DOCKETED

Docket Number:	21-BSTD-02
Project Title:	2022 Energy Code Update CEQA Documentation
TN #:	238753
Document Title:	Holland & Knight LLP Comments - Holland & Knight References (1 of 11)
Description:	N/A
Filer:	System
Organization:	Holland & Knight LLP
Submitter Role:	Public
Submission Date:	7/8/2021 4:43:20 PM
Docketed Date:	7/8/2021

Comment Received From: Holland & Knight LLP
Submitted On: 7/8/2021
Docket Number: 21-BSTD-02

Holland & Knight References (1 of 11)

The attached document is the first of 11 separate uploads that contain the references cited in Holland & Knight's DEIR Comment Letter.

Additional submitted attachment is included below.

Senate Bill No. 100

CHAPTER 312

An act to amend Sections 399.11, 399.15, and 399.30 of, and to add Section 454.53 to, the Public Utilities Code, relating to energy.

[Approved by Governor September 10, 2018. Filed with Secretary of State September 10, 2018.]

LEGISLATIVE COUNSEL'S DIGEST

SB 100, De León. California Renewables Portfolio Standard Program: emissions of greenhouse gases.

(1) Under existing law, the Public Utilities Commission (PUC) has regulatory authority over public utilities, including electrical corporations, while local publicly owned electric utilities, as defined, are under the direction of their governing boards. The California Renewables Portfolio Standard Program requires the PUC to establish a renewables portfolio standard requiring all retail sellers, as defined, to procure a minimum quantity of electricity products from eligible renewable energy resources, as defined, so that the total kilowatthours of those products sold to their retail end-use customers achieve 25% of retail sales by December 31, 2016, 33% by December 31, 2020, 40% by December 31, 2024, 45% by December 31, 2027, and 50% by December 31, 2030. The program additionally requires each local publicly owned electric utility, as defined, to procure a minimum quantity of electricity products from eligible renewable energy resources to achieve the procurement requirements established by the program. The Legislature has found and declared that its intent in implementing the program is to attain, among other targets for sale of eligible renewable resources, the target of 50% of total retail sales of electricity by December 31, 2030.

This bill would revise the above-described legislative findings and declarations to state that the goal of the program is to achieve that 50% renewable resources target by December 31, 2026, and to achieve a 60% target by December 31, 2030. The bill would require that retail sellers and local publicly owned electric utilities procure a minimum quantity of electricity products from eligible renewable energy resources so that the total kilowatthours of those products sold to their retail end-use customers achieve 44% of retail sales by December 31, 2024, 52% by December 31, 2027, and 60% by December 31, 2030.

Under existing law, a local publicly owned electric utility is not required to procure more than a specified minimum quantity of eligible renewable energy resources under the program if it receives more than 50% of its retail sales from hydroelectric generation, as specified.

This bill would revise those provisions, limit the applicability of this exception to large hydroelectric generation, and reduce that threshold to 40%.

(2) Existing law establishes the California Environmental Protection Agency, establishes the State Air Resources Board within the agency as the entity with responsibility for control of emissions from motor vehicles, and designates the state board as the air pollution control agency for all purposes set forth in federal law. The California Global Warming Solutions Act of 2006 establishes the state board as the state agency charged with monitoring and regulating sources of emissions of greenhouse gases that cause global warming.

The Warren-Alquist State Energy Resources Conservation and Development Act establishes the State Energy Resources Conservation and Development Commission (Energy Commission) and requires it to conduct an ongoing assessment of the opportunities and constraints presented by all forms of energy, to encourage the balanced use of all sources of energy to meet the state's needs, and to seek to avoid possible undesirable consequences of reliance on a single source of energy.

This bill would state that it is the policy of the state that eligible renewable energy resources and zero-carbon resources supply 100% of retail sales of electricity to California end-use customers and 100% of electricity procured to serve all state agencies by December 31, 2045. The bill would require that the achievement of this policy for California not increase carbon emissions elsewhere in the western grid and that the achievement not allow resource shuffling. The bill would require the PUC and the Energy Commission, in consultation with the state board, to take steps to ensure that a transition to a zero-carbon electric system for the State of California does not cause or contribute to greenhouse gas emissions increases elsewhere in the western grid. The bill would require the PUC, Energy Commission, state board, and all other state agencies to incorporate that policy into all relevant planning. The bill would require the PUC, Energy Commission, state board, and all other state agencies to ensure actions taken in furtherance of these purposes achieve specified objectives. The bill would require the PUC, Energy Commission, and state board to utilize programs authorized under existing statutes to achieve that policy and, as part of a public process, issue a joint report to the Legislature by January 1, 2021, and every 4 years thereafter, that includes specified information relating to the implementation of the policy.

(3) Under existing law, a violation of the Public Utilities Act or any order, decision, rule, direction, demand, or requirement of the PUC is a crime.

Because certain of the provisions of this bill would be a part of the act and because a violation of an order or decision of the PUC implementing its requirements would be a crime, the bill would impose a state-mandated local program. By expanding the requirements placed upon a local publicly owned electric utility, the bill would impose a state-mandated local program.

The California Constitution requires the state to reimburse local agencies and school districts for certain costs mandated by the state. Statutory provisions establish procedures for making that reimbursement.

This bill would provide that no reimbursement is required by this act for specified reasons.

The people of the State of California do enact as follows:

SECTION 1. (a) This act shall be known as The 100 Percent Clean Energy Act of 2018.

(b) The Legislature finds and declares that the Public Utilities Commission, State Energy Resources Conservation and Development Commission, and State Air Resources Board should plan for 100 percent of total retail sales of electricity in California to come from eligible renewable energy resources and zero-carbon resources by December 31, 2045.

(c) It is the intent of the Legislature in enacting this act to extend and expand policies established pursuant to the California Renewables Portfolio Standard Program (Article 16 (commencing with Section 399.11) of Chapter 2.3 of Part 1 of Division 1 of the Public Utilities Code), and to codify the policies established pursuant to Section 454.53 of the Public Utilities Code, and that both be incorporated in long-term planning.

SEC. 2. Section 399.11 of the Public Utilities Code is amended to read:

399.11. The Legislature finds and declares all of the following:

(a) In order to attain a target of generating 20 percent of total retail sales of electricity in California from eligible renewable energy resources by December 31, 2013, 33 percent by December 31, 2020, 50 percent by December 31, 2026, and 60 percent by December 31, 2030, it is the intent of the Legislature that the commission and the Energy Commission implement the California Renewables Portfolio Standard Program described in this article.

(b) Achieving the renewables portfolio standard through the procurement of various electricity products from eligible renewable energy resources is intended to provide unique benefits to California, including all of the following, each of which independently justifies the program:

(1) Displacing fossil fuel consumption within the state.

(2) Adding new electrical generating facilities in the transmission network within the WECC service area.

(3) Reducing air pollution, particularly criteria pollutant emissions and toxic air contaminants, in the state.

(4) Meeting the state's climate change goals by reducing emissions of greenhouse gases associated with electrical generation.

(5) Promoting stable retail rates for electric service.

(6) Meeting the state's need for a diversified and balanced energy generation portfolio.

(7) Assisting with meeting the state's resource adequacy requirements.

(8) Contributing to the safe and reliable operation of the electrical grid, including providing predictable electrical supply, voltage support, lower line losses, and congestion relief.

(9) Implementing the state's transmission and land use planning activities related to development of eligible renewable energy resources.

(c) The California Renewables Portfolio Standard Program is intended to complement the Renewable Energy Resources Program administered by the Energy Commission and established pursuant to Chapter 8.6 (commencing with Section 25740) of Division 15 of the Public Resources Code.

(d) New and modified electric transmission facilities may be necessary to facilitate the state achieving its renewables portfolio standard targets.

(e) (1) Supplying electricity to California end-use customers that is generated by eligible renewable energy resources is necessary to improve California's air quality and public health, particularly in disadvantaged communities identified pursuant to Section 39711 of the Health and Safety Code, and the commission shall ensure rates are just and reasonable, and are not significantly affected by the procurement requirements of this article. This electricity may be generated anywhere in the interconnected grid that includes many states, and areas of both Canada and Mexico.

(2) This article requires generating resources located outside of California that are able to supply that electricity to California end-use customers to be treated identically to generating resources located within the state, without discrimination.

(3) California electrical corporations have already executed, and the commission has approved, power purchase agreements with eligible renewable energy resources located outside of California that will supply electricity to California end-use customers. These resources will fully count toward meeting the renewables portfolio standard procurement requirements.

SEC. 3. Section 399.15 of the Public Utilities Code is amended to read:

399.15. (a) In order to fulfill unmet long-term resource needs, the commission shall establish a renewables portfolio standard requiring all retail sellers to procure a minimum quantity of electricity products from eligible renewable energy resources as a specified percentage of total kilowatthours sold to their retail end-use customers each compliance period to achieve the targets established under this article. For any retail seller procuring at least 14 percent of retail sales from eligible renewable energy resources in 2010, the deficits associated with any previous renewables portfolio standard shall not be added to any procurement requirement pursuant to this article.

(b) The commission shall implement renewables portfolio standard procurement requirements only as follows:

(1) Each retail seller shall procure a minimum quantity of eligible renewable energy resources for each of the following compliance periods:

(A) January 1, 2011, to December 31, 2013, inclusive.

(B) January 1, 2014, to December 31, 2016, inclusive.

(C) January 1, 2017, to December 31, 2020, inclusive.

(D) January 1, 2021, to December 31, 2024, inclusive.
(E) January 1, 2025, to December 31, 2027, inclusive.
(F) January 1, 2028, to December 31, 2030, inclusive.

(2) (A) No later than January 1, 2017, the commission shall establish the quantity of electricity products from eligible renewable energy resources to be procured by the retail seller for each compliance period. These quantities shall be established in the same manner for all retail sellers and result in the same percentages used to establish compliance period quantities for all retail sellers.

(B) In establishing quantities for the compliance period from January 1, 2011, to December 31, 2013, inclusive, the commission shall require procurement for each retail seller equal to an average of 20 percent of retail sales. For the following compliance periods, the quantities shall reflect reasonable progress in each of the intervening years sufficient to ensure that the procurement of electricity products from eligible renewable energy resources achieves 25 percent of retail sales by December 31, 2016, 33 percent by December 31, 2020, 44 percent by December 31, 2024, 52 percent by December 31, 2027, and 60 percent by December 31, 2030. The commission shall establish appropriate three-year compliance periods for all subsequent years that require retail sellers to procure not less than 60 percent of retail sales of electricity products from eligible renewable energy resources.

(C) Retail sellers shall be obligated to procure no less than the quantities associated with all intervening years by the end of each compliance period. Retail sellers shall not be required to demonstrate a specific quantity of procurement for any individual intervening year.

(3) The commission may require the procurement of eligible renewable energy resources in excess of the quantities specified in paragraph (2).

(4) Only for purposes of establishing the renewables portfolio standard procurement requirements of paragraph (1) and determining the quantities pursuant to paragraph (2), the commission shall include all electricity sold to retail customers by the Department of Water Resources pursuant to Division 27 (commencing with Section 80000) of the Water Code in the calculation of retail sales by an electrical corporation.

(5) The commission shall waive enforcement of this section if it finds that the retail seller has demonstrated any of the following conditions are beyond the control of the retail seller and will prevent compliance:

(A) There is inadequate transmission capacity to allow for sufficient electricity to be delivered from proposed eligible renewable energy resource projects using the current operational protocols of the Independent System Operator. In making its findings relative to the existence of this condition with respect to a retail seller that owns transmission lines, the commission shall consider both of the following:

(i) Whether the retail seller has undertaken, in a timely fashion, reasonable measures under its control and consistent with its obligations under local, state, and federal laws and regulations, to develop and construct new transmission lines or upgrades to existing lines intended to transmit electricity generated by eligible renewable energy resources. In determining the reasonableness of a retail seller's actions, the commission shall consider the retail seller's expectations for full-cost recovery for these transmission lines and upgrades.

(ii) Whether the retail seller has taken all reasonable operational measures to maximize cost-effective deliveries of electricity from eligible renewable energy resources in advance of transmission availability.

(B) Permitting, interconnection, or other circumstances that delay procured eligible renewable energy resource projects, or there is an insufficient supply of eligible renewable energy resources available to the retail seller. In making a finding that this condition prevents timely compliance, the commission shall consider whether the retail seller has done all of the following:

(i) Prudently managed portfolio risks, including relying on a sufficient number of viable projects.

(ii) Sought to develop one of the following: its own eligible renewable energy resources, transmission to interconnect to eligible renewable energy resources, or energy storage used to integrate eligible renewable energy resources. This clause shall not require an electrical corporation to pursue development of eligible renewable energy resources pursuant to Section 399.14.

(iii) Procured an appropriate minimum margin of procurement above the minimum procurement level necessary to comply with the renewables portfolio standard to compensate for foreseeable delays or insufficient supply.

(iv) Taken reasonable measures, under the control of the retail seller, to procure cost-effective distributed generation and allowable unbundled renewable energy credits.

(C) Unanticipated curtailment of eligible renewable energy resources if the waiver would not result in an increase in greenhouse gas emissions.

(D) Unanticipated increase in retail sales due to transportation electrification. In making a finding that this condition prevents timely compliance, the commission shall consider both of the following:

(i) Whether transportation electrification significantly exceeded forecasts in that retail seller's service territory based on the best and most recently available information filed with the State Air Resources Board, the Energy Commission, or another state agency.

(ii) Whether the retail seller has taken reasonable measures to procure sufficient resources to account for unanticipated increases in retail sales due to transportation electrification.

(6) If the commission waives the compliance requirements of this section, the commission shall establish additional reporting requirements on the retail seller to demonstrate that all reasonable actions under the control of the retail seller are taken in each of the intervening years sufficient to satisfy future procurement requirements.

(7) The commission shall not waive enforcement pursuant to this section, unless the retail seller demonstrates that it has taken all reasonable actions under its control, as set forth in paragraph (5), to achieve full compliance.

(8) If a retail seller fails to procure sufficient eligible renewable energy resources to comply with a procurement requirement pursuant to paragraphs (1) and (2) and fails to obtain an order from the commission waiving enforcement pursuant to paragraph (5), the commission shall assess penalties for noncompliance. A schedule of penalties shall be adopted by the commission that shall be comparable for electrical corporations and other retail sellers. For electrical corporations, the cost of any penalties shall not be collected in rates. Any penalties collected under this article shall be deposited into the Electric Program Investment Charge Fund and used for the purposes described in Chapter 8.1 (commencing with Section 25710) of Division 15 of the Public Resources Code.

(9) Deficits associated with the compliance period shall not be added to a future compliance period.

(c) The commission shall establish a limitation for each electrical corporation on the procurement expenditures for all eligible renewable energy resources used to comply with the renewables portfolio standard. This limitation shall be set at a level that prevents disproportionate rate impacts.

(d) If the cost limitation for an electrical corporation is insufficient to support the projected costs of meeting the renewables portfolio standard procurement requirements, the electrical corporation may refrain from entering into new contracts or constructing facilities beyond the quantity that can be procured within the limitation, unless eligible renewable energy resources can be procured without exceeding a de minimis increase in rates, consistent with the long-term procurement plan established for the electrical corporation pursuant to Section 454.5.

(e) (1) The commission shall monitor the status of the cost limitation for each electrical corporation in order to ensure compliance with this article.

(2) If the commission determines that an electrical corporation may exceed its cost limitation prior to achieving the renewables portfolio standard procurement requirements, the commission shall do both of the following within 60 days of making that determination:

(A) Investigate and identify the reasons why the electrical corporation may exceed its annual cost limitation.

(B) Notify the appropriate policy and fiscal committees of the Legislature that the electrical corporation may exceed its cost limitation, and include the reasons why the electrical corporation may exceed its cost limitation.

(f) The establishment of a renewables portfolio standard shall not constitute implementation by the commission of the federal Public Utility Regulatory Policies Act of 1978 (Public Law 95-617).

SEC. 4. Section 399.30 of the Public Utilities Code is amended to read:

399.30. (a) (1) To fulfill unmet long-term generation resource needs, each local publicly owned electric utility shall adopt and implement a renewable energy resources procurement plan that requires the utility to procure a minimum quantity of electricity products from eligible renewable energy resources, including renewable energy credits, as a specified percentage of total kilowatthours sold to the utility's retail end-use customers, each compliance period, to achieve the targets of subdivision (c).

(2) Beginning January 1, 2019, a local publicly owned electric utility subject to Section 9621 shall incorporate the renewable energy resources procurement plan required by this section as part of a broader integrated resource plan developed and adopted pursuant to Section 9621.

(b) The governing board shall implement procurement targets for a local publicly owned electric utility that require the utility to procure a minimum quantity of eligible renewable energy resources for each of the following compliance periods:

(1) January 1, 2011, to December 31, 2013, inclusive.

(2) January 1, 2014, to December 31, 2016, inclusive.

(3) January 1, 2017, to December 31, 2020, inclusive.

(4) January 1, 2021, to December 31, 2024, inclusive.

(5) January 1, 2025, to December 31, 2027, inclusive.

(6) January 1, 2028, to December 31, 2030, inclusive.

(c) The governing board of a local publicly owned electric utility shall ensure all of the following:

(1) The quantities of eligible renewable energy resources to be procured for the compliance period from January 1, 2011, to December 31, 2013, inclusive, are equal to an average of 20 percent of retail sales.

(2) The quantities of eligible renewable energy resources to be procured for all other compliance periods reflect reasonable progress in each of the intervening years sufficient to ensure that the procurement of electricity products from eligible renewable energy resources achieves 25 percent of retail sales by December 31, 2016, 33 percent by December 31, 2020, 44 percent by December 31, 2024, 52 percent by December 31, 2027, and 60 percent by December 31, 2030. The Energy Commission shall establish appropriate multiyear compliance periods for all subsequent years that require the local publicly owned electric utility to procure not less than 60 percent of retail sales of electricity products from eligible renewable energy resources.

(3) A local publicly owned electric utility shall adopt procurement requirements consistent with Section 399.16.

(4) Beginning January 1, 2014, in calculating the procurement requirements under this article, a local publicly owned electric utility may exclude from its total retail sales the kilowatthours generated by an eligible renewable energy resource that is credited to a participating customer pursuant to a voluntary green pricing or shared renewable generation program. Any exclusion shall be limited to electricity products that do not meet the portfolio content criteria set forth in paragraph (2) or (3) of subdivision (b) of Section 399.16. Any renewable energy credits associated with electricity credited to a participating customer shall not be used for compliance with procurement requirements under this article, shall be retired on behalf of the participating customer, and shall not be further sold,

transferred, or otherwise monetized for any purpose. To the extent possible for generation that is excluded from retail sales under this subdivision, a local publicly owned electric utility shall seek to procure those eligible renewable energy resources that are located in reasonable proximity to program participants.

(d) (1) The governing board of a local publicly owned electric utility shall adopt procurement requirements consistent with subparagraph (B) of paragraph (4) of subdivision (a) of, and subdivision (b) of, Section 399.13.

(2) The governing board of a local publicly owned electric utility may adopt the following measures:

(A) Conditions that allow for delaying timely compliance consistent with subdivision (b) of Section 399.15.

(B) Cost limitations for procurement expenditures consistent with subdivision (c) of Section 399.15.

(e) The governing board of the local publicly owned electric utility shall adopt a program for the enforcement of this article. The program shall be adopted at a publicly noticed meeting offering all interested parties an opportunity to comment. Not less than 30 days' notice shall be given to the public of any meeting held for purposes of adopting the program. Not less than 10 days' notice shall be given to the public before any meeting is held to make a substantive change to the program.

(f) Each local publicly owned electric utility shall annually post notice, in accordance with the Ralph M. Brown Act (Chapter 9 (commencing with Section 54950) of Part 1 of Division 2 of Title 5 of the Government Code), whenever its governing body will deliberate in public on its renewable energy resources procurement plan.

(g) A public utility district that receives all of its electricity pursuant to a preference right adopted and authorized by the United States Congress pursuant to Section 4 of the Trinity River Division Act of August 12, 1955 (Public Law 84-386), shall be in compliance with the renewable energy procurement requirements of this article.

(h) For a local publicly owned electric utility that was in existence on or before January 1, 2009, that provides retail electric service to 15,000 or fewer customer accounts in California, and is interconnected to a balancing authority located outside this state but within the WECC, an eligible renewable energy resource includes a facility that is located outside California that is connected to the WECC transmission system, if all of the following conditions are met:

(1) The electricity generated by the facility is procured by the local publicly owned electric utility, is delivered to the balancing authority area in which the local publicly owned electric utility is located, and is not used to fulfill renewable energy procurement requirements of other states.

(2) The local publicly owned electric utility participates in, and complies with, the accounting system administered by the Energy Commission pursuant to this article.

(3) The Energy Commission verifies that the electricity generated by the facility is eligible to meet the renewables portfolio standard procurement requirements.

(i) Notwithstanding subdivision (a), for a local publicly owned electric utility that is a joint powers authority of districts established pursuant to state law on or before January 1, 2005, that furnishes electric services other than to residential customers, and is formed pursuant to the Irrigation District Law (Division 11 (commencing with Section 20500) of the Water Code), the percentage of total kilowatthours sold to the district's retail end-use customers, upon which the renewables portfolio standard procurement requirements in subdivision (b) are calculated, shall be based on the authority's average retail sales over the previous seven years. If the authority has not furnished electric service for seven years, then the calculation shall be based on average retail sales over the number of completed years during which the authority has provided electric service.

(j) A local publicly owned electric utility in a city and county that only receives greater than 67 percent of its electricity sources from hydroelectric generation located within the state that it owns and operates, and that does not meet the definition of a "renewable electrical generation facility" pursuant to Section 25741 of the Public Resources Code, shall be required to procure eligible renewable energy resources, including renewable energy credits, to meet only the electricity demands unsatisfied by its hydroelectric generation in any given year, in order to satisfy its renewable energy procurement requirements.

(k) (1) For purposes of this subdivision, "large hydroelectric generation" means electricity generated from an existing hydroelectric facility located within the state that does not qualify as an eligible renewable energy resource and, as of January 1, 2018, was owned by a local publicly owned electric utility, the federal government as a part of the federal Central Valley Project, or a joint powers agency formed and created pursuant to the Joint Exercise of Powers Act (Chapter 5 (commencing with Section 6500) of Division 7 of Title 1 of the Government Code).

(2) If, during a year within a compliance period set forth in subdivision (b), a local publicly owned electric utility receives more than 40 percent of its retail sales from large hydroelectric generation under an ownership agreement or contract in effect as of January 1, 2018, it is not required to procure eligible renewable energy resources that exceed the lesser of the following for that year:

(A) The portion of the local publicly owned electric utility's retail sales unsatisfied by the local publicly owned electric utility's large hydroelectric generation.

(B) The soft target adopted by the Energy Commission for the intervening years of the relevant compliance period.

(3) An extension or renewal of a procurement agreement shall not be eligible to count towards the determination that the local publicly owned electric utility receives more than 40 percent of its retail sales from large hydroelectric generation in any year. This paragraph shall not apply to any

agreement in effect on January 1, 2015, between a local publicly owned electric utility and the Western Area Power Administration or federal government as part of the federal Central Valley Project.

(4) The Energy Commission shall adjust the total quantities of eligible renewable energy resources to be procured by a local publicly owned electric utility for a compliance period to reflect any reductions required pursuant to paragraph (2).

(5) This subdivision does not modify the compliance obligation of a local publicly owned electric utility to satisfy the requirements of subdivision (c) of Section 399.16.

(*l*) (1) (A) For purposes of this subdivision, "unavoidable long-term contracts and ownership agreements" means commitments for electricity from a coal-fired powerplant, located outside the state, originally entered into by a local publicly owned electric utility before June 1, 2010, that is not subsequently modified to result in an extension of the duration of the agreement or result in an increase in total quantities of energy delivered during any compliance period set forth in subdivision (b).

(B) The governing board of a local publicly owned electric utility shall demonstrate in its renewable energy resources procurement plan required pursuant to subdivision (f) that any cancellation or divestment of the commitment would result in significant economic harm to its retail customers that cannot be substantially mitigated through resale, transfer to another entity, early closure of the facility, or other feasible measures.

(2) For the compliance period set forth in paragraph (4) of subdivision (b), a local publicly owned electric utility meeting the requirement of subparagraph (B) of paragraph (1) may adjust its renewable energy procurement targets to ensure that the procurement of additional electricity from eligible renewable energy resources, in combination with the procurement of electricity from unavoidable long-term contracts and ownership agreements, does not exceed the total retail sales of the local publicly owned electric utility during that compliance period. The local publicly owned electric utility may limit its procurement of eligible renewable energy resources for that compliance period to no less than an average of 33 percent of its retail sales.

(3) The Energy Commission shall approve any reductions in procurement targets proposed by a local publicly owned electric utility if it determines that the requirements of this subdivision are satisfied.

(m) A local publicly owned electric utility shall retain discretion over both of the following:

(1) The mix of eligible renewable energy resources procured by the utility and those additional generation resources procured by the utility for purposes of ensuring resource adequacy and reliability.

(2) The reasonable costs incurred by the utility for eligible renewable energy resources owned by the utility.

(n) The Energy Commission shall adopt regulations specifying procedures for enforcement of this article. The regulations shall include a public process under which the Energy Commission may issue a notice of violation and correction against a local publicly owned electric utility for failure to comply with this article, and for referral of violations to the State Air Resources Board for penalties pursuant to subdivision (o).

(o) (1) Upon a determination by the Energy Commission that a local publicly owned electric utility has failed to comply with this article, the Energy Commission shall refer the failure to comply with this article to the State Air Resources Board, which may impose penalties to enforce this article consistent with Part 6 (commencing with Section 38580) of Division 25.5 of the Health and Safety Code. Any penalties imposed shall be comparable to those adopted by the commission for noncompliance by retail sellers.

(2) Any penalties collected by the State Air Resources Board pursuant to this article shall be deposited in the Air Pollution Control Fund and, upon appropriation by the Legislature, shall be expended for reducing emissions of air pollution or greenhouse gases within the same geographic area as the local publicly owned electric utility.

SEC. 5. Section 454.53 is added to the Public Utilities Code, to read:

454.53. (a) It is the policy of the state that eligible renewable energy resources and zero-carbon resources supply 100 percent of all retail sales of electricity to California end-use customers and 100 percent of electricity procured to serve all state agencies by December 31, 2045. The achievement of this policy for California shall not increase carbon emissions elsewhere in the western grid and shall not allow resource shuffling. The commission and Energy Commission, in consultation with the State Air Resources Board, shall take steps to ensure that a transition to a zero-carbon electric system for the State of California does not cause or contribute to greenhouse gas emissions increases elsewhere in the western grid, and is undertaken in a manner consistent with clause 3 of Section 8 of Article I of the United States Constitution. The commission, the Energy Commission, the State Air Resources Board, and all other state agencies shall incorporate this policy into all relevant planning.

(b) The commission, Energy Commission, state board, and all other state agencies shall ensure that actions taken in furtherance of subdivision (a) do all of the following:

(1) Maintain and protect the safety, reliable operation, and balancing of the electric system.

(2) Prevent unreasonable impacts to electricity, gas, and water customer rates and bills resulting from implementation of this section, taking into full consideration the economic and environmental costs and benefits of renewable energy and zero-carbon resources.

(3) To the extent feasible and authorized under law, lead to the adoption of policies and taking of actions in other sectors to obtain greenhouse gas emission reductions that ensure equity between other sectors and the electricity sector.

(4) Not affect in any manner the rules and requirements for the oversight of, and enforcement against, retail sellers and local publicly owned utilities pursuant to the California Renewables Portfolio Standard Program (Article

16 (commencing with Section 399.11) of Chapter 2.3) and Sections 454.51, 454.52, 9621, and 9622.

(c) Nothing in this section shall affect a retail seller's obligation to comply with the federal Public Utility Regulatory Policies Act of 1978 (16 U.S.C. Sec. 2601 et seq.).

(d) The commission, Energy Commission, and state board shall do both of the following:

(1) Utilize programs authorized under existing statutes to achieve the policy described in subdivision (a).

(2) In consultation with all California balancing authorities, as defined in subdivision (d) of Section 399.12, as part of a public process, issue a joint report to the Legislature by January 1, 2021, and at least every four years thereafter. The joint report shall include all of the following:

(A) A review of the policy described in subdivision (a) focused on technologies, forecasts, then-existing transmission, and maintaining safety, environmental and public safety protection, affordability, and system and local reliability.

(B) An evaluation identifying the potential benefits and impacts on system and local reliability associated with achieving the policy described in subdivision (a).

(C) An evaluation identifying the nature of any anticipated financial costs and benefits to electric, gas, and water utilities, including customer rate impacts and benefits.

(D) The barriers to, and benefits of, achieving the policy described in subdivision (a).

(E) Alternative scenarios in which the policy described in subdivision (a) can be achieved and the estimated costs and benefits of each scenario.

(e) Nothing in this section authorizes the commission to establish any requirements on a nonmobile self-cogeneration or cogeneration facility that served onsite load, or that served load pursuant to an over-the-fence arrangement if that arrangement existed on or before December 20, 1995.

SEC. 6. No reimbursement is required by this act pursuant to Section 6 of Article XIII B of the California Constitution because a local agency or school district has the authority to levy service charges, fees, or assessments sufficient to pay for the program or level of service mandated by this act or because costs that may be incurred by a local agency or school district will be incurred because this act creates a new crime or infraction, eliminates a crime or infraction, or changes the penalty for a crime or infraction, within the meaning of Section 17556 of the Government Code, or changes the definition of a crime within the meaning of Section 6 of Article XIII B of the California Constitution.

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Date of Issuance: July 16, 2018

PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

SAFETY AND ENFORCEMENT DIVISION
Electric Safety and Reliability Branch

Resolution ESRB-8
July 12, 2018

R E S O L U T I O N

RESOLUTION EXTENDING DE-ENERGIZATION REASONABLENESS, NOTIFICATION, MITIGATION AND REPORTING REQUIREMENTS IN DECISION 12-04-024 TO ALL ELECTRIC INVESTOR OWNED UTILITIES.

PROPOSED OUTCOME:

This Resolution extends the de-energization reasonableness, public notification, mitigation and reporting requirements in Decision (D.) 12-04-024 to all electric Investor Owned Utilities (IOUs) and adds new requirements. It also places a requirement on utilities to make all feasible and appropriate attempts to notify customers of a de-energization event prior to performing de-energization.

SAFETY CONSIDERATIONS:

De-energizing electric facilities during dangerous conditions can save lives and property and can prevent wildfires. This resolution provides guidelines that IOUs must follow and strengthens public safety requirements when an IOU decides to de-energize its facilities during dangerous conditions.

ESTIMATED COST: Costs of compliance with the new requirements are unknown.

SUMMARY

Commission Decision (D.) 12-04-024 established requirements for reasonableness, notification, mitigation and reporting by San Diego Gas & Electric Company (SDG&E) for its de-energization events.

This resolution extends the requirements established in D.12-04-024 to all electric IOUs, requires that the utilities meet with the local communities that may be impacted by a future de-energization event before putting the practice in effect in a particular area, requires feasible and appropriate customer notifications prior to a de-energization event, and requires notification to the Safety and Enforcement Division (SED) as soon as practicable after a decision to de-energize facilities and within 12 hours after the last service is restored.

BACKGROUND

California Public Utilities Code (PU Code) Sections 451 and 399.2(a) give electric utilities authority to shut off electric power in order to protect public safety. This authority includes shutting off power for the prevention of fires caused by strong winds.

Application (A.) 08-12-021 filed by SDG&E on December 22, 2008, requested specific authority to shut off power as a fire-prevention measure against severe Santa Ana winds and a review of SDG&E's proactive de-energization measures. SDG&E also requested that such power shut-offs would qualify for an exemption from liability under SDG&E's Tariff Rule 14.

Decision (D.) 12-04-024 issued on April 19, 2012 provided guidance on SDG&E's authority to shut off power under the PU Code and also established factors the Commission may consider in determining whether or not a decision by SDG&E to shut off power was reasonable. The decision ruled that SDG&E has the authority under Public Utilities Code, Sections 451 and 399.2(a) to shut off power in emergency situations when necessary to protect public safety. It also ruled that a decision to shut off power by SDG&E under its statutory authority, including the adequacy of any notice given and any mitigation measures implemented, may be reviewed by the Commission to determine if SDG&E's actions were reasonable. The decision requires SDG&E to take appropriate and feasible steps to provide notice and mitigation to its customers whenever it shuts off power. The decision also requires SDG&E to notify the Commission's Consumer Protection and Safety Division, now the Safety and Enforcement Division (SED), of the shut-off within 12 hours and submit a report to SED with a detailed explanation of its decision to shut off the power.

Southern California Edison Company (SCE) and Pacific Gas and Electric Company (PG&E) both currently exercise their authority to shut off power during dangerous fire conditions. However, there are currently no established standards on reasonableness, notification, mitigation and reporting by IOUs other than SDG&E.

DISCUSSION

The 2017 California wildfire season was the most destructive wildfire season on record, and saw multiple wildfires burning across California, including five of the 20 most destructive wildland-urban interface fires in the state's history. Devastating fires raged in Santa Rosa, Los Angeles, and Ventura, and the Thomas Fire proved to be the largest wildfire in California history. These fires further demonstrated the fire risk in California. As a result of the fires and critical fire weather conditions, both the President of the United States and the Governor of California issued State of Emergency declarations.

SDG&E exercised its statutory authority under Public Utilities Code Sections 451 and 399.2(a), to de-energize specific circuits in December of 2017. The first group of de-energization events occurred during the period of December 4 through 12, 2017. There were 55 individual circuit de-energization events involving 28 circuits (some circuits had multiple de-energization events) in various eastern San Diego County communities. A total of approximately 14,000 customers were affected.

A second group of de-energization events occurred on December 14 and 15, 2017. There were six individual circuit de-energization events involving three circuits in various eastern San Diego County communities. A total of approximately 650 customers were affected.

In 2017, SCE also used de-energization as a measure to protect its system against fire safety hazards. The de-energization event occurred on December 7, 2017 and affected customers in the community of Idyllwild. Approximately 8,061 total customers were affected in SCE's and nearby Anza Co-Op's service territories. The de-energization event occurred in response to a Red Flag Warning in effect, SCE meteorological forecasting, field-validated extreme high winds and associated fire risks in the area.

According to SCE, during such an event, the company typically attempts to notify customers who could be affected prior to de-energization if timing allows. For the December 7, 2017 event, SCE notified city, county and government officials prior to de-energizing but was not able to notify affected customers prior to the outage occurring. SCE also utilizes other wildfire mitigation practices, such as blocking of distribution reclosers in High Fire Areas, prior to de-energization. According to SCE, de-energization of circuits would be the last line of defense to protect public safety due to extreme fire weather conditions. SCE requires that such an event must be authorized by its activated Incident Management Team.

PG&E reports that prior to 2018, it did not have a policy to de-energize lines as a fire prevention measure. PG&E reported that it did not proactively de-energize lines due to extreme fire weather conditions in 2017. However, in March 2018 PG&E announced that it is developing a program to de-energize lines during periods of extreme fire conditions and has been meeting with local communities to gather feedback.

I. Current De-Energization Policies Applicable to SDG&E

D.12-04-024 established de-energization policies applicable to SDG&E addressing reporting, reasonableness review and customer notification.

A. <u>Reporting</u>

Under D.12-04-024, SDG&E is required to provide the following notifications:

- A notification to the Director of SED provided no later than 12 hours after the power shut-off.
- A report to the Director of SED provided no later than 10 business days after the shut-off event ends that includes (i) an explanation of the decision to shut off power; (ii) all factors considered in the decision to shut off power, including wind speed, temperature, humidity, and moisture in the vicinity of the de-energized circuits; (iii) the time, place, and duration of the shut-off event; (iv) the number of affected customers, broken down by residential, medical baseline, commercial/industrial, and other; (v) any wind-related damage to SDG&E's overhead power-line facilities in the areas where power is shut off; (vi) a description of the notice to customers and any other mitigation provided by

SDG&E; and (vii) any other matters that SDG&E believes are relevant to the Commission's assessment of the reasonableness of SDG&E's decision to shut off power.

As other electric IOUs shut off power in a similar manner and in similar situations, such notifications are important to allow safety oversight by SED, and it would be appropriate to have these reporting requirements apply to all electric IOUs' de-energization events.

B. Reasonableness Review

D.12-04-024 identified several factors that the Commission may consider in assessing whether an SDG&E decision to de-energize "was reasonable and qualifies for an exemption from liability under SDG&E's Electric Tariff Rule 14."[1] These factors are summarized below:

- SDG&E has the burden of demonstrating that its decision to shut off power is necessary to protect public safety.
- SDG&E must rely on other measures, to the extent available, as alternatives to shutting off power.
- SDG&E must reasonably believe that there is an imminent and significant risk that strong winds will topple its power lines onto tinder dry vegetation during periods of extreme fire hazard.
- SDG&E must consider efforts to mitigate the adverse impacts on the customers and communities in areas where it shuts off power. This includes steps to warn and protect its customers whenever it shuts off power.
- Other additional factors, as appropriate, to assess whether the decision to shut off power is reasonable.

As other electric IOUs are developing and/or instituting de-energization plans, it is important that these factors be used to assess the reasonableness of all electric IOU de-energization events in order to ensure that the power shut off is executed only as a last resort and for a good reason. However, we modify the third factor listed above by adding the phrase underlined below:

- [The IOU] must reasonably believe that there is an imminent and significant risk that strong winds will topple its power lines onto tinder dry vegetation <u>or will cause major vegetation-related impacts on its facilities</u> during periods of extreme fire hazard.

C. Public Outreach, Notification, and Mitigation

D.12-04-024 requires that SDG&E provide notice and mitigation to its customers, to the extent feasible and appropriate, whenever SDG&E shuts off power pursuant to its statutory authority.

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[1] D.12-04-024, page 30.

As other electric IOUs are developing and/or instituting de-energization plans, it is important that this requirement for public outreach, notification, and mitigation apply to all electric IOUs in order to ensure that customers are impacted to the least extent necessary. We recognize that it is not practicable to have an absolute requirement that electric IOUs provide advance notification to customers prior to a de-energization event.

II. Strengthened Requirements Applicable to all Electric IOUs

Recent California experience with wildfires demands that we enhance existing de-energization policy and procedures. In order to ensure that the public and local officials are prepared for power shut off and aware of an IOU de-energization policy, and in order to ensure proper safety oversight by SED, we adopt the following:

1. The guidelines in D.12-04-024, currently applicable to SDG&E only, shall apply to all electric IOUs.
2. The guidelines shall be strengthened as described in the following sections and the strengthened guidelines shall apply to all electric IOUs.

A. Reporting

IOUs shall submit a report to the Director of SED within 10 business days after each de-energization event, as well as after high-threat events where the IOU provided notifications to local government, agencies, and customers of possible de-energization though no de-energization occurred. Reports to the Director of SED must include at a minimum the following information:

- The local communities' representatives the IOU contacted prior to de-energization, the date on which they were contacted, and whether the areas affected by the de-energization are classified as Zone 1, Tier 2, or Tier 3 as per the definition in General Order 95, Rule 21.2-D.
- If an IOU is not able to provide customers with notice at least 2 hours prior to the de-energization event, the IOU shall provide an explanation in its report.
- The IOU shall summarize the number and nature of complaints received as the result of the de-energization event and include claims that are filed against the IOU because of de-energization.
- The IOU shall provide detailed description of the steps it took to restore power.
- The IOU shall identify the address of each community assistance location during a de-energization event, describe the location (in a building, a trailer, etc.), describe the assistance available at each location, and give the days and hours that it was open.

B. Reasonableness Review

The reasonableness review discussion in D.12-04-024 and detailed above shall apply to all electric IOUs. At this time, we are not adding additional requirements and, while we recognize that this issue along with financial liability are important ongoing discussions, this resolution is not the venue for that discussion.

C. Public Outreach, Notification, and Mitigation

Increased coordination, communication and public education can be effective measures to increase public safety and minimize adverse impact from de-energization.

- The IOU shall notify the Director of SED, as soon as practicable, once it decides to de-energize its facilities. If the notification was not prior to the de-energization event, the IOU shall explain why a pre-event notification was not possible. The notification shall include the area affected, an estimate of the number of customers affected, and an estimated restoration time. The IOU shall also notify the Director of SED of full restoration within 12 hours from the time the last service is restored.
- Within 90 days of the effective date of this resolution, each IOU shall convene De-Energization Informational Workshops with representatives of entities that may be affected by a de-energization event, including but not limited to: state agencies, tribal governments, local agencies and representatives from local communities. Workshops should be inclusive of, but not limited to, representatives of customers who are low-income, have limited English, have disabilities, or are elderly. The purpose of these workshops is to explain, and receive feedback on, the IOU's de-energization policies and procedures. The workshops should be supplemented by focused working sessions, upon request by specific groups such as communications providers or Community Choice Aggregators that might have notification needs different than those of the general public.
- Within 30 days of the effective date of this resolution, each IOU shall submit a report to the Director of SED outlining its public outreach, notification, and mitigation plan. The plan must include at a minimum, the following information:
  - Names of communities that will be invited to De-Energization Informational Workshops.
  - Names of state agencies and tribal governments that the IOU will coordinate with in developing its de-energization plan and will invite to De-Energization Informational Workshops.
  - Names of local agencies the IOU will coordinate with in developing its de-energization plan and will invite to De-Energization Informational Workshops.
  - Proposed communication methods for publicizing and convening the De-Energization Informational Workshops.
  - Details regarding its plans for notification in advance of, and during, a de-energization event, and its plans for mitigation when de-energization occurs.
- The IOU shall ensure that de-energization policies and procedures are well-communicated and made publicly available, including the following:
  - Make available and post a summary of de-energization policies and procedures on its website.
  - Meet with representatives from local communities that may be affected by

de-energization events, before putting the practice in effect in a particular area.

  - Provide its de-energization and restoration policy in full, and in summary form, to the affected community officials before de-energizing its circuits.
  - Discuss the details of any potential shut-off and mitigation measures that the communities should consider putting in place, including information about any assistance that the IOU may be able to provide during events.

- In anticipation of a specific de-energization event, the IOU shall:
  - Notify customers of planned de-energization as soon as practicable before the event.
  - As practicable and operationally feasible, notify and communicate with representatives from the fire departments, first responders, local communities, government, communications providers, and Community Choice Aggregators that may be affected by the de-energization event.
  - Discuss with local government and community representatives the details of any potential shut-off and mitigation measures the IOU can provide to lessen the negative impacts of the power outage (e.g., cooling centers).
  - Ensure that critical facilities such as hospitals, emergency centers, fire departments, and water plants are aware of the planned de-energization event.
- The IOU shall retain documentation of community meetings and information provided in electronic form, and make that information available to SED upon request. The information shall be retained for a minimum of one year after the de-energization event or five years after the community meetings, whichever comes first.
- After the de-energization event, IOUs shall assist critical facility customers to evaluate their needs for backup power and determine whether additional equipment is needed. To address public safety impacts of a de-energization event, the IOU may provide generators to critical facilities that are not well prepared for a power shut off.
- The IOU shall retain records of customer notifications and make that information available to SED upon request. The information shall be retained for a minimum of one year after the de-energization event.

COMMENTS ON DRAFT RESOLUTION

PU Code Section 311(g)(1) provides that a resolution must be served on all parties and subject to at least 30 days public review and comment prior to a vote of the Commission. Section 311(g)(2) provides that this 30-day period may be reduced or waived upon the stipulation of all parties in the proceeding or in other specified situations.

The draft resolution was mailed to parties for comment on May 30, 2018, and was noticed on the Commission's Daily Calendar on June 8, 2018. The 30-day comment period for the draft resolution was neither waived nor reduced. Parties submitted comments by June 28, 2018, and reply comments by July 6, 2018.

Based on parties' comments, several modifications were made to the draft resolution, including the following:

- One of the factors specified in D.12-04-024 for consideration during reasonableness reviews was expanded for use when applied to all IOUs.
- The requirements for reporting events that do not eventually trigger de-energization were clarified.
- The full restoration reporting period to the SED was increased from 30 minutes to 12 hours.
- The period for convening De-Energization Informational Workshops was increased from 60 days to 90 days.
- The guidance for meeting with local communities was made a general requirement, rather than tied to specific de-energization events.
- Low-income, limited English, and disability communities were added to the list of parties to include in the De-Energization Informational Workshops.
- Communications providers were added to the list of representatives to be notified in anticipation of a de-energization event.
- The requirement to provide generators and/or batteries to critical facilities was removed since most critical facilities are required to have their own back-up power resources.

Also in response to comments by the parties, we clarify that the requirements adopted in this resolution are not in conflict with IOU authority to de-energize power lines to ensure public safety provided under the PU Code. We expect an IOU to use its best judgment on a case-by-case basis to determine whether de-energization is needed for public safety. We hold this expectation even if an IOU has not complied fully with each of the requirements in this resolution, for example, if a need for de-energization arises before an IOU has meet with the impacted local communities. If an IOU did not fulfill one or more of the requirements in this resolution prior to a de-energization, the IOU shall identify the missed requirement(s) and provide an explanation in its report submitted to the Director of SED after the de-energization event.

FINDINGS

1. Under PU Code Sections 451 and 399.2(a), electric IOUs have the authority to shut off power in order to protect public safety.
2. The decision to de-energize electric facilities for public safety is complex and dependent on many factors including and not limited to fuel moisture; aerial and ground firefighting capabilities; active fires that indicate fire conditions; situational awareness provided by fire agencies, the National Weather Service and the United States Forest Service; and local meteorological conditions of humidity and winds.
3. The decision to shut off power may be reviewed by the Commission pursuant to its broad jurisdiction over public safety and utility operations.

4. The requirements for reporting, public outreach, notification, mitigation and reasonableness review in D.12-04-024 are effective, but are only applicable to SDG&E.
5. All electric IOUs may face similar safety situations requiring power shut-off in emergencies and de-energization events in their service territory.
6. De-energization of electric facilities could save lives, protect property, and prevent fires.
7. The measures in D.12-04-024 should be strengthened to further ensure that the public and local officials are prepared for de-energization events and to ensure the proper safety oversight by the Commission's Safety and Enforcement Division.

THEREFORE, IT IS ORDERED THAT:

1. All electric IOUs shall take appropriate and feasible steps to provide notice and mitigation to their customers in accordance with the guidelines in D.12-04-024 whenever they shut off power pursuant to their statutory authority.
2. All electric IOUs shall follow the notification requirements to SED established in D.12-04-024.
3. All electric IOUs shall comply with the additional guidelines stated in the section of this resolution titled "**Strengthened Requirements Applicable to all Electric IOUs.**"

This Resolution is effective today.

I certify that the foregoing resolution was duly introduced, passed and adopted at a conference of the Public Utilities Commission of the State of California held on July 12, 2018; the following Commissioners voting favorably thereon:

/s/ *ALICE STEBBINS*
ALICE STEBBINS
Executive Director

MICHAEL PICKER
President
CARLA J. PETERMAN
LIANE M. RANDOLPH
MARTHA GUZMAN ACEVES
CLIFFORD RECHTSCHAFFEN
Commissioners

DOCKETED	
Docket Number:	18-IEPR-09
Project Title:	Decarbonizing Buildings
TN #:	223785
Document Title:	Deep Decarbonization in a High Renewables Future
Description:	Energy Research and Development Division Final Project Report - Deep Decarbonization in a High Renewables Future - Updated Results from the California PATHWAYS Model
Filer:	Denise Costa
Organization:	California Energy Commission
Submitter Role:	Commission Staff
Submission Date:	6/12/2018 3:22:55 PM
Docketed Date:	6/12/2018

Energy Research and Development Division

FINAL PROJECT REPORT

Deep Decarbonization in a High Renewables Future

Updated Results from the California PATHWAYS Model

California Energy Commission

Edmund G. Brown Jr., Governor

June 2018 | CEC-500-2018-012

STATE OF CALIFORNIA

ENERGY COMMISSION

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ACKNOWLEDGEMENTS

The authors acknowledge those who helped develop the California PATHWAYS model since its inception including Dr. Jim Williams, Ben Haley, Dr. Elaine Hart, Tory Clark, Hilary Staver, Jamil Farbes, Katie Pickrell, and Dr. Sam Borgeson.

We are grateful to the California Energy Commission's Electric Program Investment Charge for the financial support that made this project possible, as well as to all those who provided comments on the draft results and reviewed the report.

PREFACE

The California Energy Commission's Energy Research and Development Division supports energy research and development programs to spur innovation in energy efficiency, renewable energy and advanced clean generation, energy-related environmental protection, energy transmission and distribution and transportation.

In 2012, the Electric Program Investment Charge (EPIC) was established by the California Public Utilities Commission to fund public investments in research to create and advance new energy solutions, foster regional innovation and bring ideas from the lab to the marketplace. The California Energy Commission and the state's three largest investor-owned utilities – Pacific Gas and Electric Company, San Diego Gas & Electric Company and Southern California Edison Company – were selected to administer the EPIC funds and advance novel technologies, tools, and strategies that provide benefits to their electric ratepayers.

The Energy Commission is committed to ensuring public participation in its research and development programs that promote greater reliability, lower costs, and increase safety for the California electric ratepayer and include:

- Providing societal benefits.
- Reducing greenhouse gas emission in the electricity sector at the lowest possible cost.
- Supporting California's loading order to meet energy needs first with energy efficiency and demand response, next with renewable energy (distributed generation and utility scale), and finally with clean, conventional electricity supply.
- Supporting low-emission vehicles and transportation.
- Providing economic development.
- Using ratepayer funds efficiently.

Deep Decarbonization in a High Renewables Future: Updated Results from the California PATHWAYS Model is the final report for the Long-Term Energy Scenarios project (Contract Number EPC-14-069) conducted by Energy and Environmental Economics, Inc. (E3). The information from this project contributes to Energy Research and Development Division's EPIC Program.

For more information about the Energy Research and Development Division, please visit the Energy Commission's website at www.energy.ca.gov/research/ or contact the Energy Commission at 916-327-1551.

ABSTRACT

This project evaluates long-term energy scenarios in California through 2050 using the California PATHWAYS model. These scenarios investigate options and costs to achieve a 40 percent reduction in greenhouse gas emissions by 2030 and an 80 percent reduction in greenhouse gas emissions by 2050, relative to 1990 levels.

Ten mitigation scenarios are evaluated, each designed to achieve the state's greenhouse gas reduction goals subject to a changing California climate. All mitigation scenarios are characterized by high levels of energy efficiency and conservation, renewable electricity generation, and transportation electrification.

The mitigation scenarios differ in their assumptions about biofuels and building electrification, among other variations. The High Electrification scenario is found to be one of the lower-cost and lower-risk mitigation scenarios, subject to uncertainties in building retrofit costs as well as implementation challenges.

This research highlights the pivotal role of the consumer in meeting the state's climate goals. To achieve high levels of adoption of electric vehicles, energy efficiency and electrification in buildings, near-term action is necessary to avoid costly replacement of long-lived equipment in 10-15 years. Furthermore, market transformation is essential to reduce the capital cost of electric vehicles and heat pumps.

Keywords: *2050 pathways, greenhouse gas emissions, climate change, California long-term energy scenarios, electrification, energy efficiency, low-carbon biofuels, low-carbon electricity*

Please use the following citation for this report:

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

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EXECUTIVE SUMMARY

Introduction

This project evaluates long-term energy scenarios through 2050 using a techno-economic model known as the California PATHWAYS model. These scenarios investigate options and costs for California in a changing climate to achieve a mandated 40 percent reduction in greenhouse gas (GHGs) emissions by 2030, and an 80 percent reduction in GHGs by 2050, relative to 1990 levels.

In 2017, California extended the state's Cap-and-Trade Program through 2030 (Assembly Bill 398, Garcia. Chapter 135. Statutes of 2017). The carbon price resulting from the Cap-and-Trade Program will help improve the economics of low-carbon alternatives, yet it is not clear whether the carbon price on its own will be sufficient to close the gap between emissions reductions achieved through current policies and the 2030 GHG target. The scenarios investigated in this research suggest that additional upfront cost incentives or subsidies, technological breakthroughs, and business and policy innovations may be required. While this research does not specifically address the role of cap and trade in meeting the state's climate goals, it highlights the physical transformations of the state's energy economy that is necessary and the challenges in accomplishing that transformation for new equipment sales, megawatts of renewable energy procured, and the production of zero-carbon fuels.

Project Purpose

This project advances the understanding of what is required for technology deployment and other GHG mitigation strategies if California is to meet its long-term climate goals. This research provides researchers and policy makers with information about key choices that could lower the costs of meeting the state's GHG reduction goals. Moreover, this analysis incorporates and evaluates the implications of the expected impacts of climate change on the electricity system through 2050 to inform California's Fourth Climate Change Assessment.

This research addresses the key questions:

- What are the priority, near-term strategies in the areas of scaling-up deployment, market transformation and reach technologies needed to achieve California's 2030 and 2050 GHG reduction goals?
- What are the risks to, and potential cost implications of, meeting the state's GHG goals if key mitigation strategies are not as successful as hoped?

Project Process

Long-term energy scenarios through 2050 are analyzed using the California PATHWAYS model, an economy wide, technology-specific scenario tool developed by Energy and Environmental Economics (E3) from 2009 through the present. The PATHWAYS scenarios leverage prior research and analysis from other state energy agencies and from E3, building upon and expanding E3's prior work.

These scenarios use the latest research from the University of California Irvine (EPC-14-074) with results providing the expected impacts of climate change on the electricity sector through

2050. These results specifically show a lower average availability of hydroelectric generation available to California and higher average temperatures, which result in lower heating demands in buildings and higher air-conditioning demands.

In addition, researchers use a least-cost capacity expansion dispatch model, E3's Renewable Energy Solutions Model (RESOLVE), to test the impact of the PATHWAYS scenarios on the California electricity grid. The RESOLVE model evaluates least-cost capacity expansion options for the California electricity sector and generation dispatch solutions through 2050 using the PATHWAYS scenario results of an electricity sector greenhouse gas constraint and a set of electricity demands. The modeled geography represents the entire state (with simplified assumptions in the rest of the Western Interconnection) through 2050.

Key changes to these scenarios, relative to E3's prior work, include updated technology and fuel cost assumptions, with lower cost trajectories for renewable electricity, energy storage and electric vehicles, and updated cost assumptions for alternative fuel trucking technologies. The analysis also includes a lower base case assumption about the consumer cost of capital. In addition, most scenarios consider a biofuels-constrained future, whereby only biomass waste and residues are available to produce biofuels from within the United States. Purpose-grown crops are excluded from these scenarios because of the potential emissions from indirect land-use change. In these scenarios, biofuel production efficiencies and costs do not change over time, resulting in relatively limited and high-cost biofuels.

Scenarios Evaluated

Three types of California long-term energy scenarios are developed, including:

- A "Reference" or business-as-usual scenario, reflecting policies prior to the passage of Senate Bill (SB) 350 (33 percent Renewables Portfolio Standard from 2030 through 2050 and historical levels of energy efficiency savings)
- A "Senate Bill 350" scenario, which reflects the impact of SB 350 (De León, Chapter 547, Statutes 2015, which requires a 50 percent Renewables Portfolio Standard by 2030 and a doubling of energy efficiency savings relative to historical goals), as well as other policies that were in place as of 2016, including vehicle electrification and reductions in short-lived climate pollutants by 2030
- "Mitigation" scenarios are evaluated which meet the state's 2030 and 2050 GHG goals using different combinations of greenhouse gas reduction strategies. The "High Electrification" scenario is one of the ten mitigation scenarios evaluated, which meets the state's climate goals using a plausible combination of greenhouse mitigation technologies.

Scenarios test the impact of over- or underperformance on key technology deployment trajectories to assess potential cost risks, and to identify priority areas for near-term action for deployment, market transformation, and "reach" technologies that may be required to meet the 2050 greenhouse gas target. A reach technology is a technology not widely commercialized today but has been demonstrated outside of laboratory conditions and has the potential to mitigate emissions from sectors that are currently difficult to address. Ten mitigation scenarios are developed in total to help identify which strategies are most critical to meeting the state's

2030 and 2050 greenhouse gas goals. These scenarios are used to identify key technology risks and to evaluate the robustness of the state's climate mitigation strategies if one strategy does not deliver greenhouse gas reductions as expected.

The report focuses on the High Electrification scenario, which is one of the lower-cost, lower-risk mitigation scenarios. This scenario includes high levels of energy efficiency and conservation, renewable electricity, and electrification of buildings and transportation, with reliance on biomethane in the pipeline to serve mainly industrial end uses. The High Electrification scenario assumes a transition of the state's buildings from using natural gas to low-carbon electricity for heating demands. This transition presents a suite of implementation challenges including uncertain feasibility and costs of retrofitting the state's existing building stock, equity and distributional cost impacts, as well as consumer acceptance.

Project Results

Achieving California's climate goals will fundamentally transform the state's energy economy, requiring high levels of energy efficiency and conservation, electrification of vehicles, zero-carbon fuels and reductions in non-combustion greenhouse gases. Meeting the state's 2030 climate goals requires scaling up and using technologies already in the market such as energy efficiency and renewables, while pursing aggressive market transformation of new technologies that have not yet been utilized at scale in California (for example, zero-emission vehicles and electric heat pumps). In addition, at least one "reach" technology that has not been commercially proven will likely be necessary to help meet the 2050 greenhouse gas goal, and to mitigate the risk of other greenhouse gas reduction solutions falling short.

To achieve high levels of consumer adoption of zero-carbon technologies, particularly of electric vehicles and energy efficiency and electric heat in buildings, market transformation is needed to bring down the capital cost and to increase the range of options available. Market transformation can be facilitated by:

1. Higher carbon prices, such as those created by the state's cap and trade and low-carbon fuel standard programs, which reduce the cost differential between low-carbon fuels and fossil fuels.
2. Codes and standards, regulations and direct incentives, to reduce the upfront cost to the customer.
3. Business and policy innovations, to make zero-carbon technology options the cheaper, preferred solution compared to the fossil fueled alternative.

Table 1 summarizes the key strategies identified through this research that should be prioritized for scaled-up use, market transformation, and as "reach" technologies that may be crucial to meet the 2050 greenhouse gas target.

Table 1: Priority GHG Reduction Strategies

Scale Up & Deploy	2030 Indicative Metrics	Key Challenges
Energy efficiency in buildings & industry	Deployment of LED lighting, higher efficiency plug loads, improved shell in existing buildings, continued improvements and enforcement of building codes, industrial EE	Consumer decisions and market failures
Renewable electricity	70 – 80% zero-carbon electricity with renewable integration solutions: flexible loads, market-based curtailment, cost-effective grid storage	Implementation of integration solutions
Smart growth	Reduced vehicle miles traveled through increased use of public transit, walking, biking, telepresence, and denser, mixed-use community design	Consumer decisions and legacy development patterns
Market Transformation	**2030 Indicative Metrics**	**Key Challenges**
Zero-emission light-duty vehicles (ZEV)	At least 6 million ZEVs, >60% of new sales are ZEVs, drivers have access to day-time charging stations and time-of-use charging	Consumer decisions and cost
Advanced building efficiency/electrification	50% of new water heater and HVAC sales are high-efficiency heat pumps	Consumer decisions, equity of cost impacts, cost and retrofits of existing buildings
Fluorinated (F)-gas replacement	Replace F-gases with lower global warming potential (GWP) refrigerants	Standards needed to require alternatives
Methane capture	Methane capture from manure, fugitive and process emissions, landfills, and wastewater	Small and diffuse point sources
Reach Technologies	**2030 Indicative Metrics**	**Key Challenges**
Advanced sustainable biofuels	Demonstrated use of sustainable, carbon-neutral biomass feedstocks to produce commercial-scale biofuels	Cost and sustainability challenges
Zero-emissions heavy-duty trucks	Commercial deployment of battery-electric and/or hydrogen trucks	Cost
Industrial electrification	Cost-competitive electrification of industrial end-uses, including boilers, machine drives, and process heating	Cost & technical implementation challenges
Electrolysis hydrogen production	Improved cost and efficiency at commercial scale. Business model for flexible hydrogen production.	Cost

Source: E3

High Electrification Scenario Direct Costs Compared to the Reference Scenario

The net cost of transforming the state's energy economy to a low-carbon system is relatively small. Fuel savings from reduced consumption of gasoline, diesel and natural gas help offset the higher capital costs associated with low-carbon technologies. The estimated 2030 total direct cost, (excluding health and climate benefits), to meet the state's climate goals range from a savings of $2 billion per year to net costs of $17 billion per year, with a base case result of $9 billion per year in 2030. This amount is less than the recovery costs associated with one large natural disaster, such as the recent 2017 wildfires in Northern California. Put differently, the estimated 2030 cost of reducing statewide greenhouse gas emissions by 40 percent is likely to range from a savings of 0.1 percent to costs of 0.5 percent of California's gross state product, and the societal benefits of the GHG reductions achieved are likely to outweigh these costs. For example, in other studies, the estimated health benefits associated with reducing GHG emissions, and thus improving air quality, have been estimated to exceed these direct costs.

The upfront capital cost investment, however, is still significant, and is spread across both businesses and households – some of which have better access to low-cost capital than others. Long-term fuel savings, or even lifecycle cost savings, may not convince businesses and households to make the switch to new technologies with which they have little experience. A key challenge is convincing millions of households and businesses to adopt these technologies and become the drivers of change to a low-carbon economy.

Finally, this study aggregates statewide costs and benefits, explicitly excluding the effect of state incentives and in-state transfers, such as Cap-and-Trade, the Low Carbon Fuel Standard, and utility energy efficiency programs. Costs borne by individual households will differ from the average and will depend on policy implementation. Further research could investigate the cost implications of specific state policies on individuals and businesses.

Uncertainty in Scenario Analysis

While these models produce numerically precise results, the long-term greenhouse gas reduction scenarios resulting from the modeling are neither predictions nor forecasts of the future. Several key assumptions, however, could change this study's findings about the High Electrification scenario as one of the lower-cost, lower-risk decarbonization pathways. First, biofuels could be available at lower cost than modeled here, particularly if sustainability concerns with purpose-grown crops are addressed, or if other jurisdictions continue to lag California in decarbonizing their economies and so do not rely on advanced biofuels, resulting in more of the global biofuel supply being available to California. Second, high costs associated with retrofitting existing buildings for electric heating could significantly increase the cost of the High Electrification scenario. This scenario assumes that building electrification could proceed in California without requiring costly early retirement of end-use equipment, and without creating cost equity impacts for natural gas customers which must be mitigated. These assumptions deserve further research and inquiry.

Benefits of this Research to California

This research has evaluated options for meeting the state's economywide climate goals, including assessing the potential effects on and implications for the electricity sector. This research provides decision-makers and researchers with information about the cost implications and emissions tradeoffs between different greenhouse gas mitigation strategies focusing on 2030 versus those focusing on 2050, and it highlights the pivotal role of the consumer to help meet the state's climate goals.

Furthermore, this research has helped fund the development of widely used energy and electricity sector planning tools, including the California PATHWAYS model and the electricity sector capacity expansion and dispatch RESOLVE model. These energy and electricity planning tools have been, and continued to be, used by many California state agencies to provide unique insights into how the electricity system may evolve during the next 15 to 30 years to achieve state goals.

The benefits of this project and research will continue to expand as future projects build on this work and through ongoing research and policy discussions within and outside California on how to achieve deep reductions in greenhouse gas emissions.

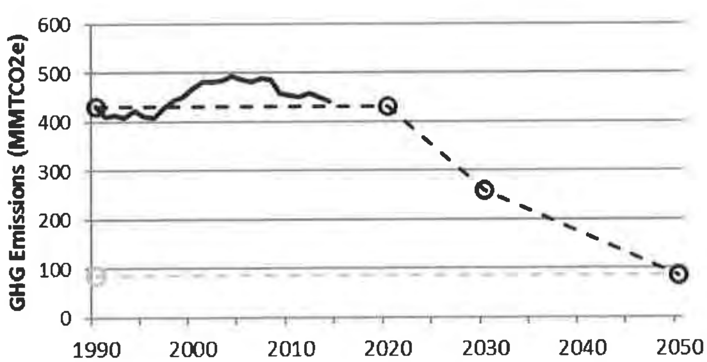
CHAPTER 1: Meeting California's Long-term Climate Goals

Introduction

Climate change presents devastating risks to human health and welfare, the global economy and ecosystems world-wide (IPCC, 2014). The impacts of climate change are already being observed globally, and in California specifically, with increased temperatures, higher incidence of wildfires, and changes to snowfall, snowmelt and precipitation patterns (CEC 2012, and Kadir et al, 2013).

California is aiming to reduce its greenhouse gas emissions (GHG) while creating an energy system that is resilient to climate risks, spurring innovation and a low-carbon transition nationally and internationally. California's climate goals are among the most ambitious in the country. California's Assembly Bill 32 (Nuñez, Chapter 488, Statutes of 2006) requires reducing statewide GHG emissions to 1990 levels by 2020, while Senate Bill 32 (Pavley, Chapter 249, Statutes of 2016) requires reducing statewide emissions to 40% below 1990 levels by 2030. The state's long-term climate commitment, laid out in Executive Order S-3-05, calls for an 80% reduction in GHGs below 1990 levels by 2050 (Figure 1). While ambitious, these goals represent the minimum level of carbon abatement scientists believe is necessary globally to stave off the effects of catastrophic climate change (IPCC, 2014).

Figure 1: California Greenhouse Gas Emissions Goals

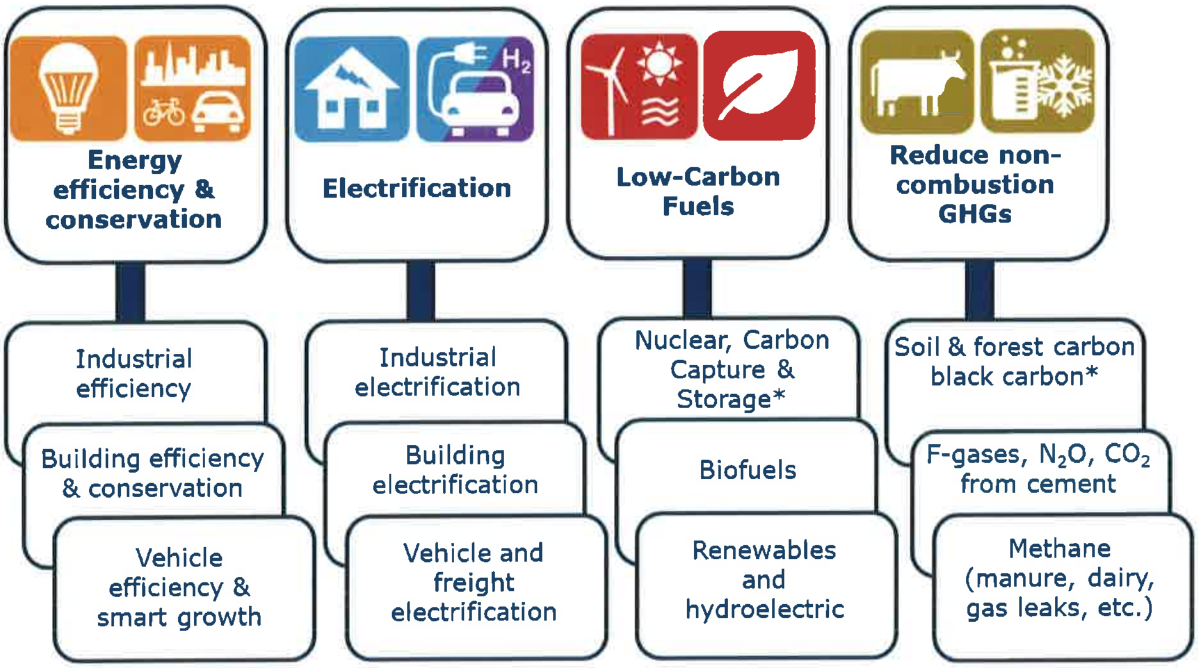


Source: E3 with historical GHG emissions data from California Air Resources Board Greenhouse Gas Emission Inventory

Pillars of Decarbonization

This work, and other related analyses, has shown that with aggressive technology deployment and adoption it is possible for California to achieve its long-term carbon reduction goals (Williams et al, 2012; Wei et al, 2012 and 2014; CCST, 2011; E3, 2016). In fact, the broad strategies necessary to mitigate the worst impacts of climate change are well understood, and similar mitigation strategies are seen in research efforts, regions and geographics (for example DDPP, 2015 and United States White House Mid-Century Strategy for Deep Decarbonization, 2016). These critical decarbonization strategies are illustrated in Figure 2 and include energy efficiency and conservation, electrification, low-carbon fuels (including electricity), and reducing non-combustion GHG emissions.

Figure 2: Pillars of Decarbonization



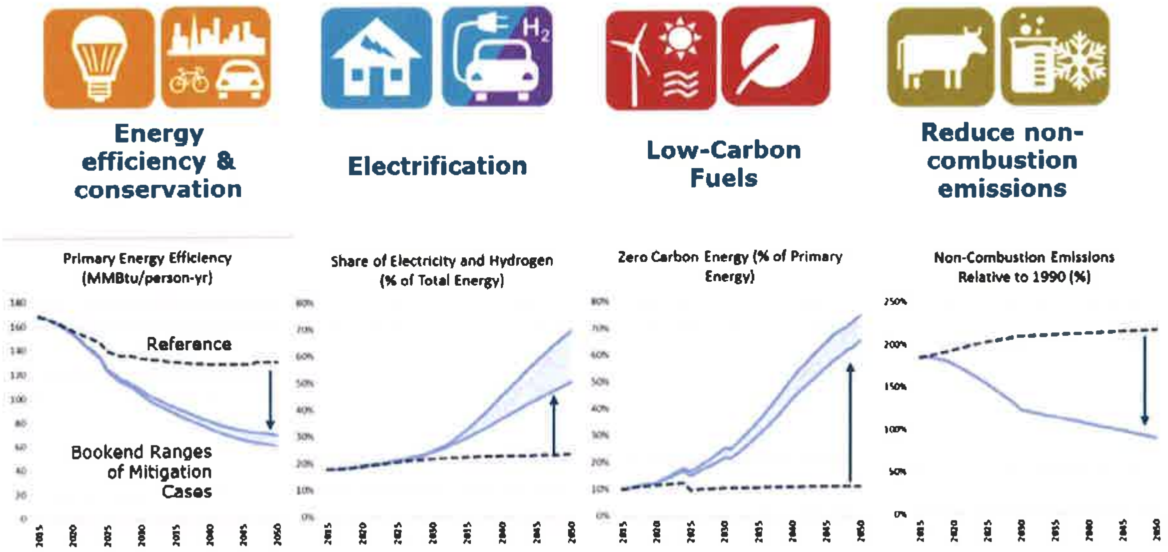
***Nuclear, carbon capture and storage, black carbon emissions and land-use, land-change and forestry emissions are not included within the scope of this analysis.**

Source: E3

Energy efficiency and conservation are essential in all sectors of the economy: industry, buildings and transportation. Electrification is necessary to reduce the state's reliance on fossil fuels, primarily in transportation, but also potentially in buildings and industry, if other decarbonization strategies such as biofuels are in limited supply, or if other mitigation strategies do not deliver as much GHG reductions as hoped. Furthermore, vehicles, buildings and industries must be powered with low-carbon fuels. The largest source of low-carbon fuel in a decarbonized future is likely to be renewable electricity, particularly in California where renewable resources are plentiful. Low carbon fuels can also be produced with nuclear power, fossil electricity generation with carbon capture and sequestration, biofuels, or using low-carbon electricity to produce fuel, such as electrolysis to make hydrogen (this pathway is called power-to-gas). Finally, non-combustion greenhouse gas emissions must be reduced, including soil and forest carbon emissions and those from fluorinated (F)-gases, methane leakage, cement manufacturing and biogenic (produced by living organisms) sources.

There is limited substitutability among these pillars (Figure 3); all mitigation scenarios rely upon switching most end use energy consumption to low-carbon fuel sources. If one source of low-carbon fuel, such as biofuels, is limited, then increasing use of decarbonized electricity and hydrogen is required.

Figure 3: Progress is Required Under the Four Pillars



Representative ranges of progress achieved in all four pillars in Mitigation Scenarios relative to the Reference Scenario (scenarios defined below).

Source: E3

Scenario Design Philosophy

This analysis does not evaluate the possibility of new nuclear power or generation with carbon capture and storage, with or without using biomass, in California. These options are explored in more detail elsewhere (for example Rhodes, 2015; Sanchez, 2015; Long, 2014). Instead, these scenarios focus on the limits and implications of a high renewable electricity future, which is the dominant strategy for low-carbon electricity in California today.

Furthermore, this analysis assumes that California's natural and working lands emit net-zero GHG emissions, which would require significant improvements over historical experience, which has seen net positive emissions from natural and working lands, largely due to wildfires. This assumption, that in the future California will be able to mitigate existing land-use emissions, is consistent with California's policy goal to turn the state's natural and working lands into a carbon sink, achieving at least net-zero GHG emissions, if not net negative GHG emissions (CARB, 2017a). In this framework, sources and sinks from natural and working land are not explicitly modeled, in large part because emissions from these sources and sinks are not currently included in the state's GHG emission inventory. New methods are being developed for California creating improved retrospective and current estimates of GHG emissions from natural and working lands. This on-going research may enable a better representation of emissions from natural and working lands in this kind of scenario analysis in the future (Battles, 2013; Gonzalez, 2015; Saah, 2016).

Continued Economic and Population Growth

These evaluated scenarios assume the current population and economic growth trends continue through 2050.[1] While these scenarios evaluate the impact of limited changes to current energy consumption behaviors, such as the impact of smart growth policies and some building energy savings from behavioral conservation, these changes are relatively minor compared to what could be possible with major societal behavioral changes. For example, the scenarios do not consider a major shift towards vegetarianism or widespread abandonment of private vehicles to meet personal transportation needs.

Limited Reliance on Advanced, Sustainable Biofuels

Biofuels, (such as ethanol, biodiesel, wood, renewable diesel, renewable gasoline and biomethane) represent a source of low-carbon energy to California. Even though the CO_2 emissions from burning these biogenic fuels would have occurred anyway as the biomass decayed, these fuels are considered net carbon neutral in the state's greenhouse gas emission inventory, which is based on the 2006 IPCC guidelines. As such, this study treats biofuels as net carbon neutral fuels.

This study limits the supply of available biofuels in three important ways. First, most scenarios exclude using purpose-grown crops or "energy crops" from the biofuel resource supply (the exception is the "high biomass" scenario). The excluded energy crops include conventional food crops such as corn and sugar cane, as well as plantation forestry and high-yielding perennial grasses like miscanthus. This study's primary data source for the biomass supply curves, the U.S. DOE Billion Ton Update Study, includes purpose grown feedstocks that are estimated to avoid indirect land-use change. However, other credible studies find that the risk of a net increase in emissions from natural and working lands is large and poorly quantified (Plevin et al, 2010; Melillo et al, 2009; Searchinger, 2008). As a result, most scenarios apply this more restrictive biomass screen to avoid the risk that the cultivation of biomass for biofuels could result in increased GHG emissions from natural or working lands.

Second, most scenarios assume that California has access to its in-state supply of waste biomass feedstocks, and up to its population-weighted share of the United States supply of sustainable biomass, based on Jaffe et al, 2017 and U.S. DOE, 2011 (with the exception of an in-state only biomass scenario). This means that most scenarios limit total biomass resources to equate to approximately 12% of the U.S. supply of waste feedstocks. None of the scenarios assume that California imports biomass or biofuels from outside the U.S. or that California uses more than its population-weighted share of the U.S. biomass supply. This assumption is based on the scenario design philosophy that as California continues to decarbonize its energy economy, the rest of the U.S. and the world will also do so, claiming access to their own supplies of biomass and biofuels. By applying these assumptions of limited biomass, the

[1] Population growth forecasts are based on the California Department of Finance projections from 2014. Economic growth trends are implicitly included in PATHWAYS via benchmarking to the California Energy Commission baseline forecast (CEC, 2016).

scenarios create decarbonization strategies for California that could be replicated in other biomass-constrained parts of the world seeking to follow a similar decarbonization trajectory.

Finally, the scenarios do not assume breakthroughs in the cost or conversion efficiency performance of biofuels technology over time. This leads to relatively conservative forecasts of future costs of biofuels in all scenarios.

Research Questions

While the broad pillars of decarbonization are generally well-understood, it is less well-understood what the biggest deployment and technology risks are in achieving these long-term plans, and how an understanding of those risks might shape polices and the research agenda today. This research addresses that gap by asking the following research questions:

- What are priority, near-term areas for California to achieve 2030 and 2050 greenhouse gas reduction goals? This question is evaluated for priorities in scaling-up deployment, market transformation and "reach" technologies.
- What are the risks and potential cost implications of meeting the state's GHG goals if key mitigation strategies are not as successful as hoped?

Through a better understanding of the cost, climate, technology adoption, and technology development risks, California, and other jurisdictions that are also seeking to reduce GHG emissions, can develop new policies or focused research and development efforts to help mitigate these risks.

GHG Mitigation Strategies Tested

To guide the analysis, the study team synthesized key greenhouse gas mitigation strategies to be modeled in PATHWAYS, testing their importance and associated risks. These strategies include deploying new technologies and socially-coordinated actions such as smart growth to reduce vehicle miles traveled. These strategies range from those with which the state has extensive experience (for example, building energy efficiency) to nascent technologies that have not been commercially developed (for example renewable hydrogen). However, the study team excluded strategies that would require dramatic fundamental innovation before they could be deployed, such as nuclear fusion, as well as uncertain events that could affect energy demand and GHG emissions but are outside the control of California decision-makers, such as an earthquake or a national or global economic shock.

The GHG mitigation strategies tested using the long-term energy scenarios include:

1. Building **energy efficiency** (EE), including conventional EE such as LED lightbulb substitution and advanced EE including building retrofits and electrification.
2. **Renewable electricity**, including solar, wind, geothermal, and small hydropower. Renewable integration solutions such as flexible building and vehicle loads, renewable diversity including out-of-state renewables, energy storage, and flexible hydrogen electrolysis are tested as well.

3. **Smart growth** that reduces light-duty vehicle miles traveled and increases the share of higher-density new construction buildings, shifting towards more multi-family homes.
4. Mitigation of **non-combustion emissions**, including methane, CO_2 from cement production and many F-gases. Mitigation of black carbon was not evaluated.
5. **Zero-emission light-duty vehicles**, including plug-in hybrid (PHEVs), battery-electric vehicles (BEVs) and hydrogen fuel-cell electric vehicles (FCEVs).
6. **Heat pumps** for buildings to replace natural gas heating in both HVAC and water heating, as well as electrification of other building end uses, including cooking and clothes drying.
7. **Biofuels** to replace liquid and gaseous fossil fuels. The focus is on advanced, sustainable biofuels, excluding corn and sugarcane ethanol.
8. **Industrial energy efficiency** and electrification.
9. Solutions for **trucking and freight** including alternative-fuel trucks such as hybrid-electric or compressed natural gas (CNG), along with zero-emission trucks including battery-electric vehicles (BEVs) and fuel cell-electric vehicles (FCEVs).
10. **Hydrogen as an energy carrier,** modeled here as hydrogen produced from centralized, grid-connected proton-exchange membrane (PEM) electrolysis for use in vehicles and, in small volumes, as a natural gas replacement in the pipeline.
11. **Production of climate-neutral fuels,** modeled here as synthetic methane produced via the reaction of CO_2 captured from the atmosphere or seawater with renewably-produced hydrogen. As an emerging technology, this option is only evaluated in one of the ten scenarios.

Each of these greenhouse gas mitigation strategies are tested in different combinations with different timing and levels of deployment in the scenarios and sensitivities, as discussed below.

Scenarios Evaluated

Three types of California long-term energy scenarios are developed, including:

- A "Reference" or business-as-usual scenario, reflecting policies before the passage of Senate Bill (SB) 350, specifically the 33 percent Renewable Portfolio Standard from 2030 through 2050 and historical levels of energy efficiency savings.
- An "SB 350" scenario, which reflects the impact of SB 350 (a 50 percent renewable portfolio standard by 2030 and a doubling of energy efficiency savings relative to historical goals) as well as other current policies as of 2016, including reductions in short-lived climate pollutants by 2030.
- "Mitigation" scenarios are evaluated which meet the state's 2030 and 2050 GHG goals using different combinations of GHG reduction strategies. The "High Electrification" scenario is one of the 10 mitigation scenarios evaluated, which meets the state's climate goals using a plausible low-cost, low-risk combination of GHG mitigation technologies.

Ten mitigation scenarios are developed to help identify which strategies are most critical to meeting the state's 2030 and 2050 GHG goals. These scenarios also isolate the estimated cost and GHG implications of key uncertainties and are used to evaluate the robustness of the state's climate mitigation strategies if one strategy does not deliver GHG reductions as expected.

Reference Scenario

The Reference scenario reflects a California GHG emissions trajectory based on energy policies that were in place prior to 2015, including the 33% Renewables Portfolio Standard (RPS). The Reference scenario excludes the impacts of SB 350, and other recent climate policies and initiatives such as the short-lived climate pollutant strategy required by Senate Bill 1383 (Lara, Chapter 395, Statutes of 2016). Key assumptions in the Reference scenario are summarized in Table 2.

Table 2: Key Assumptions in the Reference Scenario

Pillar of GHG Reductions	Sector & Strategy	Reference Scenario assumptions
Efficiency	Building electric & natural gas efficiency	Approximately 26,000 GWh of electric efficiency, and 940 million therms of natural gas efficiency in buildings, relative to baseline load growth projections (approximately equal to the 2016 CEC IEPR additional achievable energy efficiency (AAEE) mid-scenario)
	Transportation smart growth and fuel economy	Federal vehicle efficiency standards (new gasoline auto averages 40 mpg in 2030). Implementation of SB 375 (2% reduction in vehicle miles traveled (VMT) relative to 2015)
	Industrial efficiency	CEC IEPR 2016 AAEE mid-scenario
Electrification	Building electrification	None
	Zero-emission light-duty vehicles	Mobile Source Strategy from the Vision Model Current Control Program scenario: 3 million light-duty vehicle (LDV) zero-emission vehicles (ZEVs) by 2030, 5 million LDV ZEVs by 2050
	Zero-emission and alternative fueled trucks	Mobile Source Strategy from the Vision Model Current Control Program scenario: 20,000 alternative-fueled trucks by 2030
Low carbon fuels	Zero-carbon electricity	Current RPS procurement achieves ~35% RPS by 2020, declining to 33% RPS with retirements post-2030. Includes current deployment of pumped storage and the energy storage mandate (1.3 GW by 2020). No additional storage after 2020.
	Advanced biofuels	10% carbon-intensity reduction Low Carbon Fuel Standard including corn ethanol (1.2 billion GGE advanced biofuels in 2030 and 0.7 billion GGE corn ethanol in 2030)
Non-combustion GHGs	Reductions in methane and fluorinated gases	No mitigation: methane emissions constant after 2015, fluorinated gases increase by 56% in 2030 and 72% in 2050

Source: E3

SB 350 Scenario

The SB 350 scenario includes all of the assumptions in the Reference scenario, but adds in the estimated impacts of SB 350, the California Air Resources Board (ARB) Mobile Source Strategy Cleaner Technologies and Fuels scenario and the *Short-Lived Climate Pollutant Plan*. These impacts include a 50 percent RPS in 2030, a doubling of energy efficiency savings relative to the "additional achievable energy efficiency" in the California Energy Commission's 2016 *Integrated Energy Policy Report* by 2026, higher adoption rates of ZEVs and reductions in non-combustion GHG emissions.

Table 3: Key Policies and Assumptions in the SB 350 Scenario

Pillar of GHG Reductions	Sector & Strategy	SB 350 Scenario, 2030 assumptions
Efficiency	Building electric & natural gas efficiency	Approximately 46,000 GWh of electric energy efficiency and 1,300 million therms of natural gas energy efficiency in buildings, relative to baseline load growth projections (reflecting targets under California SB 350, statutes of 2015)
	Transportation smart growth and fuel economy	New gasoline auto averages 45 mpg, implementation of SB 375 (2% reduction in VMT relative to 2015)
	Industrial efficiency	Approximate doubling of efficiency in Reference scenario
Electrification	Building electrification	None
	Zero-emission light-duty vehicles	Mobile Source Strategy: Cleaner Technologies and Fuels scenario (4 million LDV ZEVs by 2030, 24 million by 2050)
	Zero-emission and alternative fueled trucks	Mobile Source Strategy: Cleaner Technologies and Fuels scenario (140,000 alternative-fueled trucks)
Low carbon fuels	Zero-carbon electricity	50% RPS by 2030, Same energy storage as Reference, 10% of some building end uses and 50% of LDV EV charging is flexible
	Advanced biofuels	Same biofuel blend proportions as Reference, less total biofuels than Reference due to higher adoption of ZEVs
Non-combustion GHGs	Reductions in methane and F-gases	34% reduction in methane emissions relative to 2015, 43% reduction in F-gases relative to 2015, 19% reduction in other non-combustion GHGs relative to 2015.

Source: E3

High Electrification Scenario

The High Electrification Scenario includes all of the assumptions in the Reference and SB 350 scenarios, however, in many sectors includes more aggressive adoption and deployment of GHG mitigation strategies to achieve the 2030 and 2050 GHG goals. These assumptions are summarized in Tables 4-6.

Alternative Mitigation Scenarios and Sensitivities

In addition to the High Electrification scenario, nine Alternative Mitigation scenarios are tested which meet the state's 2030 and 2050 GHG goals in PATHWAYS using different combinations of mitigation technologies from the High Electrification scenario. These Alternative Mitigation scenarios fall broadly into two categories: (1) reduced reliance on a key mitigation technology choice within the state, with compensating GHG mitigation strategies used to meet the 2030 and 2050 climate goals; and (2) increased reliance on a key mitigation technology choice within the state, with lower GHG mitigation in other sectors, to meet the 2030 and 2050 climate goals. The costs of these alternative scenarios are then evaluated and compared to the High Electrification scenario.

All of the scenarios include relatively high levels of electrification; some of the scenarios result in higher electric loads than the "High Electrification" scenario. The distinguishing feature of the "High Electrification" scenario is that nearly a full suite of GHG mitigation options is used, including electric heat pumps in buildings. Each of the Alternative Mitigation scenarios is described in Table 6.

In addition to these alternative technology scenarios, one additional scenario is tested. The "No Climate Change" scenario tests the impacts of not including the climate change impacts on hydroelectric availability and building energy demand in the scenario. All other scenarios include the effects of climate change.

Cost sensitivities also probe uncertainties in economy-wide mitigation costs by changing key cost inputs without changing energy or emissions assumptions. Cost sensitivities are not comprehensive but rather emphasize a few key cost inputs whose effects may bracket the overall cost uncertainty, including fossil fuel prices and demand-technology capital financing rate.

The Role of Carbon Pricing and Cap and Trade

These scenarios do not attempt to directly model or predict the effect the state's Cap-and-Trade program (Assembly Bill 398, Garcia, Chapter 135, Statutes of 2017) will have on consumer behavior or on business decisions through 2030 or beyond.

The cap and trade law requires the ARB to set a carbon price ceiling, price containment points, and define other details of the cap and trade program. The impacts of cap and trade will depend on the resulting carbon price, and the carbon price will depend on how far other complementary policies reduce greenhouse gas emissions, and the costs of alternative GHG mitigation options, including offsets and carbon permits from other linked jurisdictions, such as Quebec, Canada or Ontario, Canada.

Table 4: Key 2030 Metrics for the High Electrification Scenario

Pillar of GHG Reductions	Sector & Strategy	High Electrification Scenario, 2030 assumptions
Efficiency	Building electric & natural gas efficiency	10% reduction in total building energy demand relative to 2015. Same level of non-fuel substitution energy efficiency as the SB 350 Scenario in non-heating sub-sectors. Additional efficiency is achieved through electrification of space heating and water heating.
	Transportation smart growth and fuel economy	New gasoline ICE light-duty autos average 45 mpg, 12% reduction in light-duty vehicle miles traveled relative to 2015, 5-6% reduction in shipping, harbor-craft & aviation energy demand relative to Reference
	Industrial efficiency	20% reduction in total industrial, non-petroleum sector energy demand relative to 2015, additional 14% reduction in refinery output relative to 2015
Electrification	Building electrification	50% new sales of water heaters and HVAC are electric heat pumps
	Zero-emission light-duty vehicles	6 million ZEVs (20% of total): 1.5 million BEVs, 3.6 million PHEVs, 0.8 million FCEVs, >60% of new sales are ZEVs
	Zero-emission and alternative fueled trucks	10% of trucks are hybrid & alternative fuel (4% are BEVs or FCEVs), 32% electrification of buses, 20% of rail, and 27% of ports; 26% electric or hybrid harbor craft
Low carbon fuels	Zero-carbon electricity	74% zero-carbon electricity, including large hydro and nuclear (70% RPS), Storage Mandate + 6 GW additional storage, 20% of key building end uses and 50% of LDV EV charging is flexible
	Advanced biofuels	2.8 billion gallons of gasoline-equivalent (10% of gasoline, diesel, jet fuel and other non-electric energy demand); 49 million Bone Dry Tons of biomass: 57% of population-weighted share excluding purpose-grown crops
Non-combustion GHGs	Reductions in methane and F-gases	34% reduction in methane emissions relative to 2015, 43% reduction in F-gases relative to 2015, 19% reduction in other non-combustion CO_2 & N_2O

Source: E3

Table 5: Key 2050 Metrics for the High Electrification Scenario

Pillar of GHG Reductions	Sector & Strategy	High Electrification Scenario, 2050 assumptions
Efficiency	Building electric & natural gas efficiency	34% reduction in total (natural gas and electric) building energy demand, relative to 2015. Savings are achieved via conventional efficiency and building electrification.
	Transportation smart growth and fuel economy	24% reduction in per capita light-duty vehicle miles traveled relative to 2015, plus shipping, harbor-craft & aviation energy demand 2030 measures
	Industrial efficiency	20% reduction in total industrial, non-petroleum sector energy demand relative to 2015, 90% reduction in refinery and oil & gas extraction energy demand
Electrification	Building electrification	100% new sales of water heaters and HVAC are electric heat pumps; 91% of building energy is electric (no building electrification is possible, but requires higher biofuels or power-to-gas), Moderate electrification of agriculture HVAC
	Zero-emission light-duty vehicles	35 million ZEVs (96% of total): 19 million BEVs, 11 million PHEVs, 5 million FCEVs, 100% of new sales are ZEVs
	Zero-emission and alternative fueled trucks	47% of trucks are BEVs or FCEVs (31% of trucks are hybrid & CNG); 88% electrification of buses, 75% of rail, 80% of ports; 77% of harbor craft electric or hybrid
Low carbon fuels	Zero-carbon electricity	95% zero-carbon electricity (including large hydro), 84 GW of utility scale solar, 29 GW of rooftop solar, 52 GW out-of-state wind, 26 GW incremental storage above storage mandate, 80% of key building end-uses is flexible and 90% flexible EV charging; H_2 production is flexible
	Advanced biofuels	4.3 billion gallons of gasoline-equivalent (46% of gasoline, diesel, jet fuel and other non-electric energy demand); 64 million Bone Dry Tons of biomass: 66% of population-weighted share excluding purpose-grown crops
Non-combustion GHGs	Reductions in methane, F-gases and other non-combustion GHGs	42% reduction in methane emissions relative to 2015 83% reduction in F-gases relative to 2015 42% reduction in other non-combustion CO_2 & N_2O

Source: E3

Table 6: Alternative Mitigation Scenarios, Change in Measures Compared to the High Electrification Scenario

Scenario name (reduced reliance on key strategy)	Reduced reliance on key mitigation strategy	Increased, compensating reliance on mitigation strategies
No Hydrogen	No fuel cell vehicles or hydrogen fuel	Industrial electrification, more BEV trucks & BEVs, renewables
Reference Smart Growth	Less reduction in VMT	Industrial electrification, more renewables
Reduced Methane Mitigation	Lower fugitive methane reductions (higher fugitive methane leakage)	Industrial electrification, more ZEV trucks, renewables
Reference Industry EE	Less industrial efficiency	More ZEV trucks, renewables
In-State Biomass	Less biofuels, no out-of-state biomass used	Industrial electrification, more ZEV trucks, renewables
Reference Building EE	Less building efficiency	Industrial electrification, more renewables
No Building Electrification with Power-to-Gas	No heat pumps or building electrification	Climate-neutral power-to-gas (hydrogen and synthetic methane), industrial electrification, more ZEV trucks, renewables
Scenario name (increased reliance on key strategy)	**Increased reliance on key mitigation strategy**	**Reduced, compensating reliance on mitigation strategies**
High Biofuels	Higher biofuels, including purpose grown crops	Less ZEVs, renewables
High Hydrogen	More fuel cell trucks	Less BEVs, renewables

Source: E3

If no additional energy or climate policies are passed between now and 2030, it seems likely that the role of cap and trade in meeting the state's climate goals will be significant, as can be seen by the gap between greenhouse gas emission reductions achieved in the SB 350 Scenario and the Mitigation Scenarios. If cap and trade is the primary policy mechanism to achieve emission reductions between 2020 and 2030, then the carbon price would likely increase towards the price ceiling, and greenhouse gas reductions would be achieved through consumer price responses because of higher energy prices and longer-term investments in low-carbon technologies, including energy efficiency, zero-emission vehicles and zero-emissions fuels.

The more aggressive zero-emission technology adoption assumptions included in the Mitigation scenarios could be achieved, in part, through higher carbon prices. Carbon prices reduce emissions by increasing the price of fossil fuels relative to lower carbon alternatives. In this way, cap and trade is likely to help incentivize higher adoption rates of zero-emission vehicles and energy efficiency, for example.

Carbon pricing, however, is not a panacea for zero-carbon technology adoption, because price signals on their own cannot overcome a variety of market failures which may stand in the way (for example, upfront capital cost barriers and principal-agent problems). For this reason, it is expected that additional market transformation policies will be necessary for California to achieve its 2030 and 2050 GHG goals. While the extension of cap and trade through 2030 will certainly help to reduce GHG emissions, it may not be sufficient on its own.

Report Organization

This report is organized as follows: Chapter 2 describes the research methods, including the modeling tools used and key analytical improvements achieved through this research. Chapter 3 discusses the results for the main scenarios, including the Reference, SB 350 and High Electrification scenario. Chapter 4 discusses the cost results and findings from the Alternative Mitigation cases and additional scenario. Chapter 5 provides conclusions. Additional details about key input assumptions and scenario results by sector are provided in the Appendices.

CHAPTER 2: Methods

The California PATHWAYS Model

This analysis uses the California PATHWAYS model, an economy-wide energy and greenhouse gas mitigation model, to identify priority GHG mitigation challenges in California through a series of scenario and uncertainty analyses.

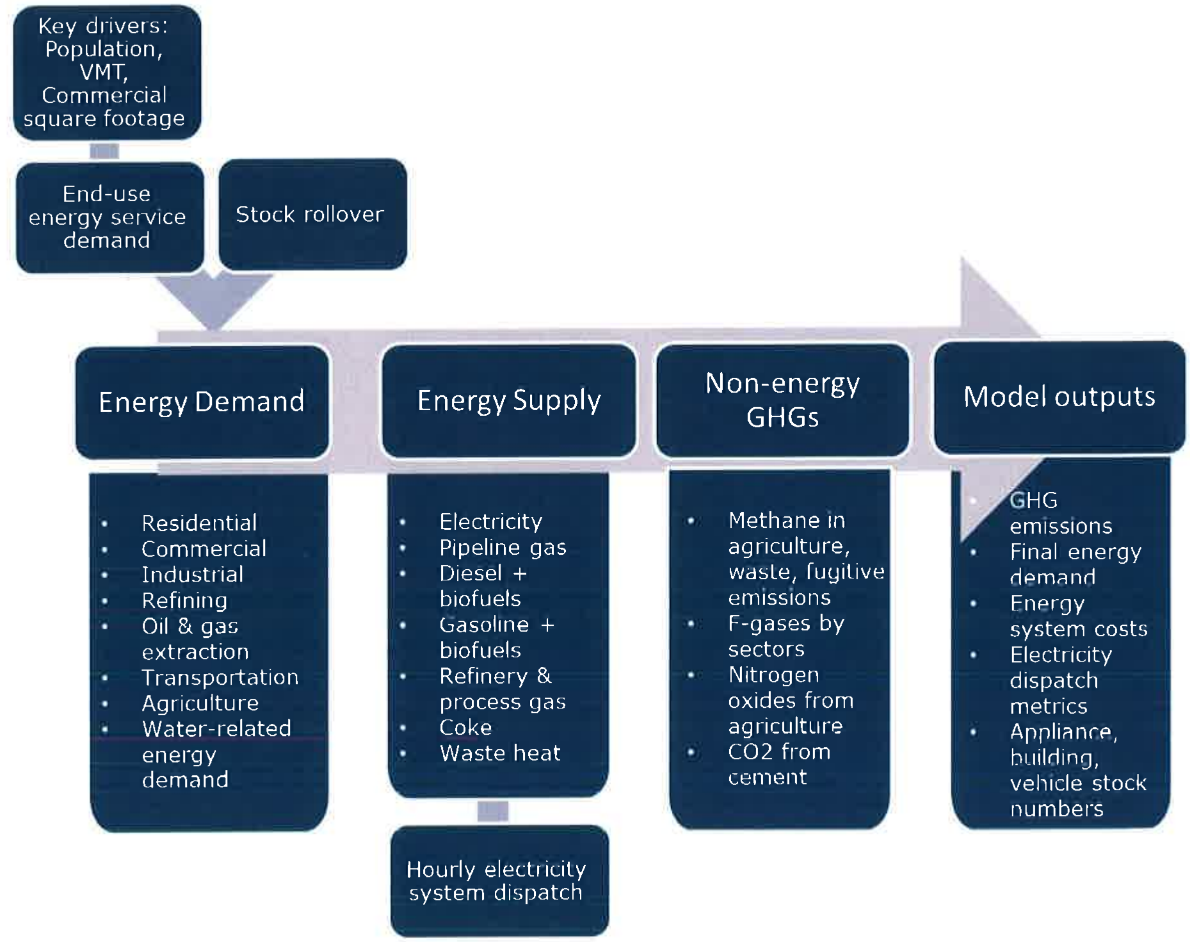
The PATHWAYS model is a long-horizon, technology-specific scenario model developed by Energy and Environmental Economics, Inc. (E3). The model has been modified and improved on over time, including through funding from this California Energy Commission Electric Program Investment Charge grant. PATHWAYS includes detailed technology representation of the buildings, industry, transportation and electricity sectors (including hourly electricity supply and demand) and explicitly models stocks and replacement of buildings, building equipment and appliances and vehicles. Demand for energy is driven by forecasts of population, building square footage, and other energy service needs. The rate and type of technology adoption and energy supply resources are all user-defined scenario inputs. PATHWAYS calculates energy demand, greenhouse gas emissions, the portfolio of technology stock in selected sectors, as well as capital costs and fuel costs and savings for each year between 2015 and 2050.

The final energy demand projections are used to project energy supply stocks and final delivered energy prices and emissions. Electricity rates are calculated endogenously to the model based on the scenario's generation supply mix, hourly electricity demand and supply. Likewise, delivered natural gas rates are calculated based on changes in annual demand and fuel costs, including the calculated cost of biomethane, hydrogen or other synthetic fuels used in the pipeline. Delivered costs of gasoline, diesel and other fuels include the blended costs of the fossil fuel and biofuel. Fossil fuel price forecasts are exogenous inputs to the model, biofuel prices are calculated endogenously to the model.

As a technology and energy-demand scenario model, the model does not explicitly model macroeconomic changes to the economy, nor does it endogenously capture consumer price responses, such as the impacts of carbon pricing or changes in energy prices. The model evaluates greenhouse gas emissions based on the emissions accounting protocols used in the Intergovernmental Panel on Climate Change (IPCC) *Fourth Assessment Report*, consistent with the California Air Resources Board statewide emission inventory.

The model ultimately calculates a broad range of outputs, including energy demand by fuel type and sector by year, greenhouse gas emissions by fuel type and sector, and annual changes in incremental capital costs and fuel costs, relative to a Reference scenario (Figure 4). For more detail about the PATHWAYS model methodology, see the Appendix B and E3, 2015.

Figure 4: Flow Diagram of California PATHWAYS Model



Source: E3

Cost Accounting Methodology and Technology Improvements Over Time

The PATHWAYS model tracks the annualized incremental cost of technologies compared to the Reference scenario technology costs, and the changes in fuel consumption. The cost accounting framework can be considered as a total resource cost accounting, whereby the total cost and benefits of measures are calculated, without attributing those costs to consumers, producers or government. Societal costs and benefits such as changes to air pollution or climate change impacts are not considered in PATHWAYS. Federal tax incentives for renewable generation are included, as these result in a net benefit to the state but these phase out over time consistent with the legislatively determined schedule. The impact of the federal Renewable Fuel Standard program is not reflected in the biofuel prices, since these are assumed to expire after 2022. The effect of the Low Carbon Fuel Standard on fuel prices is also not reflected, as these are considered transfers within the state. Given these assumptions, the cost assumptions in PATHWAYS closely reflect the marginal cost of production absent state or federal subsidies.

The scenarios modeled here include assumptions about how the cost, efficiency and performance of technologies change over time. For technologies with rapidly changing capital costs, such as solar, wind, battery storage, LED lighting, and electric vehicles, both the costs and performance are assumed to improve over time, as economies of scale are assumed to be achieved in manufacturing. In general, the researchers have relied on publicly available, published projections for these cost assumptions. Other technologies do not include assumptions about changing costs or performance over time, including many building and industrial efficiency measures, although large-scale adoptions of these technologies could lead to cost-declines and/or improvements in performance. In general, the cost and performance assumptions applied in the PATHWAYS model tend to reflect conservative assumptions about the potential for technological progress over time, to avoid overstating the potential benefits of the Mitigation scenarios.

Uncertainty and Complexity in Scenario Analysis

To paraphrase the statistician George Box, "all models are wrong, but some are useful." This statement is certainly true of the PATHWAYS model, as it is true of any long-term scenario analysis spanning decades into the future. This modeling effort was not to predict or forecast the future. Rather, these scenarios ask, "what would be necessary to meet the state's current policy goals and future GHG mitigation goals, and what are the risks in meeting those goals?"

There are many sources of uncertainty in developing long-term scenarios including future trajectories for technology capital costs, fuel costs, consumer behavior and preferences and the future political and policy environment. Furthermore, key sources of complexity which cannot be reflected in the PATHWAYS model include market dynamics, such as the interaction between costs and prices, interactions between policies and technological change, and interactions between actions taken in California and the rest of the world.

In this study design, the team attempted to capture many of these sources of uncertainty and complexity through scenario and sensitivity analysis, while acknowledging that these tools are not a crystal ball into the future.

Though less certain than a prediction, a scenario is more grounded in fact than mere speculation. The scenarios were evaluated to provide useful information about what GHG mitigation areas California should prioritize today, using the best information available about technology costs, performance and the interactions between GHG mitigation strategies.

California PATHWAYS Model Enhancements

Since the initial California deep decarbonization scenario results were published in Williams, et al, (2012), several improvements and enhancements have been made to the PATHWAYS model. These include:

- Updated input data resulting in a lower Reference case forecast of greenhouse gas emissions in California. This includes a revised, lower, population demand forecast consistent with the California Department of Finance forecast, and revised, lower, transportation vehicle stocks and transportation vehicle miles traveled from the California Air Resources Board Mobile Source Emissions Inventory, EMFAC 2014 database.
- Calibrating the starting year energy consumption and emissions to the updated *California Emission Inventory-2016 Edition*, covering GHG emissions through 2015. The

new inventory uses global warming potential (GWP) values from the IPCC Fourth Assessment Report, consistent with current international and national GHG inventory practices. This inventory practice excludes all biogenic emissions associated with biofuels.

- Updated fossil price forecasts consistent with the Energy Information Agency (EIA) 2017 Annual Energy Outlook, incorporating the effect of lower expected petroleum and natural gas prices on net economy-wide mitigation costs.
- Reflecting current California state legislation, policies and goals through 2030.
- Updated technology cost projections, particularly for solar, wind, batteries, and electric vehicles, reflecting more rapid than expected cost reductions in these technologies.
- Updated assumptions on sustainable biomass resource limits, biofuel process conversion efficiencies and costs, as well as an updated biofuel module which allows for limited optimization of least-cost liquid and gaseous biofuel pathways.
- Reflecting the impacts of climate change on building energy demand and hydroelectric generation.
- Updated assumptions for electricity resources serving California, including reduced availability of in-state wind due to environmental restrictions and the planned retirement of the Palo Verde nuclear plant by 2047.
- Technical enhancements and faster model run-time.

Integrating Climate Change Impacts on Energy System

This research grant was coordinated with three other research projects funded by the Energy Commission: a team from Berkeley Economic Advising and Research, LLC (BEAR); a team and Lawrence Berkeley National Laboratories (LBNL); and a team from the University of California, Irvine (UCI). While each team's work was funded separately, the teams worked together to share data where possible and applicable. Analysis from this study was used as a key input into the BEAR and LBNL studies. Analysis from the UCI study was used as input for this study, as described below.

The UCI team (Tarroja, 2017) provided the E3 team with data on the likely long-term impacts of climate change on electricity building demands and on hydroelectric generation through 2050. These data were fed into the PATHWAYS model to create scenarios that reflect the potential impacts of climate change on the electricity system.

Tarroja used global climate simulations that have been downscaled for California and the Fourth Climate Assessment. The team used several model simulations based on representative concentration pathway (RCP) 4.5 and RCP 8.5 scenarios to force a building energy model and a regional hydrology model; these scenarios represent a modest mitigation trajectory and a high climate change impacts trajectory, respectively.

Using the hydrology model, Tarroja estimated changes in annual hydroelectric energy availability during the same time period relative to present-day. Changes in predicted hydroelectric energy availability were relatively small in the annual average in each member of the climate model ensemble, masking larger increases in inter annual variability. As PATHWAYS cannot incorporate inter-annual variability in hydroelectric energy availability, the model with the largest average decrease (11%) in hydro-electric availability was used to estimate a worst-case typical year. Hydro-electric energy availability across all seasons was scaled down linearly from 2015 to 2050 in PATHWAYS to correspond with this 11% decrease.

Using a building energy model, Tarroja estimated changes in building heating and cooling energy demands for each of the Energy Commission's 16 Building Climate Zones and aggregated these into an annual percentage change relative to present-day. PATHWAYS incorporated the changes in building energy demands predicted for 2050 using the RCP 8.5 results, using the average change for each Building Climate Zone across the simulations in the climate model ensemble. Changes in energy demands by subsector (residential and commercial heating and cooling) were applied as scalars to PATHWAYS simulated energy demands in the absence of climate change, linearly interpolating between present-day (2015) and 2050. The changes for each climate zone and subsector ranged from 9% to 58% and are shown as geographic averages in Appendix B. Changes in water heating demand were estimated by Tarroja to be less than 0.1% in magnitude and were not included in PATHWAYS.

California RESOLVE Model for Electricity Sector Analysis

This study also used the PATHWAYS scenario results to feed into an analysis of long-term electricity sector costs using the RESOLVE model, an electric sector least-cost capacity expansion planning tool. RESOLVE has been used by the California Public Utilities Commission in the Integrated Resource Planning proceeding and by the California Independent System Operator in its SB 350 regionalization study (California ISO, 2016).

For this study, the RESOLVE model analysis timeframe was extended from 2030 to 2050, and the geographic scope of the analysis was expanded from the California ISO footprint to a California statewide footprint.

While the PATHWAYS model includes an integrated treatment of electricity supply and consumption at the hourly level, the PATHWAYS model does not perform a least-cost capacity expansion plan for the electricity sector, making it difficult to determine the optimal mix of renewable resources and energy storage. The RESOLVE model takes the PATHWAYS electricity loads and load shapes as an exogenous input. It was then run with an emissions constraint for the electricity sector that was consistent with the economy-wide High Electrification Scenario. Consequently, the study team investigated the electricity sector resource selections and costs, consistent with a PATHWAYS scenario, while taking advantage of the least-cost optimization capabilities in RESOLVE.

Using this framework, the study team investigated the importance of renewable integration solutions in RESOLVE using electricity loads and load shapes that were broadly consistent with the 2050 PATHWAYS scenarios. RESOLVE reported the impact of renewable integration solutions on total electricity costs in 2050, including incremental and marginal mitigation costs.

The study team also evaluated the cost of different 2050 GHG constraints in the electric sector to develop a "supply curve" in RESOLVE for the 2050 marginal carbon abatement cost of reducing GHG emissions in the electricity sector consistent with the High Electrification Scenario, under the optimistic and less-optimistic assumptions about renewable integration solutions. (See Chapter 3, Figure 15.) The marginal carbon abatement cost is the ratio of the increase in total resource cost divided by the GHG emission savings, and expressed in dollars per ton, \$/ton. This supply curve was compared to the incremental abatement costs for mitigation options evaluated in other sectors in PATHWAYS.

CHAPTER 3: Reference, SB 350 and High Electrification Scenario Results

This chapter discusses the key results for the main long-term energy scenarios evaluated in PATHWAYS: the Reference, SB 350 and High Electrification Scenarios. Results are shown for the High Electrification scenario for greenhouse gas emissions, energy demand, and costs relative to the Reference scenario.

Greenhouse Gas Emissions

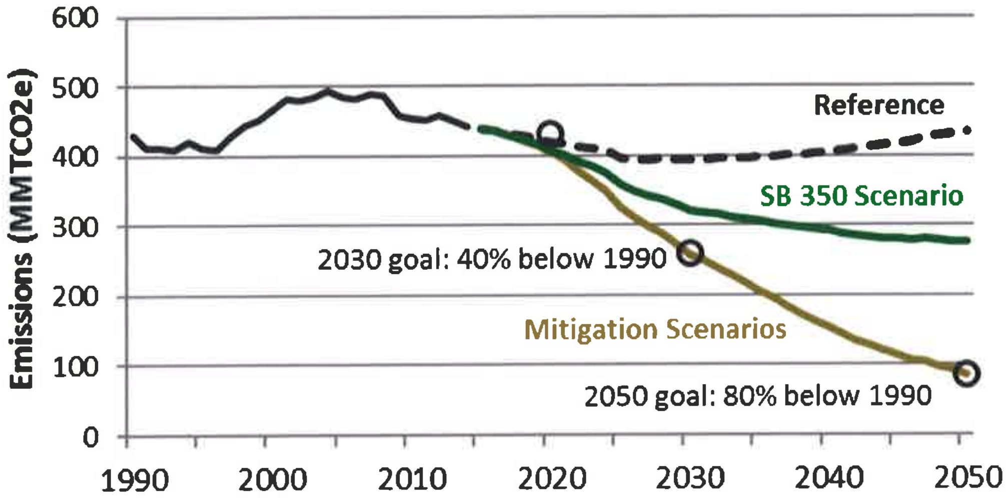
Greenhouse gas emissions in California peaked around 2004 and have been in decline since then. If California succeeds in executing on its current policy commitments, California appears likely to meet its 2020 goal of returning GHG emissions to 1990 levels, which requires keeping emissions at or below 431 million metric tons. As of 2015, California greenhouse gas emissions stood at 440 million metric tons of CO_2-equivalent (ARB, 2017a).

In the Reference scenario, GHG emissions decline modestly between 2017 and about 2027, at which point population and economic growth begin to push emissions higher through 2050. In the Reference scenario, GHG emissions in 2050 are slightly higher than the projected 2020 level.

The SB 350 scenario, which reflects the impact of higher levels of renewables, energy efficiency, and mitigation of non-combustion GHGs, results in a significant decrease in emissions between present day and 2030 but does not entirely close the gap to meet the state's 2030 GHG goal of 258.6 million metric tons of CO_2e (equivalent). In the SB 350 scenario, the gap between the 2030 goal and the projected emissions is about 63 $MMTCO_2e$. The gap to meet the 2050 goal, of 86 MMTCO2e, is much larger at nearly 190 $MMTCO_2e$.

All of the Mitigation scenarios, including the High Electrification scenario, are designed to meet the state's 2030 and 2050 greenhouse gas mitigation goals (Figure 5).

Figure 5: California Greenhouse Gas Emissions by Scenario



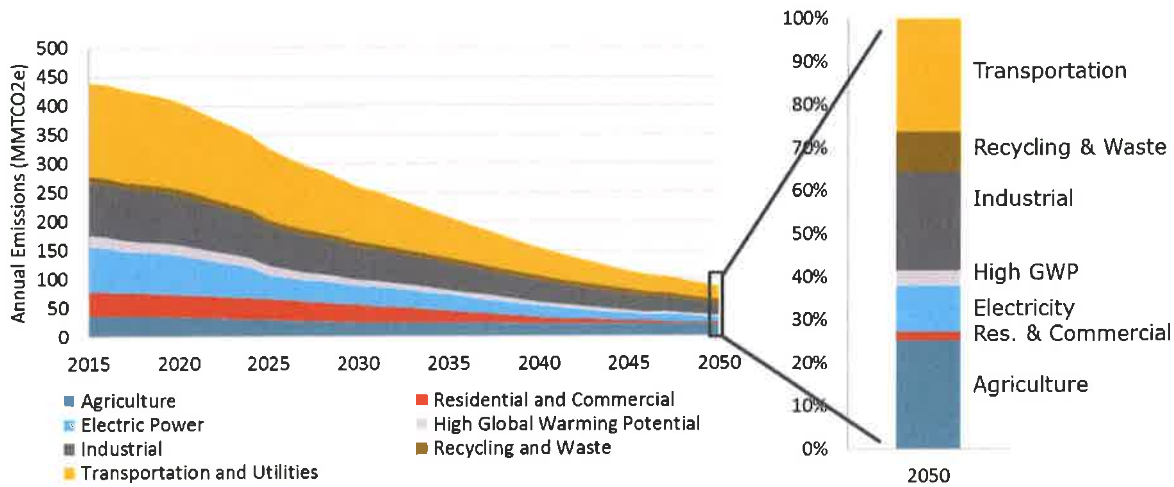
Million metric tons of CO_2-equivalent

Source: E3

In the High Electrification scenario, GHG emissions are reduced in all sectors by 2050. However, the relative proportion of emissions reductions varies by sector, since the mitigation costs and mitigation potential are not equal between sectors. By 2050, the single largest remaining source of greenhouse gas emissions is from non-combustion emissions. Methane from agriculture and waste (wastewater treatment, landfills and municipal solid waste) represent a large source of remaining emissions; methane from waste and enteric fermentation in particular are expected to be difficult to completely eliminate, although both are assumed to decline in absolute terms through 2050.

In addition to non-combustion GHG emissions, the remaining 2050 emissions budget is allocated between some remaining diesel and jet fuel use in the transportation sector (primarily for off-road and long-haul, interstate trucking), the industrial sector, assuming that industrial electrification will be relatively expensive compared to other mitigation alternatives, and the electric power sector, which continues to use about 5% of generation from fossil natural gas for resource balancing and resource sufficiency. Greenhouse gas emissions are not eliminated in any sector by 2050 in the High Electrification scenario (Figure 6).

Figure 6: California Greenhouse Gas Emissions by Sector in the High Electrification Scenario



Greenhouse gas emissions in 2050 are 86 MMT CO2e, inclusive of non-combustion GHG emissions.

Source: E3

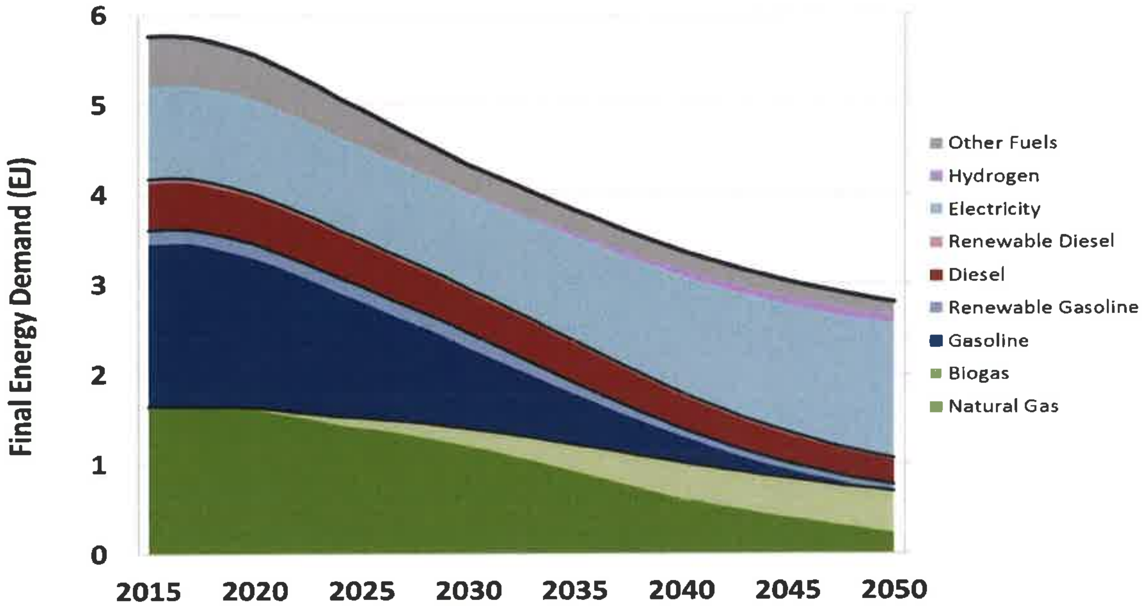
Transportation sector energy-related GHG emissions represent the largest source of greenhouse gas emissions in California, currently about 39% of the statewide total[2]. In the High Electrification scenario, this share declines over time to just over one-quarter of total statewide greenhouse gas emissions. The industrial sector energy-related emissions represent the second largest source of GHG emissions in California, with just over 20% of the total. Industrial sector emissions are expected to be among the more difficult, and more expensive to mitigate. As a result, the total share of GHG emissions from the industrial sector increases slightly over time, even as total emissions are dramatically reduced. By 2050, the remaining non-combustion emissions in agriculture and recycling and waste represent a far larger share of total GHG emissions than today, illustrating that the challenging of reducing emissions beyond 2050 will be somewhat different than the challenges of meeting the state's 2050 GHG goal.

Energy Demand Results

Final energy demand (i.e. non-electric generation energy consumption), shows that energy consumption falls by 50% in the High Electrification scenario, from nearly 6 exajoules (EJ) today to less than 3 EJ in 2050 (Figure 7). These energy savings are due to improved fuel economy standards in vehicles, efficiency associated with electrification in transportation and buildings, reductions in per capita VMT, and improved energy efficiency in buildings and industry. The efficiency advantages of electric drive and heat pumps over internal combustion engines and combustion heaters, respectively, result in dramatic reductions in final energy demand.

[2] ARB Inventory (https://www.arb.ca.gov/cc/inventory/data/data.htm) accessed on May 18. 2018.

Figure 7: Final Energy Demand by Fuel Type in the High Electrification Scenario



Source: E3

The High Electrification scenario shows a decline in fossil fuel demand across all fuel types, with the greatest reductions in gasoline and natural gas, in-part due to a greater reliance on biomethane blended into the pipeline. The High Electrification scenario biofuel assumptions are based on a least net-cost analysis across all major fuel types (gasoline, diesel and natural gas). Using these assumptions, the most efficient use of biomass is to produce renewable methane (biogas), rather than liquid biofuels. This scenario does not model the impact of the Low Carbon Fuel Standard policy which directs biofuel use towards the transportation sector. A transportation-focused biofuel sensitivity would result in less overall biofuels used to displace fossil natural gas and more biofuels used to displace diesel energy.

Decarbonization Strategies by Sector

Buildings

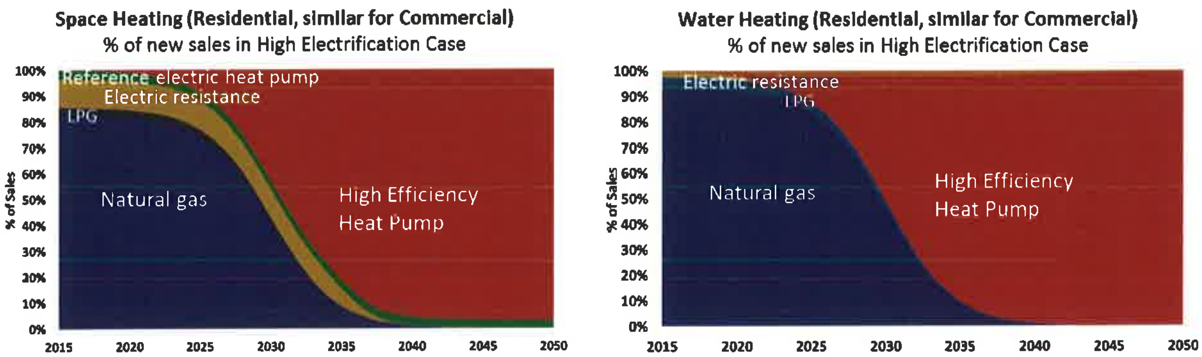
Energy efficiency in buildings is a central strategy to reducing the cost of greenhouse gas mitigation in California. The state has already committed to doubling energy efficiency savings, relative to an aggressive baseline of maintaining historical levels of efficiency savings through SB 350, however, most experts agree that achieving a doubling of energy efficiency presents many implementation challenges.

Deploying such a high level of energy efficiency will likely require substantial changes to current efficiency deployment strategies. In addition to conventional energy efficiency, deep decarbonization in buildings requires a combination of extensive building electrification, featuring heat pumps for space conditioning and water heating, or replacing fossil natural gas use with carbon-neutral renewable gas.

In the High Electrification scenario, higher levels of "conventional efficiency", (i.e. non-fuel substitution energy efficiency), are achieved through higher and faster adoption rates of LED lighting, as well as more efficient refrigeration, plug-loads, water heating, air conditioning, and space heating compared to the CEC's 2016 *IEPR* additional achievable energy efficiency potential metric. In addition, behavioral conservation measures are assumed to partially reduce lighting and HVAC energy consumption, while "smart growth" measures encourage new construction to include more high density, smaller and more efficient multi-family homes, relative to historical trends. However, of all these measures in the High Electrification scenario, it is fuel switching to high efficiency heat pumps in HVAC and water heating that achieves the largest reductions in total building energy demand, factoring in both natural gas and electric consumption. Greenhouse gas emissions decrease due to fuel-switching as well, due to the high and increasing share of renewables on the grid.

To decarbonize heating demands in buildings through a transition to electric heat pumps, without requiring early retirements of functional equipment, this transition must start by 2020 and achieve significant market share by 2030. In the High Electrification scenario, new heat pump sales must represent no less than approximately 50% of new sales of HVAC and water heating equipment by 2030 (Figure 8).

Figure 8: Percent of New Sales by Technology Type for Residential Space Heating and Water Heating in the High Electrification Case (2015–2050)



Source: E3

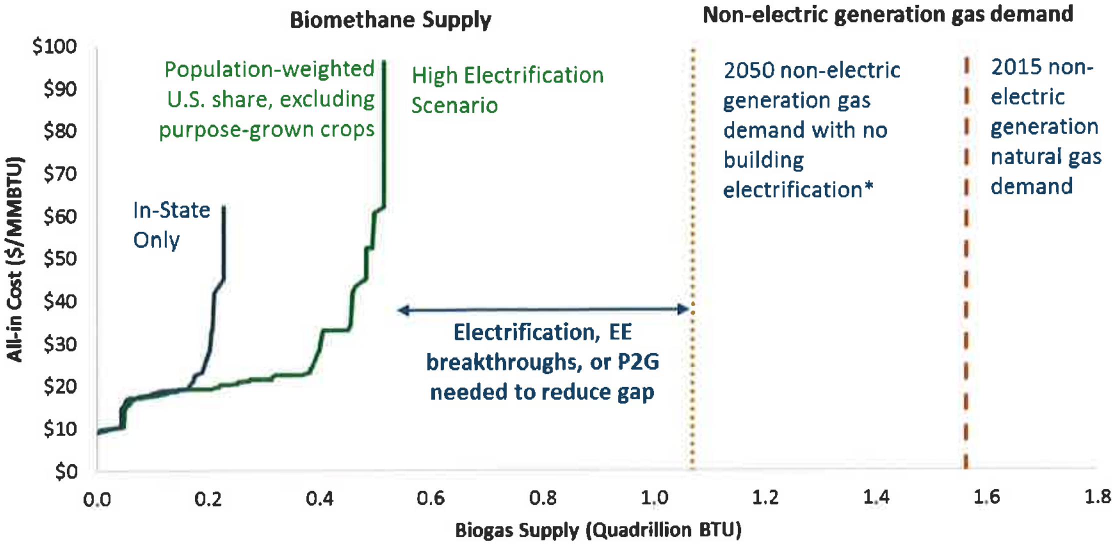
However, the electrification and renewable natural gas options still face large hurdles. Widespread use of electric heat pumps would require market transformation, to make electric heating a more attractive and cost-competitive option for households and businesses in California. Many contractors in California do not have experience sizing and installing heat pump equipment, and customers do not have experience using it. While heat pump adoption has been increasing in the U.S. northeast and southeast and in Asia, heat pump technologies are not common in California outside of some rural areas that lack access to natural gas. Furthermore, the refrigerant F-gases used in heat pump technologies have a high global warming potential and must be replaced with lower global warming potential gases in accordance with the Montreal Protocol's Kigali Amendment; state legislation is already moving in this direction. Finally, current utility energy efficiency programs and tiered electricity retail rates have not been designed with carbon savings, or fuel switching from natural gas to electric end-uses in mind, and will likely require modifications to enable, or not discourage, building electrification.

Renewable natural gas does not face the same types of customer adoption and building retrofit challenges as a building electrification strategy. However, RNG faces large technical obstacles. Biomethane supplies within California are limited, and on their own fall short of meeting the long-term demand for low-carbon gaseous fuel in the state's buildings and industries, without electrification. Even if California relies on out-of-state biomethane supplies, other states or countries are also likely to lay claim to some of the limited supplies of sustainable biomass feedstocks, which will drive up biofuel prices and could limit supplies.

Assuming California could access up to its population-weighted share of the U.S. supply of sustainable waste-product biomass, excluding purpose-grown biomass crops, there appears to be insufficient biomethane to displace the necessary amount of building and industry fossil natural gas consumption to meet the state's long-term climate goals. Even assuming extensive natural gas efficiency in buildings, without substantial building electrification, California would require a significant increase in out-of-state, zero-carbon, sustainable biofuels, hydrogen fuel or climate-neutral synthetic methane to meet its long-term climate goals. These strategies are identified as important "reach" technologies that may be necessary in the long-term, particularly if other GHG mitigation strategies, such as building electrification, do not materialize at scale.

The shortfall is estimated to be at least 600 TBTU in 2050, even after assuming high natural gas energy efficiency measures and petroleum demand reduction. This finding is based on an assumption that California has access to its population-weighted share of the U.S. supply of biomass waste and residual feedstocks, and that 100% of these biomass feedstocks are converted into biomethane with the exception of cellulosic biomass feedstocks which are assumed to be only converted to liquid biofuels. This deficiency is compounded further if only in-state biomass supplies are available. The shortfall can be reduced by electrification, climate-neutral synthetic methane, or by using purpose-grown biofuel crops. The No Building Electrification scenario with power-to-gas explores the second of these options.

Figure 9: Estimated Cost and Available Biomethane Supply to California in 2050 Compared with Non-Electric Natural Gas Demand



Note: Biomethane supply curves assume all available, non-cellulosic, biomass feedstocks are converted to biomethane. Total supply is compared with non-electric gas demand in the No Building Electrification scenario in 2050 as well as non-electric natural gas demand in 2015.

Source: E3

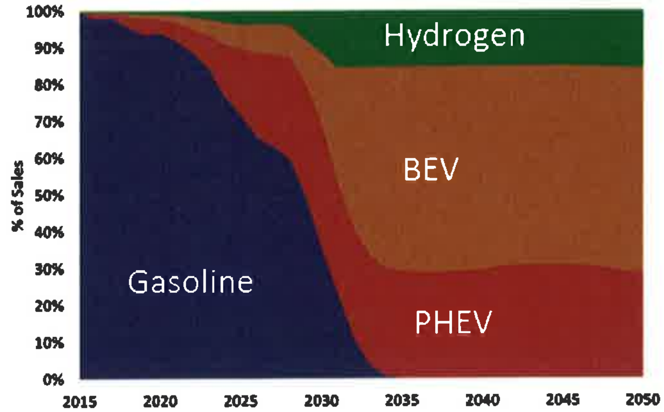
Transportation

Light duty vehicles (LDV) represent the largest source of greenhouse gas emissions in the state, while transportation emissions as a whole, including trucking and off-road transportation, is the largest source of emissions by sector. Reducing greenhouse gas emissions from the transportation sector requires a multi-pronged strategy encompassing fuel economy standards for conventional vehicles, reductions in vehicle miles traveled through smart growth strategies, as well as low- and zero-emissions vehicles and biofuels.

Encouraging consumers to more rapidly switch to purchasing zero-emissions vehicles (ZEVs), with perhaps as many as 6 million ZEVs required on the road by 2030, is a major market transformation challenge. In the light-duty vehicle fleet, the commercial advantage seems to be tilting in favor of battery electric (BEV) and plug-in hybrid electric vehicles (PHEVs), compared to hydrogen fuel-cell vehicles. As a result, by 2030, 60% of new LDV sales are assumed to be BEVs and PHEVs, while just over 10% of new sales of light-duty vehicles are assumed to be hydrogen fuel cell vehicles. This reflects the possibility that the longer ranges and shorter fueling times for fuel cell vehicles could be convincing to a portion of the market (

Figure 10). It is possible to meet the state's climate goals with a wide range of zero-emission vehicle types; the important part is achieving high volumes of ZEV sales before 2030.

Figure 10: Percent of New Sales of Light Duty Vehicles by Technology Type in the High Electrification Scenario

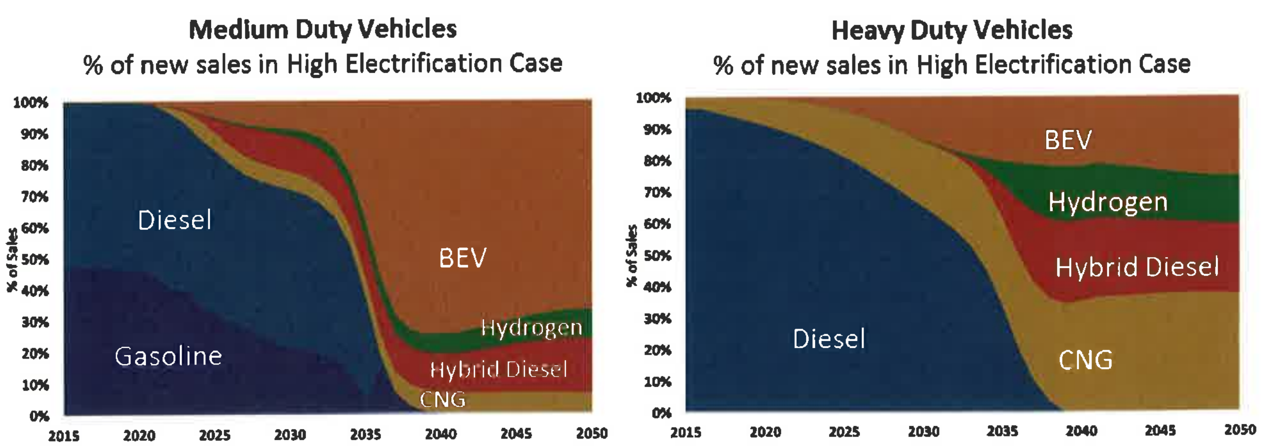


Source: E3

For light-duty ZEVs, the cost of fueling an electric vehicle is far lower than the cost of fueling a conventional vehicle. The challenge is primarily in bringing down the capital cost of the electric vehicles, ensuring that customers have a wide range of electric and plug-in hybrid vehicles to choose from, and that they have confidence in the range and performance of those vehicles. This analysis assumes that the capital cost of light duty electric vehicles will reach parity with internal combustion engine vehicles by approximately 2030. This means that before 2030, vehicle incentives may continue to be necessary to bridge the cost gap with conventional vehicles. Coordination among electric utilities and local governments to facilitate widespread deployment of vehicle charging stations is also critical.

In the medium- and heavy-duty trucking sectors, the zero-emission and alternative fueled options are more diverse than in the light duty fleet. Solutions include conventional diesel vehicles running on renewable diesel, compressed natural gas (CNG) trucks running on fossil natural gas or compressed biomethane, hydrogen fuel cell trucks, battery electric, and hybrid diesel-electric trucks. In the High Electrification case, a diverse, low-emissions trucking fleet is envisioned encompassing all of these options, because of their diverse nature (Figure 11).

Figure 11: Percent of New Sales of Medium- and Heavy-Duty Vehicles by Technology Type in the High Electrification Scenario



In this analysis, the hydrogen fuel cell trucks appear to be the most expensive to purchase and operate from among these options but they may be a competitive GHG mitigation option for a limited number of long-haul, heavy duty applications. In general, costs for short-haul zero-emission trucks are driven more by the total engine power requirements, while costs for long-haul trucks are driven more by the total fuel storage requirements (Boer, 2013). Batteries tend to be cheaper than fuel cells per unit of power but may be more expensive than hydrogen storage per unit of energy. The mitigation scenarios here assume that battery trucks can displace no more than 50% of truck vehicle miles (those used for shorter-haul distances), while fuel-cell trucks are assumed to serve longer-haul heavy duty trucking. As a result, hydrogen fuel cell heavy-duty trucks are a key "reach technology" in this scenario.

In other transportation sectors, (including buses, boats, aviation, ocean-going vessels, rail, construction, and other recreational and industrial vehicles), GHG reductions are also required, although the solutions, like in trucking, may be highly tailored to each application. Electrification of buses, port equipment, and transportation vehicles at airports, for example, represent a relatively easy GHG mitigation option, while reducing GHG emissions from aviation and shipping may be more expensive.

In the High Electrification scenario, diesel and jet fuel use in off-road transportation (including aviation, rail and shipping) represents 28% of total remaining GHG emissions in 2050, which is the largest remaining source of fossil fuel use by 2050. While decarbonization options could be developed for these sectors, including hydrogen-fueled, all-electric, or biofuel technologies, these scenarios do not necessitate implementing these solutions to achieve the 2050 GHG goal.

Industry and Agriculture

California's current industrial and agriculture GHG emissions from energy use are similar in magnitude to those of the state's electricity sector. The refining sector, oil and gas extraction, and manufacturing, (notably cement, chemicals and food processing), represent the largest sources of emissions in this category.

Reducing GHG emissions from these sectors will likely require significant increases in energy efficiency, as well as, potentially, the use of biomethane to displace fossil natural gas. Carbon pricing, through the cap and trade program, may help to achieve higher levels of energy efficiency in industry, and could encourage the use of sustainable biofuels, although more direct, industry-specific programs may also be required.

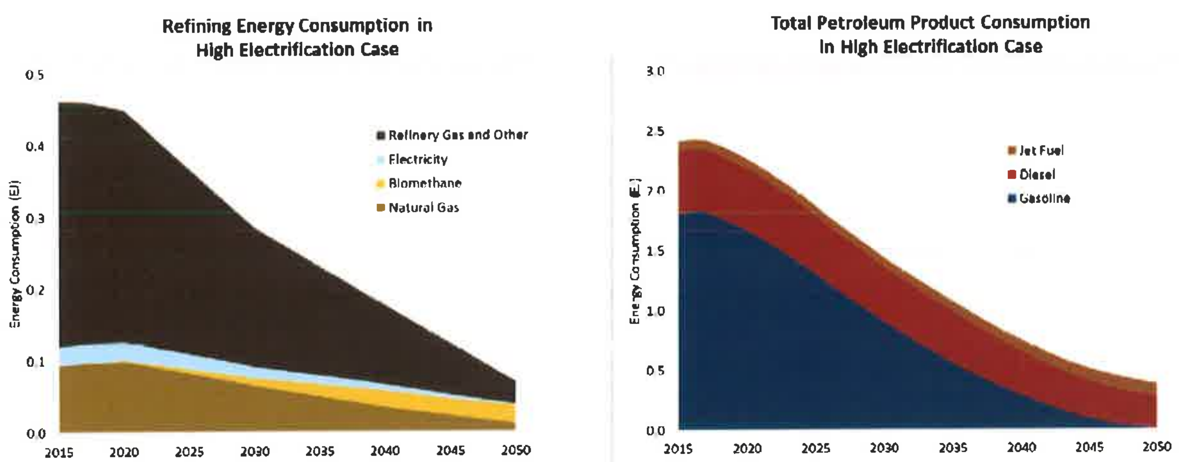
Industrial electrification is another GHG mitigation option, which is likely to be technically feasible for nearly all end uses, but at potentially high cost. The high cost of many industrial processes is due to the relative inefficiency of using a high-quality final energy carrier such as electricity as a substitute for simple combustion to make heat. While heat pumps can offer efficiency advantages for room temperature heating applications in buildings, they do not offer the same advantage for high temperature industrial processes. Consequently, the High Electrification scenario does not include any industrial electrification. Nevertheless, industrial electrification is a key "reach technology" in this study, as it serves as a backstop mitigation option in many of the alternative mitigation scenarios when cheaper options are not available.

The costs of high levels of industrial energy efficiency and electrification are not well understood and this represents an area where additional research could be helpful.

Another key uncertainty in the industrial sector is what will happen to the state's large refineries, and to domestic oil and gas extraction, over time, as in-state demand for refined petroleum products fall. This analysis assumes that, in addition to energy efficiency savings of 20 to 30% by 2030, the refining sector reduces its total production by an additional 14% by 2030.

The combined effect of energy efficiency and reduced production modeled in the refining sector result in similar levels of energy reductions as seen in the total, in-state demand for gasoline and diesel, which falls by 44% in 2030, relative to 2015, in the High Electrification Scenario (Figure 12). It is not known how California's refining sector will respond to a long-term, structural shift towards lower demand for gasoline and diesel in California from vehicle electrification. The sector could shift towards becoming a net-exporter of petroleum products, or it could reduce in-state production, as modeled. However, if greenhouse gas emissions from the refining sector do not decline significantly, it will make meeting the state's long-term climate goal very challenging. In the High Electrification Scenario, refining sector GHG emissions fall 90% by 2050 relative to today, in line with the energy-related GHG emissions reductions seen in other sectors.

Figure 12: Refining Sector Energy Consumption and Petroleum Product Consumption in the High Electrification Scenario



Source: E3

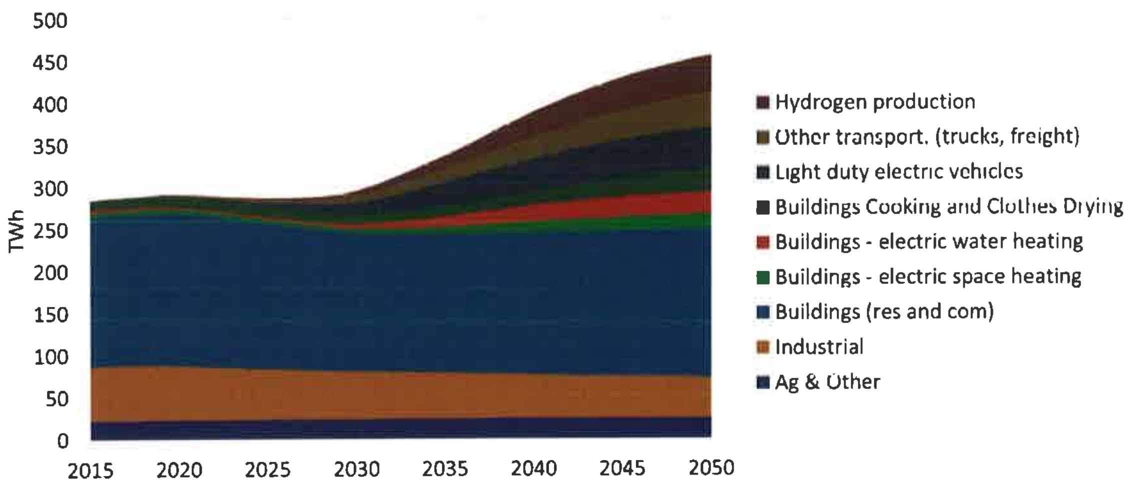
Electricity

California is well on its way to reducing greenhouse gas emissions from electricity. By 2025, the state will have eliminated the small amounts of remaining in-state and imported coal-fired generation. Currently, the state's electricity generation mix is approximately 25% renewable, 10% nuclear and 10% hydroelectric, or about 45% zero-carbon. (Diablo Canyon, California's only remaining in-state nuclear generation facility will retire in 2024/25, leaving only a small portion of imported nuclear power from Palo Verde through 2045, when that facility is likely to retire.

No new nuclear power is evaluated in this scenario.) This analysis suggests that a 70% - 85% zero-carbon electricity mix could be necessary to meet the state's 2030 climate goals. The range of zero-carbon electricity needed for 2030 reflects the potential for slower progress in other mitigation strategies than assumed in the High Electrification scenario. In this study, zero-carbon electricity serves as the major backstop strategy in 2030, as technical obstacles to about 80% zero-carbon electricity appear to be more surmountable than the challenges associated with scaling up GHG mitigation further in other sectors, and, unlike other sectors, consumer adoption challenges are less of a concern for renewable energy deployment.

Energy efficiency savings could largely offset the increase of new electrification loads in the 2030 timeframe, but by 2050, electrification loads are expected to increase California's electricity demand by approximately 60% (Figure 13). This means that the electricity sector will be providing the majority of the energy in the state, displacing fossil fuel use as the state's largest source of energy today.

Figure 13: Electricity Demand by Sector in the High Electrification Scenario

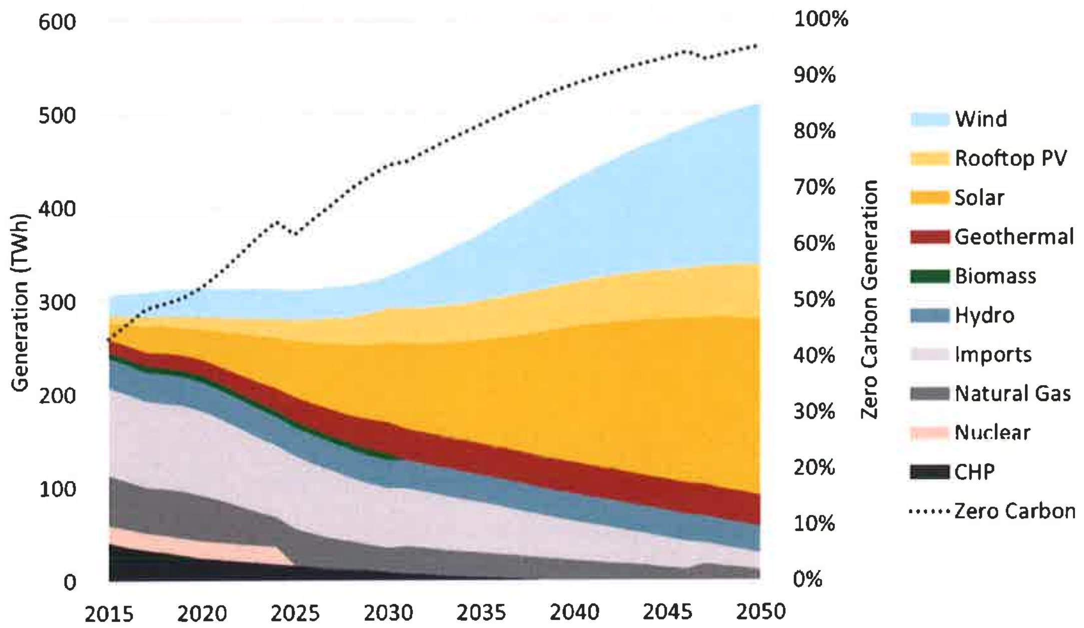


Source: E3

Renewable electricity generation is the largest single measure for reducing GHG emissions in 2050. This modeling suggests that approximately 95% zero-carbon generation and 5% gas generation is needed by 2050 (Figure 14). This generation mix (including both in-state solar and out-of-state wind to enhance resource diversity), plus aggressive deployment of flexible loads, and energy storage appears to be a lower-cost means to reduce GHG emissions than other, non-electricity sector GHG mitigation options. Achieving a 100% zero-carbon generation mix, however, appears to be cost-prohibitive without reliance on nuclear, carbon capture and sequestration (CCS), lower-cost, more abundant biofuels, or new forms of low-cost, long-duration energy storage (Figure 15).

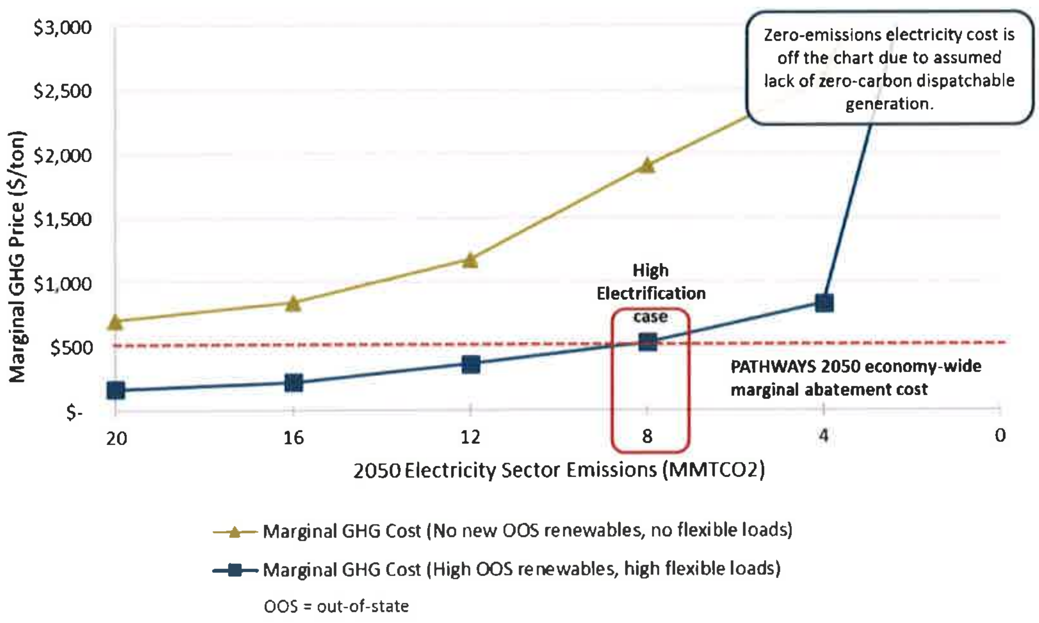
To achieve a 100% zero-carbon electricity system, affordable, zero-carbon and long-duration dispatchable resources would be necessary to maintain resource sufficiency and reliability during sequential days of low renewable energy availability. Low carbon electricity is critical for achieving economy-wide decarbonization in concert with electrification of end-uses in other sectors; it is important that low-carbon electricity is accompanied by affordable electric rates, so as not to discourage electrification.

Figure 14: Electricity Generation by Fuel Type in the High Electrification Scenario



Source: E3

Figure 15: 2050 Marginal Electricity Sector GHG Abatement Cost



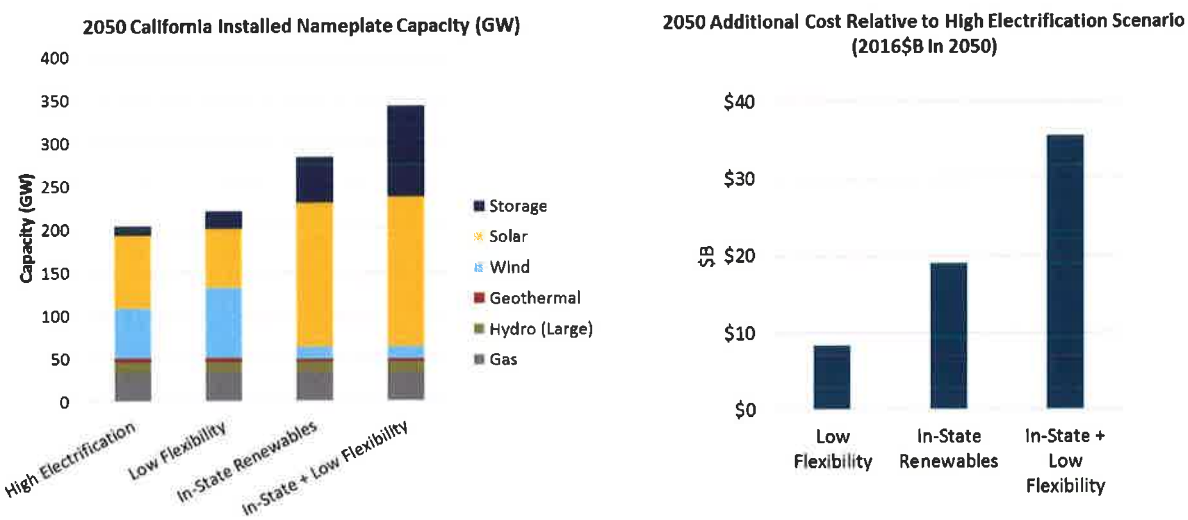
A "supply curve" for GHG emission reductions in the electricity sector using the RESOLVE model with electricity demands provided from the California PATHWAYS High Electrification Scenario. RESOLVE was constrained to yield electricity sector GHG emissions ranging from 0 to 20 MMT CO_2 in 2050, with either the High Electrification scenario renewable integration measures (blue line) or with a more limited set of renewable integration measures, excluding out-of-state (OOS)

wind delivered to California from the other Western states, and flexible loads in buildings, hydrogen production, and electric vehicle charging (gold line).

Source: E3

The annual cost savings in 2050, afforded by the diverse set of renewable integration solutions in the High Electrification scenario is modeled to be large. Relying only on in-state solar resources and renewable integration solutions, without the diversity provided by out-of-state wind, adds about $19 billion per year in costs by 2050 to achieve the same level of decarbonization (Figure 16). Moreover, if flexible loads in buildings, flexible electric vehicle charging, and flexible hydrogen electrolysis are also not available and other sectoral strategies are unchanged, the annual cost premium would reach $36 billion per year by 2050. This large cost premium results from the expense of pairing solar generation with batteries so that electricity can continue to serve demand at night, as well as overbuilding the solar generation so that it can meet demands during cloudy and wintertime periods. Beyond the cost premium, land use impacts could be significant: the land area required for new utility-scale solar in the "In-state + Low Flexibility" scenario could exceed 1,700 square miles (about 1% of state land area), versus only about 600 square miles in the High Electrification scenario.[3]

Figure 16: 2050 Capacity Additions and Cost Impacts of Electricity Sector Sensitivity Analysis



Results are based on RESOLVE modeling using electricity demands from the California PATHWAYS High Electrification Scenario

Source: E3

This analysis underlines the critical importance of renewable integration strategies, including diverse renewable generation sources, to affordably meeting the state's climate goals. It also raises many questions for additional research. These include how best to design electricity markets to incentivize diverse renewable resources, flexible loads, and optimally dispatched storage. Another question is how to compensate thermal generators whose value may

3 This assumes 8 acres per MW of installed solar including balance-of-system area (Ong et al., 2013).

increasingly be in providing capacity and resource sufficiency during periods of low-renewable generation, rather than in providing regular energy services.

Biofuels

In addition to zero-carbon electricity (renewables, nuclear or carbon capture and storage), biofuels represent the only other potential source of zero-emissions primary energy. This analysis attempts to apply a conservative lens to estimate available biofuel supplies and costs. Biofuel supply curves are developed based on estimates of the in-state supply of biomass potential, as well as California's population weighted share of the U.S. supply of biomass.

Biomass resources in California and the United States

Biomass resources are relatively limited in California. Estimates of in-state resources for biomass vary from 20–40 million bone dry tons (Table 7). California currently imports approximately 87% of its liquid biofuels from out-of-state to meet low-carbon fuel standard regulations (ARB, 2016). In this analysis, the DOE Billion Ton Update (2011) is used to estimate the U.S. supply of sustainable biomass resources, supplemented by Jaffe et al. (2016) for estimates of in-state manure, landfill gas, and municipal solid waste, yielding about 30 million bone dry tons of available in-state biomass in the scenarios. Full biomass module details are in Appendix C.

Table 7: Summary of Estimated Biomass Resources in California

Source (Million bone dry tons)	Cellulose	Wood	Lipid	Manure and Landfill Gas[4]	Misc.	Total
Billion Ton Update (Perlack et al., 2011)	3.0	14.6	0.3	1.8	0.0	**19.7**
Horvath et al. (2016)	6.4	18.5	0.0	5.0	0.0	**29.9**
California Council on Science and Technology (2013)	6.6	16.7	5.5	0.0	11.8	**40.6**
California Biomass Collaborative (Williams, R.B. et al., 2015)	2.1	16.3	0.0	13.3	3.6	**35.4**

Resources are approximately mapped to PATHWAYS fuel conversion categories, Million Bone Dry Tons.

Source: E3

The Billion Ton Update (Perlack, 2011) estimated that about 1.3 billion tons of biomass feedstock could be available nationally by 2030 for biofuel production, including wastes and residues as well as purpose-grown crops and plantation forestry. About 0.5 billion tons of the supply is associated with new cultivation of purpose-grown miscanthus, pine, eucalyptus, and other grass and tree crops.

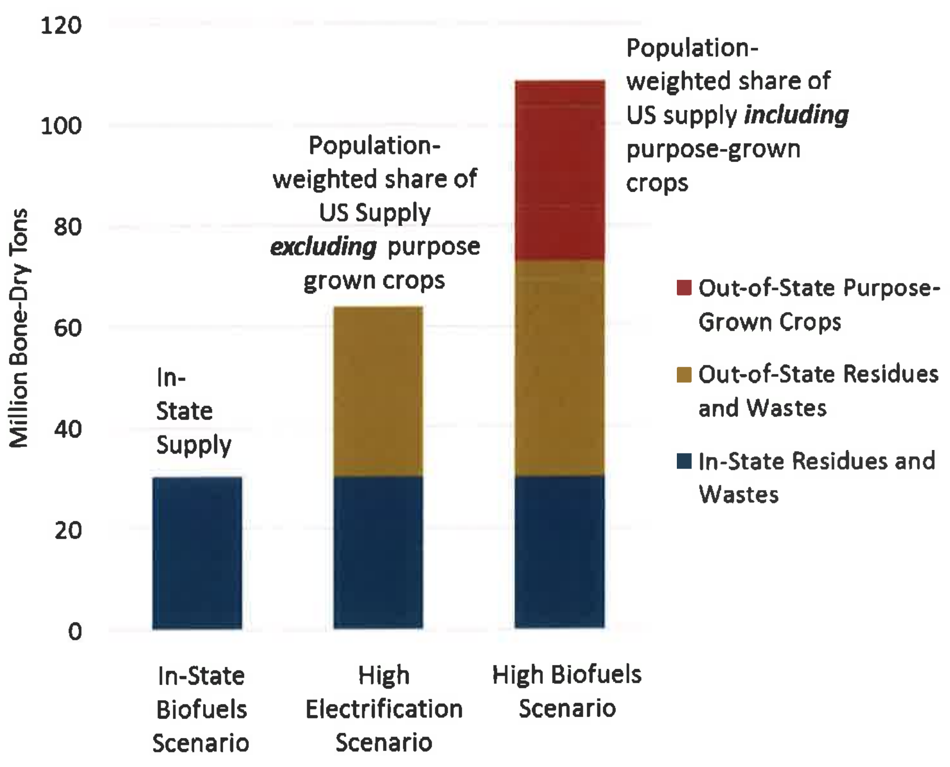
[4] In this table, one ton of landfill gas is counted as one bone dry ton. Elsewhere in the document, a weighting factor of 6 is applied to landfill gas to account for the greater energy content of landfill gas as compared with crude biomass.

Modeled Biomass Use

This analysis estimates a sustainable long-term supply and cost of biomass available to California. As discussed previously, the High Electrification scenario excludes purpose-grown crops and plantation forestry from the biomass resource supply curves due to sustainability concerns. The supply is further restricted to total no more than the cost-effective biofuel supply, given California's population-weighted share of the U.S. biomass supply, including in-state use. Imports from outside of the U.S. are excluded from the analysis. This results in 64 million bone dry tons used in the High Electrification scenario, about half from in-state and half from out-of-state (Figure 17).

The In-State Biomass scenario uses only 30 million bone dry tons (Figure 17), representing nearly all the assumed in-state supply. In contrast, the High Biofuels Scenario assumes that purpose-grown crops are included in the U.S. supply, and that California's population-weighted share increases proportionally. The extra biofuels displace more expensive mitigation measures such as hydrogen fuel-cell trucks, but this scenario is deemed to be more-risky than the High Electrification scenario, because of the uncertainty around the long-term supply of sustainable, purpose-grown biomass feedstocks. In the High Biofuels Scenario 109 million bone dry tons of biomass are used (Figure 17).

Figure 17: Assumed Biomass Use in California in 2050 in Three Mitigation Scenarios



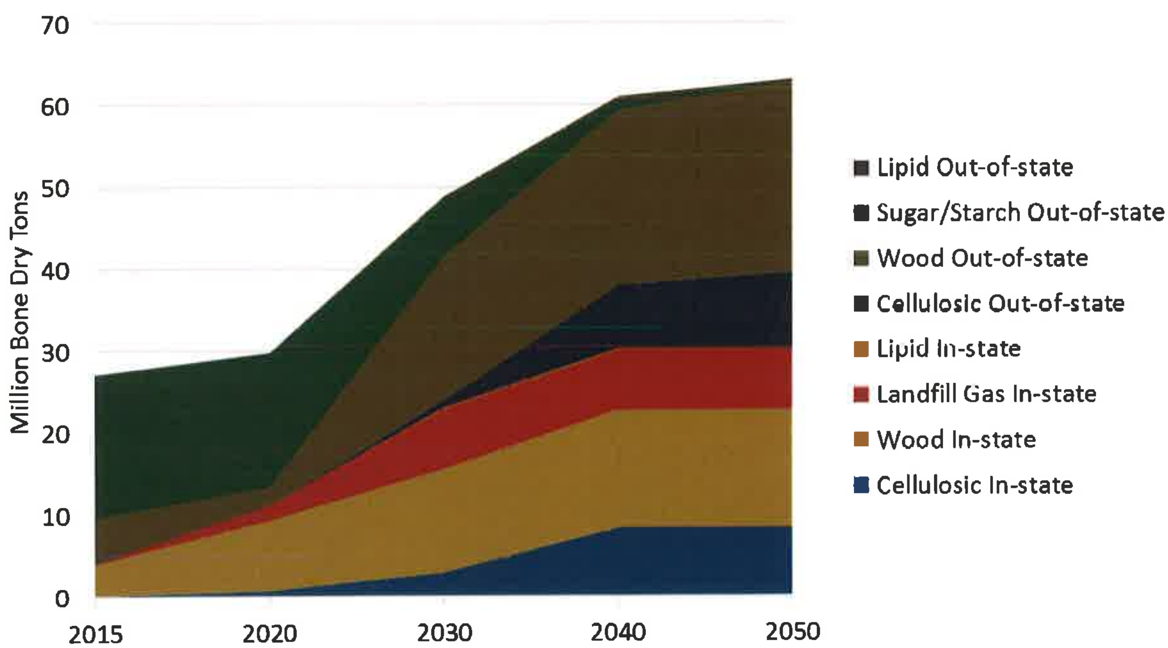
One ton of landfill gas is weighted to be six bone-dry tons based on its approximate relative energy content.

Source: E3

The High Electrification scenario assumes a large transformation in the biomass supply chain relative to today. Most of today's biofuel consists of ethanol derived from out-of-state corn from a conventional fermentation process that uses only the starch and simple sugars (Figure 18), but by 2050 the corn ethanol is assumed to be replaced with advanced biofuels dominated by out-of-state wood and cellulose associated with agriculture and forestry residues. These residues are converted to biofuels using hydrolysis, pyrolysis, and gasification. In-state utilization includes a significant amount of landfill gas, based on the Jaffe et al. (2016) analysis.

Although manure could represent an important biomethane precursor, neither in-state, nor out-of-state, manure is found to be cost-effective in the High Electrification scenario, using a total resource cost perspective. The Low Carbon Fuel Standard (LCFS) incentivizes the production of biomethane from manure because of the co-benefits of avoided methane emissions. In-state economic transfers between producers and consumers, such as those that are created by LCFS credits, are not modeled here, but could shift the feedstock supply of biomethane in California relative to the estimates of the High Electrification scenario, albeit at a higher cost. Overall, the model may be underestimating the cost of achieving manure methane reductions in the non-combustion sector, which assumes that manure methane is used to produce biofuels.

Figure 18: Assumed Feedstock Use in California in the High Electrification Scenario



This scenario excludes purpose-grown crops in 2050. One ton of landfill gas is the equivalent of six bone dry tons based on its approximate relative energy content.

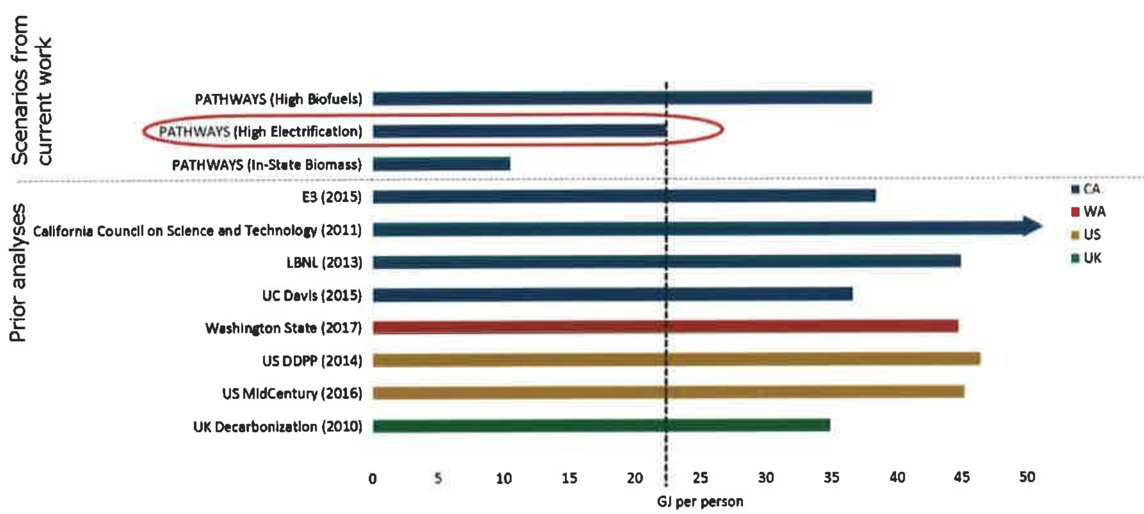
Source: E3

Comparing Biomass Use to Previous Studies

Several previous studies of deep decarbonization in California and in other regions have included biofuels as a source of net-zero carbon fuel. Eight of these analyses (Figure 19) are reviewed including studies focused on Washington, the U.S., California, and the United Kingdom. The previous PATHWAYS cases (E3, 2015) assumed a level of biomass availability more comparable to the "High Biofuels" scenarios in the current analysis. Likewise, all of the other deep decarbonization studies reviewed here, which evaluated economy-wide greenhouse gas reductions of 80% by 2050, included a higher per capita biomass use than this study's High Electrification scenario.

This literature review indicates the current High Electrification scenario is more conservative regarding the role of biofuels in a low-carbon economy than previous deep decarbonization literature. Exploring biofuel-constrained scenarios is an important contribution to the literature given ongoing research into biofuel sustainability: even those produced from waste and residue biomass could possibly have negative impacts on forest ecosystems or lead to net emissions of CO_2 from terrestrial stocks of carbon (US EPA, 2014). Moreover, recent progress in the commercialization of advanced biofuels has been slower than anticipated, especially in comparison with rapid technological progress in the commercialization of renewables and electric vehicles. Consequently, reduced dependence on biofuels in the High Electrification scenario is intended to reduce environmental risk, as well as cost risk.

Figure 19: Estimated Biomass Primary Energy Use in 2050



Estimated per capita biomass primary energy utilization in 2050 shown for selected deep decarbonization scenarios. The comparison assumes 18 GJ per bone dry ton primary energy yield, corresponding to the average yield assumed in the US analysis for the Deep Decarbonization PATHWAYS Project (Williams, 2014). References:

E3. 2015. California State Agencies' PATHWAYS Project: Long-term GHG Reduction Scenarios;

California Council on Science and Technology (CCST). 2011. California's Energy Future - The View to 2050;

LBNL. 2013. Scenarios for Meeting California's 2050 Climate Goals (see cited reference Wei et al., 2014);

U.C. Davis: Yang et al. 2015. Achieving California's 80% Greenhouse Gas Reduction Target in 2050;

Washington State: Haley, et al. 2016. Deep Decarbonization Pathways Analysis for Washington State;

U.S. DDPP: Williams, J.H., et al. (2014). Pathways to deep decarbonization in the United States.

U.S. Mid-Century: The White House. 2016. United States Mid-Century Strategy for Deep Decarbonization;

U.K. Decarbonization: European Climate Foundation. 2010. Roadmap 2050

Source: E3

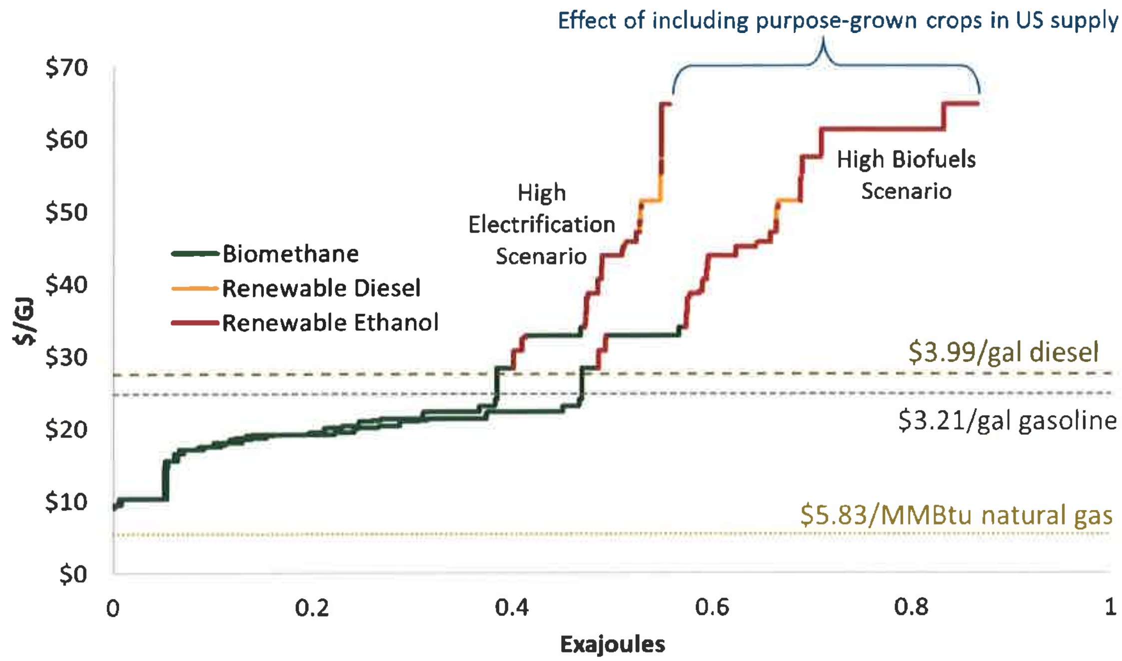
Biofuel Costs in 2050

Within each scenario, the biofuels module is used to select an array of feedstock and fuel combinations that approximately maximizes the cost-effective CO_2 abatement, within the context of the marginal abatement costs in other sectors. The PATHWAYS model attempts to capture the interactions between mitigation options: for instance, renewable ethanol as a gasoline substitute is a relatively cheap biofuel that is not heavily utilized in most mitigation scenarios because light-duty vehicles are assumed to be nearly all cost-effectively electrified by 2050. The impact of the federal Renewable Fuel Standard program is not reflected in the biofuel prices, since these are assumed to expire after 2022. Consistent with the cost methodology applied within the PATHWAYS model, the effect of the Low Carbon Fuel Standard on fuel prices is also not reflected, as these are considered transfers within the state.

In all the scenarios, biofuels are estimated to carry a significant price premium over fossil fuels. The team assumed there is a single market-clearing price for each biofuel type corresponding to the all-in cost associated with the marginal feedstock increment, relatively large CO_2 abatement costs can result as inexpensive resources are exhausted. The total economy-wide net cost of biofuels over their fossil fuel counterparts is estimated to be $17B in 2050 in the High Electrification Scenario. This net cost in 2050 is highly uncertain and is based on a conservative assumption excluding innovation in advanced biofuel conversion pathways.

In the High Biofuels Scenario, which includes the use of purpose-grown crops to produce biofuels (Figure 20), the same complement of mitigation options is assumed to be available as in the High Electrification Scenario. This means that the additional biofuels afforded by access to imported purpose-grown crops can be used to lower overall scenario costs. The additional biofuel displaces some vehicle electrification and hydrogen vehicles as well as displacing some of the marginal renewable generation and battery storage.

Figure 20: 2050 Biofuel Supply Curves



Biofuel supply curves are shown for the High Electrification scenario and the High Biofuels scenario. Costs shown are wholesale costs for gaseous fuels and retail costs for liquid fuels.

Source: E3

The cost of biofuels (as shown in Figure 20) is only part of the equation in designing a low-cost scenario, which is a function of the carbon abatement cost. The carbon abatement cost of biofuels depends on three factors: 1) the cost and conversion efficiency of producing the biofuel, 2) the GHG savings of the biofuel relative to the displaced conventional fuel, and 3) the price of the displaced conventional fuel. In the conversion assumptions applied here, key biomass feedstocks such as woody forest residues can be much more efficiently converted to biomethane than to renewable diesel (Appendix C).[5] However, other analysis suggests that liquid biofuels have a lower carbon abatement cost than biomethane.

In the High Electrification Case, biomethane is used to decarbonize a portion of the natural gas use in buildings and industry, along with providing renewable CNG for a portion of CNG trucks.[6] The mix of biofuel types produced is very sensitive to model input assumptions, and the relative costs and yields of competing biofuel pathways in the future are uncertain. This

[5] The assumptions about the available supply of methane derived from California-based waste and dairy resources are from Jaffe *et al.* (2016). These feedstocks are assumed to be transported to a California gas injection point using a variety of transportation modes, such as feeder pipeline and truck, depending on the location of the feedstock. The assumptions about the available supply of all other biomass feedstocks, including both in-state and out-of-state supplies of cellulose and woody waste, are from the Billion Tons Study update, U.S. Department of Energy (2011). These feedstocks are assumed to be transported to California via truck for processing before injection into the gas pipeline.

[6] The 2017 IEPR (California Energy Commission, February 2018) calls for further study by the CPUC regarding the technical specifications that biomethane must achieve before it can be injected into the natural gas pipeline in California. In this model, CNG trucks are assumed to use compressed natural gas from the pipeline. Pipeline biomethane costs and greenhouse gas savings can be attributed to different sectors based on policy assumptions; this sectoral allocation does not affect the total economy-wide scenario cost in PATHWAYS.

uncertainty may not be reduced until more progress is made in expanding advanced biofuel supply chains. This uncertainty underscores the necessity to encourage the most cost-effective use of this valuable but limited net-zero-carbon resource.

Overall, this analysis finds that without additional innovation in advanced biofuel conversion pathways, biofuels are expected to be a relatively expensive way to reduce GHG emissions but can nevertheless help to reduce the cost of meeting the state's climate goals relative to other options. If California were restricted to using only in-state supplies of biofuels, which is approximately the same quantity of biofuels used today (although today's mix is more heavily weighted towards corn-based ethanol) the 2030 total cost of GHG mitigation could increase by about $4 billion/year relative to the High Electrification scenario.

Even though the High Electrification scenario is less reliant on biofuels than previous analyses, it still requires a large expansion in the supply of advanced biofuels to California, from using under 0.1 exajoules (EJ) in 2015, excluding conventional ethanol and biodiesel, to 0.340 EJ by 2030 and 0.56 EJ by 2050 (4.3 billion gallons of gasoline-equivalent).

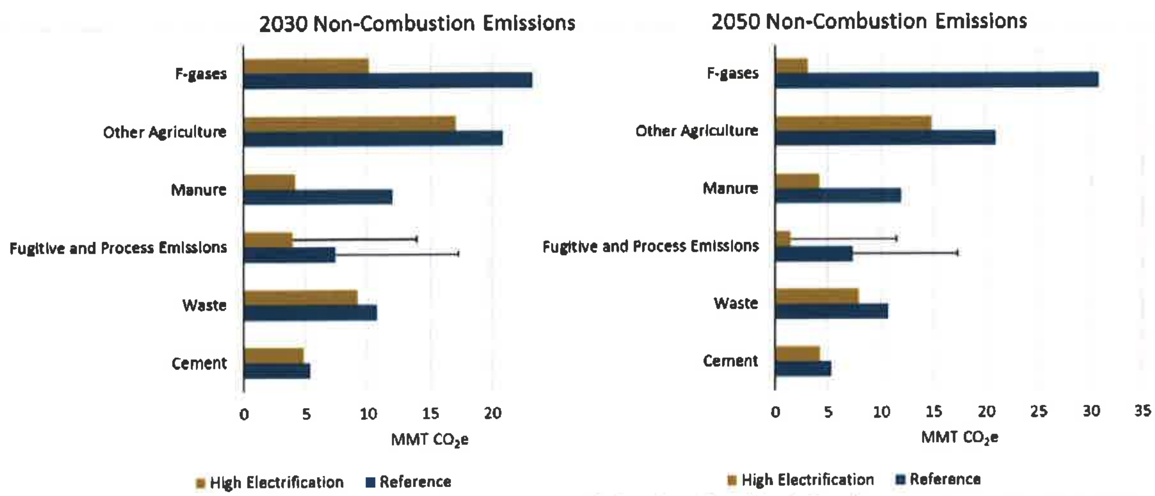
To some extent, hydrogen can serve as a substitute for biofuels as a mitigation option: in the In-State Biomass scenario, only 0.23 EJ of advanced biofuels are used in 2030 and 2050, but hydrogen fuel utilization reaches 0.2 EJ, as compared with only 0.11 EJ in the High Electrification scenario. If hydrogen fuel and vehicle costs are lower than expected, that could further reduce the need for the state to rely on advanced biofuels.

Non-Combustion Emissions

Non-combustion greenhouse gas emissions include fluorinated gases (F-gases) used as refrigerants, methane emissions from a variety of sources (including manure, waste water treatment facilities, landfills, enteric fermentation in livestock, and methane leakage from natural gas extraction, storage and pipelines), as well as carbon dioxide emissions from the chemical conversion process for making cement and nitrogen oxide emissions from fertilizer applications. This suite of non-combustion greenhouse gas emissions represented 16% of the state's total GHG emissions in 2015 and will increase significantly without mitigation efforts. Of the non-combustion emissions, methane and many F-gases are considered to be short-lived climate pollutants (SLCPs) with a disproportionate potential to add to near-term climate change, and these SLCPs are targeted for a 40% reduction by 2030 as part of the ARB's SLCP Strategy (ARB, 2017b). Reducing non-combustion greenhouse gas emissions is critical to meeting the state's climate goals, and a diverse range of strategies are needed to reduce these emissions.

In the High Electrification scenario, an aggregate 33% reduction in non-combustion emissions is achieved by 2030 relative to 2015, with a 37% reduction in SLCPs. The reduction increases to 52% in aggregate by 2050 relative to 2015, with a 54% reduction in SLCPs. Non-combustion emissions are assumed to decline by a lower proportion than the economy-wide 80% relative to 1990 by 2050, requiring greater than 80% reductions in energy emissions by 2050 in all mitigation scenarios (Figure 21). Strategies and challenges for major emission sectors are further detailed below.

Figure 21: Non-combustion Emissions in 2030 and 2050 in the Reference and High Electrification Scenario



Note: Error bars bracket potential underestimate in fugitive methane emissions from the California Greenhouse Gas Emissions Inventory: see, e.g., Wunch et al. (2016). The IPCC estimates a ~20% uncertainty in global fossil methane emissions (2013).

Source: E3

F-gases

F-gases consist primarily of hydrofluorocarbons (HFCs) that were introduced to replace ozone-depleting chlorofluorocarbons (CFCs) that were used as refrigerants and propellants subsequent to the Montreal Protocol phasing out CFCs.[7] Thus, their emissions rose considerably between 1990 and 2015. Reducing the emissions of these very high global warming potential gases can be achieved by replacing current refrigerant gases with alternatives that are less harmful to the climate, such as compressed CO_2. The U.S. committed to reducing F-gases under the Kigali Amendment to the Montreal Protocol in 2016. Whether the U.S. will follow through on these commitments remains to be seen. Nevertheless, the Air Resources Board's economic analysis for the state's SLCP Strategy found that these emissions can be avoided at relatively low cost.

Methane from Livestock and Waste

Biogenic methane emissions from the decomposition of animal waste, food waste, and wastewater represent a challenging source of GHG emissions, but if they are diverted for anaerobic digestion or if their emitted methane is captured, they represent a potential source of biomethane. Some of California's renewable electricity generation includes direct combustion of these resources today.

The ARB SLCP Strategy explores options for reducing these emissions while at the same time producing biofuel in extensive detail. However, the large number of diffuse emission sources remains a challenge. Manure that is not already centrally processed could be expensive to collect, and enteric fermentation from cows cannot be readily captured.

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[7] A small proportion of F-gas emissions, such as SF_6 used in transformers, represent long-lived gases that are not explicitly addressed by the ARB SLCP Strategy.

Fugitive Methane Emissions

Fossil methane and other gases are lost as fugitive and process emissions associated with fossil fuel extraction, processing, and transport. There is some uncertainty in estimating the scale of these emissions, particularly for natural gas extraction and from pipelines. Some research (Wunch et al., 2016) suggests that methane leakage from the pipeline gas system could be several-fold higher than official state greenhouse gas inventory estimates. The team used the high-end range of potential fugitive methane emission leaks in the state, estimating the cost of meeting the state's GHG emissions goals if methane leaks were 10 million tons higher than assumed in the Reference case. This results in an increase in the cost of meeting the state's 2030 climate goals of approximately $4 billion/year in 2030.

Other Industrial and Agricultural Sources

Remaining non-combustion GHG emissions include CO_2 released during the production of cement, nitrous oxide resulting from the application of fertilizer, and methane produced in flooded fields associated with rice agriculture. Some options exist for mitigating these emissions and are included in the High Electrification scenario, such as substituting fly ash for Portland cement used in making concrete, and increased efficiency in fertilizer application. However, the mitigation potential in these categories is expected to be relatively limited compared to other GHG emission sectors.

Discussion

Reducing methane emissions and other non-combustion emissions requires bringing down the cost and increasing the adoption rates of known strategies, such as covering landfills and manure lagoons and fixing pipeline leaks, as well as R&D and innovation to reduce emissions from enteric fermentation in cows and to reduce emissions from cement production.

Because of the high warming potential per molecule of methane and F-gases, some mitigation options in these sectors can be cheap relative to reductions in CO_2 combustion emissions, when compared in $/ton CO_2-equivalent. The average mitigation cost assumed in this study is near zero, based on assumptions from the Short-Lived Climate Pollutant Reduction Strategy (CARB, 2017). Costs of biogenic methane mitigation are assumed to be associated with biofuel production that is yielded as a co-benefit of mitigation.

Some sources of non-combustion emissions are likely very expensive to mitigate, such as enteric fermentation in cows. Consequently, all mitigation scenarios assume that nearly 90% reductions in combustion emissions by 2050 are needed to achieve California's long-term climate goals, since it is not realistic to assume that 80% reductions in non-combustion emissions will be achieved by 2050.

Climate Change Impacts on the Energy System

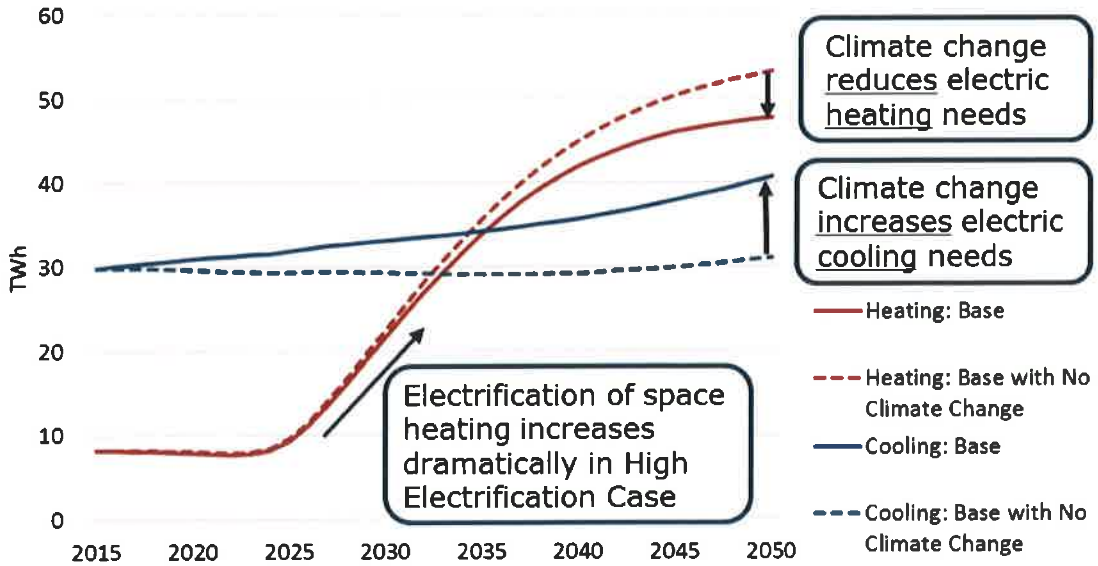
The climate impacts adapted for PATHWAYS from Tarroja (2017) were incorporated in PATHWAYS for the Reference, SB 350, and Mitigation scenarios. They were compared for the Reference and High Electrification Scenario with comparison scenarios that excluded these impacts. In the High Electrification Scenario, resulting differences in emissions and costs were very small in magnitude compared with the changes associated with climate mitigation: less than $1B differences in costs and 1 MMT CO_2e annually by 2050.

The relatively small direct impacts of climate change on the electricity system modeled in PATHWAYS are partly the result of interactions with climate mitigation: moving to a very low-carbon electricity system reduces its vulnerability to the impacts considered here. Higher total loads due to electrification and the dominance of generation by solar, wind, and new energy storage mean that the changes in hydroelectric availability and the shifts in building loads have a proportionally smaller impact. In particular, the increase in heating loads due to electrification is much larger than the increase in air conditioning loads due to climate change (Figure 22). Also, while climate change will increase air conditioning demand more than it decreases heating demand, causing a small net increase in load, the AC demand shape coincides well with solar generation, the state's most abundant renewable energy source. Space heating demands, in contrast, peak at night and in the winter when solar availability is lowest, requiring extensive use of out-of-state wind and/or storage to fully integrate these demands.

Climate change will also reduce the thermal efficiency of conventional thermal power plants due to hotter temperatures. Other research suggests that power plant peak efficiency could decline by 1-5% by mid-century in a conventional electricity grid (Bartos and Chester, 2015, and Jaglom, 2014). However, this is inconsequential in the low-carbon electricity system considered in the mitigation scenarios. Total gas generation is very small (less than 5% of annual generation in the High Electrification Scenario) and is largely used as a backup resource when solar and wind availability are low: with California's abundant solar resources, this tends to occur at night and in the winter, mitigating some of these effects of hotter temperatures on thermal efficiency.

This analysis is limited to average, direct effects of climate change on the electricity system due to climate change by mid-century. The effects of extreme events that damage infrastructure, as well as the impacts of other changes in the California economy resulting from climate adaptation or unavoidable damages, could be much larger in magnitude. Moreover, unabated climate change would have much more severe effects later in the 21st century than by mid-century.

Figure 22: Changes in Building Electricity Demand Due to GHG Mitigation and Climate Change



Building electricity demands are shown for the High Electrification Scenario with and without climate change.

Source: E3

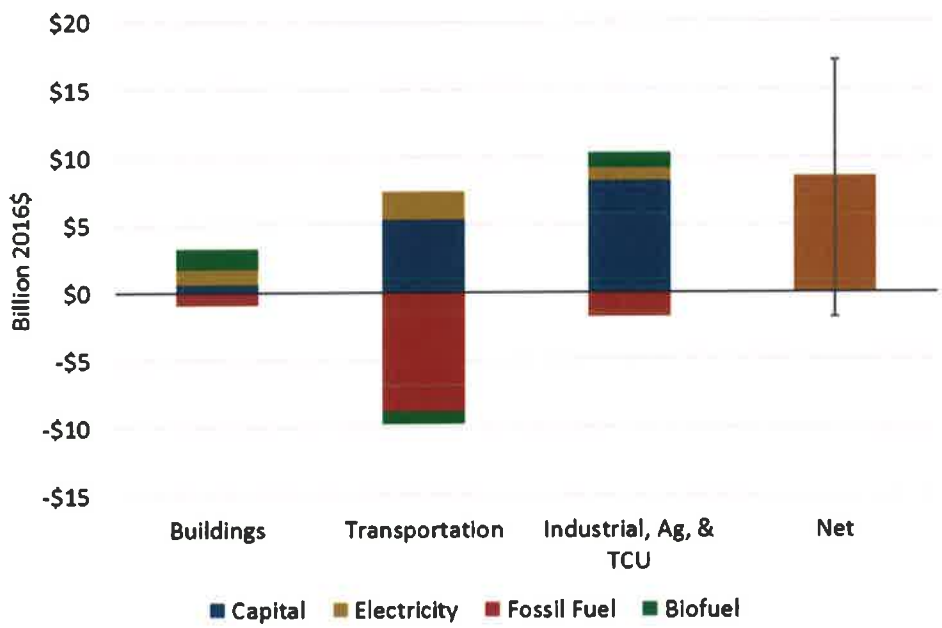
CHAPTER 4: Cost and Risk Analysis

Economy-wide High Electrification Scenario Costs

This analysis estimates the upfront, annualized capital investments and expected fuel costs and savings associated with the High Electrification Scenario.

In the High Electrification Scenario, which meets California's climate goals in 2030 using a reasonably likely, and relatively low-cost combination of strategies, the estimates range from savings of $2 billion per year to net costs of $17 billion per year in 2030, depending on the fuel price and financing assumptions. The base cost assumptions yield a net cost estimate of $9 billion per year in 2030, in today's dollars (Figure 23). This net cost is equivalent to less than a half a percent of California gross state product in 2030. Furthermore, the uncertainty range around fossil fuel prices and financing costs results in a future net cost range that spans zero.

Figure 23: Total 2030 Net Cost of the High Electrification Scenario Relative to Reference Scenario, Excluding Climate Benefits (2016$, Billions)

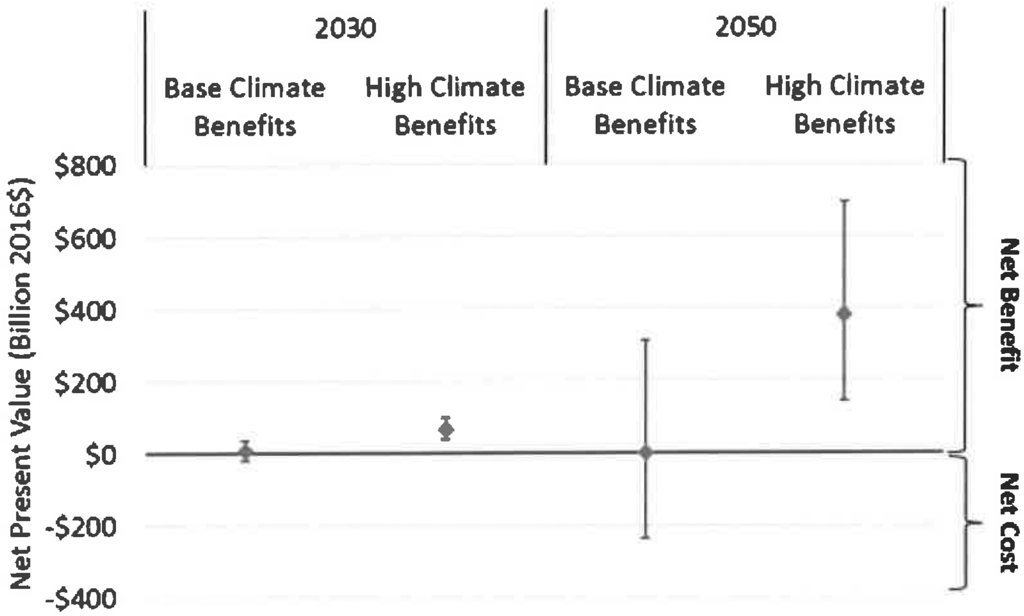


Source: E3

The net present value of the costs of GHG mitigation is compared to the societal benefits associated with reducing greenhouse gas emissions. Using two different estimates of the future benefits of avoided GHG emissions, the climate benefits of avoided emissions are found to likely be equal to, or much larger than the costs associated with reducing emissions (Figure 24).[8]

[8] This assumes a 3% discount rate and uses the 2016 U.S. government social cost of carbon, which escalates as a function of emissions year. "Base climate benefits" is based on average social cost of carbon, corresponding to $58/tCO_2$ in 2030 and $79/tCO_2$ in 2050. "High climate benefits" is based on the 95th percentile in ensemble of modeled

Figure 24: 2030 and 2050 Annual Net Present Value of the High Electrification Case, Including Climate Benefits (2016$, Billions)



Climate benefits are calculated assuming 3% discount rate and using the 2016 U.S. government social cost of carbon. "Base climate benefits" is based on average social cost of carbon. "High climate benefits" is based on the 95th percentile in ensemble of modeled climate benefits. Uncertainty ranges are based on PATHWAYS high/low fossil fuel price and financing cost sensitivities.

Source: E3

Furthermore, the benefits of reducing emissions include not only direct reductions in GHG emissions, but also indirect benefits, including: health benefits from reductions in criteria pollutants (e.g., Zapata et al., 2018), state leadership on a critical global issue, and technology innovation and support for new domestic industries. These indirect benefits are not quantified in this study but have been evaluated in other research (See for example California's 2017 Climate Change Scoping Plan for a summary of these topics).

Incremental Carbon Abatement Costs in the High Electrification Scenario

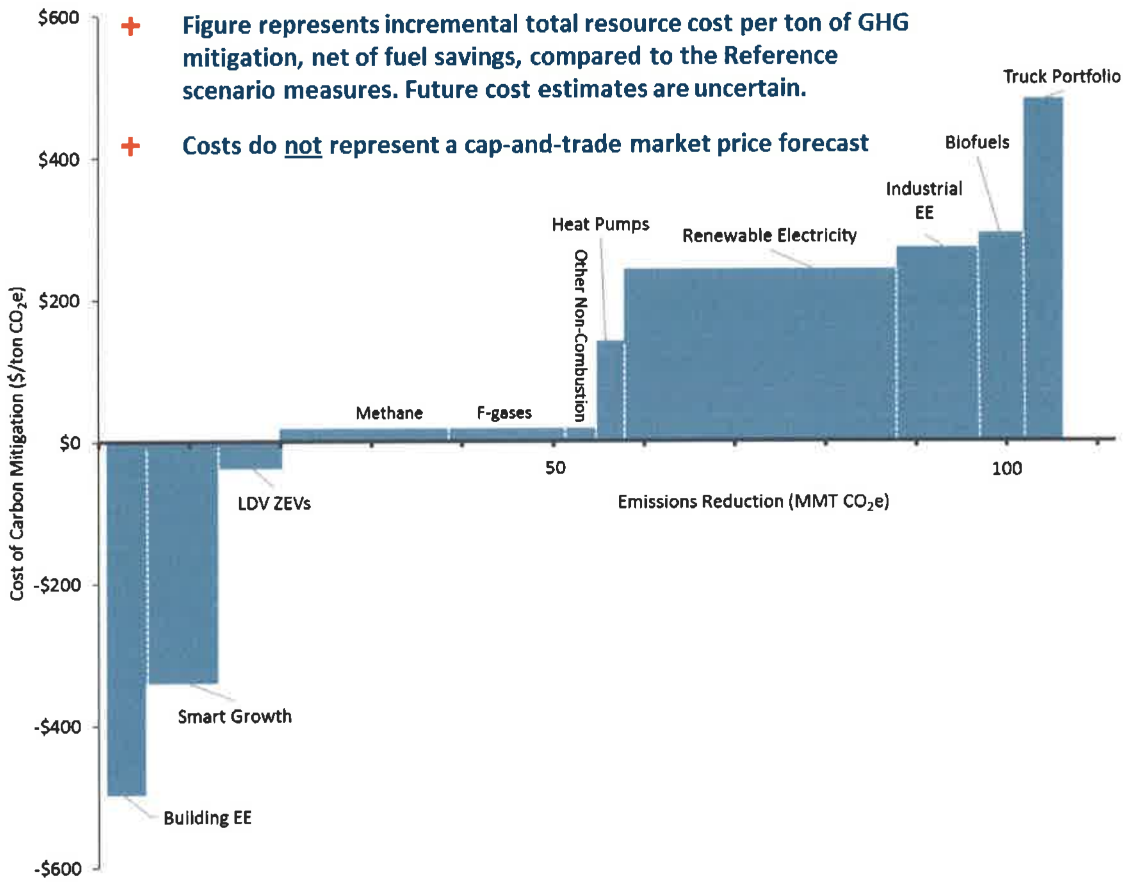
One way to visualize the relative costs and GHG savings of the measures included in a scenario is with a "carbon abatement cost curve". In this type of figure, the lifecycle costs, net of fuel savings, of a given GHG mitigation measure are compared to the counter-factual lifecycle costs in the Reference case. This cost (or savings) result is then divided by the GHG savings of the measure, compared to a Reference case, to create the cost per ton of GHG savings.[9]

climate benefits, corresponding to $175/tCO_2$ in 2030 and $244/tCO_2$ in 2050. Uncertainty ranges are based on PATHWAYS high/low fossil fuel price and financing cost sensitivities.

[9] While this metric is a useful way to compare the costs and savings of measures within a given analysis, due to the many differences in approach that can be used to calculate this metric, it is difficult to compare carbon abatement costs across different analyses without a full understanding of all of the assumptions used to develop the cost metric.

The approximate cost per ton of GHG mitigation is estimated for a suite of measures in the High Electrification scenario, based on a total resource cost metric, net of fuel savings, relative to the Reference scenario. This means that the cost estimates exclude incentives, and reflect estimates of total costs, rather than participant costs or utility costs. For each measure, the High Electrification scenario assumption is reverted back to the Reference scenario assumption. This produces an estimate of the incremental cost and greenhouse gas savings of each measure in the High Electrification scenario, summarized for 2030 and 2050 in Figure 25 and Figure 26.

Figure 25. 2030 Incremental Carbon Abatement Cost Curve (Total Resource Cost per Ton of GHG Reduction Measures, Net of Fuel Savings), in the High Electrification Scenario



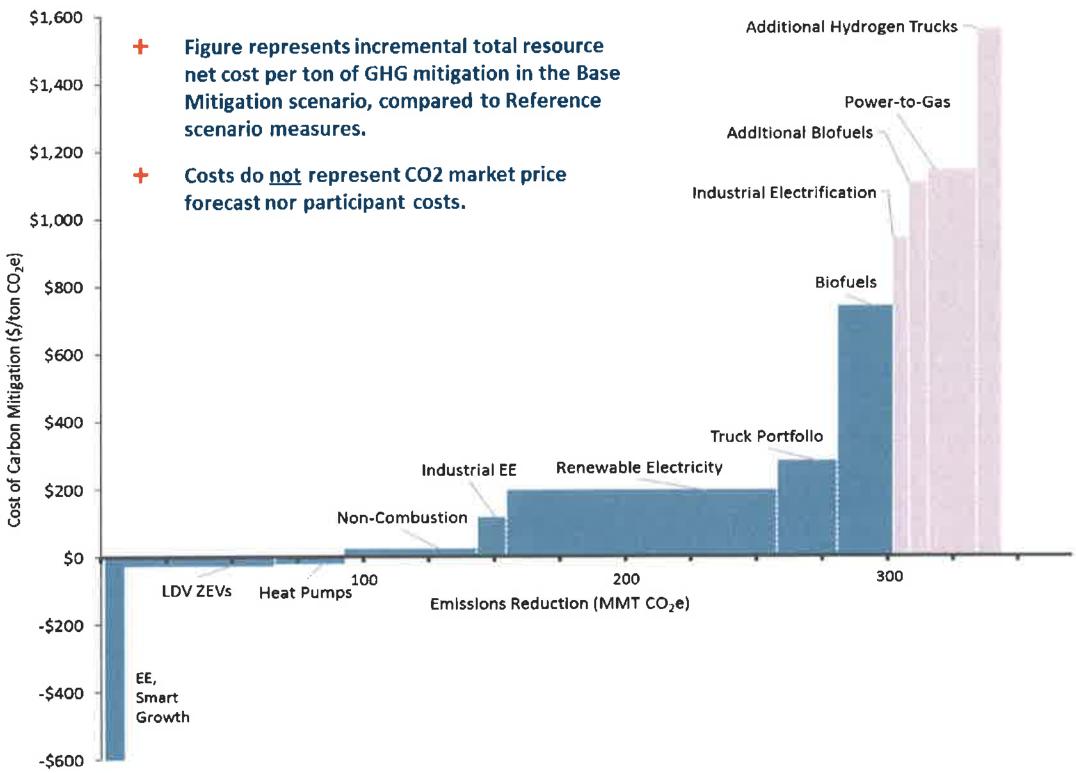
The incremental cost per ton of GHG savings for the High Electrification Scenario measures are relative to Reference Scenario measures (2016 \$/ton CO_2e), see Appendix Table A-3 for more details. Costs are based on a total resource cost assessment, net of fuel savings. Cost estimates are highly uncertain and do not represent a cap-and-trade market price forecast. Incentives are not reflected in the cost estimates. Emission reductions do not add up precisely to the total GHG reductions in the High Electrification Scenario because of interactive effects between measures.

Source: E3

Future cost estimates are highly uncertain, and the precise results shown in the incremental carbon abatement cost curves should be considered as indicative. With that caveat in mind, we broadly find that conventional building energy efficiency and "smart growth" measures, (modeled largely as a reduction in light-duty vehicle miles traveled), are estimated to be among the lowest cost sources of carbon abatement in the 2030 timeframe. In the High Electrification scenario, mitigation of methane, F-gasses and other non-combustion emissions save nearly as much GHGs as fully-balanced and delivered renewable electricity, at a lower cost per ton. The most expensive mitigation measures on a cost per ton basis in this scenario come from additional GHG mitigation from the industrial sector, advanced biofuels and zero-emission trucks.

The 2050 incremental carbon abatement cost curve for the High Electrification Scenario is shown in Figure 26 below. In addition to the cost per ton of the measures included in the High Electrification Scenario, Figure 26 also includes an estimate of the cost per ton of additional mitigation measures that are not included in the High Electrification scenario, but which are tested in the Alternative Mitigation scenarios. These measures (shown in grey) may be necessary to meet the state's 2050 GHG goal if the full mitigation potential of other GHG reduction measures assumed in the High Electrification scenario is not realized.

Figure 26: 2050 Incremental Carbon Abatement Cost Curve (Total Resource Cost per Ton of GHG Reduction Measures, Net of Fuel Savings), in the High Electrification Scenario



The incremental cost per ton of GHG savings for the High Electrification Scenario measures are relative to Reference Scenario measures (2016 \$/ton CO_2e), see Appendix Table A-4 for more details. Costs are based on a total resource cost assessment, net of fuel savings. Cost estimates are highly uncertain and do not represent a cap-and-trade market price forecast. Incentives are not reflected in the cost estimates. Emission reductions do not add up precisely to the total GHG reductions in the High Electrification Scenario because of interactive effects between measures.

Source: E3

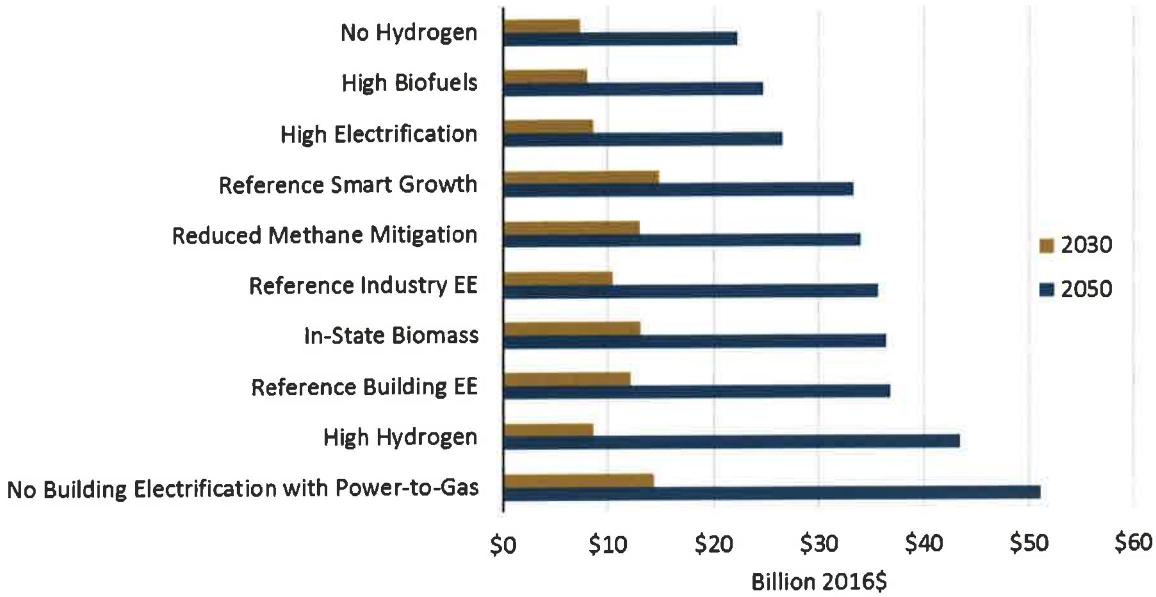
The incremental total resource cost estimates are even more uncertain in 2050 than in 2030, and are intended to qualitatively illustrate three different cost regimes for long-term mitigation strategies. The left-most tranche includes building energy efficiency and smart growth, which is expected to be a large source of near-term GHG abatement and a long-term source of cost savings, but which will deliver a relatively small amount of incremental GHG abatement by 2050 as fuels become decarbonized. The middle tranche includes most of the remaining strategies used in the High Electrification scenario: electrification, renewable electricity, and non-combustion emission reductions. Zero-emission vehicles and heat pumps are expected to be relatively inexpensive by 2050 because of declining capital costs (for vehicles) and increasing fuel savings (for both technologies). Renewable electricity makes up the largest single source of GHG savings. The renewables bar shown above averages costs over an embedded renewable supply curve that becomes steep as more and more renewable integration is needed. The third, right-most tranche, including advanced biofuels as well as additional strategies unused in the High Electrification scenario, consist of options for decarbonizing difficult-to-electrify end uses.

These cost estimates mask a great deal of uncertainty in future cost estimates and will likely change as better information becomes available. Heat pump and zero-emission vehicle incremental costs are highly sensitive to assumptions about equipment capital costs, financing costs, and the costs of displaced fossil fuels. Methane mitigation costs are relatively low because some of the costs of avoiding biogenic methane emissions are attributed to biofuel costs here. Electricity and storage capital costs have been declining rapidly while future cost declines remain uncertain. Costs of zero-emission trucks are poorly known as few models are commercially available. Biofuel costs are high because supply is assumed to be limited relative to demand, resulting in high market clearing prices; in addition, no innovation is assumed in biofuel conversion pathways over time. These conservative biofuel conversion pathways assumptions are being updated as part of on-going PATHWAYS analyses. Finally, hydrogen and power-to-gas (synthetic methane) incremental costs depend on whether the production of these energy carriers is from California-sourced grid electricity (as is assumed here), or from other sources, and the extent to which they can provide a grid flexibility benefit that offsets more expensive forms of energy storage. Because of limited commercial availability of hydrogen and power-to-gas synthetic methane, the capital costs and performance of these technologies remains uncertain.

GHG Mitigation Risk and GHG Mitigation Cost in Alternative Mitigation Scenarios

The annual net costs resulting from the Alternative Mitigation scenarios are compared in Figure 27 mitigation measures are compared across all these scenarios in Appendix A. The High Electrification scenario is among the lowest cost scenarios, however, the "No Hydrogen" scenario and the "High Biofuels" scenarios are both slightly lower cost in 2050. All other scenarios had higher costs than the High Electrification scenario.

Figure 27: Incremental Cost of All Mitigation Scenarios Relative to Reference



Costs are in 2016 billions of dollars

Source: E3

The "No Hydrogen" scenario relies on a highly electrified vehicle fleet as well as industrial electrification in order to meet the 2050 GHG goal without the use of hydrogen fuel, which may be slightly higher risk than the more diversified transportation strategy embedded in the High Electrification scenario. The costs and resource potential for industrial electrification are particularly uncertain, which is why industrial electrification is excluded from the High Electrification scenario.

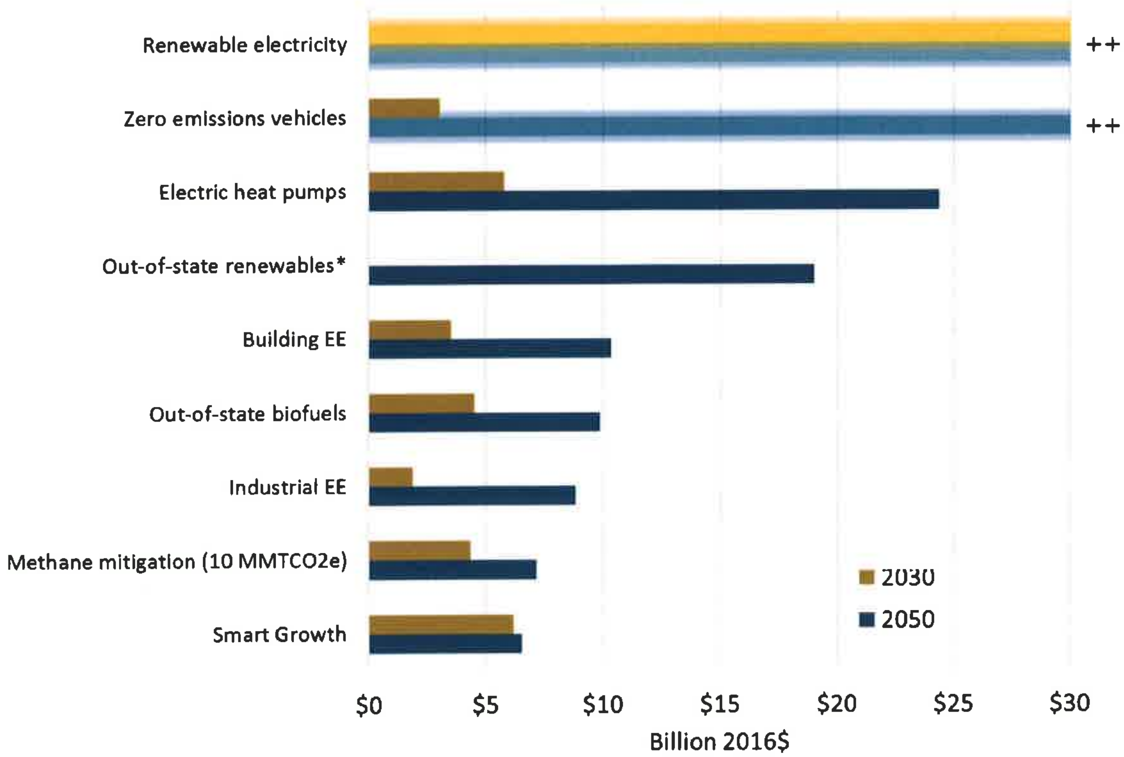
The "High Biofuels" scenario is lower cost than the High Electrification scenario because it assumes that purpose-grown biomass crops, such as miscanthus, are available at relatively low cost as a zero-carbon fuel. This strategy may be lower cost than relying on higher adoption rates of zero-emission vehicles and renewable generation, and using only sustainable biomass waste products for biofuels, as is assumed in the High Electrification scenario. It could be achieved at even lower costs than shown here with continued innovation and efficiency enhancements for biomass conversion processes. However, the "High Biofuels" scenario is also determined to be higher risk, due to concerns about the long-term availability and sustainability of growing crops for biofuels.

The No Building Electrification with Power-to-Gas scenario is found to be among the most expensive Mitigation scenario in 2050 due to the high expense of providing renewable natural gas with relatively limited biofuels. This finding, however, could change if higher incremental retrofit costs to install heat pumps in existing buildings were assumed in the other scenarios. Also, producing hydrogen from renewable fuels and synthetic methane derived from a renewable source of CO_2 are reach technologies that have yet to be commercially deployed, so cost estimates for this scenario are highly uncertain.

In terms of technology cost risk, the largest single contributor to keeping California's GHG mitigation costs reasonable is the wide scale use of renewable generation and zero-emissions light duty vehicles. In fact, it does not appear to be possible to meet the state's 2030 or 2050 GHG mitigation goals at current levels of renewable deployment. This makes sense given that all Mitigation scenarios rely heavily on fuel-switching to low-carbon electricity as a central GHG reduction strategy.

While it does appear to be possible to meet the state's 2030 GHG mitigation goal with Reference levels of ZEVs, it is not possible to meet the 2050 target without nearly complete deployment of ZEVs. This makes sense given that today's light duty vehicles represent the single largest source of greenhouse gas emissions in the state. Other key strategies for reducing the cost of GHG mitigation in the 2030 timeframe include smart growth (reducing vehicle miles traveled), electric heat pumps in buildings, methane capture, and biofuels (Figure 28).

Figure 28: Cost Savings Associated with Each GHG Mitigation Strategy (2016$, Billions)



Cost savings of each GHG mitigation strategy are estimated by comparing the cost of Alternative Mitigation Scenarios to the High Electrification Scenario. * The cost savings associated with out-of-state renewables are estimated using RESOLVE model results, rather than PATHWAYS model results. ++ The cost savings associated with renewable electricity and zero-emission vehicles in 2050 are estimated using sensitivity model runs in which these mitigation strategies are reverted back to the Reference level assumptions. The cost savings associated with these two measures exceed the values shown on the chart since it does not appear to be possible to meet the 2050 GHG goal without significant deployment of each technology.

Source: E3

In Figure 28, the cost savings of each GHG mitigation strategy are estimated by comparing the cost of Alternative Mitigation Scenarios to the High Electrification Scenario.[10] Each scenario is designed to isolate a change in one mitigation strategy, if that strategy does not succeed as hoped. Additional mitigation strategies are added to ensure that the 2030 and 2050 GHG goals are still achieved, which results in the additional cost associated with that scenario.

Discussion of Alternative Mitigation Scenario Costs and Uncertainties

If less expensive GHG mitigation strategies prove to be unachievable at the scale assumed in the High Electrification Scenario, more expensive alternatives would be necessary to compensate.

[10] The exception is the case of renewable electricity and zero emission vehicles, for which the cost savings are estimated using sensitivity model runs in which these mitigation strategies are reverted back to the Reference level assumptions.

Within the scenario design framework employed in this analysis, the effect of removing some GHG mitigation strategies and compensating with others is tested in the Alternative Mitigation scenarios, including the measures not found to be cost-effective in the High Electrification Scenario. Available alternatives are selected sequentially from this limited and upward-sloping supply curve, meaning that reducing or excluding GHG mitigation strategies from a scenario, that are responsible for large quantities of CO_2 abatement in the High Electrification scenario, result in relatively expensive Alternative Mitigation Scenarios. Other studies (e.g., Yang et al., 2016) have similarly found that marginal economy-wide mitigation costs could be much higher than average costs. It is difficult to predict with confidence whether and where an "inflection point" exists in the supply curve for decarbonization in 2050, underscoring the importance of flexible policy implementation that can incorporate better information as it becomes available.

Two key alternative mitigation strategies are used in these scenarios when other mitigation strategies fall short: hydrogen fuel cell trucks (fueled by hydrogen produced via grid electrolysis) and industry electrification. These strategies are classified as "reach technologies" in this study, meaning that they could be quite expensive but necessary to reach the 2050 goals. If progress is made in commercializing these strategies and reducing costs, or if other alternatives become available that are not modeled here, that could reduce the cost of alternative mitigation scenarios relative to the High Electrification scenario.

Several other key assumptions could change the rank order of the scenario cost savings as better information becomes available. Biofuels could be available at lower cost than modeled here with progress in increasing biofuel conversion yields, or if sustainability concerns with purpose-grown crops are addressed. Alternatively, other jurisdictions may continue to lag California in decarbonizing their economies, making more of the global biofuel supply available to California.

Finally, this analysis did not evaluate or include costs associated with retrofitting existing buildings for electric heating, cooking, and clothes drying. More research is needed to understand the costs of retrofitting existing buildings to electric alternatives. Including these costs would reduce the relative cost of strategies that instead rely on decarbonizing the existing gas pipeline. Likewise, this study did not include the costs of retrofitting natural gas pipelines to accommodate a blend of hydrogen and methane (only applicable in the No Building Electrification with Power to Gas Scenario). Future costs associated with producing hydrogen and synthetic methane, as well as blending hydrogen into the natural gas pipeline are uncertain and need further research. Building retrofit costs, as well as hydrogen, biomethane and synthetic methane costs, are likely to decline over time with a market transformation effort.

Finally, this study emphasizes the total resource cost metric that aggregates statewide costs and benefits, explicitly excluding the impact of state incentives and within-state transfers, such as the impact of cap-and-trade, the LCFS, and utility energy efficiency programs. Costs borne by individual households could differ markedly from the average, and these impacts could differ for different mitigation strategies, as well as being dependent on policy implementation. The Berkeley Economic Advising and Research (BEAR) team evaluated potential costs and benefits of these deep decarbonization scenarios to low-income and disadvantaged communities in California. Further research could investigate the specific cost implications of specific state policies on individuals and businesses. Furthermore, developing better models to predict and understand consumer behavior and consumer choices under different cost regimes could lead to the development of different GHG mitigation scenarios.

CHAPTER 5: Conclusions

This research has evaluated long-term energy scenarios in California using a variety of mitigation strategies and technologies. These findings highlight the important role that consumer decisions, households and businesses, will play in meeting the state's ambitious near-term and long-term GHG goals.

Supply-side energy policies have been very successful at increasing the use of renewable electricity and renewable fuels in California, however, these policies will not be sufficient. Consumer decisions are important to improve the energy efficiency of the state's existing building stock, to reduce vehicle miles traveled, to purchase and drive zero-emission vehicles, and potentially to switch to electric space heating and water heating options in their homes and businesses.

To accomplish this low-carbon energy transition, carbon pricing, through the state's cap and trade program will play an important role. Likewise, additional market transformation efforts, and regional policy initiatives, will be needed.

Through the evaluation of these ten scenarios, priority GHG mitigation strategies are identified and grouped into three categories: 1) strategies requiring widespread scale-up of technology deployment in the near-term; 2) strategies requiring market transformation to achieve widespread deployment, and 3) "reach" technologies which are not yet widely commercialized, but which may be required to achieve the state's 2050 GHG goals, particularly if some mitigation strategies fall short of expectations (Table 8).

High priority strategies for deployment include energy efficiency in buildings and industry, renewable electricity and renewable integration solutions, and smart growth leading to near-term reductions in light-duty vehicle miles traveled. By 2050, 85% to 95% zero-carbon electricity is expected to be required; however, 100% zero-carbon electricity is likely to be cost prohibitive compared to alternative GHG mitigation strategies.

High priority strategies that require additional market transformation include deployment of zero-emission light duty vehicles, advanced energy efficiency in buildings, including building electrification, replacement of fluorinated gases with less potent global warming potential gases, and capture of methane emissions.

Finally, at least one reach technology is likely to be required to achieve the 2050 mitigation goal. Examples of reach technologies that provide solutions in hard-to-electrify sectors include advanced, sustainable biofuels, zero-emission heavy-duty long-haul trucks, industrial electrification and hydrogen production using electrolysis. The priority strategies shown in Table 8 are based on the costs and risks to achieving the state's long-term 2050 climate goal evaluated through this reach. The 2030 "indicative metrics" are provided as a near-term metric to evaluate whether the state is on track to meet the long-term climate goals.

Table 8: Priority GHG Reduction Strategies

Scale-up & Deploy	2030 Indicative Metrics	Key Challenges
Energy efficiency in buildings & industry	Deployment of LED lighting, higher efficiency plug loads, improved shell in existing buildings, continued improvements and enforcement of building codes, industrial EE	Consumer decisions and market failures
Renewable electricity	70 – 80% zero-carbon electricity with renewable integration solutions: flexible loads, market-based curtailment, cost-effective grid storage	Implementation of integration solutions
Smart growth	Reduced vehicle miles traveled through increased use of public transit, walking, biking, tele-presence, and denser, mixed-use community design	Consumer decisions and legacy development patterns
Market Transformation	**2030 Indicative Metrics**	**Key Challenges**
Zero-emission light-duty vehicles (ZEV)	At least 6 million ZEVs, >60% of new sales are ZEVs, drivers have access to day-time charging stations and time-of-use charging	Consumer decisions and cost
Advanced building efficiency/ electrification	50% of new water heater and HVAC sales are high efficiency heat pumps	Consumer decisions, equity of cost impacts, cost and retrofits of existing buildings
F-gas replacement	Replace F-gases with lower global warming potential (GWP) refrigerants	Lack of standards to require alternatives
Methane capture	Methane capture from manure, fugitive and process emissions, landfills and wastewater	Small and diffuse point sources
Reach Technologies	**2030 Indicative Metrics**	**Key Challenges**
Advanced sustainable biofuels	Demonstrated use of sustainable, carbon-neutral biomass feedstocks to produce commercial-scale biofuels	Cost and sustainability challenges
Zero-emissions heavy-duty trucks	Commercial deployment of battery-electric and/or hydrogen trucks	Cost
Industrial electrification	Cost-competitive electrification of industrial end-uses, including boilers, machine drives, and process heating	Cost
Electrolysis hydrogen production	Improved cost and efficiency at commercial scale. Business model for flexible hydrogen production.	Cost

Source: E3

Scale-Up and Deploy

Within the category of scaling up the deployment of existing strategies this analysis indicates the state must execute its ambitious building energy efficiency goals and exceed the current renewable electricity goals to meet the GHG emission reduction goals for 2030 and 2050. Examples include continued progress in using LED lighting across nearly all lighting applications and continued improvements to the state's adoption and enforcement of appliance codes and building standards. California has a long history in using energy efficiency in buildings. To meet the state's energy efficiency goals of doubling energy efficiency achievements, however, a new paradigm for energy efficiency program design is required which is likely to require market transformation of advanced forms of energy efficiency and building electrification.

Likewise, California also has a strong track record on renewable development. In the past decade, renewables in the state have increased from 11% to over 25% of total generation (CEC, 2016). This research suggests that renewable generation requirements are expected to increase to 60%–70% (equivalent to 70%–80% zero-carbon generation) by 2030, with 85%–95% zero-carbon generation required by 2050. Achieving these high levels of renewable generation will require policy coordination to ensure that renewable integration strategies are developed and deployed in concert with higher levels of renewables.

However, achieving 100% zero-carbon generation appears to be cost prohibitive without major advances in low-cost energy storage. In the High Electrification scenario, natural gas generation provides the remaining 5% of energy requirements and helps ensure resource adequacy and energy sufficiency during periods of low renewable generation. This 5% of natural gas generation helps to contain the cost impacts of the scenario compared to a 100% zero-carbon scenario.

For 2030 and 2050, key renewable integration solutions necessary to contain the costs of high levels of renewable energy on the grid include: 1) increased reliance on flexible loads and demand-shifting, particularly in electric vehicle charging, but also in buildings and industry; 2) regional markets and regional procurement of renewable energy; 3) market-based renewable curtailment, combined with using supervisory control and data acquisition (SCADA) systems, to allow renewable curtailment as a low-cost strategy to manage variable renewables on the grid, and 4) cost-effective grid storage including hydroelectric, battery, and chemical storage.

Finally, this analysis suggests California must achieve its ambitious smart growth and sustainable community strategies as part of a suite of strategies to achieve 2030 and 2050 greenhouse gas emission reduction goals, entailing a per capita reduction in light duty vehicle miles traveled through increased utilization of public transit, walking, biking, tele-presence and denser, mixed-use community designs. Smart growth strategies are particularly important for meeting the 2030 GHG goals while fossil-fueled transportation still represents the largest share of the state's total GHG emissions.

Without any one of these three priority deployment strategies - energy efficiency, renewable generation, and smart growth - the cost of meeting the state's climate goals is expected to be much higher.

Market Transformation

Only scaling up known strategies will not be sufficient to meet the state's 2030 goal, let alone the 2050 goal. To meet the state's 2030 climate goals, business and household decisions will play a pivotal role: from vehicle purchases, to water heater and heating, ventilation and air conditioning (HVAC) purchase and installation decisions, to vehicle driving behavior. Market transformation is necessary to bring down the cost and improve the performance of customer-facing zero-emissions technologies, primarily zero-emission vehicles and electric heat pumps in buildings. Carbon pricing and other existing policies on their own are unlikely to be sufficient to overcome some of the market barriers to adoption.

Furthermore, unlike in the transportation sector, California does not have a strong market or policy framework to encourage decarbonization of buildings; a gap which the combination of higher carbon prices and new market transformation programs could help fill. Market transformation programs and incentives could be directed towards helping to bring down the upfront capital cost of electric heat pump installations and retrofits, and training HVAC professionals to gain more experience with their deployment.

The building construction, efficiency, and HVAC markets are more localized to California than the vehicle or renewable generation markets because of the high reliance on local, skilled labor for installation and construction. As a result, global markets may help reduce the equipment cost and improve the performance of high efficiency appliances, but market transformation may still be required at a local level to achieve higher levels of consumer adoption of these technologies.

Another area where market transformation is needed is to reduce emissions of non-combustion GHGs, principally fluorinated gasses ("F-gases") used primarily as refrigerants, and methane from agriculture, waste, and the extraction, production and conveyance of fossil fuels. Industry standards and regulations are needed to phase out the use of F-gases. Such regulations are under consideration at the U.S. EPA, and California legislation has been proposed to require alternatives to F-gases. The Kigali Agreements, an amendment to the Montreal Protocol, call for global reductions in F-gases, yet it remains to be seen to what degree these targets will be adhered to and enforced. Meanwhile, achieving higher levels of methane capture will require a diverse set of strategies that address the challenges posed, in particular, by the diffuse point sources from waste and dairy methane.

Reach Technologies

In addition to scale-up and market transformation of existing GHG reduction strategies, at least one, and potentially more than one, "reach" technology that has not yet been commercially proven will likely be necessary to meet the 2050 GHG goal. Reach technologies can also help to mitigate the risk that one or more "proven" GHG mitigation strategy could fall short of expectations. A reach technology should ideally help to reduce greenhouse gas emissions in otherwise difficult to electrify end-uses such as heavy-duty trucking (which currently represents GHG emissions of about 30 MMT CO2e in California today), off-road transportation (including aviation, rail, boats and other off-road equipment, and which represents about 15 MMT CO2e in California today), or industry (including manufacturing, refining, and oil and gas, which represents about 92 MMT CO2e in California today).

Examples of reach technologies include advanced, sustainable biofuels or hydrogen production from electrolysis, both of which use proven manufacturing technologies, but neither of which have achieved commercial scale. Industrial electrification and zero-emissions heavy duty trucks are other examples of reach technology areas that could be useful to meeting the state's 2050 GHG mitigation goals, but for which minimal cost and performance data are available.

Future Research Needs

These long-term energy scenarios show that natural gas electricity generation is likely to fall dramatically relative to current levels, as higher levels of zero-carbon generation are brought online. A key research question remains, however, regarding how much of the state's existing natural gas generation will still be required to support resource adequacy and ensure energy sufficiency during periods of low renewable energy availability, or whether long-duration energy storage technologies will be developed to replace this need.

Likewise, most of the scenarios evaluated in this analysis, including the High Electrification scenario, show a dramatic reduction in natural gas demand at the distribution level. An area for additional research and policy work surrounds the question of how the regulated natural gas utilities will adapt to these changing demand conditions, and whether high building electrification is practically, politically and economically feasible over this relatively short timeframe.

California's electric regulatory environment is not currently designed to prioritize low-carbon solutions in buildings. Energy efficiency programs and electric retail rates may need to be redesigned to enable greater building efficiency and electrification. Areas for additional research include an assessment of the distribution level upgrades that would be needed to enable building electrification, as well as the costs and market barriers to building electrification.

This study assumes that California will succeed in reversing historical trends and will bring GHG emissions from natural and working lands down to a zero net CO_2 emissions impact by 2050. Achieving this goal will require large changes in ecosystem carbon storage, impacting both land-use management and development practices. More research is needed to understand both the likely changes in California ecosystems in response to climate change as well as the potential for increasing carbon storage to offset other greenhouse gas emissions that are most difficult to mitigate.

GLOSSARY

Term	Definition
AAEE	Additional achievable energy efficiency
ARB	California Air Resources Board
BEV	Battery electric vehicle
CCS	Carbon capture and storage
CEC	California Energy Commission
CFC	Chlorofluorocarbons
CNG	Compressed natural gas
CO_2	Carbon dioxide
E3	Energy and Environmental Economics, Inc.
EE	Energy efficiency
EJ	Exajoule, a unit of energy equal to one quintillion (10^{18}) joules
EPIC	The Electric Program Investment Charge
EV	Electric vehicle
FCEV	Fuel cell electric vehicle
F-gas	Fluorinated gas
GGE	Gallons of gasoline equivalent
GHG	Greenhouse gas
GWh	Gigawatt-hour, a unit of energy in electricity
HDV	Heavy duty vehicles
HFC	Hydrofluorocarbons
HVAC	Heating ventilation and cooling
LCFS	Low carbon fuel standard
LDV	Light duty vehicles
MDV	Medium duty vehicles
MW	Megawatt, a unit of capacity in electricity
PHEV	Plug-in hybrid electric vehicle

PJ	Petajoule, a unit of energy equal to one quadrillion (10^{15}) joules
RPS	Renewable portfolio standard
SB	Senate Bill
SLCP	Short-lived climate pollutant
VMT	Vehicle miles traveled
ZEV	Zero-emission vehicle

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APPENDIX A:
Mitigation Scenario Assumptions and Abatement Curve Assumptions

Table A-1: Scenario Measures Assumed in 2030, Highlighted Where Different Than the High Electrification Scenario

	High Electrification	No Hydrogen	High Biofuels	Reference Smart Growth	Reduced Methane Mitigation	Reference Industry EE	In-State Biomass	Reference Building EE	High Hydrogen	No Building Electrification with Power-to-Gas
Building efficiency (% reduction in total building energy demand relative to 2015)	10%							5%		9%
Transportation VMT (% reduction in per capita light duty VMT relative to 2015)	12%			2%						
Industrial Efficiency (% reduction in total industrial energy demand relative to 2015 in non-petroleum industries)	22%					0%				
Building electrification (% of new sales of water heaters and HVAC that are electric heat pumps)*	50%									0%
LDV electrification (Millions of ZEVs)	6		5							
LDV electrification (ZEV % of total stock)	20%		17%							
LDV electrification (ZEV % of new sales)	64%		48%							
Trucking electrification (% of trucks that are BEVs or FCEVs)	4%									
Trucking - alternative fuels (% of trucks that are hybrid & CNG)	6%	9%				8%	8%			
Bus electrification (% of total)	32%									

	High Electrification	No Hydrogen	High Biofuels	Reference Smart Growth	Reduced Methane Mitigation	Reference Industry EE	In-State Biomass	Reference Building EE	High Hydrogen	No Building Electrification with Power-to-Gas
Rail electrification (% of total)	20%									
Port electrification (% of total)	27%									
Industry electrification (% of non-petroleum industry end-use fossil replaced with electricity)	0%									
Petroleum industry demand reduction	14%									
Advanced biofuels (% of fossil end-uses replaced with advanced biofuels)**	10%		12%				7%			
Advanced biofuels (Total EJ)	0.34		0.38				0.23			
Power-to-gas (% of non-electric-generation pipeline gas supplied by hydrogen and renewable synthetic methane)	0%									8%
Hydrogen fuel for vehicles (Total EJ)	0.02	0.00	0.00							
Reductions in methane (% reduction relative to 2015)	34%				10%					
Reductions in F-gases (% reduction relative to 2015)	43%									
% zero-carbon electricity, including large hydro and nuclear***	74%	74%	72%	80%	83%	82%	82%	76%	75%	76%
Approximate % RPS	70%	69%	67%	78%	83%	82%	80%	74%	71%	72%
Total electricity demand (TWh)	295	293	290	298	294	301	292	316	294	327
Electric sector combustion emissions (MMT CO_2e)	32	33	35	25	21	22	22	32	32	32

*Replacement of non-electric heaters; some electric resistance heating remains in the 2030 time period.

**Excludes hydrogen and synthetic methane used for fuel-cell vehicles and in the pipeline.

***In-state nuclear is assumed to retire by 2025. Imports of nuclear from Palo Verde continue until retirement in 2047.

Table A-2: Scenario Measures Assumed in 2050, Highlighted Where Different Than the High Electrification Scenario

	High Electrification	No Hydrogen	High Biofuels	Reference Smart Growth	Reduced Methane Mitigation	Reference Industry EE	In-State Biomass	Reference Building EE	High Hydrogen	No Building Electrification with Power-to-Gas
Building efficiency (% reduction in total building energy demand relative to 2015)	34%							22%		10%
Transportation VMT (% reduction in per capita light duty VMT relative to 2015)	24%			3%						
Industrial Efficiency (% reduction in total industrial energy demand relative to 2015 in non-petroleum industries)	22%					0%				
Building electrification (% of new sales of water heaters and HVAC that are electric heat pumps)*	100%									0%
LDV electrification (Millions of ZEVs)	35		25							
LDV electrification (ZEV % of total stock)	96%		69%							
LDV electrification (ZEV % of new sales)	100%		81%							
Trucking electrification (% of trucks that are BEVs or FCEVs)	47%	33%	27%		52%	69%	69%		65%	52%
Trucking - alternative fuels (% of trucks that are hybrid & CNG)	31%	55%			28%	19%	19%		16%	28%
Bus electrification (% of total)	88%									
Rail electrification (% of total)	75%									
Port electrification (% of total)	80%									

	High Electrification	No Hydrogen	High Biofuels	Reference Smart Growth	Reduced Methane Mitigation	Reference Industry EE	In-State Biomass	Reference Building EE	High Hydrogen	No Building Electrification with Power-to-Gas
Industry electrification (% of non-petroleum industry end-use fossil replaced with electricity)	0%	26%		26%	37%		37%	26%		37%
Petroleum industry demand reduction	86%									
Advanced biofuels (% of fossil end-uses replaced with advanced biofuels)**	46%		59%				27%			
Advanced biofuels (Total EJ)	0.56		0.86				0.23			
Power-to-gas (% of non-electric-generation pipeline gas supplied by hydrogen and renewable synthetic methane)	0%									32%
Hydrogen fuel for vehicles (Total EJ)	0.11	0.00	0.00	0.12	0.13	0.20	0.20		0.32	0.13
Reductions in methane (% reduction relative to 2015)	42%				18%					
Reductions in F-gases (% reduction relative to 2015)	83%									
% zero-carbon electricity, including large hydro	95%	93%	93%	94%	94%	94%	95%	94%	92%	97%
Approximate % RPS	103%	100%	100%	100%	101%	101%	101%	102%	97%	101%
Total electricity demand (TWh)	456	449	403	502	512	525	545	533	525	592
Electric sector combustion emissions (MMT CO_2e)	9	14	13	13	12	13	12	14	17	7

**Excludes hydrogen and synthetic methane used for fuel-cell vehicles and in the pipeline.

Table A-3: Measures used to generate 2030 Incremental Carbon Abatement Cost Curve (corresponding to High Electrification Scenario measures as compared with Reference, unless otherwise noted)

Measure	2030 Measure Description	Emissions Reduction (MMT CO_2e)	2030 Cost (2016$ / ton CO_2e)
Smart Growth	10% LDV VMT reduction relative to Reference	8	-$300
Building EE	High Electrification Scenario building energy efficiency measures as compared with Reference measures (building electrification unchanged)	4	-$500
LDV ZEVs	6 million ZEVs as compared with 3 million ZEVs	7	$0
Methane Abatement	34% reduction relative to 2014 inventory	28	$0
F-gas Abatement	64% reduction relative to ARB projection for 2030	18	$0
Other non-combustion GHG abatement	19% reduction relative to 2014 inventory	3	$0
Heat Pumps	Heat pump substitution for new heaters ramps up from zero to 50% between 2020 and 2030 as compared with no building electrification	3	$100
Renewable Electricity	74% zero-carbon electricity, including in-state solar, geothermal, wind, and 6 GW of storage beyond the storage mandate; as compared with 35% RPS	30	$200
Industrial EE	30% reduction in energy demand relative to Reference	9	$300

Measure	2030 Measure Description	Emissions Reduction (MMT CO_2e)	2030 Cost (2016$ / ton CO_2e)
Biofuels	2.8 billion gallons gasoline-equivalent advanced biofuels as compared with 1.2 billion	5	$300
Truck Portfolio	10% of trucks are alternative compared with 5% (HDVs) and 0% (MDVs)	4	$500

Table A-4: Measures used to generate 2050 Incremental Carbon Abatement Cost Curve (corresponding to High Electrification Scenario measures as compared with Reference unless otherwise noted)

Measure	2050 Measure Description	Emissions Reduction (MMT CO_2e)	2050 Cost (2016$ / ton CO_2e)
Smart Growth	21% LDV VMT reduction relative to Reference	2	-$2500
Building EE	High electrification building efficiency measures as compared with Reference measures (building electrification unchanged)	6	-$1000
LDV ZEVs	35 million ZEVs (96% of vehicle stock) as compared with 5 million ZEVs	57	$0
Heat Pumps	Nearly 100% electrification of building heating as compared with no building fuel switching in Reference	27	$0
Non-combustion GHGs	59% reduction relative to Reference	51	$0
Industrial EE	30% reduction in energy demand relative to Reference, plus high additional electric efficiency	11	$100

Measure	2050 Measure Description	Emissions Reduction (MMT CO_2e)	2050 Cost (2016$ / ton CO_2e)
Renewable Electricity	95% zero-carbon including out-of-state wind and storage with high flexible loads; as compared with 33% RPS	103	$200
Truck Portfolio	78% of trucks are alternative-fuel as compared with 5% (HDVs) and 0% (MDVs) in Reference	23	$300
Biofuels	4.3 billion gallons gasoline-equivalent of advanced biofuels as compared 0.4 billion	21	$700
Industrial Electrification	35% of industrial non-electric end use energy is electrified in In-State Biofuels Only Scenario as compared with no industrial fuel-switching in Reference	6	$900
Additional Biofuels	Additional biofuels relative to biofuels in High Electrification Scenario	7	$1100
Power-to-Gas	7% of pipeline hydrogen and 25% of pipeline synthetic methane in No Building Electrification with Power-to-Gas Scenario as compared with no power-to-gas in Reference	19	$1100
Additional Hydrogen Trucks	58% hydrogen HDVs and 57% MDVs in the High Hydrogen Scenario as compared with 14% of HDVs and 7% of MDVs in the High Electrification Scenario	9	$1600

APPENDIX B: PATHWAYS Model Input Assumptions

For each sector, references to data sources are provided as well as highlighting key assumptions.

Energy Demand

Energy Demand Equipment Financing Assumptions

The financing rate to annualize incremental equipment costs is 5% (real), with a range of 3% to 10% tested in sensitivities. Capital costs are annualized over the assumed useful lifetime of the equipment. Lifetimes of selected equipment are listed below.

Subsector	Technology	Lifetime (yr)
Residential Water Heating	Reference Gas	9
	High Efficiency Gas	9
	Electric Heat Pump	16
Residential Space Heating	Reference Gas Furnace	18
	Reference Gas Radiator	25
	High Efficiency Gas Furnace	18
	High Efficiency Gas Radiator	25
	High Efficiency Electric Heat Pump	18
Residential Central Air Conditioning	Reference	14
	High Efficiency	14
	High Efficiency Electric Heat Pump (Cooling)	14
Commercial Water Heating	Reference Gas	12
	High Efficiency Gas	12
	High Efficiency Electric Heat Pump	14
Commercial Space Heating	Reference Gas Furnace	18
	Reference Gas Boiler	25
	High Efficiency Gas Furnace	18

Subsector	Technology	Lifetime (yr)
	High Efficiency Gas Boiler	25
	High Efficiency Electric Heat Pump	15
Commercial Air Conditioning	Reference	15
	High Efficiency	15
	High Efficiency Electric Heat Pump (Cooling)	15
Transportation: Light-Duty Vehicles	Light-Duty Auto (all techs)	17
	Light-Duty Truck (all techs)	17
Transportation: Medium-Duty Vehicles	Medium-Duty Truck (all techs)	17
Transportation: Heavy-Duty Vehicles	Heavy-Duty Truck (all techs)	16
Transportation: Buses	Bus (all techs)	12

Residential Buildings and Commercial Buildings

Residential Data Sources

Description	Reference
Calibration of sectoral electricity demand input data (GWh)	California Energy Demand 2016-2026 Adopted Forecast, California Energy Commission, January 2016, CEC-200-2016-001 (15-IEPR-03)
Calibration of sectoral pipeline gas demand input data (Mtherms)	2009 residential gas usage demand from CEC Energy Consumption database and KEMA, 2009. California RASS.
Reference technology shares (% of stock)	Kema, 2009. California RASS. Percent of high efficiency clothes washers based on 2013 Navigant Potential Study. Lighting based on 2010 DOE Lighting Market Characterization Report Tables
Technology inputs including useful life, energy type, and cost assumptions	Data used in support of AEO 2013 from the National Energy Modeling System: Input filenames “rsmlgt.txt” For lighting: Energy Savings Potential of Solid-State Lighting in General Illumination Applications (DOE, 2012)

Description	Reference
Subsector energy or service demand consumption estimate used to calibrate total service demand (kWh/household)	KEMA, 2009. California RASS Energy Star Program Requirements and Criteria for Dishwashers
Per-unit technology costs	Cost projections are taken from data used in support of AEO 2013 from the National Energy Modeling System: Input filenames “rsmlgt.txt” and Input filenames “rsmeqp.txt”. Lighting from the Energy Savings Potential of Solid-State Lighting in General Illumination Applications for LED lamps and luminaires. Heat pump water heater costs from Itron report to CPUC (2014; http://www.calmac.org/publications/2010-2012_WO017_Ex_Ante_Measure_Cost_Study_-_Final_Report.pdf); see data below.
Technology efficiencies	Data used in support of AEO 2013 from the National Energy Modeling System: Input filename “rsmshl.txt” and Input filename “rsmeqp.txt”. Adjusted from UEC values taken from "rsuec.txt" and stock efficiencies from "rsstkeff.txt". DOE, 2012. Energy Savings Potential of Solid-State Lighting in General Illumination Applications.
Residential “Other” subsector efficiency capital cost	Assumed to be $0.03 / kWh (2012$).

Commercial Data Sources

Description	Reference
Calibration of sectoral electricity demand input data (GWh)	California Energy Demand 2016-2026 Adopted Forecast, California Energy Commission, January 2016, CEC-200-2016-001 (15-IEPR-03)
Calibration of sectoral pipeline gas demand input data (Mtherms)	California Energy Demand IEPR 2014 - Mid Demand Case

Description	Reference
Energy use by technology per square foot	CEUS, 2006. SCE values used for LADWP and "Other" electric service territories. Adjusted for square footage with no cooling. And for lighting: DOE Lighting Market Characterization Report, 2010.
Reference technology shares (% of stock)	Service demand share from National Energy Modeling System: Input filename "ktek.txt" adjusted for service saturation from 2006 CEUS, and for lighting: DOE Lighting Market Characterization Report, 2010.
Technology inputs including useful life, energy type, and cost assumptions	Data used in support of AEO 2013 from the National Energy Modeling System: Input filenames "ktek.txt".
Subsector energy or service demand consumption estimate used to calibrate total service demand (kWh/sq ft)	CEUS, 2006 and data used in support of AEO 2013 from the National Energy Modeling System: Input filenames "ktek.txt".
Per-unit technology costs	Data used in support of AEO 2013 from the National Energy Modeling System: Input filenames "ktek.txt". Heat pump costs were updated to AEO 2014 data from National Energy Modeling System.
Technology efficiencies	Data used in support of AEO 2013 from the National Energy Modeling System: Input filenames "ktek.txt".

Water Heating and HVAC Selected Capital Cost and Efficiency Assumptions

Subsector	Technology	Efficiency for Heating (COP)	Efficiency for Cooling (COP)	Cost (2012$)
Residential Water Heating	Reference Gas	0.62	N/A	$920/unit
	Electric Heat Pump	2.35	N/A	$2630/unit
Residential HVAC (Heating and Cooling)	Reference Gas Furnace	0.81	N/A	$2500/unit
	Reference Gas Radiator	0.82	N/A	$3500/unit
	High Efficiency Gas Furnace	0.98	N/A	$3750/unit
	High Efficiency Gas Radiator	0.98	N/A	$4000/unit

Subsector	Technology	Efficiency for Heating (COP)	Efficiency for Cooling (COP)	Cost (2012$)
	Reference Central AC	N/A	4.02	$3200/unit
	High Efficiency Central AC	N/A	7.03	$5750/unit
	High Efficiency Electric Heat Pump (Heating & Cooling)	3.22	7.03	$4500/unit
Commercial Water Heating	Reference Gas	0.78	N/A	$26/(kBTU/hr)
	High Efficiency Electric Heat Pump	2.35	N/A	$293/(kBTU/hr)
Commercial HVAC (Heating and Cooling)	Reference Gas Furnace	0.78	N/A	$10/(kBTU/hr)
	Reference Gas Boiler	0.80	N/A	$25/(kBTU/hr)
	High Efficiency Gas Furnace	0.89	N/A	$12/(kBTU/hr)
	High Efficiency Gas Boiler	0.97	N/A	$38/(kBTU/hr)
	Reference Central AC	N/A	3.37	$114/(kBTU/hr)
	High Efficiency Central AC	N/A	4.07	$194/(kBTU/hr)
	High Efficiency Electric Heat Pump (Heating & Cooling)	3.40	3.52	$112/(kBTU/hr)

For new appliances sold in 2030 when values vary over time. Coefficient of performance (COP) is the ratio of heating or cooling output to final fuel energy input. Capital costs for HVAC heat pumps are assumed to be split equally between heating and cooling subsectors.

Climate Impacts on Building Heating and Cooling Demands

These demand changes were estimated based on building energy demand simulations performed by the University of California, Irvine as part of a separately funded CEC EPIC grant (PON-14-309). Demand changes for 2050 were forecast using Representative Concentration Pathway 8.5 scenario changes, averaged over the climate models in California's 4th State Climate Assessment, for each of the CEC's Building Climate Zones. These were mapped to PATHWAYS energy geographies used for each demand subsector and linearly interpolated between 2015 and 2050. (Changes in water heating energy demands in building energy simulations were less than 1% and were not included in PATHWAYS.) Resulting statewide average changes by subsector are below.

Subsector	Average Change in Energy Demand from 2015 to 2050 due to Climate Change
Residential Space Heating	-25%
Residential Air Conditioning	+30%
Commercial Space Heating	-14%
Commercial Air Conditioning	+32%

Transportation

Transportation Data Sources

Description	Reference
VMT/Fuel use	• CARB EMFAC 2014 (LDV, MDV, HDV, and Buses) • ARB Vision 2.1 Passenger Vehicle Module • ARB Vision 2.1 Heavy Duty Vehicle Module • ARB 2012 Vision off-road (passenger rail, freight rail, harbor craft, oceangoing vessels, aviation) • Historical levels of transportation diesel consumption are calibrated to the 2016 California GHG emission inventory • Historical levels of transportation natural gas consumption are calibrated to data from the Low-Carbon Fuel Standard regulation
Fuel efficiency	• ARB Vision 2.1 Passenger Vehicle Module • ARB 2012 Vision off-road (passenger rail, freight rail, harbor craft, oceangoing vessels, aviation) • "Transitions to Alternative Vehicles and Fuels", National Academies Press, 2013, Mid case (LDV auto and truck) • Historical fuel efficiency for light-duty vehicles is calibrated based on gasoline fuel consumption in the 2015 California GHG emission inventory • Black and Veatch analysis for this study (MDVs and HDVs; see below)

Description	Reference
New Technology costs	• Electric bus costs data are from ARB, based on the 2013 CalSTART report. • Black and Veatch analysis for this study (MDVs and HDVs; see below) • Ricardo analysis of electric vehicle incremental costs for E3 used for the Pacific Gas & Electric Co EPIC report for 2016: "EPIC 1.25 – Develop a Tool to Map the Preferred Locations for DC Fast Charging, Based on Traffic Patterns and PG&E's Distribution System, to Address EV Drivers' Needs While Reducing the Impact on PG&E's Distribution Grid", available at https://www.pge.com/pge_global/common/pdfs/about-pge/environment/what-we-are-doing/electric-program-investment-charge/EPIC-1.25.pdf . Used for LDV auto and truck, PHEV and BEV costs and PHEV utility factors.
Reference technology shares	• Vehicle stocks are calibrated to the ARB Vision 2.1 "Current Control Programs" scenario
Workplace electric vehicle charger capital cost	• $4100 per vehicle in 2030 (2012$)

LDV costs and efficiencies

	Efficiency (mi/GGE)		
Vehicle Technology	2020	2030	2050
Reference Gasoline ICE Light-Duty Auto	33	40	40
Efficient Gasoline ICE Light-Duty Auto	33	45	80
Battery-Electric Light-Duty Auto	131	155	202
Hydrogen Fuel-Cell Light-Duty Auto	83	101	138
Plug-in Hybrid Electric Light-Duty Auto	131	155	202
Reference Gasoline ICE Light-Duty Truck	23	30	30
Efficient Gasoline ICE Light-Duty Truck	23	34	54
Battery-Electric Light-Duty Truck	95	111	140
Hydrogen Fuel-Cell Light-Duty Truck	60	72	95
Plug-in Hybrid Electric Light-Duty Truck	95	111	140

Notes: Gallons of Gasoline-Equivalent (GGE) are used in PATHWAYS using the High Heating Value: 129 MJ / GGE. The plug-in hybrid electric vehicles have a range of 40 mi in electric drive mode, with 75% of miles assumed driven in electric drive mode.

Vehicle Technology	Capital Cost (2016$)		
	2020	2030	2050
Reference Gasoline ICE Light-Duty Auto	$35,490	$36,645	$37,485
Efficient Gasoline ICE Light-Duty Auto	$35,490	$36,645	$37,485
Battery-Electric Light-Duty Auto	$43,050	$36,645	$37,485
Hydrogen Fuel-Cell Light-Duty Auto	$56,385	$45,675	$37,485
Plug-in Hybrid Electric Light-Duty Auto	$43,365	$39,585	$37,485
Reference Gasoline ICE Light-Duty Truck	$35,424	$37,546	$39,541
Efficient Gasoline ICE Light-Duty Truck	$35,424	$37,546	$39,541
Battery-Electric Light-Duty Truck	$46,637	$38,565	$39,541
Hydrogen Fuel-Cell Light-Duty Truck	$63,000	$45,675	$39,585
Plug-in Hybrid Electric Light-Duty Truck	$47,351	$41,522	$39,541

Medium-Duty and Heavy-Duty Truck Efficiencies and Costs

Vehicle costs and fuel economy for advanced medium- and heavy-duty trucking modes were estimated by Black and Veatch using available data from vehicle manufacturers, direct contact with OEMs, third-party transportation studies and market summaries, and previous and ongoing Black & Veatch transportation and energy storage analyses. As well as assessing 2016 values, projections were developed for the years 2025 and 2050 in constant 2012$.

Priority was given to providing estimates which illustrate the relative differences between technologies. In the case of medium and heavy-duty vehicles, there is a very wide range in application, duty, gross vehicle weight, driving speed, and driving range, resulting in significantly different costs and fuel economies, even within a specific class of truck. Furthermore, many of these technologies are still quite speculative for medium and heavy duty trucking applications. To best provide the desired relative basis between technologies, specific vehicle data was synthesized to develop representative baseline values for conventional diesel technologies, and then to apply estimated incremental costs and percent change in fuel economy for all other technologies.

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MDV Costs and Efficiencies

	Efficiency (mi/GGE)		
Vehicle Technology	2020	2030	2050
Diesel ICE	14.0	13.5	13.2
Hybrid-Electric Diesel	16.0	20.0	22.4
Compressed Natural Gas	9.7	11.1	12.2
Battery-Electric	30.1	32.5	34.3
Hydrogen Fuel Cell	12.8	13.9	15.0
Gasoline ICE	9.7	10.4	10.9

	Capital Cost (Thousand 2016$)		
Vehicle Technology	2020	2030	2050
Diesel ICE	$85	$99	$99
Hybrid-Electric Diesel	$110	$118	$113
Compressed Natural Gas	$92	$106	$106
Battery-Electric	$181	$145	$124
Hydrogen Fuel Cell	$289	$247	$180
Gasoline ICE	$75	$88	$88

HDV Costs and Efficiencies

Vehicle Technology	Efficiency (mi/GGE) 2020	2030	2050
Reference Diesel ICE	7.6	7.7	7.7
Hybrid Diesel	9.2	11.8	12.7
Efficient Diesel ICE	8.2	9.4	10.2
Compressed Natural Gas	6.8	8.5	9.7
Hydrogen Fuel Cell	8.5	10.0	11.2
Battery-Electric	13.9	16.2	17.0

Vehicle Technology	Capital Cost (Thousand 2016$) 2020	2030	2050
Reference Diesel ICE	$197	$217	$217
Hybrid Diesel	$250	$286	$277
Efficient Diesel ICE	$220	$259	$259
Compressed Natural Gas	$273	$307	$286
Hydrogen Fuel Cell	$721	$636	$477
Battery-Electric	$484	$372	$288

Bus Costs and Efficiencies

Vehicle Technology	Efficiency (mi/GGE) 2020	2030	2050
Gasoline ICE	7	7	7
Diesel ICE	8	8	8
Compressed Natural Gas	6	6	6
Battery-Electric	20	18	23

Vehicle Technology	Capital Cost (Thousand 2016$) 2020	2030	2050
Gasoline ICE	$107	$107	$107
Diesel ICE	$525	$525	$525
Compressed Natural Gas	$609	$609	$609
Battery-Electric	$731	$628	$628

Rail and Port Electrification Costs

Passenger and freight rail electrification is assumed to have a levelized capital cost of $0.73 per gallon of diesel avoided, with a 45% energy efficiency improvement. Port electrification (shore power for hoteling of ships) is assumed to have zero incremental capital cost, with a 45% energy efficiency improvement.

Industrial, Refining, and Oil and Gas

Industrial Data Sources

Description	Reference
Sectoral electricity demand input data	CEC data used in support of http://uc-ciee.org/downloads/CALEB.Can.pdf
Sectoral pipeline gas demand input data	CEC data used in support of http://uc-ciee.org/downloads/CALEB.Can.pdf Calibrated to CARB emissions inventory 2014 data
Sectoral "other" energy input data	CARB emissions inventory historical data
End-use energy decomposition by subsector	CPUC Navigant Potential Study, 2013.

Refining Data Sources

Description	Reference
Sectoral electricity demand input data	California Energy Demand 2016-2026 Adopted Forecast, California Energy Commission, January 2016, CEC-200-2016-001 (15-IEPR-03)
Sectoral pipeline gas demand input data	CEC data used in support of http://uc-ciee.org/downloads/CALEB.Can.pdf. Allocated to gas utility service territories as a function of refinery electricity demand (broken out by electric service territory). Assumed that LADWP and SCE refining demand met by SCG. Calibrated to CARB emissions inventory 2014 data
Sectoral "other" energy input data	CARB GHG Emissions Inventory. Allocated to gas utility service territories as a function of refinery electricity demand (broken out by electric service territory). Assumed that LADWP and SCE refining demand met by SCG.

Oil and Gas Extraction Data Sources

Description	Reference
Sectoral electricity demand input data	California Energy Demand 2016-2026 Adopted Forecast, California Energy Commission, January 2016, CEC-200-2016-001 (15-IEPR-03)
Sectoral pipeline gas demand input data	CEC data used in support of http://uc-ciee.org/downloads/CALEB.Can.pdf Calibrated to CARB emissions inventory 2014 data

Energy Efficiency Cost Assumptions for Industrial Sectors

Efficiency costs are a rough estimate based on personal communication with CARB staff. The efficiency costs are estimated in $/ton CO_2e avoided fossil fuel combustion. Based on PATHWAYS fuel cost and sectoral fuel compositions, these are converted to $/GJ of avoided fossil fuel combustion for model input by industrial sector.

		Modeled Cost (2012$ per GJ avoided)		
Efficiency Tranche	Estimated Cost (2012$ per ton CO_2e avoided)	Industrial	Refining	Oil & Gas Extraction
0-10% Energy demand reduction	$35	$17	$6	$10
10-20% Energy demand reduction	$135	$22	$14	$15
20-30% Energy demand reduction	$300	$31	$25	$24

Electrification Cost Assumption for Industry

Industry electrification of natural gas and diesel end uses are assumed to have a levelized capital cost of $5 per GJ electrified (2012$), with no change in process energy efficiency resulting from electrification. These costs are in addition to incremental fuel costs (or savings) from electrification. This is a placeholder assumption until better data are available.

Agriculture and TCU (Transportation, Communication, and Utilities)

Agriculture Data Sources

Description	Reference
Sectoral electricity demand input data	California Energy Demand 2016-2026 Adopted Forecast, California Energy Commission, January 2016, CEC-200-2016-001 (15-IEPR-03)
Sectoral pipeline gas demand input data	California Energy Demand 2016-2026 Adopted Forecast, California Energy Commission, January 2016, CEC-200-2016-001 (15-IEPR-03)
Sectoral "other" energy input data.	Diesel: EIA Adjusted Sales of Distillate Fuel Oil by End Use Gasoline: CARB GHG Emissions Inventory
End-use energy decomposition by subsector	CPUC Navigant Potential Study, 2013.
Energy efficiency cost assumptions	Efficiency costs are estimated at \$0.37/kWh (2012\$) based on estimated cost of switching to LED lighting.

TCU (Transportation, Communication, & Utilities) Data Sources

Description	Reference
Sectoral electricity demand input data	California Energy Demand 2016-2026 Adopted Forecast, California Energy Commission, January 2016, CEC-200-2016-001 (15-IEPR-03)
Sectoral pipeline gas demand input data	California Energy Demand 2016-2026 Adopted Forecast, California Energy Commission, January 2016, CEC-200-2016-001 (15-IEPR-03)

Energy Supply

Electricity

Electricity Data Sources

Category	Data source
Hourly end-use electric load shapes	Residential & commercial: Primarily DEER 2008 and DEER 2011, BEopt for residential space heating, cooking and other, CEUS for commercial space heating, lighting and cooking. Agriculture & Industrial: PG&E 2010 load shape data
Hourly renewable generation shapes	Solar PV: simulated using System Advisor Model (SAM), PV Watts Concentrated solar power: simulated using System Advisor Model (SAM) Wind: Western Wind Dataset by 3TIER for the first Western Wind and Solar Integration Study performed by NREL http://wind.nrel.gov/Web_nrel/
Hydroelectric characteristics	Monthly hydro energy production data from historical EIA data reported for generating units, www.eia.gov/electricity/data/eia923/ Daily minimum and maximum hydro generation limits based on CAISO daily renewable watch hydro generation data www.caiso.com/market/Pages/ReportsBulletins/DailyRenewablesWatch.aspx. Adjusted for climate change impacts based on simulated data from University of California, Irvine as part of a separately funded CEC EPIC grant (PON-14-309).
Import/export limits	Consistent with assumptions used in base case of CA electric utility/E3 study "Investigating a Higher RPS Study" (2013)
Existing generation & heat rates	TEPPC 2022 Common Case, and "Capital cost review of power generation technologies, recommendations for WECC's 10- and 20-year studies" www.wecc.biz/committees/BOD/TEPPC/External/2014_TEPPC_Generation_CapCost_Report_E3.pdf

Category	Data source
Renewable generation & transmission capital costs and capacity factors	CPUC RPS Calculator version 6.2 Utility-scale solar and wind costs updated to 2017 E3 assessment for the WECC: "Review of Capital Costs for Generation Technologies," available at https://www.wecc.biz/Reliability/E3_WECC_CapitalCosts_FINAL.pptx
Thermal generation capital costs	"Capital cost review of power generation technologies, recommendations for WECC's 10- and 20-year studies" (E3, March 2014) www.wecc.biz/committees/BOD/TEPPC/External/2014_TEPPC_Generation_CapCost_Report_E3.pdf
Energy storage capital costs	Harmonized with "mid" case RESOLVE assumptions for 2017 CPUC Integrated Resource Plan (below), adapted from *Lazard's Levelized Cost of Storage 2.0* (2016), available at https://www.lazard.com/perspective/levelized-cost-of-storage-analysis-20/
Power plant financing assumptions	"Capital cost review of power generation technologies, recommendations for WECC's 10- and 20-year studies" (E3, March 2014) www.wecc.biz/committees/BOD/TEPPC/External/2014_TEPPC_Generation_CapCost_Report_E3.pdf
Current electric revenue requirement	Revenue requirement by component, historical FERC Form 1 data, www.ferc.gov/docs-filing/forms.asp
Renewable portfolio procurement trajectory	CPUC RPS Calculator version 6.2 defines data sources for existing and contracted generators. Calibrated to 2016 electric system generation reported by the CEC (http://www.energy.ca.gov/almanac/electricity_data/total_system_power.html, accessed August 2017) and CARB emissions inventory for 2015. Reference RPS procurement estimated at 29% in 2015 and 35% in 2020.

Category	Data source
Renewable Portfolio Standard Compliance	Portfolio Content Category (PCC) 3 Renewable Energy Credits (RECs) harmonized with RESOLVE inputs for CPUC 2017 Integrated Resource Plan (see below). Water-pumping loads exempted from RPS compliance from the California Energy Demand 2016-2026 Adopted Forecast, California Energy Commission, January 2016, CEC-200-2016-001 (15-IEPR-03)
In-state renewable resource potential	Calibrated to RESOLVE simulations for 2030 for the CPUC 2017 Integrated Resource Plan (see below)
Customer-sited Solar PV capacity	California Energy Demand 2016-2026 Adopted Forecast, California Energy Commission, January 2016, CEC-200-2016-001 (15-IEPR-03)
Demand response potential	LBNL 2025 California Demand Response Potential Study (2017), available from the CPUC at http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442452698. A total of approximately 8 GW is available in PATHWAYS by 2031

Selected Resource Capital Costs

	Levelized Capital Costs (2012$/kW-yr)		
Technology	2015	2030	2050
Wind	$266	$162	$162
Utility-Scale PV	$216	$176	$176
2-hr Batteries (Li-ion)	$215	$127	$127
5-hr Batteries (Li-ion)	$495	$294	$294
8-hr Batteries (Va Flow)	$581	$360	$360

Miscellaneous Electricity Assumptions

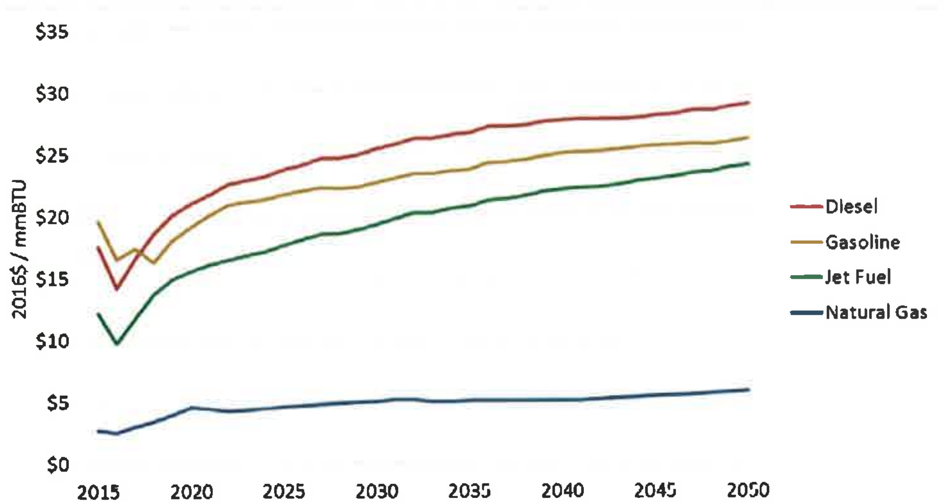
Assumption	Value
Reduction in annual hydroelectric energy budget due to climate change	11% between 2015 and 2050
Nuclear plant retirement years	2025 (Diablo Canyon) and 2047 (Palo Verde)

Assumption	Value
Out-of-state coal generation contracts	Announced retirement schedules as of June 2017, all contracts end by 2025
Additional in-state wind potential by 2030	2 GW
Additional in-state geothermal potential by 2030	2 GW
Planning reserve margin (resource adequacy provided by storage, renewables, and thermal)	15%
California net export limit	1500 MW
Portfolio Content Category 3 (PCC3) Renewable Electricity Credits (RECs)	10.1 TWh in 2015 increasing to 12.3 TWh by 2018, constant thereafter
Water-pumping loads associated with the state water project	6.0 TWh in 2015 increasing to 8.4 TWh in 2026

Fossil Fuels

Emission factors are from the EPA (2011), using Higher Heating Values. Refinery gas emissions are calibrated to the CARB emissions inventory for 2014. Fossil fuel price forecasts are taken from the EIA's Annual Energy Outlook (AEO) 2017 reference case, with alternative AEO cases tested in PATHWAYS sensitivities that vary the diesel, gasoline, and natural gas prices together for combined high and low fossil price scenarios (the high oil price scenario for liquid fuel prices is combined with the low oil and gas resource and technology scenario for natural gas prices, and vice versa). State and federal taxes are excluded. Henry Hub wholesale prices are used for natural gas (with retail delivery costs calculated in the PATHWAYS pipeline gas module), while transportation sector retail Pacific-region prices are used for gasoline, diesel, and jet fuel.

Fossil Fuel Price Forecast



Pipeline Gas

The pipeline gas revenue requirement and gas delivered rates are calculated by sector and gas utility district. The scenario impact is primarily to increase retail gas rates as delivered gas volumes fall given the need to recover capital costs. PATHWAYS does not model any costs or savings associated with partial retirement of the gas distribution system. Gas revenue requirement data are based on CPUC general rate case filings for investor-owned utilities from 2010.

Biomass and Biofuels

Biomass and biofuels assumptions and data sources are documented in Appendix C.

Hydrogen Fuel

Hydrogen fuel is assumed to be produced predominantly by grid electrolysis by 2030 in mitigation scenarios, in centralized production facilities that are flexibly dispatched with hydrogen storage of up to one week. Costs of hydrogen storage infrastructure are not currently modeled. Hydrogen is assumed to be delivered as liquid fuel for transportation, or a gaseous fuel when blended into the gas distribution pipeline. Hydrogen compression costs are included, but delivery costs from the site of production to site of consumption are not modeled. Costs and performance assumptions for hydrogen production are based on the Department of Energy H2A Analysis (2014), www.hydrogen.energy.gov/h2a_analysis.html (accessed 2014). Assumptions for electrolysis production and liquefaction are detailed below.

Assumption	Production	Liquefaction
Energy efficiency	78%	81%
Levelized capital cost (2012$ / kg-yr)*	$0.65	$0.44
Load factor (ratio of average load to peak load)	25%	50%

*This corresponds to the levelized cost for a plant running at 100% load factor per kg of total hydrogen production or liquefaction in a year, with an energy density of 0.120 GJ/kg. Thus, $0.65/kg-yr corresponds to $171/ kW-yr.

Synthetic Methane

Synthetic methane assumes air- or sea-capture of CO_2, powered by grid electricity, that is reduced to methane via electrolytically-produced hydrogen. Production is assumed to be flexibly dispatched with gas storage of up to one year. Synthetic methane is assumed to be produced in a location that would enable direct blending into the natural gas distribution pipeline. Synthetic methane blended into the gas pipeline may be used by all end-uses or compressed into CNG for use in the transportation sector. Data are from Svenskt Gastekniskt Center AB (2013): "Power-to-gas -- A Technical Review" (http://www.sgc.se/ckfinder/userfiles/files/SGC284_eng.pdf, accessed 2017). Production assumptions are detailed below.

Assumption	Value
Energy efficiency	63%
Levelized capital cost (2012$ / mmBTU-yr)*	$7.60
Non-energy variable operating costs (2012$ / mmBTU)	$6.50
Load factor (ratio of average load to peak load)	25%

*This corresponds to the levelized cost for a plant running at 100% load factor per mmBTU of total synthetic methane production in a year. Thus, $7.60/mmBTU-yr corresponds to $227/kW-yr.

Non-Combustion Greenhouse Gases

Emissions reductions and cost estimates are drawn from the California Air Resources Board Short-Lived Climate Pollutant Strategy, with some additional assumptions and differences noted below. Reference methane, CO_2, and N_2O emissions are held constant from year 2014 values based on the CARB 2016 state emissions inventory. The Reference F-gas emissions are based on the CalGAPS model[11], calibrated to match the statewide total F-gas emissions in PATHWAYS model year 2015 (18 MMT CO_2e projecting from 2010-2013 using the CARB 2015 inventory) and the CARB projected emissions in 2030 (28 MMT CO_2e, based on correspondence with CARB staff). All emissions use the IPCC Assessment Report 4 (2007) Global Warming Potentials with a 100-yr time horizon, as in the CARB emissions inventory. All costs below are in 2012$.

[11] CARB, 2013: "Methodology to Estimate GHG Emissions from ODS Substitutes"

Data Sources and Assumptions

Variable	Description
Categories of non-energy, non-CO_2 greenhouse gases	Subsector GHG emissions data from CARB's emission inventory by IPCC category: • Agriculture: (IPCC Level I Agriculture) • Cement: Clinker production • Waste: (IPCC Level I Waste) • Petroleum Refining: (IPCC Level I Energy/IPCC Level II Fugitive/Sector: Petroleum Refining) • Industrial: (IPCC Level I Industrial) minus Cement • Oil & gas Extraction: (IPCC Level I Energy/IPCC Level II Fugitive/Sector: Oil Extraction) • Electricity Fugitive Emissions: (IPCC Level I Energy/IPCC Level II Fugitive/Sector: Anything related to electricity generation including CHP) • Pipeline Fugitive Emissions: (IPCC Level I Energy/IPCC Level II Fugitive/Sector: Pipelines Natural Gas) • F-gases are captured in the "High GWP" emissions sector in CARB's emissions inventory by Scoping Plan category
Cement (clinker production)	\$10/$MTCO_2e$ with a 9% reduction by 2030 from the Reference from fly ash and other substitutes. Additional 11% reduction by 2050 assumed at the same price.
Waste	\$0/$MTCO_2e$ with a 14% reduction by 2030 from the Reference from organic waste diversion. Based on estimates from the Short-Lived Climate Pollutant Strategy and correspondence with California Air Resources Board staff. This estimate excludes the cost of biogas production and any revenue from electricity sales and LCFS credits. LCFS credits are not modeled in PATHWAYS as these are assumed to be transfers within the state. Additional 12% reduction from the Reference assumed by 2050.
Petroleum Refining fugitive and non-energy emissions	\$33/ $MTCO_2e$ with a 45% reduction by 2030 from the Reference. Based on estimates from the Short-Lived Climate Pollutant Strategy. Additional 35% reduction from the Reference assumed by 2050 at the same price.
Oil Extraction Fugitive Emissions	\$33/ $MTCO_2e$ with a 45% reduction by 2030 from the Reference. Based on estimates from the Short-Lived Climate Pollutant Strategy. Additional 35% reduction from the Reference assumed by 2050 at the same price.

Variable	Description
Electricity Generation Fugitive & Process	\$50/$MTCO_2e$ with a 40% reduction by 2030 from the Reference. Costs represent placeholder values as better cost data are needed. Additional 40% reduction from the Reference assumed by 2050 at the same price.
Pipeline Fugitive	\$33/ $MTCO_2e$ with a 45% reduction by 2030 from the Reference. Based on estimates from the Short-Lived Climate Pollutant Strategy. Additional 35% reduction from the Reference assumed by 2050 at the same price.
Agriculture: Enteric fermentation	\$100/ $MTCO_2e$ with a 16% reduction by 2030 from the Reference. Costs represent placeholder values as better cost data are needed.
Agriculture: Soil	\$100/ $MTCO_2e$ with a 22% reduction by 2030 from the Reference based on estimates from C.S. Snyder, T.W. Bruulsema, T.L. Jensen and P.E. Fixen (2009) Review of greenhouse gas emissions from crop production systems and fertilizer management effects. Agriculture, Ecosystems and Environment 133: 247-266. And George Silva (2011) Slow release nitrogen fertilizers. Available online http://msue.anr.msu.edu/news/slow_release_nitrogen_fertilizers [Accessed November 6, 2014]. Additional 30% reduction assumed by 2050 at the same price.
Agriculture: Manure	\$0/$MTCO_2e$. Based on estimates from the Short-Lived Climate Pollutant Strategy and correspondence with California Air Resources Board staff. This estimate assumes that manure collection costs are borne by biogas production and captured within the biofuels module in PATHWAYS. LCFS credits are not modeled in PATHWAYS as these are assumed to be transfers within the state.
F-gases	\$48/$MTCO_2e$ with a 63% reduction by 2030 from the Reference due to coolant switching and leak mitigation. Based on correspondence with California Air Resources Board staff. This estimate excludes the costs and savings associated with energy efficiency appliance purchases as these are captured in the equipment stocks costs in the residential, commercial and transportation sectors. Additional 27% reduction assumed by 2050 at the same price associated with full compliance with the Kigali agreement.
Land use/ land change	Assumed to result in net-zero carbon dioxide emissions.

Appendix C: PATHWAYS Biofuels Module Methodology

Table of Contents

PATHWAYS Biofuels Overview

The PATHWAYS biofuel module calculates the energy supply, delivered costs, and emissions from the production of biomass-based liquid and gaseous energy products. These biofuels are used as alternatives to fossil fuels.

In previous versions of the PATHWAYS model, including PATHWAYS 2.2, users selected biomass resources and allocated them to specific conversion pathways (e.g., gasification) and final fuel types (e.g., pipeline gas) by feedstock conversion category (e.g., woody cellulosic feedstocks). Specifying these inputs was challenging, as the task required considerable knowledge about the tradeoffs associated with each choice. At the same time, this approach could easily result in suboptimal, overly expensive biofuel portfolios. This approach precluded a selected biofuel pathway from changing over time, and it limited biofuel portfolio diversity by allowing only one conversion pathway and final fuel type for all biomass within each conversion category. To the extent that market conditions will determine dominant conversion pathways, it seems likely that these optimal conversion pathways will be diverse and will change over time.

PATHWAYS 2.5 addresses these issues by endogenously selecting optimal biofuel portfolios. PATHWAYS creates optimized least-cost biofuel portfolios given user inputs on California's ability to access national biomass feedstocks and carbon costs. Users may also identify desired biofuel penetration and optimization settings.

The remainder of this Appendix is organized as follows: Part 1 provides a detailed overview of the new biofuel logic, and Part 2 demonstrates functionality and potential use cases through illustrative modeling results. The glossary at the end of this section contains definitions of key terminology.

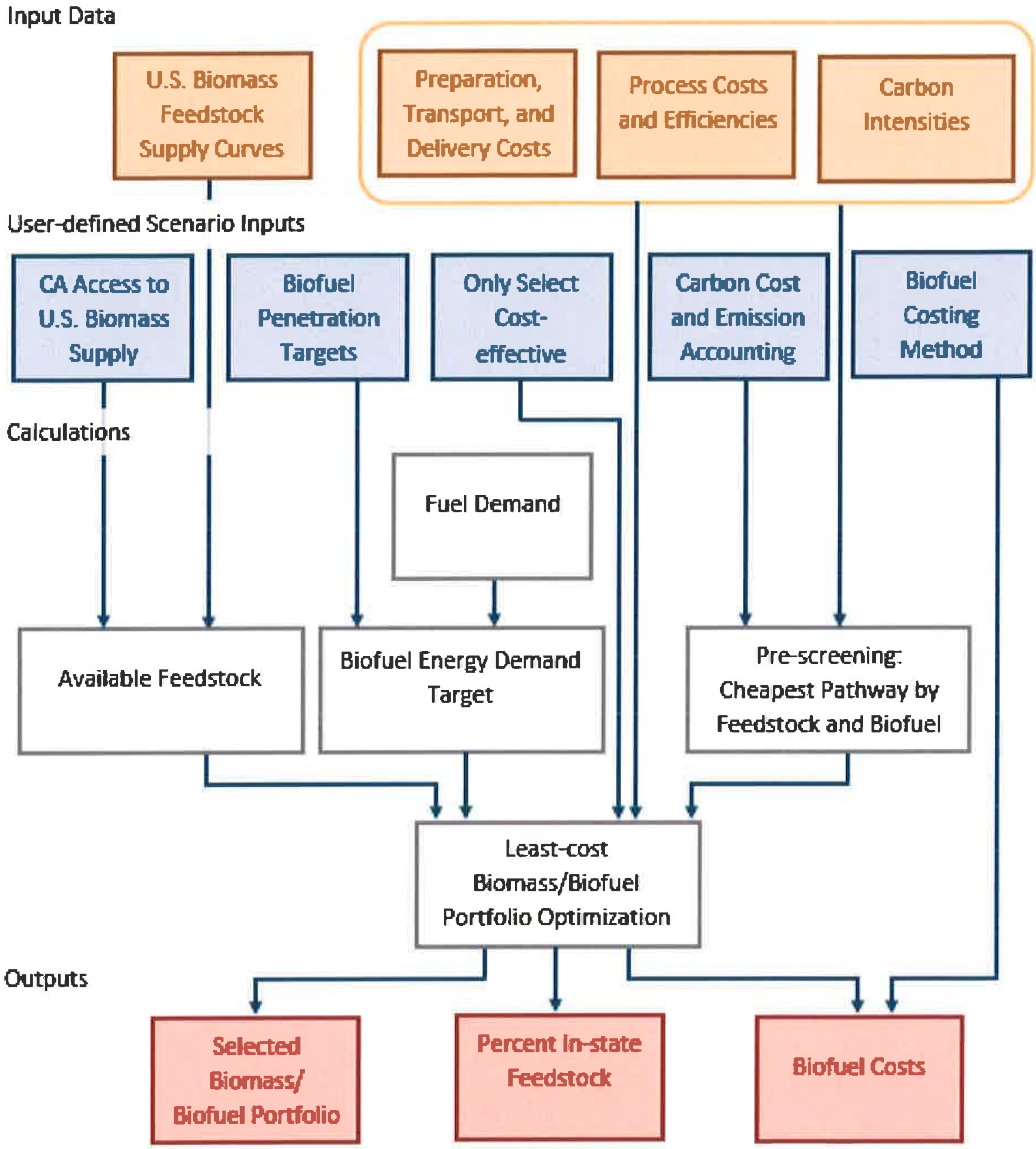
Part 1: Technical Documentation

Module Structure

The new biofuel cost minimization method optimally selects a least-cost portfolio of biomass feedstocks and biofuel conversion pathways through either of two modes: 1) meeting user-defined biofuel penetration targets (e.g., 80% renewable diesel by 2050); or 2) comparing biofuel costs to the costs of their fossil fuel counterparts to determine the overall least-cost portfolio. Under both modes, users may specify a carbon cost and an emission accounting method for PATHWAYS to consider in cost comparisons. Biofuel portfolios are subject to U.S. biomass feedstock availability and California's access to this national feedstock. These feedstock availability assumptions come from the 2011 Billion-Ton Update (BTS2011) (DOE 2011) and user inputs on California access to national supply. PATHWAYS uses the resulting optimal biofuel portfolios and associated costs in liquid and gaseous fuel supply, cost, and emission calculations.

Figure C-1 illustrates the key inputs, outputs, and logic flow of the Cost Minimization biofuel module.

Figure C-29: Cost Minimization Biofuel Module Flow Chart



PATHWAYS combines user inputs about biofuel demand, biomass supply, and biofuel selection priorities with embedded model assumptions to calculate California biomass supply curves and biofuel demand by final fuel. The model adds preparation, process, transportation, and delivery costs to BTS2011 feedstock cost curves to achieve supply curves by feedstock and conversion pathway. To obtain biofuel demand, PATHWAYS applies the percentage biofuel penetration targets to aggregate calculated final energy demand.

The model uses these supply curves and carbon costs to find optimal biofuel portfolios by key analysis year (2015, 2020, 2030, 4050, and 2050). The model has two modes for achieving this, which can be selected by the user. In one mode, the model picks the least-cost portfolio that achieves the biofuel demand, minimizing the total resource cost including any external incentives. The biofuel demands here are driven by scenario assumptions. In the other mode, unlimited biofuel demands may be requested, but the model restricts the optimization to only select feedstocks and conversion pathways that are cost-effective relative to the fossil fuel alternative, given the carbon price and other incentives. This second mode can be used to determine the optimal final fuel portfolio, as well as the optimal feedstocks and conversion pathways to meet that portfolio. Typically, this is used to establish the balance between liquid fuels and biomethane that achieves the most cost-effective CO_2 abatement for a given biomass supply. A pre-screening of the cheapest pathway (per energy unit) by feedstock and biofuel speeds up the optimization.

The biofuel module produces annual biofuel energy supply and costs by final fuel. By default, PATHWAYS calculates delivered biofuel costs on a marginal basis to simulate market-driven pricing, although users have the option to choose cost-based (average cost) pricing. Other model results include total biomass bone dry tons used by year and the percent of this selected biomass that is located within California.

The following sections describe the inputs, assumptions, and model logic in more detail. The model details are divided into five sections: Input Data, User-defined Scenario Inputs, Biofuel Energy Demand Targets, Biofuel Portfolio Selection, and Outputs.

Input Data

Biomass Feedstock Supply

Biomass supply curves (i.e. estimates of biomass resource supply potential by price) come from BTS2011 and the *Final Draft Report on The Feasibility of Renewable Natural Gas as a Large-Scale, Low Carbon Substitute* (Jaffe et al. 2016). The BTS2011 focuses on primary sources, although it also provides estimates for secondary residue and tertiary waste. A review of the literature found that the BTS2011 appears to underestimate biomethane feedstocks in California. As a result, the team supplemented the BTS2011 data with more extensive estimates of California landfill gas, manure, and municipal solid waste biomass using supply curves produced by Jaffe et al. (2016).

The BTS2011 estimates continental U.S. biomass resource potential based on current and future inventory, production capacity, availability, technology, and sustainability. Resource supply and price estimates vary by U.S. county and feedstock type. The BTS2011 groups resources into price bins of size $10 per bone dry ton (BDT) from $0-10/BDT through $90-100/BDT with an additional $100-1,000/BDT price bin. PATHWAYS aggregates these data by state for cost calculations.

The BTS2011 biomass supply curves are augmented with California landfill gas, manure, and municipal solid waste data from Jaffe et al. (2016). Additional quantities were added at a fixed all-in cost to the BTS2011 estimates from Fig. 30 in Jaffe et al. (2016)

Additional conversion efficiency and cost assumptions are required for the BTS2011 biomass supply curves to yield all-in costs, described below.

For simplification, PATHWAYS groups feedstocks into five conversion categories: cellulosic, woody cellulosic, lipid, manure, landfill gas, and starch. These categories share key characteristics that impact conversion processes and costs. Table 2 displays the categorization by feedstock.

Table C-9: California Biomethane Feedstocks from Jaffe et al. (2016)

Feedstock Type	Quantity (PJ of biomethane)	All-In Cost ($/GJ)
Landfill gas	43	$10
Manure	11	$47
Municipal solid waste	16	$19

Table C-10: Conversion Category by FeedstockFeedstock Name	Conversion Category
Cotton gin trash	Cellulosic
Cotton residue	Cellulosic
Rice hulls	Cellulosic
Rice straw	Cellulosic
Sugarcane trash	Cellulosic
Wheat dust	Cellulosic
Barley straw	Cellulosic
Corn stover	Cellulosic
Oat straw	Cellulosic
Sorghum stubble	Cellulosic
Wheat straw	Cellulosic
Annual energy crop*	Cellulosic
Perennial grasses*	Cellulosic
Orchard and vineyard prunings	Woody Cellulosic
Mill residue, unused secondary	Woody Cellulosic
Mill residue, unused primary	Woody Cellulosic
Urban wood waste, construction and demolition	Woody Cellulosic
Urban wood waste, municipal solid waste	Woody Cellulosic
Composite	Woody Cellulosic
Other removal residue	Woody Cellulosic
Conventional wood	Woody Cellulosic
Treatment thinnings, other forest lands	Woody Cellulosic
Coppice and non-coppice woody crops*	Woody Cellulosic
Fuelwood	Woody Cellulosic
Mill residue	Woody Cellulosic
Pulping liquors	Woody Cellulosic

Soy oil lipids	Lipid
Waste oil lipids	Lipid
Manure	Manure
Landfill gas	Landfill Gas
Municipal solid waste	Cellulosic
Corn (for ethanol)	Starch

*These categories represent purpose-grown crops, which can be excluded from scenarios according to user input.

Biofuel Cost and Selection Drivers

Overview

The cost minimization biofuels module calculates two distinct sets of costs for each of two purposes: 1) selecting optimal biofuel portfolios; and 2) calculating total California resource costs. While the cost calculations are similar, it may be appropriate for the costs to differ by purpose. For example, users may want to represent a policy, such as the Low Carbon Fuel Standard, that imposes carbon intensity-driven incentives and penalties to favor fuels with greater carbon benefits. The biofuel portfolio selection should consider these carbon intensity-driven incentives and penalties, but these costs should not be included in the total California resource costs, as they reflect transfer payments within the state.

For both purposes, biofuel cost calculations incorporate numerous cost components. Figure C-2 summarizes the biofuel supply chain, as conceptualized in PATHWAYS analysis. Each step requires associated costs, many of which are included in PATHWAYS' biofuel cost accounting. Note that biomass is diverse and biofuel production is nascent, so actual biofuel supply chains may combine or eliminate some of these steps.

Figure C-30: Biofuel Supply Chain

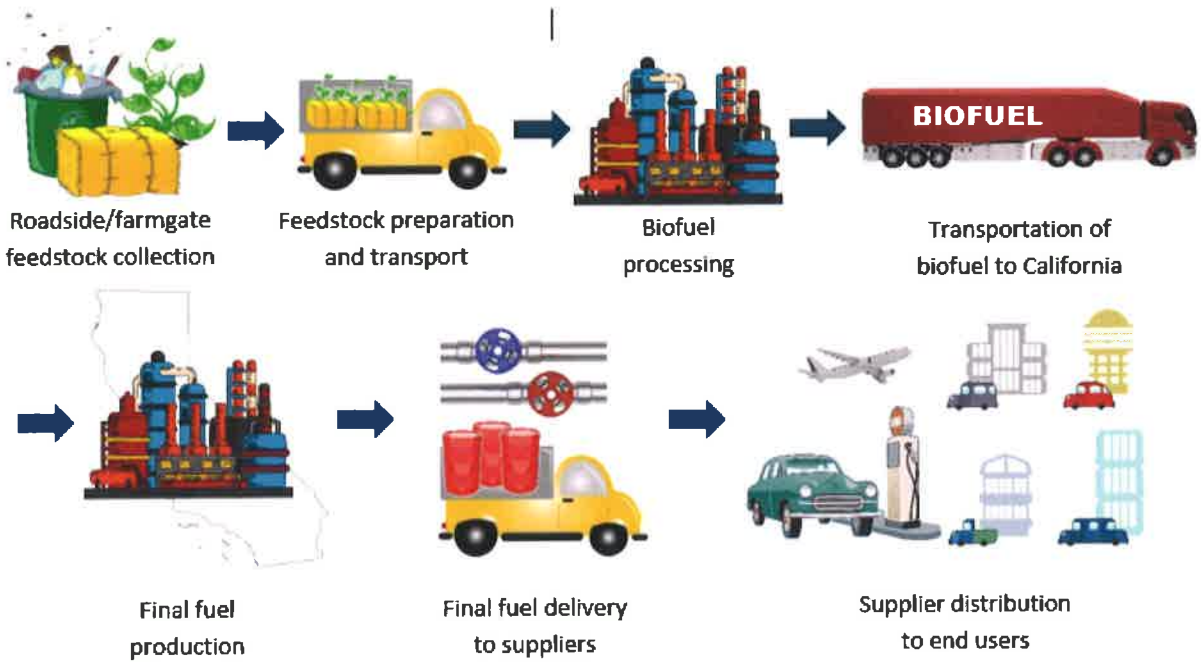


Table C-3 summarizes the cost components and costing methods included in each of the two cost calculation types.

Table C-11: Biofuel Cost Components and Costing Methods by Cost Purpose

Cost Component/Method	Selecting Optimal Biofuel Portfolios	Calculating Total California Resource Costs
 Feedstock Costs	√	√
 Feedstock Preparation and Transport Costs	√	√
 Biofuel Process Costs	√	√
 Costs of Biofuel Transportation to California Refineries	√	√
 Costs of Final Fuel Delivery to Suppliers	√	√
Incentives/Penalties based on Fuel Carbon Intensity	√	×
Bottom-up (average) vs. market-based (marginal) costing method	Bottom-up	User Input

The remainder of this subsection describes each of these cost components and costing methods in more detail.

Feedstock Costs

Feedstock costs come directly from the BTS2011, which characterizes them as farmgate or roadside costs. These costs reflect all costs associated with feedstock acquisition, access, collection, and transport to the field edge or forest roadside. The BTS2011 includes supply curves of feedstock costs by feedstock type and county. See the Biomass Supply section for more detail.

Feedstock Preparation and Transport Costs

This cost category captures the costs of collecting and transporting biomass from the farmgate or roadside to biofuel production facilities. These costs come from the ARB's Biofuel Supply Module 0.91 (BFSM 0.91) (ARB 2017). The BFSM 0.91 uses the following regression model, which is based on preliminary findings of the 2016 Billion Ton Report (BTS2016) (DOE 2016).

Equation 1

$$F_{fp} = \alpha + \beta_1 P_{fp} + \beta_2 W_f$$

Where

F_{fp}	Feedstock preparation and transport costs in $/ton by feedstock type *f* and price bin *p*
P_{fp}	Resource price, estimated as the maximum price contained in the price bin
W_f	Boolean variable set to one for woody cellulosic feedstocks and to zero for all other feedstocks
α	Constant term of estimated value -14
β_1	Coefficient of estimated value 1.19
β_2	Coefficient of estimated value -12.47

Biofuel Process Costs and Efficiencies

Biofuel production process costs reflect the costs of producing biofuels from biomass at biofuel production facilities. Biofuel production processes include pyrolysis, hydrolysis, anaerobic digestion, gasification, and fatty acid methyl esterification (FAME). Biofuel process efficiencies represent primary bioenergy losses associated with these processes.

Table C-4 and Table C-5 display the process cost and efficiency assumptions in PATHWAYS, expressed per bone dry ton of biomass. Biofuel process costs vary by conversion category. Process efficiencies vary by feedstock.

These process costs and efficiencies are harmonized with those assumed for the California Air Resources Board Scoping Plan analysis and do not assume any innovation or improvement in conversion over time. Cellulosic feedstock is only assumed to be available for conversion to liquid fuels, while woody and other feedstocks can be converted to liquid fuels or biomethane.

Table C-12: Process Costs by Conversion Category

Feedstock Conversion Category	Biofuel Process	Biofuel	Process Cost ($/ton)
Cellulosic	Pyrolysis (thermochemical)	Renewable Diesel	$145
		Renewable Gasoline	$145
		Renewable Jet Fuel	$145
	Hydrolysis (hydrotreating)	Renewable Ethanol	$128
Woody Cellulosic	Pyrolysis (thermochemical)	Renewable Diesel	$162
		Renewable Gasoline	$162
		Renewable Jet Fuel	$162
	Hydrolysis (hydrotreating)	Renewable Ethanol	$128
	Gasification	Biomethane	$143
Lipid	Hydrolysis (hydrotreating)	Renewable Diesel	$314
	FAME	Biodiesel	$345
Manure	Anaerobic Digestion	Biomethane	$168
Landfill Gas	Anaerobic Digestion	Biomethane	$266[1]
Municipal Solid Waste	Gasification	Biomethane	$70
Starch	Fermentation	Conventional Ethanol	$22

[1]Dollars per ton of raw gas

Sources: ARB BFSM (CARB 2017); Black and Veatch analysis for E3 (2016)[12]; Nathan Parker analysis for E3 (2012)

[12] Inputs aligned with other PATHWAYS assumptions. Assumes gas upgrading equipment to meet SoCalGas Rule 30 specification. Assumes ~92% moisture content in the manure feedstock.

Table C-13: Process Efficiencies

Feedstock Conversion Category	Biofuel Process	Biofuel	Process Efficiency Range[1] (GGE/ton [LHV])
Cellulosic	Pyrolysis (thermochemical)	Renewable Diesel	35-46
		Renewable Gasoline	35-46
		Renewable Jet Fuel	35-46
	Hydrolysis (hydrotreating)	Renewable Ethanol	34-56
Woody Cellulosic	Pyrolysis (thermochemical)	Renewable Diesel	35-47
		Renewable Gasoline	35-47
		Renewable Jet Fuel	35-47
	Hydrolysis (hydrotreating)	Renewable Ethanol	50-53
	Gasification	Biomethane	75-101
Lipid	Hydrolysis (hydrotreating)	Renewable Diesel	285
	FAME	Biodiesel	283
Manure	Anaerobic Digestion	Biomethane	54
Landfill Gas	Anaerobic Digestion	Biomethane	323[2]
Municipal Solid Waste	Gasification	Biomethane	26
Starch	Fermentation	Conventional Ethanol	69

[1]Varies by feedstock type; GGE is in LHV in this table (115 MJ/GGE). Elsewhere in this document and in PATHWAYS HHV is used.
[2]GGE per ton of raw gas
Same sources as for process conversion costs.

Biofuel Transportation to California Refineries

Because biofuels are often cheaper to transport than biomass, biofuel refining may occur in locations relatively close to biomass production sites and relatively far from California biofuel demand. Biofuel transportation costs reflect the costs to transport finished biofuel from biofuel refineries to California refineries, where fuel blending occurs.

Biofuel transportation cost calculations mirror those of the BFSM 0.91, which uses a constant cost of $0.0083 per ton-mile. This cost comes from a 2009 National Academies Press (NAP) study and reflects gasoline transport costs. The transportation distances come from Google Maps and denote centroid distances between U.S. states.

Table 14: Distances for Transportation to California Refineries

Resource Origin	Distance (Miles)	Resource Origin	Distance (Miles)
AK	3179	MT	1258
AL	2166	NC	2650
AR	1805	ND	1717
AZ	737	NE	1459
CA	1	NH	3083
CO	1119	NJ	2888
CT	2993	NM	992
DE	2848	NV	543
FL	2706	NY	2915
GA	2454	OH	2390
HI	2467	OK	1504
IA	1848	OR	667
ID	908	PA	2735
IL	2085	RI	3080
IN	2231	SC	2503
KS	1539	SD	1643
KY	2311	TN	2161
LA	1906	TX	1408
MA	3097	UT	794
MD	2782	VA	2648
ME	3243	VT	3082
MI	2406	WA	2794
MN	1993	WI	2178
MO	1845	WV	2548
MS	2010	WY	1156

Source: ARB Biofuel Supply Module: Technical Documentation for Version 0.91 Beta. Released January 19, 2017.

Fuel Delivery Costs

PATHWAYS captures the costs to transport final (blended) fuels to suppliers, such as gasoline fueling stations, within and outside of the biofuel module. The biofuels module includes per-unit delivery costs for liquid biofuel. Fossil fuel price forecasts contain embedded per-unit fuel delivery costs. A pipeline gas revenue requirement model determines pipeline gas delivery costs.

Liquid biofuel delivery costs come from U.S. Energy Information Administration (EIA) data. PATHWAYS uses the difference between wholesale and end use fuel prices, excluding taxes, as delivery cost estimates for each of gasoline and diesel. The estimates are $0.32/gallon for gasoline and $0.48/gallon for diesel.

Carbon Intensities

PATHWAYS may use two types of biofuel-related carbon emission accounting: net lifecycle emission accounting and ARB Emission Inventory accounting. Users define which of these two accounting methods to use for biofuel portfolio selection logic. PATHWAYS always adopts ARB Emission Inventory accounting for scenario emission calculations.

The lifecycle carbon intensities come from the ARB CA-GREET 2.0 and BFSM 0.91 models. The values typically include emissions associated with feedstock collection and extraction, biofuel processing, and transport. When estimates exist, the carbon intensities also encompass emissions from make-up nutrient application and land use change. Net lifecycle carbon intensities equal biofuel lifecycle carbon intensities (Table C-7) less conventional fuel carbon intensities (Table C-8).

Under ARB Emission Inventory accounting, biofuels are zero-emission resources. Hence, net emission reductions exclusively depend on ARB Emission Inventory fossil fuel emission factors, which are shown in Table C-8.

Table C-15: Biofuel Lifecycle Carbon Intensities

Feedstock Names	Lifecycle CI (gCO2e/MJ)
Cotton gin trash, rice hulls, and annual energy crop	Pyrolysis & Hydrolysis: 0
Cotton residue	Pyrolysis: 25 Hydrolysis: 24
Rice straw	Pyrolysis: 26 Hydrolysis: 19

Sugarcane trash	Pyrolysis: 18 Hydrolysis: 12
Barley straw	Pyrolysis: 25 Hydrolysis: 20
Corn stover	Pyrolysis: 28 Hydrolysis: 22
Oat straw and sorghum stubble	Pyrolysis: 23 Hydrolysis: 18
Wheat straw	Pyrolysis: 24 Hydrolysis: 20
Annual energy crops	Pyrolysis & Hydrolysis: 0
Perennial grasses	Pyrolysis: 38 Hydrolysis: 32
Orchard and vineyard prunings, urban wood waste, treatment thinnings, composite, other forest lands, and other removal residue	Pyrolysis: 36 Hydrolysis: -2 Gasification: 25
Mill residue, unused	Pyrolysis: 33 Hydrolysis: -4 Gasification: 24
Conventional wood, fuelwood, mill residue, and pulping liquors	Pyrolysis & Hydrolysis: 0 Gasification: 25
Coppice and non-coppice woody crops	Pyrolysis: 24 Hydrolysis: 19
Soy oil lipids	Hydrolysis & FAME: 50
Waste oil lipids	Hydrolysis & FAME: 30

Manure	AD: -273
Landfill gas	AD: 31
Municipal solid waste	Gasification: -23
Corn (for ethanol)	Fermentation: 70

Source: ARB BFSM 0.91 and ARB CA-GREET 2.0

Table C-16: Conventional Fuel Carbon Intensities

Fuel	Lifecycle CI (gCO_2e/MJ)[13]	ARB Inventory CI (gCO_2e/MJ)[14]
Natural gas	78	50
Diesel	102	70
Gasoline	100	67
Jet fuel (kerosene)	102	68

User-defined Scenario Inputs

Users may define the following inputs:

Biofuel Penetration Targets

This input defines target shares of final fuel demand to be supplied by biofuels. Users may enter measures to set target percentage biofuel penetration ratios for each final fuel and end use sector. The following five inputs define each measure:

- **Fuel**: Applicable end use fuel type to which biofuels will be directed (pipeline gas, diesel, gasoline, or kerosene for jet fuel).
- **Applicable Sector(s)**: End use sector destination(s) to which biofuels will be directed (transportation, buildings, industry, oil and gas extraction, refining, agriculture, or TCU). PATHWAYS attributes all measure-related costs and emission impacts to selected sectors pro rata.
- **Measure Start Year**: The year the measure begins. This is the first year in which a portion of the specified biofuels get introduced. PATHWAYS restricts selections to the five key analysis years (i.e. 2015, 2020, 2030, 2040, and 2050).
- **Measure Saturation Year**: The earliest year in which the specified biofuel penetration ratio could be reached. Absent additional measures, this target ratio will remain constant through the end of the analysis period.

[13] From the ARB BFSM 0.91, except for jet fuel, where the same value as diesel is assumed.

[14] http://www.epa.gov/climateleadership/documents/emission-factors.pdf

- **Saturation Ratio**: The target ratio of biofuel energy to final fuel energy demand at the saturation year. Note that pipeline gas saturation ratios apply only to natural gas demand (i.e. total pipeline gas demand less hydrogen and other power-to-gas supply, if applicable). A gasoline biofuel target ratio should include conventional ethanol, if applicable. Conventional ethanol (e.g. ethanol produced with starch) penetrations can be specified explicitly in the separate *Conventional Ethanol Share* input.

For each measure, the model calculates a target penetration trajectory by linearly interpolating the target penetration ratios between the start year and the saturation year. The target measure penetration reaches the saturation ratio in the saturation year. Absent other measures, the target penetration ratio stays at that level for the remainder of the analysis period.

Users may specify up to 20 biofuel measures. These measures are additive. Cumulative target biofuel penetrations are limited to 100% by biofuel and end use sector.

These target biofuel ratios provide an upper bound for achieved biofuel penetrations. Achieved biofuel penetrations may be further limited by feedstock availability or, in some cases, cost-effectiveness.

CA Access to U.S. Biomass Supply:

Users define the portion of national biomass feedstock made available for California biofuel production. Users may select one of the following five methods by which to allocate national biomass feedstock to California:

- **In-state Biomass:** This option restricts California's biomass use to feedstocks located within the state. This scenario assumes no biomass imports or exports.
- **Population-weighted Share:** This option allows California to use biomass from across the country, but it restricts the state's biomass use to California's share of the 2013 U.S. population. This results in California receiving access to about 12% of each type of biomass feedstock at each price point in each U.S. state
- **User Input:** This option provides users with the flexibility to explicitly specify biomass feedstock available to California as a percentage of total U.S. feedstock. Users must specify these percentages by key analysis year (i.e. 2015, 2020, 2030, 2040, and 2050), location (i.e. in-state vs. out-of-state), and conversion category (i.e. cellulosic, woody cellulosic, lipid, manure, landfill gas, municipal solid waste, and starch). The percentages apply to biomass supply pro rata across states. For example, a user could specify that California has access to 100% of in-state manure and 10% of out-of-state cellulose in 2030. Under this specification, California would receive access to 10% of each type of cellulosic feedstock at each price point in each of the other U.S. states.

In addition, users may select one or more feedstock types from Table 2 to exclude from availability: for instance, purpose-grown crops have particular concerns about sustainability associated with indirect land use GHG emissions and effects on food prices, so these are excluded from most of the mitigation scenarios described in the main body of this report.

Carbon Cost and Emission Accounting for Biofuel Selection

Users may choose to include carbon-intensity driven incentives and penalties in the costs used for least-cost biofuel portfolio selection. These incentives and penalties represent monetary transfers (e.g., government tariff or tax) between parties within California to encourage consideration of emission impacts in biofuel supply decisions.

Users specify two inputs related to emission accounting:

- **Carbon Cost**: Cost of carbon emissions in dollars per metric ton of carbon. Users specify a cost for each key analysis year.
- **Emission Accounting Method for Biofuel Selection**: This user input determines whether to apply the carbon costs to: 1) net lifecycle carbon intensity estimates, or 2) net ARB Emission Inventory accounting carbon intensity estimates. ARB Emission Inventory accounting captures anthropogenic GHG emissions within California and treats all biofuels as zero-emission resources.

Based on these two inputs, PATHWAYS calculates a \$/GJ net incentive for each combination of feedstock type, biofuel, and conversion pathway. This net incentive informs the optimal selection of biomass and biofuels. Equation 2 illustrates the calculation method, which is based on: the user-input carbon price trajectory, an estimate of the applicable biofuel carbon intensity, and a carbon intensity estimate for the replaced fossil fuel. The *Emission Accounting Method for Biofuel Selection* input determines whether these carbon intensities reflect lifecycle emissions or ARB Emission Inventory accounting.

Equation 2

$$NCI_{fcby} = CC_y \times (CIF_f - CI_{fcb})$$

Where

$\mathbf{NCI_{fcby}}$	Net carbon intensity-driven incentive (\$/GJ) for biofuel type *f* produced using conversion pathway *c* and biomass feedstock type *b* in key analysis year *y*
$\mathbf{CC_y}$	User-input carbon cost (\$/metric ton) of carbon emissions in key analysis year *y*
$\mathbf{CIF_f}$	Carbon intensity (tons/GJ) of the fossil fuel counterpart of biofuel type *f*
$\mathbf{CIF_{fcb}}$	Carbon intensity (tons/GJ) of biofuel type *f* produced using conversion pathway *c* and biomass feedstock type *b*

Carbon intensity-driven incentives only impact biofuel portfolio selection. The final PATHWAYS cost results do not reflect these carbon costs, as we assume carbon-related monetary transfers remain within the state. The PATHWAYS emission results exclusively use ARB inventory emission accounting.

Only Select cost-effective Biofuels:

The checkbox determines which of the two available modes to use for running the cost-minimization biofuel module:

- **Default Mode:** Under the default (unchecked) mode, PATHWAYS selects the least-cost portfolio of biomass and conversion pathways that meet the biofuel targets. PATHWAYS considers carbon costs when selecting between feedstocks and conversion pathways. If the available biomass feedstock supply is insufficient to meet target biofuel energy demand, PATHWAYS prioritizes maximizing biofuel energy production over minimizing costs. In this situation, the model produces a warning to ensure that users are aware of this prioritization.
- **Only Select Cost-effective Biofuels Mode:** When the *Only Select Cost-effective Biofuels* input is checked, PATHWAYS only selects biomass feedstocks and conversion pathways that are cost-effective at the given carbon price. The model minimizes net fuel costs given that total selected biofuel energy supply can be no greater than the biofuel penetration targets.

Biofuel Costing Method

Users can choose one of two methods for calculating total California biofuel resource costs: market-based (marginal) accounting or cost-based (average) accounting.

The market-based cost accounting method is the default method. Under this method, the cost of biofuels is based on a single market clearing price for each fuel, while the model minimizes the average total cost of the biofuels, excluding producer rents. The market clearing price equals the all-in cost of the marginal unit of biofuel. PATHWAYS calculates one biofuel market clearing price by key analysis year and final fuel. Equation 3 displays this calculation.

The cost-based accounting method produces a bottom-up calculation of all-in biofuel costs for each unit of biofuel and key analysis year. The all-in costs include all of the cost components outlined in Table 3, as applicable. Hence, under this method, PATHWAYS effectively calculates the integral of the selected biofuel supply curve. Dividing by the total quantity of biofuel produces the average biofuel cost by year and final fuel type (i.e. pipeline gas, diesel, gasoline, conventional ethanol, and kerosene), as demonstrated in Equation 4.

Equation 3

$$BMC_{fy} = \max_{c,b,p} C_{cbpfy}$$

Equation 4

$$BAC_{fy} = \frac{\sum_c \sum_b \sum_p \sum_l C_{cbplfy} \times B_{cbplfy}}{\sum_c \sum_b \sum_p \sum_l B_{cbplfy}}$$

Where

$\mathbf{BAC_{fy}}$	Average delivered bioenergy costs ($/GJ) for final fuel f in key analysis year y
$\mathbf{B_{cbplfy}}$	Quantity (GJ) of final fuel f in key analysis year y produced using conversion pathway c and biomass feedstock type b at price point p from location l
$\mathbf{C_{cbplfy}}$	All-in cost ($/GJ) of final fuel f in key analysis year y produced using conversion pathway c and biomass feedstock type b at price point p from location l
$\mathbf{BMC_{fy}}$	Marginal delivered bioenergy costs ($/GJ) for final fuel f in key analysis year y

Under both methods, PATHWAYS linearly interpolates costs between key analysis years to obtain annual costs.

Note that cost accounting for selecting optimal biofuel portfolios exclusively uses the bottom-up (average) accounting method, as described in the Biofuel Portfolio Selection section.

Biofuel Energy Demand Targets

As described above, PATHWAYS uses the *Biofuel Penetration Targets* and *Conventional Ethanol Share* inputs to define trajectories of biofuel demand as a percentage of final fuel demand by end use sector. PATHWAYS defines an aggregate trajectory for each of the following final fuels: pipeline gas, diesel, gasoline, conventional ethanol, and jet fuel. Table C-9 shows the mapping of biofuels to each of these fuel categories.

Table C-17: Fuel Category Definitions

Final Fuel (incl. ethanol)	Replaced Fuel	Applicable Biofuels
Pipeline gas	Natural gas	Biomethane
Diesel	Conventional diesel	Renewable diesel, biodiesel
Gasoline	Conventional gasoline	Renewable gasoline, renewable ethanol
Conventional ethanol	Conventional gasoline	Conventional ethanol
Jet fuel	Kerosene	Renewable jet fuel

As previously described, PATHWAYS calculates total fuel demand by sector. The biofuels module applies the biofuel penetration trajectories to these total fuel demands to obtain absolute biofuel energy demand by fuel category and end use sector.

Due to constraints on biomass supply and costs, these biofuel demands may not be met in a given scenario. If conventional ethanol demand exceeds the attainable conventional ethanol supply, the remaining demand is met with renewable ethanol or renewable gasoline. For all other final fuels, conventional fuels replace any demand that cannot be met with biofuels. The Biofuel Portfolio Selection section discusses these mechanics further.

Biofuel Portfolio Selection

Given the biomass supply curves, biofuel demand, and lifecycle carbon costs, PATHWAYS determines the least-cost biofuel portfolios via a two-step approach. The model first reduces the dimensionality of the problem by performing a pre-optimization screen. It then uses a linear optimization model to determine the least-cost viable portfolio of biomass and biofuels for each of the five key analysis years.

PATHWAYS selects biofuel portfolios that minimize aggregate biofuel costs. For the purpose of biofuel portfolio selection, biofuel costs include all cost components in the righthand column of Table 3. As shown in the table, these costs may include carbon intensity-driven incentives and penalties. The model uses the cost-based (average) accounting approach for biofuel selection. The resulting portfolio may not minimize market-based (marginal) costs. Hence, the portfolios may not minimize total scenario costs if users select market-based scenario cost accounting.

Step 1: Pre-optimization Screening

The pre-optimization screening compares the $/GJ costs of competing conversion pathways for each potential combination of feedstock type and final fuel. For each feedstock and final fuel, PATHWAYS removes all but the lowest cost conversion pathway. For example, suppose a lipid biomass feedstock could produce a gigajoule of biodiesel or a gigajoule of renewable diesel, both of which would replace a gigajoule of conventional diesel. The model would compare the $/GJ costs of using FAME to create biodiesel to the costs of using hydrolysis to create renewable diesel. It would then pass only the cheaper option for consideration in the biofuel portfolio optimization.

This pre-optimization screening uses the costs for optimal biofuel portfolio selection, which include any carbon-intensity driven incentives and penalties. The screening occurs by key analysis year, as costs and efficiencies may change throughout the analysis period.

Step 2: Portfolio Optimization

After determining the cheapest conversion pathway by feedstock, final biofuel, and key analysis year, PATHWAYS compares costs across feedstocks and biofuels using a linear optimization. The model makes selection decisions for each feedstock type at each price point. The objective functions and constraints vary by mode.

Under the Default mode, the model uses bottom-up cost calculations to select the biomass-biofuel portfolio that minimizes aggregate costs, which includes feedstock, delivery, process, transportation, and carbon costs.[15] Equation 5 presents the optimization specification under the Default mode. The biomass in the selected portfolio must adhere to California feedstock availability constraints (constraint #1). The target biofuel demand ratios act as soft constraints that are binding unless the feedstock availability constraints prevent them from being attainable (constraint #2). Under this set up, the model would select a higher-cost biofuel portfolio that meets the biofuel penetration targets over a lower-cost biofuel portfolio that does not meet these targets. The model will provide a warning if there are no feasible biofuel portfolios that meet the biofuel penetration targets. Constraint #3 ensures that the model only selects viable feedstock type, conversion pathway, and final fuel combinations.

Under the Only Select Cost-effective Biofuels mode, the model minimizes aggregate costs across all biofuels and their conventional fuel counterparts. Equation 6 displays the optimization specification under this mode. As in Equation 5, California feedstock availability constrains the biomass selection (constraint #1), and the model may only select viable feedstock type, conversion pathway, and final fuel combinations (constraint #3). However, the target biofuel demand ratios simply provide an upper bound on biofuel selection (constraint #2). Subject to these constraints, the model selects all biofuels that are cheaper than their conventional fuel counterparts at the given carbon price.

Equation 5

$$\boldsymbol{Mininimize} \sum_f \sum_b \sum_p \sum_l BioSupply_{fbply} \times \left(BioPrice_{fbply} - ConvFuelPrice_{fy} + NCI_{fby}\right) + SlackConvSupply_{fy} \times Penalty$$

[15] Note that cost minimization of bottom-up calculated costs may produce a different result than cost minimization of marginal, or market-based, costs.

$$\textbf{s.t.}\ \ (1) \sum_f FeedstockUse_{fbply} \leq CABioAccess_{bply}$$

$$(2) \sum_f \sum_b \sum_p \sum_l BioSupply_{bfply} + SlackConvSupply_{fy} = BioDemand_{fy}$$

$$(3)\ FeedstockUse_{fbply} \leq CABioAccess_{bply} \times ViablePathway_{fb}$$

Equation 6

$$\textbf{Mininimize} \sum_f \sum_b \sum_p \sum_l BioSupply_{fbply} \times \left(BioPrice_{fbply} - ConvFuelPrice_{fy} + NCI_{fby}\right)$$

$$\textbf{s.t.}\ \ (1) \sum_f FeedstockUse_{fbply} \leq CABioAccess_{bply}$$

$$(2) \sum_f \sum_b \sum_p \sum_l BioSupply_{bfply} \leq BioDemand_{fy}$$

$$(3)\ FeedstockUse_{fbply} \leq CABioAccess_{bply} \times ViablePathway_{fb}$$

Where

$BioSupply_{fbply}$	Selected biofuel energy (GJ) for final fuel *f* produced from biomass feedstock type *b* at price point *p* from location *l* in key analysis year *y*
$BioPrice_{fbply}$	All-in cost ($/GJ) of final fuel *f* in key analysis year *y* produced using the screened-in conversion pathway from biomass feedstock type *b* at price point *p* from location *l*
$ConvFuelPrice_{fy}$	All-in cost ($/GJ) of conventional fuel used for final fuel *f* in key analysis year *y*
NCI_{fby}	Net carbon intensity-driven incentive ($/GJ) for biofuel type *f* produced using the screened-in conversion pathway from biomass feedstock type *b* in key analysis year *y*
$SlackConvSupply_{fy}$	Decision variable representing conventional fuel demand used to meet biofuel demand for final fuel *f* in key analysis year *y*
Penalty	Large penalty for failing to meet biofuel demand
$FeedstockUse_{fbply}$	Decision variable representing selected biomass feedstock of type *b* at price point *p* from location *l* used to produce final fuel *f* in key analysis year *y*
$CABioAccess_{bply}$	California access to biomass feedstock of type *b* at price point *p* from location *l* in key analysis year *y*
$BioDemand_{fy}$	Biofuel demand (GJ) by final fuel *f* in key analysis year *y*
$ViablePathway_{fb}$	Boolean variable set to one if there is a viable conversion pathway between biomass feedstock type *b* and final fuel *f*

Outputs

PATHWAYS uses the optimized biofuel portfolio to inform liquid and gaseous blended fuel prices and emission intensities. The biofuels module calculates annual biofuel energy supply by sector and final fuel. The module achieves these annual estimates by linearly interpolating biofuel supply between the five key analysis years. The module may adjust these trajectories to ensure that the supply never exceeds the biofuel penetration targets. PATHWAYS also linearly interpolates biofuel prices between key analysis years, as discussed previously.

PATHWAYS combines these annual biofuel supply trajectories with hydrogen and power to gas supply trajectories to calculate annual fuel compositions of liquid and gaseous end use fuels (i.e. pipeline gas, diesel, gasoline, or kerosene for jet fuel). The model uses these fuel compositions along with the biofuel, fossil fuel, and other fuel price trajectories to calculate weighted average annual prices by end use fuel. Similarly, the model calculates annual weighted average carbon emission intensities by end use fuel based on annual fuel composition and emission intensity trajectories.

The model also provides users with biofuel-specific diagnostic outputs. Users can explore the total biomass quantity used, the portion of this biomass coming from outside of California, and the resulting biofuel penetrations in liquid and gaseous fuels.

Glossary

- **Biofuels**: Biomass-derived liquid and gaseous fuels, including biomethane, renewable gasoline, renewable ethanol, conventional ethanol, renewable diesel, biodiesel, and renewable jet fuel.
- **Conversion categories**: Each biomass feedstock can be classified into one of the following conversion categories: cellulosic, woody cellulosic, lipid, manure, landfill gas, municipal solid waste, and starch. Feedstocks within each conversion category share key biofuel-related properties, including viable biofuel conversion pathways and costs.
- **Conversion pathways**: Processes for converting biomass into biofuel. PATHWAYS uses the following conversion pathways: anaerobic digestion, gasification, pyrolysis, hydrolysis, fermentation, and FAME. For conversions that require multiple conversion steps, PATHWAYS selects one primary process name to represent the entire conversion process (e.g., starch requires hydrolysis and fermentation for ethanol production, so this document refers to the combined process as "fermentation").
- **Final fuel types**: Fuels delivered to end users. These may contain a blend of biofuels and conventional fossil-derived fuels. Final fuels include pipeline gas, gasoline, diesel, and kerosene for jet fuel. In some instances, PATHWAYS also considers conventional ethanol separately from other gasoline fuels.
- **Key analysis years**: The five years in which PATHWAYS performs biofuel portfolio optimization: 2015, 2020, 2030, 2040, and 2050.

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DOCKETED	
Docket Number:	19-SB-100
Project Title:	SB 100 Joint Agency Report: Charting a path to a 100% Clean Energy Future
TN #:	229800
Document Title:	Clean Air Task Force Comments - On SB 100 Joint Agency Report - Charting a Path to a 100% Clean Energy Future
Description:	N/A
Filer:	System
Organization:	Clean Air Task Force
Submitter Role:	Public
Submission Date:	9/19/2019 4:22:42 PM
Docketed Date:	9/19/2019

Comment Received From: Clean Air Task Force
Submitted On: 9/19/2019
Docket Number: 19-SB-100

On SB 100 Joint Agency Report - Charting a Path to a 100% Clean Energy Future

Additional submitted attachment is included below.

CLEAN AIR TASK FORCE

September 19, 2019

California Energy Commission
California Public Utilities Commission,
California Air Resources Board

Re: SB 100 Joint Agency Report: Charting a Path to a 100% Clean Energy Future, Docket No. 19-SB-100

Dear Chair Hochschild, Chair Nichols and Commissioner Randolph:

Thank you for the opportunity to comment on the September 5th, 2019 Joint Agency Workshop on the above-referenced Senate Bill 100 Report.

SB 100 is a pace-setting, model piece of legislation that embodies a critical principle for deep decarbonization of power grids: technology-inclusiveness and creating more options. By allowing for and enabling a variety of zero carbon technologies to meet power supply beyond the requirement of 60% renewable energy, SB 100 reflects best practice thinking from the analytic community on an affordable zero carbon energy transition. The technology-inclusive SB 100 approach has been copied by five other states – Washington State, New Mexico, Nevada, New York, Colorado – and is being considered in several others.

The central theme of our comments is that the joint agency report on implementing SB 100 should remain firmly rooted in the principle of technology-inclusiveness and optionality, and explore ways to make diverse options real in the mid-century time frame and after.

1. The SB 100 report should remain rooted in the key principles of technology inclusiveness and optionality

a. *Diversity and optionality increases affordability*

The importance of technology inclusivity and optionality has been emphasized in a wealth of literature in recent years. A recent meta-study of 40 deep grid decarbonization studies concluded that retaining firm zero carbon energy – whether nuclear, fossil with complete carbon capture, or firm renewables such as advanced geothermal – is likely to reduce the cost of decarbonization substantially, as compared with relying on variable renewable sources such as wind, hydroelectric power and solar energy.[1] A typical recent detailed analysis of the role of firm energy in a Northeast and Southern electric system, for

[1] Jenkins, Jesse D., Max Luke, and Samuel Thernstrom. "Getting to Zero-carbon Emissions in the Electric Power Sector." *Joule* 2.12 (2018): 2498-2510. (Link here)

example, found a dramatic cost difference between 100% clean electric systems that harness wind, solar, and firm resources and those that rely solely on wind and sun.[2] (See Figure 1 below)

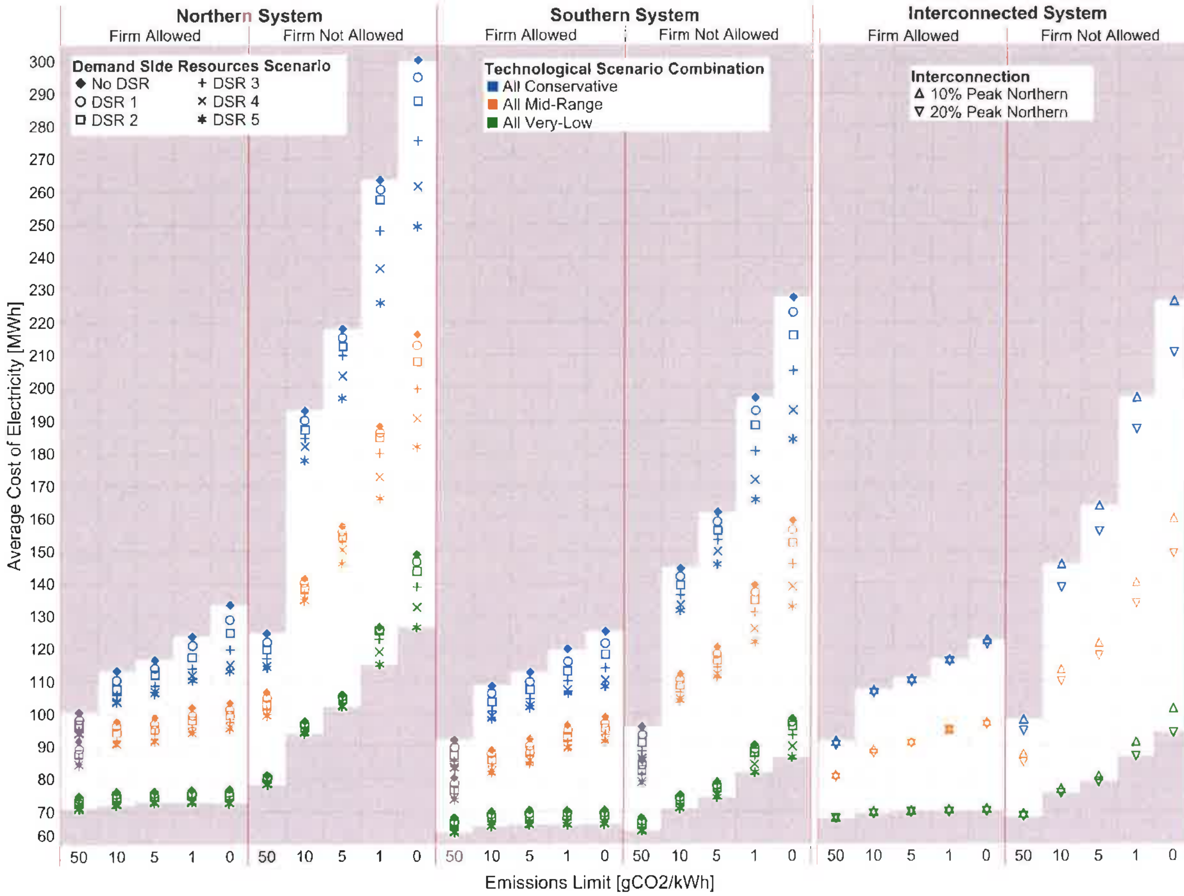


Figure 1: Costs of achieving zero-carbon grids are much higher where firm resources are not allowed and only wind, solar and storage are permitted. Used by permission from Sepulveda, Nestor A., et al. "The role of firm low-carbon electricity resources in deep decarbonization of power generation." *Joule* 2.11 (2018): 2403-2420

Analysis performed by CATF suggests that similar patterns apply to California. The fundamental dynamic driving the need for firm energy in California, as in much of the Northern hemisphere, is ***seasonal variability***. Wind and sun do not just vary on ***daily*** cycles; they vary substantially over ***weekly*** and ***monthly*** periods.

[2] Sepulveda, Nestor A., et al. "The role of firm low-carbon electricity resources in deep decarbonization of power generation." *Joule* 2.11 (2018): 2403-2420. ("Across all cases, the least-cost strategy to decarbonize electricity includes one or more firm low-carbon resources. Without these resources, electricity costs rise rapidly as CO_2 limits approach zero. Batteries and demand flexibility do not substitute for firm resources. Improving the capabilities and spurring adoption of firm low-carbon technologies are key research and policy goals.") (Link here).

This seasonal effect can be seen in California for wind in Figures 2-3 below, illustrating smoothed, daily-average production[3] for onshore wind and solar photovoltaics:

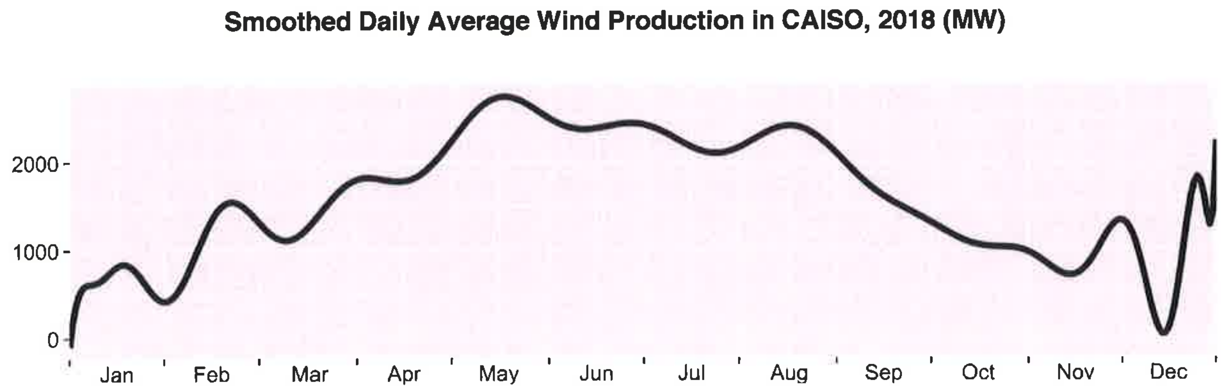


Figure 2

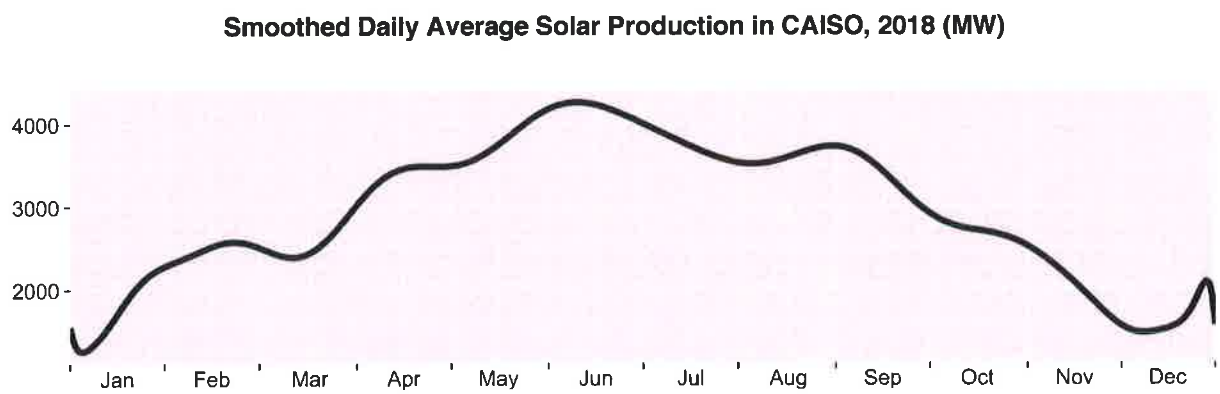


Figure 3

We see a variation in output of 300% or more between seasons.

What happens when we combine wind and solar output to equal 100% of California electric demand on an annual basis, and contrast it to actual demand in each day, week and month? Assuming that we have a 50% wind/50% sun system, we get a pattern like Figure 4 below:

[3] This daily average smoothing conceals more significant variability *within* the day.

Smoothed Daily Load & Renewable Energy Generation, Mixed Renewable Scenario (MW)
Scenario definition: 2018 wind and solar generation scale to each meet 50% of total 2018 CAISO load

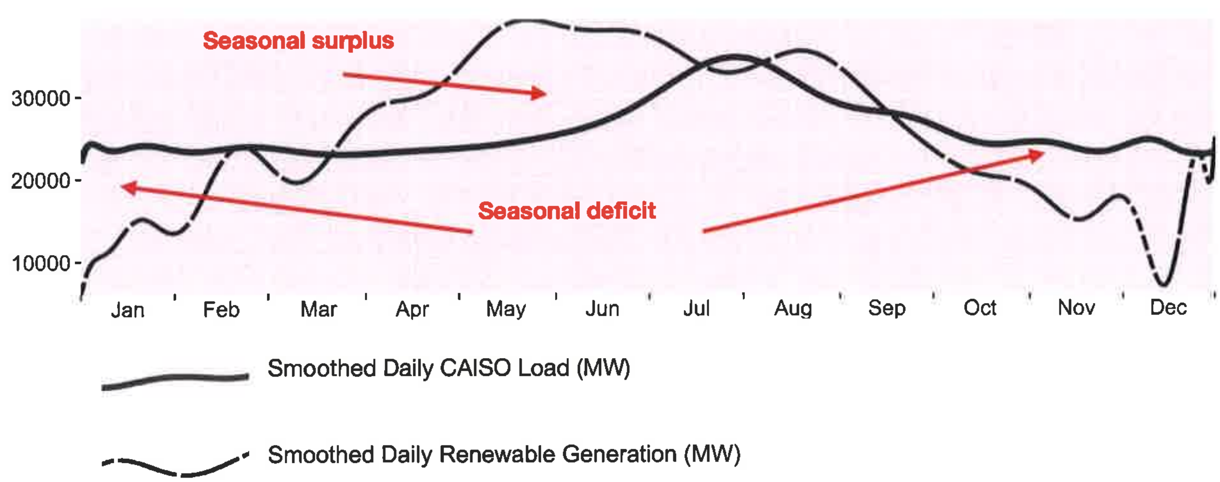


Figure 4

There are multiple weeks of average surplus above demand during the summer months but substantial deficits September through February.

The consequence of this seasonal variation is that, even when California procures enough wind and solar output to meet total electricity demand on an ***annual average*** basis, ***roughly 27% of hours of the year cannot be served by wind and sun.*** This is shown in the "heat map" below, Figure 5, in which yellow, orange and red hours are unserved by variable wind and sun:

Percent of Hourly Load Served, Mixed 100% Wind and Solar Scenario

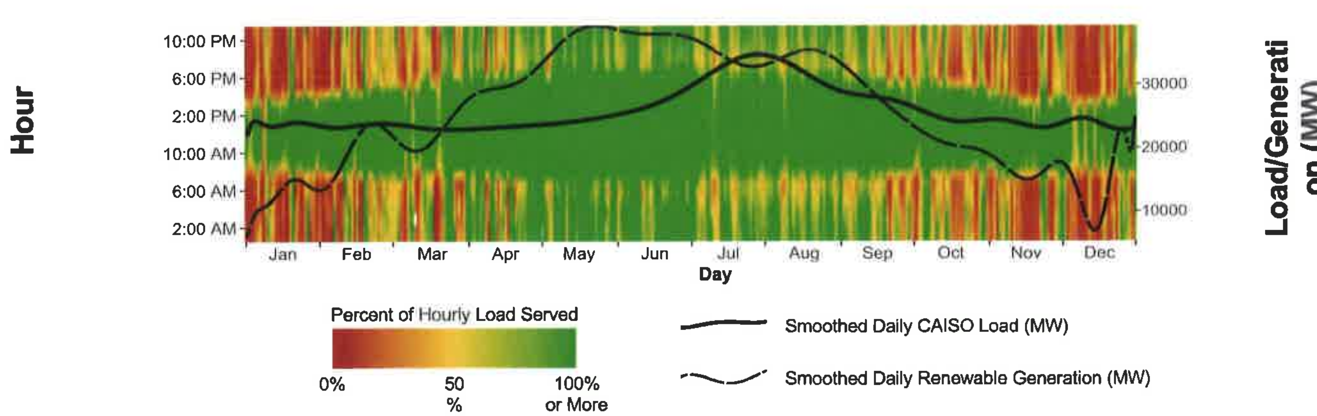


Figure 5

In theory, we could use battery storage to harvest surpluses and use them in deficit periods. But this is where cost comes in. The sheer amount of storage that must be built to capture maximum surplus, and then utilized infrequently, becomes cost prohibitive, even at very low storage costs.

In Figure 6, we see that the accumulated surplus during the year equals 35,946,633 MWh, or roughly 14% of California's annual electric usage. To contain that much energy at peak storage time, you would need a storage system equivalent in instantaneous capacity larger than the generating capacity of the entire US electric grid.

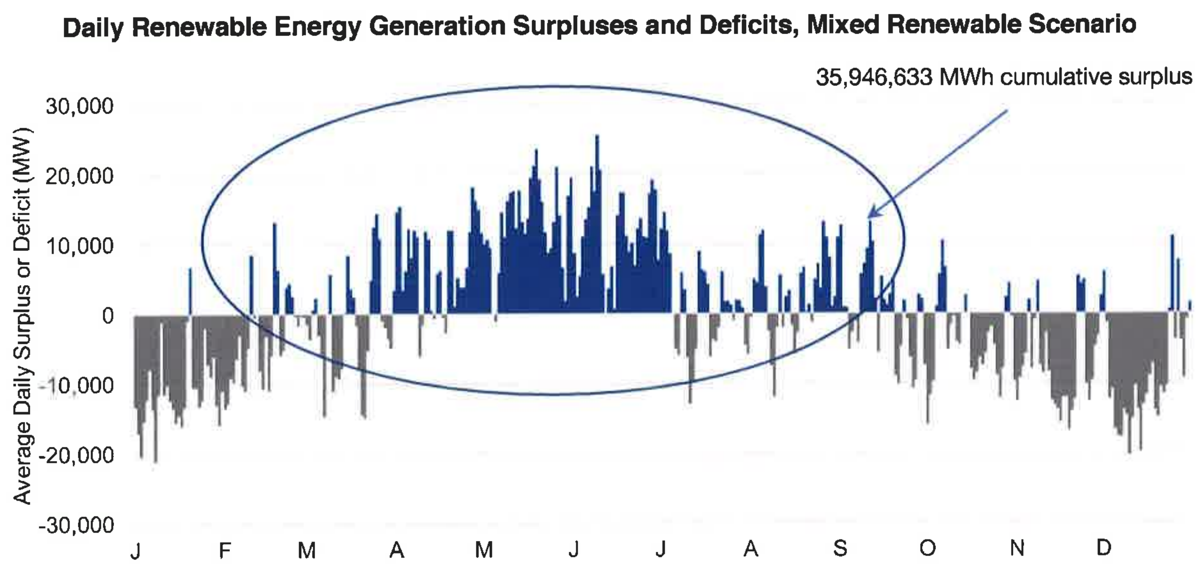


Figure 6: California surplus and deficit patterns under a 100% renewable energy scenario.

That much capacity will incur a very large capital expense. The US Department of Energy estimates the current cost of grid scale energy storage to be just under $500/kwh of capacity.[4] Let us assume we drop that cost by roughly 85% to $80/kwh. The total cost of such a battery storage system would be ***$2.9 trillion,*** or more than California's annual GDP of $2.7 trillion.

But that in some way understates the problem, because this storage capacity would be used at a very low rate – about 1% of capacity in an average year. That is because only a small amount of the storage capacity would be used regularly to balance daily variations in solar and wind output. Most of the storage capacity would need to be built to store peak seasonal surplus and thus only cycle seasonally. That means large capacity divided by little use, resulting in very large per unit costs for stored energy.

[4] US EIA, "U.S. Battery Storage Market Trends "(May 2018)
https://www.eia.gov/analysis/studies/electricity/batterystorage/pdf/battery_storage.pdf

The result, depicted in Figure 7 below, shows that the escalating costs of storage per unit output required, as wind and sun percentages become higher, drive very large system cost increases of roughly sevenfold as wind and sun go from 60% to 80% of energy supply, and roughly twenty four times as wind and sun provide all system energy.

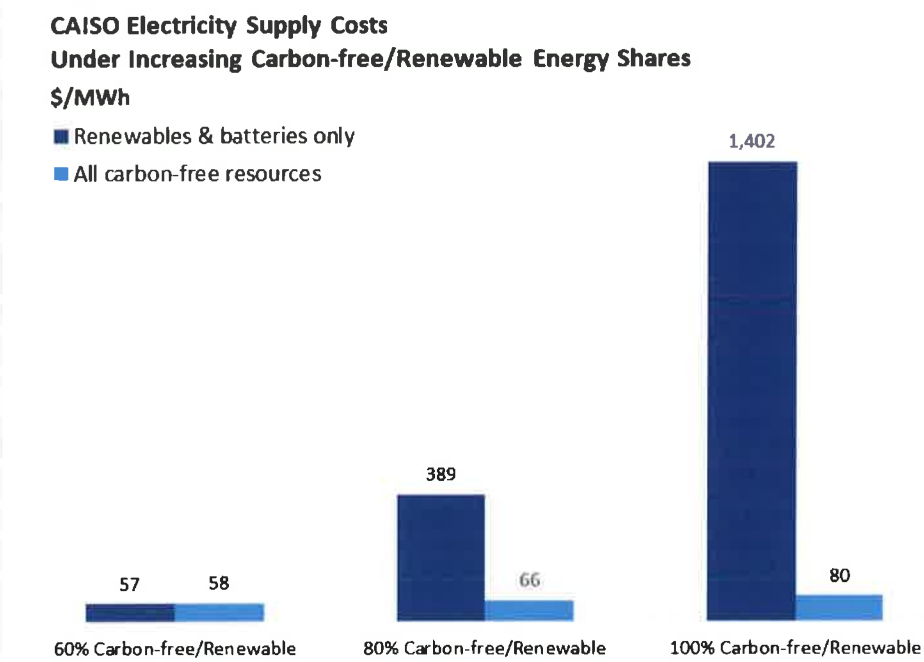
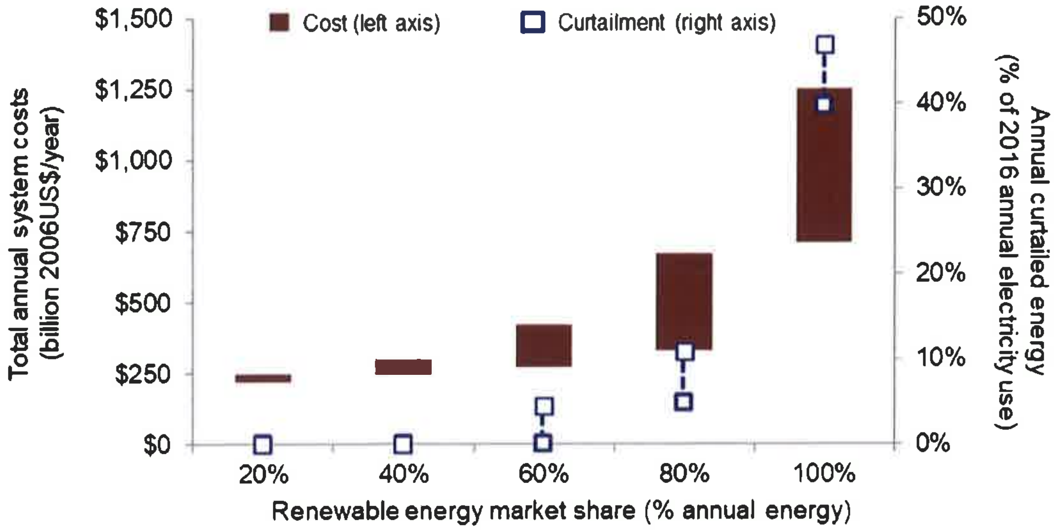


Figure 7. California energy systems costs with increasing shares of wind and solar, versus a mixed system including firm zero-carbon sources. Source: Clean Air Task Force calculated from CAISO data and aggressive assumptions on renewable energy and storage cost reductions.[5]

A similar cost escalation pattern has been seen in national studies, such as a recent one conducted by National Renewable Energy Laboratory analyst Bethany Frew, which also assumed a transcontinental electric grid and optimal demand response mechanisms (see Figure 8 below).

[5] The analysis assumes very aggressive further cost reductions in wind and solar energy compared to current projections by the US Energy Information Administration. Specifically, the analysis assumes that wind costs drop from $1,624 per kw to $1,000/kw and that solar PV drops from $1,969/kw to $700/kw.



Jenkins et al., Getting to Zero Carbon Emissions in the Electric Power Sector, Joule (2018), https://doi.org/ 10.1016/j.joule.2018.11.013, adapted from Frew, Bethany A., Jacobson, M. et al. "Flexibility mechanisms and pathways to a highly renewable US electricity future." *Energy* 101 (2016): 65-78.

Figure 8: Costs of supplying power in a national study of increasing shares of wind and solar. (Source: see Figure description above).

It has been suggested that these kinds of high cost tails can be avoided by building substantially more wind and solar to meet California's peak demand, and then curtailing wind and solar in times of surplus – thus minimizing the need for storage. However, this does not solve the problem, as Figures 7 and 8 show. In CATF's analysis (Figure 7), very little storage is used at the 80% carbon free grid mark and additional amounts are added only as needed in the movement towards 100% carbon free – yet the cost curve is well on its upward trend. And in Figure 8, one can see that an optimized mix of curtailment and storage still yields a system with substantial curtailment that provides 70-80% of energy from wind and sun rather than 100%, which still incurs steep costs.

None of this analysis is to gainsay a substantial role – likely greater than the statutory SB 100 minimum of 60%, which itself is three times today's share – for renewables such as wind and solar energy in cost-effectively achieving the electric system decarbonization challenge. And it is always possible that technological breakthroughs could occur that would make it possible to increase the percentage of economically affordable wind and solar to much higher levels.[6] But such breakthroughs may not occur. Supporting policies to bring other zero-carbon options to market will provide greater certainty of success.

b. Diversity and optionality increases the chance of success in low carbon build-out

Apart from cost, there may be serious issues associated with siting necessary zero carbon infrastructure of any kind. While public concerns over siting nuclear energy plants are historically well-known, and the siting of new gas-fired power plants with carbon capture is not likely to be without controversy, it is also true that very large buildouts of a wind- and solar-dominated system and associated transmission may also face obstacles.

For example, Figure 9 below depicts the amount of zero-carbon energy that would need to be added each year to the California grid to meet the state's mid-century zero-carbon target, compared to various historical addition rates. To achieve these targets on wind and solar alone would require California to deploy those sources at five times the best historic rate, every year for the next 25 years – the equivalent of nearly ten of the world's largest onshore or offshore windfarms ***every year***. In nuclear terms, this would amount to construction of more than one Diablo Canyon size plant (2256 MW) every year. Figure 10 shows similar national figures for various technologies.

[6] It is sometimes argued that "demand response," that is, the ability to curtail customer load, will alleviate the surplus and deficit problems outlined in this testimony. While this resource can be valuable, it is a question of scale and duration. Today, the California grid operator reports that the system has in place 350 MW of maximum load reduction/demand response — representing less than 1% of peak demand. See California ISO, 2018 Annual Report on Market Issues and Performance, http://www.caiso.com/Documents/2018AnnualReportonMarketIssuesandPerformance.pdf, pp. 29, 42. These agreements are generally understood to require interruptions for a few hours a few times a year. By contrast, as Figure 5 demonstrates, 100% wind and solar scenarios produce power deficits equal to as much as 75% of demand ***over many weeks***. It is not likely that California businesses, industries and consumers would effectively agree to multi-week and seasonal curtailment of demand, or that this would be good for the California economy if they did.

It also may be argued that interconnection of California to other control areas will alleviate the surplus and deficit problem. While greater interconnections can help at the margins, we must assume that other regions will be pursuing similar levels of decarbonization and are likely to adopt similar levels of variable energy. And wind and solar tends to be highly correlated on a daily and weekly across the nation. As a result, even with seamless national interconnection, as is assumed in the study referenced in Figure 8, substantial surplus and deficit problems are experienced at very high levels of wind and solar, with the resulting cost impacts shown in the figure.

Illustrative zero-carbon energy deployment to achieve California grid decarbonization target (TWh)

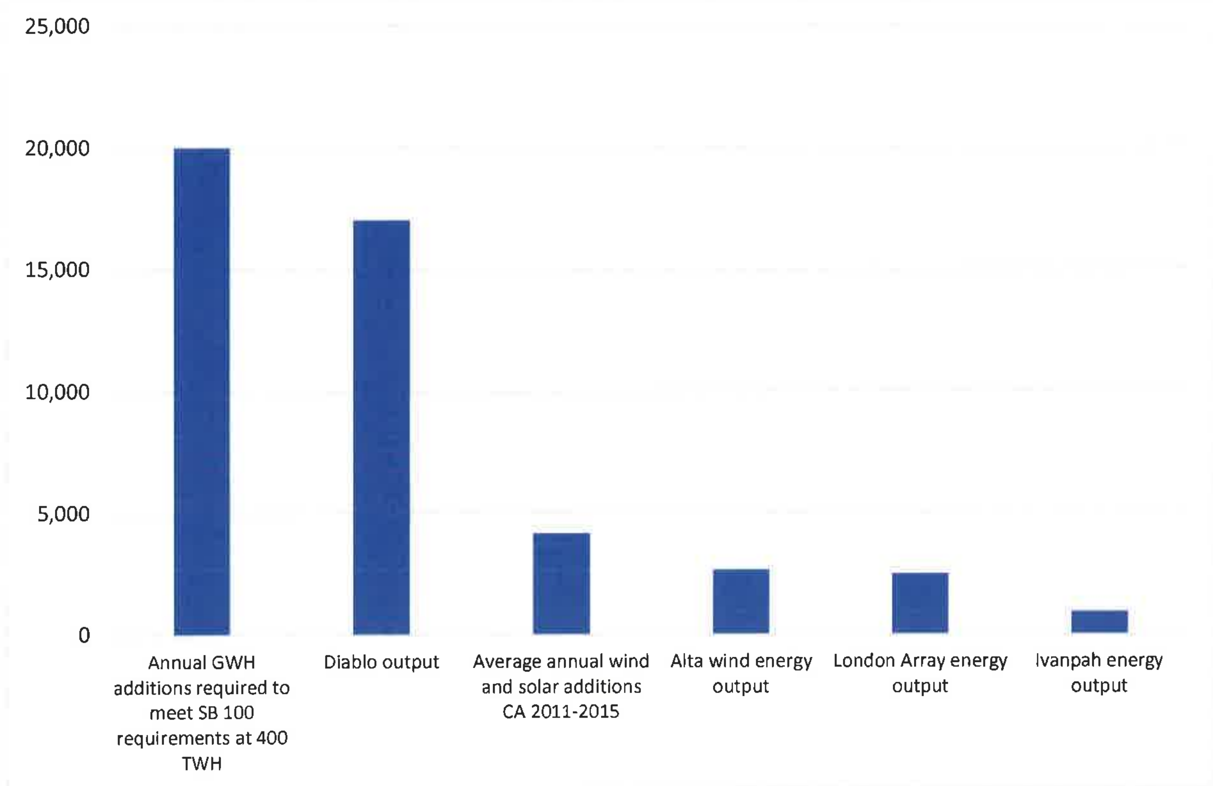


Figure 9: Annual zero-carbon energy deployment rates required to meet California's 2045 zero-carbon grid requirement starting in 2020, assuming increased electrification. It is assumed that all current zero-carbon energy infrastructure would need to be replaced by midcentury. (Source: Clean Air Task Force calculated with historical data from published reports of the California Energy Commission, California PUC)

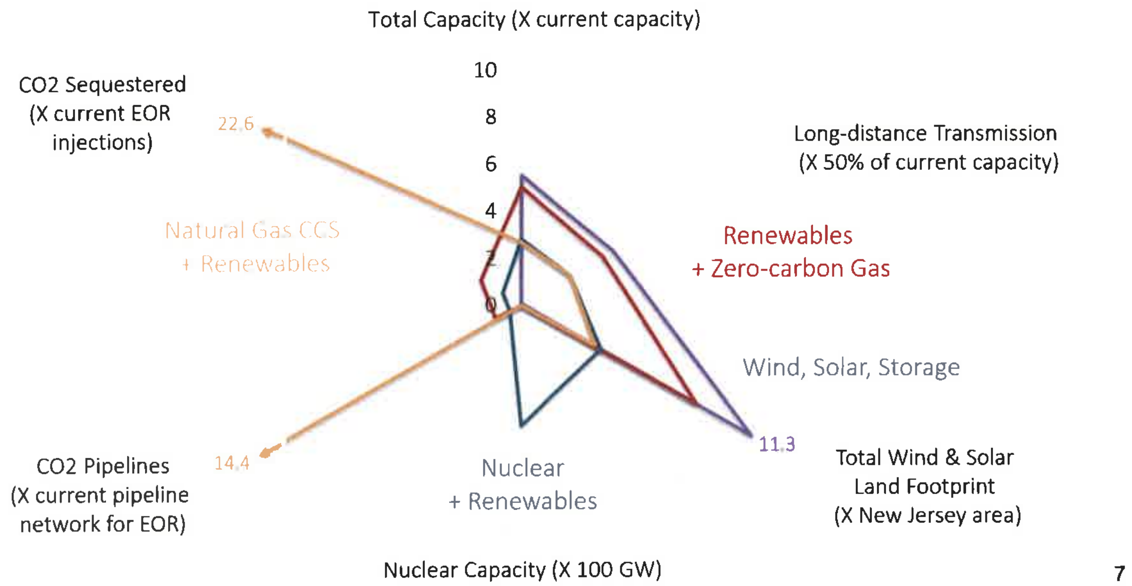


Figure 10: National buildout required for 100% carbon-free electricity, by technology. Source: J. Jenkins, *Critical bottlenecks in decarbonization of the U.S. electricity grid*, Jesse D. Jenkins, PhD, Princeton Rapid Switch Workshop (June 12, 2019), used by permission of author

By any measure, this is blistering and unprecedented pace of energy system buildout. It would be challenging enough to imagine achieving this with all of the available options. The difficulty increases as options are increasingly taken off the table.

The sheer engineering feat required is complicated further by public acceptance issues. Around the nation, and even, or especially, in more environmentally oriented states such as California, there have been substantial battles and delays over siting renewable energy infrastructure and associated transmission.[7] Additional transmission needed to knit together diverse wind, sun and hydro resources are especially dramatic as renewable energy shares increase – requiring as much as a twenty-fold increase in US transmission capacity and interties for very high renewable energy scenarios, according to the National Renewable Energy Laboratory (see Figure 11 below). Just one such transmission line, in New England, has recently consumed roughly a decade of environmental debate, and is still not resolved.[8]

[7] See P. Field, et al, Resolving Land Use and Energy Conflicts (2018); https://www.cbsnews.com/news/new-york-wind-turbines-face-uphill-battle/ ; and https://friendsofmainesmountains.org/?category=Anti-Wind+Groups

[8] https://www.bostonglobe.com/metro/2018/11/22/plans-bring-hydropower-from-canada-cornerstone-state-energy-policy-faces-mounting-obstacles/3j6iBavrm4Libx8QdpX67M/story.html

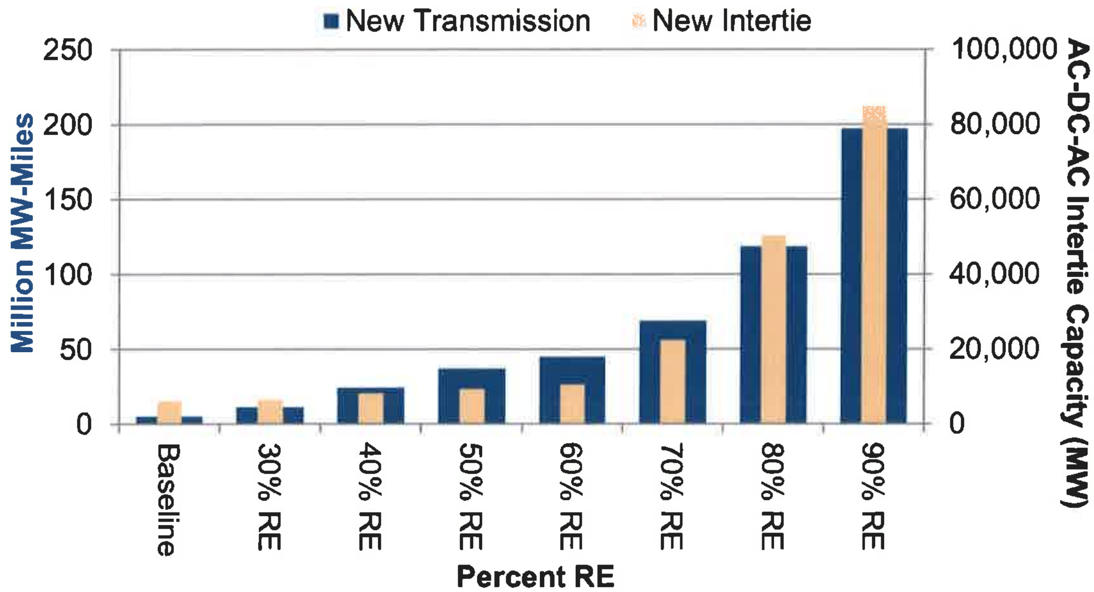


Figure 11: Transmission required for various levels of renewable energy deployment. Source: National Renewable Energy Laboratory, "Renewable Electricity Futures Study," Executive Summary, p. 26.

c. Conclusion: Allow and Support Developing Firm Zero-carbon Electricity Options

A diverse approach provides resiliency to the strategy by proving optionality in case insurmountable hurdles are faced in one pathway. As we have discussed, in addition to cost issues, a large build-out of wind and solar energy capacity, along with the substantial increase in transmission capacity that would be necessary to serve a wind- and sun-dominated system, may well face substantial and well organized opposition which has already emerged around relatively small scale proposals. At present, California law forbids construction of new in-state plants because there exists no federal waste repository. The use of natural gas with carbon capture and careful methane emissions management, although based on well-demonstrated technologies, will likely face challenges from those opposed to the use of any fossil fuels for reasons including local health and environmental effects. The more options we have, the greater will be our chance of success. The joint agency report should explore the opportunity for incentives and other policies to bring additional zero-carbon options to market.

2. <u>The joint agency report should consider potential synergies between technology optionality and innovation in the power sector and the need to decarbonize the non-electric parts of the California energy economy</u>

Executive order B-44-18 commits California to total, economy-wide carbon neutrality by 2045. But electricity represents only 16% of the state greenhouse gas emissions.

Where we cannot replace emitting energy sources with carbon-free electricity, four additional and overlapping energy pathways could be critical and should be addressed in comprehensive climate legislation or enacted as complementary policies:

- Zero-carbon liquid or gaseous fuels that can be used for transport, high temperature industrial heat, and building heat (and to create firm, non-weather-dependent electricity)
- Direct sources of zero-carbon high temperature heat such as supercritical geothermal energy and high temperature nuclear energy
- Industrial processes that do not inherently produce carbon emissions
- Direct carbon capture for otherwise unavoidable industrial carbon emissions

I was honored last year to be part of a group of authors who published an article in *Science* entitled "Net-zero emissions energy systems." [9] The key insight of that article is that it is best to think of a net-zero greenhouse gas emissions energy economy as a ***system*** of complementary and overlapping parts. These parts include zero-carbon electricity, fuels, storage, low-carbon industrial processes, and carbon capture and sequestration from fossil fuel use. A greatly simplified schematic picture of such a system can be seen in Figure 12 below.

Note that there are a variety of interconnections and complementarities between these pathways and potential pathways for carbon-free power sector. For example, zero-carbon liquid or gaseous fuels can be made (a) via electrolysis of water which requires zero-carbon electricity, but also by (b) stripping carbon from responsibly-sourced natural gas through steam reforming and carbon capture and (c) direct chemical conversions using nuclear energy.[10] Likewise, carbon capture is not only useful for directly capturing power and industrial emissions, but also for decarbonizing industrial heat or producing carbon-free hydrogen from natural gas. And zero-carbon fuels, as well as nuclear and carbon capture, as discussed below, can be important enablers of a zero-carbon electric grid in complement to wind, solar and energy storage.

These potential complementarities should be taken into account in the joint agency report.

[9] Davis, Steven J., et al. "Net-zero emissions energy systems." *Science* 360.6396 (2018): eaas9793.

[10] See Clean Air Task Force, "Fuel Without Carbon" (2018), https://www.catf.us/wp-content/uploads/2018/12/Fuels_Without_Carbon.pdf

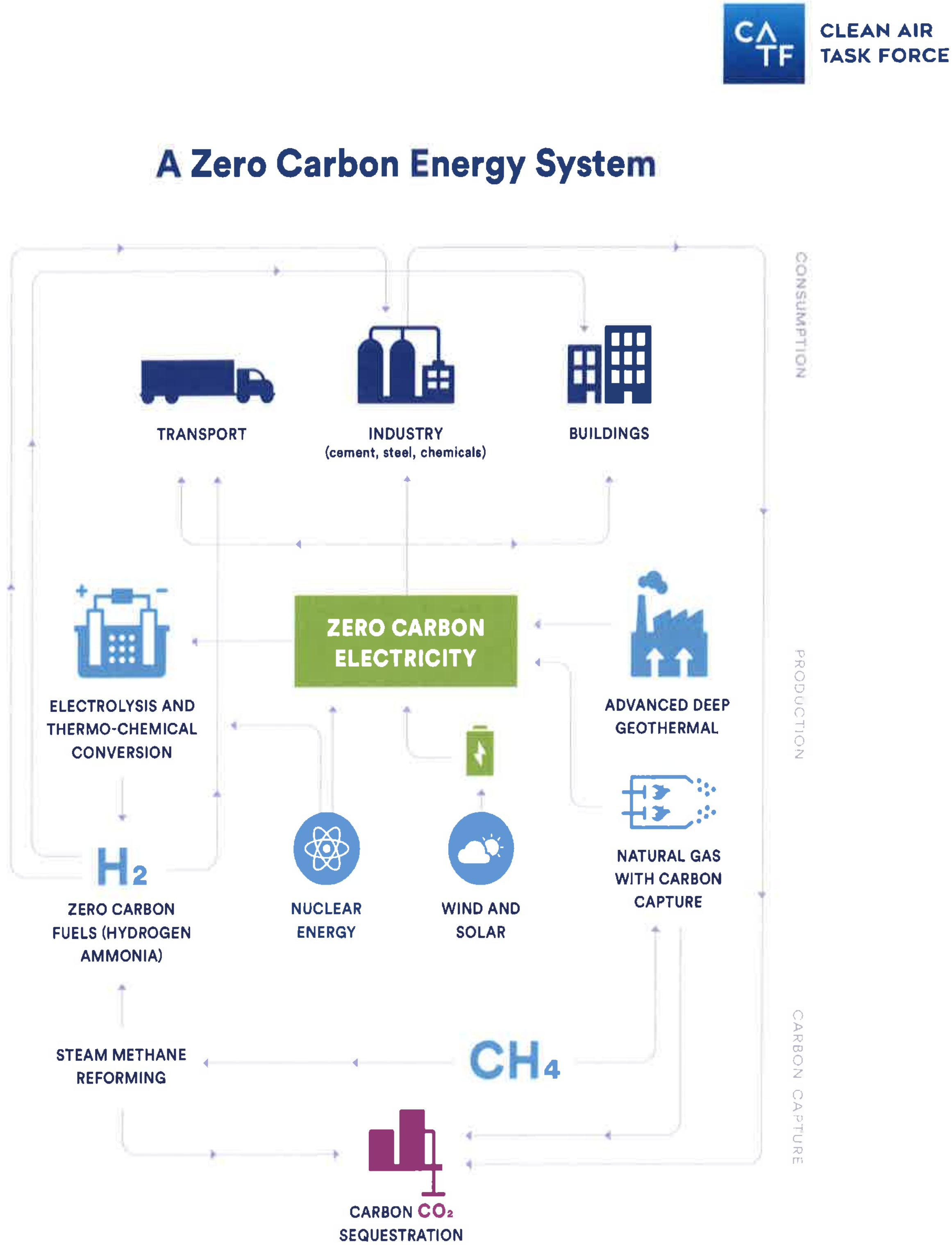


Figure 12: Schematic of a zero-carbon energy system (Source: Clean Air Task Force, 2019)

3. <u>The joint agency report should explore specific state policies to enhance optionality and technology diversity for the zero carbon grid</u>

California has historically been a world leader in bringing forward low-emission vehicle and power technologies to market through mandates and incentives. Most recently, the CPUC's storage procurement mandate has helped stimulate the national market for energy storage. Similar "market pull" policies should be considered in the joint agency report for zero carbon power technologies, particularly those that have potential application to other energy sectors.

Potential technology candidates for incentives, grants and mandates include:

- Long duration electrical energy storage
- Renewable energy resources physically coupled to long duration storage
- Natural gas generating facilities equipped with carbon capture and sequestration
- Thermal generating units fueled entirely by zero carbon fuels such as hydrogen and ammonia
- Dedicated non-generating facilities that produce zero carbon fuels such as hydrogen and ammonia for use in electric generation facilities
- Advanced dispatchable renewable energy technologies such as deep hot rock geothermal energy
- Nuclear fission or fusion technologies, whether located in or outside of the state, consistent with other laws of the state

Another, more generic approach that could be considered is a requirement for load-serving entities to test the market for zero carbon "firm" energy in specific tranches without specifying technology type. At a minimum, such a solicitation or request for proposals would reveal the range of technologies and price points the private sector is able to offer.

4. Conclusion

CATF once again appreciates the opportunity to file these comments, and stands ready to assist the agencies by providing further information on the ideas contained in this letter. Our local California contact point is Deepika Nagabhushan at 1 (847) 505-4149 or dnagabhushan@catf.us.

Respectfully submitted,

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Boston, MA 02109
armond@catf.us
Mobile: 617.680.0341

DOCKETED	
Docket Number:	18-IEPR-09
Project Title:	Decarbonizing Buildings
TN #:	223817
Document Title:	Building Decarbonization
Description:	Presentation by Martha Brook at the June 14, 2018 IEPR Workshop on Achieving Zero Emission Buildings
Filer:	Stephanie Bailey
Organization:	California Energy Commission
Submitter Role:	Commission Staff
Submission Date:	6/14/2018 1:01:29 PM
Docketed Date:	6/14/2018

CALIFORNIA ENERGY COMMISSION

Building Decarbonization

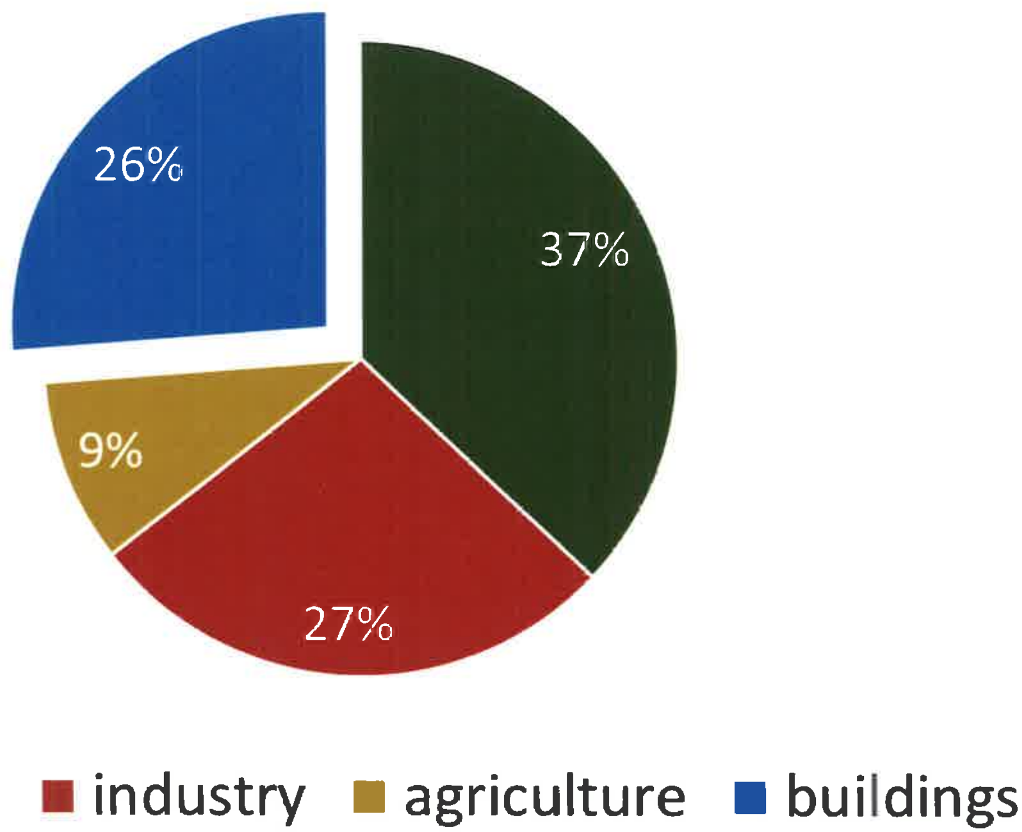
2018 Update
Integrated Energy Policy Report

June 14, 2018

Martha Brook
Advisor to Commissioner McAllister

CALIFORNIA ENERGY COMMISSION

CA GHG Emissions



Fossil Fuels & Buildings

- Direct emissions from fossil fuels used in CA buildings for space and water heating ~ 10% CA GHG emissions (33 MMTCO2e in 2016)
- Fossil fuels produce NOx, CO and other hazardous pollutants
- 93% of Californians live in ozone non-attainment areas

CALIFORNIA ENERGY COMMISSION

Pacific Coast Collaborative

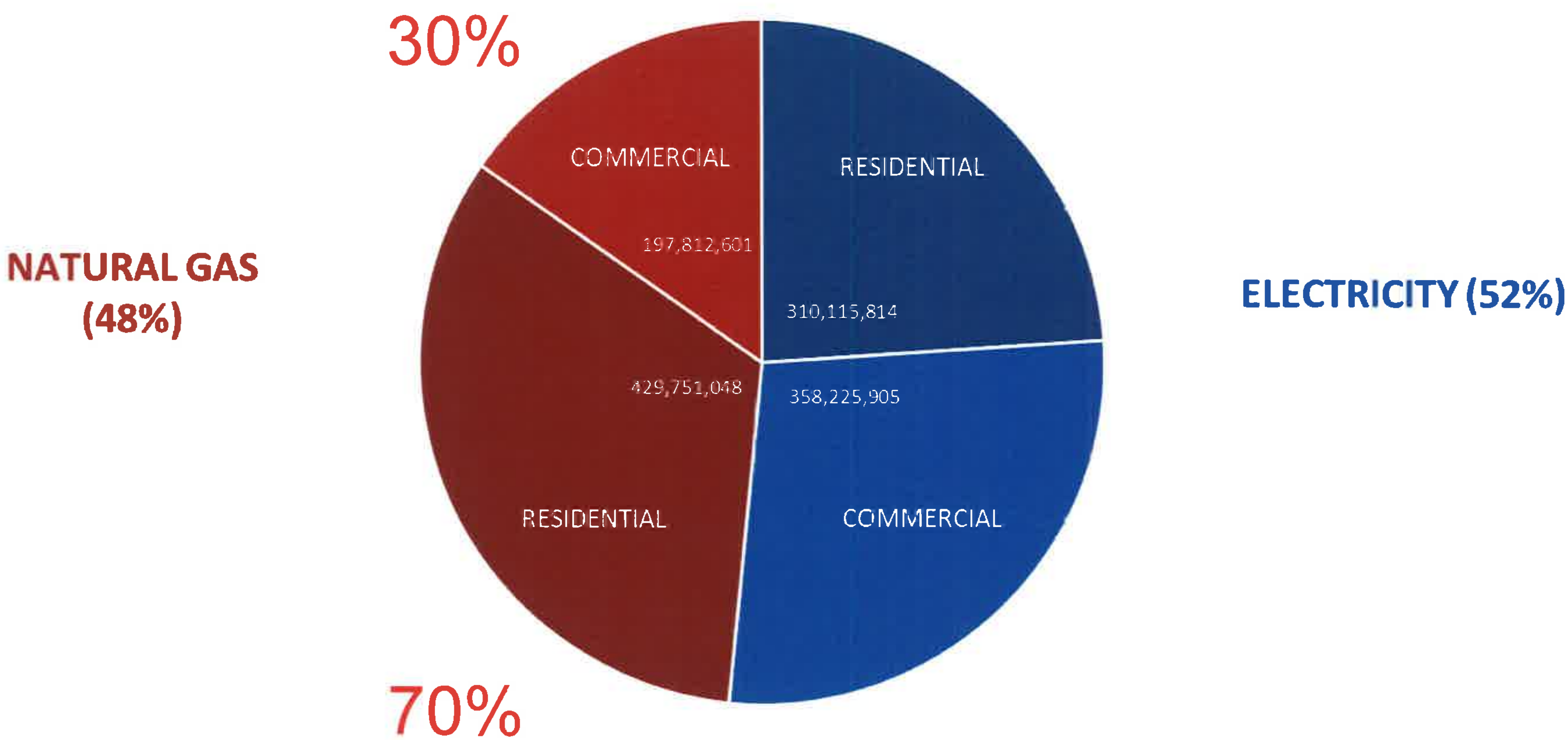
- North America's Pacific Coast represents the world's fifth largest economy, with 55 M people & combined $3 T GDP
  - British Columbia, Washington, Oregon, California
  - Vancouver, Seattle, Portland, San Francisco, Oakland, Los Angeles
- In 2016, the PCC committed to lower the carbon intensity of heating fuels in residential and commercial buildings, aka THERMAL DECARBONIZATION

Pacific Coast Collaborative
Thermal Decarbonization

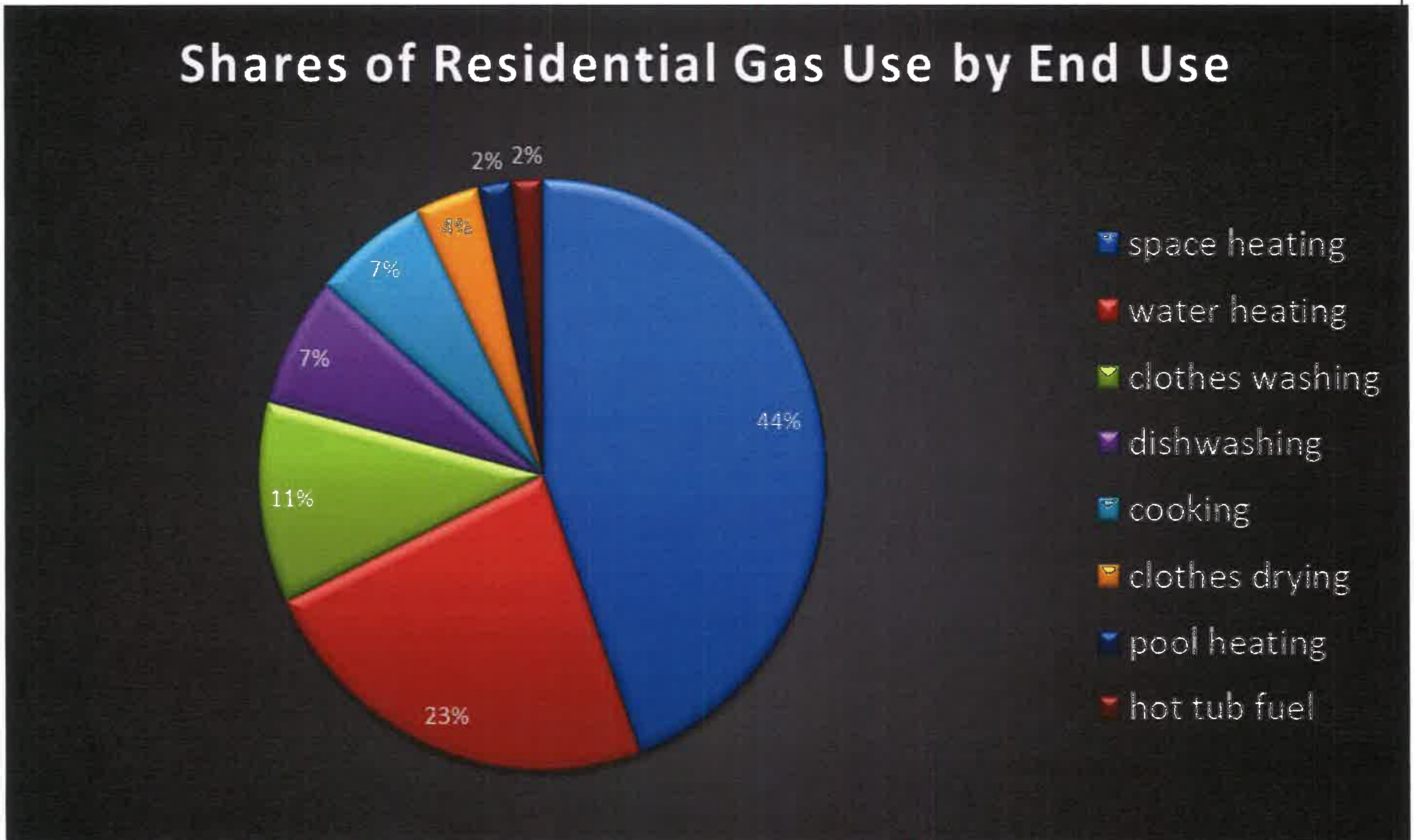
PATHWAYS:

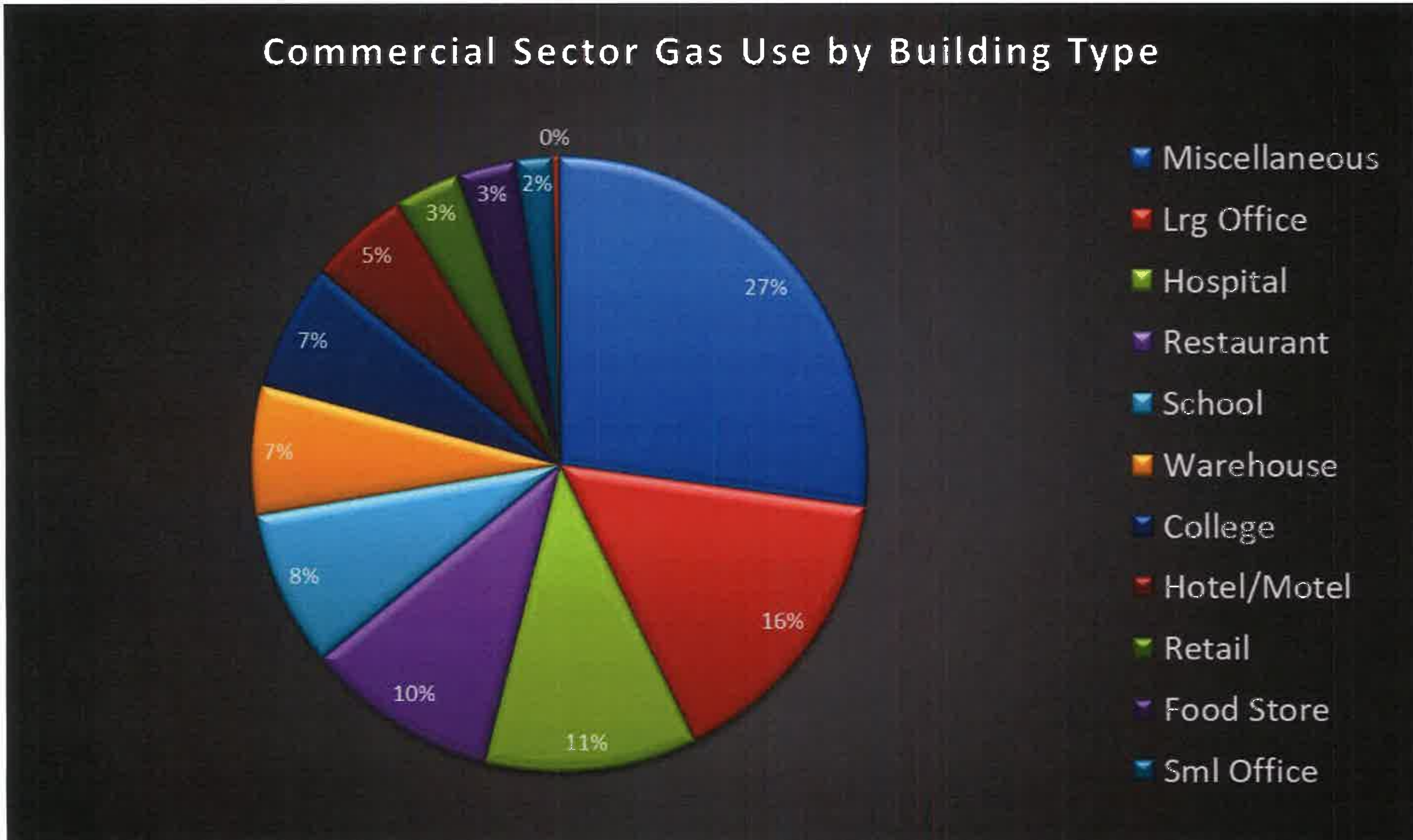
- Electrification
- Renewable Natural Gas
- Energy Efficiency

2016 Energy Use in California Buildings (MMBtu)



CALIFORNIA ENERGY COMMISSION




Commercial Sector Gas Use by Building Type
0%
2%
3%
3%
5%
7%
7%
8%
10%
11%
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27%
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Lrg Office
Hospital
Restaurant
School
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College
Hotel/Motel
Retail
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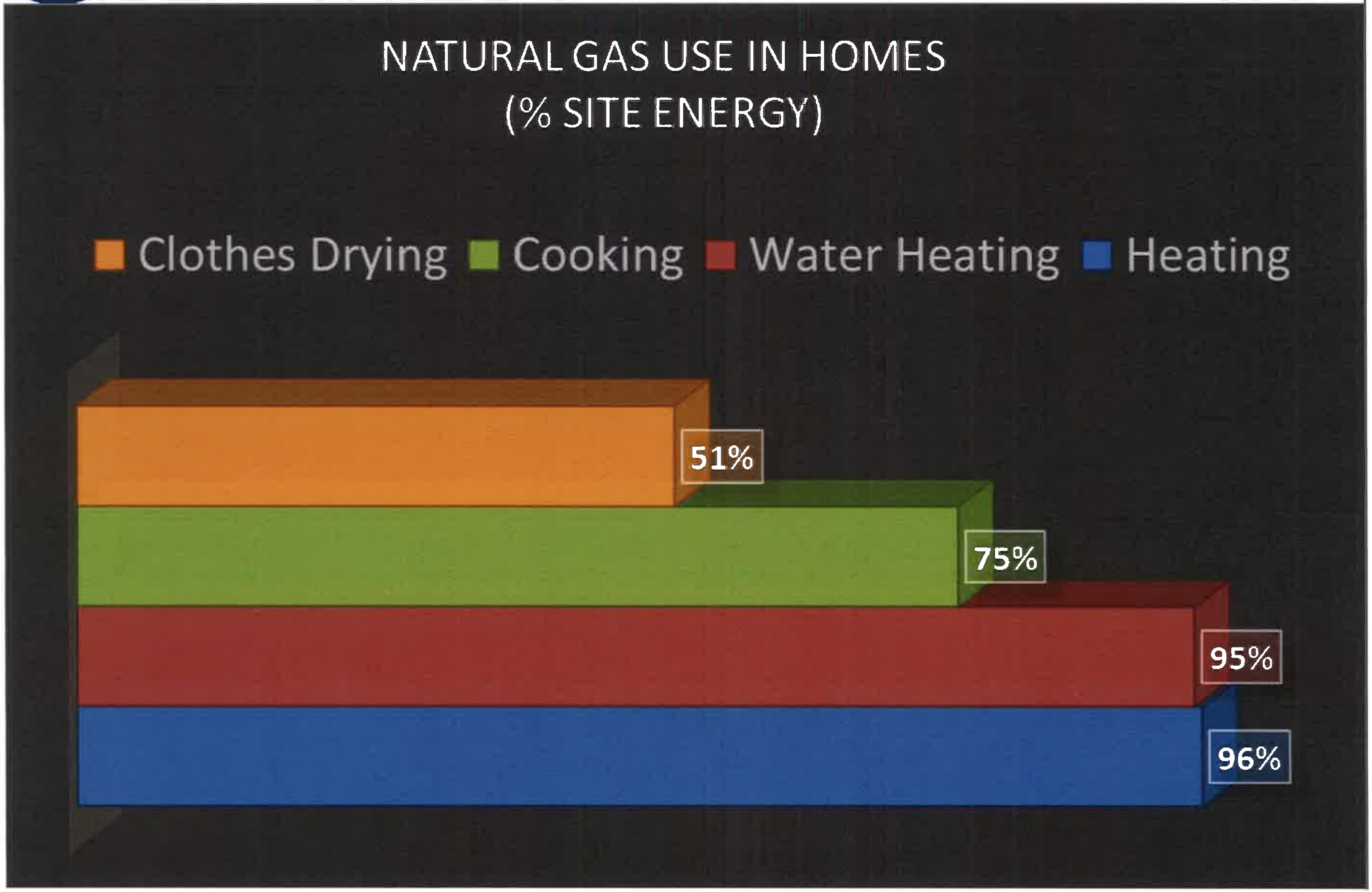
NATURAL GAS USE IN HOMES
(% SITE ENERGY)
Clothes Drying
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Water Heating
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51%
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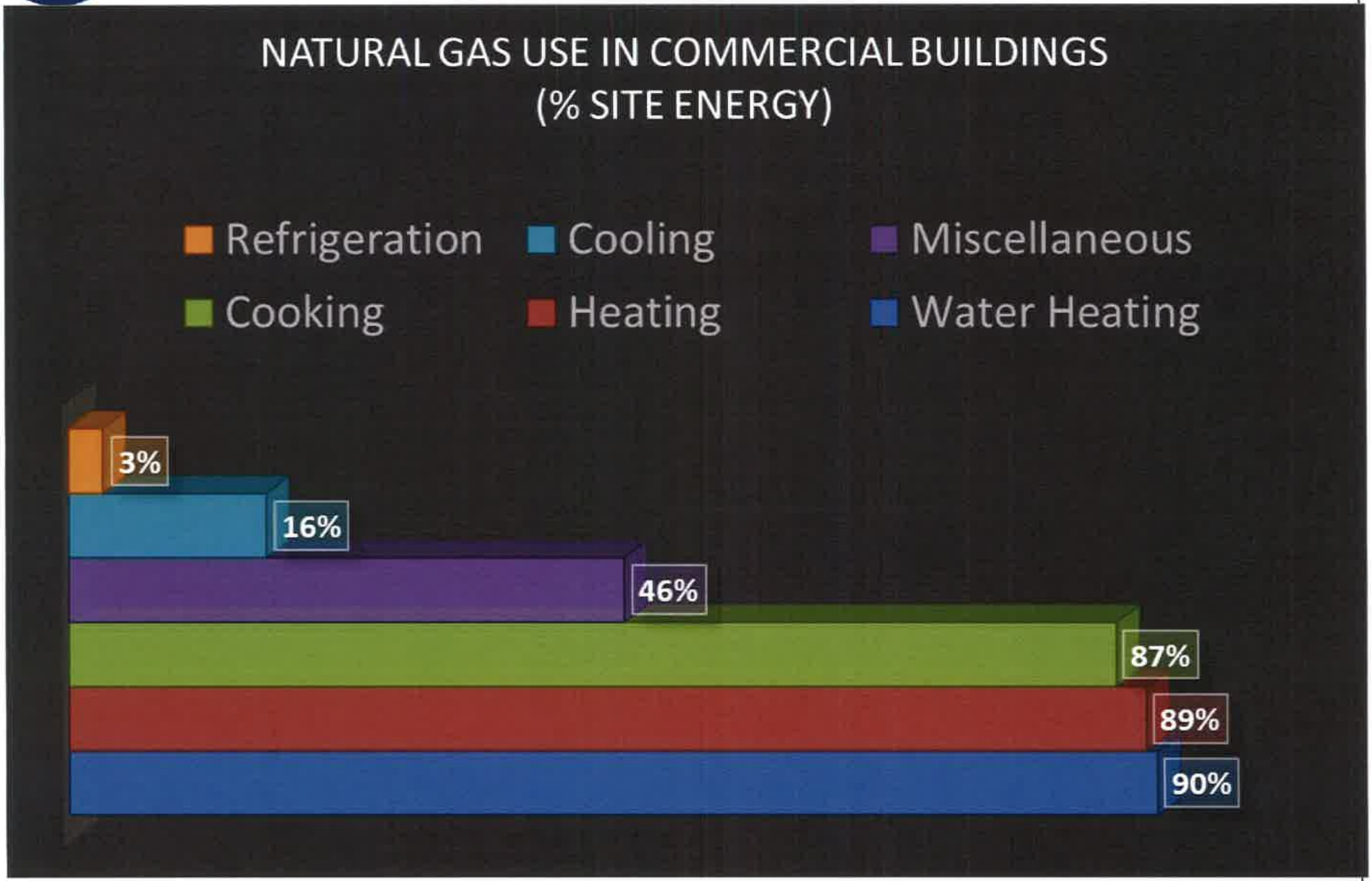
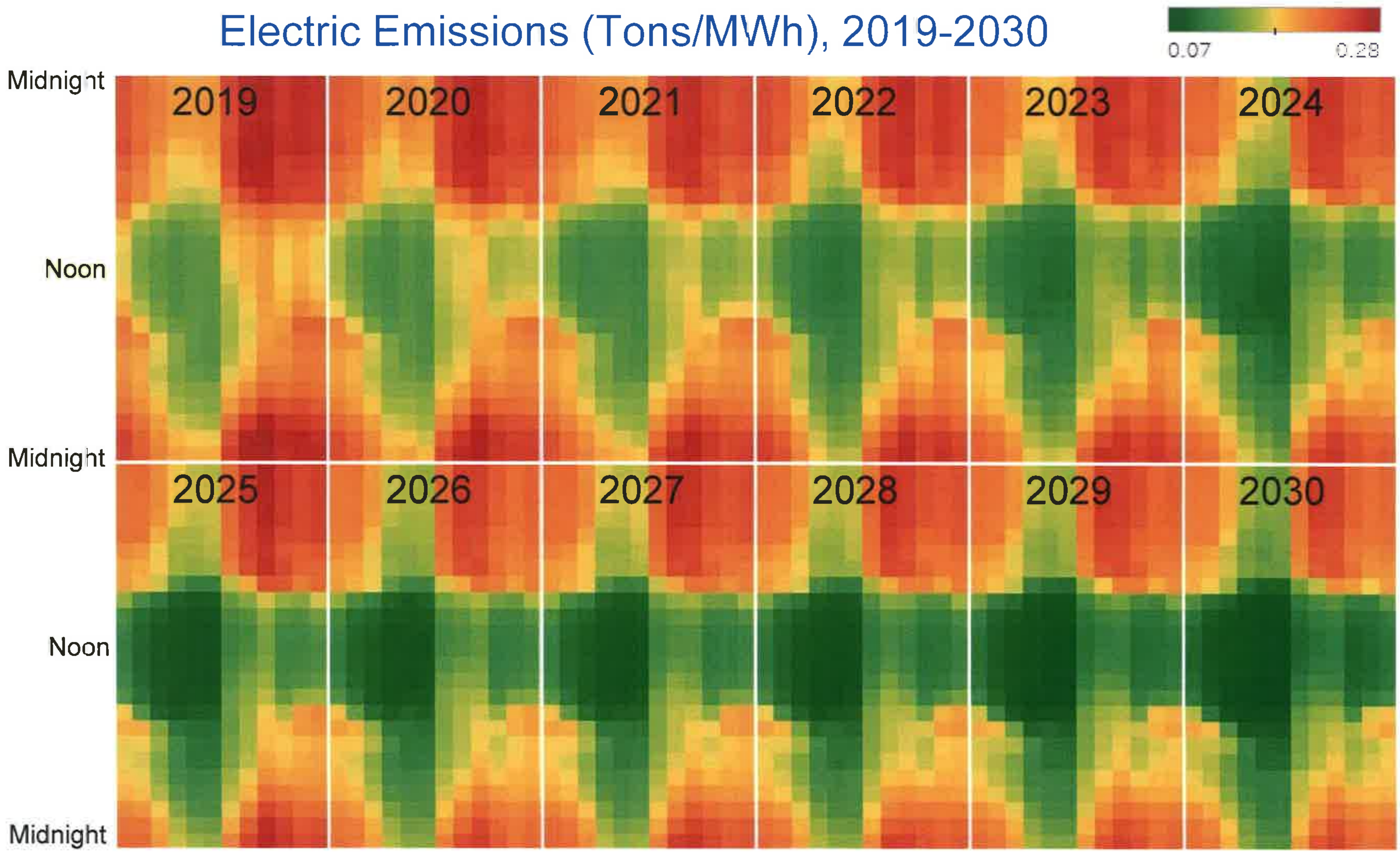
CALIFORNIA ENERGY COMMISSION



CALIFORNIA ENERGY COMMISSION

Electricity CO_2 Intensity



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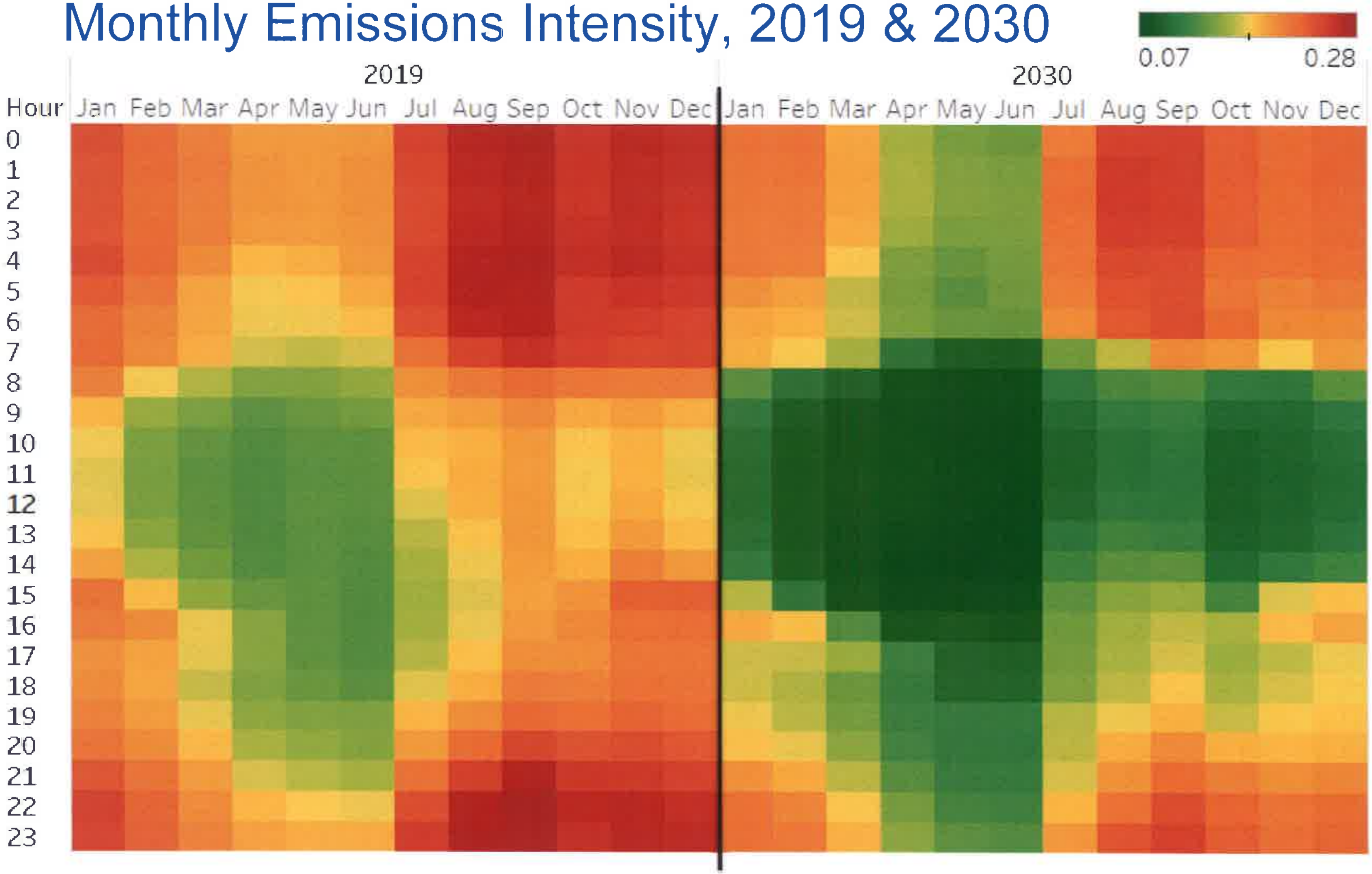
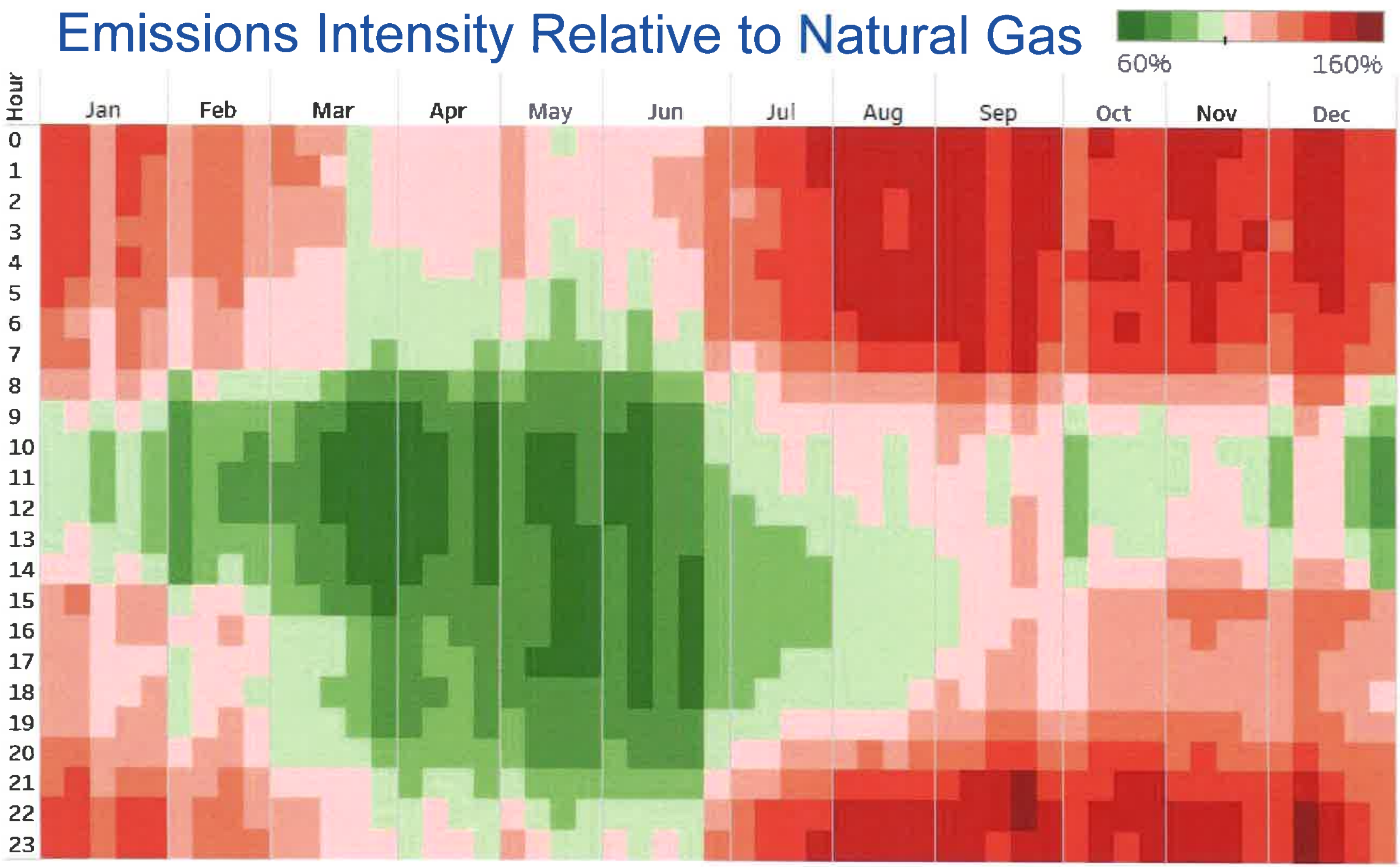
Electricity CO_2 Intensity

Monthly Emissions Intensity, 2019 & 2030

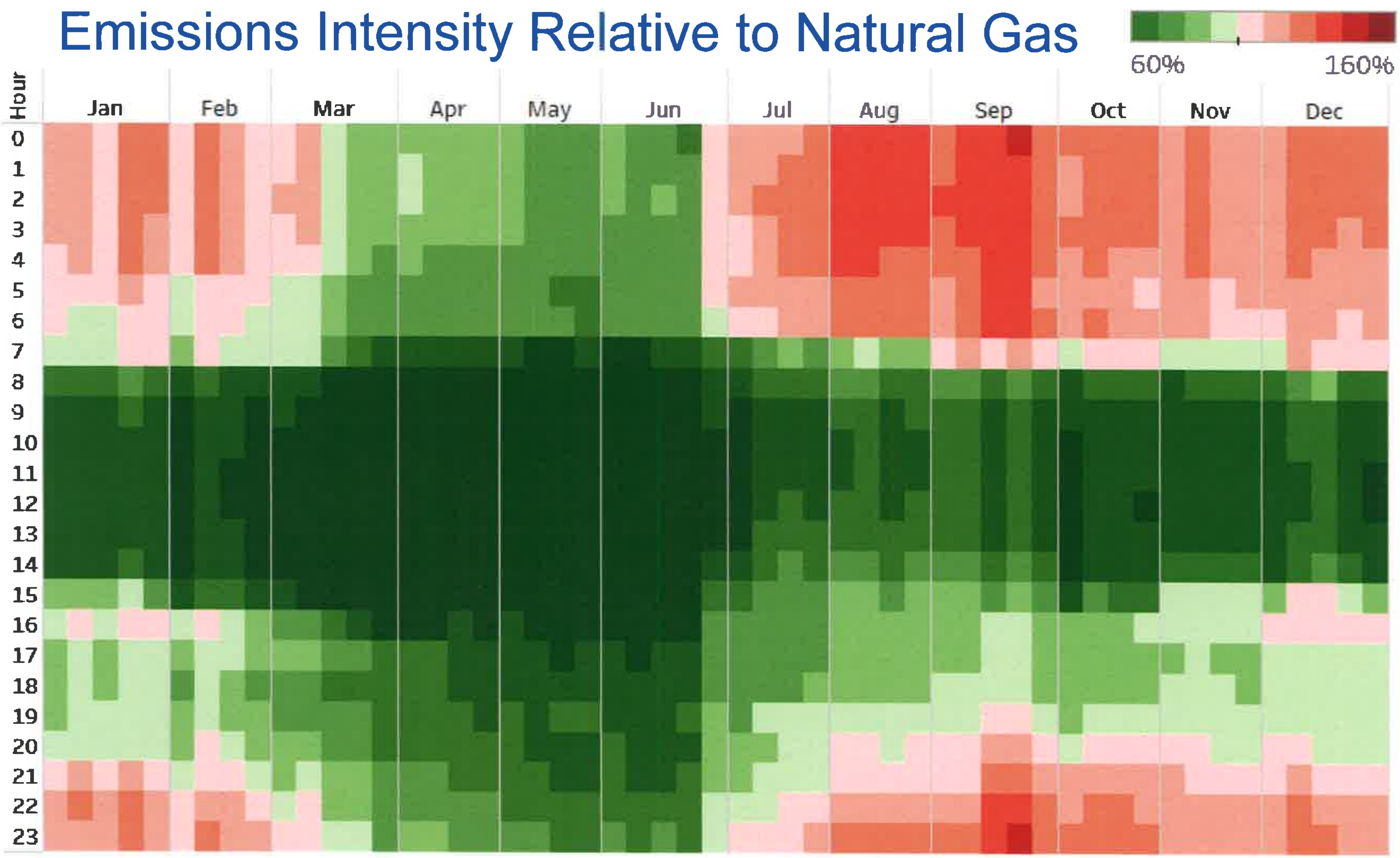


Buildings Perspective: 2019



CALIFORNIA ENERGY COMMISSION

Buildings Perspective: 2030



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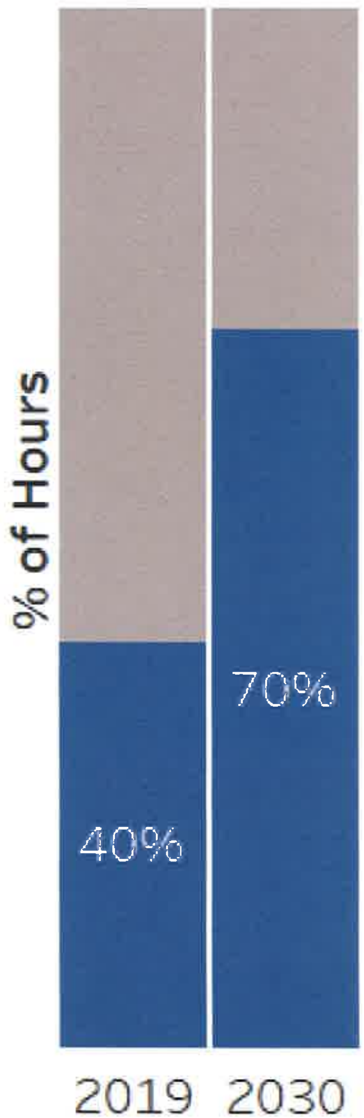
Buildings Perspective



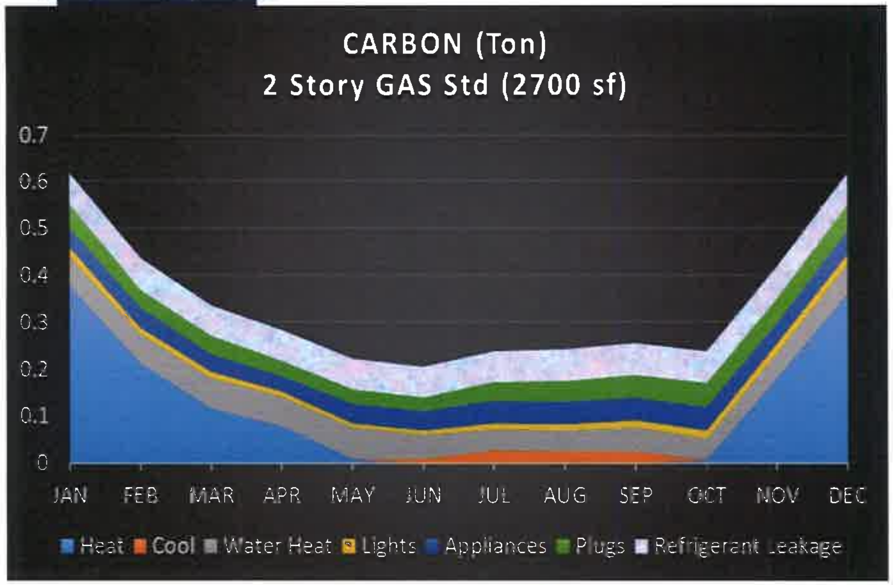
Electricity will be cleaner than natural gas 70% of the time by 2030

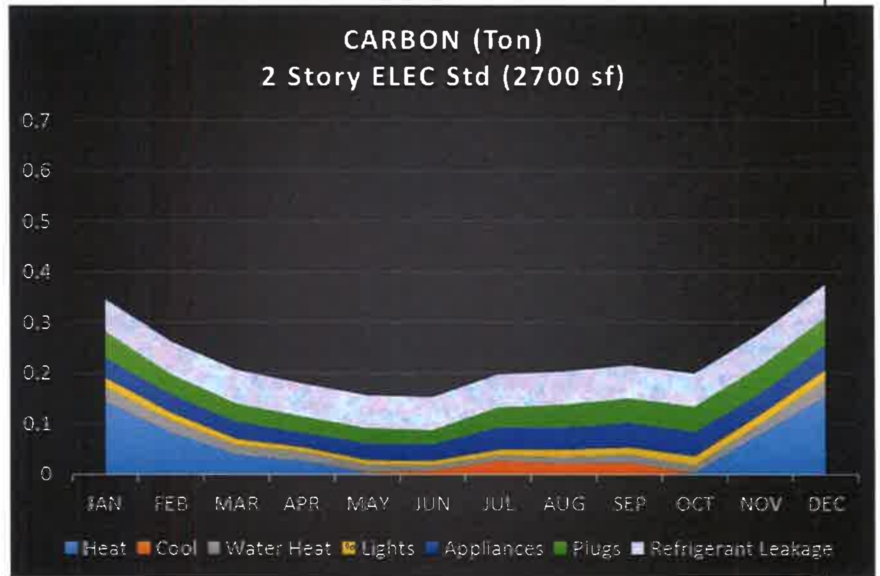
– Increase from 40% in 2019

CALIFORNIA ENERGY COMMISSION

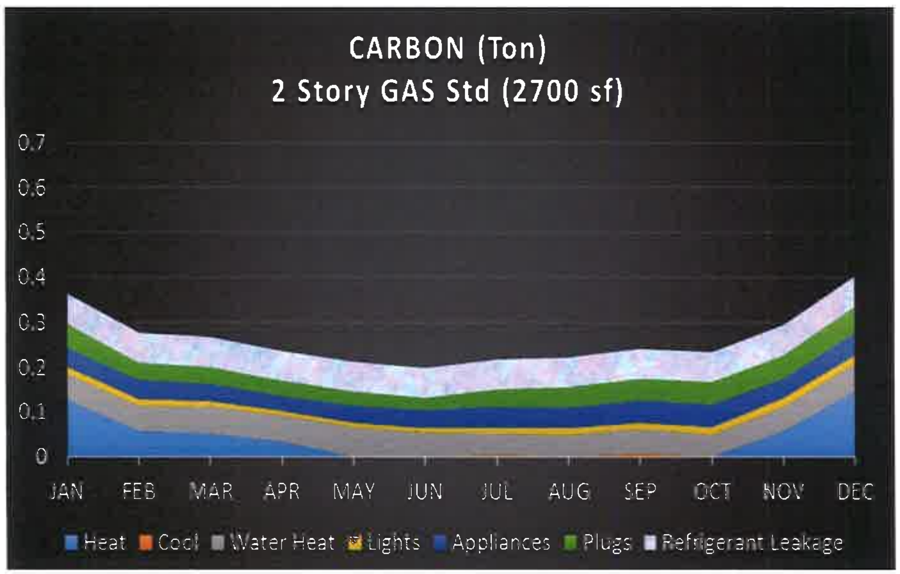
2019 Title-24 Residential

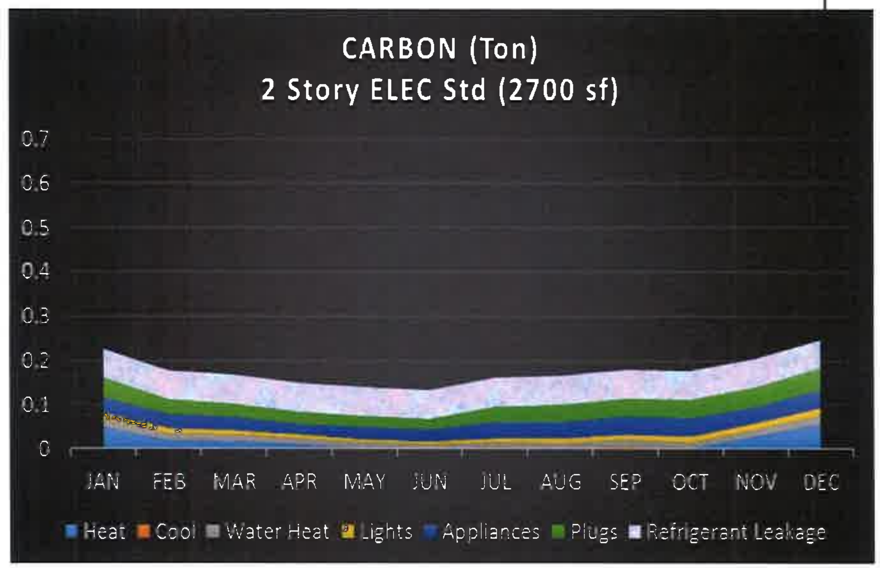
Sacramento





Los Angeles





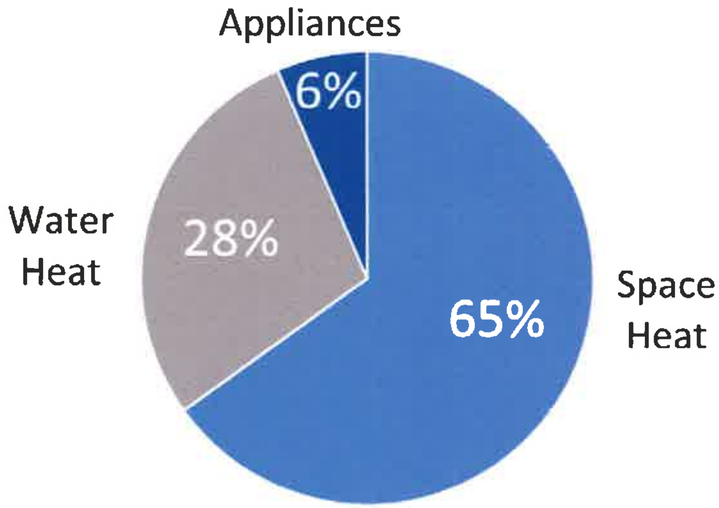
CALIFORNIA ENERGY COMMISSION

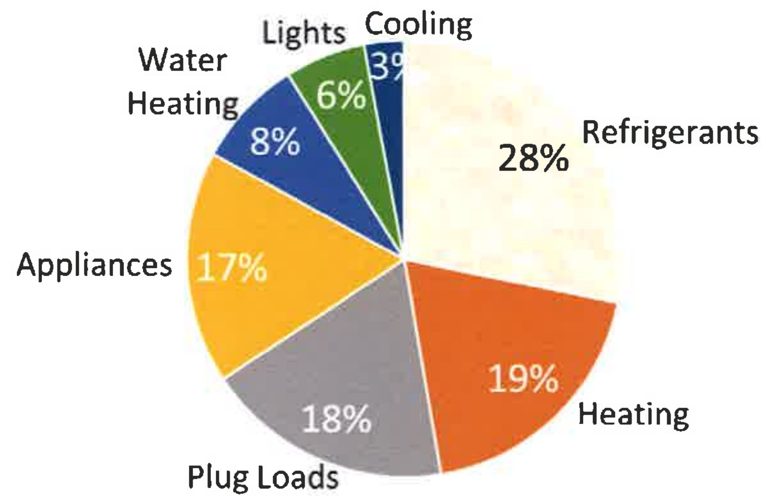
2019 Title-24 Residential

Emission reductions: Mixed Fuel to All Electric

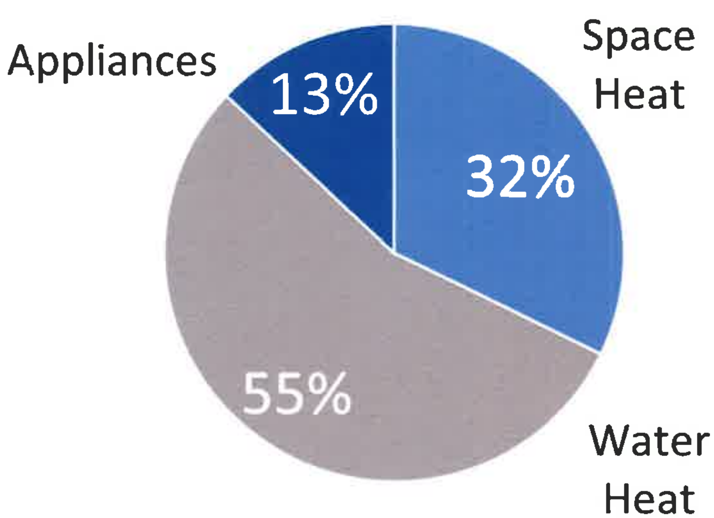
Remaining emissions: All Electric

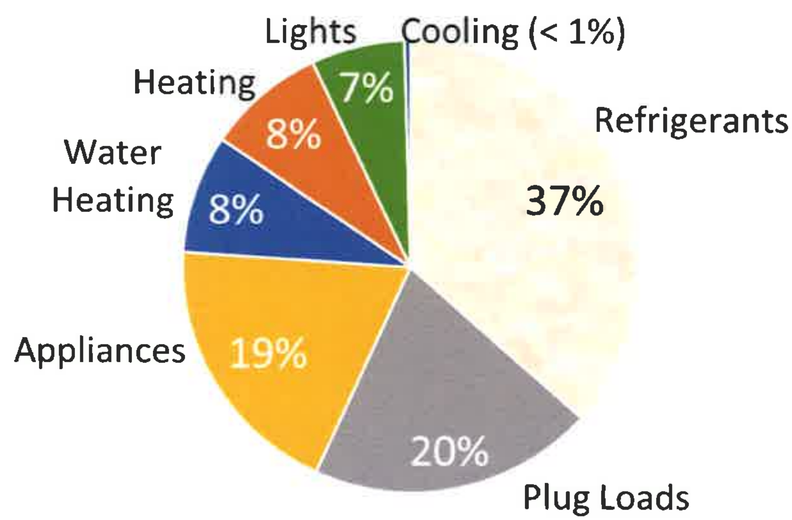
Sacramento





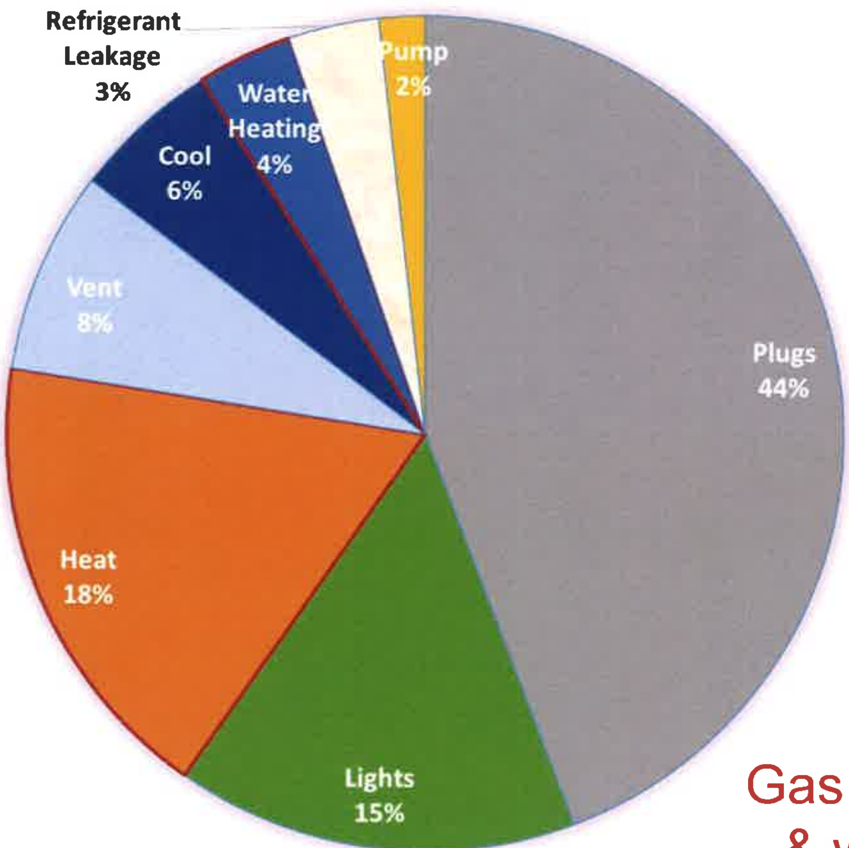
Los Angeles





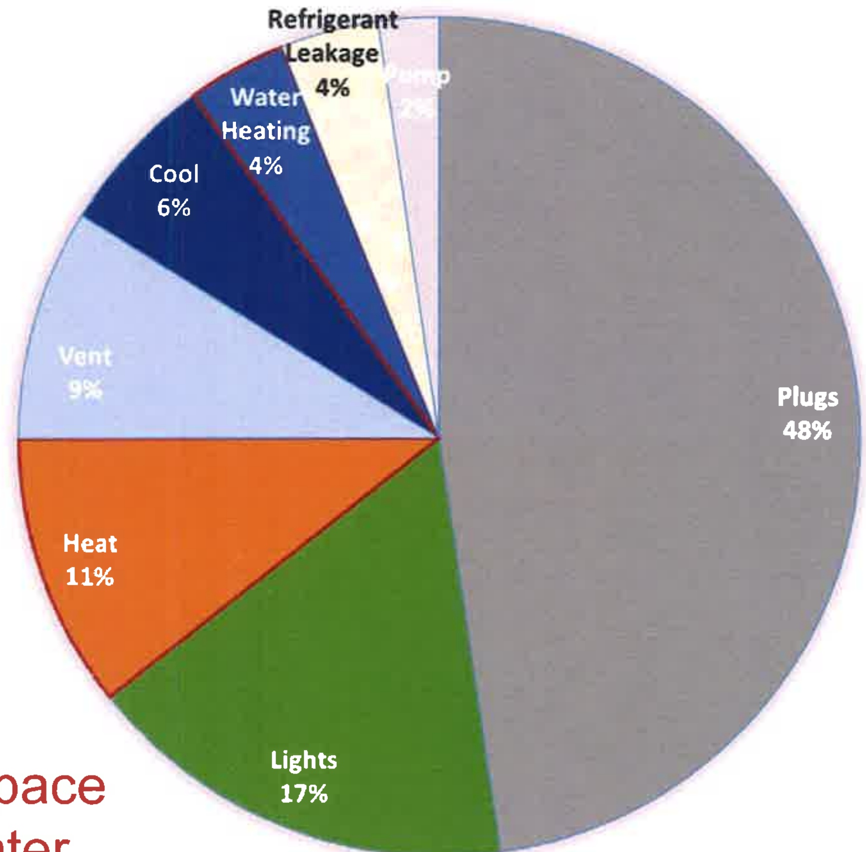
Large Office

Shares of Annual GHG emissions



Sacramento

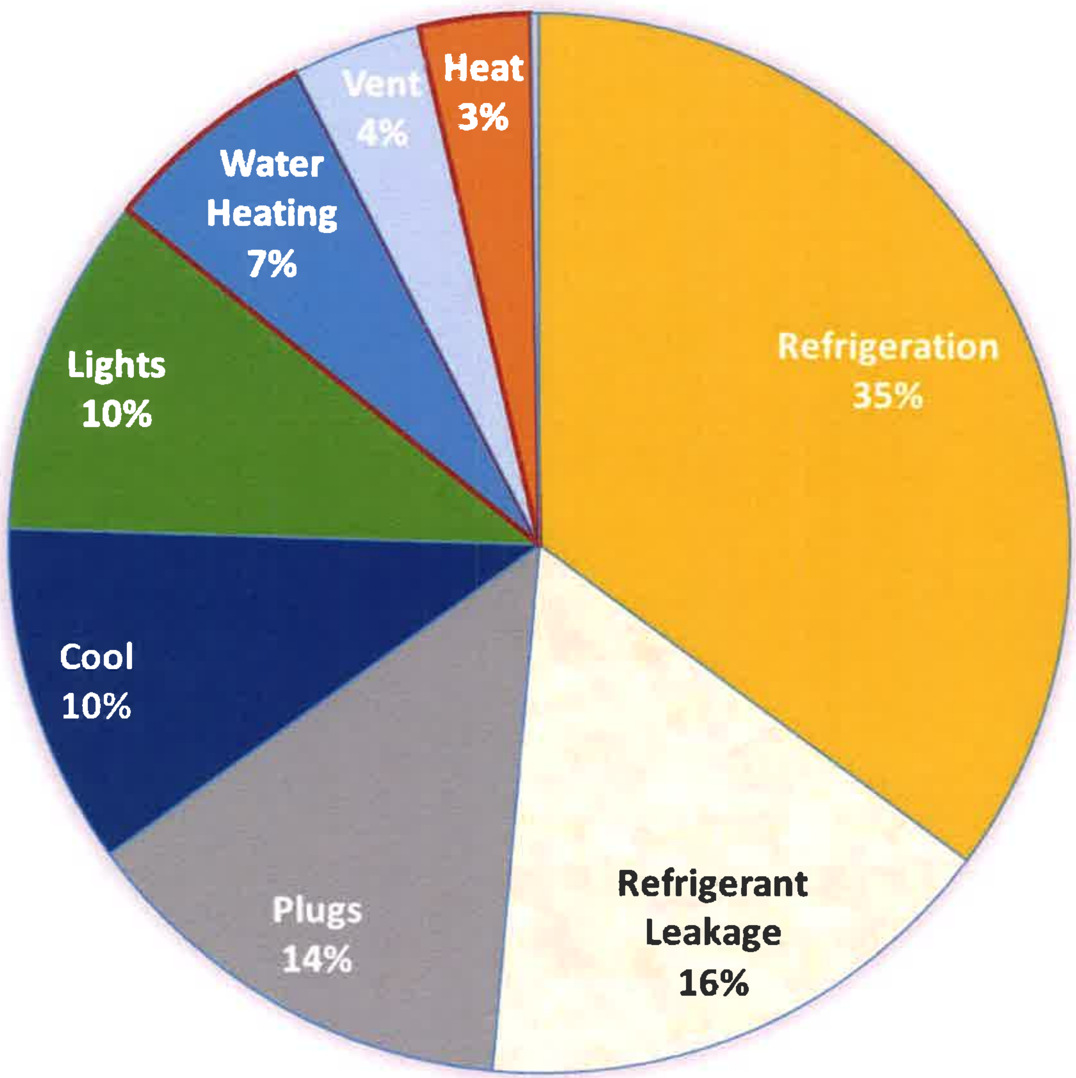
Gas space & water heat



Los Angeles

Retail Store with Refrigeration

Shares of Annual GHG emissions



- 24,000 sf, ½ with refrigeration
- 1.3 W/sf refrigeration load
- Gas water heating
- Gas space heating