The Path to Net Zero: A Decarbonization Roadmap for California

Technical Appendix
April 2022

1 Modeling approach, methodology and assumptions

1.1 Overall modeling approach

The Path to Net Zero: A Decarbonization Roadmap for California (Roadmap) relies on multiple economic and electric power systems scenario modeling tools to evaluate a range of assumptions that could affect how California meets its economywide decarbonization and policy targets by 2045. The approach leverages past analyses of California decarbonization pathways, along with updated cost and technology assumptions. The methodology used in this study leverages a number of modeling tools to examine decarbonized futures on different geographical scales, including a Western Electricity Coordinating Council (WECC)-wide electricity capacity expansion model, a comprehensive reliability assessment of California's electric generation supply portfolio through 2045 and an evaluation of illustrative economic impacts both across the state and in San Diego Gas & Electric's (SDG&E) service area.

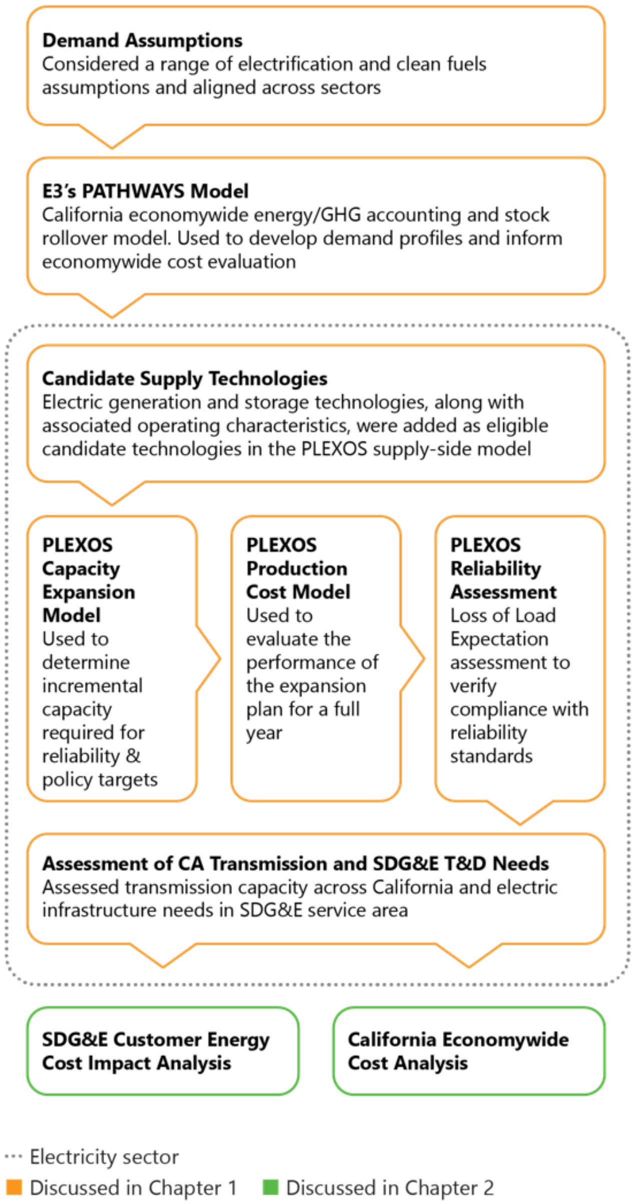
The Roadmap presented here is our evaluation of the combination of assumptions that should allow the state to meet its decarbonization goals, while helping to ensure feasibility, reliability and affordability. By 2030, the Roadmap yields a reduction in greenhouse gas (GHG) emissions of approximately 44% below 1990 levels, exceeding the state's 2030 requirement of 40% below 1990 levels.[1] By 2045, the Roadmap yields approximately an 84% reduction in GHG emissions, relative to 1990 levels, five years earlier than the current state goal.[2] Finally, to achieve the state's goal of net zero GHG emissions by 2045, carbon dioxide removal (CDR) technologies are used to remove the remaining 68 million metric tons (MMT) of emissions from the atmosphere.[3] Uncertainties related to the future costs and efficiency of CDR technologies like direct air capture (DAC), and other CDR technologies and strategies, made them difficult to model and were not evaluated as part of the analysis.

The methodology used in this study allowed SDG&E to evaluate a large number of assumptions, some of which involve substantial uncertainties. Furthermore, SDG&E was able to assess an array of possible strategies for decarbonization in terms of their cost to consumers, levels of investment needed and practicality. It also allowed assessment of the risks that could arise – for example, if there were complete electrification of the building and transportation sectors, as some have envisioned, that might require appliance and vehicle switching to degrees that could be highly disruptive. Though this study leveraged advanced modeling techniques with a large number of assumptions and considerations, the Roadmap acknowledges that technological, modeling, ecosystem and behavioral uncertainties exist that should be explored further.

[1] Senate Bill (SB) 32 requires statewide GHG emissions are reduced to 40% below the 1990 level by 2030.
[2] Executive Order (EO) S-03-05 establishes a statewide goal to reduce GHG emissions to below 80% below 1990 levels by 2050.
[3] EO B-55-18 establishes a statewide goal to achieve carbon neutrality as soon as possible, but no later than 2045.

The modeling approach, summarized in Figure A1, included the following components:

FIGURE A1
SDG&E net zero modeling approach

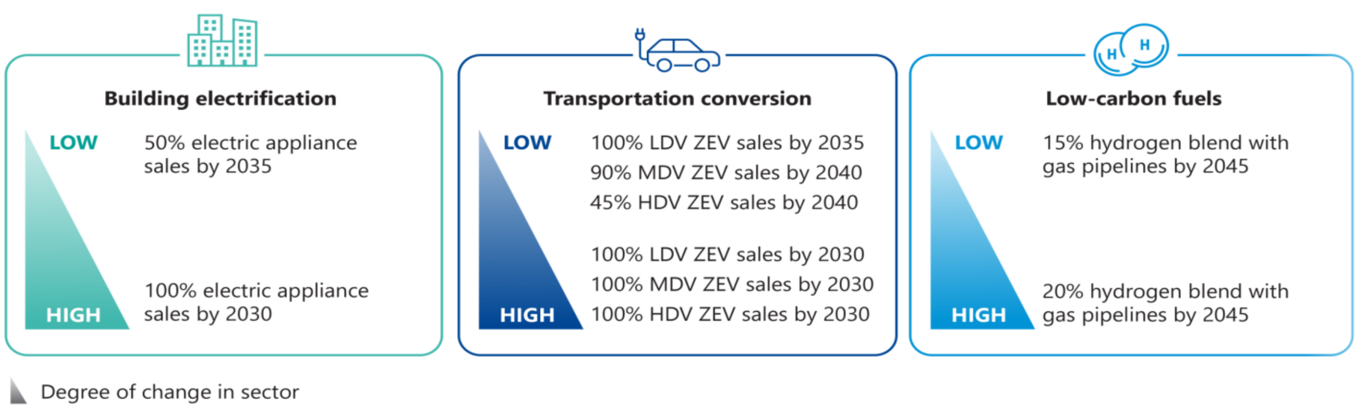


1) Demand Assumptions: This study leveraged modeling efforts outlined in the October 2020 Energy and Environmental Economics, Inc. (E3) report, *Achieving Carbon Neutrality in California*, to inform assumptions about the factors that affect how sectors of the economy demand and consume energy.

Most assumptions used to inform the Roadmap derive from the three decarbonization pathways outlined in the E3 report.[4] This study also considered distinct assumptions consistent with a comparatively slower pace of electrification and a greater dependence on clean fuels.[5]

All assumptions, and clusters of such assumptions, include a number of common elements: high levels of energy efficiency, behind-the-meter solar growth, renewable electricity generation and electrification of the transportation and buildings sector along with deep reductions in non-energy and non-combustion GHG emissions like methane and hydrofluorocarbons. The figure below outlines the range of assumptions considered across building electrification, transportation conversion and low carbon fuels:

FIGURE A2
Analyzing uncertain futures: ranges of assumptions modeled



Building Electrification: The Roadmap assumes 100% electric appliance sales by 2035. As the attributes of new appliances are altered these new appliances then diffuse into more widespread application as new replaces old. No forced retirements were assumed (natural replacement).

Transportation Conversion: The Roadmap assumes 100% light-duty vehicle (LDV) sales, 90% medium-duty vehicle (MDV) and 93% heavy-duty vehicle (HDV) zero-emission vehicle (ZEV) sales by 2035.[6] No forced retirements were assumed (natural replacement).

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[4] These pathways are the "High Carbon Dioxide Removal," "Balanced," and "Zero-Carbon Energy" pathways, as described in E3's October 2020 "Achieving Carbon Neutrality in California" report.
[5] In this cluster of assumptions, the existing gas distribution system is leveraged with an objective of improving affordability, maintaining dispatchable low-carbon energy reliability and reducing emissions.
[6] The presented Roadmap assumes 10% compressed natural gas (CNG) MDVs by 2035. CNG used as fuel for transportation follows the same blend as that specified in the pipeline gas blend, therefore it's a split between conventional natural gas, renewable natural gas and hydrogen.

Low-Carbon Fuels: The study evaluated several decarbonization strategies for clean fuel pipeline blending over the study horizon, replacing natural gas with clean fuels, i.e., clean hydrogen and renewable natural gas.[7] The Roadmap projects the composition of the fuel in the pipeline to be comprise of 58% natural gas, 28% renewable natural gas and 14% clean hydrogen in 2045.

Additionally, the electricity required to produce hydrogen for use in industry, electric generation and gas pipeline blending is assumed to be off-grid and is not included in the electricity consumption and net peak demand values. The electricity used to produce hydrogen for use in the transportation sector is assumed to be on-grid is included in the electricity consumption and net peak demand values.

2) **PATHWAYS Demand Model:** This study used the E3 PATHWAYS economywide energy and GHG accounting model to test different "what-if" approaches to decarbonization and project – through 2045 – energy demand, cost and GHG emissions across California's economy.[8] The PATHWAYS model takes into consideration the timing of investments to replace appliances, vehicles, buildings and other infrastructure along with growth and sectoral changes across the economy. It captures the dynamics between incremental new loads from transportation and buildings and examines the role of low-carbon fuels such as biofuels and hydrogen.

   The main outputs used in this study of the PATHWAYS modeling are annual electric demand, net electricity peak, non-electric fossil and low-carbon fuel demand, non-electric economywide costs (represented as equipment stock costs) and non-electric emissions in California. These outputs are combined with PLEXOS supply-side modeling to yield implications for economywide costs and GHG emissions.

[7] Clean hydrogen refers to either "green" or "blue" hydrogen. See, for example, the World Economic Forum for definitions of these sources of hydrogen, in particular *Grey, blue, green – why are there so many colors of hydrogen?*, available here: https://www.weforum.org/agenda/2021/07/clean-energy-green-hydrogen.
[8] Modeling efforts leverage version 2.3.2 of the E3 PATHWAYS model. Additional details about the PATHWAYS model can be found on E3's website at https://www.ethree.com/tools/pathways-model/.

3) **Energy Exemplar's PLEXOS®:** This study used Energy Exemplar's PLEXOS software, an advanced power system modeling tool used for electricity market modeling, to complete an iterative process to determine a capacity expansion solution for California's power market that met stringent requirements for reliability and emissions.

   This analysis used PLEXOS for three functions: (1) a deterministic WECC-wide capacity expansion simulation; (2) a deterministic production cost model; (3) a stochastic simulation to confirm power system reliability.

   Candidate Supply Technologies: As a first step in electric generation supply modeling, the study identified a variety of mature and emerging electric generation technologies to meet the projected electricity demand from PATHWAYS and to help enable the state to achieve its decarbonization goals over the study horizon. Eligible candidate technologies were input into the PLEXOS model (see next section), along with their financial, technical and operational parameters and characteristics. Subject-matter experts evaluated candidate technologies, prioritizing those with proven commercial viability, practicality and achievability within California, and taking account of the state's existing regulations.

   The following eligible candidate technologies were considered and included in the PLEXOS capacity expansion model. The same set of eligible candidate technologies and assumptions were used across all modeled assumption clusters. All technologies are in-state unless otherwise specified.

   - Renewable and Clean Generation Technologies
     - Land-based solar photovoltaic and solar thermal generation
     - Land-based wind generation
     - Off-shore floating wind generation
     - Geothermal
     - Out-of-state solar and wind
   - Energy Storage Technologies
     - Short Duration (Li-ion/zinc)
     - Long Duration (Flow)
     - Pumped Storage (Hydro)
   - Near Zero and Zero Emissions Dispatchable Technologies
     - Biomass
     - Natural Gas with carbon capture and sequestration (CCS), both new build and retrofits of existing natural gas facilities
     - 100% clean hydrogen generation - new build
     - Hydrogen retrofits of existing natural gas facilities

   Expansion candidate technology and fuel price assumptions were largely consistent with those used in the RESOLVE model developed for the California Public Utilities Commission (CPUC) 2019 Integrated Resource Plan (IRP) proceeding. This study leveraged the "mid-case" in the RESOLVE 2019 Resource Cost and Build dataset, the most recent publicly available version at the onset of this study.

Technologies unique to this analysis include Natural Gas and CCS and hydrogen-based generation. Costs for these resources were derived from Black & Veatch practical technology and engineering expertise. The CCS costs and characteristics assumptions modeled are consistent with those found in the National Energy Technology Laboratory's (NETL) 2019 Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity Report.

Hydrogen cost assumptions were developed using California-specific market intelligence by Black & Veatch subject-matter experts. A fully delivered (storage, fuel and transportation) all-in cost projection was developed and utilized, as reflected in Table 1 below.

Table 1. Hydrogen Fuel Pricing Assumptions ($/MMBtu)[9]

Fuel Type	Min (USD), 2021-2030	Max (USD), 2021-2030	Min (USD), 2030+	Max (USD), 2030+
Clean Hydrogen Production	$18.00	$70.00	$10.00	$26.00
Hydrogen Storage + Transportation	$2.00	$40.00	$2.00	$40.00

a. **PLEXOS Capacity Expansion Model:** A deterministic long-term capacity expansion simulation was completed to forecast how the power system may evolve over the study horizon. The capacity expansion model was used to determine the cost-optimal mix of incremental power generation capacity needed through 2045 to meet the California electricity demand generated by PATHWAYS. To determine the optimal resource mix, only technologies included as eligible candidate supply technologies, as noted above, could be selected by the model as new generation resource builds.

As a first step in electric power system modeling, key inputs and assumptions were entered into the zonal WECC-wide model to optimize least-cost resources and satisfy the modeled demand profiles, while still meeting the study's emissions and renewables goals. The study developed a deterministic WECC modeling in PLEXOS, utilizing SDG&E specific information and California electric generation baseline resources, and implemented the following assumptions and constraints:

- *Model horizon:* A zonal model horizon of 2021–2045 with electricity demand in all 8760 hours of each year as modeled in the PATHWAYS output.
- *Electric Generation Emissions*: This study implemented emissions constraints leveraging two methods: (1) A California GHG emissions constraint of 38 MMT in 2030 and 0 MMT in 2045, and (2) hourly import emissions constraints. Both targets were embedded to serve retail sales with 100% clean energy by 2045 to ensure compliance with SB 100.

[9] Hydrogen fuel pricing is based on Black & Veatch's analysis and confidential market data specifically for this study, which assumes large quantities of hydrogen transported via pipeline. Values should not be assumed to be replicated outside of this study, nor be assumed to be applicable to smaller quantities of hydrogen production and transport.

- *Existing Generation Technologies and Units:* Existing generation resource technologies were included based off of the California Independent System Operator (CAISO) CAISO PLEXOS Model. Generation characteristics including retirement, availability capacity, emissions and price curves were included, consistent with 2019 IRP assumptions from the CPUC.

- *Expansion Candidate Technologies:* Expansion candidate technology characteristics and pricing as described above in section 3 "Candidate Technologies".

After a long-term capacity expansion model for the given assumptions was modeled and reviewed, production cost modeling and reliability modeling was performed.

b. **PLEXOS Production Cost Model:** This study utilized PLEXOS for production cost modeling. Using a deterministic linear programming technique, it identifies the most economic dispatch of resources across various weather conditions to meet operational needs on an hourly basis in CAISO (e.g., demand, ancillary service) for a bulk power system and ensure that load is reliably met in every hour of every day at every location. If infeasibilities such as unserved energy or emissions violations occurred, adjustments were made to the capacity expansion and the production cost model was rerun until infeasibilities were resolved.

   Unlike a capacity expansion model, production cost models evaluate the power system over a shorter timeframe but at a higher temporal resolution. The mixed-integer simulation was run over the full 25-year horizon (2021–2045) to determine the optimal dispatch and total system cost of the available generation resources.[10]

c. **PLEXOS® Reliability Assessment:** This study leveraged PLEXOS to model power system reliability based on the resource selections made in the capacity expansion model. A Monte Carlo-based stochastic simulation calculated the loss of load expectation (LOLE) for each capacity expansion build during key benchmark years (primarily 2045), leveraging 30 years of weather, renewable generation, random outage data and load variables. The stochastic model runs a number of samples against the forced outage probabilities to determine the number of loss-of-load events. In doing so, the simulation includes unserved energy estimates for every hour within the simulation horizon where demand exceeds generation. Capacity expansion builds were deemed reliable if they met the criteria of 1 loss-of-load event in 10 years, the industry standard for reliability found in the North American Reliability Corporation (NERC) guidelines.[11]

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[10] Production cost modeling utilized the optimized build as a result from the long-term capacity expansion. Production cost simulations were run for each year in the 25-year planning horizon to determine annual emissions, energy generation by technology and total energy system costs of the power system necessary to inform the full economywide costs of the presented Roadmap. This simulation also included emissions targets consistent with those in the long-term capacity expansion plan. Additionally, annual production simulation identified where potential infeasibilities and unserved hours occurred, informing the years in which reliability assessments should be considered and revisions to capacity build should be made.

[11] NERC: Reliability Standards for the Bulk Electric Systems of North America: LOLE is defined as the expected number of days per time period (usually a year) for which the available generation capacity is insufficient to serve

As described in the narrative of this study, this approach to studying reliability identified the critical need for clean dispatchable generation resources. The study observed that as renewable generation increased and emissions targets forced much lower utilization of conventional natural gas plants, new or retrofitted clean firm resources were required to fill the need previously served by the gas generators. This study tested numerous variations of builds including the addition of even more renewable resources and battery energy storage. We found, however, that those resources alone were unable to meet the LOLE requirement more cost-effectively than a clean-firm dispatchable resource, such as 100% clean hydrogen generation. This result is consistent with other findings in the published academic literature and is a crucial insight that comes from full reliability analysis.

If capacity expansion model builds did not meet the 1-in-10 criteria, more zero emission firm generation resources were evaluated and added to the capacity resource mix to increase reliability; the LOLE analysis was repeated until the minimum LOLE criteria was met. Once a final, reliable build was determined, total build and system costs were modeled in the PLEXOS capacity expansion and production cost model.

While previous studies of California decarbonization relied on a planning reserve margin to guarantee reliability, SDG&E believes that this is insufficient to model the variability of a predominantly renewable generation portfolio. As such, the Roadmap was developed using the LOLE approach, which models the impact of weather variability on both demand and renewable generation and measures the instances that the electricity system is not able to serve all of the required load (a loss of load event). For power customers, what ultimately matters is the actual reliability of the grid and that is what this approach assesses.

4) **Transmission Investment:** Based on the PATHWAYS and PLEXOS expansion plans (i.e., expected system peaks, electricity consumption) an assessment was conducted to estimate the transmission investment needed to bring new generation resources to serve load.

   To determine in-state, greater CAISO and WECC incremental transmission, the study used the PLEXOS long-term capacity expansion plan, with the generation capacity informing the zonal transmission needs from renewable generation to in-state load centers. The study utilized transmission costs developed by CAISO and WECC to estimate incremental transmission costs associated with incremental generation resources.[12]

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bulk power demand at least once per day (actual local reliability depends on many additional factors, such as redundancy of local power lines and transformers). LOLE counts the days with loss-of-load events, regardless of the number of consecutive or nonconsecutive loss-of-load hours in the day. The study applies the industry standard of 0.1 days per year or 1 day in 10 years.

[12] In-state capital transmission investment utilized the 2019 CAISO Whitepaper: Transmission Capability Estimates as an input to the CPUC Integrated Resource Plan Portfolio Development. Out-of-state transmissions capital investment was based on the CPUC SB380 Phase 3 Analysis by FTI on Out of State Transmissions projects to California.

2 Analysis of household impacts and economywide costs

2.1 SDG&E average residential customer energy cost impacts analysis

The following approach was used to estimate SDG&E-specific residential bundled customer (delivery and commodity) economic impacts:

- Estimated investments needed to support the Roadmap: SDG&E calculated Roadmap-related electric infrastructure investments and related costs by utilizing outputs from the PATHWAYS tool (specifically LDV, MDV, HDV electric vehicle (EV) stock figures, as well as changes in net peak demand). Investments related to the development of clean fuels infrastructure was not included in the scope of the analysis.

- Developing illustrative financial and rates models: Utilizing the Roadmap-related cost estimates described above, along with SDG&E capital plan figures and projected generation costs (outputs from the PLEXOS production cost model), illustrative electric and gas financial and rates models were run to estimate potential residential bundled customer rate impacts within the SDG&E service area.[13] Additional details are provided below – these assumptions were leveraged as starting points and were further refined given outputs from the emissions modeling efforts.

  - Key Revenue Requirement Assumptions:
    - Electric basis: used allocations embedded in approved 1/1/22 rates
    - Gas basis: used allocations embedded in approved 1/1/22 rates
    - 2022-2026 SDG&E 5-year capital plan data (electric and gas) and estimated decarbonization-related capital investments (electric only)
    - CPUC and Federal Energy Regulatory Commission (FERC) Filings
      - CPUC 2019 General Rate Case
      - 2020 CPUC Cost of Capital
      - FERC Transmission Owner Formula Rate 5, Cycle 4 Filing
      - FERC Form 1 and 2 data

  - Key Sales/Determinants Assumptions:
    - Electric basis: 2020 California Energy Demand Update (CEDU) through 2032
    - Gas basis: 2020 California Gas Report

- Estimating Annual Household Energy Spend: The study estimated the ongoing energy costs for a representative residential household in SDG&E's service area by leveraging these financial and rates modeling results, assumptions and outputs directly from PATHWAYS, external data sources and proprietary SDG&E data.[14] This illustrative analysis helped frame how decarbonization efforts could potentially impact an SDG&E residential household's overall ongoing energy expenses in 2045 (specifically, expenses related to electric and gas utility bills and gasoline for transportation).

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[13] Generation capital investment cost estimates were levelized throughout the study horizon. Levelization utilized the National Renewable Energy Laboratories (NREL) Capital Cost Recovery Factor from the 2021 Annual Technology Baseline (ATB).

[14] Including the Energy Information Administration's (EIA) 2021 Annual Energy Outlook (AEO), U.S. Bureau of Labor Statistics, California Department of Industrial Relations, U.S. Department of Energy Fuel Conversion Factors and EIA Conversion Factors.

- General Financial Assumptions:
    - All SDG&E-specific cost estimates, rate projections and annual household energy spend figures are shown in real $2021, so exclude potential future inflation effects.
    - Projected electric and gas rates do not assume future changes in rate design.
    - Illustrative annual household energy spend analysis was focused on ongoing energy costs only.

Annual household energy spend analysis:

The annual household energy spend analysis utilized outputs from the financial and rate models to forecast illustrative energy cost impacts of the Roadmap for average residential bundled customers in SDG&E's service area. The analysis only estimates ongoing energy costs for residential customers and does not include upfront investment costs associated with electrifying appliances or vehicles, or the use of behind-the-meter solar generation.

Over the decarbonization timeline, the analysis assumes average adoption rates of certain low-emission technologies (electrified appliances and transportation) consistent with the PATHWAYS modeling assumptions and results. Utility-related costs leveraged estimated residential class average rates and forecasted residential consumption from the financial and rates modeling process. Moreover, the analysis attempted to estimate annual energy expenses for two different customer types (see residential customer types below).

Residential customer types:

To illustrate how decarbonization of the energy grid will impact customers differently, SDG&E modeled the annual household energy expenses of two different types of residential customers.

- The Adopter customer type represents a residential customer who electrifies their appliances and vehicles at the average pace of the Roadmap. Electric and natural gas consumption in the baseline year is based on SDG&E's estimated average residential customer consumption in 2022. For an Adopter, forecasted energy consumption in 2045 was derived from the change in average residential consumption estimated in the financial and rate modeling efforts, relative to the 2022 starting point. The drivers of these consumption changes include increasing adoption rate of low-emission appliances and vehicles, as well as efficiency increases in appliances and vehicles.

- The Non-Adopter customer type represents a residential home that makes no changes to its electric and gas consumption patterns from 2022–2045 and drives gasoline vehicles – in other words, a residential customer who does not embark on the decarbonization Roadmap.

Transportation Assumptions

Transportation costs were broken down into two categories: the gasoline costs of internal combustion engine (ICE) vehicles and EV-related charging costs. The Adopter customer type assumes a residential household will adopt EVs at the average rate that EVs penetrate the total vehicle stock (increasing over time). The Non-Adopter customer type assumes that the household will not adopt EVs at all, but rather continue to operate ICE vehicles through 2045.

Certain transportation-related assumptions were similar for both customer types, such as the number of vehicles per household and vehicle miles traveled. Transportation costs differ between the customer types due to their choice of vehicle technology, vehicle efficiencies, and the cost of each vehicle fuel type through 2045. While EV penetration rates reflected both plug-in hybrid vehicles (PHEVs) and battery electric vehicle (BEV), a simplifying assumption was made to leverage BEV efficiencies as a proxy for EVs in general.

Retail gasoline prices through 2045 were projected by taking the annual 2021 average price of a gallon of gasoline by component from the California Energy Commission's (CEC) weekly gasoline price breakdown.[15] Next, the average 2021 price of the crude oil component was aligned with the Energy Information Administration's (EIA) 2021 Annual Energy Outlook (AEO) crude oil $/barrel forecast, while other gasoline components were held constant at a real $2021 level.[16]

Forecasted Electric Cost Assumptions:

In addition to transportation, electric costs differ between customer types based on the rate at which each sample customer switches from natural gas appliances to electric. The Adopter customer type assumes that a household would adopt electric appliances in place of natural gas appliances at the average rate at which the total appliance stock electrifies within the Roadmap, incrementally increasing electric usage over time.

The Non-Adopter customer type assumes that a household's electric and natural gas consumption will stay constant at the baseline 2022 levels. In other words, the Non-Adopter household will not substitute any of its current natural gas appliances with electric appliances through 2045, and the existing appliance efficiencies will remain constant. Forecasted electric rates are applied to the specific electric consumption of each customer type through 2045.

Forecasted Natural Gas Cost Assumptions:

Natural gas costs for each customer type reflect the estimated household consumption in the future combined with forecasted $/therm price increases.[17] Natural gas commodity prices were leveraged from the CA RESOLVE model. Forecasted natural gas rates are applied to the specific natural gas consumption of each customer type through 2045. As overall system throughput declines, the per unit cost to deliver gas to SDG&E gas customers is projected to increase.

The Adopter customer type assumes a household decreases its natural gas usage over time, in alignment with projected gas throughput decreases and forecasted electrification of appliances and vehicles. The Non-Adopter customer type once again assumes that a customer's energy consumption will not change over time and the household natural gas usage will remain constant at the 2022 baseline level.

[15] CEC Estimated Gasoline Price Breakdown and Margins – 2021 data.

[16] Carbon costs were not included in the scope of this analysis. If those factors were included then the savings for adopter households would be much larger.

[17] The commodity portion of the gas rate reflects different amounts of blending, aligned with the methodology used for economywide costs which leveraged outputs from PLEXOS, RESOLVE and PATHWAYS.

Table 2. Annual Household Energy Spend by customer type

	Non-Adopter		Adopter	
	2022	2045	2022	2045
Electricity	$1,614	$1,563	$1,657	$3,146
Natural Gas	$569	$2,106	$569	$835
Gasoline	$2,064	$1,574	$2,012	$255
Total	**$4,248**	**$5,243**	**$4,238**	**$4,236**

Table 3. Annual Household Energy Spend Key Assumptions

Key Assumptions – Adopter (Real $2021)	Source[18]	2022	2045
Electric Rate ($/kWh)	Calculated	$0.345	$0.334
Gas Rate ($/therm)	Calculated	$2.06	$7.63
Gasoline Price ($/gallon)	CEC and EIA[19]	$4.18	$5.69
Electric Consumption (kWh/mo)	Calculated	400	784
Nat Gas Consumption (therm/mo)	Calculated	23.0	9.1
Vehicles per Household (LDVs)	PATHWAYS	1.77	1.95
Vehicle Miles Travelled (miles/yr)	PATHWAYS	11,233	9,492
EV Penetration (%)	PATHWAYS	2.6%	84%

2.2 Economywide costs analysis

A California economywide cost estimate was generated across anticipated supply- and demand-side investments. Economywide costs were calculated from modeling output, publicly available sources and stock cost assumptions embedded in E3's PATHWAYS tool, with minimal adjustments focused on updates to key costs that had shifted since their input into the PATHWAYS tool (i.e., costs of electric/hydrogen fuel-cell vehicles, space heaters and water heaters). Similarly, liquid and pipeline fuel costs were measured utilizing demand output data, with updated costs assumptions primarily from 2021 EIA AEO data, embedded PATHWAYS cost assumptions and Black & Veatch assumptions.

The economywide cost calculation provides a high-level estimate of cumulative expenditure between 2021 and 2045 associated with the decarbonization Roadmap represent full costs (not incremental).[20] As referenced in the white paper, percentage of California GDP figures were calculated to help frame the overall size of the economywide investments. To do this, annual estimated economywide costs were compared with annual projected California GDP estimates. GDP was forecasted by using 2021

[18] Residential rates and consumption (for both electric and gas) were calculated using a high-level, illustrative rates model utilizing internal data as well as outputs and assumptions derived from demand-side and supply-side modeling.

[19] Average 2021 oil crude oil price taken from CEC Estimated Gasoline Price Breakdown and Margins and aligned with EIA 2021 Annual Energy Outlook crude oil forecast. Other gasoline components are held constant at a 2021 level.

[20] This study did not include the cost of emissions removal required in 2045 and beyond, nor did it include a "business as usual" economywide cost estimate.

California GDP and applying a real growth rate of 2.7% annually through 2045.[21] On a discounted basis, estimated economywide costs through 2045 were projected to be approximately $2.7T in real 2021 dollars.[22] Of this total, approximately 75% is related to equipment stock costs, approximately 17% is fuel and approximately 8% is electric generation and production. Within equipment stock costs, the majority (approximately 67%) is comprised of transportation-related investments.

This calculation reflects both supply- and demand-side cost estimates, leveraging cost assumptions that are provided subsequently in this appendix.[23]

- The demand-side cost estimates were captured as follows:
  - PATHWAYS model output, reflecting updated assumptions for key cost elements including decarbonization of the transportation, buildings, and industrial sectors including transportation and building stock costs, conventional fuels, pipeline fuels and biofuels
  - PATHWAYS fuel demand output with out-of-model calculations for conventional fuels, hydrogen fuels and biofuels.
    - PATHWAYS outputs incorporate fuel savings and lifecycle costs for decarbonization, and the out-of-model calculations supplement the PATHWAYS model by incorporating upfront capital expenditures not included in PATHWAYS.

- The supply-side cost estimates were captured as follows:
  - PLEXOS model outputs for capacity additions (new generation, storage) and their associated capital and operations (such as fuel) and maintenance costs.
  - Electrical transmission infrastructure costs via out-of-model calculations for additional transmission infrastructure as previously described.

Supply cost methodology

On the supply side, generation costs are calculated as the product of new generation and storage capacity, output by the PLEXOS capacity expansion model, and the associated capital cost for each resource type based on CPUC's RESOLVE IRP. Cost assumptions from Black & Veatch were utilized for CCS technologies and hydrogen fuel assumptions. Total new build and capital costs estimates were pulled directly from the long-term capacity expansion model. Annual system costs of power system operation derived from simulation results of the production cost model for each year in the study horizon. Modeled new build capacity expansion costs in California were levelized each year over the study period.

Transmission infrastructure costs were broken into the following categories, each with a unique calculation method:

[21] Represents 10-year historical real CAGR, U.S. BEA GDP by State SQGDP2.
[22] Utilizing a real discount factor of 10%, consistent with the factor used in E3 PATHWAYS to levelize (annuitize) costs.
[23] All economywide cost figures are presented in 2021 dollars.

a. **Transmission Infrastructure for the rest of California:** Calculated based on the in-state renewable generation capacity expansion plan developed in PLEXOS. The study used various published transmission outlooks developed by CAISO to determine the costs and incremental transmission capacity to move the renewable generation to various load centers.

b. **Transmission Infrastructure beyond California, needed for imports:** Calculated as the product of transmission costs for delivery of imports for each resource type and their proximity to California, based on the PLEXOS expansion plan. With each model completed, the PLEXOS expansion plan determines the generation needs in each zone. New transmission investment was determined as required when incremental generation exceeded aggregated zonal transmission line capacities. Transmission capacity costs are based on public reports and studies developed by CAISO, as well as studies submitted to CPUC as part of various long-term planning analysis.

End-use Stock cost methodology

On the demand side, the PATHWAYS model calculates capital cost estimates on an annualized, full-cost basis for a wide range of end-use technologies (or stocks), from zero-emissions vehicles to electric appliances.[24] These stock costs were largely left unchanged, with the exception of the items described below. Original cost inputs for the PATHWAYS model can be found in the input files in the "California PATHWAYS Scenarios Data (4/6/2015 ZIP file)" at https://www.ethree.com/tools/pathways-model/.

The following resources were utilized to update certain costs:

Transportation

- National Renewable Energy Laboratories (NREL) Transportation Annual Technology Baseline (ATB) Data
  - Light-duty automobiles – BEV, PHEV and HFCV
- National Renewable Energy Laboratories (NREL) Electrification Futures Study: End-Use Electric Technology Cost and Performance Projections through 2050
  - Light-duty trucks – BEV and PHEV
  - Medium-duty vehicles – BEV
- California Air Resources Board (CARB) Advanced Clean Trucks Total Cost of Ownership Discussion Document - Preliminary Draft for Comment
  - Heavy-duty vehicles – HFCV

Buildings

- U.S. Energy Information Administration (EIA) Updated Buildings Sector Appliance and Equipment Costs and Efficiencies
  - Residential
    - Space heaters – High Efficiency Electric Heat Pump
    - Water heaters – High Efficiency Electric and Heat Pump Electric
  - Commercial
    - Space heaters – High Efficiency Electric Heat Pump and Reference Electric Boiler
    - Water heaters – High Efficiency Electric Heat Pump

[24] PATHWAYS assumes a real discount rate of 10% to perform the cost annualization over the life of the technology.

Levelized stock costs for each year were exported from the PATHWAYS model and added to the levelized electric generation costs to determine the annual levelized cost. Annual fuel costs and electric generation system costs were included as a levelized cost assumption. All costs were updated and adjusted to reflect 2021 USD.

Fuel cost methodology

Fuel demand forecasts by PATHWAYS were exported from the model to calculate study-specific cost assumptions. Data from the 2021 EIA AEO was leveraged for conventional fuels, with the exception of refinery and process gas and wood, each of which were calculated directly in the PATHWAYS model.[25] Pipeline natural gas and hydrogen fuel pricing were consistent with the pricing used in capacity expansion modeling.

[25] 2021 EIA AEO data was utilized to be consistent with the cost methodology of earlier PATHWAYS models, but to use more recent and updated cost values since the version of the PATHWAYS utilized in this study used EIA 2013 AEO data.

3 Supporting data tables for whitepaper figures

3.1 Supporting data tables

Table 4. Emissions by State Economic Sector (MMT) (Whitepaper Figure 4)

State Economic Sector	CARB 2019* Actuals	2030 GHG Emissions	2045 GHG Emissions
Electric Power	59.0	31	~0
Transportation	170.3	87	11
Buildings	57.2	43	13
Industrial	99.9	51	25
Agriculture	31.8	24	19
Total CA GHG Emissions	***418.2***	***236***	***68***

- *CARB 2000-2019 GHG Inventory (2021 edition, by economic sector).

Electricity sector versus economywide emissions removal

While our Roadmap is able to achieve near zero-emissions from the electricity sector, the assumptions on technology conversion that underpin the economywide sector model still show that there will be some emissions in the broader economy outside of the electric sector. Following the approach taken by all other major studies, we quantify the emissions that remain, ~68 MMT in 2045 as provided by sector in Table 4 above, but do not estimate the cost of removing remaining emissions in 2045 and beyond—as those technologies are still at an early stage of evolution.

Table 5. Growth in Energy Consumptions (all values in TWh)* (Whitepaper Figure 6)

End Use	SDG&E		California	
	2030	2045	2030	2045
Total Energy Usage	***31***	***50***	***352***	***549***
MD/HD Charging	2	5	19	51
LDV Charging	2	6	26	70
Hydrogen Fuel Production	1	5	6	54
Buildings	17	23	200	257
Industry, Agriculture, and Other	9	11	101	117

- *Values represent 1-in-2 weather year.

Table 6. Growth in Net Peak Demand (all values in GW)* (Whitepaper Figure 6)

Net Peak Demand and Breakdown	SDG&E		California	
	2030	2045	2030	2045
Net Peak Demand	***5.7***	***8.5***	***65.7***	***93.4***
Date/Time	8/24 @ 7pm	9/27 @ 7pm	8/24 @ 7pm	9/27 @ 7pm

- *Net Peak Demand = Base Load – BTM PV – CHP.

Table 7. Generation Capacity (all values GW) (Whitepaper Figure 7)

Resource Type	SDG&E		California	
	2030	2045	2030	2045
Installed Capacity	***8.6***	***15.8***	***135.8***	***355.8***
Natural Gas	3.8	2.8	44.0	37.2
Imports	0.9	1.0	22.1	33.7
Storage*	1.6	2.5	14.0	44.0
Solar	1.6	3.9	38.2	183.6
Wind	0.7	0.7	6.8	21.9
CCS**	0.0	1.0	0.0	4.0
Hydrogen	0.0	3.9	0.0	20.0
Other***	0.0	0.0	10.7	11.4

- *Includes both short- and long-duration battery energy storage and pumped hydroelectric storage.
- **Natural gas generation with CCS. Includes new builds and retrofits.
- ***Other includes oil, coal, geothermal, biomass, hydroelectric, and nuclear.

Table 8. Electric Generation Production (Annual Electricity Breakdown) (Whitepaper Figure 7)

Resource Type	California	
	2030	2045
Natural Gas	27%	0%
Imports	23%	17%
Solar	27%	44%
Wind	7%	16%
CCS	0%	1%
Hydrogen	0%	14%
Other*	15%	9%

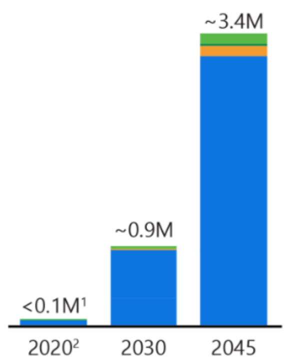
- *Other includes oil, coal, geothermal, biomass, hydroelectric, and nuclear.

Table 9. ZEV Adoption (Thousands of Vehicles) (Whitepaper Figure 9)

Vehicle Type (thousands)	SDG&E		California	
	2030	2045	2030	2045
ZEV Total	***914***	***3,366***	***8,676***	***32,061***
LD PHEV and BEV	866	3,101	8,178	29,405
LD HFCV	10	115	97	1,086
MD/HD BEV	37	131	388	1,375
MD/HD HFCV	1	19	13	195

FIGURE A3

Projected zero-emission vehicle adoption in SDG&E service area



	2020	2030	2045
Share, LDV ZEV	2%	27%	87%
Share, MDV + HDV ZEV	<1%	25%	86%

LDV PHEV + BEV

LDV HFCV

MDV + HDV BEV

MDV + HDV HFCV

[1] Estimated as ~69.6K vehicles.
[2] 2020 represents actuals based on CEC (2021) Zero-Emission Vehicle and Infrastructure Statistics (for light-duty vehicles only).
Note: 2030 + 2045 shown are projected ZEVs (for light-duty, medium-duty, and heavy-duty vehicles).

Figure A3 presents projected vehicle adoption for the SDG&E service area.

Table 10. EV Charging Infrastructure Needed in San Diego (Whitepaper Figure 10)

Projected # of EV Chargers* (thousands)	SDG&E	
	2030	2045
Total EV Chargers	180	640

- *Includes projected public, workplace and multi-unit dwelling chargers to support light, medium and heavy-duty vehicles.

Table 11. Building Electrification (% Electrified) (Whitepaper Figure 11)

Appliance Type	SDG&E/CA 2030	SDG&E/CA 2045
Residential Space Heating	20%	70%
Residential Water Heating	34%	96%
Commercial Space Heating	23%	69%
Commercial Water Heating	45%	98%

Table 12. Hydrogen End Use Breakdown (Whitepaper Figure 12)

Hydrogen End Use	California 2045
Clean Hydrogen Demand	***6.5 MMT***
Electric Generation (Hydrogen Combustion)	5.2 MMT (80%)
Transportation, Buildings and Industry	1.3 MMT (20%)

Table 13. Pipeline Gaseous Fuel Mix (percentages calculated by volume) (Whitepaper Figure 12)

Gaseous Fuel Type*	California 2045
Natural Gas	58%
Renewable Natural Gas	28%
Hydrogen	14%

- *Pipeline mix serves residential and commercial buildings, the industrial sector and natural gas electric generation.