scenarios involve the installation of equipment that may operate far beyond 2030, CEC staff computed GHG emissions (the metric under review in this analysis) out to 2045. This required an extension by CEC staff of the electric generation system emission intensities to cover the period 2031 through 2045. CEC staff obtained draft electric generation system emission intensities reported by CEC Staff in the SB 100 workshop and used these to extend emission intensities out for this time horizon.[297] Although SB 100 requires complete decarbonization of the electric generation sector by 2045 there are ambiguities about how to interpret this legislation. Depending upon the scenario, staff used a 2045 electric generation system emission intensity in the range of 0.045 to 0.047 tonnes/MWh for the 2045 value. Emission intensities for years 2031 through 2045 were computed by linear interpolation from the 2030 values depicted in **Figure C-16** to these endpoint values.

Translating California Electric Generation System Emissions into Residential and Commercial Sector GHG Emissions

Once the total electric generation system emissions serving all California load were determined, the portion of those GHG emissions attributable to the residential and commercial building sectors had to be computed. DAO staff used the annual energy share method to compute this portion of aggregate electric generation sector GHG emissions.[298] In this approach, for each scenario in each year the incremental residential energy and commercial sector electric energy are added the sectoral sales projections of the 2019 IEPR Mid-Mid demand case and the resulting residential and commercial shares of total sales were computed for each year. Since all of the scenarios involve only changes in energy consumption for residential and commercial sectors, if any, then the combined residential and commercial building share of total electric sales can be used to compute the portion of total electric

297 SB 100 Draft Results Presentation, Senate Bill 100 Draft Results Workshop, California Energy Commission, September 2, 2020, https://www.energy.ca.gov/event/workshop/2020-09/senate-bill-100-draft-results-workshop.

298 As noted in Chapter 2, the 1990 baseline GHG emissions attributable to the residential and commercial sectors also used an annual electricity sales method to develop the attributable portion of GHG emissions.

generation GHG emissions to the residential and commercial sectors for overall AB 3232 assessments. Even in the base case the residential and commercial building share is gradually increasing through time, but this becomes much more pronounced as building electrification adds substantial load in just the residential and commercial building sectors.

Table C-16 reports these combined residential and commercial building shares on an annual basis for each scenario.

Table C-16: Annual Percentage Shares of Combined Residential and Commercial Building of Total Electric Sales, by Scenario

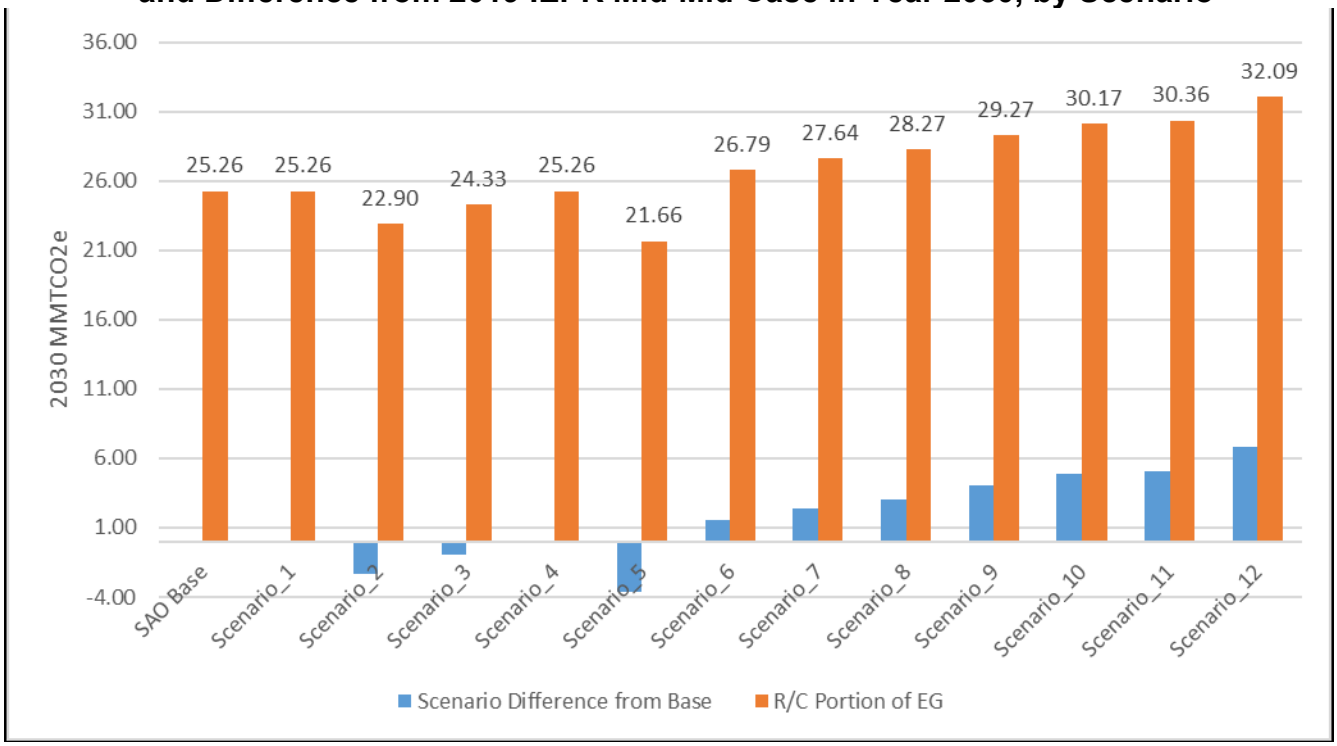
Scen	Sector	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Base	Res+Com	0.713	0.713	0.713	0.714	0.715	0.716	0.717	0.718	0.719	0.720	0.722
2	Res+Com	0.713	0.712	0.712	0.712	0.711	0.711	0.711	0.710	0.710	0.710	0.710
3	Res+Com	0.712	0.710	0.710	0.710	0.711	0.711	0.712	0.713	0.713	0.714	0.716
4	Res+Com	0.713	0.713	0.713	0.714	0.715	0.716	0.717	0.718	0.719	0.720	0.722
5	Res+Com	0.713	0.713	0.713	0.714	0.715	0.716	0.717	0.718	0.719	0.720	0.722
6	Res+Com	0.714	0.715	0.717	0.719	0.721	0.723	0.725	0.727	0.729	0.731	0.734
7	Res+Com	0.715	0.716	0.718	0.721	0.724	0.727	0.729	0.732	0.734	0.737	0.740
8	Res+Com	0.716	0.717	0.720	0.723	0.726	0.729	0.732	0.735	0.738	0.741	0.744
9	Res+Com	0.716	0.719	0.722	0.726	0.730	0.733	0.737	0.740	0.743	0.747	0.750
10	Res+Com	0.717	0.720	0.723	0.728	0.732	0.736	0.739	0.743	0.747	0.750	0.754
11	Res+Com	0.717	0.721	0.725	0.730	0.734	0.739	0.743	0.747	0.751	0.755	0.759
12	Res+Com	0.718	0.722	0.727	0.732	0.737	0.742	0.747	0.751	0.755	0.759	0.764

Source: CEC staff

Residential and Commercial Building Portion of Electric Generation System GHG Emissions

Once combined residential and commercial building sales shares have been determined by year and scenario, simple multiplication by the all-sector electric generation system GHG emission projections gives the portion of electric sector GHG emissions by year and scenario. **Figure C-17** shows the change in these resulting GHG emissions for each scenario in the key year of 2030.

Figure C-17: Residential and Commercial Portion of Electric Generation GHG Emissions and Difference from 2019 IEPR Mid-Mid Case in Year 2030, by Scenario



Source: CEC Staff

Table C-17 provides the annual GHG emissions for each year for each scenario attributable to the combined residential and commercial building sector's use of electric energy. A discussion of the incremental resource cost assumptions used is reported at the end of the cost and cost effectiveness section where other elements affecting electric generating system costs are discussed.

Table C-17: Residential and Commercial Building Portion of Electric Generation System GHG Emissions (MMTCO2e)

Scen #	Sector	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Base	Res+Com	33.4	33.8	34.2	33.1	31.9	30.8	29.7	28.6	27.5	26.4	25.3

Scen #	Sector	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
2	Res+Com	33.4	33.7	34.1	32.7	31.3	29.9	28.5	27.1	25.7	24.3	22.9
3	Res+Com	33.1	33.2	33.4	32.0	30.6	29.2	28.2	27.2	26.3	25.3	24.3
4	Res+Com	33.4	33.8	34.2	33.1	31.9	30.8	29.7	28.6	27.5	26.4	25.3
5	Res+Com	32.7	32.4	32.1	30.5	28.8	27.2	26.1	25.0	23.9	22.8	21.7
6	Res+Com	33.8	34.6	35.4	34.2	33.0	31.8	30.8	29.8	28.8	27.8	26.8
7	Res+Com	33.9	34.8	35.7	34.6	33.5	32.4	31.4	30.5	29.5	28.6	27.6
8	Res+Com	34.0	35.0	36.0	35.0	33.9	32.8	31.9	31.0	30.1	29.2	28.3
9	Res+Com	34.1	35.1	36.1	35.3	34.5	33.7	32.9	32.0	31.1	30.2	29.3
10	Res+Com	34.1	35.1	36.2	35.4	34.6	33.8	33.1	32.4	31.7	30.9	30.2
11	Res+Com	34.4	35.6	37.0	36.2	35.5	34.7	33.9	33.0	32.1	31.2	30.4
12	Res+Com	34.4	35.7	37.1	36.4	35.6	34.9	34.3	33.8	33.2	32.7	32.1

Source: CEC staff

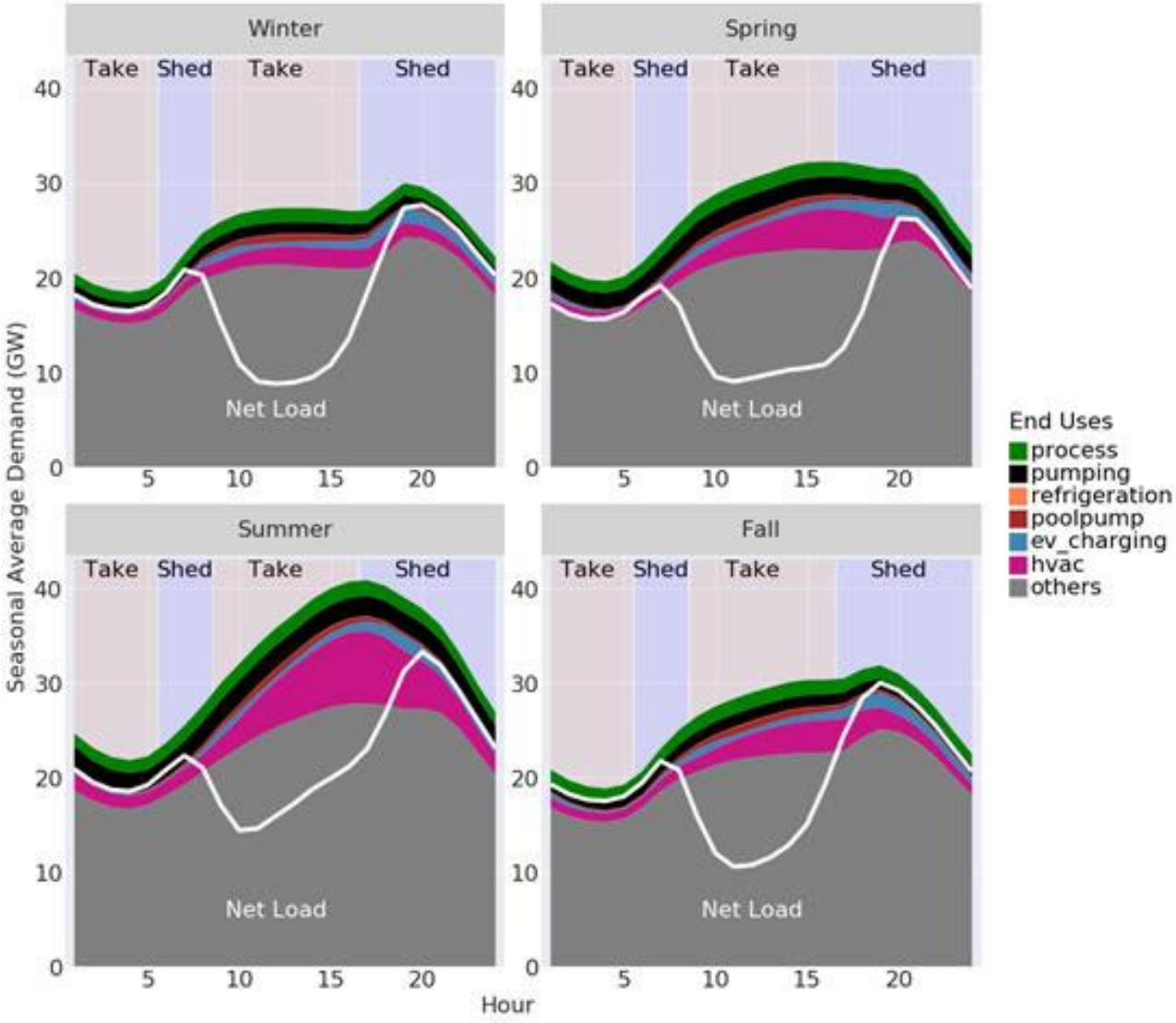
Assessing Demand Flexibility (amplifies Scenarios 6-12)

This demand flexibility assessment focused on the load shift potential of emerging electrical end uses resulting from residential and commercial electrification. While the majority of current and near term load shift potential is in end uses already fueled by electricity, its potential has previously been assessed by the CPUC to include demand response in various electricity system planning and implementation efforts.[299] This analysis applied the load shift

299 California Demand Response Potential Study Phase 3 Final Report, Lawrence Berkeley National Laboratory, July 2020.

hourly schedule, as defined by the CPUC, which aims to flatten the net system load profile shown in **Figure C-18**.

Figure C-18: Load Shift Hourly Schedule to Manage Net System Load



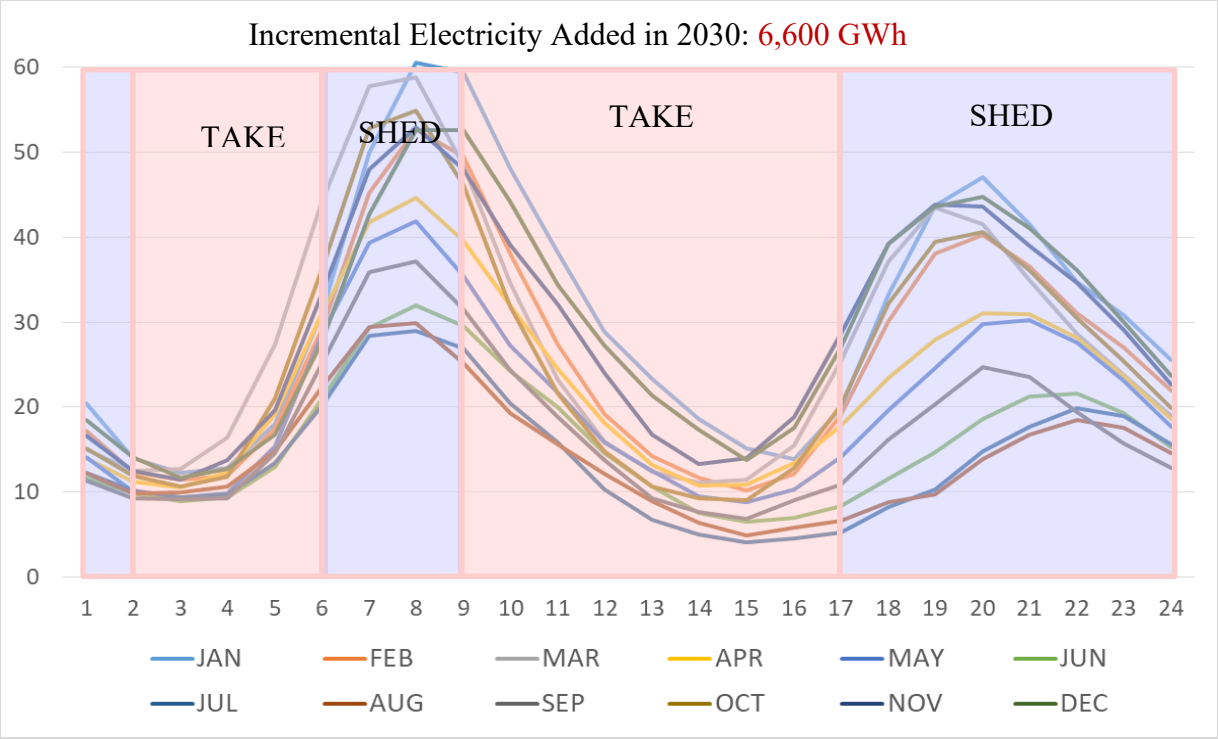
Source: California Demand Response Potential Study Phase 3 Final Report

The three electrification end uses studied for new load shift potential were residential water heating, residential space heating and cooling, and commercial space heating. Commercial space cooling was assessed to have the highest building sector load shift potential in the LBNL study; it is not included in this electrification analysis. Commercial buildings are expected to already provide space cooling in Staff's electrification analysis, so there is no incremental commercial space cooling assumed to result from switching space heating fuels.

Staff's Scenario 6 was used to establish the levels and patterns of electrical demand available to shift. 2030 was chosen as the study year; no cumulative analysis over multiple years was assessed. The 2030 annual energy and hourly demands (summed for each hour, by month)

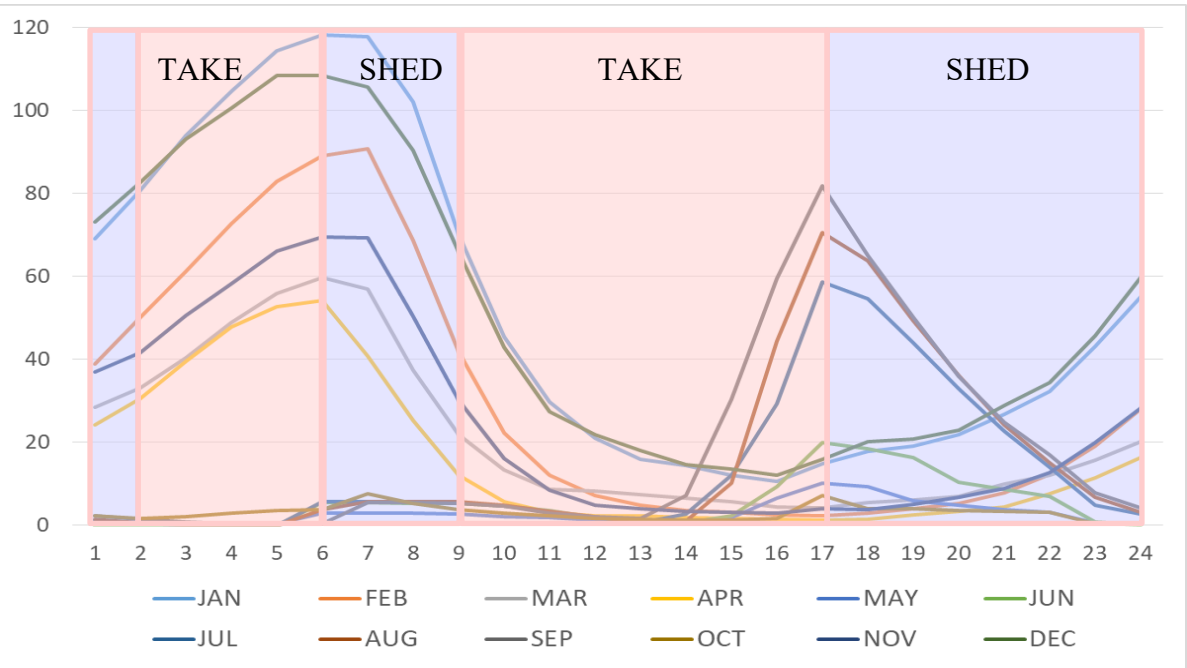
are illustrated in **Figure C-19**, **Figure C-20**, and **Figure C-21**. The load shift shed and take schedule is also delineated here.

Figure C-19: Scenario 6 Residential Water Heating



Source: CEC staff

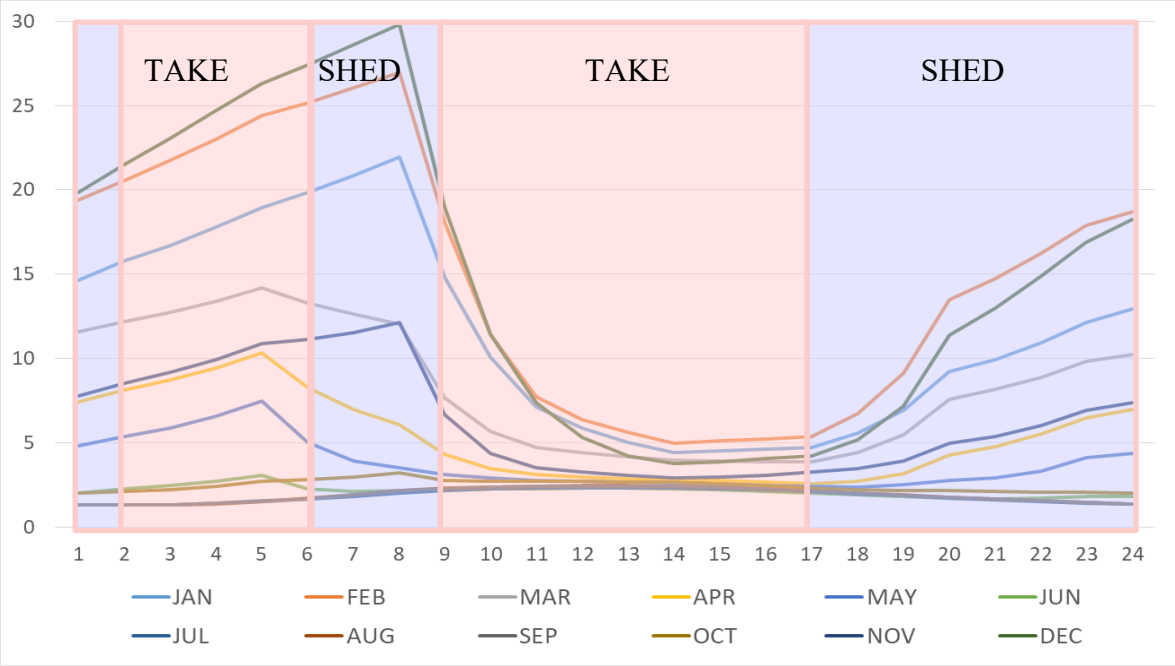
Figure C-20: Scenario 6 Residential Space Heating and Cooling



Source: CEC staff

Figure C-21: Scenario 6 Commercial Space Heating

Incremental Electricity Added in 2030: 1,800 GWh



Source: CEC staff

Twenty percent of each hourly end use demand in the load shift shed periods were used to determine the increments of load available for the take periods. This constraint applied to the load shift potential could be interpreted as either a technical or a market barrier. It is reasonable to assume that within the ten-year study period (by 2030), only a fraction of electric space conditioning and water heating equipment would include the control technologies to enable load shifts. It is also reasonable to assume that only a fraction of the population would choose to participate in future load shift programs.

The results of this load shift potential study are shown in **Table C-18**. It is important to note that this staff analysis of electrification load shifting applied no cost constraint, so it should be interpreted as technical rather than economic potential.

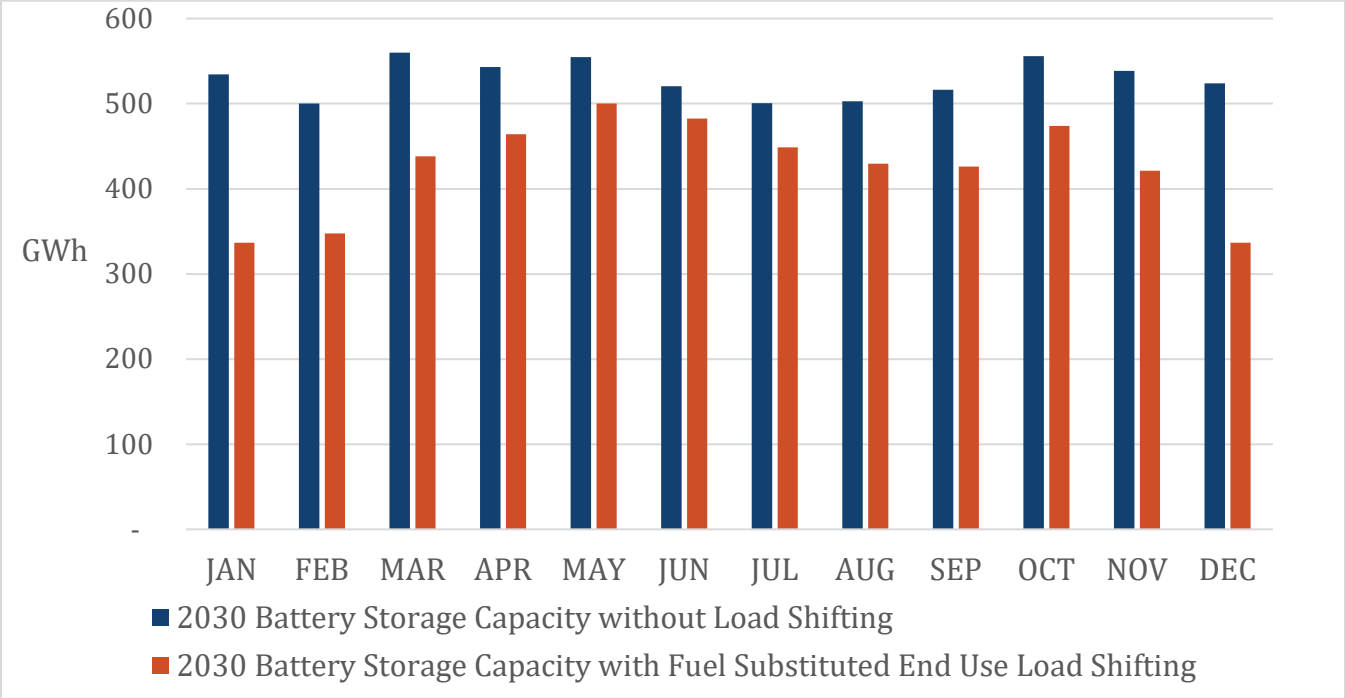
Table C-18: Load Shift Potential of Major Electrification End Uses

Load Shift End Use	GWh per shift event
Residential Water Heating	4.0
Residential Space Heating and Cooling	2.9
Commercial Space Heating	0.9

Source: CEC staff

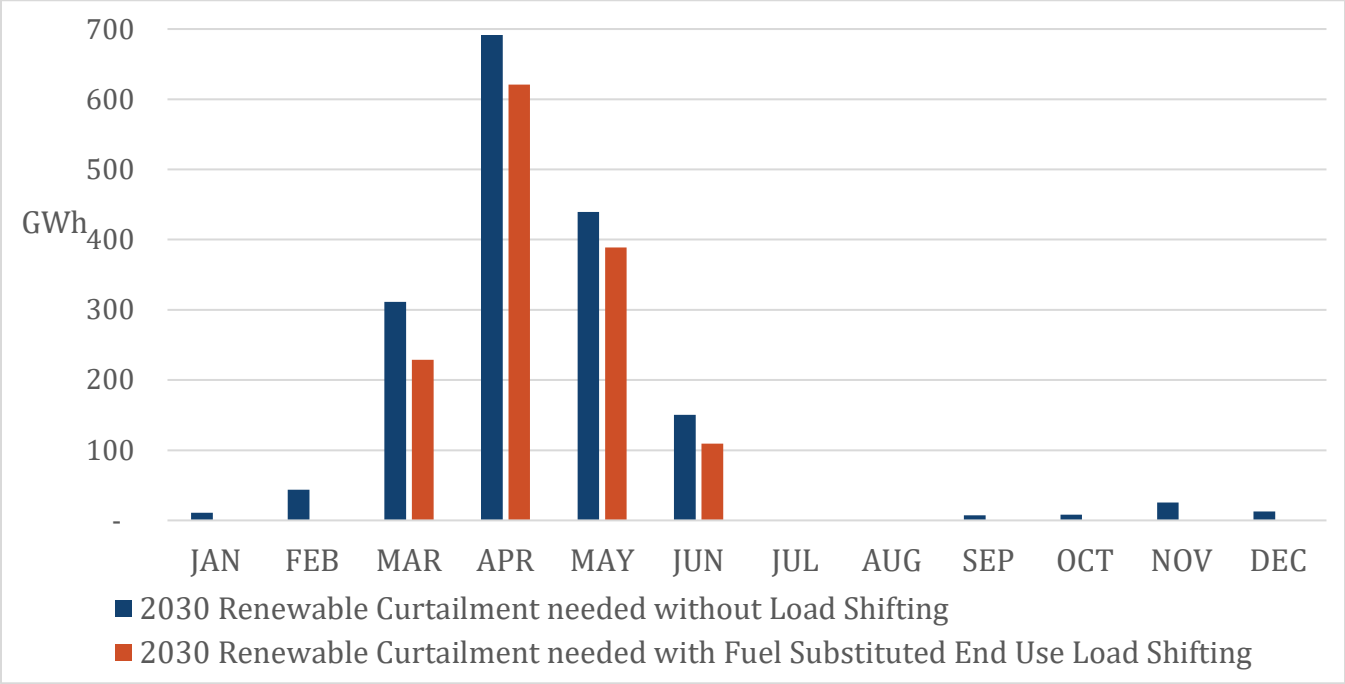
The potential reductions in the needs for both battery storage and renewable curtailments within the electricity system were also assessed for the load shifting assessed above. In the analysis described in the following section, *Assessing Electric Generation Impacts from Electric Load Changes*, Staff estimated the electricity system resources needed to meet expected demand, including the new demands from electrification. Hourly battery storage and renewable curtailment needs were estimated for future years. These results were used along with the electrification end use load shift potential to assess the electricity system impacts summarized in **Figure C-22** and **Figure C-23**. These figures show that the levels of electrification included in Scenario 6 (100 percent of equipment in newly constructed buildings and 20 percent of existing equipment by 2030) could reduce the need for both electricity system storage and renewable curtailment by approximately 20 percent in 2030.

Figure C-22: Future Battery Storage Needs for California's Electric Generation System



Source: CEC staff

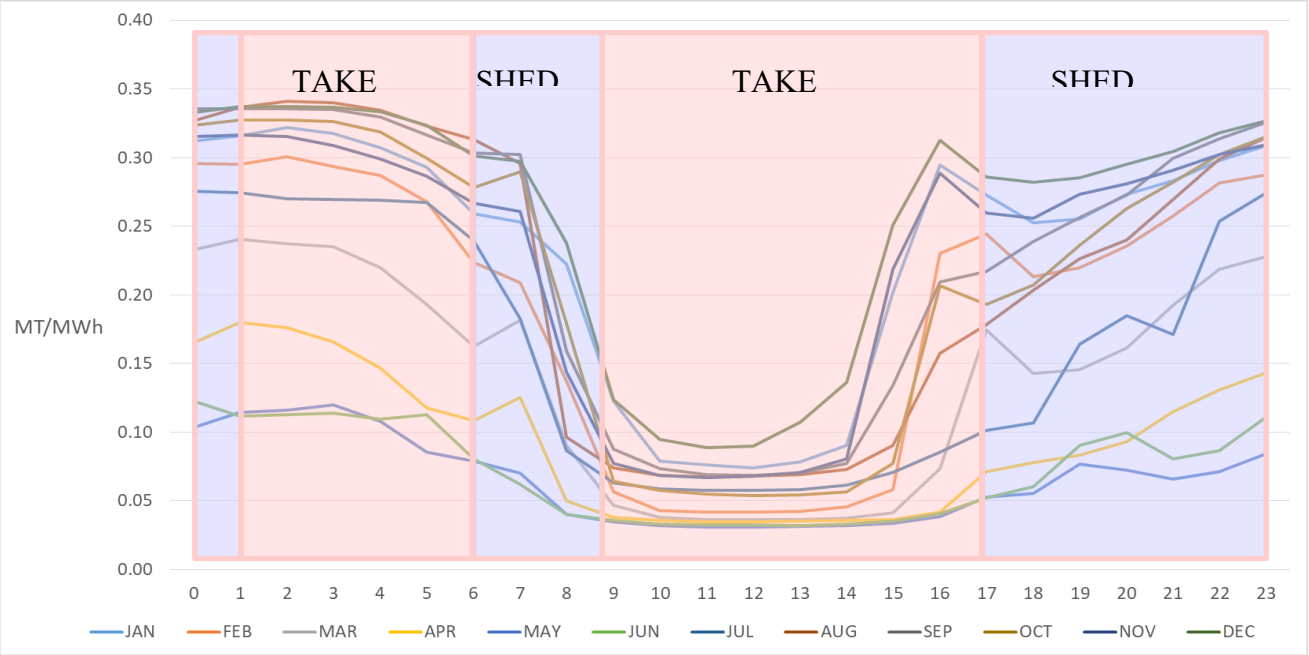
Figure C-23: Impact of Load Shifting on Future Electricity System Renewable Curtailment Needs



Source: CEC staff

GHG emission reductions from this load shift potential was studied and found to be minimal. This is due to two main factors: (1) the relative hourly emission intensities of the electric generation system expected in 2030 do not align with the current load shift schedule, as described above to manage the net system load profile; and (2) the electrification end use load profiles are not necessarily conducive to reducing GHG emissions using this same load shift schedule. In **Figure C-24**, it is evident that the morning take period would result in increased GHG emissions from a shed event either the evening before or later the same morning. Residential water heating exemplifies the limitations that specific end uses have to shift loads for GHG emission reductions. Looking back at **Figure C-19**, the highest water heating demands are during the morning shed period. These loads would be partially shifted to the morning take period, which as previously stated has relatively high electricity emission intensities. Residential and commercial space heating also have their highest loads in the morning, as seen in **Figure C-20** and **Figure C-21**, and analogous GHG emission impacts would result from the load shift schedule used in Staff's analysis.

Figure C-24: Shed/Take Schedule and Hourly Electric Generation System Emission Intensities in 2030



Source: CEC staff

Integration Across Multiple Strategies

The methods used to quantify impacts for individual strategies generally prevent combining impacts from multiple strategies; therefore, the scenario results described below cannot be added together. Since the methods used do not yield results that can be added, it should be apparent that no effort was undertaken to develop an optimal scenario. Refining analytic methods that allow multiple strategies within a scenario or scenario optimization is an effort for future cycles of the building decarbonization effort.

(III) Modeling Results

This section will describe three types of results for all scenarios: (i) GHG emissions compared to 1990 baseline and 2030 business as usual counterfactual and GHG emission reductions relative to the 2030 business as usual projections; (ii) energy system impacts for both electricity and gas, and (iii) cost implications of each scenario.

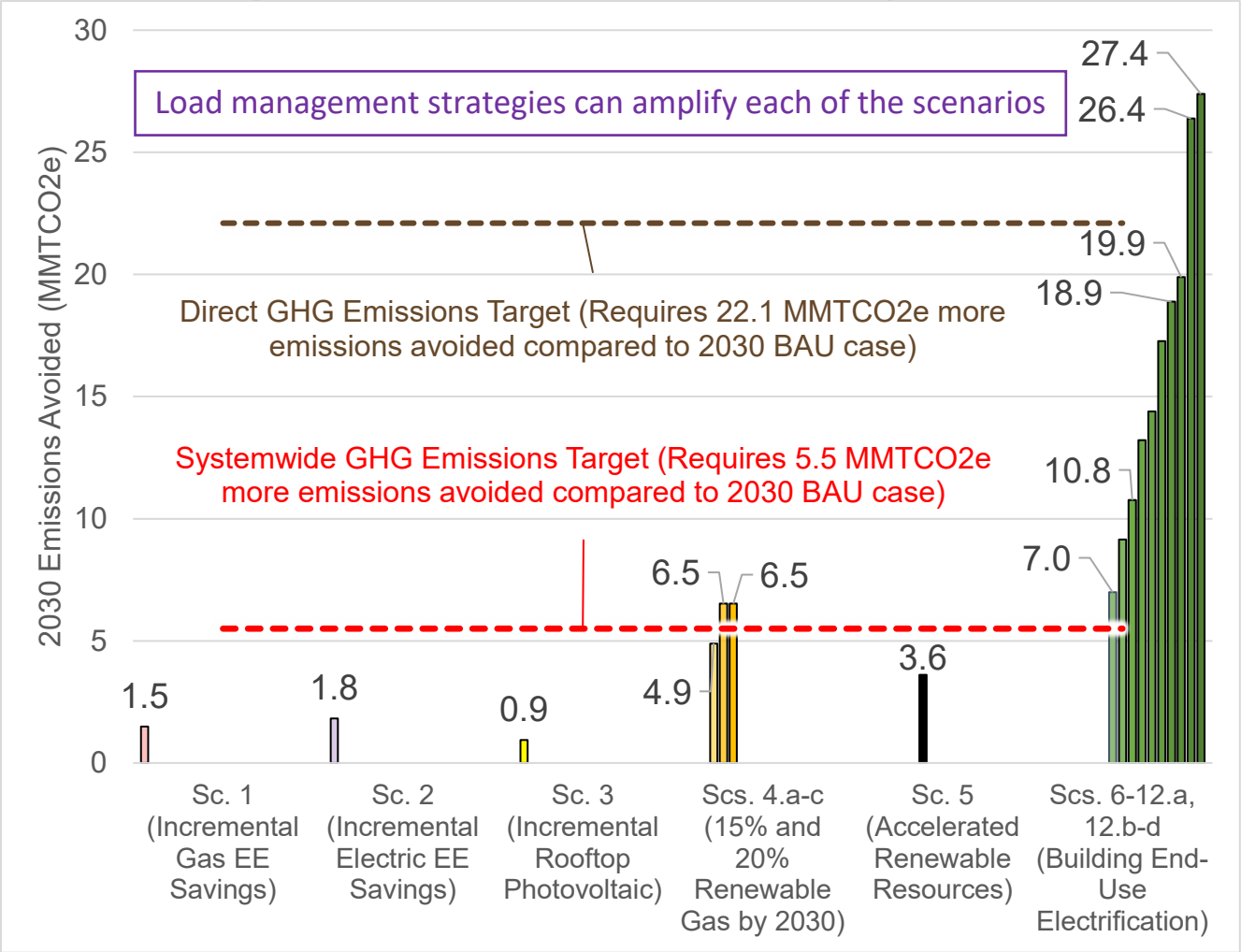
(i) GHG Reductions

Figure 11 illustrates each scenario's independent potential impact relative to achieving the 2030 40 percent direct and systemwide emissions reduction targets. **Figure 11** depicts the potential GHG emissions avoided in 2030 in $MMTCO_2e$ while **Figure C-26** translates the potential impacts in terms of overall percentage reduction relative to 1990 systemwide GHG emissions. Chapter 3 reports the percentages relative to the direct emissions target, which reveal that only the most aggressive electrification cases as well as the success of SB 1383 can achieve the direct emissions 40 percent target.

Since the current analysis examines each strategy independently, the results are not additive. As can be seen in **Figure C-25** and **Figure C-26**, the electrification scenarios (represented in green on the far right of the figure) have the most potential for not only achieving the 2030 40

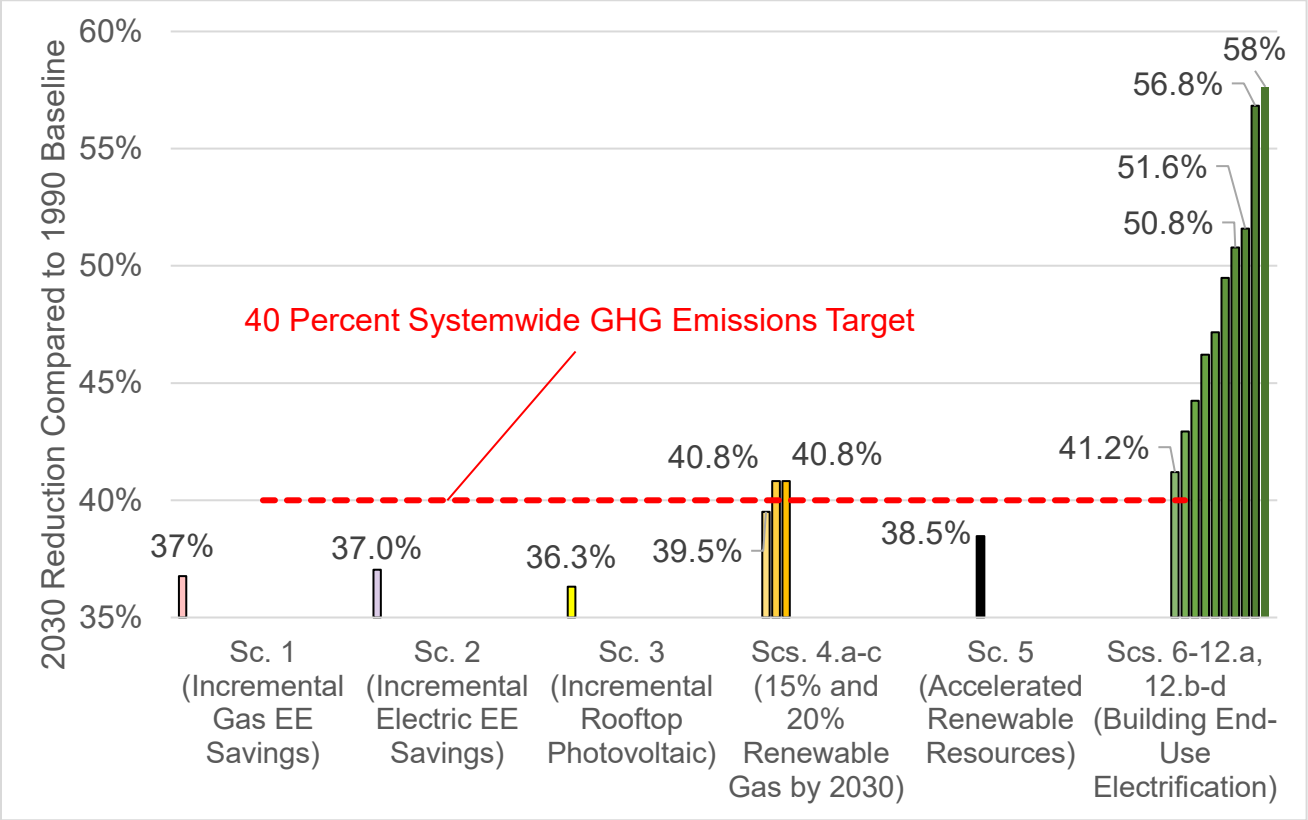
percent systemwide emissions reduction target, but the additional building GHG reduction to achieve the state's 2045 carbon neutrality goals. As such, this evaluation places more focus on the electrification scenarios compared to the impact scenarios since they have the clearest pathway in achieving the 40 percent systemwide emissions target and California's mid-century climate goals.

Figure C-25: Annual GHG Reduction for 2030 by Scenario



Source: CEC staff

Figure C-26: Emission Reductions Relative to 1990 Systemwide GHG Baseline and 40 Percent Target

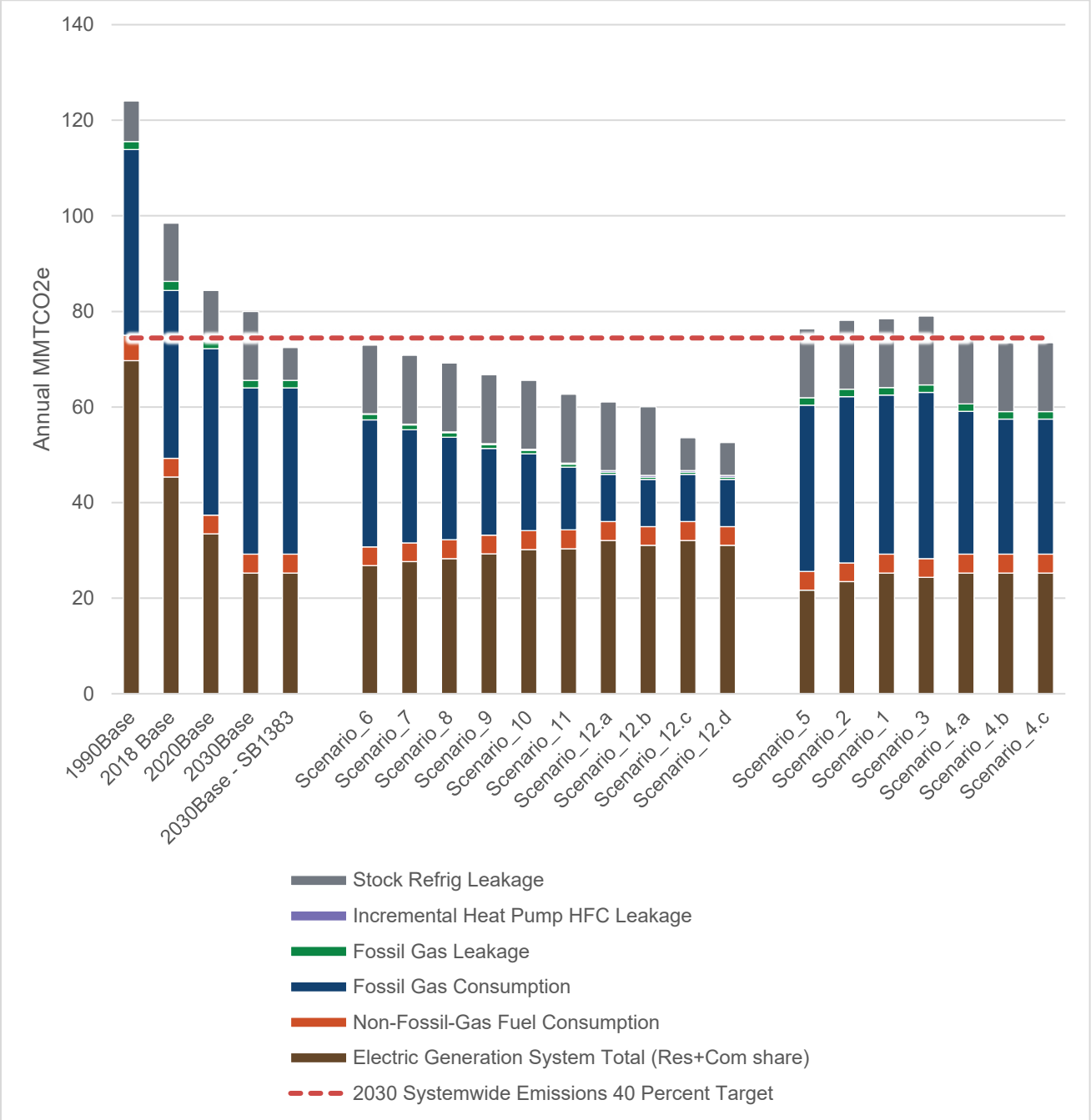


Source: CEC staff

Figure C-27 shows the estimated statewide GHG emission impacts in 2030 for the scenarios, relative to the 40 percent reduction target (horizontal line), the 1990 baseline, and the 2030 business-as-usual scenario. The first bar on the left in **Figure C-27** illustrates the 1990 GHG emission baseline of 124 $MMTCO_2e$ and implies a 40 percent reduction target of 74 $MMTCO_2e$ for 2030. The next set of four bars shows the historical emission values for 2017 and the 2030 business-as-usual case (2030Base) with and without achieving the state goal to reduce HFC emissions pursuant to SB 1383 (Lara, Chapter 395, Statutes of 2016).

As described in Chapter 2 and shown in **Figure C-27**, GHG emissions have decreased from 1990 levels, but additional GHG reduction needs remain when observing the 2030 business-as-usual case without SB 1383 succeeding (2030Base). However, as seen with the "2030Base-SB1383" scenario, the state would meet the 2030 building decarbonization goal if SB 1383 goals are achieved independent of other building decarbonization strategies.

Figure C-27: Statewide GHG Emissions for Building Decarbonization Scenarios



Source: CEC staff using CARB GHG inventory

In addition to the impact of meeting SB 1383 goals, **Figure C-27** illustrates the potential GHG emission reduction from Scenarios 1-5 compared to electrification strategies. Scenarios 1-5 approach the 40 percent systemwide emissions target while keeping gas fuel combustion relatively the same, with the exception of Scenario 1, the incremental gas energy efficiency. The electrification scenarios exceed 40 percent reduction target while reducing gas fuel combustion. Scenario 6 would result in 41.2 percent GHG emission reduction while Scenario 12.a would achieve a 50.8 percent GHG emission reduction. CEC Staff considered modifications to Scenario 12.a such as the type of technology replacement and the success of

SB 1383 and found that the most aggressive scenario (Scenario 12.d, which includes "single-best" technology and assumes SB 1383 succeeding) could achieve a reduction of 57.6 percent compared to 1990 levels.

Table C-19 presents the numerical values from **Figure C-27**. This table allows readers to examine the GHG reduction potential compared to an alternative 1990 baseline (e.g., a baseline that excludes electric generation system emissions or incremental electric generation emissions). To do create a direct emissions baseline, one can adjust the "2030Base" by omitting 1990 electric generation system emissions, 69.68 $MMTCO_2e$, from the total GHG emissions. To calculate the incremental electric generation system emissions, subtract the scenario's electric generation total compared to the "2030Base" value, 25.26 $MMTCO_2e$.

Table C-19: Statewide GHG Emissions in 2030 from All Sources Attributable to Buildings for All Building Decarbonization Scenarios ($MMTCO_2e$)

	Gas Combustion	BTM Gas Leakage	Non-Gas Fuel Consumption	Incr HP Refrig Leakage	Stock Refrig Leakage	Elec Gen System Total (Res+Com share)	Total GHG Emissions
1990Base	38.83	1.71	5.35	0.00	8.49	69.68	124.06
2018Base	35.08	1.90	3.94	0.00	12.17	45.35	98.43
2020Base	34.83	1.55	3.94	0.00	10.60	33.44	84.37
2030Base	34.79	1.55	3.94	0.00	14.40	25.26	79.95
2030Base - SB1383	34.79	1.55	3.94	0.00	6.90	25.26	72.45
Scenario_1	33.29	1.55	3.94	0.00	14.40	25.26	78.45
Scenario_2	34.79	1.55	3.94	0.00	14.40	23.44	78.12

	Gas Combustion	BTM Gas Leakage	Non-Gas Fuel Consumption	Incr HP Refrig Leakage	Stock Refrig Leakage	Elec Gen System Total (Res+Com share)	Total GHG Emissions
Scenario_3	34.79	1.55	3.94	0.00	14.40	24.33	79.01
Scenario_4.a	29.89	1.55	3.94	0.00	14.40	25.26	75.05
Scenario_4.b (Selected renewable gas scenario in report)	28.27	1.55	3.94	0.00	14.40	25.26	73.43
Scenario_4.c	28.27	1.55	3.94	0.00	14.40	25.26	73.43
Scenario_5	34.79	1.55	3.94	0.00	14.40	21.66	76.34
Scenario_6 ("Minimal electrification" in report)	26.54	1.18	3.94	0.10	14.40	26.79	72.96
Scenario_7	23.64	1.05	3.94	0.13	14.40	27.64	70.80
Scenario_8 ("Moderate electrification" in report)	21.46	0.95	3.94	0.16	14.40	28.27	69.18
Scenario_9	18.12	0.81	3.94	0.20	14.40	29.27	66.73
Scenario_10	16.11	0.72	3.94	0.22	14.40	30.17	65.56
Scenario_11	13.13	0.58	3.94	0.27	14.40	30.36	62.68
Scenario_12.a ("Aggressive electrification" in report)	9.87	0.44	3.94	0.32	14.40	32.09	61.07

	Gas Combustion	BTM Gas Leakage	Non-Gas Fuel Consumption	Incr HP Refrig Leakage	Stock Refrig Leakage	Elec Gen System Total (Res+Com share)	Total GHG Emissions
Scenario_12.b ("Efficient aggressive electrification" in report)	9.87	0.44	3.94	0.36	14.40	31.04	60.06
Scenario_12.c (12.a with SB1383 Toggle On*)*	9.87	0.44	3.94	0.32	6.90	32.09	53.57
Scenario_12.d (12.b with SB1383 Toggle On)	9.87	0.44	3.94	0.36	6.90	31.04	52.56

As seen with Scenario 12.c and Scenario 12.d, all scenarios have the potential of reducing stock HFC refrigerant emissions from 14.40 to 6.9 MMTCO2e in 2030 if SB 1383 is successful.

Source: CEC staff

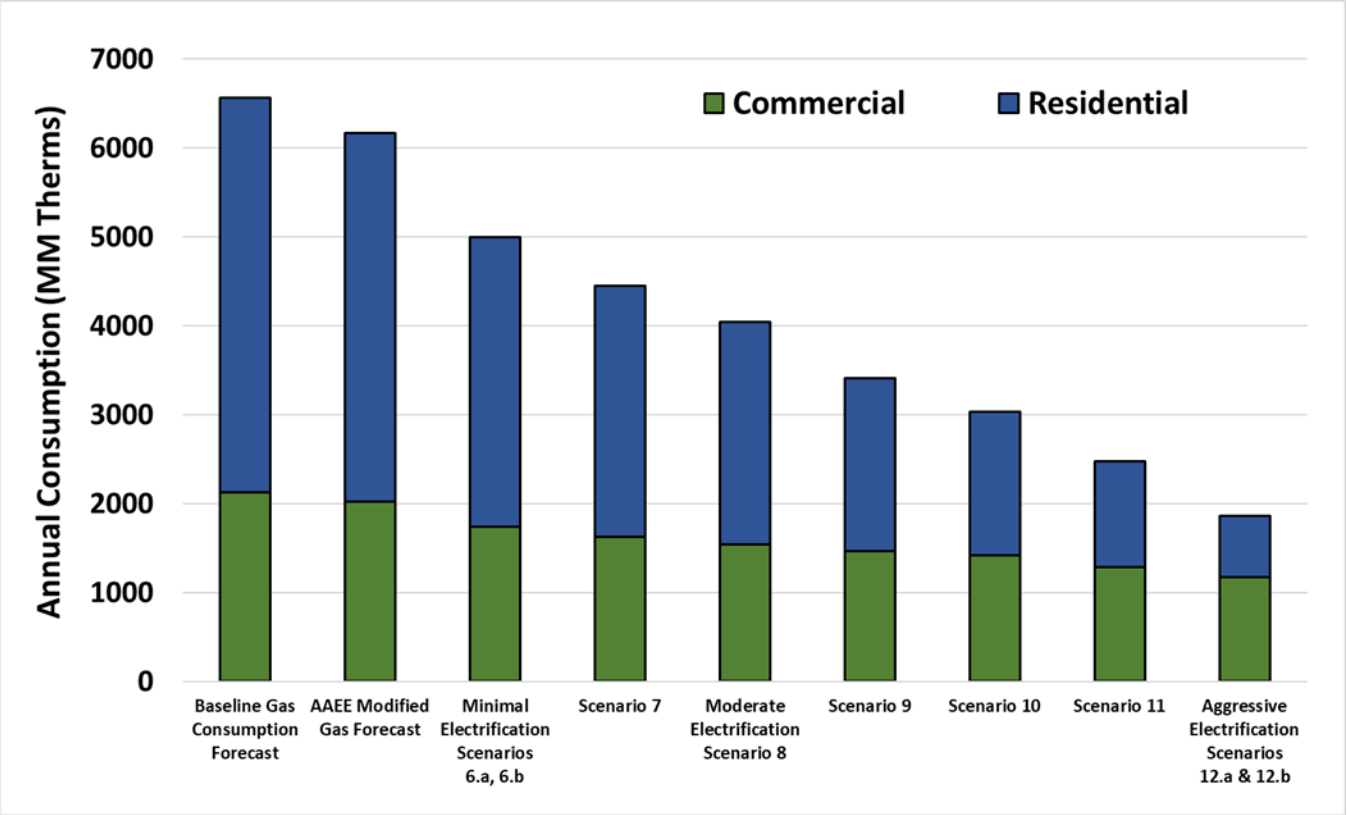
(ii) Energy System Impacts and Grid Implications

This section presents the results of analysis, using the FSSAT tool previously described, to determine how the various building electrification scenarios impact the electricity and gas systems. Building end use decarbonization, also referred to as building electrification or fuel substitution, displaces gas consumption and increases electricity consumption on an annual basis. The latter is also described on an hourly basis and potential grid implications are discussed.

Annual Gas System Impacts

For each of the electrification scenarios 6 through 12 the 2019 mid-mid AAEE (scenario 3) planning forecast was used to adjust the 2019 mid IEPR baseline forecast (business-as-usual case or 2020-30 Baseline Case) before any electrification was applied. The adjustment has a small impact retaining 94 percent of the baseline consumption in 2030 as indicated in the second column shown in **Figure C-28**. The FSSAT computes remaining gas consumption, after each electrification scenario efforts are applied, with granularity of utility, sector, end-use, and technology.

Figure C-28: Statewide Annual Gas Demand in 2030



Source: CEC staff

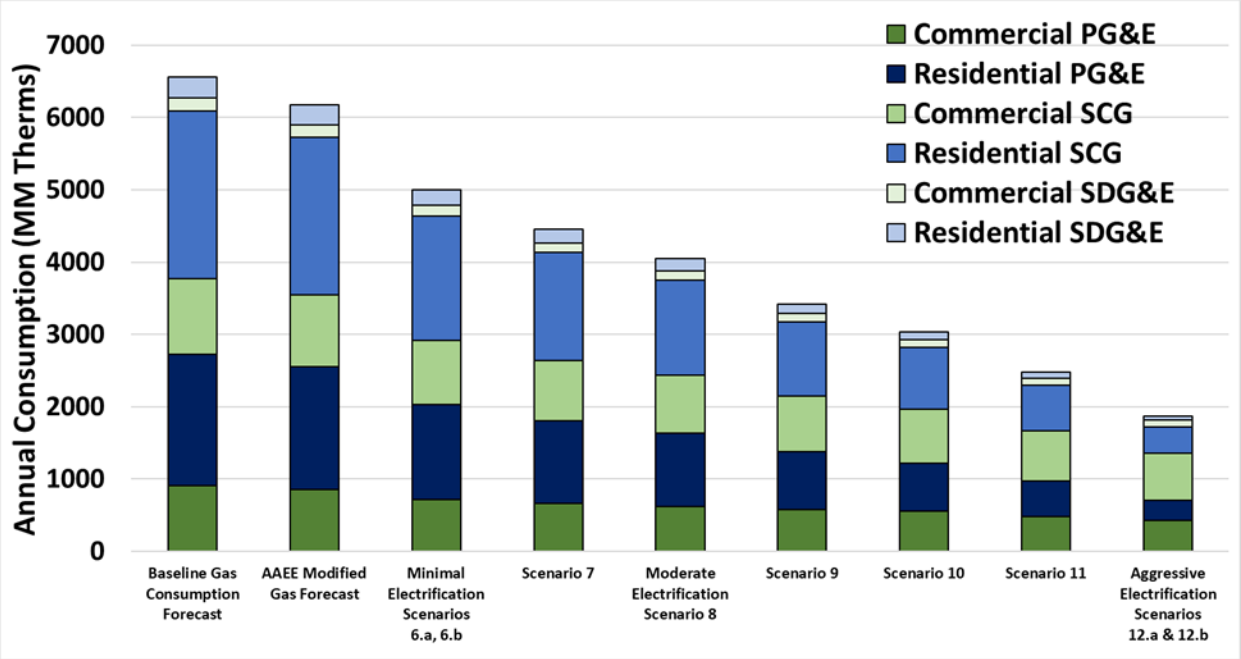
Electrification is possible for 87 percent of residential and commercial gas consumption. Of that, the residential sector accounts for 77 percent of the gas consumption considered for electrification. Further refinement of the miscellaneous share of commercial building consumption may be possible in future updates and lower the 38 percent of gas consumption attributed to uncategorized end-uses in commercial buildings. Uncategorized end-uses cannot be considered for electrification because the substitution is completed at a technology level. The 87 percent of residential consumption evaluated for electrification is split between space and water heating, whereas the commercial sector has 84 percent of gas consumption eligible for electrification in the same two end-uses.

In the Minimal electrification scenario (Scenario 6), which has the least amount of electrification in existing buildings, gas consumption is reduced to 76 percent of the Business-as-Usual Case in 2030. In the moderate electrification scenario (Scenario 8) consumption is reduced to 62 percent of the baseline forecast in 2030. In the Aggressive electrification scenario (Scenario 12), electrification efforts reduce gas consumption to 28 percent of the baseline forecast in 2030. **Figure C-28** shows these changes in gas consumption.

As mentioned in the FSSAT methodology section, scenarios can be designed that have differential penetration rates for each major utility service area but to date staff has only designed scenarios that have common statewide penetration rates. This is exhibited in **Figure C-29**. As data becomes available from statewide pilot programs and utility incentive program efforts staff can update these assumptions appropriately. It is however apparent that all electrification scenarios 6 through 12, from Minimal to Aggressive penetration, have

significantly smaller remaining gas consumption than can be achieved by added energy efficiency alone.

Figure C-29: Statewide Annual Gas Demand by sector and utility in 2030 Modified

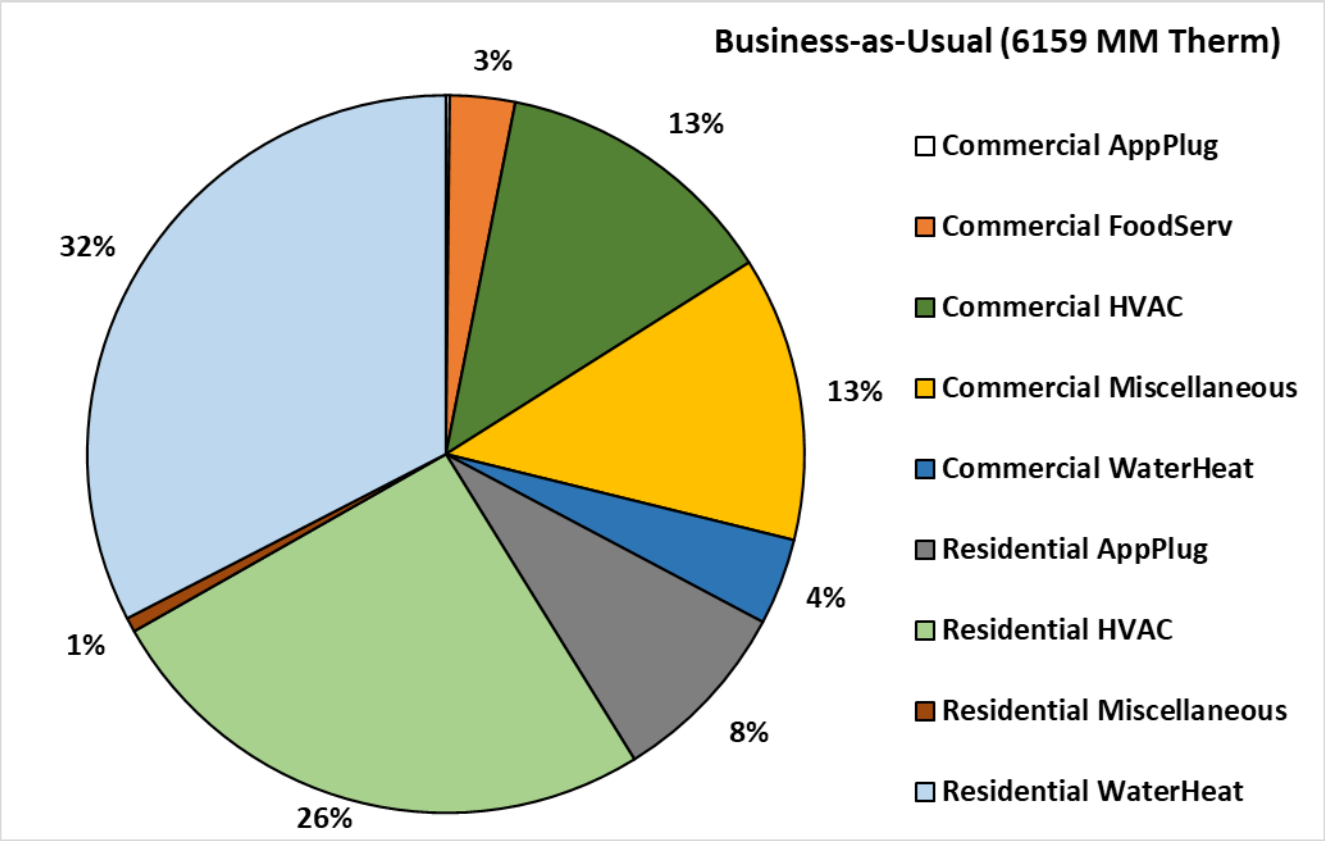


Source: CEC staff

The business-as-usual case gas consumption in 2030 is 6159 MM therms as shown in **Figure C-30** and consists of the baseline consumption modified by mid-AAEE. The gas consumption remaining after Minimal electrification efforts in Scenario 6 is 5000 MM therms in 2030, as shown in **Figure C-31**. The end-use distribution of remaining gas consumption does not appear markedly different than before electrification, it is simply diminished in magnitude to 81 percent of gas consumption prior to electrification.

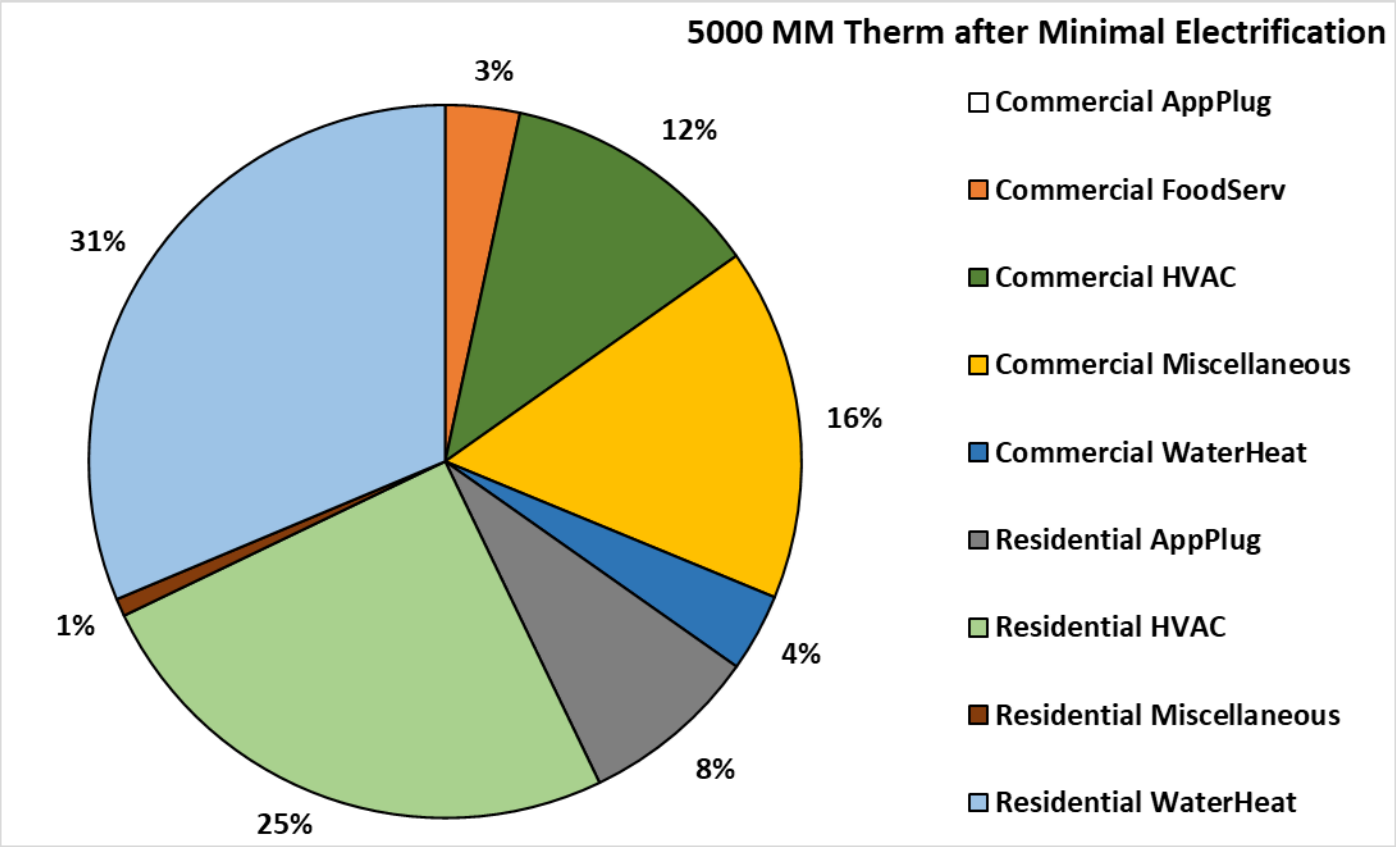
Figure C-32 shows the end-use break down of the remaining 1864 MM therms of gas consumption in 2030 after Aggressive electrification efforts in Scenario 12. Besides the dramatic reduction from the Business-as-Usual Case leaving only 30 percent of gas consumption, the end use break-down after electrification efforts is very different. Only 28 percent and 33 percent commercial water heating and HVAC remain respectively; similarly, 18 percent of residential water heating and 15 percent of residential HVAC remain.

Figure C-30: Business-as-Usual Case Gas Consumption in 2030



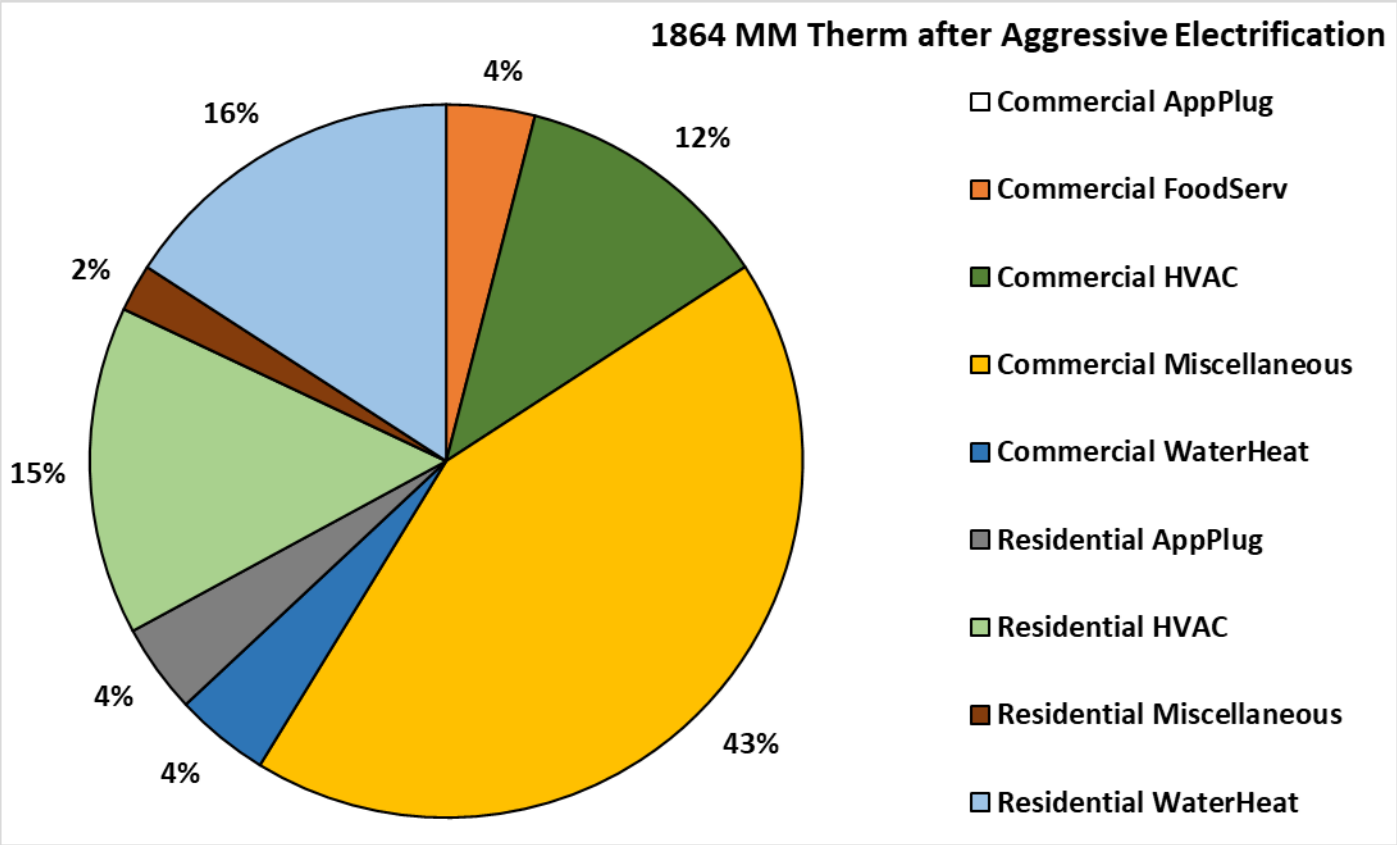
Source: CEC Staff

Figure C-31: Gas Consumption Remaining After Minimal Electrification Scenarios 6.a and 6.b in 2030



Source: CEC Staff

Figure C-32: Gas Consumption Remaining After Aggressive Electrification Scenarios 12.a and 12.b in 2030



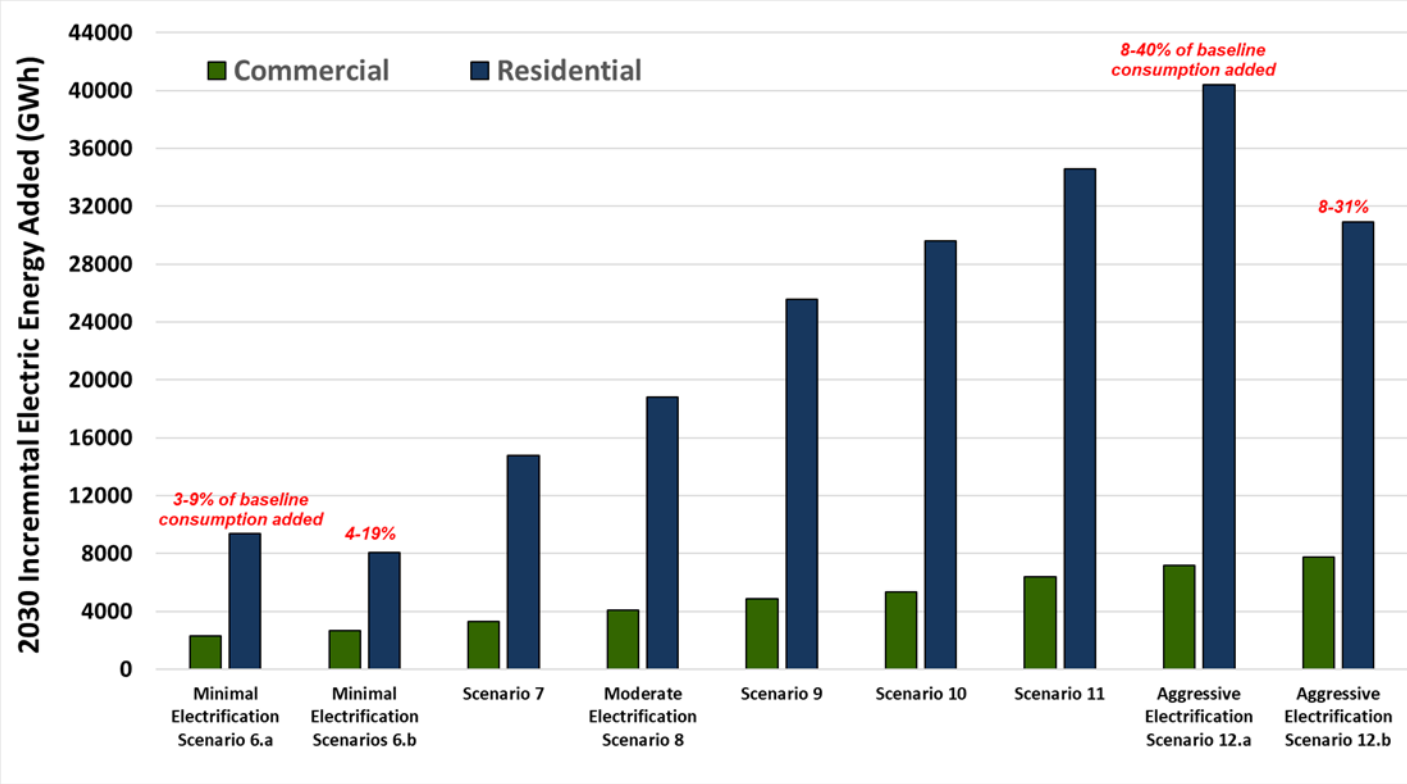
Source: CEC Staff

Annual Electricity System Impacts

The FSSAT tool determines the incremental electric energy added as a result of the technology substitutions specified in each of the electrification scenarios the scenarios. The output is generated with the granularity of utility, sector, end-use, and technology. As shown in **Figure C-33** it is apparent that all electrification scenarios, from Minimal to Aggressive penetration, result in the addition of substantial incremental electric energy; generally, the more gas displaced the more incremental electricity additions.

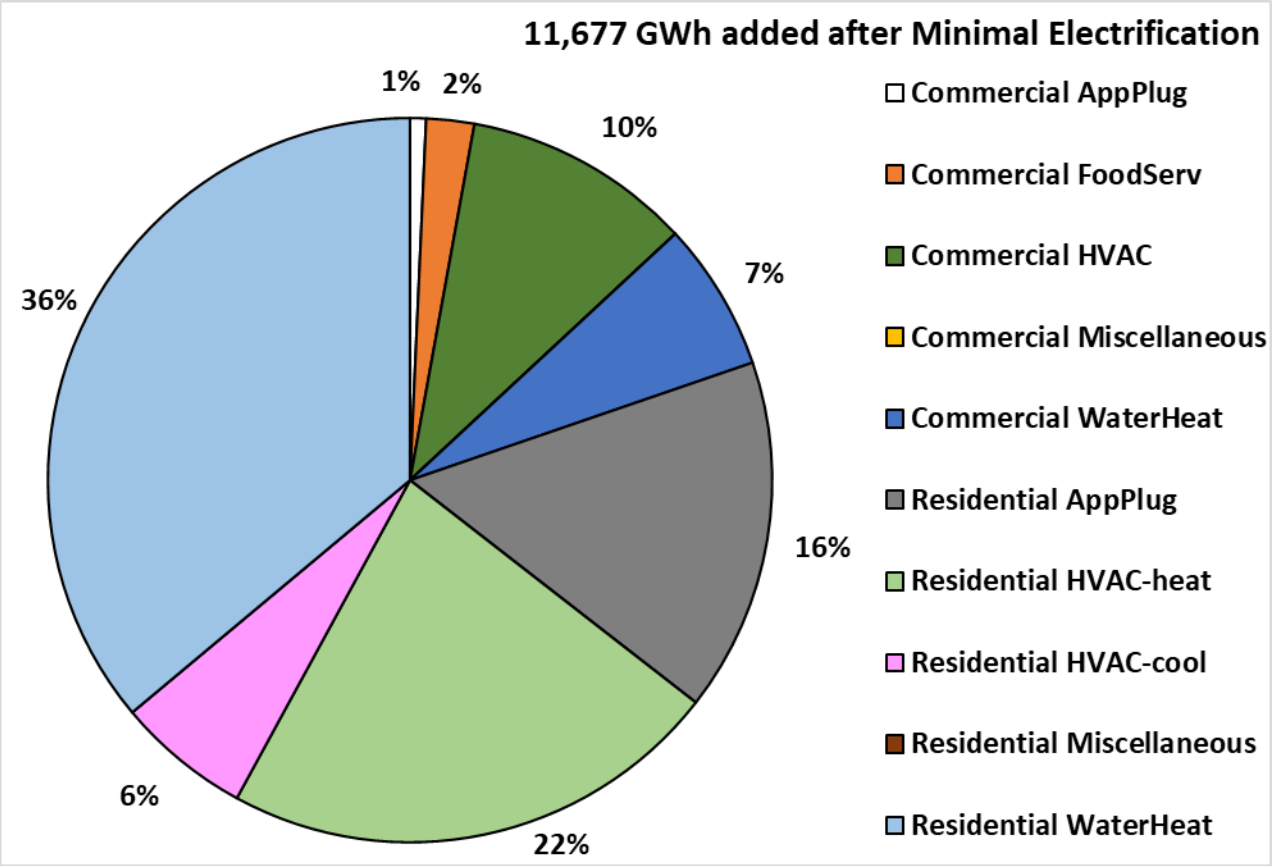
Scenario 6.a, the lowest electrification scenario, is shown in the left-most column of **Figure C-33**. It adds 3 to 9 percent of the baseline electricity consumption forecast in 2030 for the commercial and residential sectors respectively. In the Aggressive electrification scenario (Scenario 12.a), shown in the penultimate column of **Figure C-33**, electrification efforts add 8 to 40 percent of the baseline electricity consumption forecast in 2030 for the commercial and residential sectors respectively. The right-most column of **Figure C-33** portrays the incremental electricity added in 2030 due to Scenario 12.b in which only the "realistic best" single technology from the high efficiency technology mix otherwise utilized is employed. For this case much less, incremental electricity is added even though the amounts of gas displaced are identical; only 8 to 31 percent of the baseline electricity consumption forecast in 2030 for the commercial and residential sectors is added, respectively.

Figure C-33: Statewide Annual Incremental Electricity Demand added by Scenario-Specific Electrification in 2030



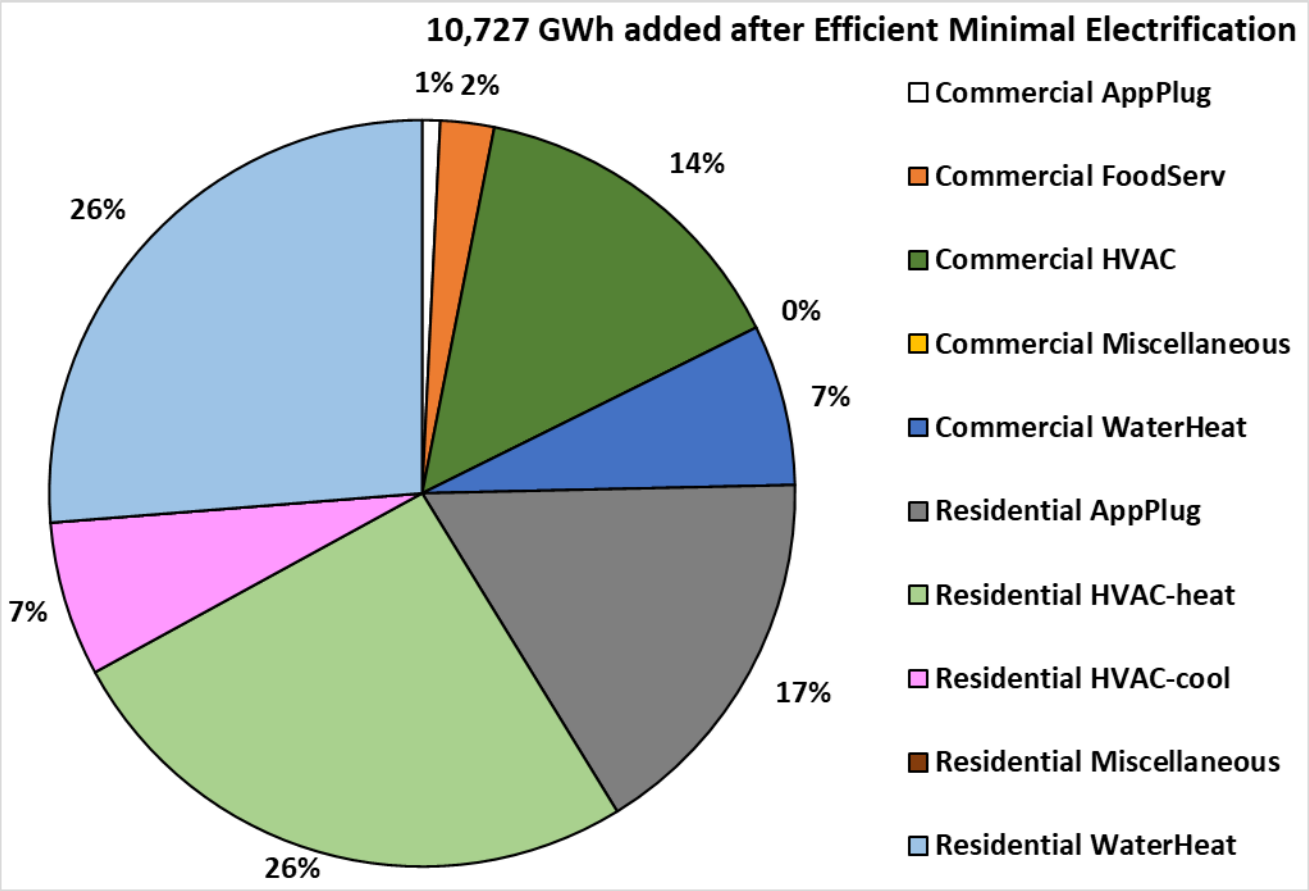
Source: CEC staff

Figure C-34: 2030 Incremental Electricity added after Minimal Electrification Scenario 6.a



Source: CEC staff

Figure C-35: 2030 Incremental Electricity added after Minimal Electrification Scenario 6.b



Source: CEC staff

The incremental added electricity consumption after the "minimal electrification" scenario (Scenario 6.a) is 11,677 GWh in 2030 and the end-use breakdown is shown in **Figure C-34**. Eighty-six percent of the incremental electricity added in the commercial sector is from water heating and HVAC. This is commensurate with the larger gas consumption reductions in those particular end-uses. Similarly, 80 percent of the incremental electricity added is in the Residential sector because the gas displacement is greatest there as well.

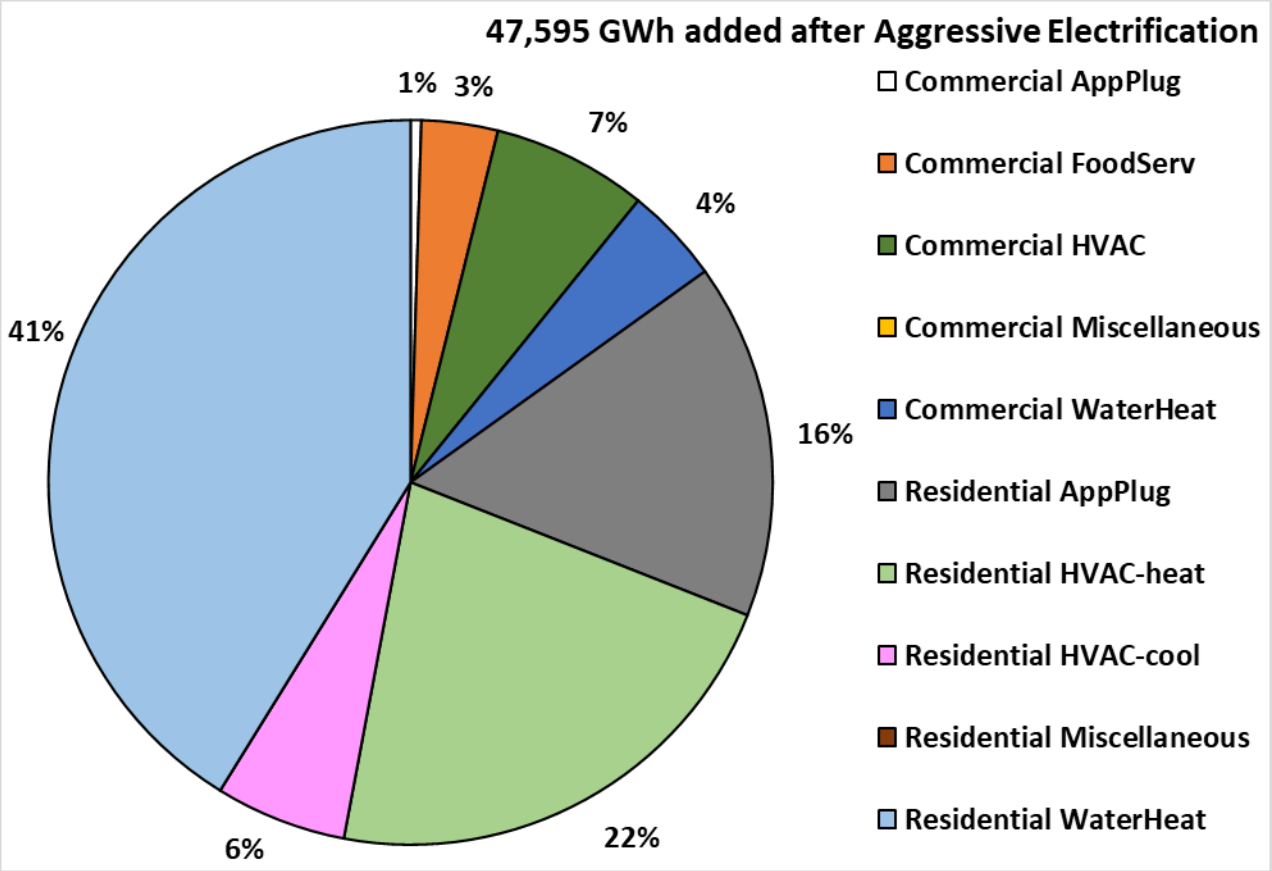
If however a variation of the "minimal electrification" scenario (Scenario 6.b) in which only the "realistic best" single technology from the high efficiency technology mix otherwise utilized is employed is disaggregated, as shown in **Figure C-35**, one observes that the residential sector constitutes slightly less of the incremental electric added at 75 percent and the total is also less at 10,727 GWh. The distribution from water heating and HVAC stays steady at 87 percent for the commercial sector and 78 percent for the Residential sector but the amount of incremental electricity added by water heating relative to HVAC is less for both and rather marked for the Residential sector dropping from 45 to 35 percent.

All of the effects described for the low electrification scenarios are more pronounced for the high electrification scenario. The incremental added electricity consumption after the high electrification scenario (Scenario 12.a) is 47,595 GWh in 2030 and the end-use breakdown is shown in **Figure C-36**. In the commercial sector, 74 percent of the incremental electricity

added is from water heating and space conditioning, and similarly 81 percent of the incremental electricity added in the residential sector is in the same end-uses.

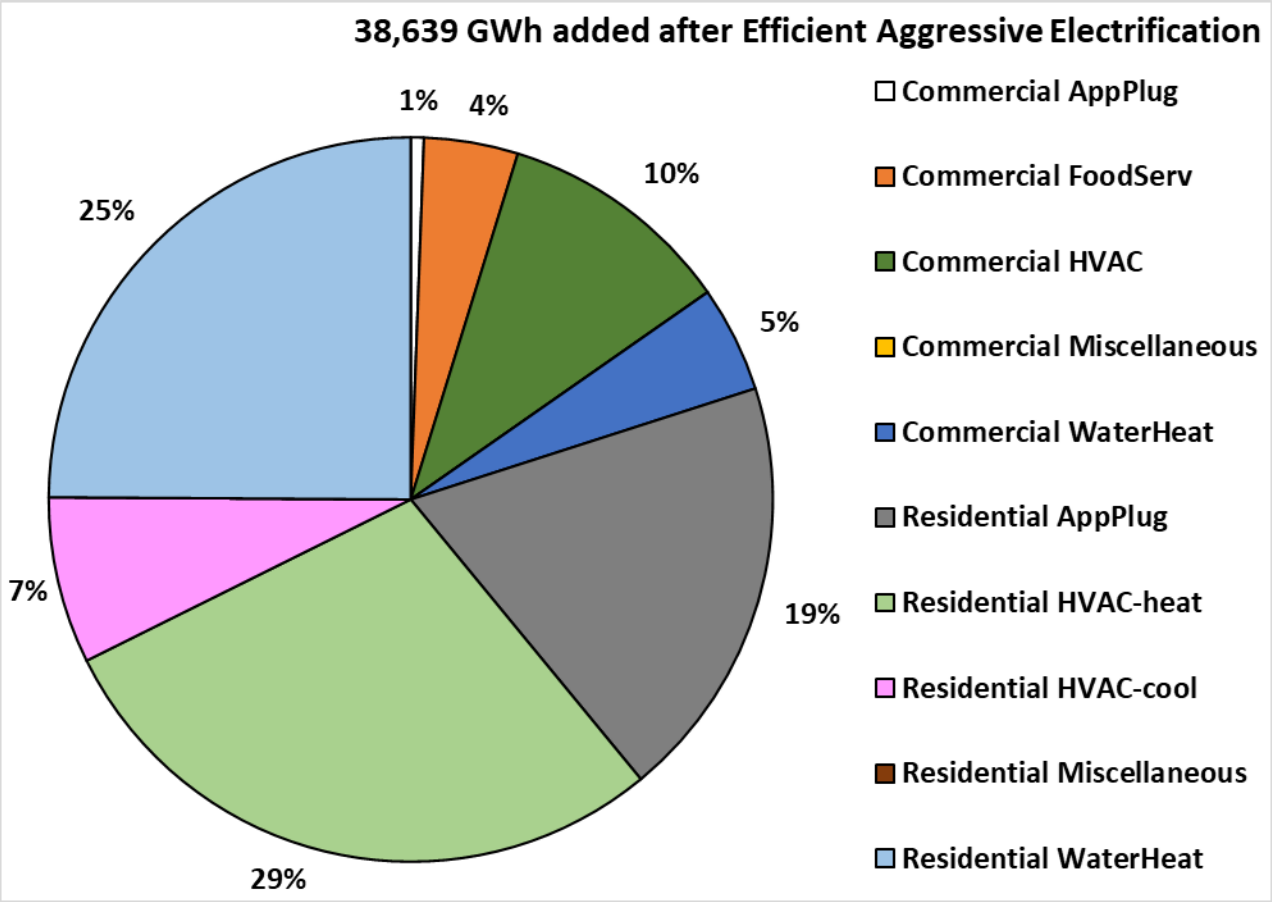
For a variation of the high electrification scenario (Scenario 12.b) in which only the "realistic best" single technology from the high efficiency technology mix otherwise utilized is employed is disaggregated, as shown in **Figure C- 37**, one observes that the total incremental electricity added is also less at 38,639 GWh.

Figure C-36: 2030 Incremental Electricity added in Aggressive Electrification Scenario 12.a



Source: CEC staff

Figure C- 37: Incremental Electricity added in Efficient Aggressive Electrification Scenario 12.b



Source: CEC staff

Hourly Electricity System Impacts

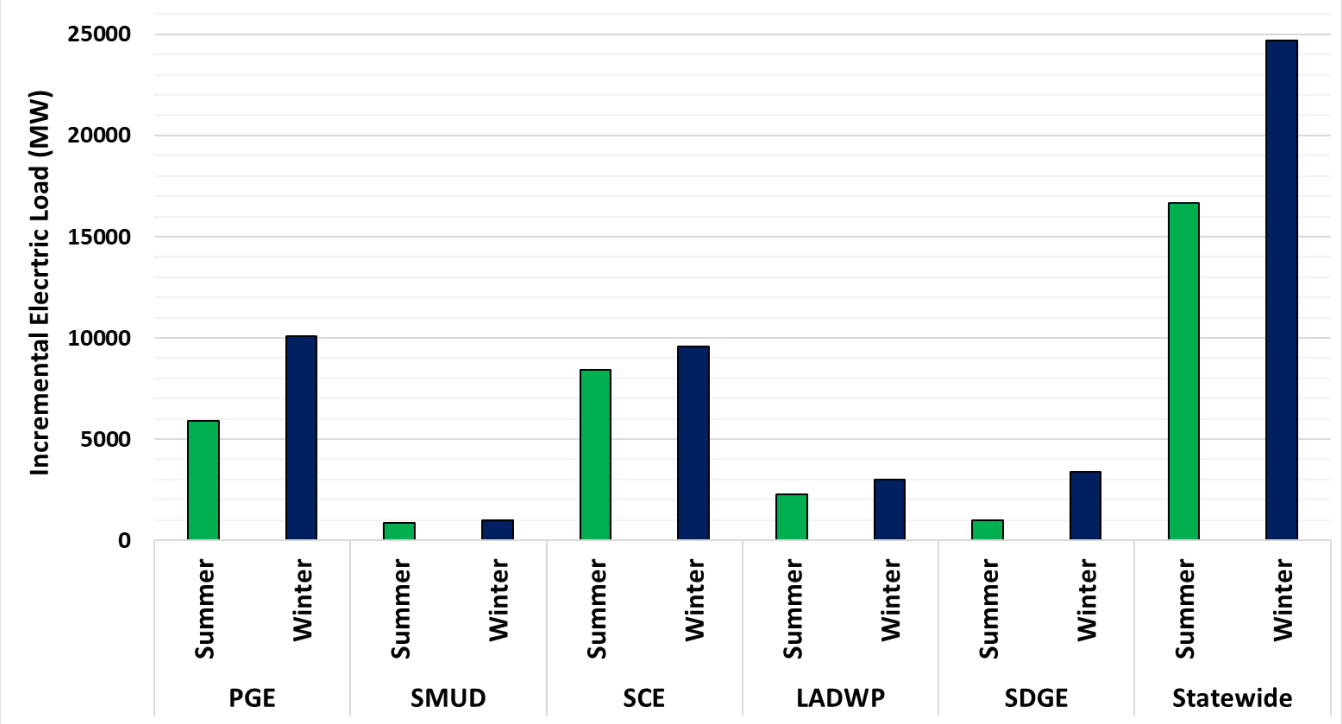
In addition to reporting annual incremental electricity impacts due to electrification efforts, the FSSAT tool includes an optional hourly load impact module that combines annual incremental electric energy at the sector, end-use, and technology level with an hourly load profile to develop hourly loads at the same level of granularity for each major electric utility. These disaggregated hourly impacts are summed across each sector, end-use, and technology level to develop aggregate load impacts for each major electric utility.

The structure of the hourly module as well as the hourly load profiles utilized in FSSAT originate from the 2019 IEPR hourly AAEE projection tool. Guidehouse staff conducted additional load profile studies for heat pump technologies and CEC staff subsequently reprocessed these heat pump space conditioning load profiles to better distinguish between heating and cooling. These modified space heating and cooling profiles replaced the original heat pump space conditioning load profile in the FSSAT.

The tool estimates incremental space conditioning load for existing homes that did not have air conditioning but will gain this capability when a heat pump replaces the gas space heating equipment. Both summer and winter incremental loads grow for all electrification scenarios studied. Winter loads continue to increase more than summer loads increase in all cases and

over all utilities. The latter is demonstrated explicitly in **Figure C-38** for the high electrification Scenario 12.a with a mix of technologies in 2030.

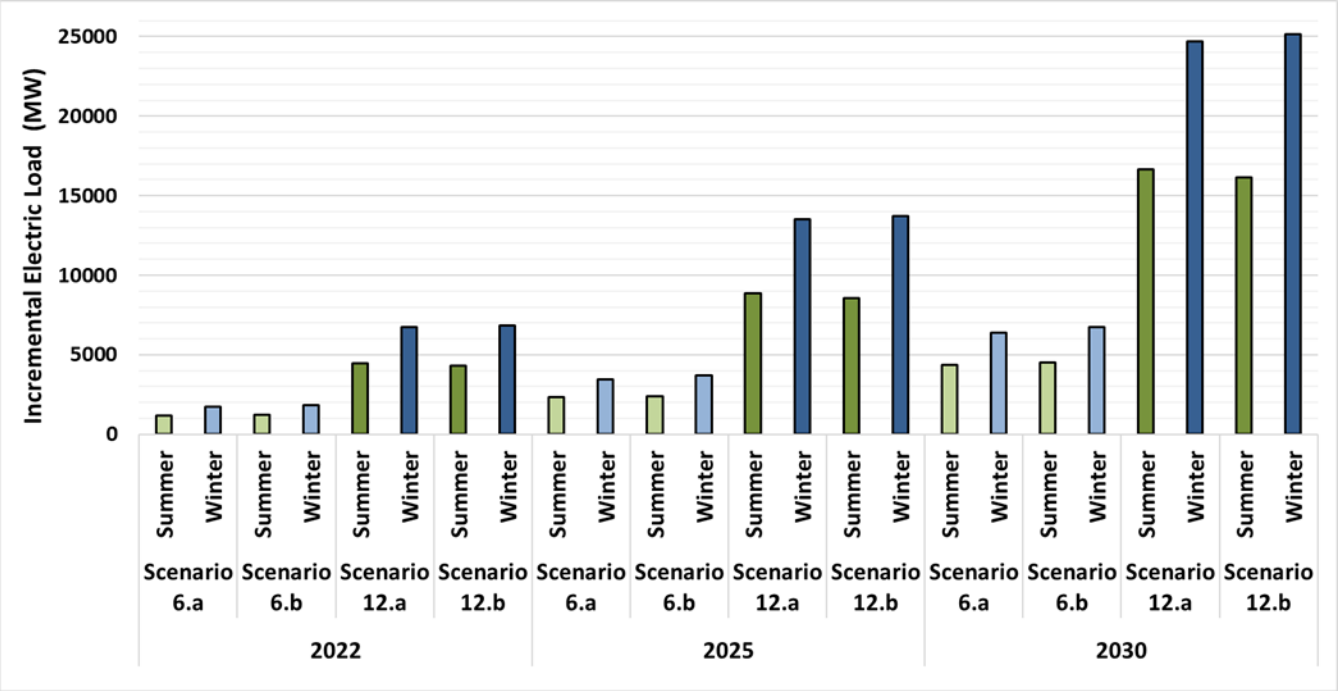
Figure C-38: 2030 Seasonal Maximum Incremental Load for Aggressive Electrification Scenario 12.a by Utility & Statewide



Source: CEC staff

Figure C-39 shows the same seasonal maximum incremental loads for each of the bookend scenarios, Scenarios 6.a & 6.b and Scenarios 12.a & 12.b, in three key years on a statewide level. Scenario 6 has the lowest penetration of electrification required to meet AB 3232 goals while Scenario 12 exceeds these goals; it is more in line with achieving the broader mid-century decarbonization goals outlined in SB 100. Both scenarios are shown in two variations, one with the high efficiency mix of replacement technologies and the other only utilizing the single best of the aforementioned mix.

Figure C-39: 2030 Seasonal Maximum Incremental Load for Bookend Scenarios

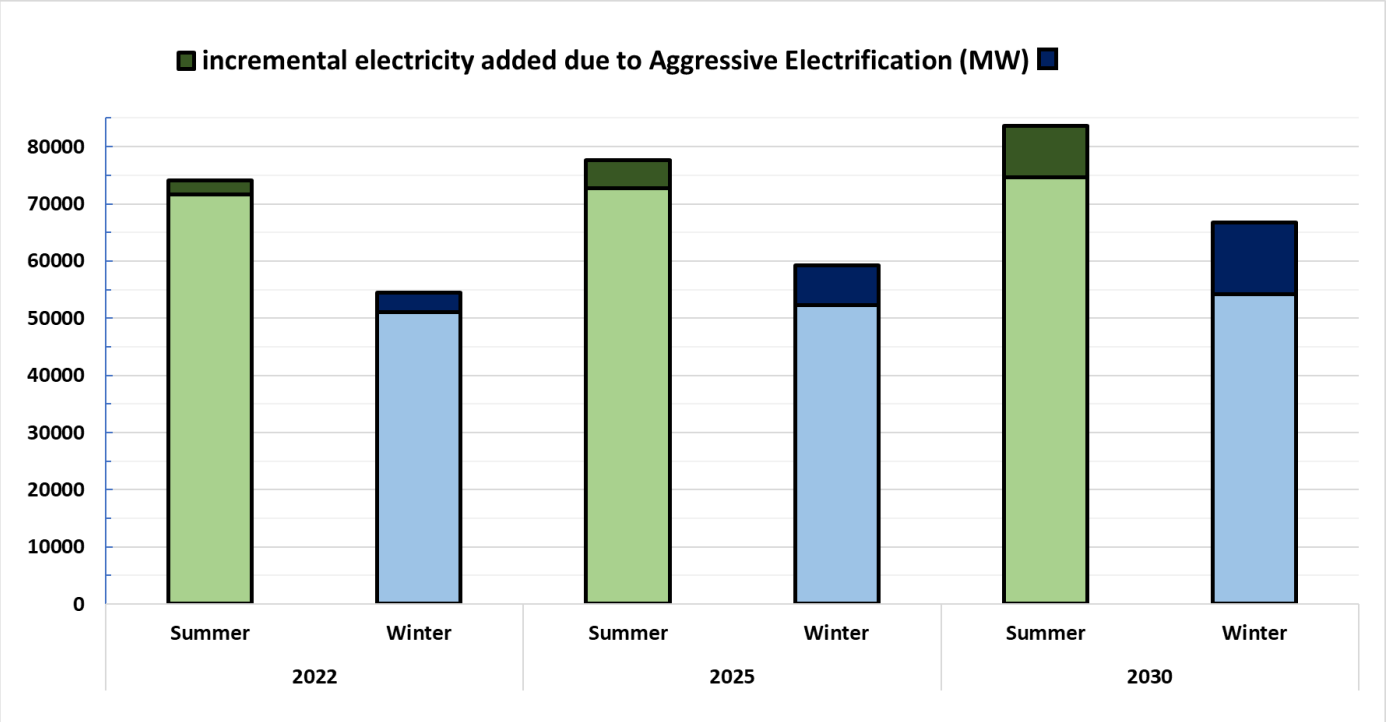


Source: CEC staff

The full impact of added electricity from electrification efforts can only be assessed when measured against the baseline loads. Similar to the business-as-usual case, where various load modifiers are incorporated with the baseline consumption forecast to create a managed forecast, this can be accomplished on an annual basis, as well as, on an hourly basis. In the annual case, the percentage of baseline load added by electrification was reported in **Figure C-18**. For the hourly impacts, CEC modified the baseline load forecast developed by the DAO forecasting team available for California ISO managed territory and analyzed the peak load dates, hours, and magnitudes by season. Winter was defined as the four months from November through February and summer as June through the middle of October.

Electrification results in increased peak loads and increases the magnitude of the peaks across the time period as shown in **Figure C-40**. While winter loads are affected more than summer loads the baseline peak loads are not coincident with the incremental electrification peaks. This results in a 6 percent addition to the new IOU winter peak load and an 8 percent addition to the new IOU summer peak load in the year 2030.

Figure C-40: Aggressive Electrification Scenario 12.a Winter and Summer Peak Load Impacts for Three IOU's

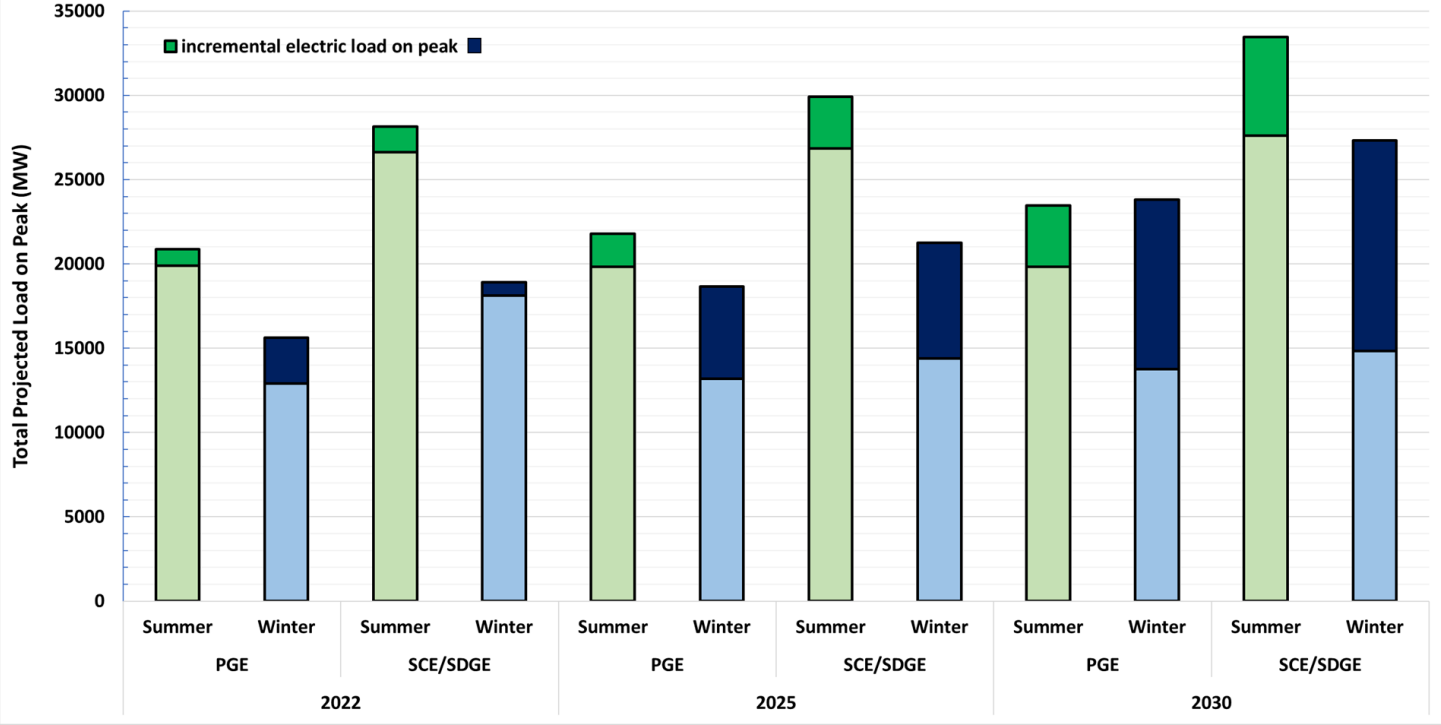


Source: CEC staff

The seasonal concentration of winter space heating loads resulting from electrification added to very little electric space heating in the baseline demand forecast can shift peak dates and hours for individual utilities in the winter. Electrification of water heating yields a more uniform impact across the seasons and thus has limited impact on summer or winter peak loads. This finding results in a 6 percent addition to the new IOU winter peak load and an 8 percent addition to the new IOU summer peak load for the "aggressive electrification" scenario. Impacts from the "minimal" or "moderate" electrification scenarios are difficult to show because they are less than 2 percent statewide. Electrification efforts cause impacts to managed peak loads at a scale that shift the dates and hours of these peak loads in the winter season for individual utilities but does not have this effect statewide.

Repeating this analysis for Northern and Southern California IOU's separately, as shown in **Figure C-41**, shows an increase in peak load growing in magnitude across the projection time period. Winter peak loads are affected more than summer loads, which is indicative of the shift of winter space heating loads to electric end uses. Peak incremental electric load additions are also not coincident with managed peak load dates and hours and become significant enough in impact to shift those dates and hours by 2030. As illustrated in **Table C- 20**, peak loads are shifted from early evening hours to morning hours which may be further indicative of added electrified space heating during the winter. Summer peak dates and times are not shifted by 2030 in the scenarios examined.

Figure C-41: Aggressive Electrification Scenario 12.a Winter and Summer Peak Load Impacts & Peak Load Shifts for North vs. South IOU's



Source: CEC staff

Table C- 20: Aggressive Electrification Scenario 12.a Winter Peak Load Shifts

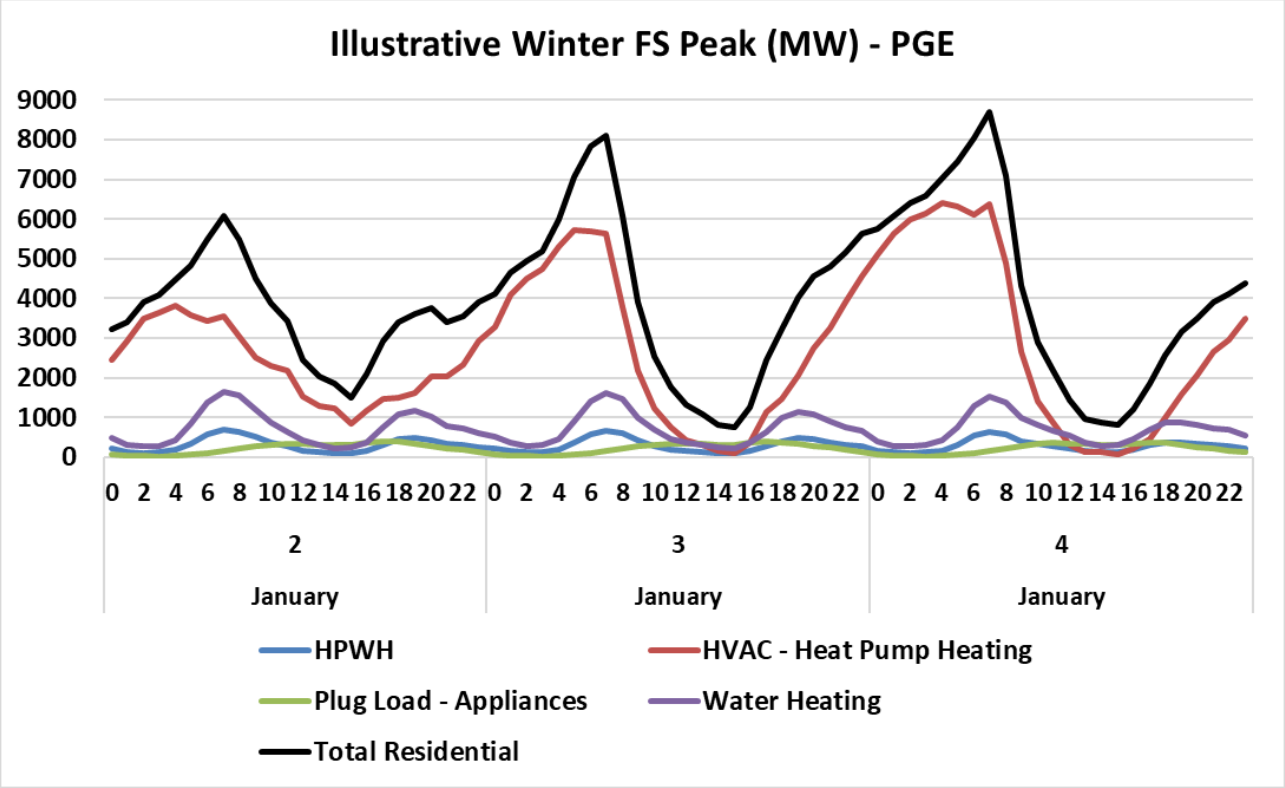
	Northern CA (PGE) Peak Load Date/Time	
	Managed Forecast	Managed plus added electric load from electrification
2022	December 12, 6pm	January 6, 7am
2025	December 8, 6pm	January 2, 7am
2030	December 9, 6pm	January 3, 7am
	Southern CA (SCE/SDGE) Peak Load Date/Time	
	Managed Forecast	Managed plus added electric load from electrification
2022	November 9, 5pm	November 9, 5pm
2025	November 12, 5pm	December 1, 6am
2030	November 13, 5pm	December 2, 6am

Source: CEC staff

Figure C-42, Figure C-43, Figure C-44, and Figure C-45 depict the hourly load patterns for Pacific Gas & Electric representing Northern California and Southern California Edison and San Diego Gas & Electric representing Southern California. The figures illustrate winter peaks and summer peaks respectively as the second of each of the three 24-hour cycles shown. Both winter and summer hourly load results exhibit extremely pointed peaks with daily cycles

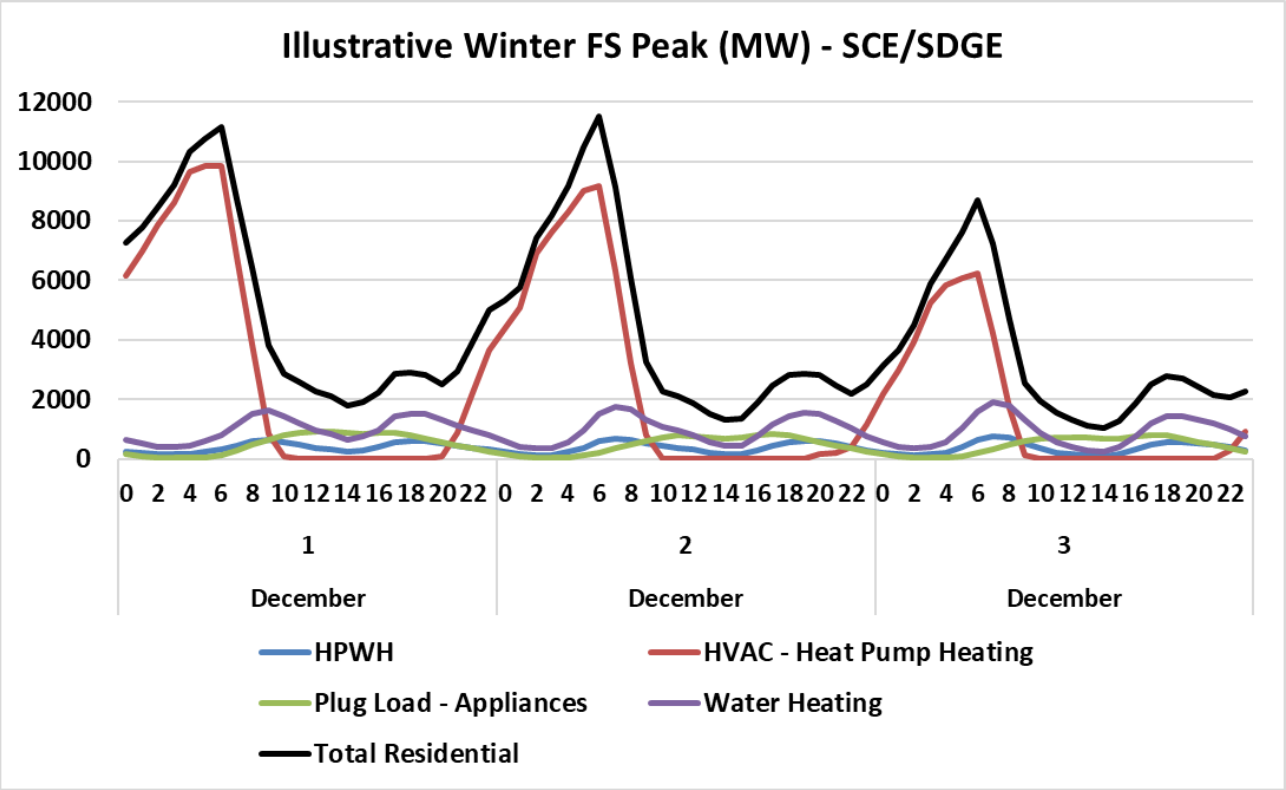
ramping up and down steeply on consecutive days. This may in part be because there is slight diversity between space heating and water heating and the other electrified appliances are not consequential for determining peak loads. Space heating and air conditioning load profiles are not yet reflective of the diversity in existing housing thermal integrity as based on housing vintage, nor the varying behavioral patterns of their occupants. This remained true despite great efforts by staff to investigate three separate sources of heat pump load profiles: Guidehouse modified, E3, and NREL. All available profiles exhibit these effects, the most extreme of which are seen in two southern California climate zones and therefore captured in the Southern California Edison and San Diego Gas & Electric hourly load profiles in Figure C-43 and Figure C-45.

Figure C-42: Northern CA 2030 Residential End-Use Loads on Winter Maximum Incremental Load Day after Electrification



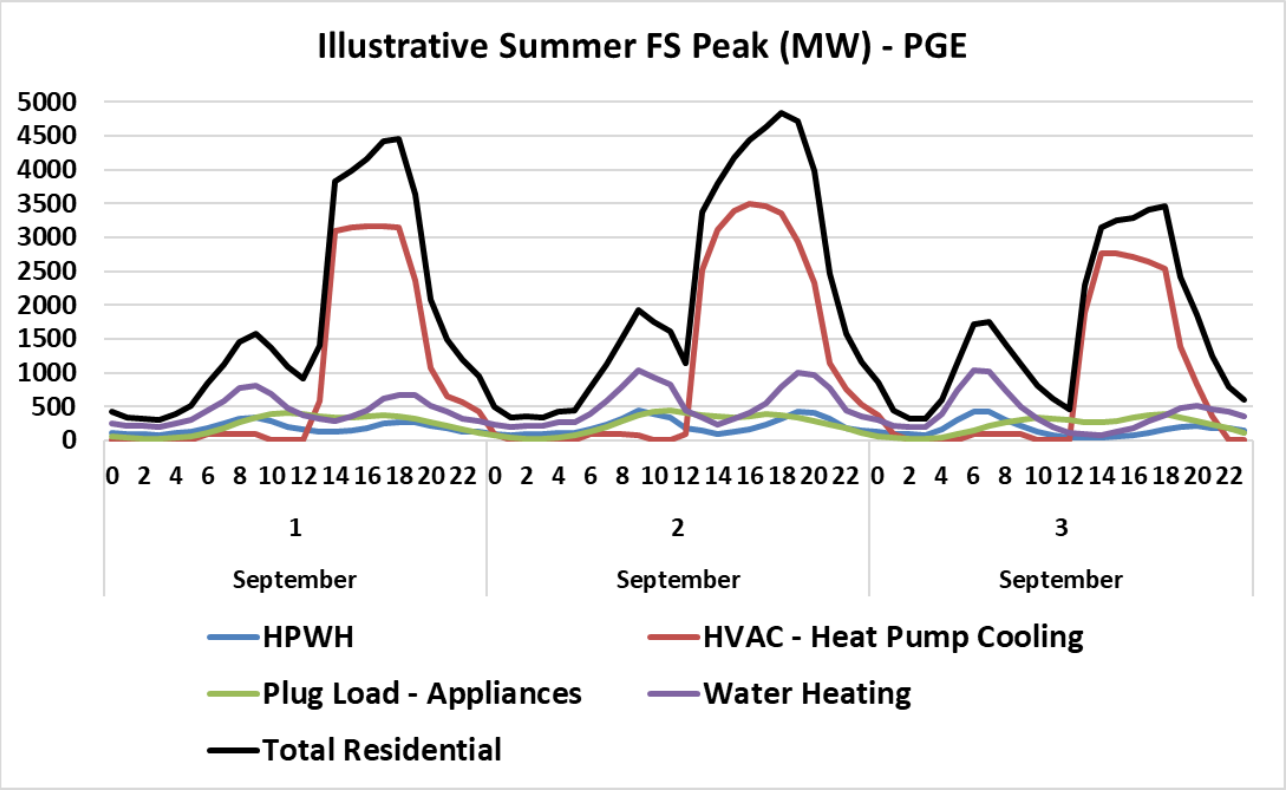
Source: CEC staff

Figure C-43: Southern CA 2030 Residential End-Use Loads on Winter Maximum Incremental Load Day after Electrification



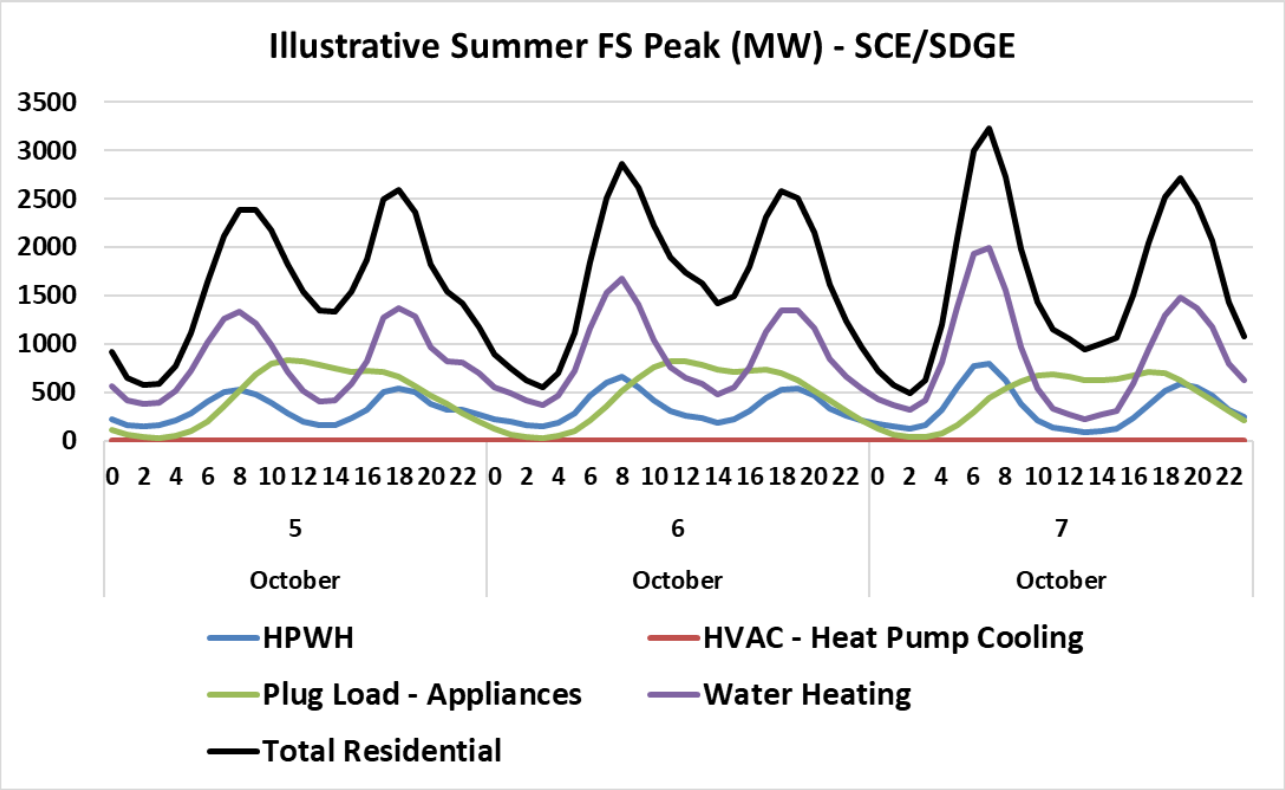
Source: CEC staff

Figure C-44: Northern CA 2030 Residential End-Use Loads on Summer Maximum Incremental Load Day after Electrification



Source: CEC staff

Figure C-45: Southern CA 2030 Residential End-Use Loads on Summer Maximum Incremental Load Day after Electrification



Source: CEC staff

(iii) Costs and Cost-Effectiveness

AB 3232 directs the CEC to evaluate the cost per metric ton of CO_2 equivalent of the potential building decarbonization strategies relative to other statewide GHG reduction strategies. It also directs the CEC to consider the cost-effectiveness of strategies to reduce GHGs from space and water heating. This assessment applies a similar definition of cost-effectiveness as the CARB *2017 Scoping Plan Update*, which is based on AB 32 (Núñez, Chapter 488, Statutes of 2006) and AB 197 (E. Garcia, Chapter 250, Statutes of 2016). Unlike common energy efficiency cost-effectiveness tests, cost-effectiveness defined in this assessment "means the relative cost per metric ton of various GHG reduction strategies, which is the traditional cost metric associated with emission control."[300] This evaluation excludes any additional estimations of the benefits (i.e., the valuation of the social cost of carbon, as well as, health, and other benefits) from potential emission and pollution abatement.

300 California's 2017 Climate Change Scoping Plan. California Air Resources Board. November 2017. Page 44 https://ww2.arb.ca.gov/sites/default/files/classic//cc/scopingplan/scoping_plan_2017.pdf.

Estimates of the cost per metric ton must be interpreted carefully, particularly when comparing to other studies, since different assumptions can change the scope and magnitude of the evaluation. For example, the costs per metric ton estimates here *exclude* upstream methane abatement and avoided infrastructure costs upstream from a building. Most of the building decarbonization scenarios assume activities and technology replacement happening until 2030, while the GHG emission and cost impacts accrue beyond 2030 to 2045. As such, the dollar per ton cost estimates are reported and compared to a 2045-time horizon.

Table C-21 provides an overview of the avoided annual GHG emissions for 2030, cumulative avoided GHG emissions from 2020 to 2045, net cost to implement the strategy, and the cost per ton. The avoided annual GHG emissions for 2030 are reflected in **Figure C-25** and **Figure C-26** and demonstrate the effectiveness of building electrification. Since the current analysis examines each strategy independently, the results are not additive. As can be seen in **Figure C-25** and **Figure C-26**, the electrification scenarios (represented in green on the far right of the figure) have the most potential for not only achieving the 2030 40 percent systemwide emissions reduction target, but the additional building GHG reduction to achieve the state's 2045 carbon neutrality goals. As such, this evaluation places more focus on the electrification scenarios compared to the impact scenarios since they have the clearest pathway in achieving the 40 percent systemwide emissions target and California's mid-century climate goals.

The last column in **Table C-21** reports the estimates of the cost per metric ton of estimates reductions for each scenario to 2045. Scenario 1, incremental electric energy efficiency, has the lowest cost per metric ton, exemplifying the potential operational savings from energy efficiency. The renewable gas scenario has the highest cost per metric ton estimates. The electrification scenarios have estimated costs per metric ton ranging from $39 to $142. As expected, the deeper the penetration of electrification, the more GHG emissions avoidance.

The additional scenarios, Scenarios 12.b-d, depicts a sensitivity to Scenario 12.a that varies whether each replaced electric technology is assumed to be the single-best efficient technology out of the mix of technologies that could be used for replacement and whether SB 1383 succeeds. It can be seen in **Table C-21** that this additional assumption for Scenario 12.b increases the GHG reduction impact in 2030 by 1.0 $MMTCO_2e$ and 2045 cumulative GHG reductions by 10.9 $MMTCO_2e$. Since CEC Staff has no data on the cost consequences or 2045 implications of SB 1383 succeeding, those values are not assessed.

Table C-21: Costs and Avoided Emissions by Selected Scenario

Scenario	Avoided annual GHG emissions in 2030 (MMTCO2e)	Cumulative Avoided GHG emissions 2020-2045 (MMTCO2e)	Total discounted net costs (Million 2020 $)	Discounted costs per avoided GHG emissions ($/tonne)
Scenario 1: Incremental Gas Energy Efficiency Savings	1.5	17.8	-1,415	-$79
Scenario 2: Incremental Electric Energy Efficiency Savings	1.8	14.7	-8,338	-$566
Scenario 3: Incremental Rooftop Photovoltaic	0.9	10.8	-1,715	-$159
Scenario 4.a: 15% Renewable Gas by 2030	4.9	23.2	8,114	$350
Scenario 4.b (called Scenario 4 in main report): 20% Renewable Gas by 2030 - Low Cost Synthetic Gas Starting in 2026	6.5	28.1	9,634	$343
Scenario 4.c: 20% Renewable Gas by 2030 - High Cost Synthetic Gas Starting in 2026	6.5	28.1	11,284	$402
Scenario 5: Accelerated Renewable Electric Generation Resources	3.6	n.a.	n.a.	n.a.
Scenario 6.a ("minimal electrification" scenario in main report): 100% New Construction, 15% Replace on Burnout, 5% Early Retirement, no panel upgrades	7.0	74.2	2,880	$39
Scenario 7: 100% New Construction, 35% Replace on Burnout, 5% Early Retirement, no panel upgrades	9.1	108.1	4,780	$44
Scenario 8 ("moderate electrification" scenario in main report): 100% New Construction, 50% Replace on Burnout, 5% Early Retirement	10.8	133.5	6,236	$47

Scenario	Avoided annual GHG emissions in 2030 (MMTCO2e)	Cumulative Avoided GHG emissions 2020-2045 (MMTCO2e)	Total discounted net costs (Million 2020 $)	Discounted costs per avoided GHG emissions ($/tonne)
Scenario 9: 100% New Construction, 75% Replace on Burnout, 5% Early Retirement	13.2	172.1	10,531	$61
Scenario 10: 100% New Construction, 90% Replace on Burnout, 5% Early Retirement	14.4	195.1	13,175	$68
Scenario 11: 100% New Construction, 90% Replace on Burnout, 35% Early Retirement	17.3	231.3	24,720	$107
Scenario 12.a ("aggressive electrification" scenario in main report): 100% New Construction, 90% Replace on Burnout, 70% Early Retirement	18.9	270.4	37,862	$140
Scenario 12.b ("efficient aggressive electrification" in main report): 100% New Construction, 90% Replace on Burnout, 70% Early Retirement (single-best efficient technology)	19.9	281.2	39,947	$142
Scenario 12.c: 100% New Construction, 90% Replace on Burnout, 70% Early Retirement; SB 1383 Target Met	26.4	n.a.	n.a.	n.a.
Scenario 12.d: 100% New Construction, 90% Replace on Burnout, 70% Early Retirement (single-best efficient technology); SB 1383 Target Met	27.4	n.a.	n.a.	n.a.

Note: The GHG emission and costs impacts for Scenario 6.b were not assessed. As stated in the renewable gas section, the

cumulative emission reductions and costs occurring beyond 2030 were not assessed for the renewable gas scenarios.

Source: CEC staff

Cost assumptions

Most of the cost assumptions used for this analysis are based on those assumed in the CARB 2017 Scoping Plan. For example, and as described in the main text, all costs are discounted at a 10 percent real discount rate. The PATHWAYS documentation that supports the CARB 2017 Scoping Plan cites that a 10 percent discount rate "roughly reflects the historical average of real credit card interest rates [for households]."[301] It also states that 10 percent roughly approximates an average pretax return on investment for the commercial sector. The discount rate is supposed to reflect the opportunity costs of capital to firms and households.

An annual inflation rate of 2 percent is assumed, which is used to adjust all input costs to the same base dollar year of 2020. Guidehouse told CEC staff that a 2 percent annual inflation rate is a standard assumption. CEC Staff consulted with CARB and CPUC staff regarding these levels of the real discount rate and inflation rate and the other agencies found them acceptable. Future work could vary the inflation rate or real discount rate to perform sensitivity analysis. This analysis did not discount the emissions.

These costs include the annualized incremental technology costs over the life of the equipment and the operational fuel costs (or savings) of using the equipment. The total costs are discounted using a 10 percent discount rate, which is the same rate used in the *2017 Scoping Plan Update* and reflects the opportunity cost of capital to firms and households. Since costs occur across the 2045-time frame, this discounting of costs allows for a common apples-to-apples metric, the present value, which is used to compare costs across measures. Similar to the PATHWAYS model, FSSAT applies a capital recovery factor to annualize capital costs, which is a function of the average expected useful life of the technology and the real discount rate, to the cumulative technology costs.[302] As such, costs are not incurred only in the first year but extend out beyond 2030.

As mentioned above, the assumptions required an analysis out to a 2045-time horizon since the costs from electrification occurring in 2020-2030 are spread out beyond 2030, and emission abatement continues during an equipment's lifetime. As such, truncating the costs and emissions abatement at 2030 with the given assumptions would have provided a distorted perspective of the dollar per metric ton estimates. By reporting a costs and emissions out to a

301 California PATHWAYS Model Framework and Methods (Model version: 2.4). Energy and Environmental Economics, Inc. January 2017. Pages 28 & 42. https://ww3.arb.ca.gov/cc/scopingplan/2030sp_appd_pathways_final.pdf.

302 See Equation 16 on page 103 and Equation 18 page 116 in Sathe (2020). Sathe, Amul Sathe (Guidehouse), Karen Maoz (Guidehouse), John Aquino (Guidehouse), Abhijeet Pande (TRC), and Floyd Keneipp (Tierra Resource Consultants). 2020. Fuel Substitution Reporting Tools. California Energy Commission. Publication Number: CEC-200-2020-001.

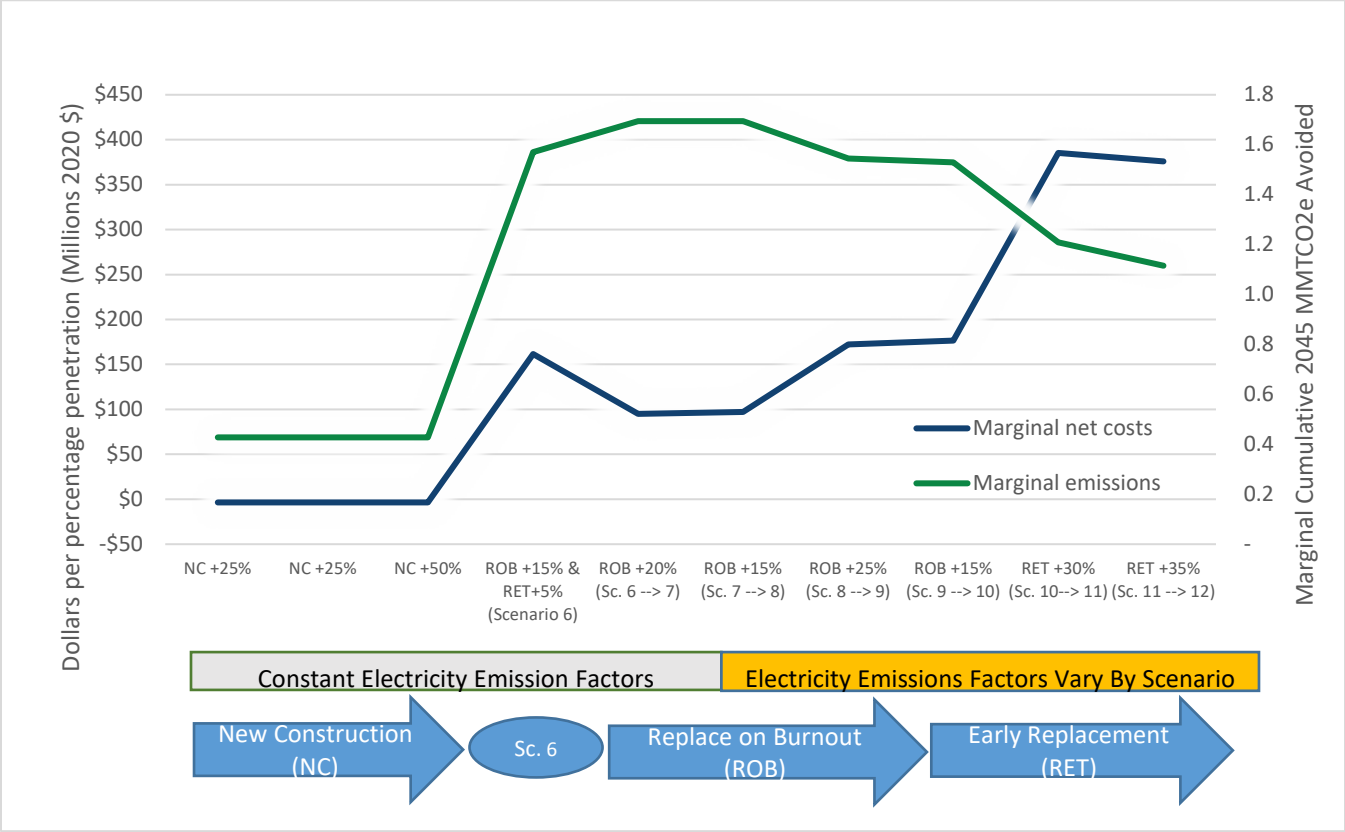
2045-time horizon allows for a more useful metric when comparing other cumulative dollar per ton estimates. Unlike the other scenarios that have fixed technologies that provide emission abatement over time, the renewable gas scenarios require continued operational expenses to maintain their displacement of gas and emissions mitigation. As such, to be consistent with the other scenarios, CEC staff estimated the costs of activities occurring within a 2030-time horizon.

Cost impacts from different penetration rates of electrification

Figure C-46 exhibits what happens to costs and emissions as the penetration of building end-use electrification programs increases. CEC staff assumes that the order of priority of the type of electrification penetration is new construction (NC), replace on burnout (ROB), and early replacement (RET). Interpreting the marginal values is interpreted as the change in total net costs that comes from a one percentage increase in either NC, ROB, or RET. As such, **Figure C-46** helps show the marginal impacts of each scenario since each scenario with the exception of Scenario 6, increases the percentage penetration of either ROB or RET (e.g., "Sc. 8 → Sc. 6" reports the marginal impact of increasing ROB by 25 percent compared to Scenario 8, which assumes NC, ROB, and RET at 100 percent, 50 percent, and 5 percent). CEC staff assumes that a non-zero amount of early retirement will occur and thus is included in Scenario 6, the lowest penetrating electrification scenario. Thus, the interpretation of the marginal values for Scenario 6 is not the same as the other levels since both RET and ROB increase at the same time. As can be seen at the bottom of the figure, the electric generation emission factors vary by scenario. The emission factors for the lower levels of electrification penetration are held constant for tractability purposes and will likely be updated in forthcoming updates to the FSSAT analysis.

Figure C-46 depicts several fundamental principles of FSSAT and the potential of electrification. Marginal net costs increase as electrification increases, illustrating the relative expense of replace on burnout and early retirement strategies. As shown in the figure, FSSAT estimates negative marginal costs of new construction (-$3.5 million per New Construction percentage increase) but at lower marginal emissions abatement compared to the other replacement strategies. Driven by the varying electricity emission factors, the marginal emissions avoided decrease as electrification penetration increases

Figure C-46: Marginal emissions and net costs of varying rates of electrification rates penetration of NC/ROB/RET in FSSAT over a 2045 time horizon



Note: "Scenario 12" refers to Scenario 12.a.
Source: CEC staff

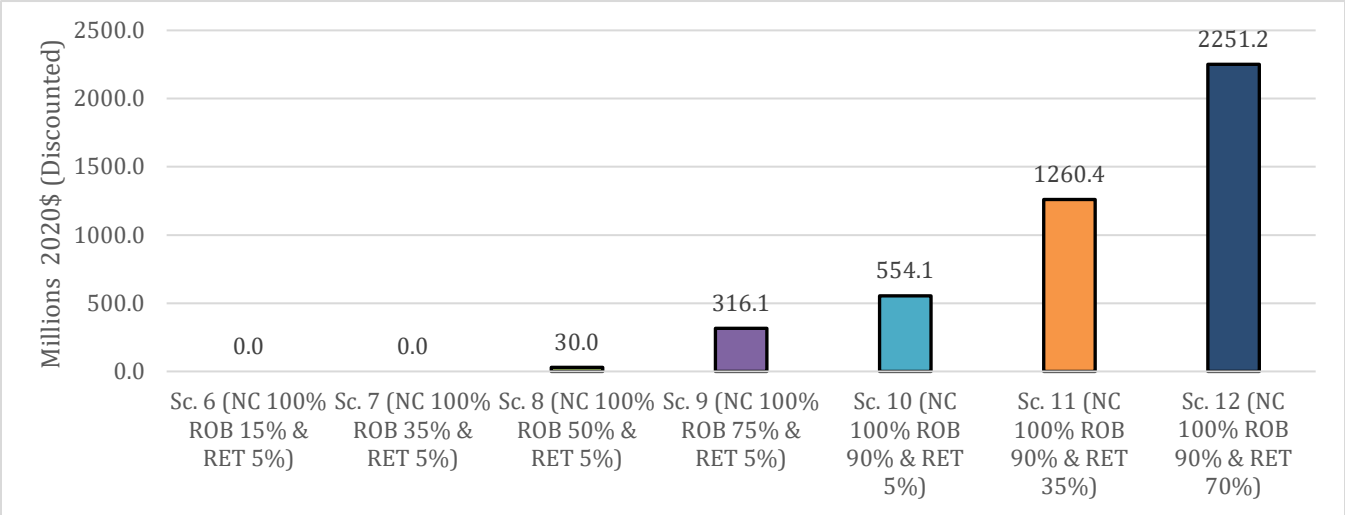
Please refer to the FSSAT methodology report and materials shared in the docket to understand the data and methodology used for estimating costs and emissions reductions.[303] CEC staff shared a workbook for the June 9th workshop which describes the cost assumptions by technology type for FSSAT.

Scenario 8 is the first scenario in which panel upgrade costs are triggered. This can be seen in **Figure C-46** at "Sc 7→8" marginal net costs slightly increase because of the need for panel upgrade costs. The magnitude of these marginal impacts increases since the costs for panel costs upgrades increase at an increasing rate. For example, **Figure C-47** shows the discounted costs for panel costs upgrades by scenario where these costs range from $30 million to $2.3 billion which adds less than $1 to $9 to the cost per metric ton for an entire scenario. As can be seen in the figure, marginal costs from increasing penetration rates of electrification increase at an increasing rate. Note that a lack of primary data exists that detail the number of buildings that require a panel upgrade in California. FSSAT approximates

303 Sathe, Amul Sathe (Guidehouse), Karen Maoz (Guidehouse), John Aquino (Guidehouse), Abhijeet Pande (TRC), and Floyd Keneipp (Tierra Resource Consultants). 2020. Fuel Substitution Reporting Tools. California Energy Commission. Publication Number: CEC- 200-2020-001.

aggregate panel upgrade costs by using the percentage of gas removed due to electrification as an indicator to estimate when a panel upgrade is required.

Figure C-47: Electrical Panel Upgrade Costs by Scenario (Discounted 2020 $)



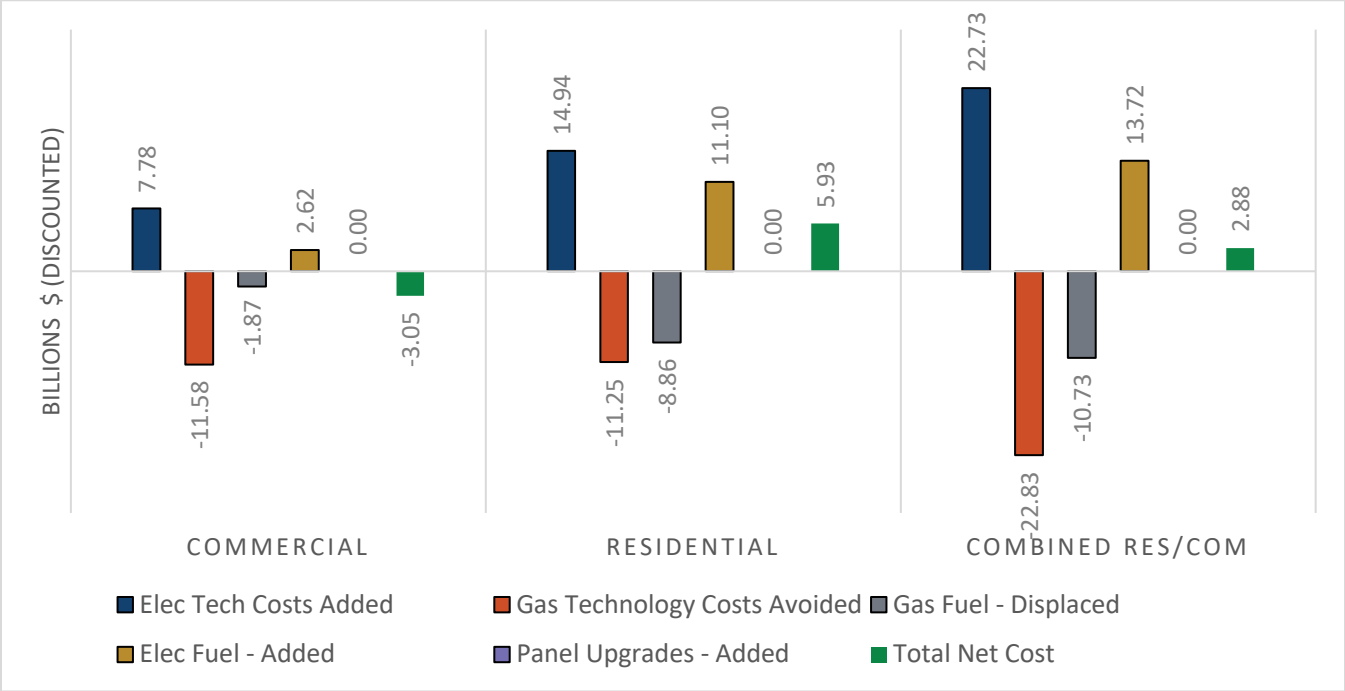
Note: Scenario 12 refers to Scenario 12.a.and 12.b.
Source: CEC staff

Cost disaggregation of electrification scenarios

The cost components of the electrification scenarios are shown by incremental technology and net fuel cost compared to gas use. As mentioned above, ancillary costs, like electrical panel upgrades, are also calculated in FSSAT. **Figure C- 48** and **Figure C- 49** illustrate the disaggregated cumulative total net cost by sector for Scenario 6 and Scenario 12.a-d, the lowest and highest electrification scenarios. The incremental technology costs are represented by the first two bars for a sector, where the blue bar represents the electric technology cost added and the orange bar represents the avoided gas technology costs. The equipment, installation, and contractor overhead and profit costs represent the total added electric technology costs. Avoided gas technology costs are broken down by labor and technology costs, which also includes avoided air conditioner costs for certain types of replacements. These costs exclude any avoided infrastructure costs.

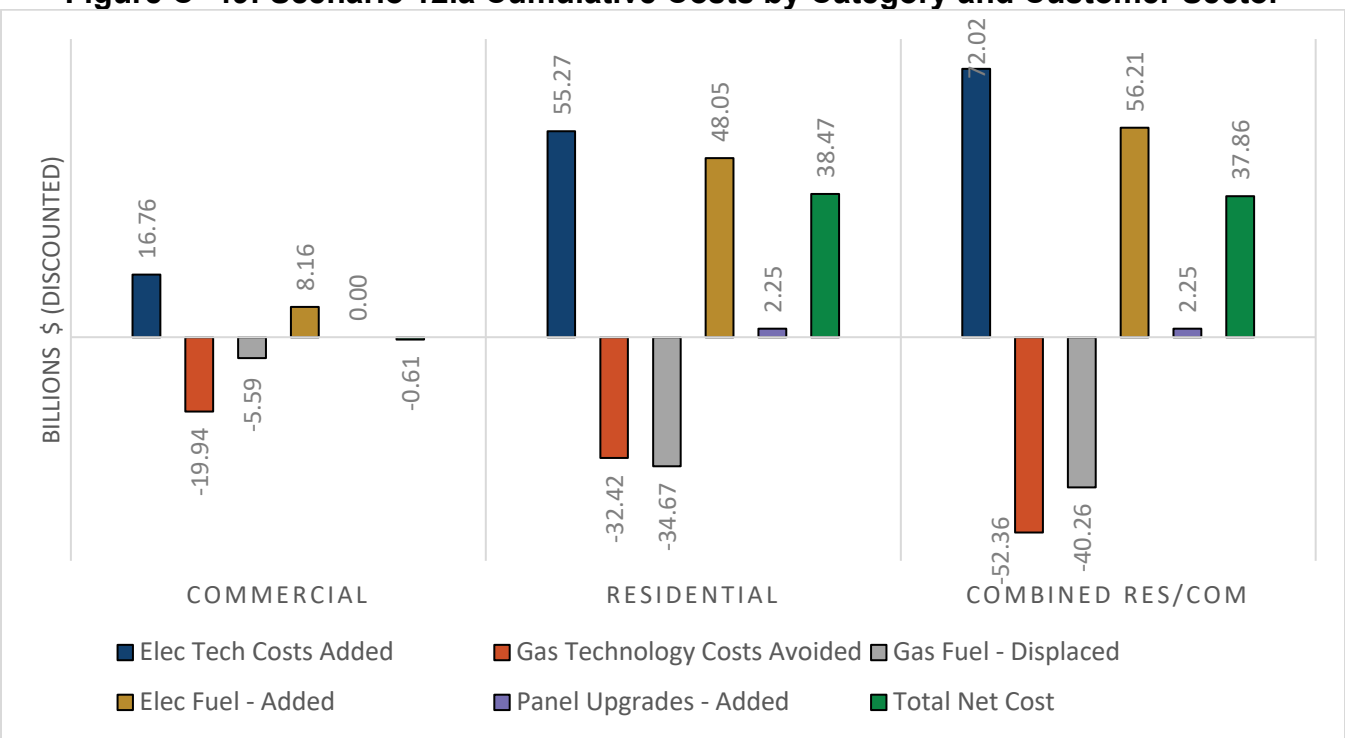
As can be seen for the combined residential and commercial sector bars on the right of the figures, the incremental technology costs for Scenario 6 and Scenario 12.a are negative $100 million and $19.66 billion. The grey and gold bars represent the displaced gas fuel costs and the electric fuel costs of using the equipment. Together, they represent the net operational fuel costs, which depend on the efficiency of the equipment and the input forecast of rates for electricity and gas. For Scenario 6 and Scenario 12.a, the net operational costs total $2.99 billion and $16.95 billion. Taken together the net total costs for Scenario 6 and Scenario 12 are $2.88 billion and $37.88 billion.

Figure C- 48: Scenario 6.a Cumulative Costs by Category and Customer Sector



Source: CEC Staff

Figure C- 49: Scenario 12.a Cumulative Costs by Category and Customer Sector

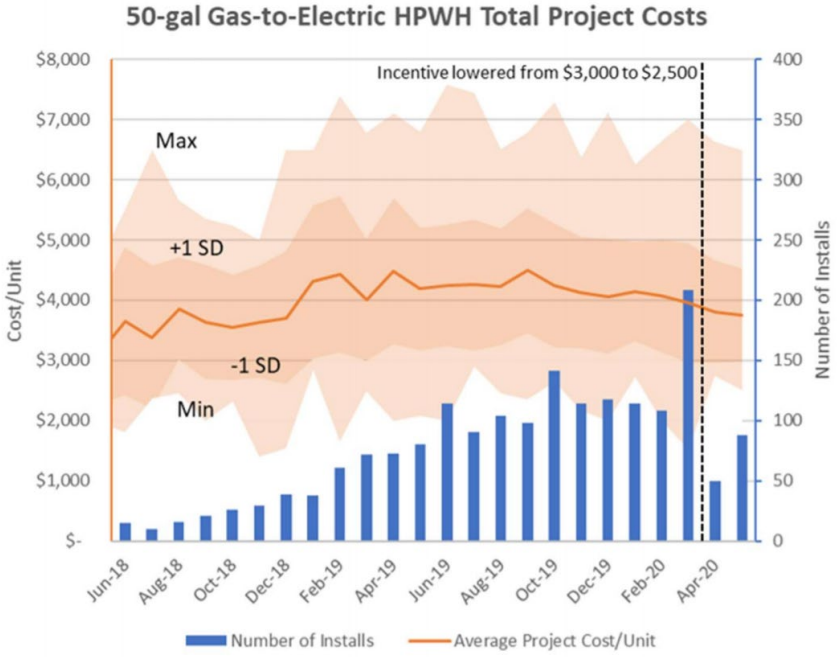


Source: CEC Staff

In September 2020, SMUD submitted to the docket their program-wide aggregated average costs for their heat pump water heater and space heating heat pump programs that the utility has been running since 2018 and 2019. These costs are comparable to what CEC staff are

assuming for retrofit costs in the FSSAT. For example, the average gas-to-electric 50-gallon heat pump water heater project costs is $4,155 per unit (See **Figure C-50**), which is comparable to what to the input assumptions for the FSSAT analysis.[304]

Figure C-50: SMUD Monthly Heat Pump Water Heater Installs and Project Costs



Source: Sacramento Municipal Utility District. Sacramento Municipal Utility District Comments – SMUD Residential Electrification Project Costs (September 2020). TN# 234862. Docket Number 19-DECARB-01. September 22, 2020. Figure 1 (page 4)

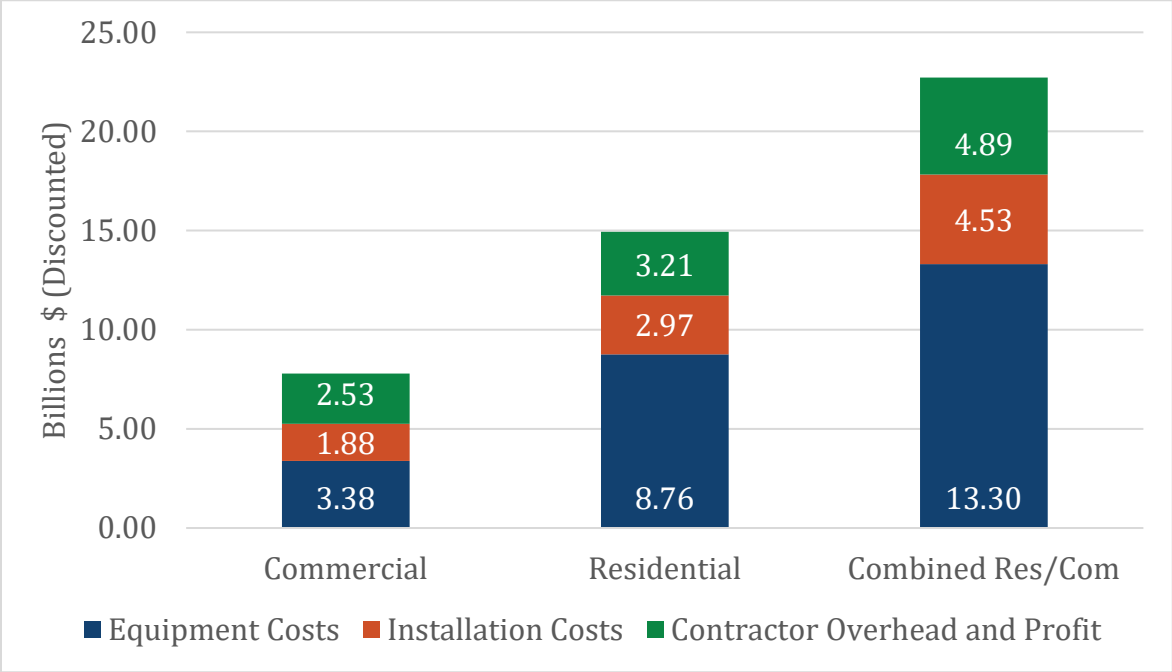
Market transformation and potential electrification cost reductions

Comments from stakeholders for the June 9, 2020 CEC workshop discussed how market transformation efforts could influence total net costs and how the aggregated effects from electrification can influence electric and gas rates.[305] Comments from the Resources Defense Council argue for the strong need to incorporate market transformation of clean energy technologies into the cost estimation. The FSSAT currently cannot model such transformation, but using the disaggregated costs figures of different electrification scenarios (see **Figure C-48** and **Figure C- 49** above), staff produced a post-processing estimation of impacts from electric technology equipment cost reductions of 20 and 30 percent.

Figure C-51: Added Electric Technology Costs by Cost Component for Scenario 6

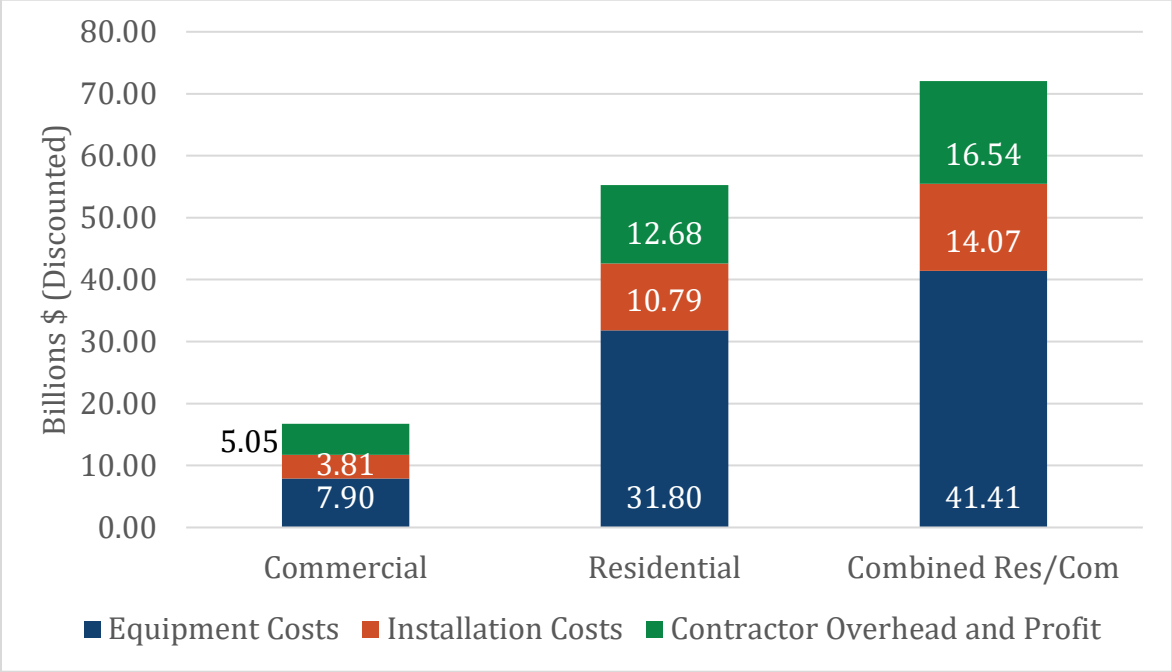
304 Sacramento Municipal Utility District Comments – SMUD Residential Electrification Project Costs (September 22, 2020). Docket Number 19-DECARB-01, September 22, 2020. https://efiling.energy.ca.gov/GetDocument.aspx?tn=234862&DocumentContentId=67717.

305 September NRDC comment submitted to the docket: https://efiling.energy.ca.gov/GetDocument.aspx?tn=234687&DocumentContentId=67539.



Source: CEC Staff

Figure C-52: Added Electric Technology Costs by Cost Component for Scenario 12.a



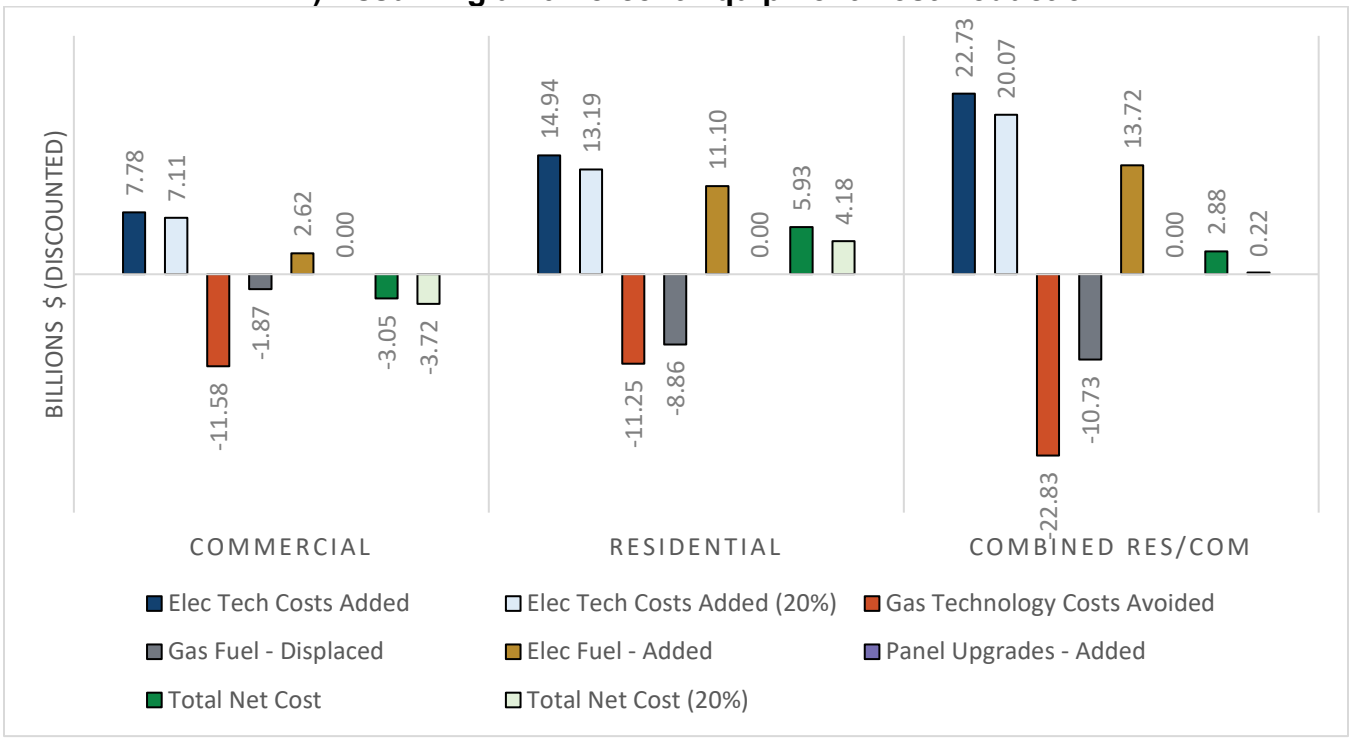
Source: CEC Staff

Figure C-51 and Figure C-52 illustrate the added electric technology costs (as reported as ""Elec Tech Costs Added" in Figure C- 48 and Figure C- 49) broken down by equipment, installation, and contractor profit and overhead costs for Scenarios 6 and 12.a. Staff adjusted the equipment costs by different percentages to emulate the market transformation analysis. Figure C-53 and Figure C-54 show the impacts to Scenario 6 from a 20 and 30 percent

reduction. Figure C-55 and Figure C-56 show the impacts for Scenario 12.a. By decreasing the added electric technology costs, the incremental technology costs drop lower, driving total net costs and dollar per ton estimates down. Investigating the impacts of different cost reduction rates can easily be done with the data provided in the figures.

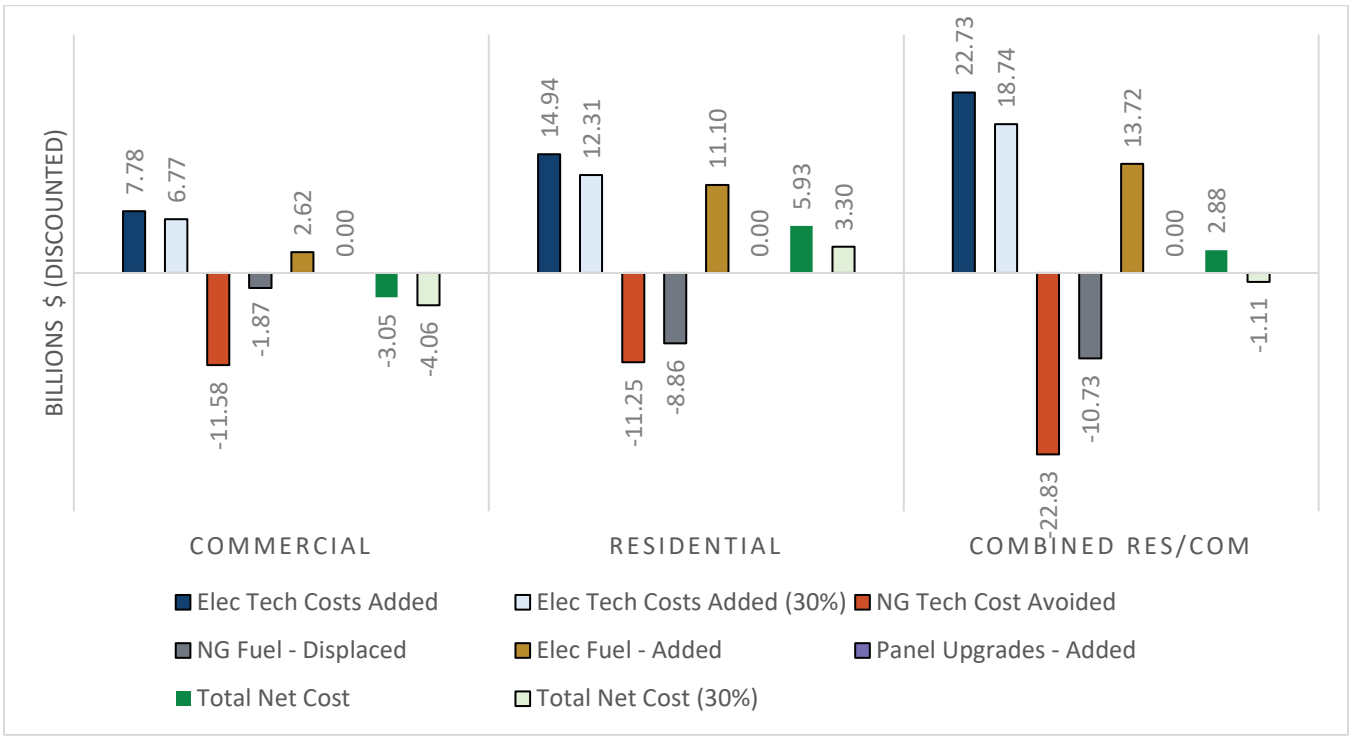
As can be seen in the figures, market transformation of 30 percent reduction drives costs to become negative for scenario 6 while bringing them down to $25.44 billion (compared to $37.86 billion for scenario 12.a. Such dynamic market transformation efforts could significantly affect the cost per metric ton estimates for a scenario or technology. However, despite the goal of lower technology costs through time, great uncertainties likely exist regarding the costs and performance in the field of such lower-cost technologies. As mentioned in the next steps section, staff intends to add a market transformation mechanism when modeling electrification in FSSAT for the next IEPR cycle.

Figure C-53: Market Transformation Impacts to Scenario 6 (100% NC, 15% ROB, 5% RET) Assuming a 20 Percent Equipment Cost Reduction



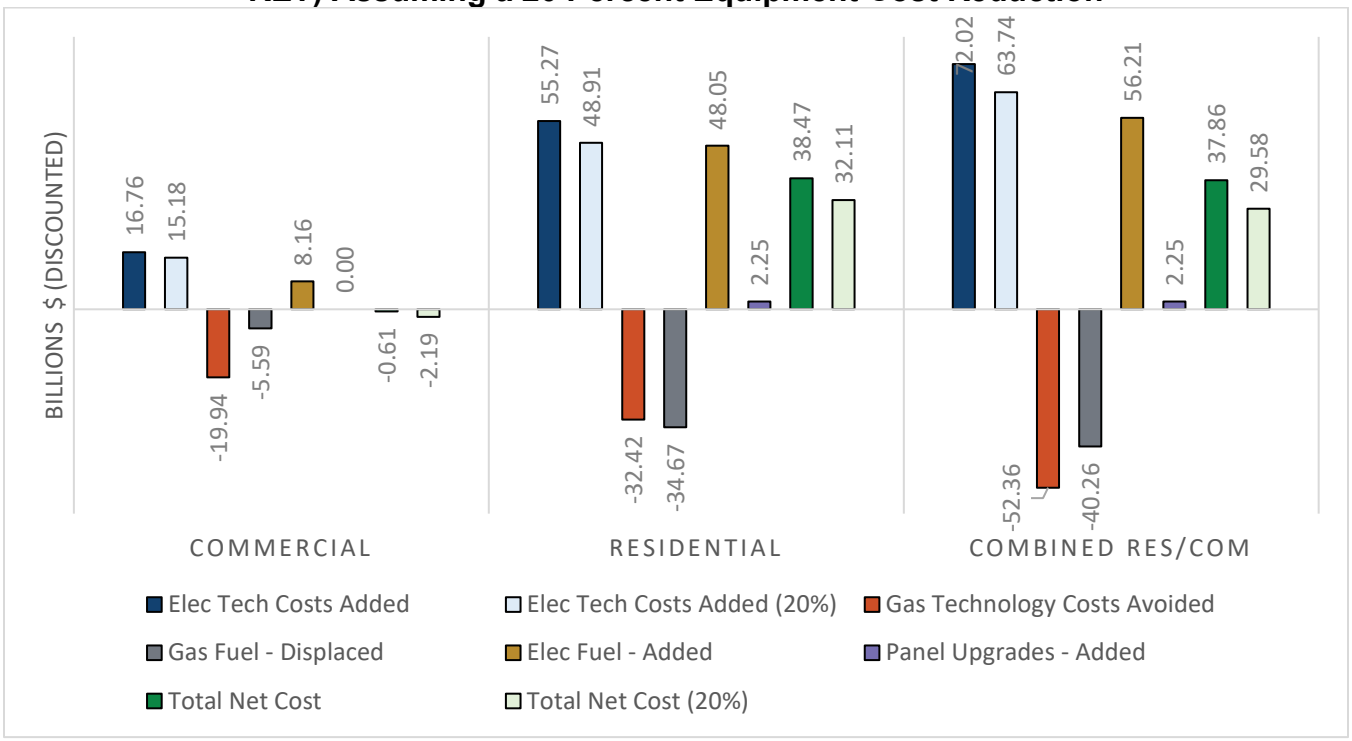
Source: CEC Staff

Figure C-54: Market Transformation Impacts to Scenario 6 (100% NC, 15% ROB, 5% RET) Assuming a 30 Percent Equipment Cost Reduction



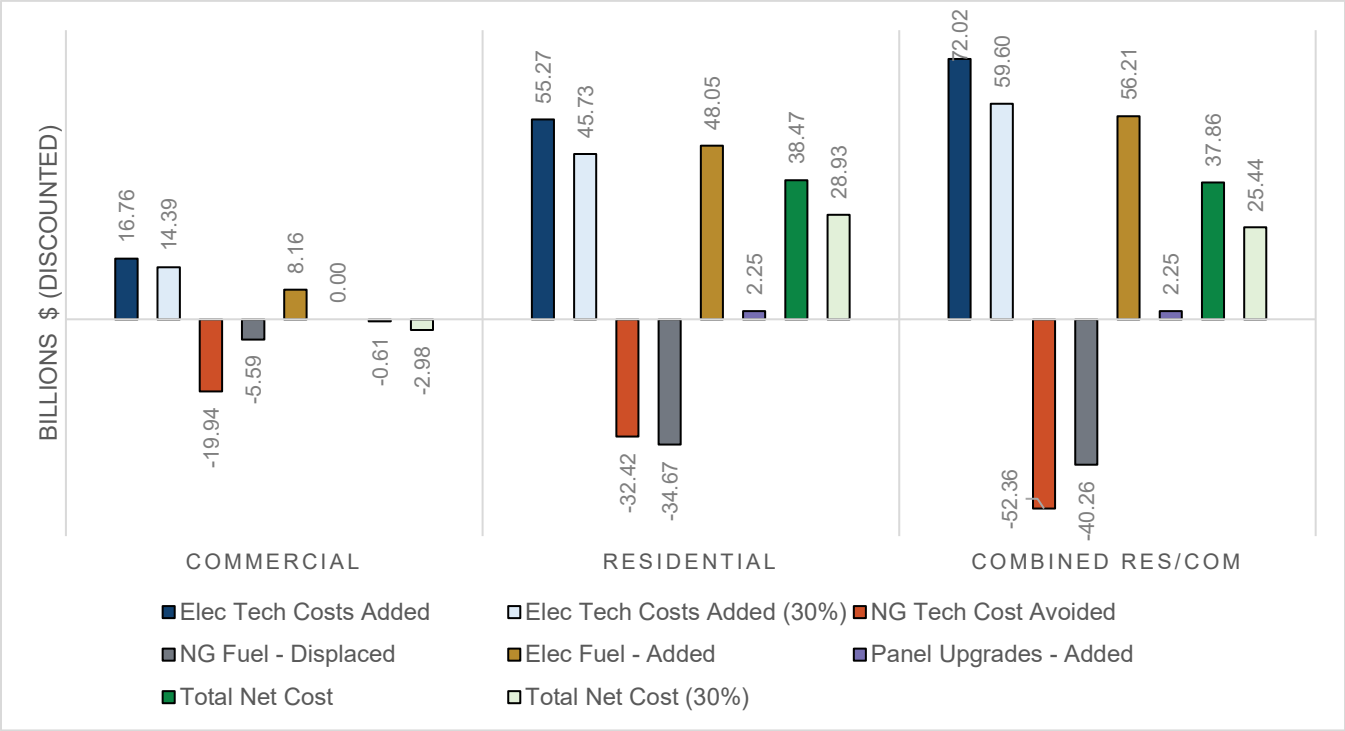
Source: CEC Staff

Figure C-55: Market Transformation Impacts to Scenario 12.a (100% NC, 90% ROB, 70% RET) Assuming a 20 Percent Equipment Cost Reduction



Source: CEC Staff

Figure C-56: Market Transformation Impacts to Scenario 12.a (100% NC, 90% ROB, 70% RET) Assuming a 30 Percent Equipment Cost Reduction



Source: CEC Staff

Marginal Cost of Carbon Reduction

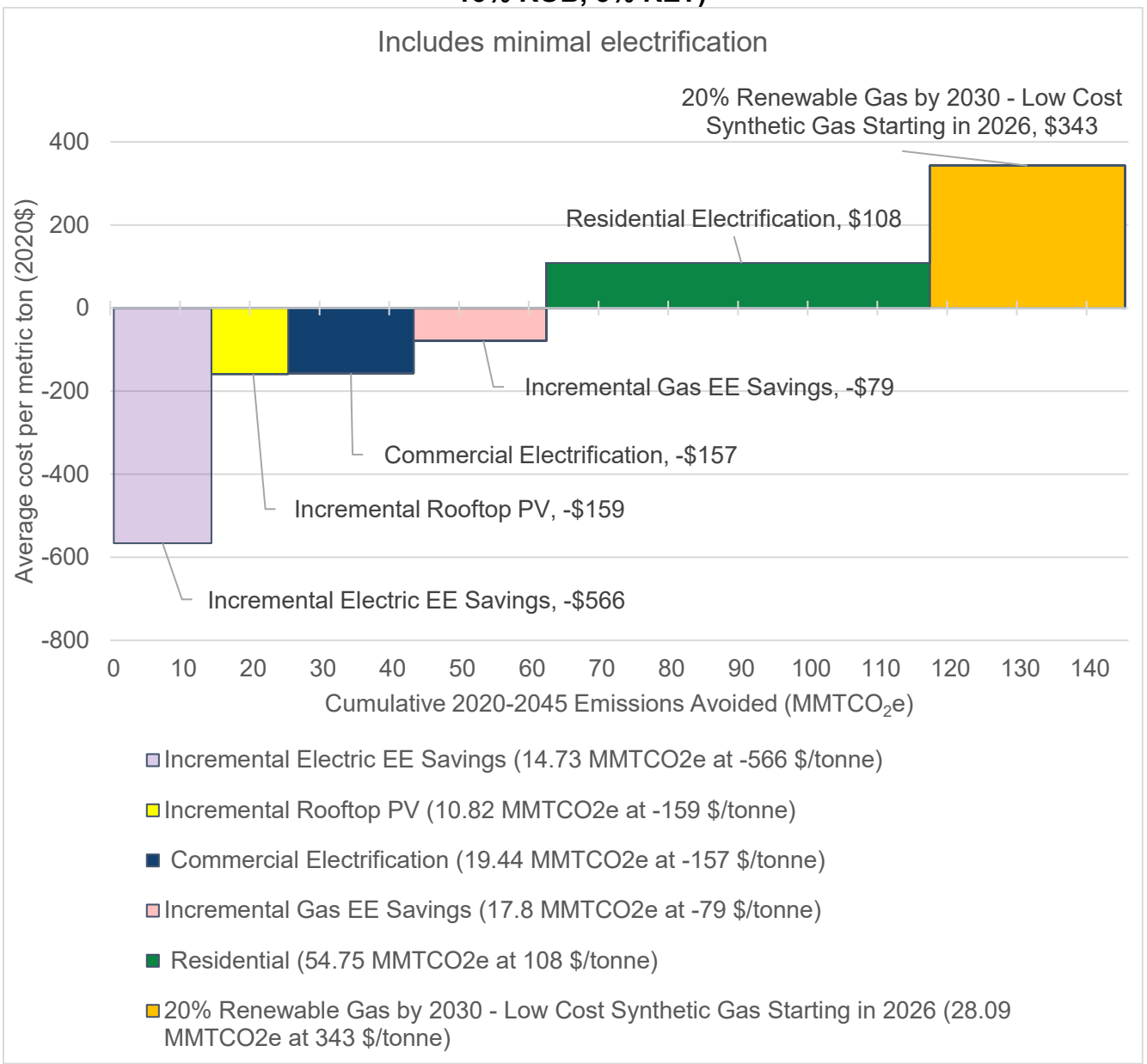
Marginal abatement cost curves (MAC curves) plot out the marginal costs of achieving a cumulative amount of emission abatement, in order from the least- to most-expensive scenario, measure, or technology. MAC curves show emission abatement potential and associated abatement costs but should be considered alongside other evidence when weighing the merits of numerous climate change mitigation strategies. As such, one of the few disclaimers when interpreting the building decarbonization MAC curves is that because many of the scenarios interact with each other, isolating the cost and GHG savings of individual scenarios and measures is challenging. Since all scenarios were derived independently from one another, the uncertainty of knowing the interactive effects from combining strategies should give caution when estimating total cost and GHG reduction potential for designing an optimal decarbonization strategy.

Figure C- 57 and **Figure C-58** report the aggregated MAC curves for Scenario 6 and Scenario 12.a, the core bookends for electrification penetration. They also include the other building decarbonization scenarios and provide several insights:

- The combined GHG reduction potential of electrification from both sectors are either competitive or significantly outweigh the combined GHG reduction potential from all but the electrification scenarios.
- The highest GHG reduction potential is electrification occurring in the residential sector.

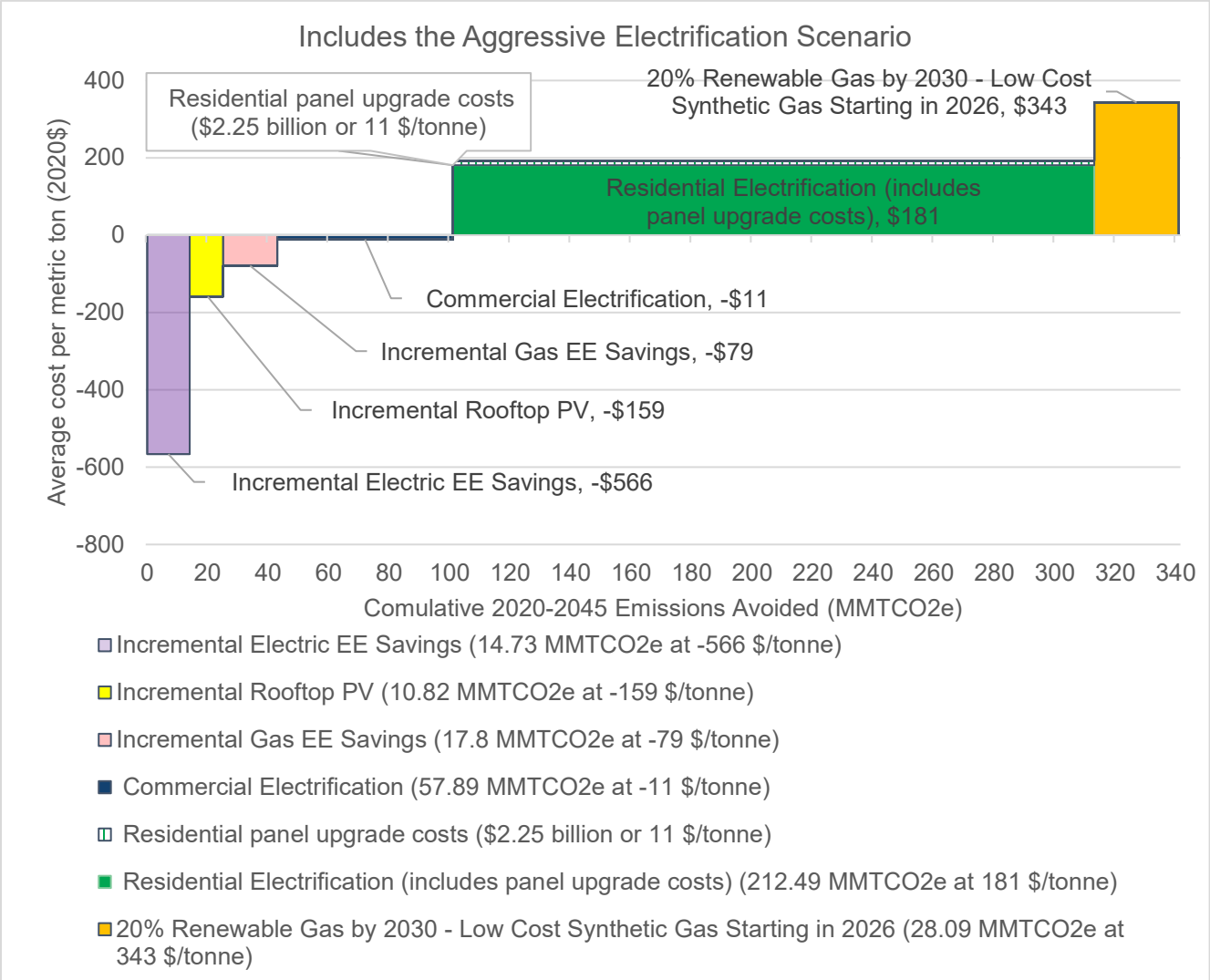
- The abatement costs for electrification in the commercial sector are negative and are even more negative than the incremental gas energy efficiency scenario (Scenario 1) for Scenario 6.
- The marginal abatement costs for each sector increase as electrification penetration increases.
- Incremental electric energy efficiency is the most cost-effective scenario while Scenario 4b (20 percent renewable gas penetration by 2030 – low cost synthetic gas starting in 2026) is the least cost-effective scenario.

Figure C- 57: Aggregated Marginal Abatement Cost Curve Using Scenario 6.a (100% NC, 15% ROB, 5% RET)



Source: CEC Staff

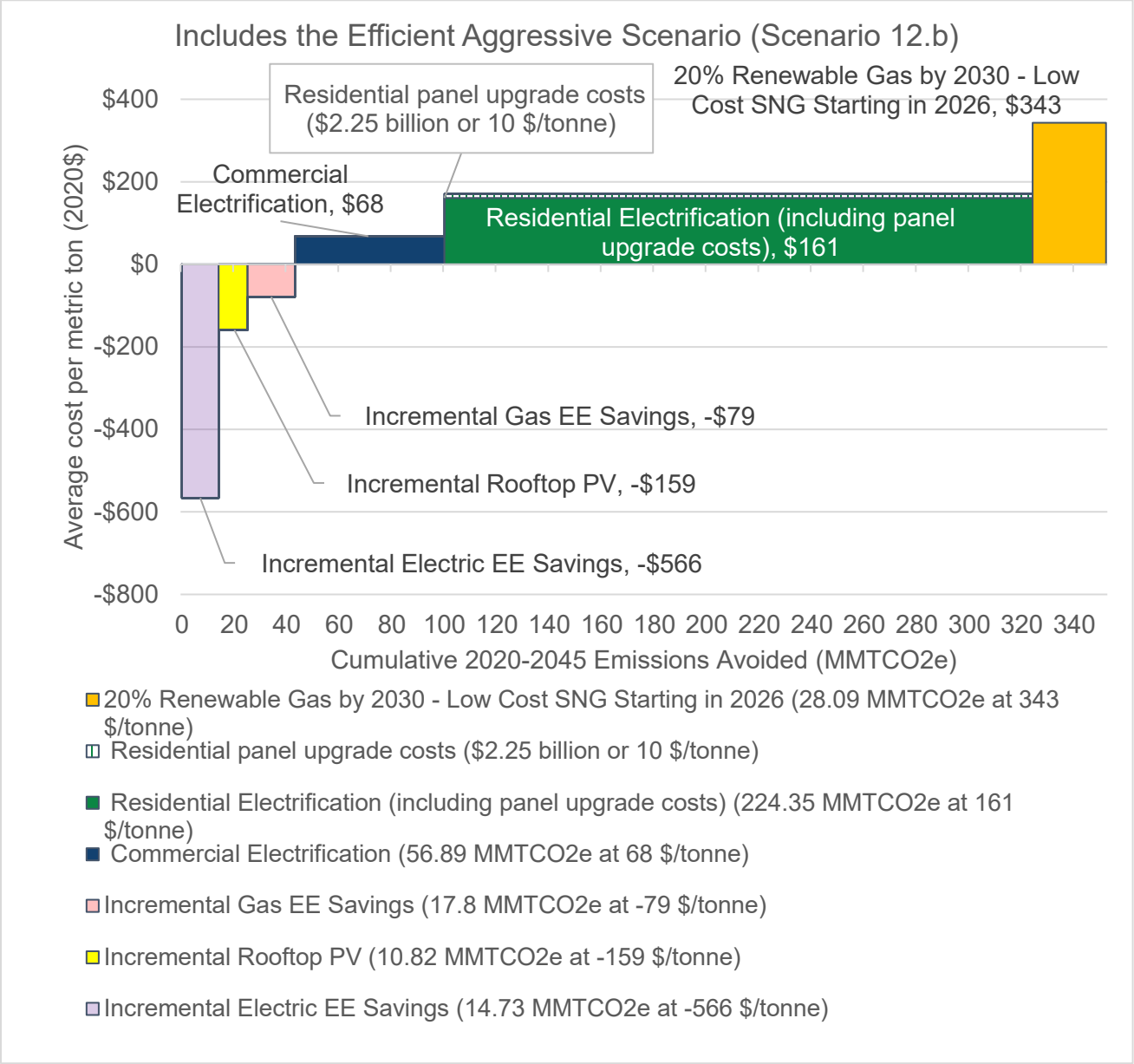
Figure C-58: Aggregated Marginal Abatement Cost Curve Using Scenario 12.a (100% NC, 90% ROB, 70% RET)



Source: CEC staff

Figure C-59 presents the MAC curve for Scenario 12.b, which depicts the scenario 12.a but where only the single-best efficient electric technology is replaced. This slight change of assumptions decreases costs and increases GHG reduction potential for the residential sector, but the commercial sector has positive marginal abatement costs and less abatement potential.

Figure C-59: Aggregated Marginal Abatement Cost Curve Using Scenario 12.b (100% NC, 90% ROB, 70% RET and "Single-best Technology" Replacement)



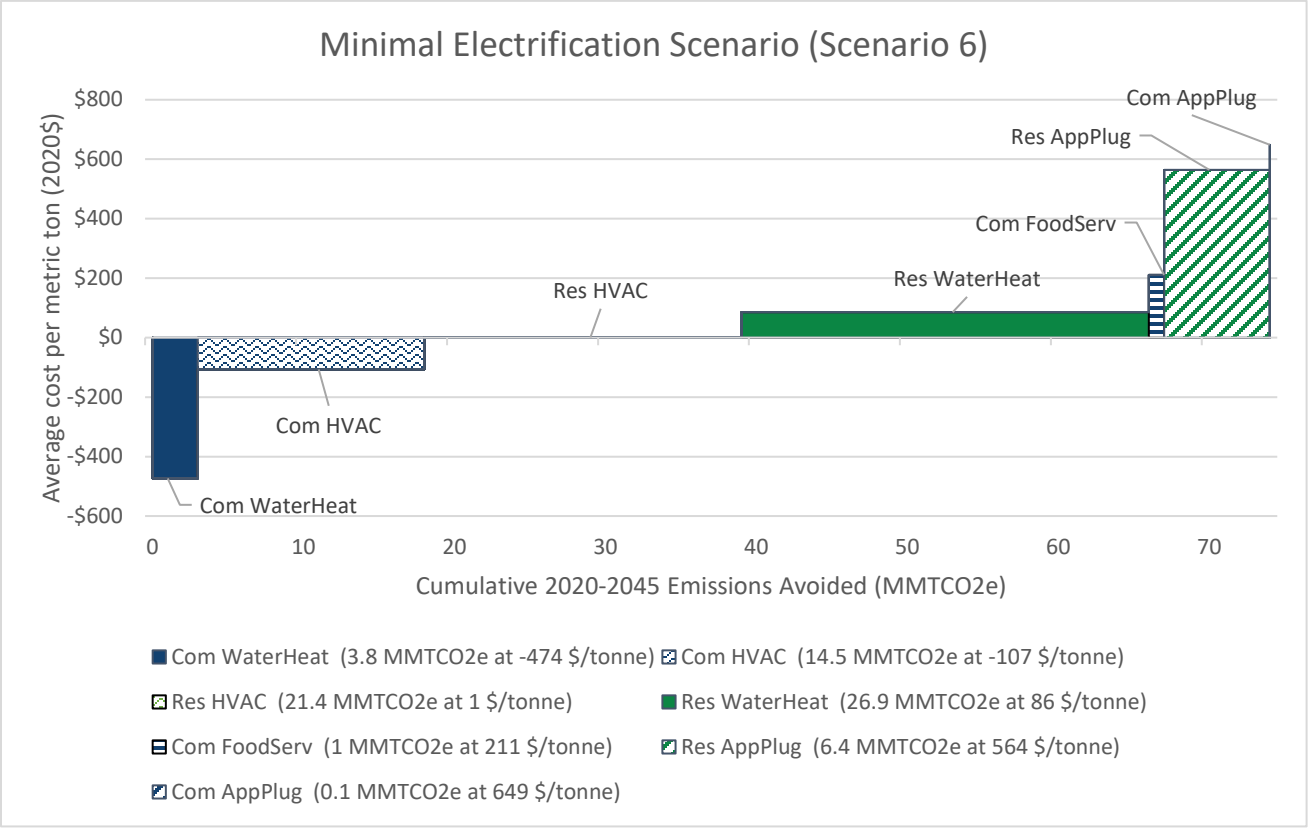
Source: CEC staff

Figure C-60 and **Figure C-61** further break down the electrification abatement potential by end use and shows the relative cost effectiveness of electrification by sector and end use for Scenario 6 and Scenario 12.a.[306] Since these costs include both new and existing residential

306 Electrical panel upgrade costs are estimated to not occur in Scenario 6 and do not affect dollar per ton estimates. However, since electric panel upgrade costs cannot be reported at the technology or end-use level, any dollar per ton estimates at this level of disaggregation would underreport the costs for scenarios that require electrical panel upgrades.

and commercial buildings, they can help assess the cost effectiveness of strategies that target space and water heating. As reported earlier in **Table C-21**, the estimated dollar per ton value for Scenario 6 is $39 per ton (i.e., the weighted average of dollar per ton estimates by end use, including electrical panel upgrade costs). Seeing the breakdown of a sector's GHG abatement potential by end use, as seen in Figure 17 provides several observations. First, commercial water heating is the most cost effective and its large negative dollar per ton estimate (-$474 to -231 per ton) helps explain why the entire commercial sector reported has a negative abatement cost estimate. Second, residential HVAC and water heating potential have the largest potential of GHG emission reduction and have varying costs, $1 to $96 for residential HVAC and $86 to $120 per ton for residential water heating. Third, electrification of residential and commercial appliance end uses (e.g., laundry and cooking) are estimated to be the least cost effective where their dollar per ton estimates are greater than $550 dollars per ton, which is an order of magnitude greater than other end use estimates. Note that CEC staff believes that the present technology replacement assumptions for the laundry and cooking end uses are aggressive and are likely driving up these costs.

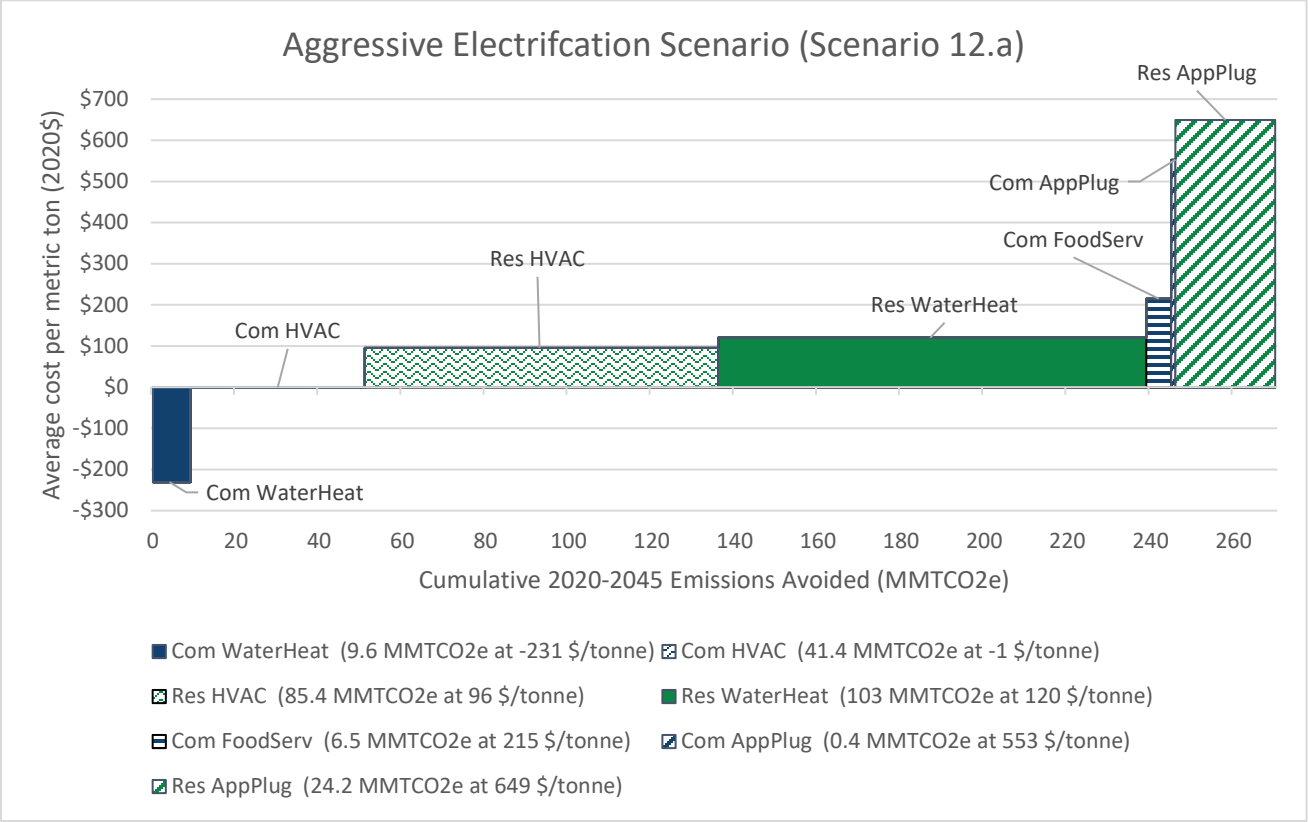
Figure C-60: Marginal Abatement Cost Curve by End Use for Scenario 6 (100% NC, 15% ROB, 5% RET)



Note: Does not include panel upgrade costs.

Source: CEC staff

Figure C-61: Marginal Abatement Cost Curve by End Use for Scenario 12.a (100% NC, 90% ROB, 70% RET)

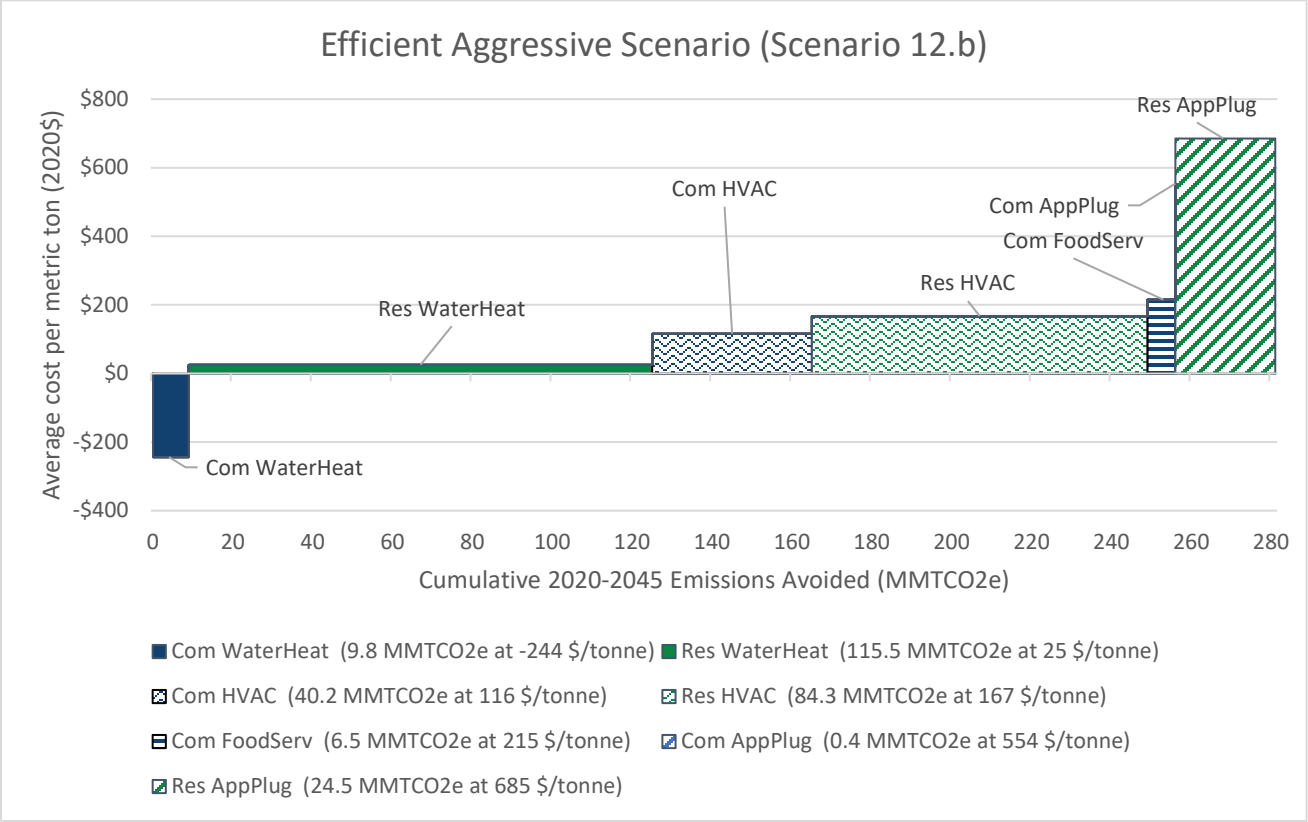


Note: Does not include panel upgrade costs.

Source: CEC staff

Figure C-62 presents the same end use curve but with the Scenario 12.b. Comparing the end use MAC curves for Scenarios 12.a and 12.b shows a noticeable difference in the abatement costs of residential water heating, where costs are considerably reduced from $120 to $25 per ton because of the improvement in energy efficiency. The increased abatement cost of other end uses can be attributed to the higher incremental technology costs since these technologies are more expensive relative to the other mix of technologies. However, as discussed above, this outcome highlights the importance of considering the affects from market transformation on abatement costs. Another observation of **Figure C-62** when comparing the end use costs when assuming the replacement of the most efficient technologies is that electrification of water heating technologies has dominant cost effectiveness compared to the other end uses.

Figure C-62: Marginal Abatement Cost Curve by End Use for Scenario 12.b (100% NC, 90% ROB, 70% RET and "Single-best Technology" Replacement)



Note: Does not include panel upgrade costs.

Source: CEC staff

Taken together, the summary of costs for each scenario, the aggregated MAC curves, and the MAC curves by sector and end provide the tools needed to help evaluate the cost effectiveness of building decarbonization. Many of the scenarios along with Scenarios 6 have cost per metric ton estimates of less than $50 per ton. The renewable gas impact scenarios have a much higher estimate, almost $350 per ton. By understanding the disaggregated cost per metric ton estimates at the end use or technology level can help state policy makers prioritize where to target electrification efforts and which pathways need more research and development to increase cost effectiveness.

Resource cost impacts, electricity cost impacts, and translating impacts to rates

This section discusses the work developed by SAO/EAD staff that examined the incremental resource cost assumptions, the electricity cost impacts, and the translation of cost impacts to consumer rates. All these cost impacts are currently not included in the final cost and cost-effectiveness calculations for each scenario.

Incremental Resource Cost Assumptions for AB 3232 Scenarios

The annual levelized fixed cost of incremental resources includes annualized capital investments to be recovered and fixed operations and maintenance (FO&M) costs. The standard assumptions for capital expenditures (CAPEX), weighted average cost of capital (WACC), tax rates, recovery periods, and fixed operations and maintenance costs are based on

the National Renewable Energy Laboratory (NREL) 2020 Annual Technology Baseline (ATB).[307] As financing assumptions for storage are not included in the NREL ATB, financing assumptions for storage were aligned with California Senate Bill 100 Inputs and Assumptions.[308] Regional multipliers based on the NREL Regional Energy Deployment System (ReDS) Model were used to adjust costs based on resource location.[309] Since the fixed costs for existing resources is not included in the 2019 IEPR Mid – Mid case model, only incremental costs compared to the base case were used for analysis. The 2030 total incremental fixed costs for each scenario are displayed in Table C-22.

Table C-22: 2030 Total Incremental Fixed Costs by Scenario (000's 2018 U.S. Dollars)

2030	Base	Scenario 2	Scenario 3	Scenario 5	Scenarios 6.a, 6.b, 7, 8	Scenario 9	Scenario 10	Scenarios 11, 12.b, 12.d	Scenarios 12.a, 12.c
thousands $	N/A	-2,260,628	-2,245,078	2,139,333	1,451,934	1,862,598	2,260,628	2,472,045	3,708,137

Source: CEC staff

Electricity Rate Impacts

Staff estimated the change in residential and commercial rates for two scenarios, 6.a and 12.a. Staff estimated this impact for three major categories of revenue requirements, procurement, transmission, and distribution, and compared the scenario rate to the 2019 IEPR mid-case electric rate scenarios.[310] These scenarios should be considered indicative of the possible direction and magnitude of impacts. Further grid planning studies are needed to quantify impacts on distribution, transmission and reliability needs more accurately. Also, these scenarios do not account for the potential benefits of load flexibility.

The incremental installed cost of generation resources described earlier represents the incremental fixed costs of each scenario for California as a whole. To estimate the impact on individual planning area electricity rates, staff calculated the change in procurement rates from the combined effects of changes in costs for energy and capacity. Staff used energy prices produced by the PLEXOS production cost model simulations discussed earlier. The model simulations produce an hourly cost of energy served by planning area, which accounts for the

307 National Renewable Energy Laboratory 2020 Annual Technology Baseline.

308 E3 - Energy and Environmental Economics, Inc., Inputs and Assumptions: CEC SB 100 Joint Agency Report (June 2020). TN# 234532. Docket Number 19-SB-100. August 31, 2020.

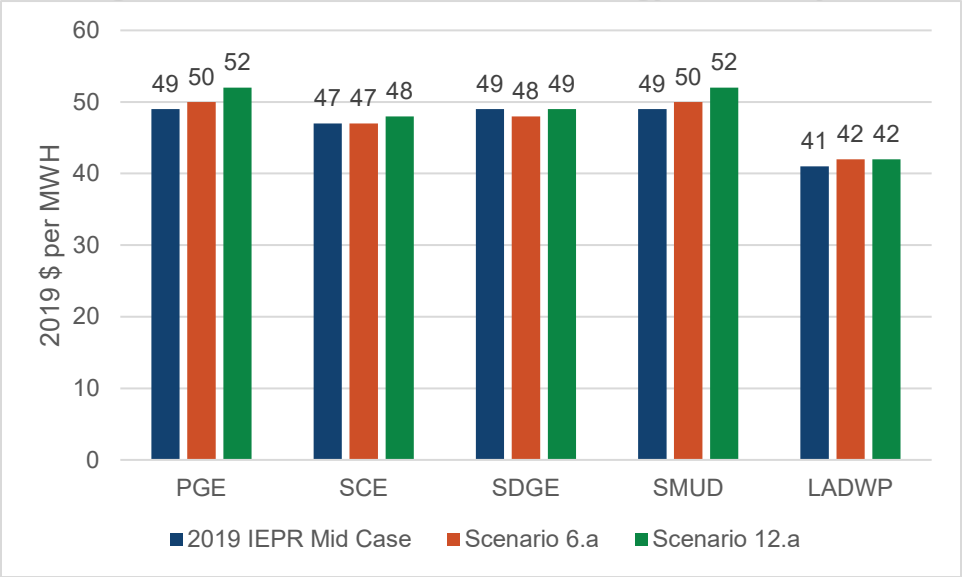
309 NREL Regional Energy Deployment System (ReEDS) Model Documentation: Version 2018.

310 CEC, California Energy Demand 2020-2030 Revised Forecast, https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report/2019-integrated-energy-policy-report/2019-iepr#accordion-4131, January 2020 ; Lynn Marshall, Electricity Rate Scenarios - Preliminary Inputs and Assumptions.

https://efiling.energy.ca.gov/GetDocument.aspx?tn=227215&DocumentContentId=58049.

cost of both energy and ancillary services. **Figure C-63** shows the load-weighted annual average price.

Figure C-63: Wholesale Cost of Energy Served by Planning Area, 2030 (2019$)



Source: CEC staff

Prices increase the most in high-electrification Scenario 12.a, about 6 percent in Northern California, and 4 percent in LADWP and SMUD, reflecting the increased use of higher marginal cost resources and imports. In low-electrification Scenario 6.a prices increase only about 2 percent.

Additional procurement cost recovery occurs though capacity prices. Assuming battery storage is the marginal resource added to meet growth in demand, one can estimate a capacity price as the levelized-installed cost less the resources' estimated energy and ancillary services margins, known as the net cost of new entry. The installed cost is also adjusted for the expected load carrying capability to determine the effective capacity the resource can provide. In analysis for the CPUC Avoided Cost Calculator (ACC), the avoided capacity cost of new 4-hour battery storage was estimated to decline from $190 in 2020 to $60 per MW in 2030 (2019$).[311] While the ACC uses comparable installed costs as this study, the amount of storage modeled is less than the scenarios here. As more storage is added to the system, both the load-carrying capability and opportunity to earn energy and ancillary services revenues may decline, increasing the needed capacity payment. For this analysis, staff used the 2020 capacity price of $55.08[312] escalated 2.5 percent annually. This yields a 2030 price of $65 per

311 CPUC 2020 Avoided Cost Calculator Update, https://www.cpuc.ca.gov/general.aspx?id=5267.

312 SCE, Updated Testimony Energy Resource Recovery Account (ERRA) 2020 Forecast of Operations, November 8, 2019.

MW (2019$), $5 higher than the ACC result. Reliability studies of electrification scenarios could provide insight into changes in resource load-carrying capability and revenue opportunity as electrification increases.

While higher energy and capacity prices contribute to higher costs for new resources than in the base case, the growth in load also has the effect of diluting the per-unit cost of any above-market resources in a utilities' portfolio. While a utility with a low-cost portfolio will likely need to increase procurement charges, net procurement rates decrease for utilities with more expensive resources.

The significant increases in demand caused by building decarbonization may necessitate additional investment in distribution and transmission infrastructure compared to what is already planned to serve the base case load forecast.

Distribution revenue requirements comprise 40-45 percent of rates and cover the costs of connecting customers and investing, operating, and maintaining infrastructure including poles, wires, and substations. The base case distribution revenue requirement forecast also accounts for recent efforts to reduce wildfire risk such as vegetation management, grid hardening, and emergency preparation. They also reflect ongoing investment by utilities in safety and grid modernization to enhance DER integration. Only a portion of these costs will increase as demand increases with decarbonization. To approximate these incremental revenue requirements, staff used marginal distribution capacity costs estimated for utility rate design and cost of service studies. For IOUs, these were drawn from the most recent rate design window proceedings.[313] These are estimates of load-driven marginal costs applicable to the delivery of electricity to a customer site, including expansion and upgrades to sub-transmission and distribution assets. These costs per KW of load growth can then be applied to the demand forecast scenarios to approximate the incremental revenue requirements. **Table C-23** shows the values used. The capacity cost values are applied to the increase in peak demand associated with each sector to calculate the additional revenue requirement, which is added to the base case revenue requirement. Since the new revenue requirement is divided by higher sales, the distribution rates decrease, even in the case of Southern California Edison with the highest marginal costs of adding distribution capacity. The Southern California Edison residential distribution rate decreases by 5 percent and 9 percent in Scenarios 6.a and 12.a respectively. With smaller changes in load in the commercial sector, distribution rates decrease by 2 to 3 percent.

Table C-23: Marginal Distribution and Transmission Capacity Costs, $ per KW, 2019$

313 PG&E A.19-11-019, 2020 GRC Phase II; SCE A.20-10-012, Phase 2 of 2021 General Rate Case; SDG&E A.19-03-02, 2020 Rate Design Window.

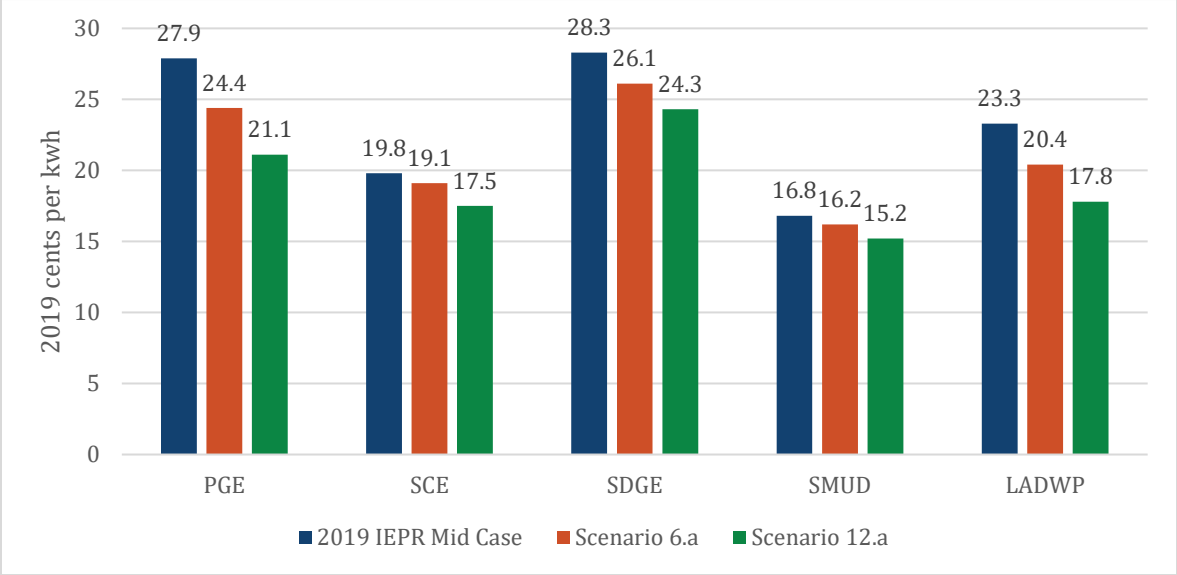
Planning Area	Distribution	Transmission
PGE	61	14
SCE	177	28
SDGE	71	14
SMUD	40	14
LADWP	146	28

Source: CEC staff

The same methodology was used to estimate the incremental transmission revenue requirement needed to serve the increased peak demand. Marginal transmission capacity costs were drawn from utility cost of service studies or those compiled for the CPUC avoided cost calculator. As with distribution rates, the increase in transmission revenue requirements is smaller than the increase in sales, causing the transmission rate to decline.

The rate for public goods charge programs was assumed to escalate with inflation, essentially assuming program spending will grow proportionate with sales. **Figure C-64** shows the combined effects of the changes in procurement, distribution, and transmission on 2030 residential rates compared to the mid-case electric rate scenario developed for the 2019 IEPR. In Scenario 6.a, rate decreases range from 3 percent in Southern California Edison and SMUD to 12 percent in Pacific Gas & Electric and Los Angeles Department of Water and Power. In Scenario 12.a, rates decrease by as much as 24 percent in Los Angeles Department of Water and Power and Pacific Gas & Electric, but only 9 percent in SMUD.

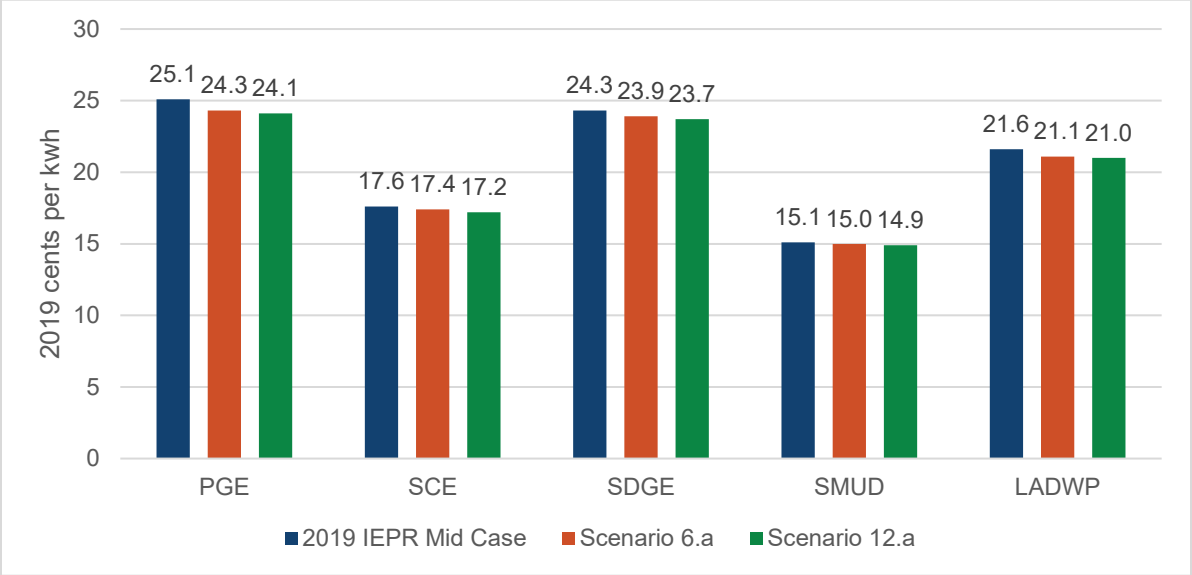
Figure C-64: Residential Planning Area Electricity Rates in 2030



Source: CEC staff

Figure C-65 shows the commercial sector rates in 2030. Because the increases in commercial sales and peak demand are much less than in the residential sector, rate impacts are much smaller. Rates decrease by 1 to 2 percent in Scenario 6.a, and 3 to 4 percent in Scenario 12.a.

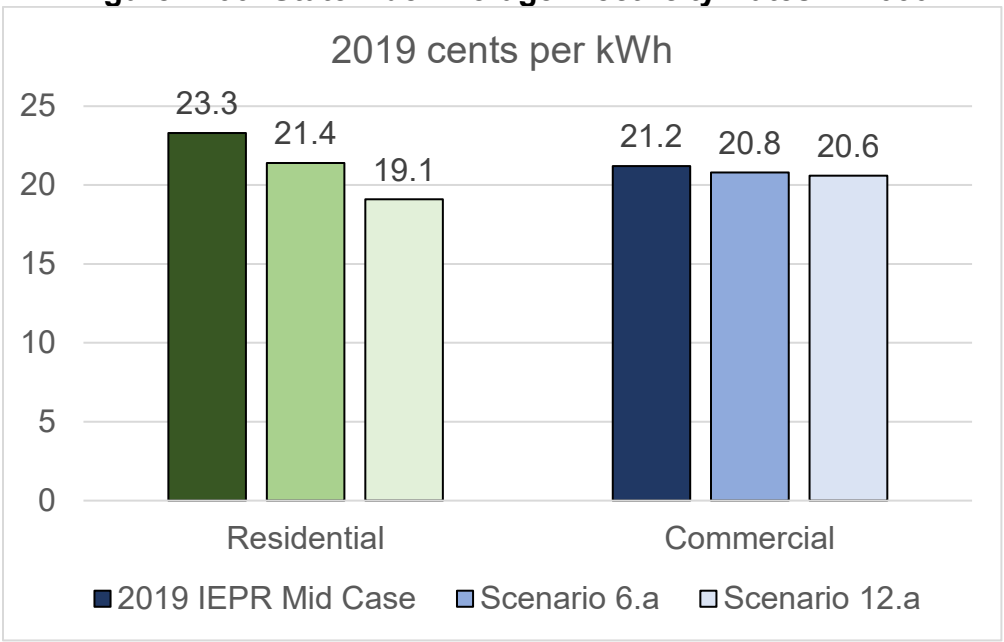
Figure C-65: Commercial Sector Planning Area Electricity Rates in 2030



Source: CEC staff

Figure C-66 shows the statewide average sector rates compared to the mid-case electric rate scenario developed for the 2019 IEPR. In the low electrification scenario, the statewide average residential rate is 2 percent lower. In the high electrification scenario, residential rates are 18 percent lower than previously projected, and commercial rates are 3 percent lower.

Figure C-66: Statewide Average Electricity Rates in 2030



Source: CEC staff

These scenarios are presented as indicative of the potential magnitude of effects on rates. Distribution and transmission planning studies can quantify more accurately the necessary grid investment needed compared to what is already planned. Investment in distribution upgrades could be needed in advance of the load growth, which could cause rates to temporarily increase in the initial years. Large increases in peak load could trigger the need for more costly upgrades than reflected in the marginal cost assumptions used here. On the other hand, utility work-in-progress to support grid resiliency, DERs and transportation electrification may also serve to support building decarbonization. Also, these scenarios do not include the effect of demand flexibility, which could reduce generation and grid capacity costs. Based on recent studies of TOU rates, well designed time-variant rates can be expected to reduce capacity needs.

These rates represent the average annual rate required to collect the utility revenue requirement. As the load of an electrification customer increases and their load shape changes, an important consideration for achieving the targeted benefits is the availability of rate designs that encourage technology adoption and that encourage use during low cost and low emission hours. Many standard residential rates collect all or most costs volumetrically and were designed based on the current average household use and load profile. These rates would collect excess revenues from households whose use is substantially higher than average, and those customers will pay more than their cost of service. Utilities would indirectly refund this surplus through balancing accounts or reserves but would not fairly reimburse the customers who were overcharged. Offering rates that use a fixed charge to collect those costs that do not increase with demand can better align rates with cost of service and encourage customer adoption of electric technologies. Second, rate designs that allocate costs by time of use will encourage customers to shift load to hours when costs and GHG emissions are lowest.

Uncertainties of this comprehensive analysis

The analyses presented here result from a series of "what if" scenario analysis and is not a forecast of expected outcomes. Currently, there are no specific policies and programs in place that would accomplish the estimated GHG reduction and costs. As explained at the beginning of Chapter 3, each of scenarios have been assessed independently and their impacts cannot be added together. It is possible that a combination of strategies could be the best approach to implement for the 2030 time period as the state works toward the more ambitious 2045 economy-wide decarbonization goals.

The most important element missing from these analyses is the role that energy consumers will play in making choices for electric appliances rather than gas ones, adopting energy efficiency measures, and heeding the warning of climate scientists to reduce carbon emissions across the board. Better understanding of consumer behavior is essential but will require substantial time and effort to collect the appropriate data and understand how to best guide California's residents toward the state's climate and energy goals.

Building Decarbonization vs. Other GHG Reduction Strategies

CEC staff used the CARB *2017 Scoping Plan* to evaluate and compare the cost per metric ton estimates of the AB 3232 analysis to other statewide GHG reduction strategies reported in the Scoping Plan.[314] The estimates appear similar across studies.[315] For example, CARB reports negative abatement costs (-$300 to -$200 per ton) for energy efficiency measures. They also report that combined energy efficiency and building electrification measures have negative abatement costs (-$120 to -$70 per ton). Likely examining the building electrification cost effectiveness independent of energy efficiency would reveal comparable results as reported for AB 3232.

Some of the other statewide GHG reduction measures estimated in the 2017 Scoping Plan were mobile sources clean fuels technology (CFT) and freight, liquid biofuels (18 percent carbon intensity reduction target for the Low Carbon Fuels Standard), and a short-lived climate pollutant strategy measure. No estimates from agricultural or soil management measures were reported. The cost per metric to estimates for these measures are less than $50 per ton for the CFT measure, $100 to $200 per ton for the liquid biofuels measure, and $25 per ton for the short-lived climate pollutant strategy. Their building decarbonization abatement estimates are similar or more cost-effective than some of these statewide measures. AB 3232 are cost effective relative to measures outside the buildings sector domain.[316]

Looking beyond strictly statewide GHG reduction potential, there are other sources that report estimated marginal abatement costs. For example, *McKinsey & Company* continuously reports on estimates of GHG abatement and develops MAC curves.[317] In the *Journal of Economic Perspectives*, Gillingham and Stock report their systematic review of abatement cost estimates.[318] The estimates from these two sources show that the estimates from AB 3232 are cost effective relative to measures outside the buildings sector domain. Please note that comparing across studies may not provide an apples-to-apples comparisons. These other

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314 See Table 10 in California's 2017 Climate Change Scoping Plan. California Air Resources Board. November 2017. Pages 44—46. https://ww2.arb.ca.gov/sites/default/files/classic//cc/scopingplan/scoping_plan_2017.pdf.

315 The other California specific study Staff is aware of is: Mahone, Amber, Zachary Subin, Jenya Kahn-Lang, Douglas Allen, Vivian Li, Gerrit De Moor, Nancy Ryan, Snuller Price. 2018. Deep Decarbonization in a High Renewables Future: Updated Results from the California PATHWAYS Model. California Energy Commission. Publication Number: CEC-500-2018-012. https://www.ethree.com/wp-content/uploads/2018/06/Deep_Decarbonization_in_a_High_Renewables_Future_CEC-500-2018-012-1.pdf.

316 Comparing across studies may not provide a direct comparison. These other studies may have different cost and discounting assumptions and may be examining different scopes of potential total emission abatement.

317 See https://www.mckinsey.com/business-functions/sustainability/our-insights/greenhouse-gas-abatement-cost-curves.

318 See Table 2 (page 59) in Gillingham and Stock (2018) for a brief background on marginal abatement cost curves. Gillingham, K., & Stock, J. H. (2018). The Cost of Reducing Greenhouse Gas Emissions. Journal of Economic Perspectives, 32(4), 53–72. https://doi.org/10.1257/jep.32.4.53.

studies may have different cost and discounting assumptions and may be examining different scopes of potential total emission abatement.

(IV) Next steps: Necessary Analytic Improvements

As required by AB 3232, the CEC will conduct additional analysis of building decarbonization strategies in the 2021 and future IEPRs. As the knowledge base and experience with the newer building decarbonization strategies grows, these initial estimates can be improved upon. These technical improvements to the analysis can help inform policymaking and program design. The following are ongoing, near-term, mid-term, and long-term improvements that are needed for these future analyses. Many of these improvements require more data from outside stakeholders or data from program experience (e.g., data collected from the experience from the implementation of BUILD and TECH required by SB 1477). Therefore, the dividing lines between what is identified as near- versus long-term are not precise.

Ongoing or Near-Term Improvements Required for Needed Assessments

- Identify an input of near-term reach codes and electrification efforts to support decarbonization impacts to include in demand forecasts and demand scenarios
- Extend time horizon of analysis to mid-century to enable improved analysis of alternative trajectories to achieve major decarbonization in the residential and commercial building sectors
- Acquire improved data and expand assessment tools to understand the nature of propane and wood use in rural California
- Work with CARB staff to acquire improved data and expand assessment tools for modeling HFC impacts from electrification technologies and ensuring assessment tools (e.g., the mechanisms and associated costs) align with CARB's proposed SB 1383 HFC-related rulemaking and support federal actions
- Improve cost impact assessments by shifting from annual average electric prices to TOU rates as the basis for incremental electrical operating costs
- Improve disaggregated impact assessments by improving the modeling of Low-income households in the residential sector
- Improve modeling of building envelope efficiency measures to better reflect electrical load consequences of electrification and to guide refocus of gas utility energy efficiency programs toward measures useful in the near-term to achieve gas GHG emission reductions which will continue to provide benefits once the building is electrified
- Improve the understanding of the energy efficiency benefits of electrification strategies
- Improve linkages to supply-side assessment tools to support improved understanding of impacts of building decarbonization on bulk energy generation and supply systems
    - Conduct a formal reliability analysis of multiple scenarios of electrical load increases in conjunction with the California ISO and other balancing authorities
    - Conduct assessments of likely revenue and rate impacts of major fuel substitution shifts from gas consumption to electricity consumption

- Improve modeling of costs by allowing for market transformation where technology cost reductions can decline over time as electrification penetration increases
- Improve modeling of electric technology load shapes
    - Acquire improved data and expand assessment tools to improve the modeling of Heat Pump Load profiles by vintage
    - Acquire improved data and expand assessment tools to understand the marginal hourly and annual emission intensities
- Build on the work assessing seasonal and peak impacts of incremental building electrification conducted in this report and integrally incorporate a reliability assessment into the first forecast
- Endeavor to align SB 350 with AB 3232 by expressing how achievement of efficient electrification at the rate called for to achieve a 50 percent reduction in building GHG emissions by 2030 would affect attainment of the SB 350 2030 energy efficiency doubling goal

Mid-Term Improvements Requiring Improved Data Collection by Distribution Utilities

- Revise, as necessary, IOU energy efficiency measure tracking systems to distinguish between electrification versus same fuel energy efficiency measures and coordinate reporting of building electrification programs by publicly owned electric utilities
- Improve data on retrofit costs in existing buildings ancillary to the end-use equipment costs including:
    - Vintages of housing with inadequate electric panel capabilities, as built, to support added electric loads and current capabilities as a result of upgrades through time since built
    - The attribution of costs between heat pumps and electric vehicles for electric panel upgrades
    - Necessary upgrades to in-home wiring to support specific electric appliances
    - Develop credible estimates of workforce requirements to accommodate skilled electrician tasks
- Work with electric utilities to acquire an understanding of distribution system upgrades needed to support building electrification with and without additional load increases from use of electric vehicles
- Further refinement of the miscellaneous share of commercial building consumption may be possible in future updates and lower the percentage of gas consumption attributed to uncategorized end-uses in commercial buildings
- Coordinate customer-specific distribution mapping to understand how gas customers map to electric distribution circuits, especially in Southern California with a multitude of single fuel utilities
- Work with gas utilities to obtain more detailed cost data to improve the modeling of the cost consequences from renewable gas penetration

    - The role of renewable gas, hydrogen and engineered carbon removal should continue to be assessed
    - Explore the role of renewable gas, hydrogen, and other zero-carbon alternatives such as engineered carbon removal in a low carbon future, to replace and/or complement the use of fossil gas with focus on identification of the most suitable applications, availability and pricing, and opportunities to repurpose existing infrastructure to integrate the usage of renewable gas, hydrogen, and engineered carbon removal
- Further exploration is needed of the building decarbonization potential of behind-the-meter storage systems, both paired with a PV system and as a standalone system

Longer-Term Improvements Needed to Predict Consumer Participation in Retrofit Programs

- Use program evaluation data collected from near-term electrification programs (e.g., BUILD and TECH from SB 1477) to better inform the consumer behavior assumptions used in future analyses
- Disaggregate assessment tools to better identify electrification and GHG savings attributable to multi-family, low-income and disadvantaged communities for which substantial barriers appear to exist, thus enabling better program design
- Develop an improved understanding of consumer awareness about building electrification goals, willingness to undertake retrofits, and financial support required to offset costs. As research on consumer behavior is collected and implementation data from pilot programs becomes available, more capabilities including these aspects of a predictive behavior can be incorporated in the model to transform the FSSAT into a genuine forecasting tool