THE FUTURE OF ELECTRICITY PRICES IN CALIFORNIA:

UNDERSTANDING MARKET DRIVERS AND FORECASTING PRICES TO 2040

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EXECUTIVE SUMMARY

California has given energy efficiency and renewable energy resources a central role in the state's long-term energy plan, and the government is relying on investments in new technologies to help reach its climate goals. The future price of grid electricity will play a vital role in determining the economic viability of these investments.

This report aims to explain the most important drivers of electricity prices in California and review current forecasts for retail prices for the next 20-30 years. We provide an overview of California's electricity market structure and discuss how prices are determined within this framework. We then identify specific factors that will be most important in determining future prices and examine the results of recent forecasts by Energy Information Administration (EIA) and Energy and Environmental Economics, Inc (E3).

Our research and analysis indicate that electricity prices will continue to increase at rates that will make investments in energy efficiency and renewable energy wise decisions with strong returns for retail consumers.

California's Electricity Market Structure

The electricity system in California is currently a mix of regulated and deregulated markets, which has important consequences for understanding the impacts of different factors on prices.

In the wholesale market, utilities purchase large amounts of power primarily from independent electricity producers at a competitive wholesale price that is set using an auction process administered by the California Independent System Operator (CAISO). In the retail market, electric utilities sell power to end-use consumers at prices that are regulated by the California Public Utilities Commission (CPUC).

These retail rates (residential, commercial, and industrial) are negotiated every few years and are meant to reflect the cost of providing electricity plus a fair rate of return on investments and equity. Retail prices are influenced by many factors, including:

1. Cost of generating electricity or purchasing power on the wholesale market
2. Cost of maintaining existing assets and investing in new infrastructure
3. Government policies

Fundamental Market Drivers of Electricity Prices

About 60% of the electricity generated in California comes from natural gas power plants, making the price of natural gas a key driver of operating costs and retail electricity prices (EIA 2013). Based on the remaining generation mix, natural gas power plants are also primarily responsible for determining prices in the wholesale market, which further increases the impact of natural gas prices on retail prices.

With total system load forecasted to increase due to population growth and the fact that most new power plants being planned are gas turbines, California's use of natural gas will continue to increase and its price will be a significant driver of retail prices. Population growth and aging generation, transmission, and distribution assets will also require increasing expenditures by utilities to maintain or upgrade existing equipment and add new grid infrastructure. The costs associated with these investments will be recovered through higher retail prices.

Impacts of Environmental Policies

In addition to these fundamental drivers, electricity prices will also be influenced by California's environmental policies, including the cap and trade system that is part of Assembly Bill 32 and the Renewables Portfolio Standard (RPS).

The cap and trade system implicitly places a price on emissions, making fossil fuel generation more expensive relative to other forms of generation and increasing the cost of acquiring power from self-owned fossil generation as well as the wholesale market.

The magnitude of the impact from cap and trade will depend on the price of emission allowances (or permits), which is itself determined by the cost of reducing emissions for utilities and electricity generators. The RPS requires 33% of the electricity consumed in California to be produced by renewable sources by 2020 and will affect retail prices through the cost of compliance for utilities, the impact of more renewables in the wholesale market and any amount of additional investment that is needed to maintain grid reliability with larger shares of intermittent generation. Interactions between cap and trade, the RPS, and energy efficiency policies may also have important consequences for retail prices, but are less understood.

Forecasting Future Electricity Prices

Due to the scale and complexity of electricity markets along with the large degree of uncertainty associated with future technological improvements, natural gas prices and emission allowance prices, it is very difficult to make accurate quantitative projections of long-run electricity prices. EIA's most recent Annual Energy Outlook (2013) projects relatively modest electricity price increases in the range of 1.9-3.4% per year during the period 2013-2040, while work done by E3 (the Greenhouse Gas (GHG) Calculator) anticipates higher growth rates of between 3.5-6.3% per year from 2008 to 2020.

The GHG Calculator indicates that prices will increase more slowly in PG&E, SCE, and SMUD territories, but increase much more rapidly in LADWP territory. Neither model accounts for price increases that may result from the permanent shutdown of the 2.2 GW San Onofre Nuclear Generating Station in southern California. The AEO has the advantages of being newer and more detailed, but doesn't allow for modeling combinations of scenarios and also has a recent history of underestimating price increases.

The GHG Calculator was created specifically for California and allows for a large amount of customization in the scenarios that are modeled (including higher emission allowance prices and the creation of a "worst case" scenario), but is much less sophisticated and is built on older data that may not accurately reflect the current reality.

Within the current market and regulatory framework, existing forecasts project that retail electricity prices will continue to increase over the next several decades.

Natural gas prices will have a significant impact on retail prices and are a large source of uncertainty due to their historical volatility and the recent advances in hydraulic fracturing. Other important drivers of this increase include increased costs of maintaining aging assets, new investments in grid infrastructure to accommodate population growth and upgraded existing transmission/distribution, higher costs of procuring electricity under the cap and trade program, and costs associated with achieving a 33% RPS by 2020.

Sustained low natural gas prices would put downward pressure on prices, as would larger-than-expected savings from energy efficiency programs and technological breakthroughs that result in lower costs for renewable sources of electricity. Overall, increasing prices for grid electricity bode well for the economic viability of new investments in energy efficiency and small-scale renewables.

INTRODUCTION

With some of the most forward-thinking climate goals in the country, California has given energy efficiency and renewable energy resources a central role in the state's long-term energy plan, and the government is relying on investments in new technologies to help reach its climate goals.

However, a key factor in determining the economic viability of these investments is the future price of grid electricity. All else being equal, if the price of electricity increases over time, putting solar panels on the roof or re-insulating a home become more attractive options to business owners and households, while declining electricity prices will have the opposite effect.

This report aims to explain the most important drivers of electricity prices in California and review current forecasts for retail prices over the next 20-30 years.

To accomplish this goal, we provide an overview of the structure of electricity markets in California and discuss how prices are determined within this framework.

We then identify the specific factors that will be most important in determining future prices and examine the literature on methods that are available for forecasting what those prices are likely to be.

In addition to fundamental market drivers, we also review the literature to evaluate the likely impacts of state environmental policies that are either already in place, like a Renewable Portfolio Standard, or have just begun, such as the Cap and Trade program.

Finally, we consider several future scenarios and discuss effective business strategies for negotiating escalation rates in the context of each scenario.

In short, the research and analysis indicate that electricity rates will continue to increase at rates that will make investments in energy efficiency and renewable energy a wise decision with strong returns.

FUNDAMENTAL DRIVERS OF ELECTRICITY PRICES

Overview of Market Structure and Electricity Supply

The current state of California's electricity markets is a hybrid system of regulation and deregulation, which can be traced back to restructuring efforts initiated in the mid-1990's that were followed by an electricity crisis in 2000-2001. Today's system is comprised of deregulated wholesale markets administered by the California Independent System Operator (CAISO) and regulated retail markets overseen by the California Public Utilities Commission (CPUC).

A large majority of consumers in the state are served by one of the three largest investor owned utilities (IOUs) – Pacific Gas & Electric (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E). These "big three" procure electricity from a combination of their own generating assets and the wholesale market and then sell electricity to residential, commercial, and industrial consumers at retail rates that are regulated by CPUC. The rest of the state is served by smaller, municipally owned utilities[1] that are not subject to regulation by the CPUC due to their public nature.

About 70% of the electricity consumed in California is generated from within the state, with the other 30% coming from generators in the Pacific Northwest and Southwestern U.S. (see Figure 1). California is a large net importer of electricity and sells very little power back to these neighboring states.

In the retail markets (residential, commercial, and industrial), prices are determined by a cost of service regulation model under which an IOU earns an amount of revenue equal to the cost of providing electricity plus a negotiated "fair" rate of return on its investments and capital assets[2]. Both the costs and the rate of return are determined through a rate case process involving the

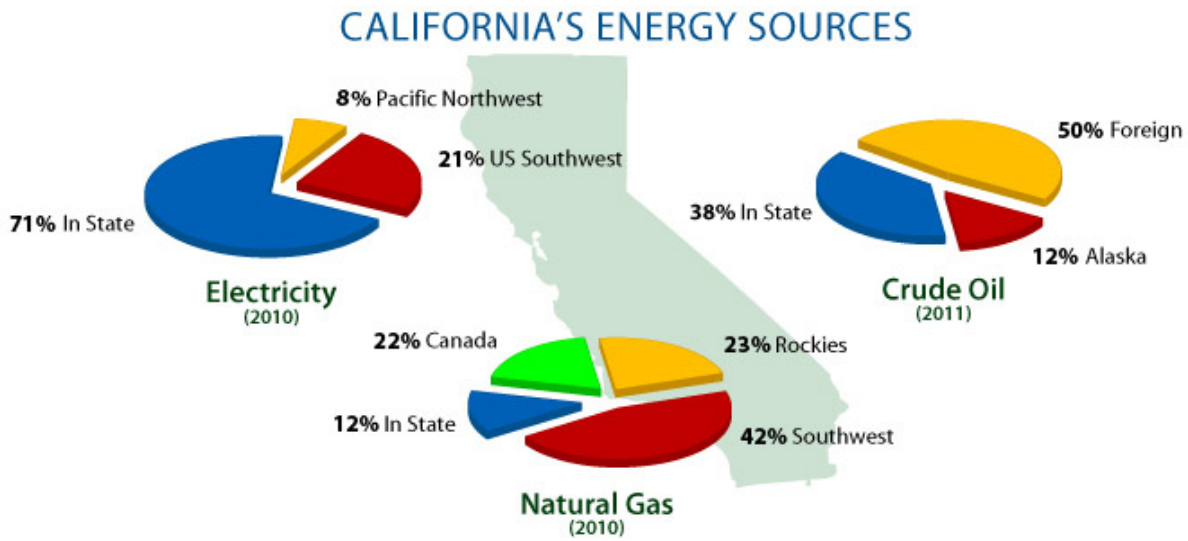

Figure 1: California's Energy Sources
Source: California Energy Almanac (CEC 2013a)

[1] The two largest municipal utilities are Sacramento Municipal Utility District (SMUD) and Los Angeles Department of Water and Power (LADWP).

[2] As of the most recent ruling in December 2012, the "fair" rate of return for the IOUs included a Return on Equity (ROE) of about 10% and a Return on Rate Base (ROR) of about 8% (CPUC 2012).

CPUC, which takes place approximately every three years. Cost of service regulation establishes a direct link between the costs incurred by a utility and the rates that consumers pay. In such a system, any long-run trend, such as demand growth, that requires additional generating capacity to be built or increasing fuel prices will push prices upward and vice versa.

The cost of generating electricity varies by source and so it is important to understand the existing generation mix. Of the 70% of California's electricity that comes from inside the state, the majority (60%) is generated by natural gas power plants, while only a very small amount (1%) comes from coal (see Figure 2).

The other primary sources of electricity generated inside the state include hydropower (13%) and nuclear (9%), while other renewable sources (geothermal, wind, biomass, solar) make up almost all of the remaining 17%. At present, solar is responsible for a very small share (1%) of generation in the state.

The remaining 30% of electricity that California consumes is imported primarily from coal and natural gas plants in Nevada and Arizona along with hydroelectric plants in Washington and Oregon.

Once a power plant has been built, the cost of producing electricity is based solely on operating costs, which vary widely depending on the fuel that is used. For renewables (including hydro and nuclear), operating costs are relatively low because the fuel is essentially free[3].

Natural gas generators, on the other hand, will have operating expenses that are highly dependent on the price of fuel. Because so much of California's power comes from natural gas power plants, natural gas prices play an important role in determining electricity prices.

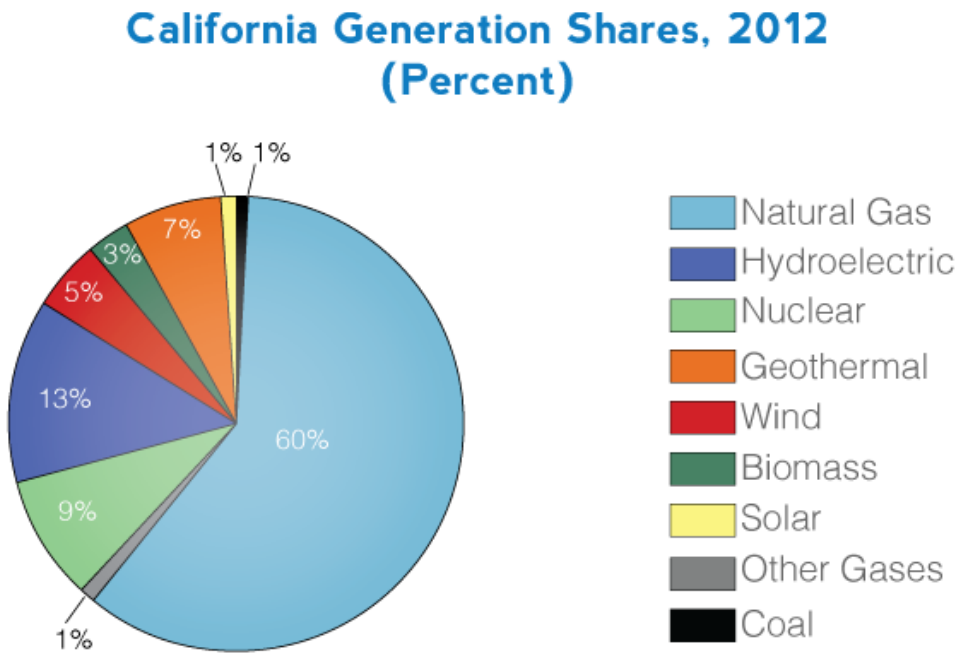

Figure 2: CA Electricity Generation Mix (2012)
Source: Energy Information Administration, Electric Power Monthly, February 2013

[3] Fuel costs for nuclear are not zero, but are very small on a kWh/$ basis.

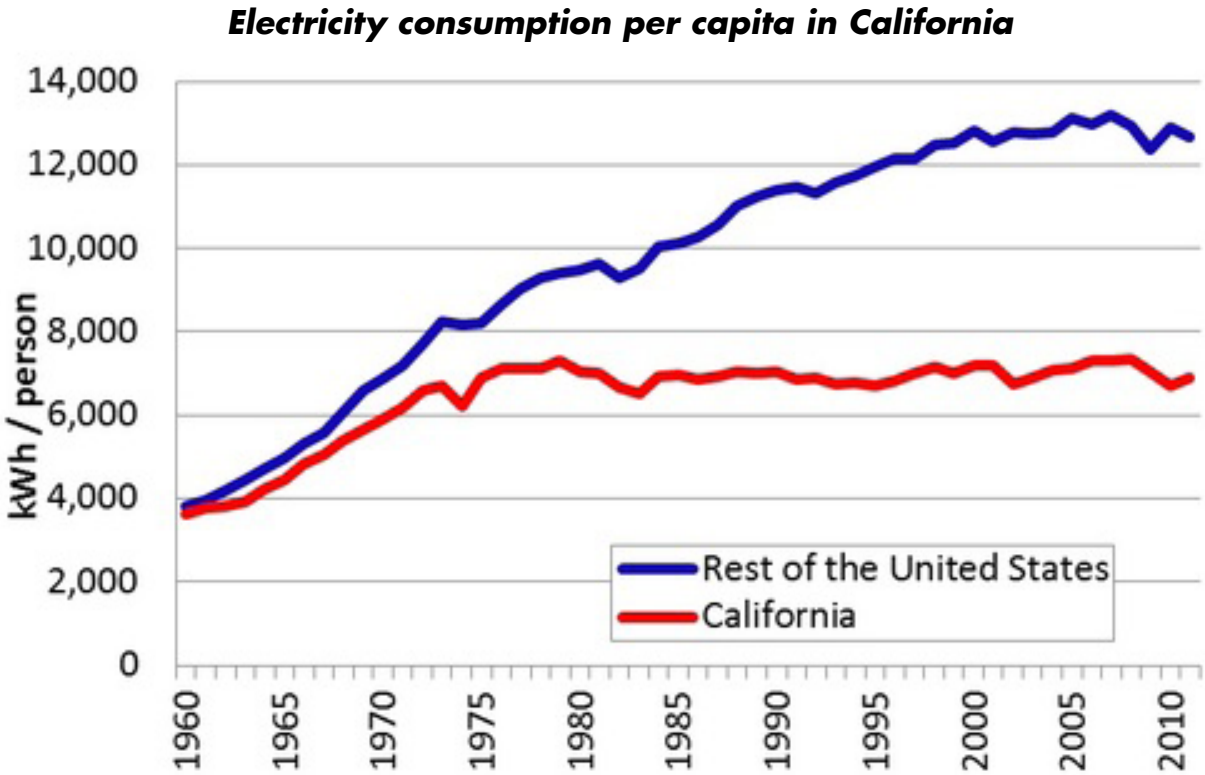

Figure 3: Electricity consumption per capita in California
Source: U.S. Energy Information Administration

Capital Investments in Electricity Infrastructure

The population of California is expected to increase to almost 48 million people by 2040 (State of California 2013), representing an increase of approximately 26%.

Even if the state is able to eventually begin decreasing the amount of consumption per capita through energy efficiency and other conservation measures (see Figure 3), this growth will increase overall electricity demand by a substantial amount and require significant investments in new electricity infrastructure.

Additionally, significant investments will be needed to maintain and eventually replace existing assets once they have reached the end of their useful life. Due to the cost-of-service regulatory structure, these investments will impact future electricity prices only to the extent that the IOUs are the ones making the investments as opposed to third-party firms.

One type of investment that will be needed is in brand new infrastructure, including power plants, substations, and transmission and distribution lines. The type of generation that will be built will be primarily based on cost and will have important ramifications for utility costs as well as prices in the wholesale market.

Most new generation to come online in recent years has been in the form of natural gas turbines (including combined cycle) and renewables.

The renewables trend is due partially to the declining relative costs of wind and solar, but is being driven primarily by policies such as the federal production tax credit and the California's RPS.

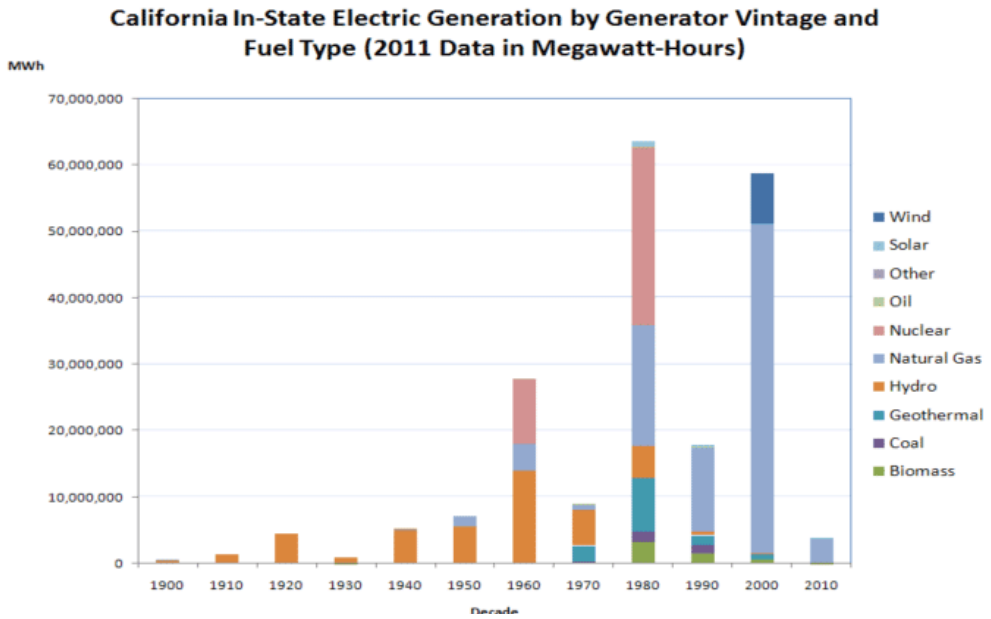

Figure 4: California in-State Electric Generation by Generator Vintage and Fuel Type (2011 Data)
Source: California Energy Almanac (CEC 2013a)

Siting and permitting new generating units in California is a time consuming process, so new additions to the grid in the next six to eight years are relatively easy to project[4].In terms of transmission and distribution, significant investments will be required to maintain and upgrade a system that has been operating in much the same way for the past 100 years.

New investments will be needed to expand service in growing areas, add two-way communications technology to the grid (i.e. "smart grid"), and improve grid reliability as more distributed generation and renewables come online. Utilities estimate that upgrading to a smarter grid will cost between $6-8 billion over the next decade (CPUC 2011).

In addition to brand new investments, utilities will also be forced to maintain aging assets or replace them altogether. When California decided to restructure its electricity markets, the IOUs were forced to sell off the majority of their generating assets.

The generators they were allowed to keep were primarily hydroelectric and nuclear plants. The newest of these plants were built in the 1980s, while the majority are considerably older (see Figure 4).

Hydro and nuclear are generally considered "base load" generation in the sense that they provide large amounts of steady power at a very low marginal cost, making them very valuable to the grid and unlikely to be retired unless absolutely necessary[5]. As the cost of maintaining this old equipment increases, retail prices will also rise.

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[4] The California Energy Commission has continually kept track of the status of all new power plant projects since 1996 and lists them at http://www.energy.ca.gov/sitingcases/all_projects.html

[5] Southern California Edison recently announced it will be permanently shutting down the 2.2 GW San Onofre Nuclear Generating Station in San Clemente (http://www.edison.com/pressroom/hot_topics.asp?id=7886).

Natural Gas Prices

Natural gas is the dominant fuel used to generate electricity for California and the overwhelming majority of new plants being planned in the state will also run on natural gas (CEC 2013b). There are two pathways through which the price of natural gas can impact the costs incurred by utilities. In both cases, higher natural gas prices will result in higher electricity prices.

The first pathway is the direct impact on the cost of generating electricity from power plants that are owned by an IOU. The second is an indirect effect based on how the natural gas price influences the price of wholesale power.

The direct impact of natural gas prices on an IOU's generating costs is straightforward, but the impact of gas prices on wholesale price warrants further discussion. Because the wholesale market is deregulated in California, the price of a MW of power is determined by supply and demand. When supply and demand change throughout the day, the price adjusts to reflect these changes. As the market organizer, CAISO is tasked with keeping the grid in balance and setting the price of power.

To accomplish this, it operates a day-ahead (spot) market using an auction process. First, the demand for electricity is forecasted for every hour of the next day using a model incorporating population, weather, economic conditions, past usage, and other factors. To provide the power to meet this demand, electricity suppliers submit bids to CAISO for the amount of power they are able to supply in each hour along with the price per MW that they would be willing to accept for providing that power.

CAISO sorts the bids from lowest to highest price and then beginning with the lowest price, selects bids until the demand is met (see Figure 5). The market price for all transactions is set at the value of the last (most expensive) bid that ends up being selected, which is often called the "marginal bid" and the corresponding generator is said to be the "marginal generator" or "on the margin."

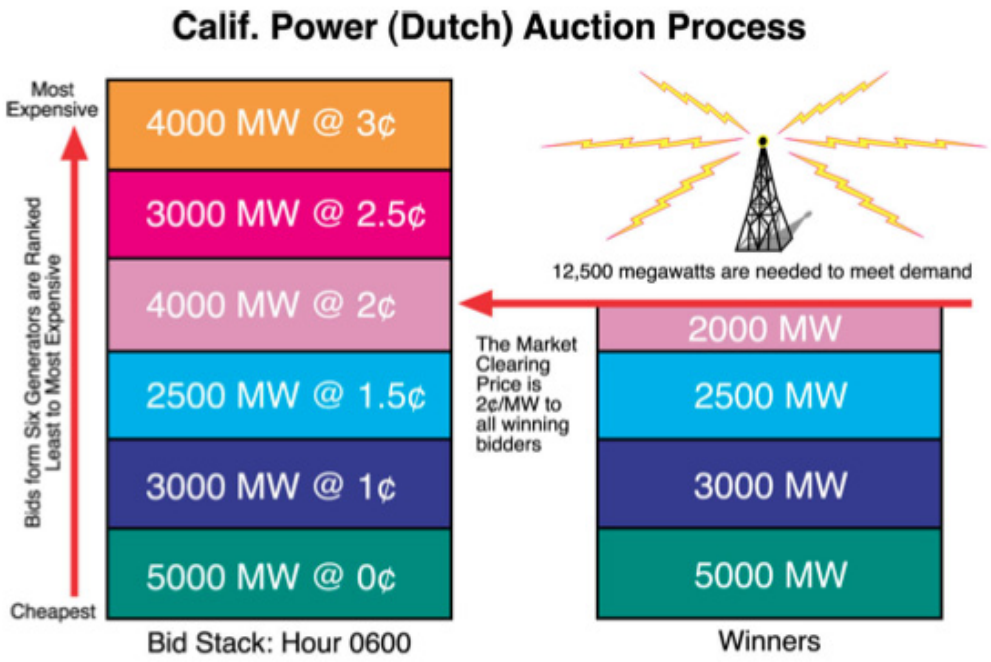

Figure 5: Auction Process in California Day-Ahead Wholesale Market
Source: Warwick (2002)

As a result of the auction process, electricity suppliers generally submit bid prices that are equal to their operating costs[6] and the price of electricity in the wholesale market ends up being driven entirely by the operating costs of the marginal generator.

Given the existing generation mix in California, the marginal generator is almost always a natural gas power plant (see Figure 6).

As gas prices increase, the operating costs (and thus bids) of natural gas power plants will also increase, which will shift the purple line in the graph up.

Because this is the region of the supply curve where demand intersects (represented by the black dashed lines), this shift will result in an increase in the price of wholesale power.

When we consider that system load will continue to increase and the majority of new plants being planned in the near future are natural gas, it seems reasonable to expect this situation to continue so that natural gas prices will be a primary driver of wholesale electricity prices for the foreseeable future.

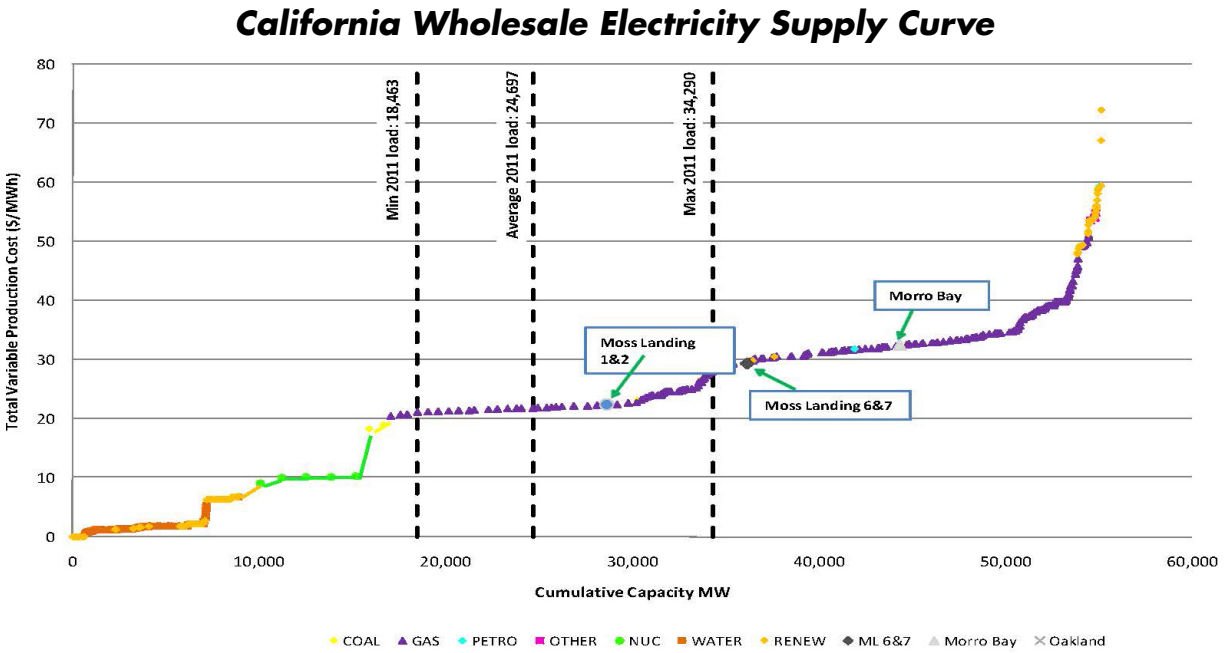

Figure 6: California Wholesale Electricity Supply Curve
Source: Dynegy (2012)

[6] Suppliers do not know the bids of other suppliers, so submitting a bid equal to operating costs guarantees that breaking even is the worst possible outcome that can happen. If they are selected and are not the marginal generator, then the market price will be higher than their costs and they will earn profits. If they are not selected, then the market price will be lower than their costs and they will avoid losses. Finally, in the case where they are the marginal generator, the price is set at exactly their operating cost and they break even. Submitting a bid lower than operating costs increases the likelihood of being selected, but has no effect on profits if the supplier would have already been selected and could result in the firm losing money if the market clearing price ends up being lower than their actual costs. Similarly, submitting a bid higher than operating costs won't impact the market price if the firm is selected and could result in the firm missing out on making profits if they end up not being selected. CAISO has an entire division dedicated to making sure no producers are exercising market power or manipulating the market through collusive bidding.

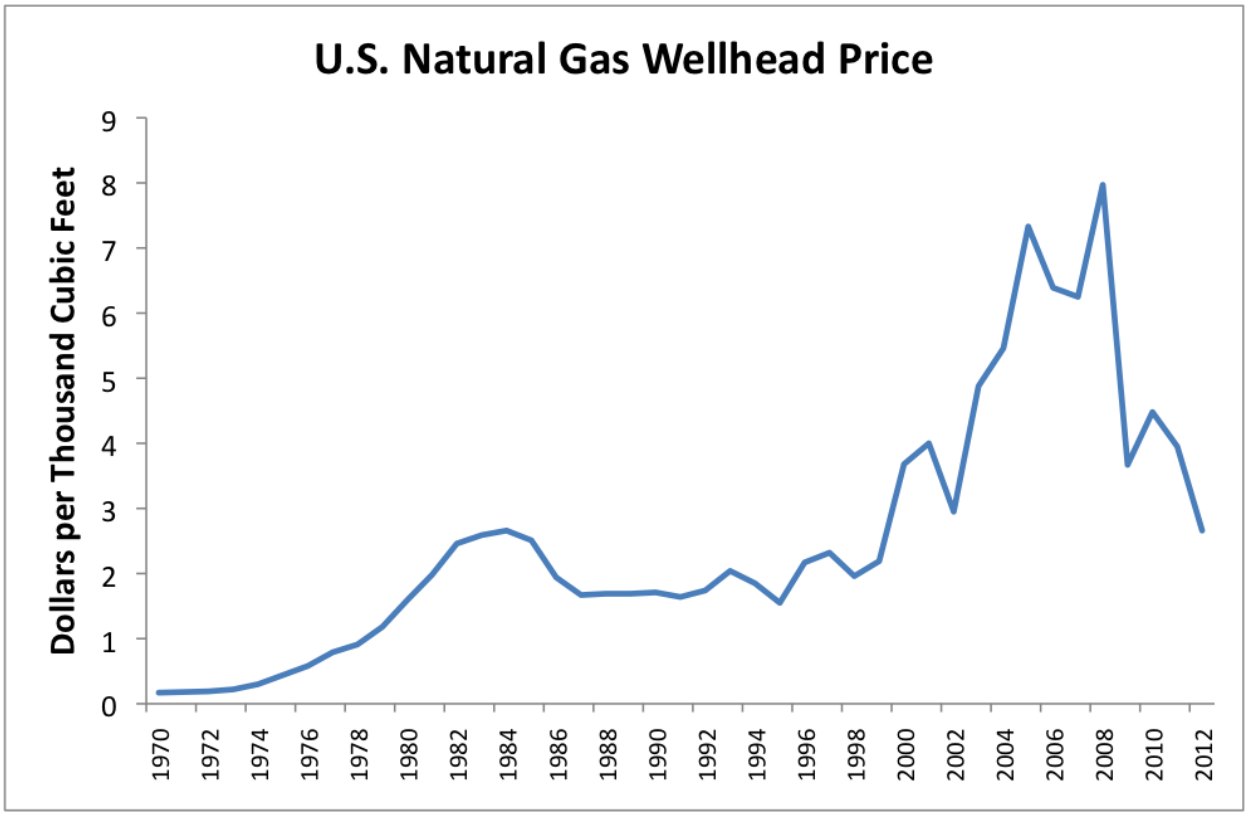

Figure 7: U.S. Natural Gas Prices 1970-2012
Source: EIA

With existing natural gas transport and storage infrastructure, the price of natural gas faced by power plant operators is determined in integrated regional markets.

Thus, despite the fact that California receives natural gas from several different regions (refer back to Figure 1), the prices in those regions will be very similar regardless of origin and will be affected by the same large-scale market forces.

Over the past 40 years, natural gas prices have been quite volatile, especially in the past two decades (see Figure 7).

A major current trend is the recent advancement of hydraulic fracturing (commonly called "fracking") techniques, which has resulted in a boom in production from shale deposits and other resources that were previously uneconomical to extract.

The large increase in supply caused a significant decrease in the price of natural gas beginning in 2009.

The duration of this boom and other subsequent market trends will have a major impact on the price of electricity in California, but the high volatility of gas prices makes forecasts of future electricity prices very uncertain.

Additional Factors that Influence Wholesale Market Prices

Although natural gas prices are likely to have the biggest impact on wholesale prices due to the fact that natural gas generators are almost always on the margin in California, there are other factors that can affect wholesale prices by affecting other parts of the supply and demand curves.

Supply Side Factors

On the supply side, changing the generation mix will change the shape of the supply curve and thus likely have an impact on price. Shutting down a nuclear plant would remove low cost generation from the bid stack and shift the curve depicted in Figure 6 to the left and would be expected to result in higher wholesale prices in the short-run. The long-run impacts of shutting down a nuclear power plant would depend on the type of generation used to replace it.

In contrast, constructing new nuclear plants would have the opposite effect and shift the supply curve out to the right and lower wholesale prices, all else equal[7].

Currently, there are no new nuclear plants being planned in California (CEC 2013b), which is primarily due to a 1976 state law that prohibits construction of new nuclear power plants in California until a means of disposal of high-level nuclear waste is approved (World Nuclear Association 2013).

Increasing generation from wind or solar would have a similar effect because of their almost non-existent marginal costs. The magnitude of the impact from renewables would depend on the hour of the day due to the intermittent nature of the resources.

Demand Side Factors

On the demand side, increased electricity consumption pushes the vertical demand curve in Figure 6 to the right, requiring the use of higher cost generation and pushing wholesale prices up. Changing demand throughout the day is the primary reason why wholesale market prices change in the short run. Long-run growth in electricity consumption would tend to increase wholesale prices in all hours. Reducing consumption through improved efficiency works to offset growth in consumption and would reduce wholesale prices.

In addition to fundamental market forces, California has also adopted several environmental policies to address climate change that will likely affect the retail price of electricity. The primary piece of legislation that drives many of these policies is Assembly Bill 32 (AB 32), which requires California to reduce its greenhouse gas (GHG) emissions to 1990 levels by 2020.

The bill was signed into law by Governor Schwarzenegger in 2006 and gives California's Air Resources Board (ARB) broad authority to develop and implement policies to achieve these emissions reductions (Nunez 2006).

In addition to AB 32, Governor Schwarzenegger also signed Executive Order S-3-05, which creates a longer-term goal of reducing emissions to 80% below 1990 levels by 2050.

Under AB 32, the ARB has instituted several expansive policies to reduce emissions that include a cap-and-trade system, renewable portfolio standard[8], transportation sector programs, and energy efficiency programs (EPRI 2013). This section will describe the ways in which these policies can affect electricity prices and also survey the literature to provide an idea of what the magnitudes of these effects are likely to be.

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[7] New nuclear plants, however, are hugely expensive and would thus require a very large capital investment that would increase electricity rates in California if built by a utility.

[8] California's RPS was originally passed in 2002 with the goal of having 20% of the state's retail electricity sales come from renewable sources by 2017. Under AB 32, the goal was accelerated to 20% by 2010 and Executive Order S-3-05 further accelerated the goal to its current level of 33% by 2020.

Cap and Trade

The most important and far-reaching policy to come out of AB 32 is the cap and trade program. A cap and trade program is a market-based policy for reducing GHG emissions that sets a limit on the total amount of emissions from the sectors covered by the program (the "cap") and then distributes permits within those sectors that each allow for some small amount of emissions.

The total amount of emissions from all of the permits is equal to the cap and program participants are allowed to buy (sell) permits from (to) other participants (the "trade").

The motivation for trading is that firms have different costs of reducing emissions (often called "abatement costs") and therefore a firm with high costs may be willing to buy a permit from a firm with lower abatement costs[9].

The price of a permit will be set by the trades and will implicitly be determined by the costs of reducing emissions for program participants.

Over time, the cap is gradually lowered and the number of permits decreased until a target level of emissions is reached.

The primary appeal of a cap and trade programs is that it guarantees the emissions target will be reached (by virtue of the cap) and is also efficient in the sense that participants with the lowest costs of reducing their emissions will be the ones to do so.

California's cap and trade program is designed to achieve the emissions targets laid out by AB 32, with a cap of approximately 2.37 billion tons of CO2 equivalent emissions (CO2e).

In the California system, the state issues emission allowances that are specific to the cap and trade program as well as offset credits for emissions reductions that are achieved outside of the program.

The program officially began on January 1, 2012 and includes three compliance periods that run from 2013-2014, 2015-2017 and 2018-2020.

All stationary sources that emit 25,000 metric tons of CO2e or more per year are covered under the program. These sources include large industrial sources (e.g. cement, refineries, oil, and natural gas producers) as well as electricity generation and imports.

Covered entities must register with ARB, report their GHG emissions annually and surrender allowances and offsets that match emissions at the end of each compliance period.

Beginning in 2015, the cap and trade program will expand to provide upstream coverage of small combustion emission sources at the fuel provider level (e.g. fuel wholesaler or first entity to offer fuel on the market) for transportation fuels as well as residential and commercial use of natural gas (Cliff 2013).

An important feature of any cap and trade system is the manner in which permits are distributed. In the California cap and trade system, electric utilities (and other industrial entities) are initially given an amount of allowances to cover their existing emissions for free, rather than being required to purchase them through an auction process (Cliff 2013).

The intent here is to ease transition into the program and protect retail consumers from pass through costs that are likely to come from electricity generators who do not receive free allowances.

[9] As a simple and concrete example, consider two firms, A and B. Suppose that for firm A to reduce its emissions by one unit, it will require an investment of $100. Firm B, however, is able to reduce its emissions by one unit at a cost of only $50 and owns a one-unit emissions permit. In this situation, both firms have an incentive to make a trade. A has the incentive to buy the permit for any price up to $100 since acquiring the permit would be cheaper than making the investment to reduce its emissions, while B has an incentive to sell the permit for any price greater than $50 since it can reduce its emissions for less than that. If the two firms negotiate a price of $75, A saves $25 by using the permit instead of reducing its emissions and B has made $25 after spending $50 to reduce its own emissions.

Another portion of allowances goes to a "reserve" which is to be used for containing prices in the event that they get too high. Whatever portion remains after the free allocation and allocation to the reserve is put up for auction, with the proceeds going to the state for future budget needs.

These reserve allowances are available to be purchased from the state beginning in 2013 at predetermined prices of $40, $45 and $50 per ton (EPRI 2013). The prices of reserve allowances are set to increase by 5% per year plus inflation and provide an important backstop option if allowance prices in the system spike.

Initially, only 5% of the allowances were put up for auction in 2013, but this share will increase to approximately 50% for the beginning of the next compliance period in 2015.

Total Costs for Utilities Under Cap and Trade

The key question for this study is how a cap and trade program affects the price of electricity. Parmesano and Kury (2010) outline three mechanisms for how a cap and trade program will influence electricity prices (and rates).

The first of these is that the total costs, and thus the revenue requirement, will change under cap and trade. In order to comply with the program, a utility needs to obtain an amount of allowances to cover its emissions. In the California system these allowances are initially given to the utility for free (this lessens the impact on total costs), but as the program goes along utilities may require additional allowances, which would need to be purchased.

Even without the need for additional allowances, utilities will be looking for cost-effective ways to reduce their emissions so that they can sell allowances that become unnecessary (Parmesano and Kury 2010). "Cost-effective" emissions reductions will be those that are cheaper than the cost of buying additional allowances.

If the price of allowances is very low, then utilities may choose to simply buy any additional allowances that are needed to comply with the cap and trade program. In this case, the revenue requirement of the utility is unlikely to change very much and the impact on electricity price will be small.

On the other hand, if allowances are very expensive, the utility will be incentivized to make more expensive investments rather than risk having to buy additional allowances. One strategy for reducing loads in California that is gaining momentum is the use of dynamic pricing to shift loads and reduce demand. These types of investments could lead to larger impacts on the utilities revenue requirement in the short run, but may also lead to a reduced need for emission allowances in the future.

Impacts on Electricity Procurement

The second way in which a cap and trade program can affect retail electricity prices is by affecting the costs associated with procuring additional electricity. As electricity demand changes throughout the day, utilities must procure additional supply from either the wholesale market or self-owned generating assets.

Since electricity generators are required to purchase their emission allowances, both the wholesale price and O&M costs of fossil-fuel generators will be higher under cap and trade, which may cause the resource mix used by the utility to change.

For the wholesale market, the exact consequences are potentially even larger depending on the extent to which the cap and trade program affects the bid stack (refer back to Figure 6).

If the price of allowances is high enough so that the new marginal generating unit (with cap and trade) uses a different technology than the old marginal unit (without cap and trade), then the wholesale price impacts may be even larger.

As the resource mix and dispatch order changes, the pattern of utility energy costs across the hours of the year will also be affected, which is the third effect of a cap-and-trade program on utility costs.

These changes in the time pattern of energy costs are important because the time pattern is a key driver for time-of-use electric rates and affects the optimal design and cost-effectiveness of programs designed to shift loads from high-cost to low-cost periods (Parmesano and Kury 2010).

Author **Region**	**Scenarios**	**Additional Policies**	**Allowance Price in 2020[1]**
CARB (EDRAM)			
California	Scoping Plan	Vehicle standards, 20% RPS, etc.	$10
WCI (ENERGY 2020)			
WCI	Stationary Sources		$71
WCI	Economy-wide		$24
WCI	Economy-wide – High Energy Prices	Limited amount of offsets, banking allowed, current RPSs	$18
WCI	Economy-wide – Low Energy Prices		$56
WCI	Economy-wide – High Natural Gas Prices		$20
WCI	Economy-wide – No Offsets	No offsets	$63
Electric Power Research Institute (MRN-NEEM)			
California	Binding Reductions[2]	No offsets, no banking	$60 - $103
California	Safety Valve[3]	Safety valve[4]	$60
Roland-Holst (BEAR)			
California	Economy-wide[5]		$23 - $214
California	20% Cap-and-Trade[6]	No banking, no offsets, all CARB policies	$23 - $179
California	20% with Efficiency Innovation[6]		$8 - $161
Palmer et al. (Haiku - electricity sector only)[7]			
California	Auction	20% RPS, no offsets, no banking, first-deliverer compliance	$58
California	Local Distribution Company (LDC) Allocation		$127
WCI	Auction		$21
WCI	LDC Allocation		$26

Notes

1. All prices are in 2007$/metric ton CO_2e. ARB and MRN-NEEM do not specify year for dollars, so we assume their dollars are for the year preceding the year in which the study was released - 2007$ for CARB and 2006$ for CRA.
2. Multiple scenarios that meet the goal of 1990-level emissions in 2020 but vary for 2020-2050 (no reduction from 1990 emissions to 80% reduction from 1990 emissions by 2050).
3. Values approximate because estimated from a figure.
4. Safety valve allows additional emissions and breaks the cap.
5. Economy-wide scenarios that vary in the effectiveness of complementary policies.
6. Sectors covered by the cap-and-trade policy vary.
7. Emissions targets for the electricity sector derived from the assumed contribution of the electricity sector within an economy-wide policy, assuming a linear emission path to 2020, where emissions are 30% below the 2020 baseline (64 million short tons in 2020).

Table 1: Estimated Allowance Prices Under Different Policy Scenarios
Source: EAAC 2010

In short, the degree to which electricity prices are impacted by a cap and trade program will primarily depend on the price of emission allowances.

The actual level of this price depends on many things, including the ease of substitution to low-emission sources of generation, the extent to which consumers switch to low-emission products in response to price changes, the pace of technological progress, and the impacts of a variety of policies (EAAC 2010).

Due to the inherent uncertainty underlying these factors, predicting what the allowance price with any type of precision is nearly impossible and the best that can be hoped for is forecasts based on reasonable estimates of technological opportunities and behavioral responses under different plausible policy scenarios.

In 2010, the Economic and Allocation Advisory Committee (EAAC) for ARB reviewed several studies using a variety of models that estimate the price of allowances under different scenarios and found predicted allowance prices for 2020 ranging from $8 per metric ton of emissions (2007 dollars) all the way up to $213 per metric ton (see Table 1).

Renewables Portfolio Standard

Besides cap and trade, the other hugely important piece of legislation for the electricity sector is the RPS. The idea of an RPS began in California in the mid-1990s and has become the preferred method of supporting renewable energy in the U.S[10].

Though RPS designs may have slight differences, the core idea is to require a certain quantity of electricity production (or consumption) to be sourced from renewable sources.

An RPS establishes binding numeric targets for renewable energy supply and retail supplier obligations generally increase over time.

California's RPS was originally adopted in 2002 with the goal of achieving 20% renewable electricity by 2010 and was subsequently updated in 2007 so that 33% of electricity sales must come from renewable sources by 2020.

Technologies eligible for California's RPS include photovoltaics (PV), solar thermal electric, wind, certain biomass resources, geothermal electric, certain hydroelectric facilities, ocean wave, thermal and tidal energy, fuel cells using renewable fuels, landfill gas, and municipal solid waste conversion, not the direct combustion of municipal solid waste (DSIRE 2013).

The primary goal of an RPS is to encourage renewable energy supply, but pursuing this goal can also potentially have substantial impacts on electricity markets and ratepayers. Ex-ante, the impact of an RPS on retail electricity prices is ambiguous.

Fischer (2010) highlights this lack of consensus by citing several studies that find an RPS increases retail electricity prices, others that find little to no impact and still others finding that an RPS actually reduces prices.

Her partial equilibrium analysis indicates that an RPS effectively subsidizes renewable electricity production and its impact on retail electricity prices will depend on the relative elasticity of supply for renewable and fossil fuel generators.

In 2007, Lawrence Berkeley National Lab (LBNL) reviewed 28 studies that looked at the retail price impacts of RPS policies across the U.S. and found that projected rate impacts were generally less than 1% (Figure 8).

Focusing on the projections for the early CA RPS targets (17% and 20%), two studies projected decreases in retail rates, one study projected essentially no impact and another projected an increase in rates of around 1%.

[10] As of March 2013, binding RPS targets exist in 29 states, Washington, D.C. and 2 U.S. territories.

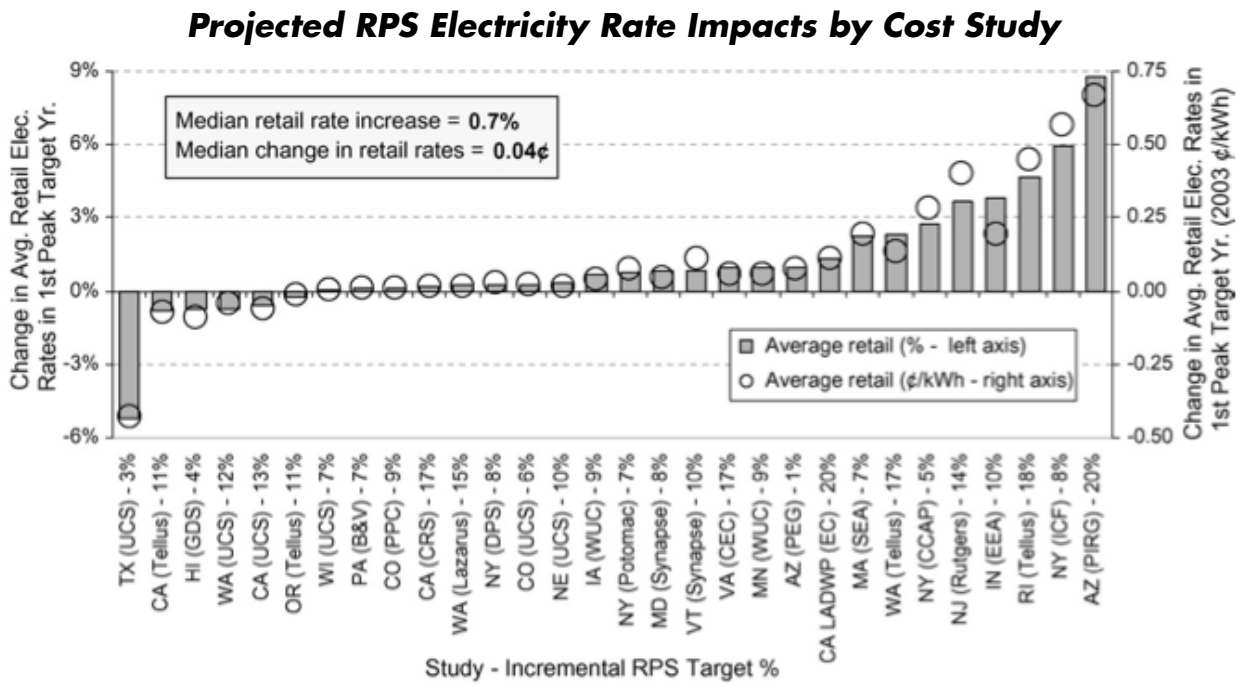

Figure 8: Projected RPS Electricity Rate Impacts by Cost Study
Source: Wiser et al. 2007

Recent work by Paul et al. (2013) models the retail price impacts of a national 80% Clean Energy Standard[11] and find similarly moderate effects for California.

Preliminary work on the impacts of achieving 33% renewable energy in California by 2020 show slightly higher nominal average retail rate increases that are in the range of 4-5% per year (CPUC 2009; EAAC 2010).

The primary reasons for the price increases are increasing transmission and distribution costs along with higher fuel and operating costs for all types of generation. In addition to generation costs, there are also other factors that can affect the impact of an RPS on electricity prices.

Tra (2009) analyzes the heterogeneous impacts of an RPS using an econometric approach and finds that a 10% increase in RPS requirements results in a 3% increase in residential electricity rates on average[12], but also finds that the impact is significantly smaller in states with higher wind and solar energy potential and larger for utilities that are subject to a higher RPS.

Most studies agree that the cost of renewable electricity generation compared to fossil fuel generation is the primary determinant of the price impact of an RPS.

Higher costs for renewable generation are more likely to result in higher retail prices and vice versa. Projections of future costs are regularly made using some combination of historical data, assumptions based on learning curves and engineering models, however these projections are inherently subject to a high degree of uncertainty.

[11] A Clean Energy Standard is similar to an RPS, but includes a broader range of non-CO2 emitting technologies (e.g. hydro, nuclear) and even some low-CO2 emitting technologies (e.g. coal with carbon capture and storage)

[12] Tra also estimates the impact of an RPS on commercial and industrial rates and finds effects of similar magnitude.

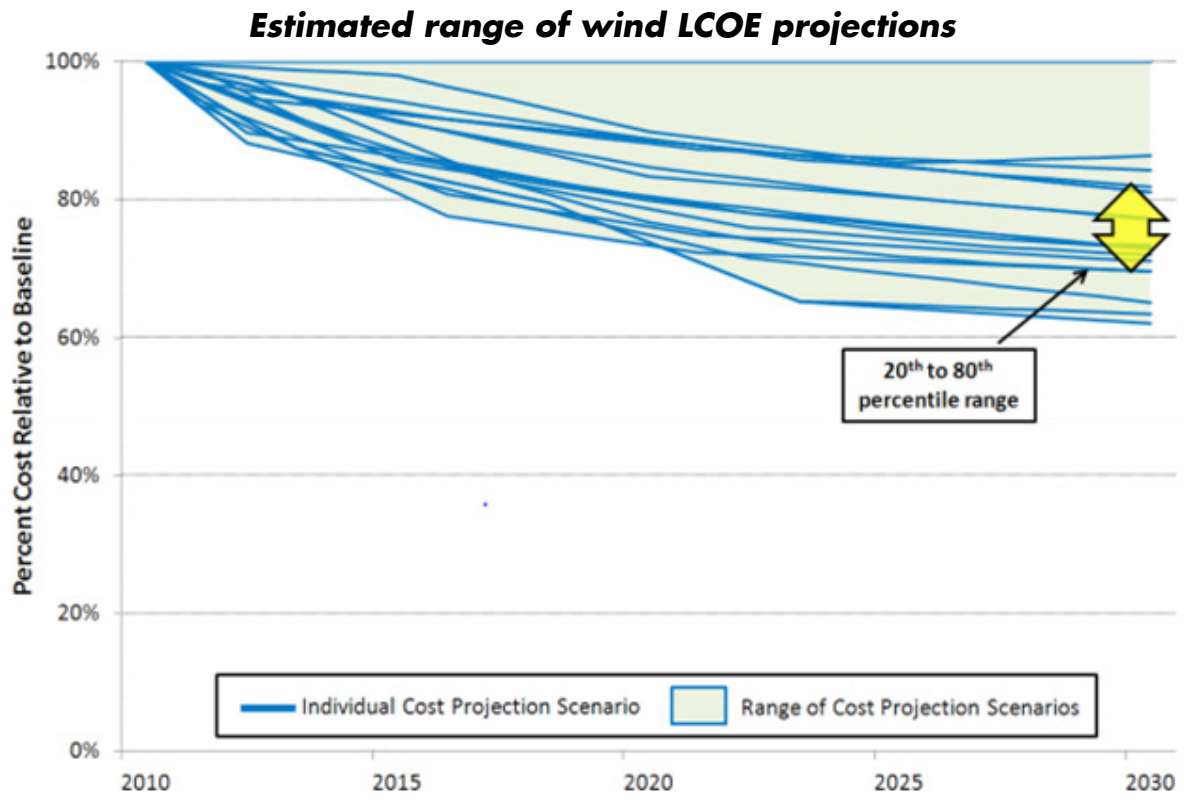

Figure 9: Estimated range of wind LCOE projections across 18 different land-based scenarios
Source: Tegen, et al. (2012)

Costs for wind and solar are generally predicted to continue decreasing over time (see Figure 9), but predicting how these future prices will compare to future costs of fossil generation with any degree of certainty is nearly impossible.

Other Complimentary Policies

Other policies in California may also have an impact on the price of electricity. California has a long history with energy efficiency dating back to the late 1970's and currently spends approximately $1.4 billion each year on programs to reduce electricity consumption (Blumstein 2010).

Conceptually, energy efficiency is typically thought of as a low cost resource that reduces electricity demand and puts downward pressure on electricity prices.

To encourage utilities to invest in energy efficiency, California utilizes a "decoupling" policy that makes the utility's revenues independent of the amount of electricity sold. Under decoupling, a revenue requirement is determined based on costs and the rate is adjusted so that the requirement is met for the observed amount of electricity consumed.

Expenditures on energy efficiency programs do not factor into the revenue requirement due to their publicly funded nature. The vast majority of energy efficiency activities in California are publicly funded programs that are implemented and managed by investor-owned utilities.

Recent research suggests that ratepayer-funded energy efficiency programs reduced electricity consumption by an average of 0.9% per year between 1992 and 2006 at a cost of about $0.05/kWh (Arimura et al. 2011).

The state has developed a long-term plan for energy efficiency with ambitious goals that aim to increase future energy savings through the use of zero net energy buildings, more stringent building codes, and accelerated market transformation efforts (State of California 2011).

Interactions Between Policies

California is planning to meet its 2020 emissions targets using a cap and trade system in addition to other regulatory policies already in place that are designed to stimulate greater levels of energy efficiency, increase development of renewable energy, and induce higher levels of fuel economy in the transportation sector.

The total amount of emissions reductions needed to hit the AB 32 target is estimated to be 80 Mt CO2e and the most current analysis assumes that the "complementary policies" will be responsible for approximately 62 Mt (78%) of those reductions, while the remainder will come from cap and trade (ARB 2011).

The consequence of this for the electricity sector is that the cap in the cap and trade system will depend on the effectiveness of policies in non-electric sectors such as industry, agriculture and transportation, which will in turn affect allowance prices (EPRI 2013).

In general, as the cap and trade system becomes responsible for more reductions, the price of emissions allowances will rise (see Table 2).

These interactions between policies create a large degree of uncertainty for utilities that participate in the cap and trade system and are only beginning to be rigorously researched.

Variable and Performance Scenario	Increases Allowance Prices in 2020	Decreases Allowance Prices in 2020
CPs fail to achieve estimated emission reduction targets	X	
CPs exceed estimated emission reduction targets		X
Offset supply is significantly lower than the maximum use limit of 218 Mt	X	
Offset supply is sufficient to meet the maximum use limit		X
Economic and emissions growth is higher than forecasted	X	
Economic and emissions growth is lower than forecasted		X
CPs in jurisdictions with linked cap-and-trade programs fail to achieve estimated emission reduction targets	X	
CPs in jurisdictions with linked cap-and-trade programs exceed estimated emission reduction targets		X

Table 2: Variables Affecting the Level of Emission Reductions to be Achieved in the Cap-and-Trade Program and the Associated Impacts on Allowance Prices
Source: EPRI (2013)

FORECASTING FUTURE ELECTRICITY PRICES

Forecasting Methods

Given the ubiquitous consumption of electricity and its importance to the economy as a whole, forecasting the level of future prices is an endeavor that can provide useful information to utilities, consumers, and policymakers.

Understanding what future prices are likely to be is particularly important for decision-makers in utilities because of the long lifetime of assets as well as the long-term nature of resource plans and electricity contracts. Good long-run forecasts should possess the following characteristics (Hamm and Borison 2006):

• **Probabilistic** – Single-path estimates do not provide any information on the uncertainty of the estimates, which is very important when considering risk exposure.

• **Accuracy** – Though somewhat obvious, it's better that point estimates be close to the true outcome rather than far away. Also, the probability distribution of future electricity prices should accurately reflect the true uncertainty.

• **Usefulness** – Good forecasts provide information for both current operations and future investment decisions.

• **Efficiency** – Good forecasts effectively balance accuracy with cost, the amount of resources needed, and the speed with which they can be updated.

By far, the most common forecasts of electricity prices are short-run forecasts that predict hourly wholesale market prices in day-ahead (spot) markets (Contreras et al. 2003; Crespo Cuaresma et al. 2004; Yamin, Shahidehpour, and Li 2004; Garcia et al. 2005; Gonzalez, Contreras, and Bunn 2012; Hickey, Loomis, and Mohammadi 2012; Liu and Shi 2013).

These forecasts are particularly important to electricity traders in deregulated wholesale markets, who rely on them to decide their bidding strategies, allocate assets, negotiate bilateral contracts, hedge risks, and plan facility investments (Li et al. 2007).

Long-run price forecasts are much less common and have generally been taken up by government entities such as the Energy Information Administration (EIA) and California Energy Commission (CEC).

Broadly, there are two types of forecasting approaches used to model electricity prices. The first group includes models that are generally referred to as "engineering models." These models typically contain detailed data on generating plants, loads, and the transmission system that is used to match supply to demand and produce hourly, location-specific prices (Hamm and Borison 2006).

To the extent that the data provides an accurate depiction of the real-world electricity system, engineering models can produce very accurate forecasts. The major problem with this type of model is that it requires projections for inputs that are themselves very uncertain, including technology, fuel prices, electricity demand, and the configuration of the electric system.

In short, these models are capable of generating very accurate forecasts if we get the details of the future electric system right, but as we move further out into the future, it becomes less and less likely that this will actually be the case.

The second approach contains models known as "econometric" or "finance" models. This approach generally specifies a statistical relationship between electricity prices in different periods (i.e. hours, days, months, or years) and then uses historical price data (or price futures data) to forecast future prices. The advantage of financial models is that using data from markets inherently contains information from a variety of different sources.

Econometric models can also be specified that incorporate data on other variables that are thought to affect the price of electricity so that relationships between those variables and price can be estimated.

The primary problems with financial and econometric models are that they do not capture fundamental changes in the electricity system that may occur and can also produce results that are heavily influenced by unique events in the past that are unlikely to be repeated (such as the CA electricity crisis in 2000-2001).

California as a Whole

The most up-to-date forecasts for long-run electricity prices in California come from EIA's 2013 Annual Energy Outlook (AEO) and independent efforts commissioned by the CPUC. The AEO utilizes the National Energy Modeling System (NEMS), which simulates the production, imports, conversion, consumption, and prices of energy out to 2040, subject to assumptions on macroeconomic and financial factors, world energy markets, resource availability, behavioral and technological choice criteria, cost and performance characteristics of energy technologies, and demographics.

NEMS falls into the category of engineering-type models in that it balances supply and demand for each fuel and consuming sector accounting for economic competition among the various fuels and energy sources (EIA 2013a).

NEMS can function at the regional level and is capable of producing forecasts that are specific to California. The forecast work commissioned by CPUC is based on a tool called the "GHG Calculator" created by Energy and Environmental Economic, Inc. (E3) from 2006 to 2007.

The GHG Calculator model utilizes outputs from a production simulation model similar to NEMS as inputs into a simplified spreadsheet model that estimates greenhouse gas emissions, rate impacts, and utility cost impacts out to 2020 for the entire state as well as individual utility territories[13].

Results from AEO 2013

The AEO Reference case projection assumes trends that are consistent with historical and current market behavior, technological and demographic changes, and current laws and regulations. The potential impacts of pending or proposed legislation, regulations, and standards are not reflected in the Reference case projections.

To account for the uncertainty associated with future trends in energy markets, policy impacts, demographics, technology, and the economy as a whole, the AEO contains several other cases that modify the assumptions used in the Reference case. Escalation rates from the Reference case and a subset of the other cases most relevant for California are presented in Table 3.

The table includes both nominal (not adjusted for inflation) and real (inflation-adjusted) annual escalation rates out to 2040 for each case, as well as the differences between each case and the Reference case. Examining the table, nominal escalation rates range from a low of 1.9% (several cases) to a high of 3.4%, with the Reference case coming in at an even 2%.

Results from the AEO provide quantitative estimates of the future impacts of the drivers discussed in this report. In the nuclear and renewables cases, annual escalation rates remain essentially unchanged from the reference case.

The high nuclear case assumes that all existing nuclear generation will remain online until 2040 and the low nuclear case assumes that nuclear plants will be shutdown at the end of their 40-year license period.

Lower renewable technology costs and better than expected technologies lower the escalation rate, while the scenario in which technology remains fixed results in a higher escalation rate. The differences between both of these renewables scenarios and the reference case are very small – 0.1% in either direction.

Cases involving natural gas and GHG prices have larger impacts on the forecasted escalation rate. EIA expects the price of natural gas in the electricity sector to increase over the next 30 years, but estimates vary by a factor of two during the timeframe depending on the scenario being considered.

The emergence of hydraulic fracturing as a technique to extract shale gas has been responsible for a recent plunge in prices and the persistence of the fracking boom will be a significant factor in the future level of prices. If production levels remain high, EIA expects natural gas prices to stay around $4 until about 2030. In the alternative scenario where gas production slows, prices are forecasted to rise to $6 by 2020 and continue to steadily climb after that.

[13] For a more detailed explanation of the GHG Calculator, see Price, et al. (2010)

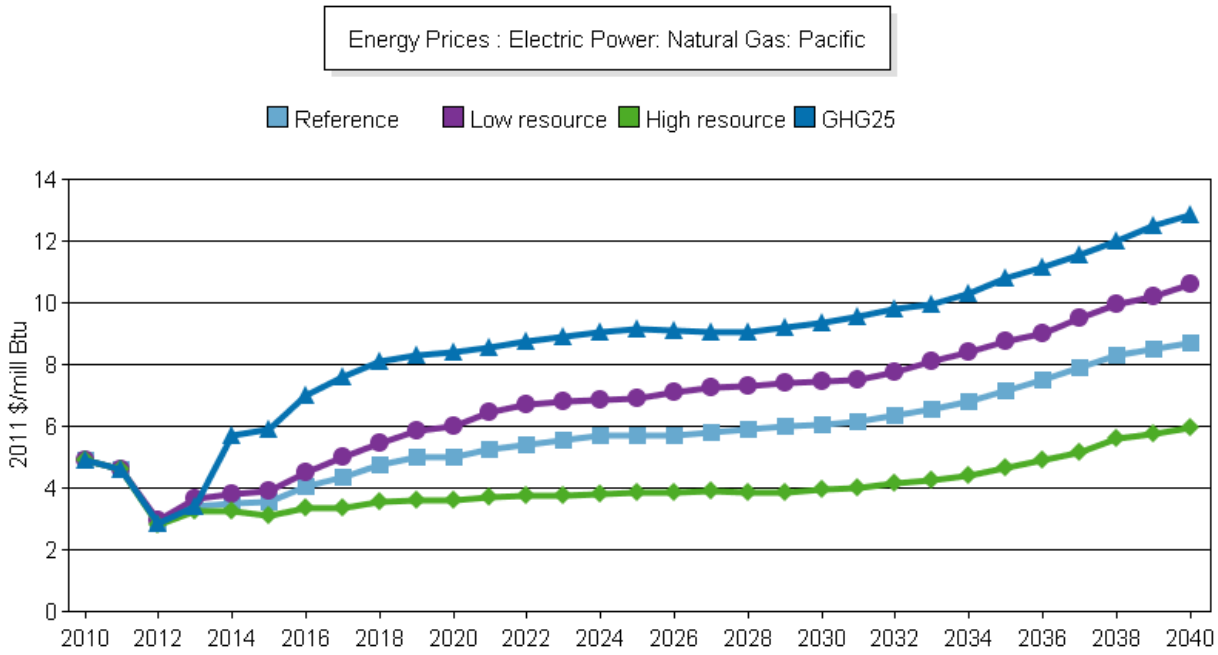

Figure 10: Annual Average Natural Gas Price in the Electric Power Sector, 2010-2040
Source: EIA Annual Energy Outlook (2013a)

The price of GHG allowances under California's cap and trade program also has and impact on the escalation rate. For each of the AEO GHG scenarios, EIA specifies a starting point for allowance prices (either $10, $15 or $25 per ton) and assumes that the price will grow 5% per year as the cap is progressively lowered (EIA 2013a).

Results from Table 3 show that as the price of GHG allowances increases, so too will the escalation rate. Time paths for these scenarios are shown in Figure 10. The AEO only models starting GHG prices up to $25 per ton, which results in an allowance price in 2020 of about $33.50. As discussed earlier, however, there is uncertainty regarding what the price of GHG allowances will be, with studies estimating 2020 prices of over $100 under certain scenarios (refer back to Table 1).

In cases with very high GHG prices, utilities would begin purchasing reserve allowances at a cost of $40-50 per ton in 2013 and increasing 5% per year in each subsequent year after that.

If high GHG price scenarios were combined with high natural gas prices, escalation rates would likely start to approach 4%[14].

EIA has been using the NEMS model to generate the projections in AEO since 1994 and periodically releases evaluations of previous forecasts.

Though not available for California specifically, comparing the projections for electricity prices in the Reference case to the actual historical prices provides information about the accuracy of the AEO.

[14] It is important to recognize that the impacts of natural gas prices and GHG allowance prices are not independent. Higher natural gas prices would likely reduce the amount of natural gas used for electricity production and also reduce the associated emissions. This would, in turn, reduce the amount of emissions required in the cap and trade program, which would lower allowance prices. The converse would be true for lower natural gas prices. These interactions will likely act to mitigate severe price impacts to some degree rather than compounding them.

EIA Scenario	Nominal Escalation Rate (Ann 2011-2040)	Difference from Nominal Ref Case	Real Escalation Rate (Ann 2011-2040)	Difference from Real Ref Case
Reference	*2.0%*		*0.3%*	
Low Econ Growth	3.4%	1.4%	0.6%	0.3%
High Econ Growth	1.9%	-0.1%	0.1%	-0.2%
Low Nuclear	2.1%	0.1%	0.4%	0.1%
High Nuclear	2.0%	0.0%	0.2%	-0.1%
Low Renewable Tech Cost	1.9%	-0.1%	0.1%	-0.2%
Low Gas Resource	2.2%	0.2%	0.5%	0.2%
High Gas Resource	1.9%	-0.1%	0.1%	-0.2%
Tech fixed at 2012	2.1%	0.1%	0.4%	0.1%
High Technology	1.9%	-0.1%	0.1%	-0.2%
Best Available Demand Tech	1.9%	-0.1%	0.1%	-0.2%
GHG$10	2.2%	0.2%	0.5%	0.2%
GHG$15	2.2%	0.2%	0.6%	0.3%
GHG$25	2.4%	0.4%	0.6%	0.3%
GHG$10+ Low Nat Gas Price	2.0%	0.0%	0.2%	-0.1%
GHG$15+ Low Nat Gas Price	2.1%	0.1%	0.3%	0.0%
GHG$25+ Low Nat Gas Price	2.3%	0.3%	0.4%	0.1%

Table 3: 2013 EIA AEO Projected Escalation Rates for California

Projected vs. Actual
(percent difference)

	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
AEO 1994	0.3	3.1	7.5	10.7	13.7	18.8	25.9	26.6	23.8	29.4	31.1	32.4	28.1	22.9	24.0	21.8	26.8	32.8	
AEO 1995		0.6	3.9	5.4	8.0	12.6	17.6	18.1	15.5	20.8	22.6	24.0	19.8	15.0	15.8	13.9	16.8	22.3	
AEO 1996			5.0	6.4	8.4	12.8	18.1	18.4	14.2	19.5	19.6	20.8	17.2	10.6	11.5	8.1	11.2	14.8	16.3
AEO 1997				3.6	5.4	9.9	14.7	13.9	9.1	12.6	11.5	11.2	6.3	0.2	0.3	-3.5	-1.1	1.6	2.0
AEO 1998					1.3	2.3	5.9	4.0	-1.8	0.9	-0.2	-1.1	-5.9	-12.5	-12.7	-16.3	-14.9	-12.7	-12.8
AEO 1999						0.5	3.4	1.4	-4.4	-2.6	-3.2	-3.2	-8.4	-14.7	-15.6	-19.6	-18.6	-16.8	-16.9
AEO 2000							0.7	-0.8	-7.3	-6.5	-8.7	-9.7	-15.2	-20.7	-21.3	-25.1	-25.1	-23.3	-23.8
AEO 2001								2.1	-3.3	-3.5	-5.9	-6.8	-13.6	-20.3	-22.6	-27.0	-26.7	-25.5	-25.7
AEO 2002									-1.0	-2.9	-6.1	-6.0	-10.9	-17.3	-17.6	-20.8	-19.6	-17.5	-16.5
AEO 2003										-2.9	-7.2	-7.9	-12.8	-20.3	-21.3	-25.1	-23.5	-22.3	-21.5
AEO 2004											-2.7	-5.9	-11.8	-19.0	-20.6	-23.9	-22.1	-20.6	-19.8
AEO 2005												-0.5	-5.5	-15.3	-19.5	-24.8	-24.0	-22.8	-22.2
AEO 2006													5.1	-3.5	-8.9	-15.8	-16.2	-15.8	-16.7
AEO 2007														-3.7	-4.3	-8.7	-8.8	-8.7	-10.8
AEO 2008															0.0	-2.8	1.1	0.9	-1.7
AEO 2009																-0.5	-4.3	-12.6	-10.0
AEO 2010																	-1.0	-4.3	-10.2
AEO 2011																		-1.8	-7.6
AEO 2012																			-0.6
Average Absolute Percent Difference	0.3	1.8	5.5	6.5	7.4	9.5	12.3	10.7	8.9	10.2	10.8	10.8	12.3	14.0	14.4	16.1	15.4	15.4	13.8

Sources: Projections: Annual Energy Outlook, Reference Case Projections, Various Editions.

Historical Data: U.S. Energy Information Administration, Annual Energy Review 2011, DOE/EIA-0384(2011) (Washington, DC, September 2012) , Table 8.10.

Table 4: Comparing electricity price projections in the AEO Reference case to actual prices

Table 4 shows the percentage differences between projected and actual prices for each year's AEO dating back to 1994.

Blue cells represent instances where the Reference case projections were higher than the actual prices and green cells represent instances where the projections were lower than actual prices.

As expected, the further out into the future the projections go, the less accurate they become. This is a feature of all forecasts.

Second, AEO Reference case projections have tended to underestimate future prices by 10-15% since 1998. If we adjust the Reference case estimates to reflect this trend, the nominal escalation rate from 2011-2040 increases from 2.0% to 2.6% and the real escalation rate increases from 0.3% to 0.6%.

Results from GHG Calculator

In addition to the AEO forecasts for California from the EIA, the CPUC also commissioned research in 2006 to understand the potential for California to reduce its greenhouse gas emissions (GHG) and the associated costs to ratepayers under AB32.

The resulting research was completed in 2008 (updated in 2010) and contained forecasts for electricity prices out to 2020 under several different assumptions about natural gas prices, emission allowance prices, renewable technology costs and a host of other parameters[15].

For the purposes of comparison, we specified several cases in the GHG model that correspond to cases in AEO. **The Reference case used in the GHG model assumes that a statewide 33% RPS is achieved, the price of emissions allowances is $10 in 2012 (rising 5% per year out to 2020) and the 2020 price of natural gas is $7.85.**

[15] The GHG Calculator is available for download from the E3 website (http://ethree.com/public_projects/cpuc2.php), allowing for users to specify their own assumptions for key variables in the model.

Scenario	Nominal Escalation Rate (Ann 2008-2020)	Real Escalation Rate (Ann 2008-2020)	Difference from Ref Case
Reference (33% RPS+GHG$10)	*4.5%*	*2.7%*	*0.0%*
Low Natural Gas Price	3.5%	1.7%	-1.0%
High Natural Gas Price	5.0%	3.2%	0.5%
GHG$25	4.5%	2.7%	0.0%
GHG$50	5.5%	3.7%	0.9%
GHG$100	6.3%	4.5%	1.7%
GHG$100 + High Natural Gas Price	6.7%	4.9%	2.2%

Table 5: Comparing electricity price projections in the AEO Reference case to actual prices
Source: E3 GHG Calculator – available at http://ethree.com/public_projects/cpuc2.php

All other parameters are specified at their default values. Based on the AEO's projections of natural gas prices in 2020, we specify a low gas price scenario of $3.50 per MM Btu and a high gas price scenario of $10 per MM Btu.

Separate scenarios are also run with emission allowance prices starting at $25, $50 and $100 as well as a "worst-case" scenario involving high gas prices and an emissions price of $100.

The GHG calculator estimates only real escalation rates and so we assume an average inflation rate of 1.8% (similar to EIA) to convert to nominal rates. The results of the modeled scenarios are presented for all of California in Table 5. Comparing the results from the GHG Calculator with the projections from AEO 2013, we see that the GHG Calculator forecasts escalation rates in the range of 3.5-6.7% during the period 2008-2020.

As in the AEO model, higher natural gas prices and higher emissions allowance prices result in faster growth rates, with combination of the two resulting in annual escalation rates of nearly 7%. By looking at the reference cases, we see that the GHG Calculator anticipates the RPS to have a significantly larger impact on prices than the EIA model.

A clear benefit of the GHG Calculator is that it is publicly available in an easy-to-use spreadsheet model, allowing for more customized forecasts than AEO. Another important benefit is that in addition to modeling impacts for all of California, it also estimates rate impacts for the individual utility service territories in the state.

Results for PG&E, SCE, SMUD, and LADWP are presented in the following sections. The weaknesses of the GHG Calculator are that it is a significantly simpler model than NEMS and is also based on data that is three years old. To the extent that important variables have changed between 2010 and 2013, results from the GHG Calculator will be biased.

Pacific Gas & Electric

PG&E provides electric service to approximately 5.2 million households and businesses in central and northern California.

This section aims to highlight unique factors that could cause the escalation rate in PG&E territory to differ from the state as a whole. PG&E procures 60% of its electricity supply from 3rd party generators (including the wholesale market) with the remaining 40% being generated by a fleet of nuclear, fossil fuel and hydroelectric power plants.

PG&E Energy Supply Capital Expenditures by Department

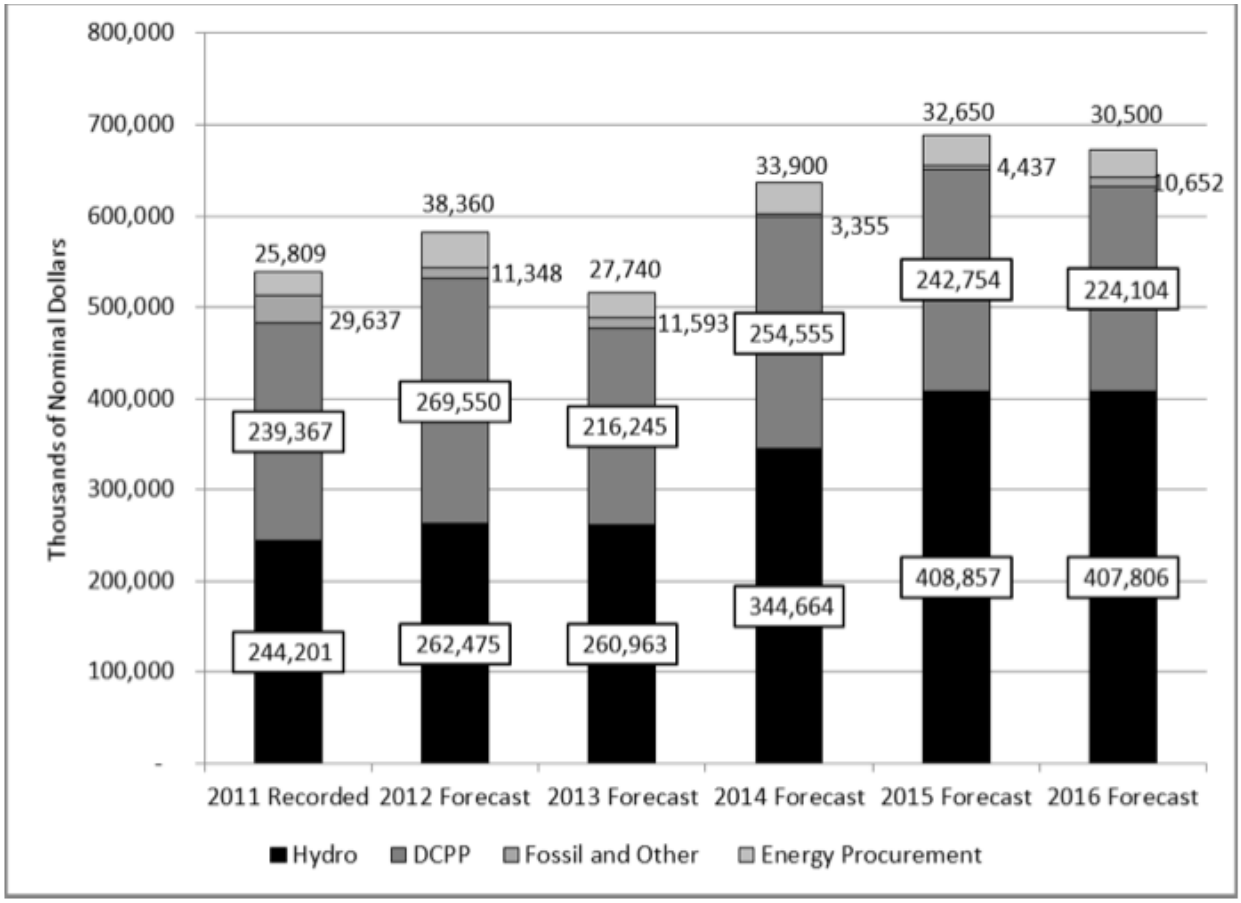

Figure 11: PG&E Energy Supply Capital Expenditures by Department
Source: PG&E (2012)

This generation portfolio includes the 2.24 GW Diablo Canyon nuclear facility, three natural gas power plants, and the largest privately owned hydroelectric system in the U.S., consisting of 68 powerhouses with a total capacity of 3.90 GW (PG&E 2012).

PG&E's current and near-term capital expenditures are dominated by Diablo Canyon and its hydroelectric system (Figure 11).

The forecasted increases in capital expenditures are driven almost entirely by the hydro system, which consists of many dams built in the early 1900s. Between 2011 and 2014 alone, PG&E forecasts that maintenance costs for hydro generating equipment will increase from $28 million to $48 million (PG&E 2012).

As these assets continue to age, they are likely to continue requiring larger and larger investments to keep them operational.

Because hydroelectric plants are clean, reliable, and dispatchable power sources that have zero fuel costs, they are a hugely valuable part of the electric system from an operational standpoint and are unlikely to be shut down unless they become completely non-functional.

The final amount of capital expenditures made by PG&E must be approved by the CPUC during the 2014 general rate case and so the forecasts presented in Figure 11 should be interpreted as the maximum possible level of expenditures.

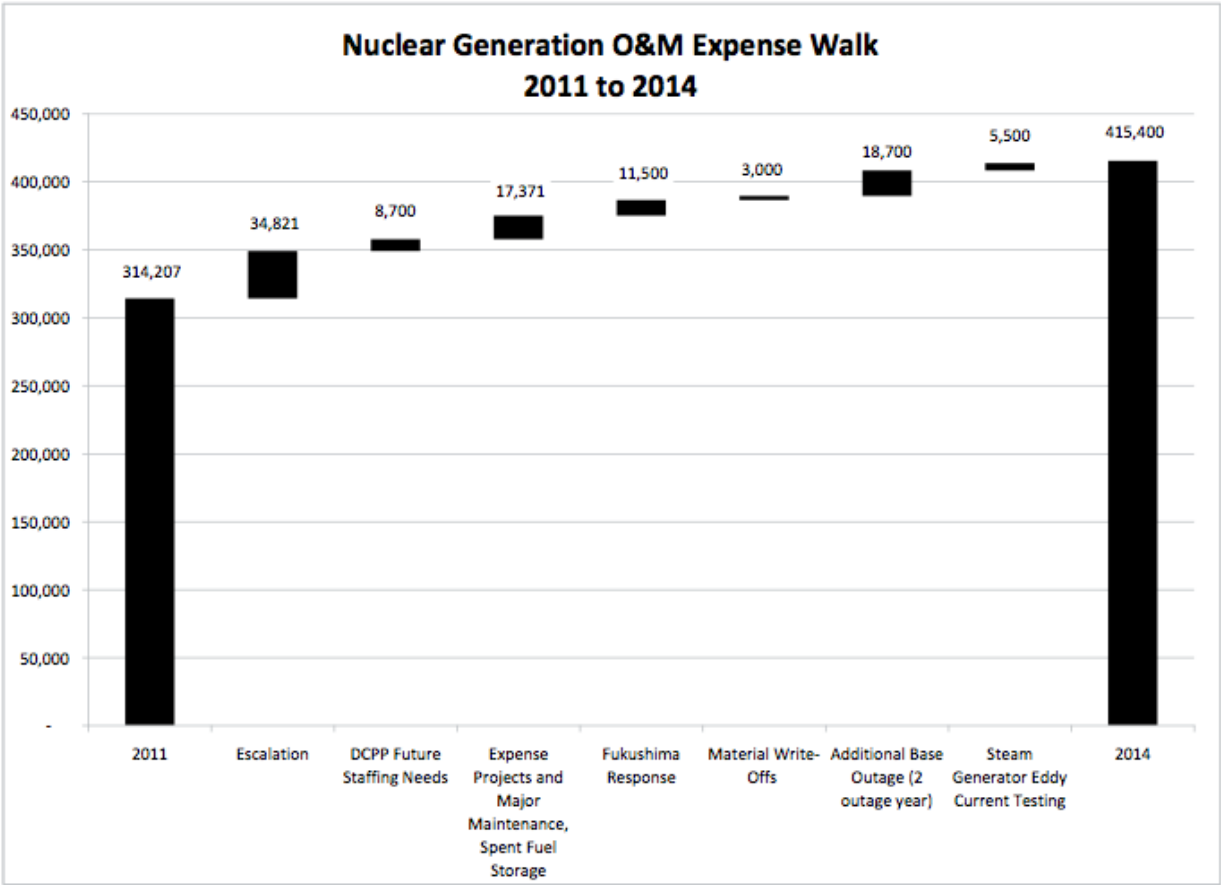

Figure 12: Increases in O&M Expenditures for Diablo Canyon, 2011-2014
Source: PG&E (2012)

Diablo Canyon is the other major source of operations and maintenance costs for PG&E and those costs are also projected to increase in the short-term (Figure 12).

The reasons for increasing O&M costs include a refueling outage, eddy current testing, upgrades mandated after the Fukushima accident, additional staffing requirements, and costs of complying with new regulations.

The operating licenses for the two reactors at Diablo Canyon are currently scheduled to expire in September 2024 and April 2025, respectively (PG&E 2012). At present, it is unclear whether or not the licenses will be extended further into the future.

Using the GHG Calculator, we can forecast the escalation rates for electricity prices within PG&E territory for the period 2008-2020 (Table 6). The nominal escalation rates shown in the table are subject to the same caveats as the results for CA as a whole, but a more useful comparison can be made between the PG&E-specific results and those for the entire state.

Overall, PG&E is forecasted to experience slower price growth rates in all scenarios because of their low reliance on natural gas. The difference is particularly large in the scenarios with high emission allowance prices.

Scenario	Nominal Escalation Rate (Ann 2008-2020)	Real Escalation Rate (Ann 2008-2020)	Difference from CA Avg.
Reference (33% RPS+GHG10)	4.4%	2.6%	-0.2%
Low Natural Gas Price	3.4%	1.6%	-0.1%
High Natural Gas Price	4.8%	3.0%	-0.2%
GHG$25	4.8%	3.0%	0.3%
GHG$50	4.8%	3.0%	-0.6%
GHG$100	5.6%	3.8%	-0.6%
GHG$100 + High Natural Gas Price	6.0%	4.2%	-0.6%

Table 6: Projected Escalation Rates in PG&E Service Territory using the GHG Calculator
Source: E3 GHG Calculator – available at http://ethree.com/public_projects/cpuc2.php

Southern California Edison

Similar to PG&E, Southern California Edison (SCE) is a huge utility that serves approximately 5 million residential, commercial and industrial customers in central and southern California.

Unlike PG&E, SCE provides only electricity to its customers and also has a slightly different portfolio of electric power plants that rely more heavily on nuclear and natural gas generation and less on hydroelectric power. Before 2013, a large chunk of SCE's generation capacity came from two nuclear power plants – the San Onofre plant in South San Clemente and the Palo Verde plant in Phoenix, Arizona.

Together, these two plants made up about 2.3 GW out of SCE's total generating capacity of 5.5 GW (about 42%). Due to a radiation leak, however, the San Onofre plant hasn't generated electricity since January 2012 and SCE announced on June 7, 2013 that the plant will be shut down permanently. The shutdown of San Onofre is likely to put upward pressure on short-run electricity prices in SCE territory for several reasons. First, although CAISO has already found enough generating capacity to keep the grid running reliably via reserves and increased imports, permanent solutions will require adding new capacity in southern California (primarily in the form of natural gas) and new transmission lines to access other resources that lie outside of the Los Angeles and San Diego areas (EIA 2013b).

At present, the continued outage of San Onofre is being cited as the primary reason why wholesale power prices in California were 59% higher during the first half of 2013 compared to the first half of 2012 (EIA 2013c).

Secondly, as described earlier in the report, shutting down a nuclear plant from the grid removes a low-cost resource from the system and will result in higher wholesale prices if replaced by generation with higher marginal costs. Long-run solutions to the problem will reduce wholesale prices back to more normal levels, but will likely require capital expenditures that will be recouped through higher rates[16].

[16] Ultimately, the CPUC will decide how much SCE customers will have to pay for the shutdown of the reactors. Other sources of funding to cover the shutdown include Mitsubishi Heavy Industries Ltd., who manufactured the failed plumbing, and a nuclear power insurer. It also remains to be seen whether or not SCE will be required to refund some or all of the $529 million it charged customers for replacement power since the plant was shut or the $813 million charged for operating it when it wasn't generating electricity.

Scenario	Nominal Escalation Rate (Ann 2008-2020)	Real Escalation Rate (Ann 2008-2020)	Difference from CA Avg.
Reference (33% RPS+GHG10)	4.4%	2.6%	-0.2%
Low Natural Gas Price	3.4%	1.6%	-0.1%
High Natural Gas Price	4.8%	3.0%	-0.2%
GHG$25	4.8%	3.0%	0.3%
GHG$50	5.2%	3.4%	-0.2%
GHG$100	6.0%	4.2%	-0.3%
GHG$100 + High Natural	6.4%	4.6%	-0.3%

Table 7: Projected Escalation Rates in SCE Territory using the GHG Calculator
Source: E3 GHG Calculator – available at http://ethree.com/public_projects/cpuc2.php

Another key question that has yet to be resolved is whether or not consumers will continue to pay back SCE for the initial $2.1 billion investment that was required to construct the plant now that it is no longer producing electricity.

Finally, there are also significant costs associated with the actual decommissioning of San Onofre and SCE estimates that $300-450 million of those costs will be absorbed by ratepayers via higher rates (Chediak and Polson 2013).

Neither AEO 2013 nor the GHG Calculator takes into account the impacts of the San Onofre shutdown, so quantitative estimates of the rate impacts are presently unavailable.

In addition to San Onofre, SCE also operates a significant amount of natural gas generation (about 1.25 GW) and will therefore be more exposed to carbon prices than PG&E.

SCE's non-generating assets continue to age and the company anticipates that significant capital expenditures will be required to upgrade a transmission and distribution system that was mostly built immediately after World War II (SCE 2010).

The company argued in its 2012 rate case that many of these assets have reached or exceeded the end of their useful lives and must be replaced in order to continue providing reliable service (SCE 2010). To date, CPUC has not accepted the full amount of these T&D requests, but large future investments are likely inevitable.

Forecasted escalation rates for SCE territory are presented in Table 7. Similar to PG&E, SCE is generally expected to experience slower price growth than the state as a whole out to 2020, but faster than PG&E in scenarios with high emissions allowance prices due to its larger reliance on natural gas generation.

The loss of San Onofre will likely eat into these differences in short-run, resulting in escalation rates that are even closer to those for the entire state.

Municipal Utilities

Municipal utilities such as Sacramento Municipal Utility District (SMUD) and Los Angeles Department of Water and Power (LADWP) are in a slightly different position than the large IOUs when it comes to setting prices.

Due to their public nature, municipal utilities are not regulated by the CPUC since they have no shareholders and are assumed to be striving to provide electricity at the lowest possible cost for the consumers in their territory and set prices at a level to recover those costs and make any required investments.

Despite this key difference, their prices are subject to many of the same drivers as private utilities, including the RPS, cap and trade, fuel prices, and factors that affect the price of power in the wholesale market.

Municipal utilities can have wildly different generation portfolios. SMUD, for example, gets about 48% of its electricity from the wholesale market and generates the remaining 52% from hydropower (11%), natural gas (39%) and wind power (2%) (SMUD 2013). LADWP, on the other hand, buys only 5% of its electricity from the wholesale market and gets the majority of its electricity from coal (39%), nuclear (11%), natural gas (22%) and wind (8%) (LADWP 2010).

In these utilities, escalation rates will be primarily driven by fuel costs, necessary upgrades to distribution assets, and the costs of complying with the RPS and cap and trade programs.

Table 8 shows the forecasted escalation rates for SMUD and LADWP territories using the GHG calculator. Comparing the impacts of different scenarios for the two utilities, prices in SMUD territory are expected to rise more slowly than the state as a whole, while LADWP is forecasted to prices increase much more rapidly than the rest of the state. This difference can be primarily explained by the difference in generation portfolios between the two utilities, particularly LADWP's relatively high current reliance on coal.

	SMUD			***LADWP***		
Scenario	**Nominal Escalation Rate (Ann 2008-2020)**	**Real Escalation Rate (Ann 2008-2020)**	**Difference from CA Avg.**	**Nominal Escalation Rate (Ann 2008-2020)**	**Real Escalation Rate (Ann 2008-2020)**	**Difference from CA Avg.**
Reference (33% RPS+GHG10)	3.8%	2.0%	-0.7%	6.3%	4.5%	1.8%
Low Natural Gas Price	2.5%	0.7%	-1.0%	5.8%	4.0%	2.2%
High Natural Gas Price	4.4%	2.6%	-0.6%	6.8%	5.0%	1.8%
GHG$25	4.4%	2.6%	-0.1%	6.8%	5.0%	2.3%
GHG$50	5.0%	3.2%	-0.5%	7.7%	5.9%	2.3%
GHG$100	5.5%	3.7%	-0.8%	9.0%	7.2%	2.7%
GHG$100 + High Natural Gas Price	6.0%	4.2%	-0.7%	9.0%	7.2%	2.3%

Table 8: Projected Escalation Rates in SMUD and LADWP Territories using the GHG Calculator
Source: E3 GHG Calculator – available at http://ethree.com/public_projects/cpuc2.php

CONCLUSION

Retail electricity prices in California are the product of a highly complex regulatory and market environment that involve a variety of different players. Within this environment, price levels are determined by many factors including the general state of the economy, fuel prices, maintenance costs, the amount of new capital investments, technological development and environmental.

This report described the mechanisms of how these factors affect the price of electricity and reviewed existing forecasts of what future prices will be under different scenarios.

The three most important drivers of California electricity prices over the next few decades are likely to be the price of natural gas, the price of emission allowances in the cap and trade program, and the costs associated with achieving the RPS target of 33% renewable electricity supply by 2020.

Recent advances in hydraulic fracturing technology have resulted in a boom in gas production and dramatic decreases in the price of natural gas over the past four years. How long gas prices stay low will have a significant impact on electricity prices. The effect of California's RPS on electricity prices is mixed. Recent research suggests that the original 20% RPS had a negligible impact on prices; however results from the GHG Calculator indicate that achieving the 33% RPS may be more costly.

Finally, the cap and trade program is in its very early stages and projections of future prices of emissions allowances remain very uncertain, with values ranging from $8-213 per metric ton.

Forecasting long-run electricity prices is an incredibly difficult task that is rife with uncertainty regarding assumptions about key variables and this uncertainty is borne out in the results of the two models that were compared. EIA's most recent Annual Energy Outlook (2013) projects relatively modest electricity price increases in the range of 1.9-3.4% per year during the period 2013-2040, while work done by E3 (the GHG Calculator) anticipates higher growth rates of between 3.5-6.3% per year from 2008 to 2020. The GHG Calculator indicates that prices will increase more slowly in PG&E, SCE, and SMUD territories, but increase much more rapidly in LADWP territory.

Neither model accounts for any impact that may be associated with the shutdown of the San Onofre Nuclear Generating Station in southern California. The AEO has the advantages of being newer and more detailed, but doesn't allow for modeling combinations of scenarios and also has a recent history of underestimating price increases.

The GHG Calculator was created specifically for California and allows for a large amount of customization in the scenarios that are modeled (including higher emission allowance prices and the creation of a "worst case" scenario), but is much less sophisticated and is built on older data that may not accurately reflect the current reality.

Overall, it appears likely that retail electricity prices will continue to increase, making long-term investments in energy efficiency and renewables appealing options for homeowners and businesses.

Moving forward, the next couple of years will provide very useful new information regarding the price of emission allowances as more permits are auctioned and the costs of large-scale renewable projects will be revealed as utilities make plans for complying with the RPS.

Meanwhile, fundamental changes in market structure (such as the introduction of dynamic pricing or a deregulated retail market where consumers can choose their energy provider) seem likely to continue gathering interest amongst researchers and policymakers and are sure to be evaluated at least partly on their likely impact on retail electricity prices. ne thing that is certain is that future prices will have a significant impact on new investments in renewable generation and energy efficiency as well as millions of people who consider electricity a necessity.

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APPENDIX

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