The Future of Cap-and-Trade Program in California:

Will Low GHG Prices Last Forever?

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EXECUTIVE SUMMARY

New or expanded climate protection policy at the U.S. federal level has become extremely unlikely under the administration of Donald Trump. This void in climate change-related policy may be filled in part by states and regions where residents and political leaders take action to reduce greenhouse gas (GHG) emissions. California has one of the most comprehensive GHG reduction policy frameworks in place including a market-based Cap-and-Trade Program and "complementary policies" that mandate sector-specific adoption of renewables, energy efficiency measures, and other sources of reduced or cleaner energy use. Understanding how this approach has worked, and where it may lead, provides insights for policy makers and market participants in California and lessons for other states or regions that may choose to pursue similar GHG reduction policies.

In this paper, we analyze how the California GHG market has performed to date and where it could be heading as GHG caps tighten in the future to a 40% reduction below 1990 levels by 2030 and an 80% reduction by 2050. Our approach goes a step further than the economic analysis in the California Air Resources Board's (ARB) 2017 Updated Scoping Plan by simulating how the interaction of electric and non-electric sectors could affect GHG emissions reductions, GHG allowance prices, and electric power prices over the long run after accounting for the GHG abatement accomplished through complementary measures.[i]

There is considerable uncertainty as to what technology, market, and policy conditions will materialize in the distant years. In our analysis we present a range of projections across four long-term scenarios to explore how several key factors interact to affect California's Cap-and-Trade Program, the future electric power sector resource mix, and wholesale electric energy prices:

- **Current Trends** assumes continued technology development along with existing and planned complementary policies for the electric and non-electric sectors;
- **Limited Complementary Policies** assumes less GHG abatement from sector-specific mandates;
- **Lower Cost Clean Alternatives** assumes that expanded technology development in non-electric sectors, such as transportation, brings lower cost clean alternatives to the market inducing greater abatement at lower GHG prices; and
- **Low Natural Gas Prices** assumes lower natural gas prices on a sustained basis through 2050 than in the Current Trends scenario.

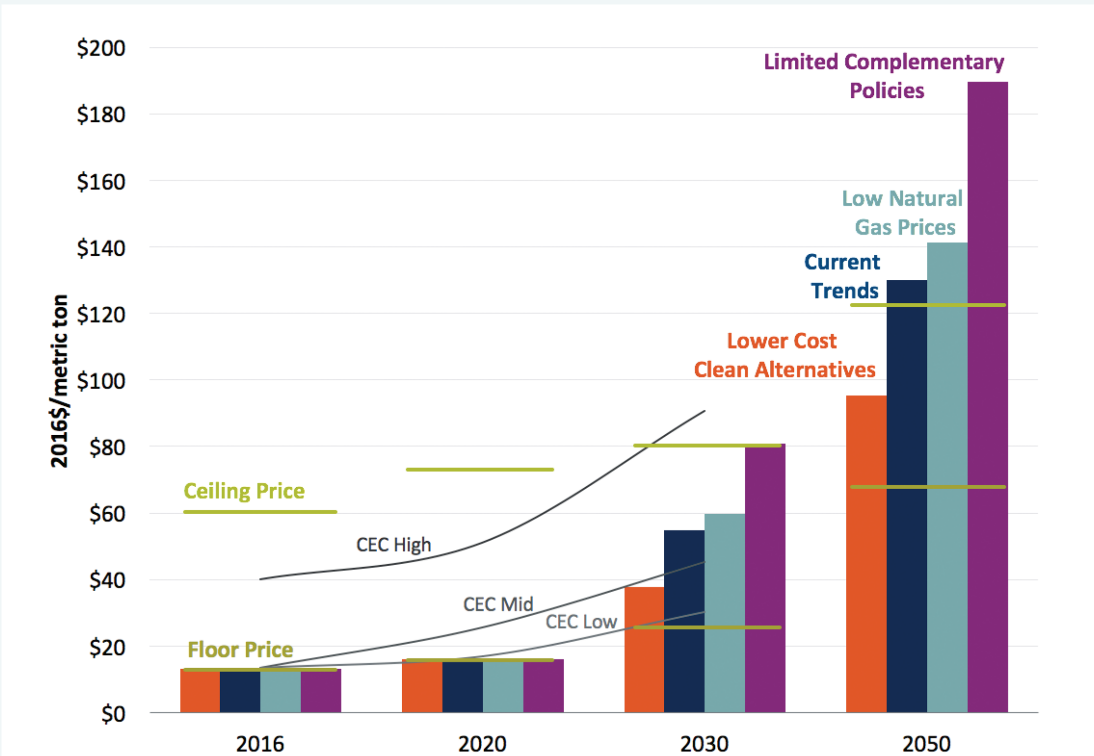
Importantly, we focus on the impact of policy on GHG allowance prices, wholesale energy prices, and electric sector evolution, but do not quantify the overall cost or distribution of costs incurred by pursuing a blend of market-based and regulatory initiatives. As such, we recognize that our analysis does not provide a social cost basis for selecting among policy alternatives.

Our analysis leads us to the following takeaways concerning the outlook of future GHG prices and achieving its long-run GHG reduction requirements in California:

GHG prices likely remain at or near the floor through 2020, increasing afterwards subject to a wide range of uncertainty. The level of complementary policies, innovation in lower-cost clean energy technologies, and natural gas prices can all have big impacts on future GHG prices.

GHG prices are likely to remain near the floor price through 2020 due to reduced demand for energy relative to initial program expectations, the large volume of banked and unsold allowances built up in the first five years of the Cap-and-Trade Program, and the continued effects of existing complementary policies. After 2020, GHG prices can vary within a large range. We find that GHG prices in the Current Trends scenario would rise to $55/ton in 2030, ranging from approximately $35/ton to $80/ton, and about $130/ton in 2050, ranging from $95/ton to $190/ton (all in 2016 dollars), as shown in Figure 1. GHG prices are lower in scenarios that assume rapid innovation of clean technologies that accelerates consumer adoption of lower-GHG alternatives, such as low-cost energy storage technologies and electric vehicles, but higher if complementary policies fail to deliver expected GHG emission reductions or if low natural gas prices persist.

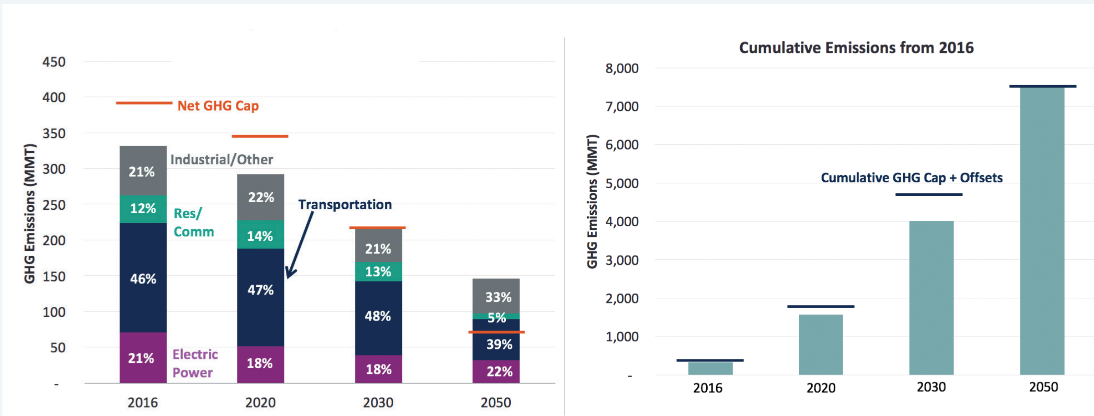
FIGURE 1 GHG Prices for All Scenarios



Non-electric sectors will play an increasingly important role in GHG emission reductions, accomplished largely by complementary policies, but supplemented by GHG price-driven reductions.

To meet the longer-term targets (80% reduction by 2050), GHG reductions will shift from the electric sector in the near term to the non-electric sectors over the long term. This is necessary because non-electric sectors currently account for 80% of GHG emissions in California. Even with the planned and potentially expanded complementary policies assumed under the Current Trends scenario, the GHG emission reduction will need to be supplemented by reductions driven by rising GHG prices in both electric and non-electric sectors. The limited potential for additional low cost GHG emission mitigation in the non-electric sectors beyond those mandated through complementary policies, however, translates into high GHG prices. On the other hand, lower cost alternatives through continued clean energy innovation could dramatically reduce the costs of reducing GHG emissions and drive down long-term GHG prices.

FIGURE 2 GHG Emissions under the "Current Trends" Case

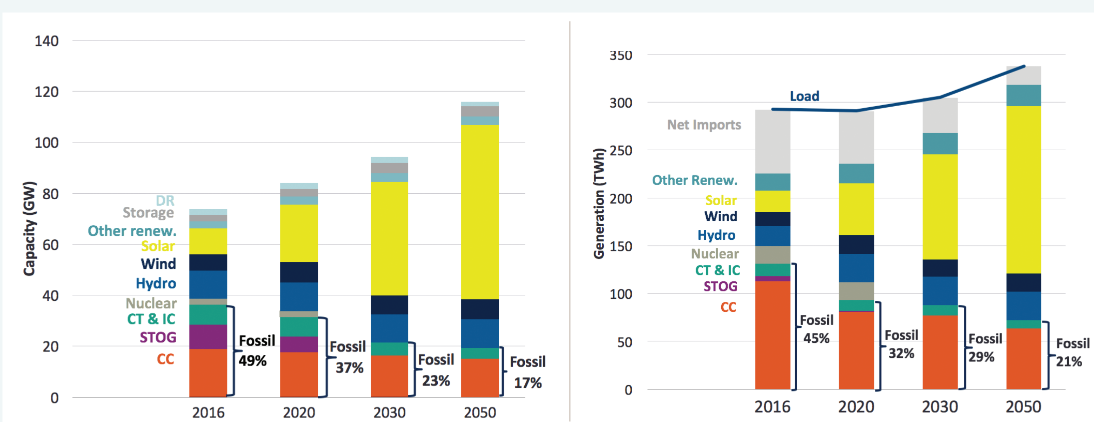


Notes: The "Net GHG Cap" accounts for allowances held in Allowance Price Containment Reserve (decreasing allowed emissions) and offsets (increasing allowed emissions).

Despite significant additions of renewable generation, we find that the electric sector does not achieve full decarbonization in 2050. Full decarbonization will likely require further development of storage technologies beyond the current mandates, expansion of CAISO market footprint, and/or increased transmission capability for imports and exports.

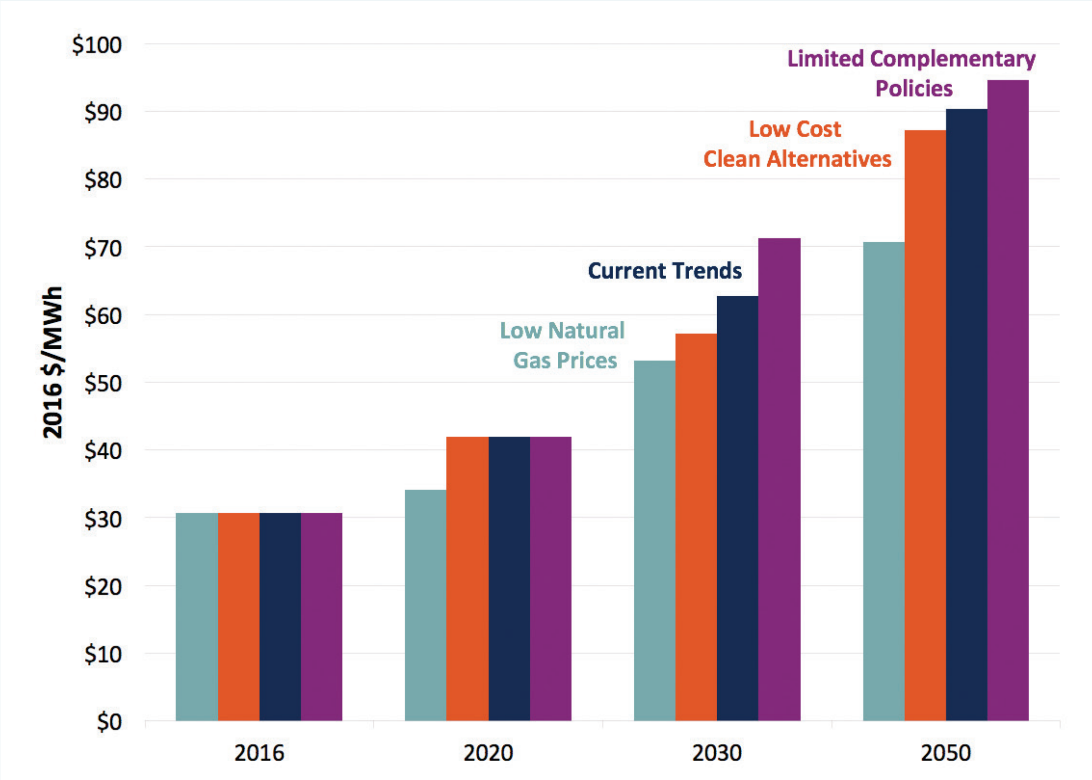
The electric sector supply mix is likely to change significantly over this time with large additions from renewable resources (in particular solar PV) and the retirement of conventional fossil units. Zero-emitting resources could account for 80% of the in-state generation by 2050, with the remainder largely coming from fossil units needed to integrate the renewables to maintain reliability. In essence, renewables become economically self-limiting once they are competing with each other to contribute to GHG emission abatement. In the absence of additional electricity storage, expansion of the CAISO market, or increased transmission capability our analysis concludes that GHG reductions from non-electric sectors are more cost-effective than full electric sector decarbonization for meeting the long-term GHG emissions cap in California.[ii]

FIGURE 3 Installed Capacity and Generation in CA for Scenario "Current Trends"



California wholesale energy prices increase over the long term for all cases, driven by rising GHG prices and gas prices, but there is a diminishing GHG price impact due to underlying differences in generating capacity across scenarios. In 2050, wholesale energy prices become somewhat insensitive to GHG prices, differing by just $7/MWh in the three cases with equivalent gas prices despite a $100/ton difference in GHG price. As the system becomes increasingly decarbonized, high GHG price cases result in significantly greater entry of renewables and CC-CCS (and a lower market heat rate) that shield wholesale energy prices from the higher GHG allowance prices. The lowest wholesale energy prices occur in the Low Natural Gas Prices case as lower natural gas prices more than offset the higher GHG prices ($10/ton above Current Trends).

FIGURE 4 California Wholesale Energy Prices



Further improving the economic competitiveness of clean energy technologies, such as bulk energy storage and electric vehicles, through investments in innovation will be essential over the long term to avoid the higher GHG prices that could prove to be politically untenable.

The difference in GHG prices between the Low Cost Clean Alternatives case and the Current Trends case demonstrate the potential benefits that clean energy innovations could bring to the market and the economic importance of developing these technologies going forward. Such new and improved technologies could improve the use of renewables (e.g., through bulk energy storage increasing the load factor on the power system in times when renewables are available) and reduce the costs to switching consumer decisions away from fossil fuel applications (e.g., through the widespread use of electric vehicles). While a sustained effort of designing complementary policies to reduce GHG emissions and suppress prices can provide a similar effect, reducing emissions through mandates can obscure the true costs to consumers of achieving the GHG reduction policy. Analysis should be conducted for complementary policies and investments on technology innovation to determine if they increase the societal cost of meeting GHG targets relative to market-based approaches.

In summary, while California has started down its path to reducing GHG emissions by putting a comprehensive policy framework in place for decarbonizing its economy, significant uncertainties lie ahead for California's Cap-and-Trade Program and the future outlook of its GHG prices. As the GHG price is a critical input to the dispatch decisions and generator profit margins in the electric sector, system planners have to make long-term strategic decisions based on expectations of the market and policies. The multi-sector model we have developed presents an analytical tool that helps to understand these dynamics in the GHG market, examine the impacts of key underlying drivers of GHG prices, and facilitate decision making with a focus on the electric sector. Other states and regions contemplating a major decarbonization should consider the way that complementary policies, GHG prices, and customer adoption of clean-energy technologies will interact using the California experience as a starting point for developing their own programs.

I. INTRODUCTION

The California Cap-and-Trade Program, originally passed as a part of the Global Warming Solutions Act of 2006 (AB 32) and recently extended to 2030 in AB 398, is the broadest and most significant state policy in the U.S. to limit greenhouse gas (GHG) emissions through an economy-wide cap. The California Cap-and-Trade Program covers over 85% of GHG emissions in the state, including the electric, transportation, residential, commercial, and industrial sectors, and it plays a crucial role within California's portfolio of GHG policies to reduce 2020 GHG emissions to 1990 emissions levels, 2030 emissions to 40% below 1990 levels, and 2050 emissions to 80% below 1990 levels.

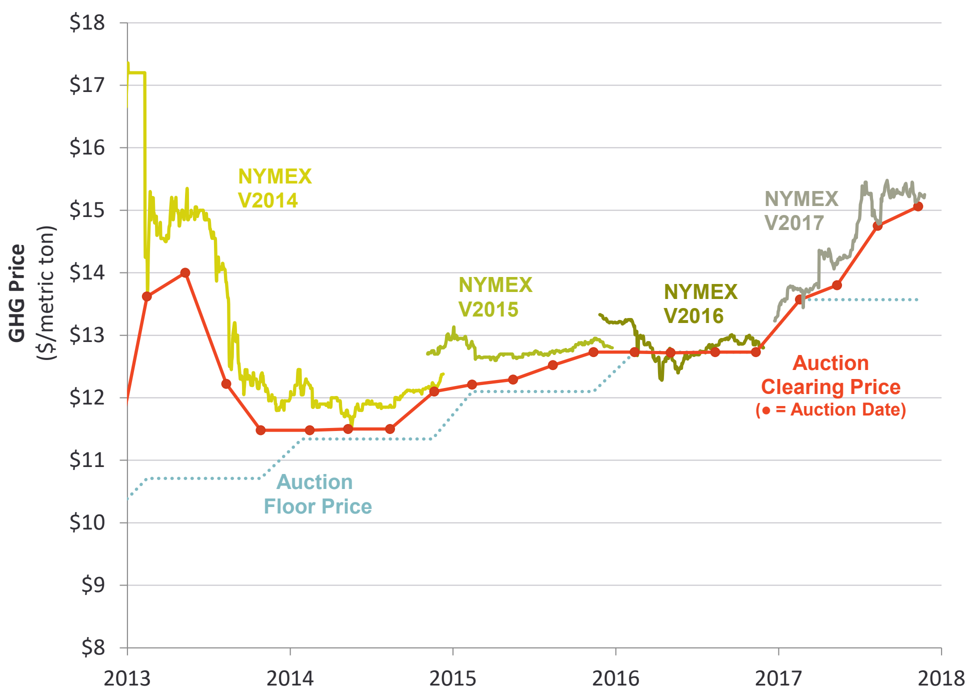
While the early years of the program were marked by low GHG prices and an oversupply of allowances, the recent extension to 2030 and the resolution of a major lawsuit against the program have driven prices up off the floor price over the past 6 months to about $15/ton. Do we expect GHG prices to rise even higher to meet the state's long-term goals of emission reductions or return to the floor price? Where will emissions reductions occur across the electric and non-electric sectors? And, what does the future electric power sector generation mix look like to meet the ambitious long-term GHG caps?

In this paper, we explore the causes and effects underlying the California Cap-and-Trade Program to understand the potential for future GHG emissions reductions and the associated GHG prices. Using an integrated, multi-sector modeling approach, we provide an analysis of how GHG prices may change going forward, the impacts of future GHG prices on economy-wide emission reductions, and the impacts on the electric sector generation resource mix and prices. Finally, we analyze the impacts on GHG prices and emission reductions from a few key uncertainties related to complementary policies, low-cost clean energy technology innovation, and the price of natural gas.

II. THE CALIFORNIA GHG MARKET THROUGH 2020

California GHG prices have mostly remained at or just above the floor price since the program began in January 2013, but have climbed off the floor price in 2017. Figure 5 shows that after an initial period of volatility, GHG prices stabilized in the latter half of 2013 around $12/ton and over the subsequent three years floated just above the floor price.[iii] The market has shifted over the past year from a period of oversupply in the quarterly GHG allowance auctions with allowances briefly trading below the auction floor prices to a tighter market in the two most recent auctions in which demand exceeded supply by 55% and prices cleared $2/ton above the floor price.[iv]

FIGURE 5 California Auction and NYMEX GHG Prices

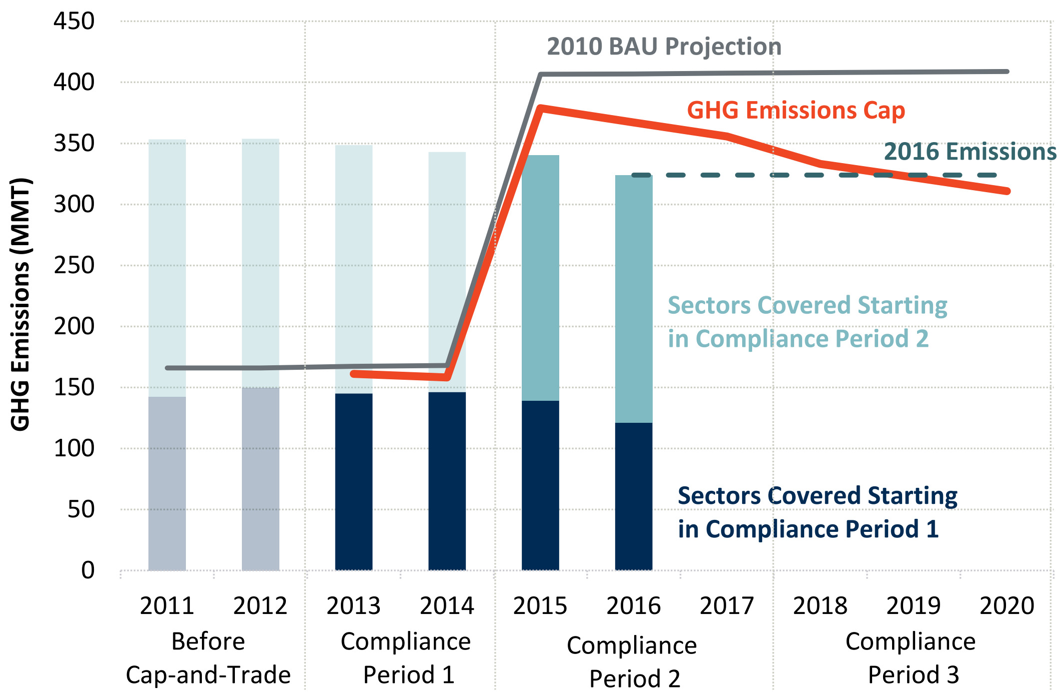


Sources: NYMEX prices from SNL. Auction Clearing Prices and Floor Prices from ARB, Auction and Reserve Sale Information, November 30, 2017.

Prior to the recent uptick in prices, the oversupply conditions in 2016 and early 2017 became so significant that allowances remained unsold in the auctions. This occurred because the California Air Resources Board (ARB) initially set the cap so high that only limited reductions were necessary to meet the GHG emissions caps through 2020. Although the ARB updated their projection of GHG emissions following the 2008 recession to account for lower projected fuel demand, the correction did not sufficiently account for the slower economic growth that has occurred since. For example, electricity demand in 2013 was 5% lower than projected in 2010 following the correction.[v] The result is that actual GHG emissions have been much lower than projected by the ARB and consequently much lower than the GHG cap.

As Figure 6 shows, during Compliance Period 1 (2013 and 2014) actual emissions (dark blue columns) from capped sectors were well below the 2010 projection of emissions even in 2011, the first year following the projection.[vi] At the end of Compliance Period 1, the difference between the actual emissions and the cap resulted in an excess of 50 million metric tons (MMT) of GHG allowances.[vii] Moving into Compliance Period 2 (2015 to 2017), an additional 200 MMT of GHG emissions from fuel suppliers (primarily transportation fuel and natural gas) were incorporated into the program cap in 2015, but the cap itself increased by 230 MMT (based on the 2010 projection). The recently-reported GHG emissions show that total emissions dropped by 16 MMT in 2016 with emissions for capped sectors (indicated by the height of the solid light blue column in Figure 6) totaling 324 MMT, or 43 MMT below the 2016 cap. The reduction in GHG emissions in 2016 exceeded the total reductions in the first three years of the program and was driven by lower GHG emissions in the electric sector due to an increase in hydro generation with the end of the California drought, an increase in renewables, and a decrease in imported coal generation.[viii] At the same time, transportation-related emissions, the largest category of emissions in California, increased slightly by 2 MMT.

FIGURE 6 California Projected and Reported Emissions versus Emissions Cap

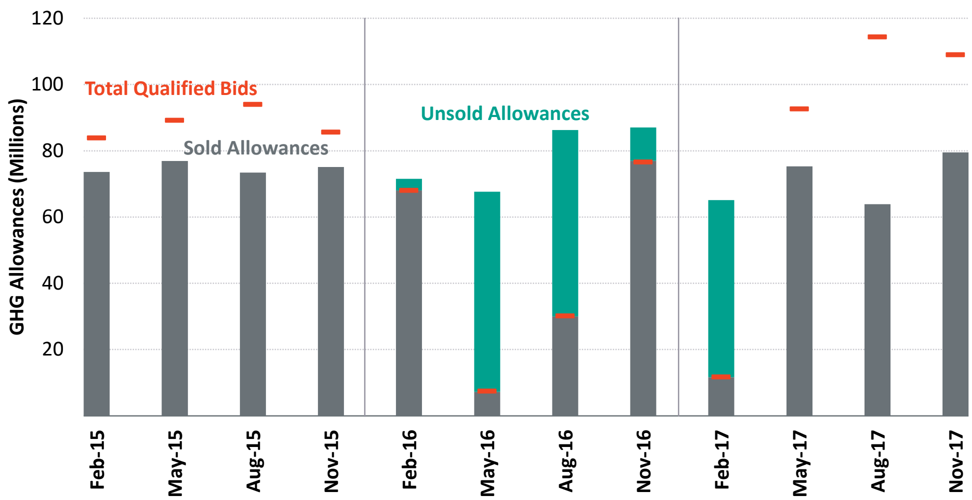


Sources and notes: Lighter columns represent emissions that are not capped in a given year. Projected Emissions – CARB, California GHG Emissions - Forecast (2008-2020), October 28, 2010. Actual Emissions - CARB, Annual Summary of GHG Mandatory Reporting Non-Confidential Data for Calendar Year 2011 to 2016. GHG caps are net of allowances held in the Allowance Price Containment Reserve.

The use of carbon offsets for complying with the Cap-and-Trade program have also added to the oversupply in the market with 76 MMT of offsets previously submitted to the ARB or held by market participants.[iv] As shown in Figure 7, the GHG market responded to the oversupply of allowances in the 2016 auctions and the first auction in 2017 by drastically reducing purchases of allowances, as they were not needed for compliance in the short term. Over this time, a total of 184 MMT of allowances went unsold in the auctions. This reduction in

allowance purchases in the quarterly auctions is likely to bring the GHG allowance supply and demand back into balance in the short term, but will increase the supply of allowances available in future auctions.

FIGURE 7 Allowances Sold in GHG Auctions, 2015-2017



Source: ARB, Auction and Reserve Sale Information, August 22, 2017

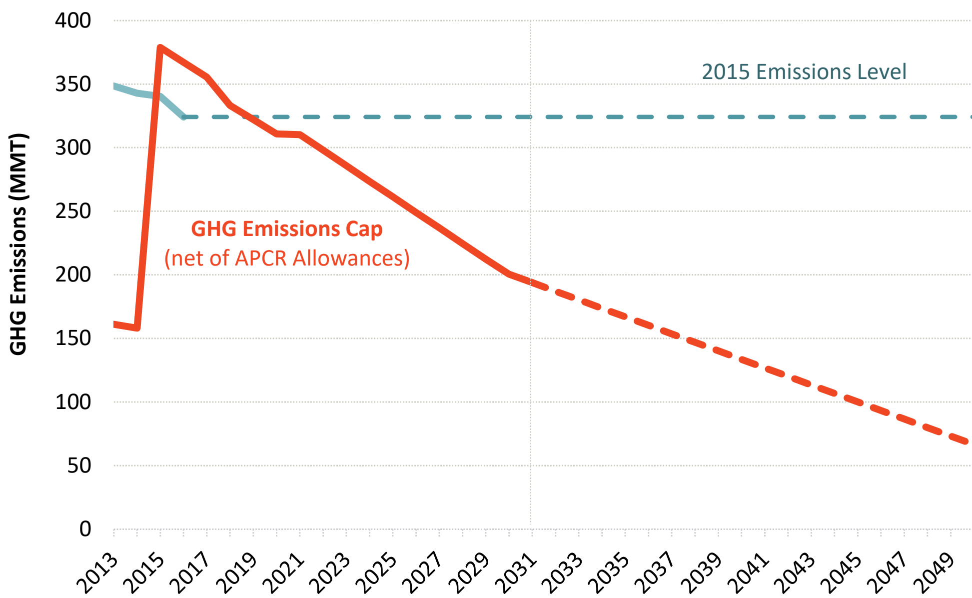
Looking forward to Compliance Period 3 (2018 to 2020), banked and unsold allowances from the first five years of the program will likely keep GHG prices low. Following the reductions in emissions in 2016, meeting the GHG emission caps in 2020 will require an additional 13 MMT of emissions reductions relative to 2016 emissions (as shown in Figure 6). Complementary policies and the rising floor price are expected to continue reducing GHG emissions such that there are likely to be sufficient allowances available in the market that GHG prices remain at or near the floor price. If participants continue to price in longer-term compliance into the near-term markets, as recently seen in the market with the extension to 2030, prices may float a few dollars above the floor price through 2020 as a result of banking/hedging activity.

III. THE POST-2020 CAP-AND-TRADE PROGRAM

Beyond 2020, the passage of SB 32 provided a path forward for GHG reductions and AB 398 enshrines the role of the Cap-and-Trade program to achieve an additional 40% emission reduction by 2030.[x] The ARB recently approved amendments to the Cap-and-Trade regulations, including a GHG emissions cap through 2030 that matches the requirements under SB 32 as well as an approach for setting the annual cap until 2050.[xi]

Figure 8 shows how the proposed GHG emissions cap through 2050 (taking into account the allowances placed in the Allowance Price Containment Reserve or APCR) will decrease relative to 2015 GHG emissions. While the market currently enjoys an excess of allowances, such significant reductions in emissions in future years will lead to rising GHG allowance prices to drive down future GHG emissions.

FIGURE 8 California's Existing and Proposed GHG Emissions Cap through 2050



Source: ARB, California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms, Final Regulation Order, approved September 18, 2017. GHG allowances are net of allowances held in the Allowance Price Containment Reserve (APCR).

In addition to the future GHG cap, the ARB also implemented changes that could have material impacts on GHG prices. In particular, the ARB changed its handling of allowances that continue to go unsold in the auctions. Instead of reintroducing the allowances into future auctions once prices rise off the floor price, starting in 2018 the ARB will move allowances that remain unsold in the GHG auctions for over two years into the APCR. This adjustment will likely shorten the time for auctions to remain at the floor price as the supply of allowances in the quarterly auctions will decrease. A second change concerning the APCR was to set a single price at which entities can purchase allowances held in the APCR starting in 2021.[xii] The design of the APCR will undergo further changes following the passage of AB 398, including the introduction of a hard price ceiling at a level to be determined by the ARB. These changes ultimately will reduce the range of GHG prices in the long-term between the floor price and the future ceiling price and provide increased price certainty to market participants. These changes, among others, indicate an inclination to tighten the market and remove slack allowances.

Beyond the design of the future Cap-and-Trade regulations, there are several more fundamental economic uncertainties that are likely to have a significant impact on post-2020 GHG prices.

The scale and success of complementary policies to reduce GHG emissions: The Cap-and-Trade Program is just one part, indeed not even the largest part, of California's broad portfolio of policies to reduce GHG emissions. The Climate Change Scoping Plan developed by ARB also includes a portfolio of "complementary policies," which target reducing GHG emissions through direct regulatory measures as opposed to GHG price signals from the Cap-and-Trade Program. Key complementary policies include electric sector programs that promote renewable energy and energy efficiency and several programs in the transportation sector, such as the Low Carbon Fuel Standard (LCFS) and Pavley II Vehicle Efficiency Standards. In 2015, the California Legislature passed SB 350, committing the state to increasing its electric sector energy efficiency programs and setting a 50% RPS by 2030, demonstrating that the state will continue its "hybrid" approach of pursuing both complementary policies and a Cap-and-Trade Program well beyond 2020.[xiii] It remains unclear, however, what policies will be used to target transportation sector emissions through 2030 and what new policies will be implemented beyond 2030 to continue to drive down transportation emissions. The scale and success of GHG emissions reductions achieved through complementary policies are a major uncertainty in projecting future GHG prices. Each additional GHG-related policy measure that leads to emission reductions shifts the burden of meeting future GHG caps away from price-sensitive, market-based emissions reductions and reduces future GHG prices (but may increase the total costs of compliance).[xiv]

The prices of GHG-intensive fuels, such as natural gas and oil: The underlying price of fuels, independent of GHG prices, will have a major impact on fuel use and emissions, and thus also impact GHG prices. Lower fuel prices will likely result in increased fuel consumption and increased GHG emissions in the short term and affect the GHG price required to achieve similar reductions in GHG emissions. However, there is great uncertainty about the future of fuel prices. For example, crude oil prices were over $100/barrel in 2014 and declined to less than $50/barrel in 2016. Natural gas prices have also declined over the past 10 years, temporarily falling to less than $2/MMBtu for several months in the last few years from over $10/MMBtu in 2008. Natural gas prices are an important driver in the electric sector as well as in the residential and commercial sectors for influencing fuel usage.

The cost of clean technology alternatives in the non-electric sectors: The cost of clean energy alternatives in the non-electric sectors could affect how easy it is for consumers to switch from GHG intensive fuels. For example, motorists have been found to reduce their long-term usage of gasoline by about 7% for each 10% increase in gasoline prices.[xv] That is a meaningful, though somewhat low demand elasticity, but consumers respond to changes in overall fuel prices, not just the much smaller GHG price adder component. Roughly speaking, every $1/ton of GHG prices raises the gasoline price by one cent per gallon. Thus, to add a dollar to the gasoline price, GHG emissions would have to be priced at $100/ton, from which we might expect about a 20-25% reduction in gasoline usage at current gasoline prices. However, if the cost of electric vehicles becomes much lower, consumers would be more likely to switch to electric vehicles and therefore reduce gasoline consumption and GHG emissions for any given level of GHG price.

The costs of alternative, low-GHG technologies in the electric sector: The availability and costs of lower GHG-emitting technologies in the electric sector will also play a significant role in setting GHG prices in the long-term. For example, the cost and performance of batteries will impact the price of both electric vehicles (discussed previously) and the ability and costs associated with integrating more intermittent renewables on the power grid. The cost of carbon capture and sequestration (CCS) technologies for coal- and especially natural gas-fired generation would also affect the cost of reaching a low-GHG future and will impact the GHG price necessary for (and the timing of) CCS deployment in California.[xvi]

Linkages with other cap-and-trade programs: The current linkage with Quebec and future linkage with Ontario are the first steps in expanding the geographic scope of the Cap-and-Trade Program. This may alter the outlook for GHG allowances as each additional jurisdiction brings its own unique mix of sectorial GHG emissions, complementary policies, and long-term emissions reduction goals. For example, Quebec has very low electric sector emissions due to its large capacity of its hydroelectric generation facilities. Therefore, a greater share of the reductions in GHG emissions required to meet Quebec's future goals will have to come from the transportation and industrial sectors than in California. The Ontario program that began earlier this year will link its market with California and Quebec starting in 2018.

Federal and international policy developments and leakage: Over the long run, the status of GHG reduction policies outside of California – both domestically and internationally – will influence the performance of the California policy. While a pause in the U.S. federal policy development is likely under the current administration and Congress, additional political shifts could still occur. The timetable for international activity likewise is highly uncertain. In either case, the California program would probably be more effective and less costly in the context of strong U.S. federal policy and international action. This is particularly important when considering leakage issues, wherein California industries move production to other states or countries in response to higher energy prices, which can lead to apparent emission reductions in California (and real income loss) while not reducing overall global GHG emissions. While leakage is not desirable, it does have the superficially salutary effect of reducing GHG prices.

While each uncertainty could have a significant impact on GHG prices, we focus in this study on the impact on GHG prices due to the uncertainties created by complementary policies, the development of low cost clean energy technologies in the non-electric sector, and the price of natural gas.

IV. GHG PRICE PROJECTIONS

To analyze long-term trends in the Cap-and-Trade Program in California and the dynamics driving GHG prices, we developed a model that allows us to bring together critical factors across the California economy that shape the outlook for future GHG prices. By incorporating projected non-electric sectors emissions and abatement cost curves into a detailed electric sector capacity expansion model, we can consider the economic trade-offs between reducing emissions in the electric sector and non-electric sectors to comply with the economy-wide GHG caps, thus allowing GHG prices to be determined endogenously at economy-wide equilibrium. The model simulates the electricity sector in the entire Western U.S. We provide a more detailed description of the model, known as CAT_Xpand, in Appendix A.

To help system planners and policymakers understand the future direction of the GHG market and what uncertainties drive GHG prices, we developed several alternative scenarios that capture several of the most significant uncertainties discussed in the previous section. We first present our GHG prices under the Current Trends scenario and the corresponding outlook for the electric and non-electric sectors. Then, in alternative cases, we show how GHG prices and other metrics in the electric and non-electric sectors may be affected by key uncertainties and changes in the compliance opportunity set, including emissions reductions from complementary policies, non-electric elasticity of demand, and natural gas prices. Table 1 summarizes the differences between the input assumptions among the cases we analyzed. More details about the key assumptions are provided in Appendix B.

TABLE 1 Summary of Modeled GHG Scenarios

Key Assumptions	Current Trends	Limited Complementary Policies	Lower Cost Clean Alternatives	Low Natural Gas Prices
Non-Electric Sectors Complementary Policies	Base	Delayed adoption of complementary policies in the non-electric sectors	Base	Base
Non-Electric Sectors Consumer Price-Responsiveness	Base	Base	Double the consumers' price elasticities from the Base	Base
Natural Gas Prices	2016 AEO Reference Case*	2016 AEO Reference Case*	2016 AEO Reference Case*	2016 AEO High Oil and Gas Resource and Technology Case*

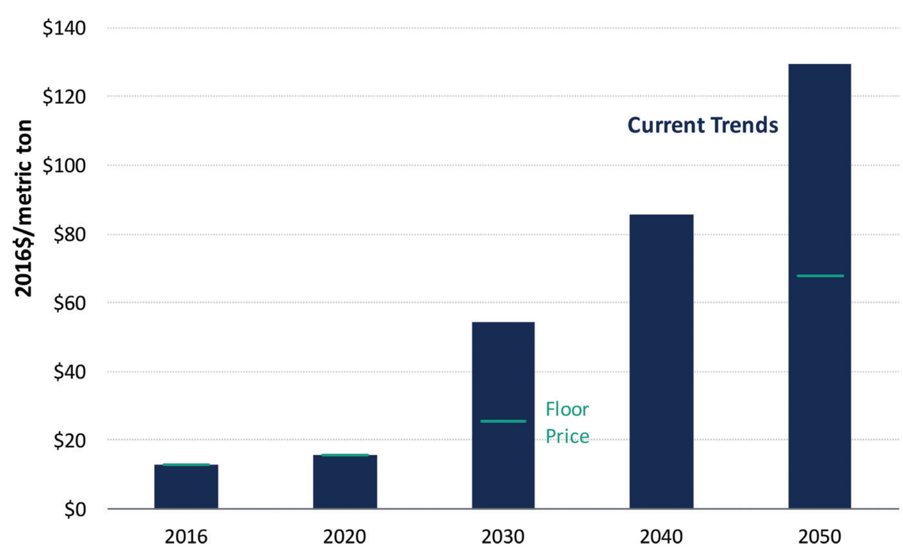
**The 2016 AEO forecasts are applied starting after 2020. Prior to that, the gas price outlook is based on NYMEX futures transactions in Dec 2015 for 2016 and 2017 delivery years in all scenarios, transitioning linearly over a 3 year period (2018-2020) to the AEO forecasts.*

A. CURRENT TRENDS OUTLOOK

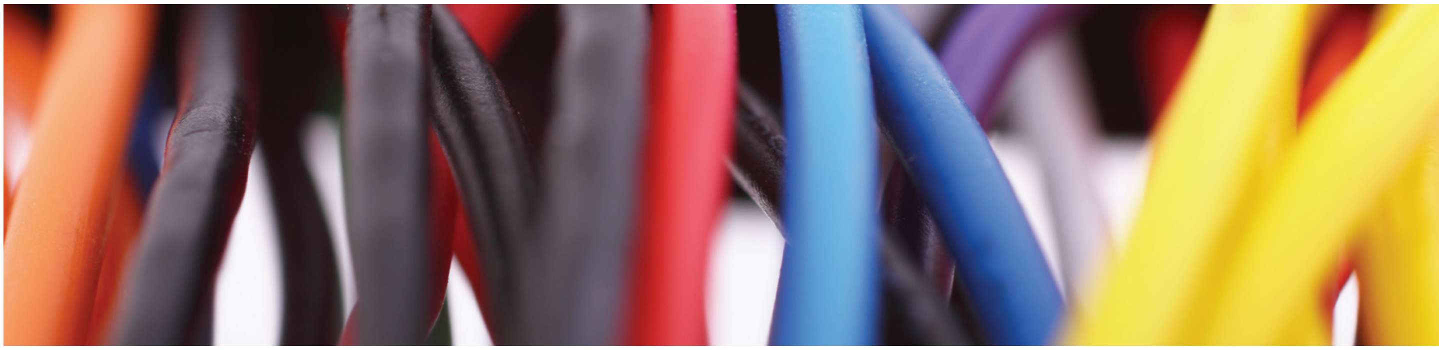
California GHG Prices

While GHG prices are likely to remain low in the near-term, we expect them to rise significantly after 2020 to reach the long-term GHG emission reduction goal of 40% below 1990 by 2030 and 80% below 1990 by 2050. Figure 9 shows that in the near-term our Current Trends GHG prices remain at the floor price through 2020, but then rise above the floor price to \$55/ton in 2030, \$85/ton in 2040, and \$130/ton in 2050 (in 2016 dollars). The rising GHG prices reflect the market transitioning from the current period of over-supply to a market that requires additional incentives to drive consumers away from higher-emitting fuels as well as to develop and adopt low-GHG technologies over and above a sustained program of complementary policies. The Current Trends GHG prices rise smoothly over the time horizon analyzed because our model allows market participants to make trade-offs over time by banking GHG allowances for future use.

FIGURE 9 California GHG Price Outlook under Current Trends



Sources: CEC, "2015 IEPR Carbon Price Projections Assumptions"; CAT_Xpand results.



The assumed perfect foresight and unlimited banking results in a decades-long intertemporal transfer of GHG allowances, via banking through the 2020s to compliance during the 2040s. While we do expect the tightening GHG emissions cap to result in some near-term banking as a hedge against higher compliance costs in the future, most businesses are not likely to make investments to reduce near-term emissions for the purpose of reducing the compliance costs for a decade or more into the future. With shorter horizons for banking, we expect GHG prices would be lower than our projections in mid-term (2020 to 2030), but higher than our projections in the long-term.

California Sectoral GHG Emission Patterns

Meeting long-term GHG reduction goals requires reductions in GHG emissions across all sectors of the California economy. Figure 10 shows projected Current Trends GHG emissions by sector as a result of the steadily declining GHG emissions cap (shown as a red bar in the figure). In the earlier years the GHG cap exceeds the total emissions and excess allowances are banked for later use. The buildup of banked allowances allows for the total annual emissions in 2050 to be higher than the annual GHG caps, while still achieving the emissions reduction goal on a cumulative basis.

FIGURE 10 Annual GHG Emissions by Sector under Current Trends

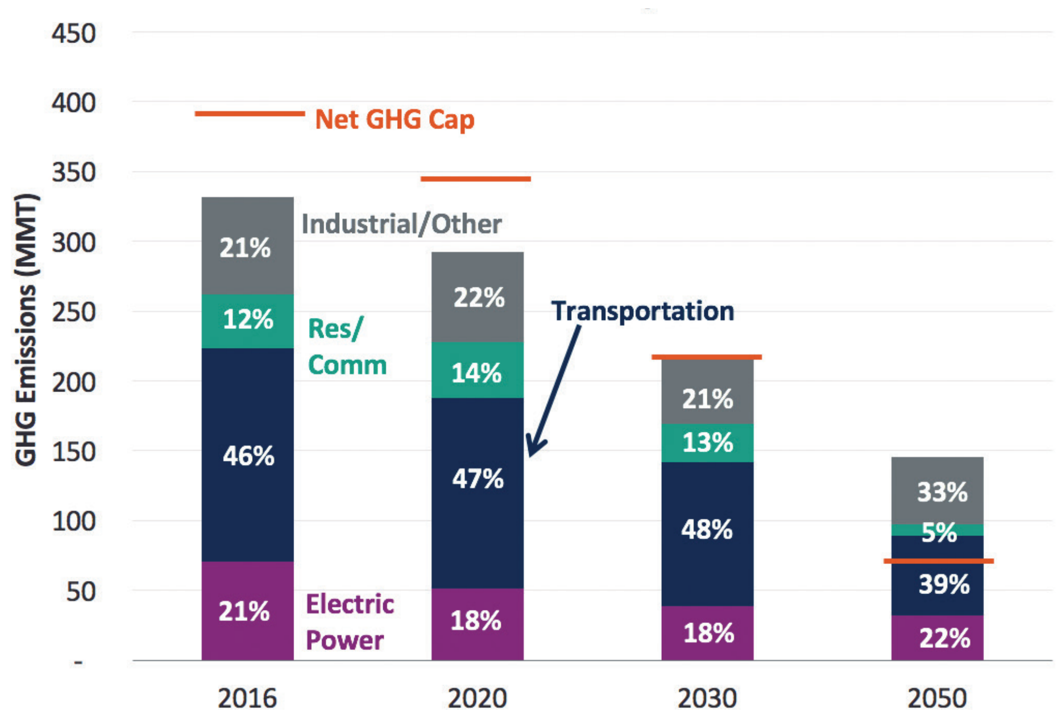


FIGURE 11 Cumulative Emissions under Current Trends

Notes: The "GHG Cap" accounts for allowances held in Allowance Price Containment Reserve (decreasing allowed emissions) and offsets (increasing allowed emissions).

We find that the non-electric sectors are the primary source of emission reductions both in the near- and long-term, with the transportation sector as the largest contributor in all periods. Non-electric sectors account for over 50% of the emissions reductions (relative to 2015) in 2020 and nearly 80% of the reductions in 2050, mostly driven by complementary policies. As a result, the sectoral mix of GHG emissions changes over time. Somewhat surprisingly, the percentage of electric sector emissions increases from 2020 to 2050 (from 18% to 22% as shown in Figure 10), whereas the percentage of emission from the transportation sector declines from 47% to 40%. The electric sector GHG emissions decline through 2030 to about 40 MMT, a reduction of 55% from 2010 emissions. We find that most of the emission reductions occur from energy efficiency as required by SB 350 and the increasing RPS requirements (50% in 2030).

Even with GHG price of $130/ton (in 2016 dollars) in 2050, however, *full decarbonization of the electric sector does not occur*. This outcome occurs due to the need to balance the intermittent renewable generation and load with gas-fired resources.[xvii] As dispatchable, zero-emission technologies (such as geothermal, biomass, and hydro) are limited by resource availability, gas plants are needed to meet load when wind and solar PV resources are not available. In this analysis, we have not added storage capacity beyond the existing mandates that reach 1.3 GW in 2020, which would help balance renewable generation with load. In the absence of additional storage capacity or a regional RTO that combines operations of California electric system with the rest of the Western Electricity Coordinating Council (WECC), our analysis finds that GHG emissions reductions from the non-electric sectors are more cost effective than fully decarbonizing the electric sector under our assumed Current Trends conditions.

California Electric Sector Supply Mix Evolution

Our modeling approach presents a detailed picture of the California electric sector within a wider economy-wide analysis of GHG reductions. This window into the electric sector helps us understand the drivers of the reductions in electric sector emissions and the underlying dynamics that occur at different GHG prices. We find that as the GHG cap tightens, the electric generation mix in California is likely to evolve into a very different blend in 2050 from what it is today. Figure 12 shows the changing electricity generation mix in California over time, highlighting the growing role of solar PV and decline of fossil generation in California. Generation from in-state renewables (including wind, solar, biomass, and geothermal) provides about 50% of its load in 2030 and about 65% in 2050, driven by California's RPS, federal tax credits for renewables, and decreasing costs for solar PV.[xviii] Taking hydro and nuclear generation into account, total generation from zero-emitting sources (renewables, nuclear, and hydro) climbs to 60% by 2030 and about 73% by 2050, a significant increase from 33% today. While these figures seem high when compared to present-day numbers, natural gas generation still remains around 20% of the energy generation mix through 2050 even under such a stringent GHG policy.

FIGURE 12 Generation in California under Current Trends

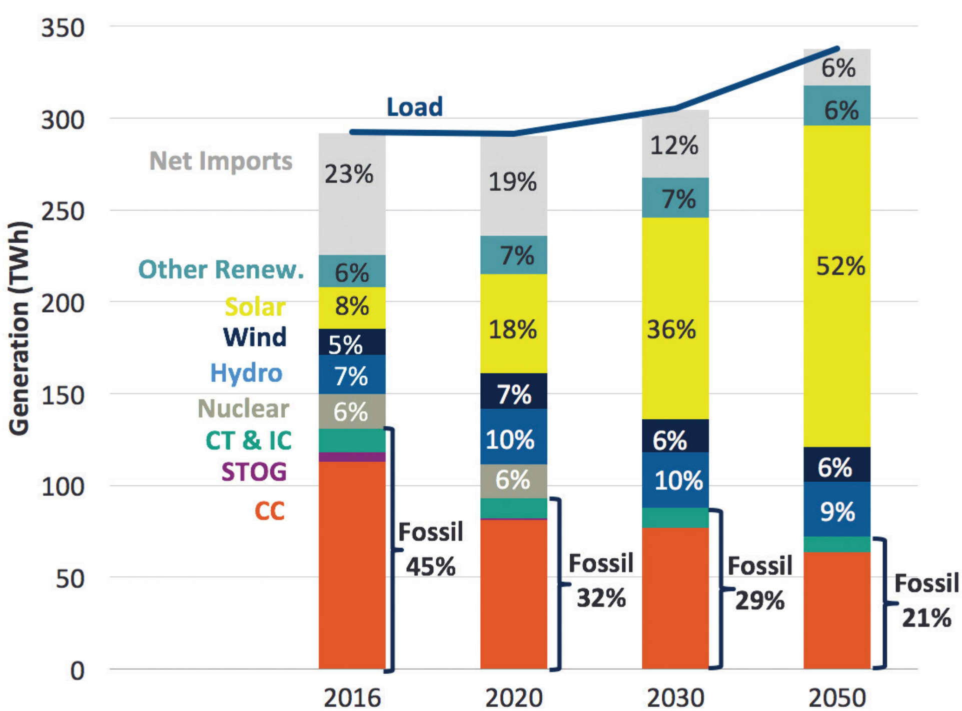


FIGURE 13 Installed Capacity in California under Current Trends

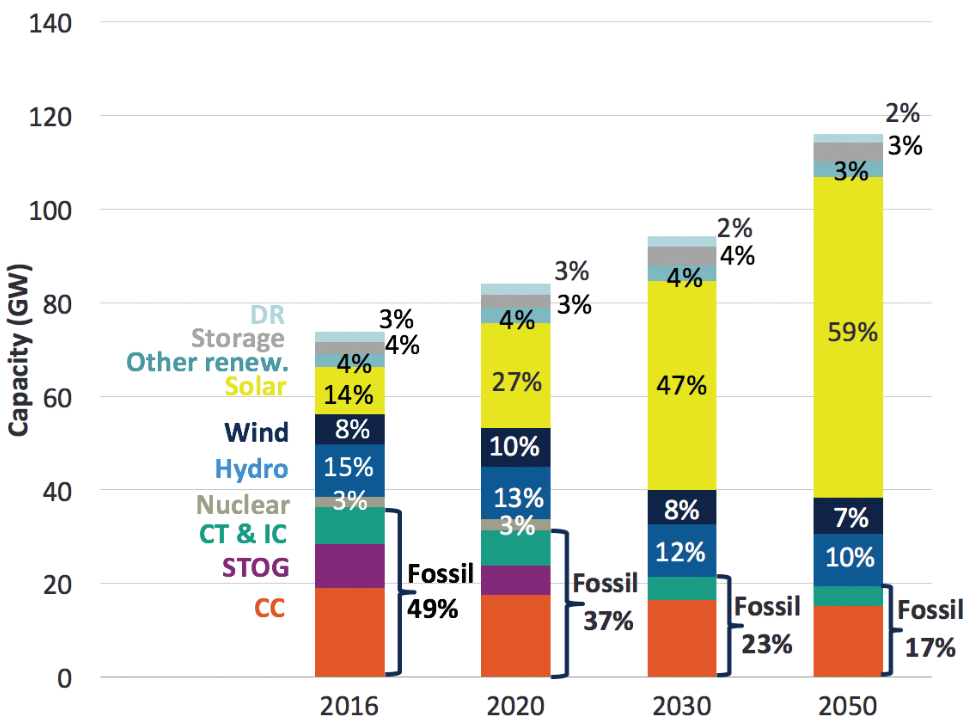
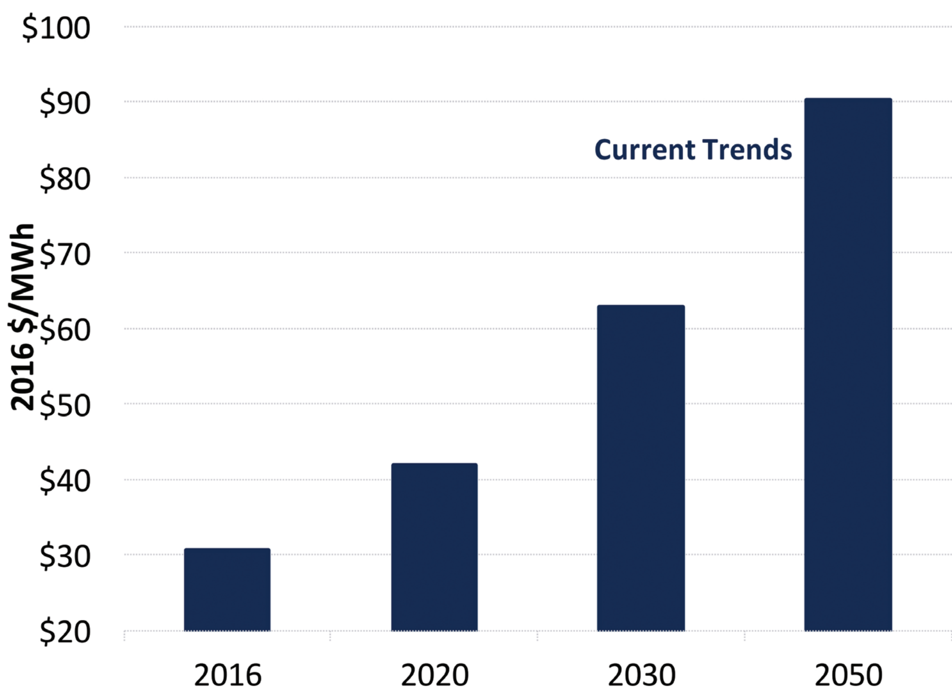


Figure 13 depicts a similar trend found for the installed capacity of resources in California. By 2050, solar continues to grow to over 60 GW of total capacity (an additional 24 GW from 2030) while wind capacity slightly grows with new builds roughly replacing retirements of the existing wind fleet (assuming a 40-year physical life of the wind turbines). As early as 2030, wind and solar PV represent more than half of the total fleet nameplate capacity. The rest of the fleet remains similar to today except for the retirement of 9 GW of steam oil & gas units (STOG) due to once-through cooling (OTC) requirement, 4 GW economic retirement of combined cycle units, and planned retirement of 2.3 GW Diablo Canyon nuclear units at the end of its license period in 2025/2026.

Finally, Figure 14 shows California average energy prices under the Current Trends scenario. Energy prices increase from around $30/MWh in the near term to around $60/MWh by 2030 and $90/MWh by 2050 (in 2016 dollars). Most of the increase is driven by the GHG price increases, partially offset by the price depression effect of increasing renewable penetration.

FIGURE 14 California Energy Price under Current Trends



Electric Sector in the Rest of Western U.S.

The electric sector in the rest of WECC shows a similar transition to a cleaner energy future, albeit to a much lesser extent due to less stringent clean energy policies in the other western states. By 2030, about 4 GW of wind and 9 GW of solar PV capacity are added, driven by RPS requirements, federal tax credits, and the cost decline. Because solar capital cost continues to decline at a faster rate than wind based on the National Renewable Energy Laboratory's forecast, it becomes more economic than wind in the long term. By 2050, an additional 20 GW of solar is built to meet the growing electricity demand and to replace existing wind that retires after assumed 40 year lifetime. About 22 GW of natural gas-fired combined cycle generation and 30 GW of natural gas-fired combustion turbine generation are also added while about 10 GW coal generation is retired by 2050, most of which have already been publicly announced. The GHG emissions across the rest of the western states do not decline significantly from today because the remaining coal-fired power plants operate at higher capacity factors with natural gas prices rising above $5/MMBtu after 2020. The wholesale energy prices in 2050 are around $45/MWh in real 2016 dollars.

Although California RPS and high GHG prices in California might provide incentives for building renewables in the rest of WECC to export to the California market, such development cannot be achieved without expanding the transmission capacity between California and other regions in WECC. The process of building transmission lines across transmission planning regions is complicated and often takes many years to get approved and built. In our analysis, we rely on the transmission capacity assumptions in CAISO's 2014 Long Term Procurement Plan (LTPP) study, which accounts for planned transmission expansion in WECC by 2024, and no transmission capacity is added between California and other regions in WECC.[xix] As a result, our modeling does not project large amounts of renewable additions in the rest of WECC exporting into California. In fact, as California adds large amounts of solar after 2045, it starts to export electricity during the times when excess solar generation is available in California.

B. THE EFFECTIVENESS OF COMPLEMENTARY POLICIES

As shown previously, much of the emissions reductions under the Current Trends case occur through complementary policies assumed in the non-electric and electric sectors. To understand the sensitivity of our GHG price projections to assumptions concerning complementary policies, we developed a scenario in which the non-electric complementary policies in the Current Trends case are assumed to be less effective at achieving GHG reductions.

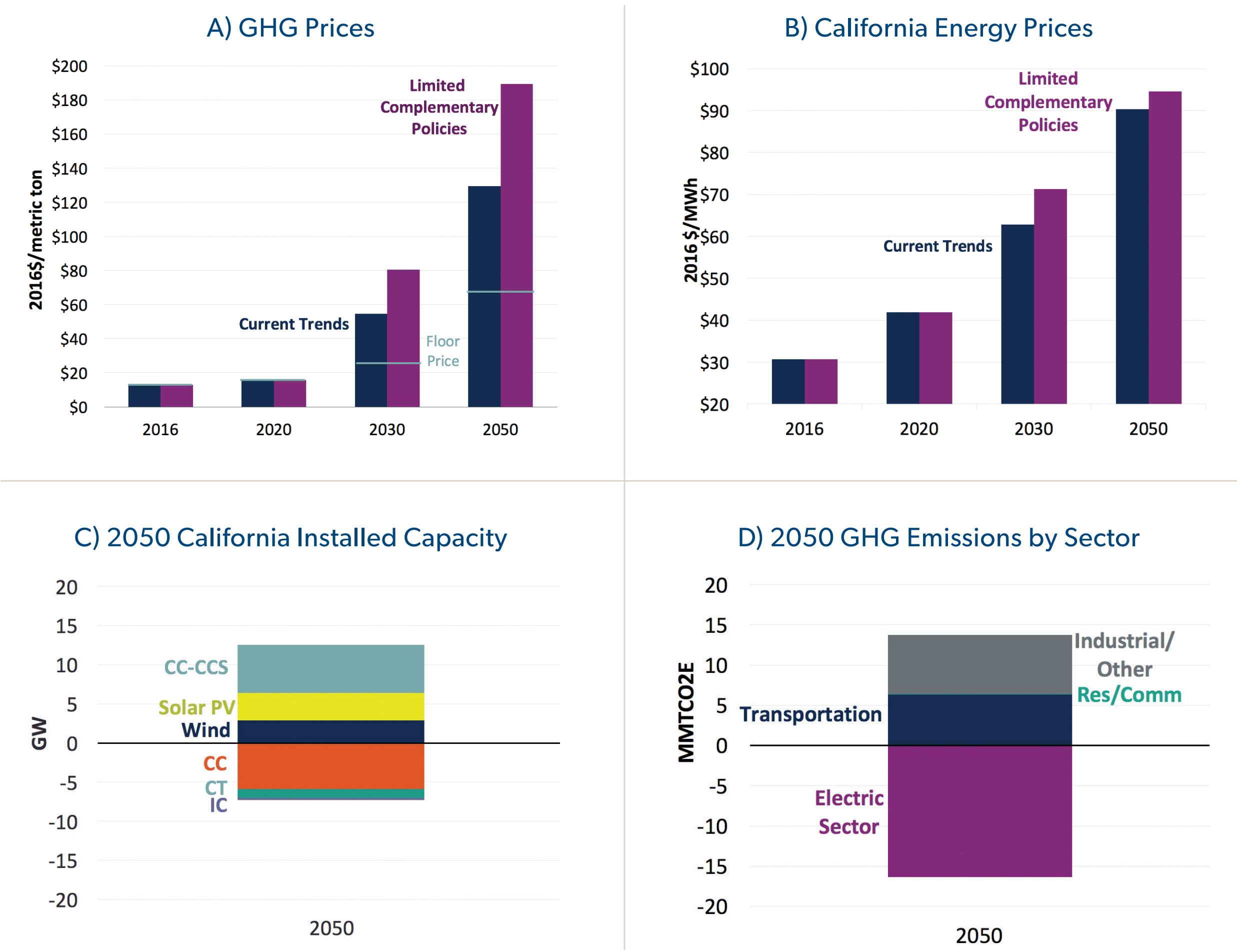
In the Current Trends scenario, we used projections of non-electric GHG emissions from an analysis completed by a researcher at the Lawrence Berkeley National Laboratory (LBNL) that considered different assumed levels of complementary policies through 2050 (see Appendix B for additional description of our assumptions). The LBNL analysis identifies three future cases that extend and build upon existing policies based upon a review of the possible effects of additional programs and technologies that could develop over the long term.[xx] In the Current Trends, we assume that the projected emissions reductions under the LBNL "Uncommitted Policies" scenario (LBNL Scenario 2) are achieved in 2030 and that the "Potential Policy and Technology Futures" scenario (LBNL Scenario 3) measures are achieved in 2040.[xxi] For the "Limited Complementary Policies" case, we assume the policies are phased in over a longer period of time, such that policies that LBNL Scenario 2 achieves by 2030 in the Current Trends are achieved instead by 2035, while policies that LBNL Scenario 3 achieves by 2040 are achieved by 2050 in this scenario. As a result, the Limited Complementary Policies scenario projects about 15% more GHG emissions in 2030 and 2050 after considering the impact of complementary policies alone and thus a net increase in the price-driven reductions required across all sectors.

The results of this scenario illustrate the considerable economic leverage that the complementary policies have on potential GHG prices. Figure 15 shows how the Limited Complementary Policies scenario compares to the Current Trends case in terms of GHG prices, wholesale energy prices, installed generation capacity, and emissions by sector. The more limited complementary policies result in GHG prices that are much higher than the Current Trends: by 2030, the GHG price is $80/ton (in 2016 dollars) and by 2050 the price rises to $190/ton, which are 45% higher in 2030 and 2050, respectively. More GHG emissions reductions occur in the electric and residential/commercial sectors driven by the increased GHG prices. Transportation emissions do not change from the Current Trends case as reduced abatement from complementary policies are matched nearly one-for-one by increased reductions due to the rising GHG price.

In the electric sector, we find that solar PV capacity increases by over 3.5 GW in 2050 and 6 GW of CC-CCS is built by 2050. (CC-CCS is not built in the Current Trends case.) With less GHG reductions from complementary policies, the Cap-and-Trade Program results in higher GHG prices that spurs higher levels of new technology adoption.

Despite the significant increase of 2050 GHG prices from $130/ton in the Current Trends case to $190/ton (almost a $60/ton increase), *wholesale energy prices only increase by $7/MWh*. This is a somewhat surprising and important result that the average price of power in 2050 is relatively insensitive to a significant increase in future GHG prices, since under the current generation mix, with natural gas-fired generation setting the price in most hours, a $60/ton GHG price would be expected to increase energy prices by $30/MWh. However, in 2050 the generation mix will have changed and become cleaner on average and at the margin, which reduces the impact of higher GHG prices on the wholesale energy prices. Policymakers in other settings, worried about the potential impact of high GHG prices from their policies, should bear in mind that if/when such high GHG prices occur, it is likely much of the lower cost compliance alternatives have already driven a lot of GHG emissions out of the market. Therefore, the economic impact of high GHG allowance prices is considerably attenuated across overall energy consumption.

FIGURE 15 Limited Complementary Policies Case – Comparison to Current Trends

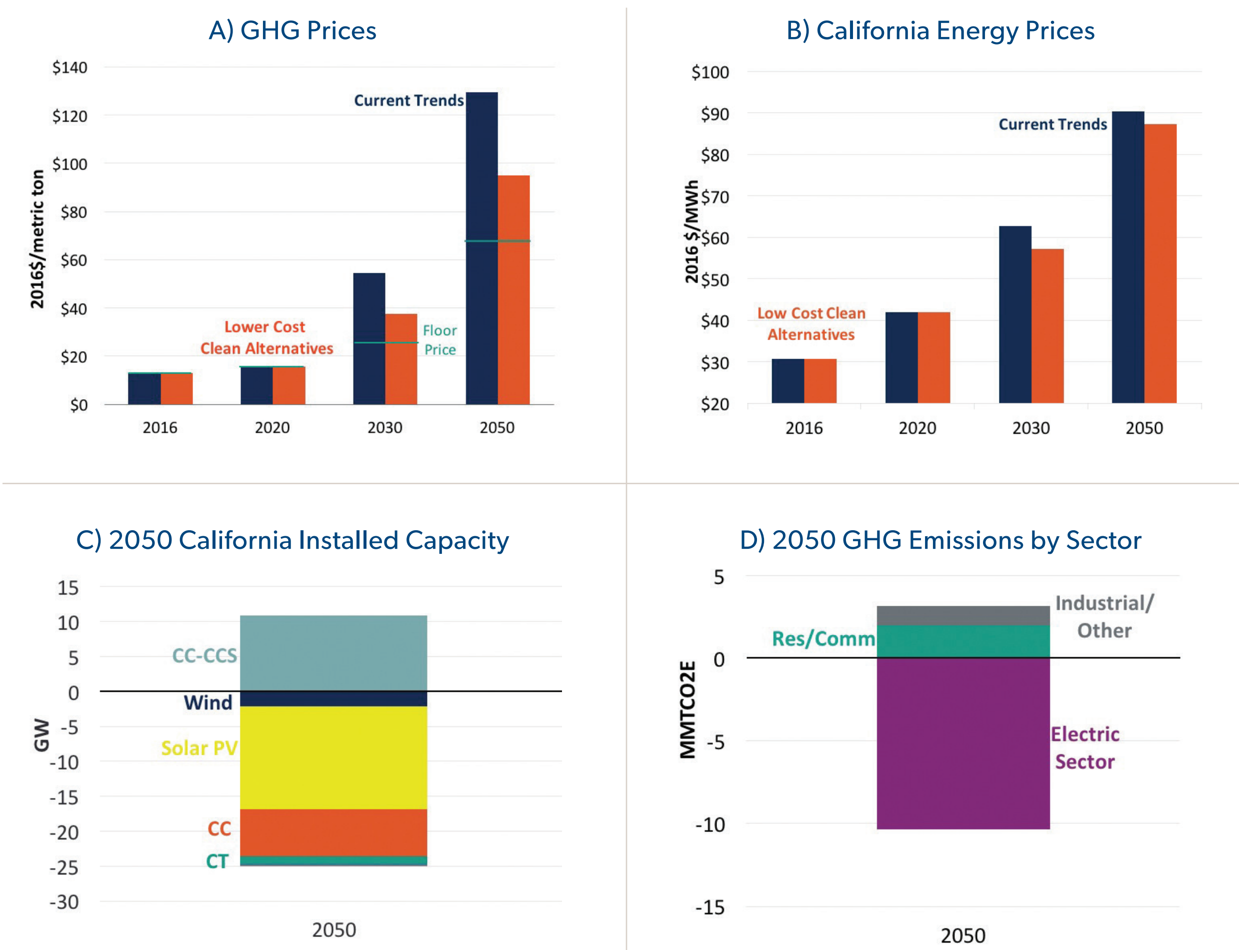


C. IMPACT OF LOWER-COST CLEAN TECHNOLOGIES IN NON-ELECTRIC SECTORS

We also analyzed an alternative case in which the introduction of less expensive clean technology in the non-electric sector enables consumers to respond more significantly to fossil fuel price changes by reducing their GHG emissions at any given level of GHG price. The increased price responsiveness of consumers is represented by doubling the reductions in fossil fuel consumption at each level of GHG prices, essentially making consumers twice as responsive to higher fuel prices. For example, in the transportation sector, we increase the elasticity of demand for transportation fuels (e.g., gasoline) from -0.7 to -1.4. The increase implies that if gasoline prices rise from $2.50/gallon to $3/gallon, the typical driver that would reduce their travel from 10,000 miles per year to 8,300 miles per year. This annually saves about a half ton of GHG emissions per vehicle. While this level of response may not be realistic based on what we would expect from current technology or customer behavior in the past, it reflects a test of how significant consumer response to higher GHG prices could be if more economical options were available for clean energy alternatives.[xxii]

Figure 16 shows that this greater price response causes GHG prices to be considerably lower than in the Current Trends case, by $15/ton in 2030 and by $35/ton (or about 1/3 lower) in 2050. The resulting wholesale energy prices in California are $5/MWh lower in 2030 and $3/MWh lower in 2050. As we discussed in the previous section, if we assume gas is always on the margin, then a $35/ton GHG price decrease should lead to about a $15-$25/MWh decrease in the electricity price. But the electricity price in this scenario decreases only by $3/MWh from the Current Trends case. This is not because of the reduced carbon intensity of the market by that time. Instead, under these assumptions, the greater emissions reductions from the non-electric sectors reduce the need for emissions reductions from the electric sector. It therefore increases the generation from carbon intensive fossil units, which offsets some of the price decrease we would have otherwise seen due to GHG prices alone. The result is that more fossil fuel-fired power plants stay online and fewer solar PV and wind are developed beyond the RPS minimums.

FIGURE 16 Lower Cost Clean Alternatives Case – Comparison to Current Trends



D. IMPACT OF LOWER NATURAL GAS PRICES

Natural gas is a widely-used fuel in both electric and non-electric sectors in California. Due to there being little in-state coal capacity, the California electric sector is more dependent on natural gas generation (currently providing 43% of electricity demand in California) than the rest of the U.S. (which averages 34% of its generation from natural gas).[xxiii] However, the electric sector accounts for less than half of natural gas demand in the state

(45%) with the remainder consumed in the residential (21%), industrial (25%), and commercial (9%) sectors.[xxiv] As such, natural gas prices affect consumption and GHG emissions in all sectors and ultimately affect the GHG prices needed to reach the emission reduction goals. We ran a sensitivity case with lower natural gas prices in which gas prices remain less than $3/MMBtu through 2050, or $2-3/MMBtu lower than Current Trends prices in current dollars.[xxv]

FIGURE 17 Low Natural Gas Prices Case – Comparison to Current Trends

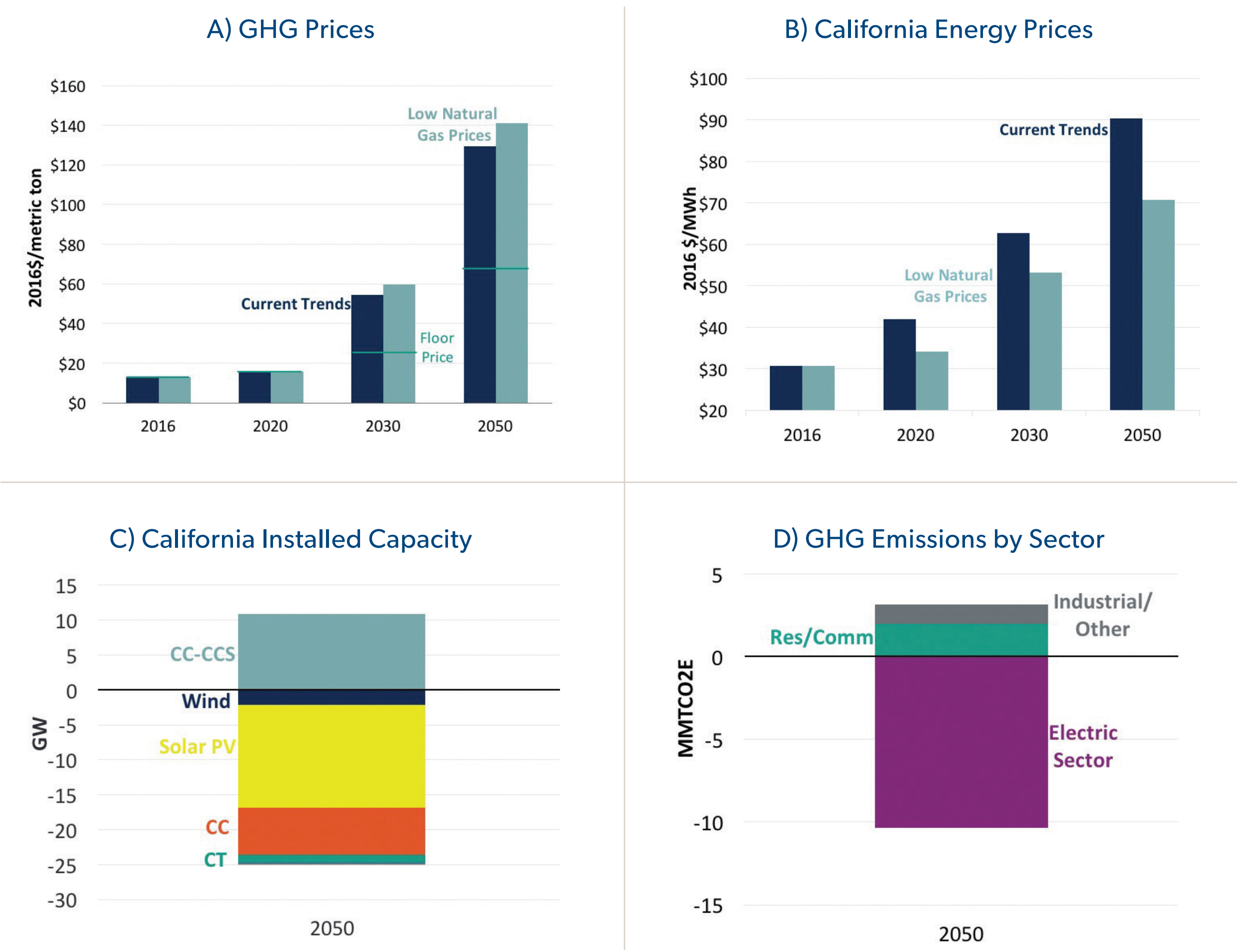


Figure 17 shows that the additional demand for – and emissions from the use of – cheaper natural gas results in GHG prices increasing by $5/ton in 2030 and to $12/ton in 2050. Wholesale energy prices (in Figure 17B), on the other hand, decrease as a result of lower natural gas prices, which more than offsets the increased GHG prices. Driven by the combination of higher GHG prices and lower natural gas prices, 11 GW more of new CC-CCS are added by 2050, displacing 2 GW of wind and 15 GW of solar PV. Over the same period, 8 GW more of existing (non-CCS) CC, CT, and internal combustion (IC) plants are retired. This case demonstrates that CC-CCS is more likely to be the marginal GHG reduction technology in a future with low gas prices.

The increase of GHG prices in the Low Natural Gas Prices case is the opposite of what would be generally expected elsewhere in the country. That is, in regions where coal is a significant portion of the fuel mix, low natural gas prices would make it cheaper to switch from coal to gas generation (and thus reduce GHG emissions and prices). In these regions (such as MISO or PJM), the lower the natural gas prices, the lower the GHG price needs to be for the natural gas generation to displace coal generation. However, in California and in the WECC generally, there is relatively little coal-fired generation capacity (compared to the eastern U.S.). As such, the emission reductions tend to occur by switching away from gas-fired generation to cleaner generation technologies such as renewables. Low gas prices obstruct this shift. A lower natural gas price means that a higher GHG price is necessary for renewables to become more economic than building new conventional natural gas plants.

V. CONCLUSIONS

The California Cap-and-Trade Program is a central element of the state's overall policy mix to reach its GHG emission reduction goal. To meet the California GHG reduction goals for 2030 (40% reduction) and 2050 (80% reduction), GHG prices will have to rise dramatically to drive consumers away from higher-emitting fuels and incentivize the development and adoption of clean technologies, as well as suppress some demand for fossil fuels outside of the electric sector. We find that GHG prices (in real 2016 dollars) will likely need to rise from the current price around $15/ton to $55/ton in 2030 and $130/ton by 2050 even with more aggressive complementary policies, such as RPS and the Low Carbon Fuel Standard.

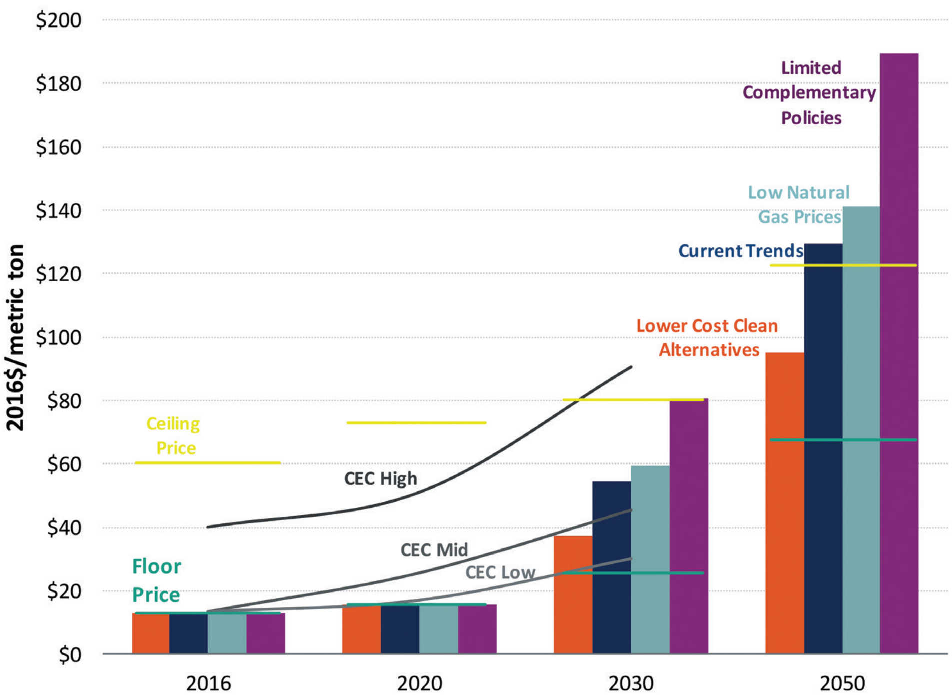
Key findings of our Current Trends case include:

- Most of the decarbonization has to come from outside the electric sector via complementary measures, which we base on LBNL's projection of technology improvements and potential future policies, and derive from estimated price response from non-electric fossil fuel users. Marginal costs of emissions reductions from non-electric sectors largely set the GHG prices under the Current Trends outlook.
- With banking of GHG allowances over the period 2021-2050, California does not quite achieve the 80% emissions reduction annual goal in 2050. Total emissions levels after 2035 are higher than the annual emission caps. This is because the tightening GHG emissions cap results in some banking of allowance in earlier years with the anticipation of higher compliance costs in the future. However, California achieves the cumulative emission reduction goal during the period 2021-2050.
- In the electric sector, we find that the system will have significant additions from renewable resources (in particular solar PV) by 2050. Under our Current Trends case assumptions, 60% of the California capacity will be wind and solar by 2050.
- However, we do not find that nearly complete decarbonization of the electric sector will occur by 2050. Under our Current Trends scenario, fossil fuels remain at around 20% of the generation mix in 2050 and electric GHG emissions in the Current Trends remain above 30 MMT throughout the period analyzed.
- Notwithstanding quite high GHG prices, average wholesale energy prices do not increase nearly as much as they would with today's generation mix because the electric sector is significantly decarbonized by 2050.

As with any long-term projections, our Current Trends GHG price outlook hinges on the assumptions of key underlying drivers, which are uncertain by nature. While these were grounded in the state's own economic assumptions about its future policies and widely-used public sources for industry data, they are of course uncertain. This is especially true when projected far into the future and when the policy and technology landscape is likely to have evolved from what we now can foresee. As a result, our Current Trends scenario reveals the consequences of what the current trends will lead to and would need to improve to do better.

Given the uncertainties, we evaluated scenarios involving three key factors: lower natural gas prices, reduced effectiveness of complementary policies, and greater demand elasticity in non-electric sectors. Figure 18 shows that these can cause GHG prices in 2030 to range from $37/ton to $80/ton in 2030 (-31%/+48%) around the Current Trends case and from $75/ton to $160/ton in 2050 under these sensitivities (-27%/+46%).

FIGURE 18 GHG Prices by Case



These results reinforce our observations under the Current Trends case about the importance of factors outside of the electric sector to California GHG prices. In particular:

- The effectiveness of future complementary policies will significantly impact the level of GHG prices. We find that a decrease of 15% in the emissions reduction from complementary policies results in GHG prices increasing by about 50% in 2030 and 46% in 2050. In addition, the majority of future California GHG emissions reductions must come primarily from the non-electric sectors, especially transportation. Complementary policies that accelerate adoption of electric vehicles and rail usage are the primary drivers behind these GHG reductions. However, as promising as these technology improvements may be, they depend on technology innovation, political decisions to develop the needed infrastructure, and behavioral adoption, all of which are uncertain but could be nudged by state policies, including how GHG revenues are recycled back into the economy.

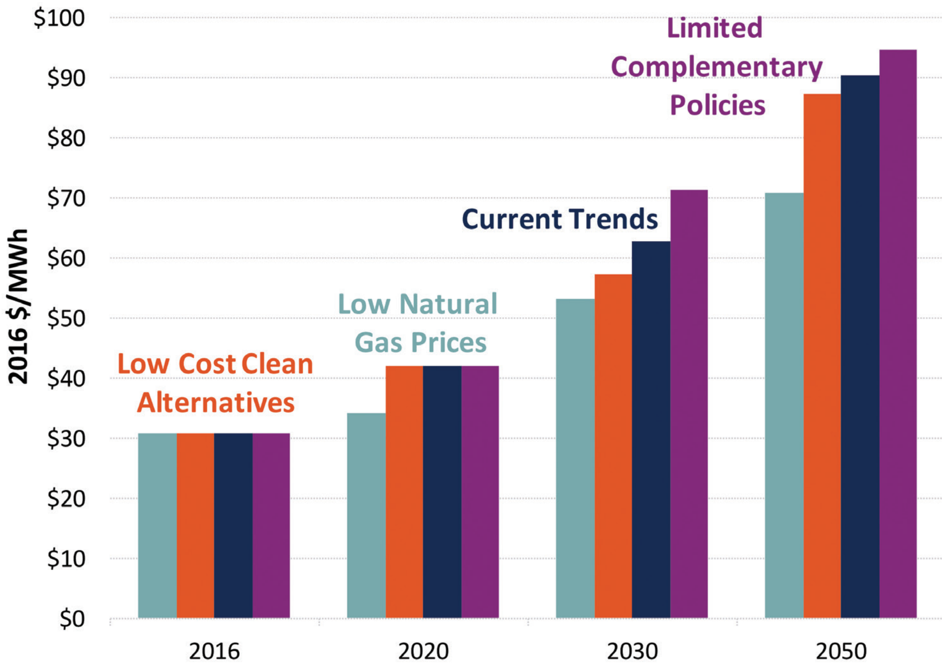
- Lower cost clean energy development in the non-electric sectors reduces GHG prices, but causes somewhat more GHG to be emitted in the electric sector, since the more the non-electric sector reduces its fossil fuel usage, the less pressure there is on the electric sector to do so.

- Unlike other parts of the country, in California lower natural gas prices lead to higher GHG prices because: 1) there is almost no gas-displacement of coal-fired generation in California, 2) demand for natural gas in non-electric sectors increases, and 3) switching away from gas-fired generation to renewable resources becomes less economic.

- Alternative scenarios project further electric sector emission reductions when: (1) natural gas prices are lower and CC-CCS becomes more economic, or (2) if GHG prices rise high enough to incentivize further renewable deployment. Notwithstanding these effects, we do not project the full decarbonization of the electric sector.

The projected California wholesale energy prices across these cases reflect the underlying differences in investment and operation decisions that occur in each scenario. Figure 19 shows wholesale all-hours real energy prices range in 2030 from \$53/MWh to \$70/MWh and from \$70/MWh to \$95/MWh in 2050. While wholesale energy prices increase over time across all cases, we find there is a diminishing GHG price impact due to underlying differences in generating capacity across scenarios. In 2050, wholesale energy prices become somewhat insensitive to GHG prices differing by just \$7/MWh in the three cases with equivalent gas prices but \$100/ton difference in GHG price. The declining average impact of GHG prices on wholesale energy prices as the system becomes increasingly decarbonized occurs due to more renewable penetration depressing the prices and the low carbon emission rate of CC-CCS reducing the impact of GHG prices on marginal generation costs. Wholesale energy prices in the Lower Gas Case decrease as a result of lower natural gas prices, which more than offset the increased GHG prices.

FIGURE 19 California Energy Price by Case



We are not suggesting that these results represent a precise forecast of GHG or power prices. Their main point is to highlight the interdependencies of key policies and market conditions, and the potential limitations, or perhaps risks, of relying on hoped-for exhaustion of electric and other GHG emissions via prices. Thus, our analysis shows that in the absence of technology breakthroughs, it is very plausible that GHG prices will become much, much higher than the initial few years of experience under the Cap-and-Trade Program might have lead people to expect. This is because the long-term GHG targets for California require reductions beyond the extensive reliance on the foreseen complementary policy opportunities and thus require reductions across consumer sectors with a fairly low demand elasticity for setting the GHG prices.

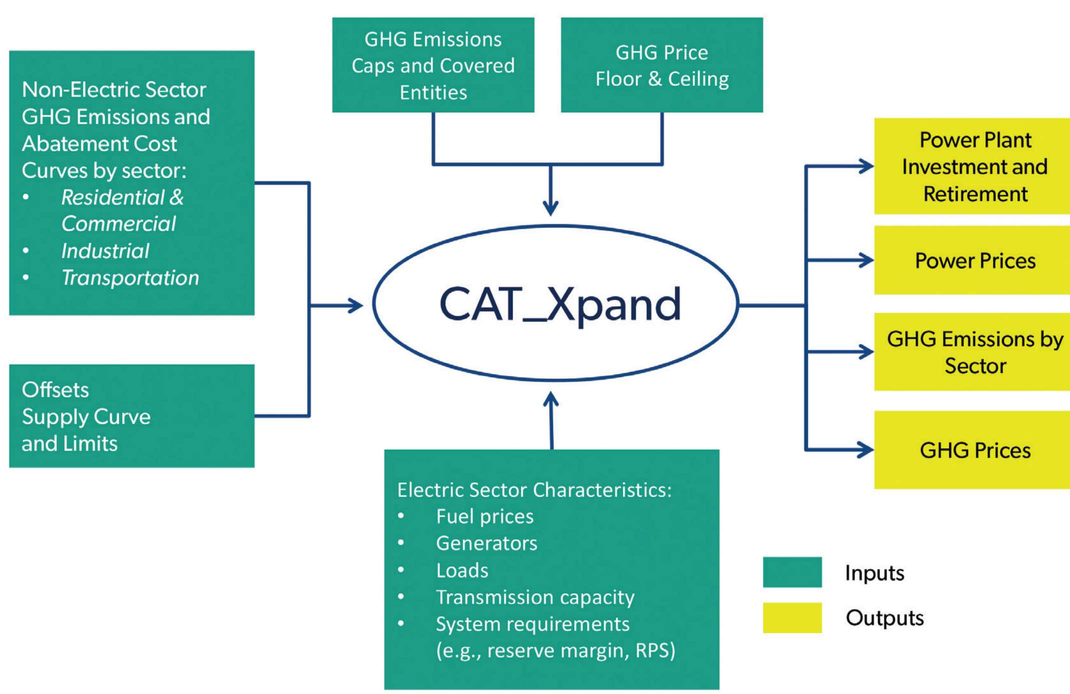
Importantly, an unfounded conclusion to draw from this analysis would be that complementary policies are *per se* superior to market alternatives. Just because complementary policies here result in the majority of emissions reductions and might be able to avoid high GHG prices for the Cap-and-Trade Program, that alone does not prove that complementary policies are more cost-effective or beneficial than potential market responses. Complementary policies have a real cost to consumers and tax payers, but it is not revealed through the GHG market (nor are those costs in any way reflected in our power or GHG market modeling). Instead, it is felt in taxes to fund the programs and the prices of other goods and services. Their costs should be considered in parallel with the types of market costs revealed here to determine which is more attractive.

In sum, while California is on a path to dramatically reduce GHG emissions and is leading the nation for its endeavor to decarbonize its economy, significant uncertainties still lie ahead for the California Cap-and-Trade Program and the future outlook of GHG prices. As GHG prices are a critical input to electric sector operation and investment decisions and generator profit margins, system planners in the electric sector have to make long-term strategic decisions based on expectations of the market and policies. The model we developed here presents an analytical tool that helps to better understand the dynamics of the GHG market and how strongly the GHG constraints and prices will interact with other state policies for alternative means of reducing fossil fuel usage or for fostering new electrification technologies. Other states considering their own decarbonization should consider the insights from California when setting their own policies, and they should conduct similar analytic studies to evaluate the tradeoffs of alternative policy instruments and to develop successful GHG reduction policies.

APPENDIX A: THE MODELING TOOL: CAT_XPAND

We developed the CAT_Xpand modeling tool to analyze California's long-term GHG compliance with the Cap-and-Trade Program. CAT_Xpand is an augmentation of the Xpand tool, which is an electric sector model Brattle has, by incorporating non-electric sectors emissions in order to model economy-wide GHG policies. Figure 20 provides a schematic view of the modeling tool we developed for this analysis.

FIGURE 20 Schematic Representation of CAT_Xpand



The Xpand tool is a least-cost linear programming (LP) model that simulates long-term generation expansion and short-term dispatch of the electric sector over a modeling horizon of several decades in meeting electricity demand forecasts, environmental regulations, and reliability requirements. It also incorporates limits on technology availability by region and type, and constrained transmission interconnections between regions, among other resource planning factors. By incorporating projected non-electric sectors emissions and abatement cost curves, the CAT_Xpand tool considers the economic trade-offs between reducing emissions in the electric sector and non-electric sectors to comply with the economy-wide GHG caps, thus allowing GHG prices to be determined endogenously at economy-wide equilibrium. Like any LP problem, the model operates on the following three key elements that define the utility resource planning problem to be optimized:

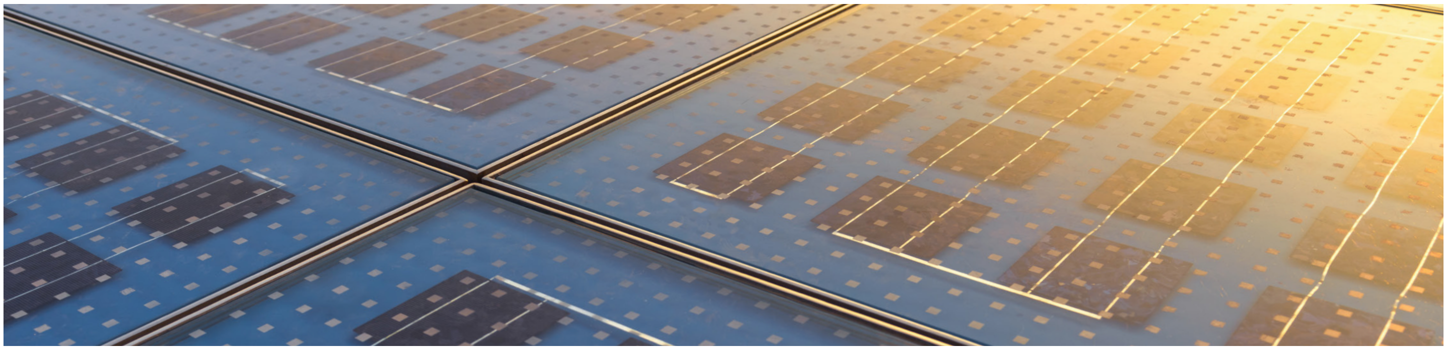
A. OBJECTIVE FUNCTION

The objective function of any LP is a mathematical function describing the performance to be maximized or optimized by the model, expressed in terms of the variables that correspond to decisions the model can make about operations. In CAT_Xpand, the objective function to be minimized is the total system cost (in present value) over the entire modeling horizon. The component costs to be jointly minimized include the capital costs for new resources, the costs of operating and maintaining existing and new generation capacities (Fixed O&M and Variable O&M), fuel costs, the costs incurred for exporting or importing powers from other regions (i.e., hurdle rates), and emission charges that electric and non-electric sector GHG emitters have to pay.

B. DECISION VARIABLES

Decision variables are what an optimization model can manipulate (and then reevaluate the resulting costs) in order to find the optimal solution that minimizes the total system cost while meeting all constraints and obligations regarding the future electricity demands and other system requirements. Key decision variables include:

- **Generation dispatch.** These plant usage decisions are made for each demand period for each year and each generator in the model. In the absence of other constraints, with a given generation fleet available at any time, in order to minimize the total system cost, the unit that has the lowest variable cost, including variable O&M and fuel cost, will be dispatched first, subject to the units' operational constraints such as availability and maximum output. Other units are then added in increasing cost order until total tranche demand is satisfied.
- **New capacity additions and retirements.** These two decision variables determine the selection of generic new capacity (based on it having all-in development and operating costs below future market prices) and the economic retirement of existing capacity (in situations where the plant's avoidable, to-go costs exceed the projected market prices). Additions are based not only on economic value but also on the strict need to meet reserve margin requirements that assure the system always has a sufficient pool of available capacity to achieve reliability goals.
- **Imports and exports.** Using a topography of multiple WECC sub-regions connected with measures of their cumulative feasible transmission interface capacity, CAT_Xpand also determines the appropriate trading (imports and exports) of power between regions to further reduce each region's electricity cost. This is affected by the relative cost of producing power locally versus importing from neighboring regions, including the transaction cost that has to be incurred when power is moved across regions based on the transmission tariffs, as well as the transmission limits.
- **Sectoral GHG emission reductions.** Given the information on the GHG abatement curve for the non-electric sectors and the generation and emission profiles of the generators in the electric sector, CAT_Xpand determines the most economical way to meet the GHG cap by comparing the cost of abatement from the non-electric sector with that from dispatch of the electric sector in order to find the lowest cost solution and reach an equilibrium price for GHG.



C. CONSTRAINTS

Constraints in any LP reflect the limits on how far the decision variables can be adjusted and any rules there are for standards or targets their collective use has to satisfy. In power systems generally, such constraints include not using plants or power lines beyond their maximum loading limits, meeting all demands in all periods, holding adequate reserve margins, satisfying (or not exceeding) pollution limits, and observing various plant scheduling restrictions. As described in more detail later, CAT_Xpand has many such conditions imposed on acceptable solutions to its objective function. Collectively, they restrict the range of allowable values for the decision variables (plant expansions, plant usage, etc.) to combinations that are said to be "feasible" (i.e., do not result in any constraint being violated). When CAT_Xpand (or any linear program) searches for the optimal value of its objective function, it does so by moving around the perimeter of the feasible region to find the most valuable (or least cost, depending on the specification) combination of operating conditions that satisfies all the constraints. Specifically, in our CAT_Xpand model the key constraints include:

- **Supply-demand constraints.** This constraint represents the requirement for electric supply (including net imports) to be no less than the contemporaneous load in each area in each period.[xxvi] The model categorizes the hourly load into the more aggregated tranche levels that are not necessarily chronological but still reserve the variations of the load that are important to affect the dispatch and capacity addition decisions among different technology types. In CAT_Xpand, this process is done within each of the four quarters. It groups all the hours in a quarter into 18 tranches, starting with the highest load hours. The model calculates the optimal deployment of generation units to meet the average load level in each tranche, and the associated costs. The shadow price of the demand constraint is the energy price for each region for each tranche.
- **Reserve margin constraints.** As discussed previously, the reserve margin constraint enforces the resource adequacy requirements in each market region for maintaining reliability. CAT_Xpand models the reserve margin requirement as annual peak load for each modeling region plus the additional capacity requirement on top of the peak load as specified in their local resource adequacy requirements, often set by state regulatory convention or by an ISO where present. In minimizing the total system cost through decisions on new capacity additions and retirements, the model ensures that the required capacity in each year is available in order to satisfy these reliability constraints. The shadow price of the reserve margin constraint is the capacity price for each reserve margin region used by the model to evaluate such additions and closures.
- **Emission cap constraints.** The emission cap constraint models the cap and trade program in California. It requires all the emissions from the in state generators (based on their generation output, heat rates and fuel emissions rates) and all emissions from the imported power (based on the emission factors designated by ARB, as discussed previously) have to be less than or equal to the total GHG cap. The shadow price of the emission cap constraint is the California GHG price forecast.
- **RPS constraints.** For regions with RPS requirements, the constraints are added so that the total generation from eligible technologies is equal to or larger than the required share of generation from renewables. (Renewables can be added by the model because they are economically attractive, in addition to being required in order to meet the RPS rules.) The shadow price of this constraint is the REC prices.

- **Transmission constraints.** In CAT_Xpand, transmission representation uses a "pipes" approach that simulates flow between regions, limited by available transfer capabilities. Within each region, transmission is assumed to be unconstrained. A pipes approach treats transmission flows as though they are directionally controllable and independent of each other on adjacent paths, when in fact they interact in a more complex, less controllable way due to Kirchoff's Laws of Electricity. However, at the level of aggregation in CAT_Xpand, the pipes approach is a useful approximation that does not interfere with (in fact, facilitates) the purpose of identifying future expansion needs and projecting GHG prices (since neither of these depends strongly on very local, short term conditions). It is common in power system expansion models to use a "pipes" approximation; the applied limits are derived from results from more formal transmission engineering models.
- **Operational constraints.** These constraints specify how much electricity each plant can generate as a maximum given its capacity and availability. Generally, the availability of a plant is a function of the forced outage rate and planned outages, usually scheduled in off-peak seasons during a year. However, for intermittent renewables, including wind and solar that are not dispatchable, their production limits are specified with fixed generation schedules/availability factor that reflect the shape of historical seasonal and hourly outputs from 2005, distributed across the load tranches based on the same hours-to-tranches mapping as load.

With the objective function and constraints encoded as outlined previously, plus all the plant operating cost parameters for their fuel, VOM, and other expenses, the model optimizes the decision variables so that the total system cost is minimized. As a result, it forecasts the generation mix, capacity mix, and emissions over time and the various prices such as energy prices, GHG prices, REC prices and capacity prices.

APPENDIX B: KEY ASSUMPTIONS DEVELOPMENT

Our analysis builds on previous analyses that focus primarily on the infrastructure and additional costs necessary to achieve the long-term goals in California, such as the E3 California Pathways study[xxvii] and studies by researchers at the LBNL.[xxviii] These analyses provide important insights into the potential paths to decarbonizing the economy and account for rates of technology development, turnover of infrastructure, and future policy mandates to identify what GHG emission are achievable over the next several decades. Our analysis takes the additional step of analyzing the role that the Cap-and-Trade Program will have on achieving reductions across the economy beyond those achieved through complementary policies, and further provide insights on how GHG emissions and allowance prices are affected by complementary policies and other factors in the economy.

Analysis of the California Cap-and-Trade Program requires representation of all sectors in the economy covered under the GHG emissions cap. Figure 21 shows that the transportation sector was the largest contributor, emitting 37% of the total GHG emissions in 2014, followed by the industrial sector (24%), the electric sector (20%), residential and commercial sectors (11%), and agriculture sector (8%). In our modeling approach, we utilize sector-by-sector projections of future GHG emissions from the LBNL analysis that account for future portfolios of complementary policies across the non-electric sectors and develop GHG emissions abatement curves to further reduce GHG emissions in these sectors in response to GHG prices. We integrate the non-electric abatement curves and GHG caps with a detailed characterization of the electric power sector, which allows us to capture the interactions between electric sector GHG emissions and emissions from the rest of the economy, and provide deeper insights about the electric sector under the Cap-and-Trade Program.

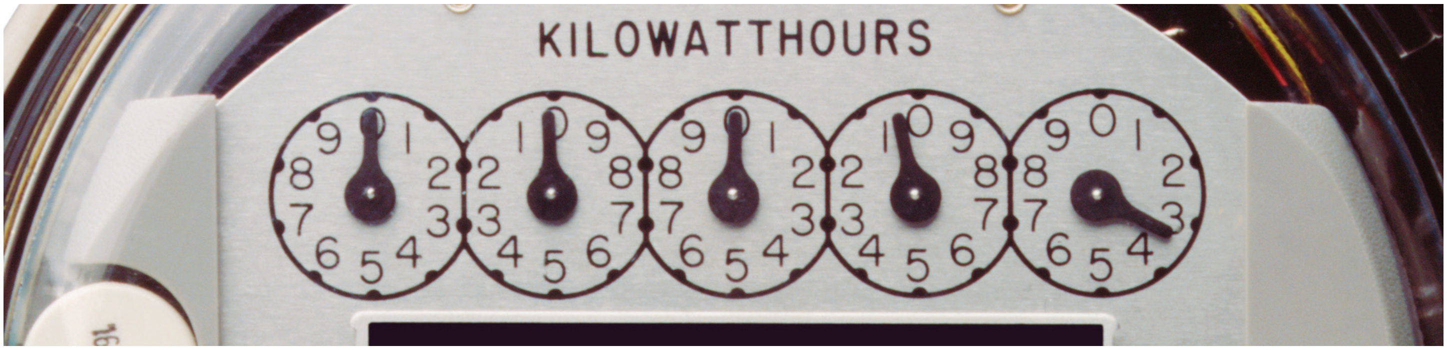
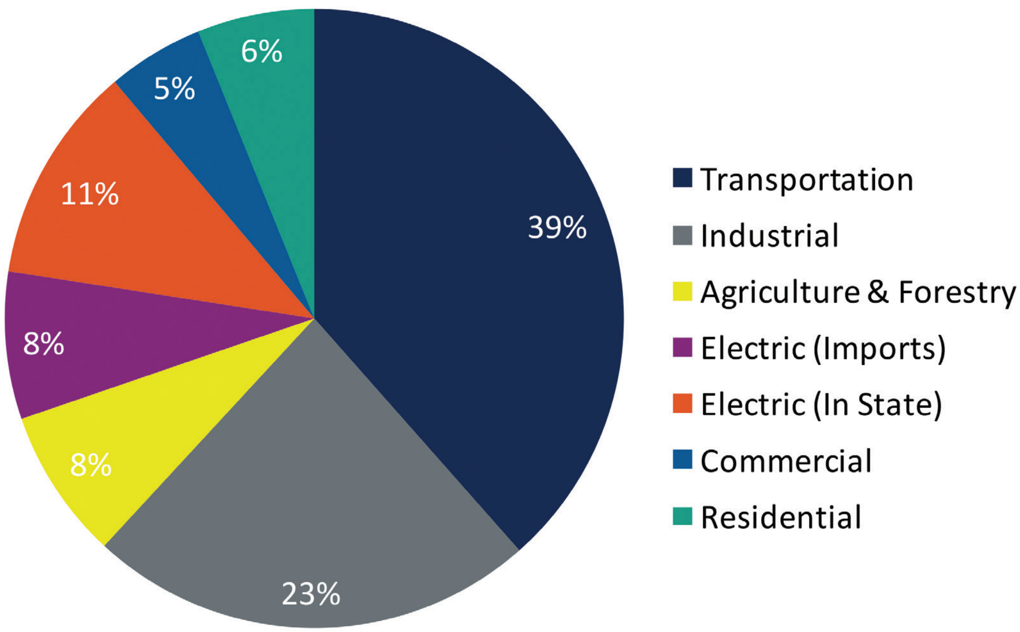


FIGURE 21 2014 California GHG Emissions by Sector



Source: ARB, California's Greenhouse Gas Inventory by Sector & Activity, Ninth Edition: 2000 to 2014, March 30, 2016.

We provide a summary of key assumptions CAT_Xpand uses to optimize the power system under an economy-wide GHG emissions cap:

- For the **electric sector**, the major inputs include: (1) technical characteristics of power plants, such as capacity, heat rate, and fuel emission rate; (2) economic characteristics of power plants, such as O&M costs, investment cost for new plants, and fuel prices; (3) electric loads, load profiles, and renewable production profiles; (4) transmission capacity constraints amongst different WECC regions and hurdle rates for power transfer between regions; and (5) system requirements, such as reserve margin requirement, RPS requirement, etc. All of the inputs assumptions are developed based on public sources through a well-vetted process.

- For the **non-electric sectors**, including transportation, residential/commercial, and industrial sectors, we utilize projections of GHG emissions by researchers at LBNL under several potential scenarios with increasingly stringent complementary policies, but before a GHG price is applied. For example, in the transportation sector, LBNL increases the deployment of Zero Emissions Vehicles from the current target of 13% in 2050 in the "Committed Policies" scenario to a high case of 60% in the "Potential Policy and

Technology Futures" scenario and the efficiency of conventional vehicles from 40 miles per gallon in 2040 ("Committed Policies") to 54 miles per gallon in 2050 ("Potential Policy and Technology Futures").[xxix] We generate a Current Trends projection of GHG emissions for our modeling purposes based on these scenarios by phasing in the more stringent complementary policies through 2050. Then for the potential emission reductions due to consumer's price responsiveness to GHG and fuel prices, we construct GHG emission abatement curves based on the GHG emissions reductions that result from the complementary policies (which we draw from the LBNL analysis) and the estimated elasticity of demand for the fuel type in each sector.[xxx]

- The Cap-and-Trade Program also allows for compliance via **carbon offsets**. The offset credits are generated through ARB-approved "offset protocols," including reductions in ozone depleting substances and reforestation efforts.[xxxi] Up to 8% of each entity's compliance can be achieved through the retirement of carbon offsets that have been approved by the ARB under current Cap-and-Trade regulations. AB 398 reduces the offset limits for 2021 to 2025 to 4% and 6% thereafter.[xxxii] We developed an offset supply curve as an input to CAT_Xpand based on the analysis of several different supply curves from publicly-available studies by the ARB and the Western Climate Initiative (WCI).[xxxiii]

- We then apply a **GHG emission cap,** which limits the emissions from the electric sector and non-electric sectors. We set the long-term cap and allowances held in the APCR based on the recently proposed Cap-and-Trade amendments that reflect SB 32 as well as gubernatorial executive orders. Emissions reductions necessary to meet the cap can either be due to complementary policies (as projected by the LBNL study) or driven by rising GHG prices, as endogenously determined by CAT_Xpand across electric and non-electric sectors.

- Lastly, GHG **floor prices and ceiling prices** are also inputs to CAT_Xpand. The floor price is determined per the parameters in the current regulations, increasing annually by inflation plus 5%. Although the current program does not include a hard price ceiling, the APCR mechanism is intended to provide a "soft ceiling" and some certainty of the upper bound of future GHG prices. We set the GHG ceiling price based on the third tier APCR increasing at inflation plus 5%. We have not incorporated the adjustments to APCR pricing or the transfer of unsold allowances into the APCR that the ARB proposed in the 2016 amendments.

ENDNOTES

i. The Cap-and-Trade Program regulations analyzed in this paper are similar but not identical to those recently approved by ARB in September 2017. Changes required in AB 398 to the Allowance Price Containment Reserve and limits on the use of offsets for compliance have not been incorporated into the analysis presented in this paper.

ii. A regional RTO would combine operations of California electric system with a significant portion of the rest of WECC and provide additional options to integrate high levels of renewables into the system and additional power from a large pool of existing, dispatchable generation. For more information on the impacts of an expanded western RTO, see: http://www.caiso.com/informed/Pages/RegionalEnergyMarket.aspx

iii. Throughout this paper we present prices that represent dollars per metric ton, but refer to the price in terms of "$/ton" for simplicity. The floor price rises each year by 5% plus inflation. The first auction occurred in November 2012 with a floor price of $10/ton. In 2017, the floor price is $13.57/ton.

iv. The unsold allowances in the quarterly auctions will be held by the ARB until two consecutive auctions clear above the floor price. The allowances will then be returned into the auctions over time, under the limitation that previously unsold allowances can represent a maximum of 25% of the California allowances offered at the auction in which they are returned.

v. The CEC projected 2013 electricity consumption of 292,649 GWh in December 2009. Actual electricity consumption in 2013 was 278,921 GWh. For the 2009 projection of demand, see: http://www.energy.ca.gov/2009publications/CEC-200-2009-012/CEC-200-2009-012-CMF.PDF, p. 37. For the actual 2013 electricity consumption, see: http://www.energy.ca.gov/2015_energypolicy/documents/index.html#adoptedforecast

vi. Results from the allowance auctions are available here: https://www.arb.ca.gov/cc/capandtrade/auction/auction.htm

vii. The total banked allowances accounts for an excess of allowances in both California and Quebec.

viii. Hydro generation California in 2016 was near the average level of hydro generation since 2000, but was notably higher than the historically low generation in the most recent years.

ix. ARB, Linked California and Quebec Cap-and-Trade Programs Compliance Instruments Aggregated by Type and Account, October 24, 2017. Available at: https://www.arb.ca.gov/cc/capandtrade/complianceinstrumentreport.xlsx

x. California Legislative Information, SB-32 California Global Warming Solutions Act of 2006: emissions limit. (2015-2016), https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB32. California Legislative Information, AB-398 California Global Warming Solutions Act of 2006: market-based compliance mechanisms: fire prevention fees: sales and use tax manufacturing exemption. (2017-2018), https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201720180AB398

xi. The changes to the Cap-and-Trade regulations included in the 2016 amendments can be found here: https://www.arb.ca.gov/regact/2016/capandtrade16/capandtrade16.htm

xii. Currently, there are 144 MMT allowances held for APCR auction through 2020. An additional 55 MMT of allowances will be withheld from the allowance allocations and auctions from the 2021 to 2030 caps and added to the APCR starting in 2021.

xiii. The Senate leadership package also included proposals for reducing transportation emissions by 50% by 2030 (the last "50" in the 50-50-50 plan) but this portion of the legislation did not pass.

xiv. For example, the average cost of RPS compliance in California in 2014 was $100/MWh. Assuming generation from RPS-qualified resource primarily displaces natural gas-fired combined cycle generation with CO_2 emissions rate of 0.4 metric tons/MWh, the costs of GHG abatement would be $250/metric ton. This carbon abatement cost is much higher than the projected marginal cost of abatement across all scenarios in our analysis. For RPS compliance costs, see: http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=8323

xv. We assume a long-run elasticity of demand for gasoline of -0.7 based on analysis summarized in Lin, C.-Y. Cynthia, and Lea Prince. "Gasoline price volatility and the elasticity of demand for gasoline." *Energy Economics* 38 (July 2013): 111-117. Several studies we reviewed estimate long-run elasticity of demand for gasoline of more than double the value we assumed in our analysis for the Current Trends scenario. We incorporate the higher long-run elasticity of demand for gasoline in the Lower Cost Clean Alternatives scenario.

xvi. In this study, we assume gas CC-CCS will become economically feasible at about $90/MWh all-in incremental cost at an 85% capacity factor. Cost of solar PV generation is expected to become lower in the future, decreasing at a rate of 5-6% per year for the next ten years, then decreasing at a slower rate after that based on 2016 National Renewable Energy Laboratory's Annual Technology Baseline.

xvii. While storage may help to address this issue to some extent by shifting electricity from the hours with excess generation to lower output hours, a large amount of deployment for the seasonal shifts in generation necessary to fully decarbonize the electric power sector is unlikely without significant cost reduction or additional mandates.

xviii. The RPS prior to 2030 is modeled as what is required in California legislation to hit 50% in 2030 and after 2030 is assumed to be constant at 50%.

xix. The recently-released Renewable Energy Transmission Initiative 2.0 (known as RETI 2.0) report found significant transmission capacity is currently available to meet the 2030 RPS mandate of 50% with resources within California but there are "several potential transmission constraints in California and along the major import-export paths that could limit the delivery of additional renewable energy." California Natural Resources Agency, Renewable Energy Transmission Initiative 2.0 Plenary Report, Public Review Draft, December 16, 2016, p. 6. In addition, interregional transmission planning between CAISO and neighboring transmission planning regions may result in additional capacity to import renewables into California. See: https://www.caiso.com/planning/Pages/InterregionalTransmissionCoordination/default.aspx

xx. Greenblatt, Jeffrey B. "Modeling California Policy Impact on Greenhouse Gas Emissions." *Energy Policy* 78 (2015): 158 - 172.

xxi. For example, the LBNL analysis assumes high speed rail is deployed in California by 2030 with 27 million riders in Scenario 2 but 54 million riders in Scenario 3.

xxii. We did not increase the level of electricity demand to reflect potential increase in the use of electric vehicles hence the resulting GHG prices in this sensitivity case are likely understated.

xxiii. EIA, "What is U.S. electricity generation by energy source?," https://www.eia.gov/tools/faqs/faq.cfm?id=427&t=3, April 18, 2017.

xxiv. California Energy Commission, Supply and Demand of Natural Gas in California, http://www.energy.ca.gov/almanac/naturalgas_data/overview.html, n.d.

xxv. Natural gas prices are based on the AEO 2016 High Oil and Gas Resource and Technology Case.

xxvi. Technically, it is allowed in practice and in the model to curtail load if there is insufficient supply, but it is an expensive practice that is relied upon rarely.

xxvii. Energy+Environmental Economics, "Summary of the California State Agencies' PATHWAYS Project: Long-term Greenhouse Gas Reduction Scenarios", April 6, 2015. Available at: https://ethree.com/documents/E3_Project_Overview_20150406.pdf

xxviii. Greenblatt, Jeffrey B. "Modeling California Policy Impact on Greenhouse Gas Emissions." *Energy Policy* 78 (2015): 158 - 172.

xxix. Id.

xxx. To create the incremental abatement curves, we reviewed previous studies that analyze the price response of consumers to changes in fuel prices based on existing technologies. For the transportation sector, we assume a long-term elasticity of demand of -0.7 based on values reported in Lin, C.-Y. Cynthia, and Lea Prince. "Gasoline price volatility and the elasticity of demand for gasoline." *Energy Economics* 38 (July 2013): 111-117. For residential/commercial, we assumed the higher end of the range of retail natural gas elasticity of demand used by the ARB-sponsored Market Simulation Group reported in Borenstein, Severin, James Bushnell, Frank A. Wolak, and Matthew Zaragoza-Watkins. "Report of the Market Simulation Group on Competitive Supply/Demand Balance in the California Allowance Market and the Potential for Market Manipulation." Market Simulation Group. June 2014. For industrial, we calculated the elasticity of demand based on emissions in two scenarios modeled by the EIA in AEO2014 that assumed different GHG prices ($10/metric ton and $25/metric ton). Our analysis found that the implied annual price elasticity of demand for fuel with respect to GHG prices ranges from -0.01 to -0.07 with an average of -0.04, which we used in our analysis. See: US EIA, 2014 Annual Energy Outlook, Energy-Related Carbon Dioxide Emissions by Sector and Source, Pacific and Energy Prices by Sector and Source, Pacific for Greenhouse Gas $10 and Greenhouse Gas $25 cases.

xxxi. For more information on the Compliance Offset Program, see: https://www.arb.ca.gov/cc/capandtrade/offsets/offsets.htm

xxxii. California Legislative Information, AB-398 California Global Warming Solutions Act of 2006: market-based compliance mechanisms: fire prevention fees: sales and use tax manufacturing exemption. (2017-2018), https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201720180AB398

xxxiii. California Air Resources Board, "Updated Economic Analysis of California's Climate Change Scoping Plan." Staff Report to the Air Resources Board, 2010. Western Climate Initiative. "Discussion Draft Economic Analysis Supporting the Cap-and-Trade Program: California and Quebec." Prepared by the WCI Economic Modeling Team, 2012.

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