CALIFORNIA ENERGY COMMISSION

2007 Integrated Energy Policy Report

DRAFT COMMITTEE REPORT

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This report was prepared by the California Energy Commission's Integrated Energy Policy Report Committee as part of 2007 Integrated Energy Policy Report Proceeding - Docket # 06-IEP-1 and associated subdockets. The report will be considered for adoption by the full Energy Commission at its Business Meeting on November 21, 2007. The views and recommendations contained in this document are not official policy of the Energy Commission until the report is adopted.

2007 Integrated Energy Policy Report Proceeding

The *2007 Integrated Energy Policy Report* is a product of the 2007 Integrated Energy Report Proceeding, Docket Number 06-IEP-1, and its supporting record. Several staff provided significant contributions to the development of this Draft Committee Report.

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Preface

This *2007 Integrated Energy Policy Report* (*IEPR*) was prepared in response to Senate Bill 1389 (Bowen), Chapter 568, Statutes of 2002, which requires that the California Energy Commission prepare a biennial integrated energy policy report that contains an integrated assessment of major energy trends and issues facing the state's electricity, natural gas, and transportation fuel sectors and provides policy recommendations to conserve resources; protect the environment; ensure reliable, secure, and diverse energy supplies; enhance the state's economy; and protect public health and safety (Pub. Res. Code § 25301[a]). This report fulfills the requirement of SB 1389.

The report was developed under the direction of the Energy Commission's 2007 Integrated Energy Policy Report Committee (Committee). As in previous IEPR proceedings, the Committee recognizes that close coordination with federal, state, and local agencies is necessary to adequately identify and address critical energy infrastructure and related environmental challenges. In addition, input from state and local agencies is needed to develop the information and analyses that these agencies need to carry out their energy-related duties. This *2007 IEPR* reflects the input of stakeholders and federal, state, and local agencies that participated in the IEPR proceeding. The information gained from workshops and stakeholders was essential in developing the recommendations in this report. The Committee would like to thank stakeholders for their participation and thoughtful contributions to the process.

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Executive Summary

Climate change is the most important environmental and economic concern of this century. Greenhouse gas emissions are the largest contributor to global warming, and reducing those emissions poses an enormous and urgent challenge. Responding to that need, Governor Arnold Schwarzenegger and the California legislature took collective action and placed the reduction of greenhouse gas emissions at the front and center of government and business agendas. In passing Assembly Bill 32 (Nuñez, Chapter 488, Statutes of 2006), the Global Warming Solutions Act of 2006, the Governor and the Legislature mandated that California must reduce its greenhouse gas emissions to 2000 levels by 2010 and to 1990 levels by 2020.

AB 32 marks a significant change for California's energy goals. Before its passage, California's energy-related legislation focused on stabilizing and/or minimizing energy costs, ensuring supply, limiting our dependence on imports and fossil fuels, and generally benefiting the state's economy while minimizing pollution and adverse environmental and public health effects. AB 32 has changed the priorities: California must still achieve its previous energy goals, but it must do so while reducing the volume of carbon dioxide emissions that result from burning fossil fuels for electricity and transportation. Slowing global warming requires meeting energy needs as much as possible with zero- or low-carbon energy sources. Carbon dioxide (CO_2) emissions are the primary culprit in trapping gases in the atmosphere and causing the "greenhouse effect" that prompts global warming.

Scientific consensus expects that temperatures in the state will increase during this century and precipitation patterns will change drastically, threatening California's environmental quality and robust economy. Even an average annual 3-degree temperature rise will have widespread consequences – worsening air pollution, intensifying heat waves, increasing coastal floods, reducing farmland productivity, increasing wildfires and pest infestations, decreasing fish populations and reducing snowpack—resulting in less hydropower and possible water shortages.

Affordable and reliable energy drives California's successful economy. Energy represents nearly $100 billion in expenditure each year to power the state. California has led the nation in effective action to reduce emissions and improve air quality and has held the line on per capita consumption of electricity. But with a growing population and economy, how can California ensure energy supplies keep pace with the growth and simultaneously reduce its carbon footprint?

California's Energy System—Powering a Nation/State

Today one in eight Americans, over 37 million people, live in California. The state's population has doubled since 1965, a growth rate faster than that of any other developed region in the world. In fact, if California were a nation, it would be the 33rd largest nation in the world. The

state Department of Finance predicts that California will add another 5 million people in the next decade moving towards 60 million residents by 2050.

California is the second largest emitter of greenhouse gases in the United States and about the twelfth largest in the world. In 2004, the state produced some 492 million metric tons of carbon dioxide (greenhouse gas emission equivalent). Reducing California's "carbon footprint"[1] to meet AB 32 goals will require approximately a 29 percent[2] cut in emissions below the 2020 levels the state's current trajectory would produce.

The state's immense energy system is dominated by petroleum to serve the transportation sector and natural gas to heat homes and generate electricity. California currently emits 492 metric tons of greenhouse gases annually. Most of California's greenhouse gas emissions, or 81 percent, are carbon dioxide produced from fossil fuel combustion, 2.8 percent are from other sources of CO_2, 5.7 percent are from methane, and 6.8 percent were from nitrous oxide. Of those emissions, 22 percent derive from electricity generation and over 39 percent from transportation. Figure ES-1 shows the expected effects of the major emission reduction strategies compared to the projected growth in emissions without these efforts.

The Electricity Sector

California leads the nation in the lowest electricity use per person. While per capita electricity consumption in the United States increased by nearly 50 percent over the past 30 years, California's per capita electricity use remained almost flat, due in large part to a variety of cutting-edge energy efficiency programs and cost-effective building and appliance efficiency standards (see Figure ES-2). The state also changed the way it generates electricity. Before the oil crisis of the 1970s, petroleum was the fuel source for over half of the state's electricity. Today, cleaner-burning natural gas fuels over 41 percent of the state's electricity, and renewables account for almost 11 percent.

Since 2003, California's energy policy has relied on the "loading order"[3] to meet its growing energy needs, first with energy efficiency and demand response; second, with renewable energy and distributed generation; and third with clean fossil-fueled sources and infrastructure improvement. This strategy has had the benefit of reducing our carbon emissions and

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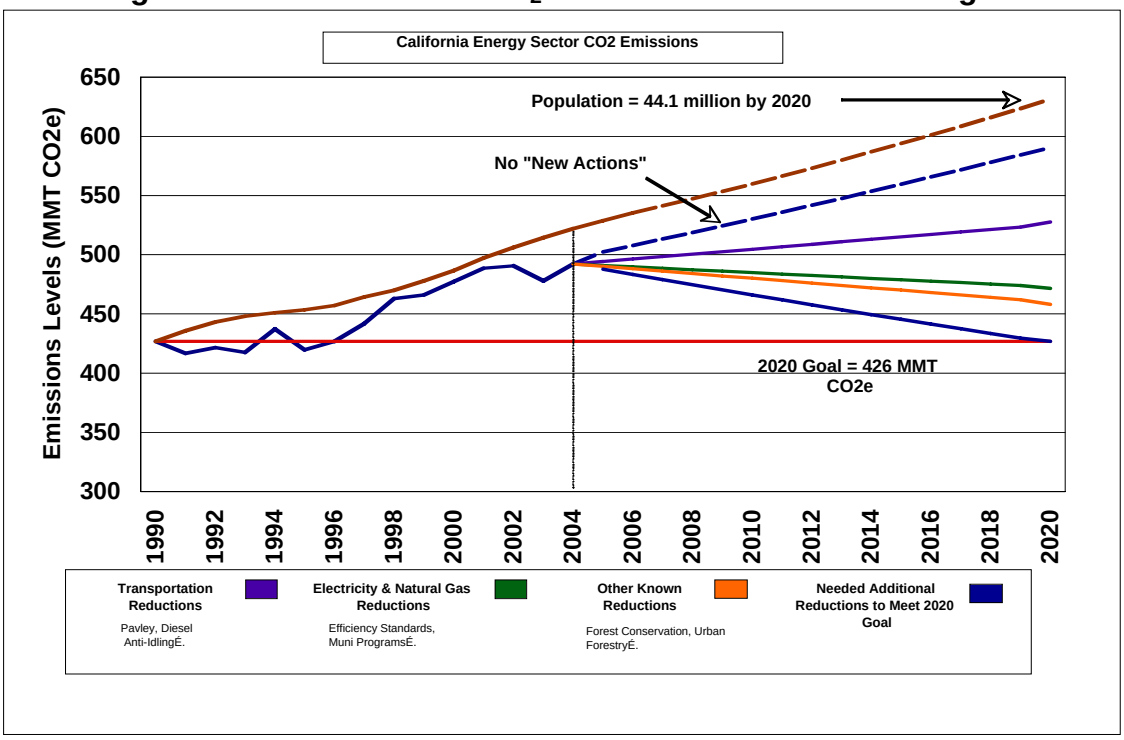
[1] "Carbon footprint" refers to the carbon dioxide emissions that result from burning fossil fuels for electricity and transportation and that are the primary culprit in trapping gases in the atmosphere and causing the "greenhouse effect" and hence global warming.

[2] Reduction of greenhouse gas emissions from a "business-as-usual" 2020 level as projected by the Climate Action Team based on 174 million metric tons CO_2 equivalent. This number is an increase from the previous estimate of 145 million metric tons CO_2 equivalent estimated in 2005 by the Climate Action Team.

[3] The "loading order," adopted as the state's energy policy, is the accepted protocol that describes the priority sequence for actions to address increasing energy needs.

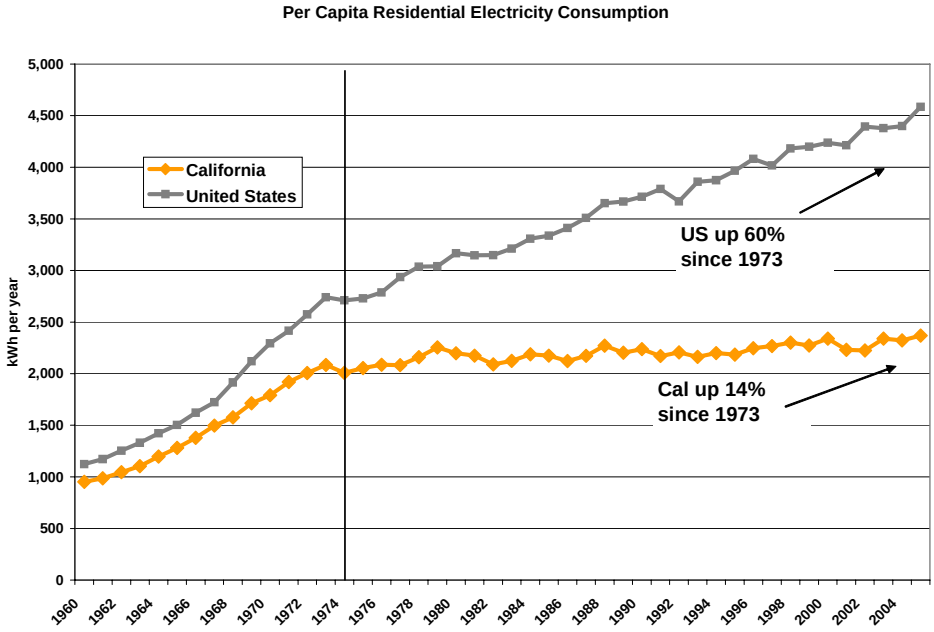
diversifying sources of energy supply. Energy efficiency, which successfully flattened the state's per capita electricity use, will continue to be the keystone of California's energy strategy.

Figure ES-1: California's CO_2 Emission Reduction Strategies



Source: California Energy Commission, Climate Action Team data

Figure ES-2: California Holds the Line on Electricity Consumption



Source: California Energy Commission

California's Building and Appliance standards have saved consumers more than $56 billion in electricity and natural gas costs since 1978 and averted the need to build the 30 large power plants that would otherwise have been necessary to meet electricity needs. It is estimated the standards will save an additional $23 billion by 2013.

Senate Bill 1078 (Sher, Chapter, Statutes of 2002), introduced a Renewable Portfolio Standard requiring annual increases in energy generation from renewable resources equivalent to at least 1 percent of sales, with an aggregate goal of 20 percent by 2010. The Renewable Portfolio Standard was designed to address California's growing dependence on natural gas for electricity generation and encourage long-term power purchase contracts that financial institutions require for generation projects. Since 2004, the Energy Commission has recommended a further goal of 33 percent renewables by 2020. This enhanced target was endorsed by the California Public Utilities Commission and Governor Schwarzenegger in 2005, and its codification is currently pending before the Legislature. Hampered by complex rules, insufficient transmission, inconsistent application among retail sellers, and a lack of transparency in its application, the state's efforts to meet the Renewable Portfolio Standard goals have not yet kept pace with the mandate. The state's current use of renewables for 11 percent of electricity is not on the trajectory to meet Renewable Portfolio Standard goals by 2020. There are, however, indications that the state's investor-owned utilities are on track to achieve 20 percent, although likely not by 2010.

The Transportation Sector

Transportation is the single largest contributor to California's greenhouse gas emissions, producing over 39 percent of the state's total emissions in 2004. Despite, or perhaps because of, its attachment to the automobile, California adopted stringent tailpipe emission standards as early as 1966, and in 1971 adopted automobile nitrogen oxides standards—both the first such standards in the nation. The California Smog Check Program, which assured the effectiveness of vehicle emission control systems, went into effect in 1984. In 1992, the first of many phases of reformulated clean burning gasoline came to California, and in 1993 the state enacted new standards for cleaner diesel fuel.

Demand for gasoline and diesel is expected to increase in California by 1 to 2 percent each year as a growing population registers more vehicles and drives more miles. While national demand grew by 1.5 percent in the first half of 2007 according to American Petroleum Institute figures, consumption in California actually dropped. Californians used nearly 1 percent less gasoline in April 2007—10.5 million fewer gallons of gasoline than the previous April—according to figures released by the California Board of Equalization. This was the fourth straight quarter in which Californians have used less gas than they did during the same period the year before.

As the second largest consumer of transportation fuels in the world (behind the United States as a whole)— more than 16 billion gallons of gasoline and nearly 3 billion gallons of diesel each year—California would like to replicate its success with electricity efficiency in the area of transportation fuels. However, federal law prohibits states from setting the minimum number

of miles per gallon new cars and light trucks must achieve. Earlier this decade, the Energy Commission and the California Air Resources Board spent several years reviewing the technical and economic aspects of a major reduction in the petroleum dependence of California's transportation sector.[4] Based on this research, in 2005, Governor Schwarzenegger appealed to the United States House of Representatives "to establish new fuel economy standards that double the fuel efficiency of new cars, light trucks and SUVs."[5] In June 2007, the United States Senate voted to raise the fuel efficiency standard for cars to 35 miles per gallon by 2020. As of October 2007, the House had taken no action. The proposed 35-mile-per-gallon standard pales in comparison to Japan's current standard of 45 miles per gallon and Europe's more than 50 miles per gallon by 2012 and may ultimately be too little, too late.

The California legislature also took advantage of a federal Clean Air Act provision that allows states to set their own emission standards (with a waiver from the United States Environmental Protection Agency)[6] and passed California's Clean Car Law (Assembly Bill 1493, Pavley, Chapter 200, Statutes of 2002), the first such regulation in the United States, to limit greenhouse gas emissions from passenger cars and light trucks. The Clean Car Law would cut greenhouse gas emissions by 30 percent by 2016 for all cars sold in California starting in 2009. As allowed under federal law, 11 other states have adopted these California standards pending receipt of the Environmental Protection Agency waiver. Unfortunately, the agency has failed to act on California's waiver request for nearly two years, declaring it lacks the authority to regulate greenhouse gases—a declaration rejected by the United States Supreme Court in its recent decision which states that the Environmental Protection Agency does have the authority to regulate CO_2 emissions and should reconsider its refusal to do so.

Meeting California's Electricity Needs

Electricity powers the California economy and accounts for 22 percent of the state's carbon emissions. Demand for electricity is forecast to grow at a steady pace, fed by a projected increase in population—currently more than 36 million and projected to grow to 42 million by 2020.[7] Even with a slight decrease in the rate of population growth, from 1.8 percent to 1.3 percent annually, the cumulative growth will significantly affect statewide annual electricity consumption. Projected effects of currently adopted building and appliance standards and

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[4] California Energy Commission and the California Air Resources Board *AB 2076 Report*, adopted 2003.

[5] May 13, 2005 letter from Governor Arnold Schwarzenegger to Pete Domenici, chairman, Energy and Commerce Committee of the U.S. House of Representatives and Jeff Bingaman, member, Energy and Commerce Committee, U.S. House of Representatives.

[6] <http://www.greencarcongress.com/2007/04/us_epa_opens_co.html> The EPA has historically granted all 53 such waivers previously sought by California.

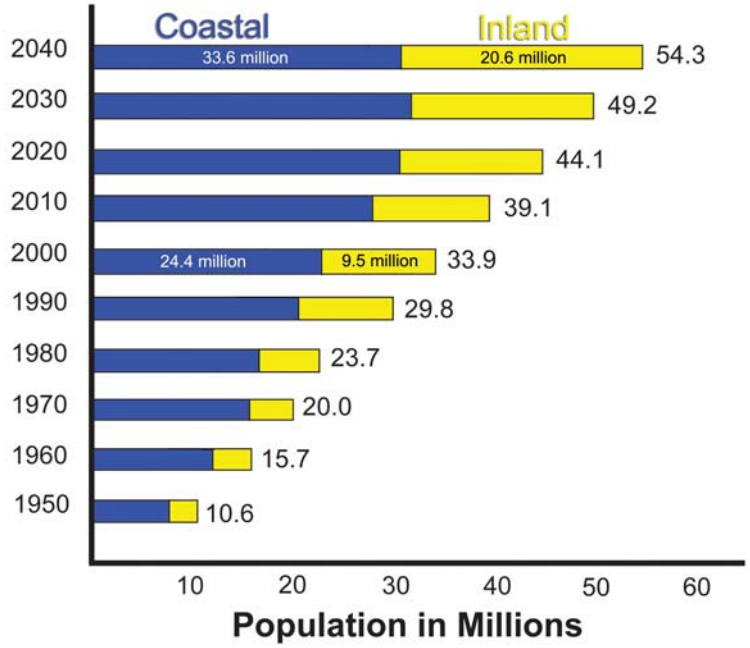
[7] California Department of Finance, Demographic Research Unit, July 2007.

energy efficiency programs mitigate the population growth to a projected average increase in electricity demand of 1.4 percent annually.

Although California's per capita energy consumption has flattened over the last quarter century, "peak"[8] demand per capita is growing at the rate of 1.6 percent (850 megawatts) per year. This increase in peak demand is the result of the population moving inland to the hotter areas of the state, prompting an increase in demand for electricity to power air conditioning.

While nearly 70 percent of the state's population lives along coastal California, it is the state's inland areas – the Southland's Inland Empire, and the Sacramento and San Joaquin Valleys – where the population is growing most rapidly (Figure ES-3). By 2040, nearly 40 percent of the state's population, or more than 20 million people, will reside inland. This inland population growth not only drives demand for more electricity, it changes the pattern of energy use for electricity generation. The climate inland is more extreme than along the coast. In the summer, hotter inland areas require more air conditioning than coastal areas, increasing peak demand even more dramatically than overall electricity demand.

Figure ES-3: California's Inland Population Increases



Source: California Department of Finance, Demographic Research Unit projections and Public Policy Institute of California

[8] "Peak" refers to a sudden, sharp increase in demand for electricity prompted by increased use of primarily air conditioning during the hottest hours of day on the hottest days of the year.

New Goals Require New Analytical Tools

The new challenges posed by AB 32 prompted the Energy Commission to expand its current repertoire of analytical tools to refine its understanding of the actions California must take to achieve major reductions in greenhouse gases for the electricity sector. As a result, the Commission undertook two major analytical projects and updated a standard analysis tool in a third project.

The Scenario Analyses Project assessed the implications of the key strategies that are important for the electricity system. Rather than focusing on the range of uncontrollable external forces affecting the energy industry, Energy Commission staff developed scenarios that focused on broad policy options available to decision makers. The resulting "policy-driven" scenario analyses demonstrate the economic and greenhouse gas emission consequences of the various scenarios—for example, increasingly aggressive levels of carbon-free energy resources—and provide a context for understanding the consequences of efforts now underway by the ARB, the CPUC, and the Commission itself to establish regulatory requirements for specific load-serving entities.

The Portfolio Analysis Project conducted analyses based on Modern Portfolio Theory that enabled staff to consider risk when analyzing different combinations of actions that utilities can take to meet future electricity demand. The portfolio analysis enables decision makers to assess the potential changes to an existing portfolio's risks and costs brought about by adding assets with their own individual risk and cost profiles.

Finally, staff substantially overhauled its cost of generation model to make it more accurate, user friendly, flexible, transparent, and better documented. Though a principal weakness of the model is its inability to determine how technology costs will evolve through time, the Energy Commission has committed to using the 2009 IEPR cycle to extensively refine the input data used for developing technologies and to working with industry and academic experts to properly update technology costs over time.

Using Conventional Resources to Meet AB 32 Goals

Even as California continues to move in the direction of increasing its preferred strategies of efficiency and renewable resources, conventional fuels will continue to be the mainstay of California's resource mix to meet electricity needs for the immediate future. Conventional generation resources currently account for some 70 percent of the state's electricity supply. Even in 2020, 80 percent of the state's electricity will come from conventional generation, the vast majority of which is planned to be natural gas fired. Of the nearly 24,000 megawatts of new capacity licensed since 1998, only 36 plants—12,910 megawatts—have been built and are in operation. An additional 2,278 megawatts are currently under construction, and although 13 plants totaling 8,361 megawatts have been approved, construction has not moved forward for lack of power purchase agreements needed to obtain financing. Of the total anticipated and potential megawatts, 99 percent will be fueled by natural gas and 1 percent by geothermal. While nuclear and "clean" coal-fired generation offer the potential to generate electricity with lower carbon emissions, the Energy Commission does not expect them to contribute

significantly to the state's near-term AB 32 goals given the economic and regulatory barriers these technologies face.

Efficiency and Demand Response

Energy efficiency is the cornerstone of California's energy strategy. Cutting edge programs and cost-effective building and appliance efficiency standards are largely responsible for limiting electricity-related carbon emissions.

With the pressure of increasing population and the continued growth in drier, hotter inland areas, efficiency and demand response programs become even more important to California. The Energy Commission, with the CPUC, recognizes that California must step up its energy efficiency efforts in the carbon-constrained future of AB 32. Assembly Bill 2021 (Levine, Chapter 734, Statutes of 2006), requires the Energy Commission, in consultation with the CPUC and the publicly owned utilities, to produce a statewide estimate for both investor-owned utilities and publicly owned utilities of "all potentially achievable cost-effective electricity and natural gas efficiency savings and establish statewide annual targets for energy efficiency savings and demand reduction over 10 years."

Scenario analyses conducted as part of this proceeding have demonstrated that cost-effective efficiency programs can, when coupled with renewables development, allow California to achieve at least a proportional reduction[9] of carbon emissions from the electric sector. These analyses highlight the need to capture all cost-effective energy efficiency. The September 17, 2007, Proposed Decision from the CPUC emphasizes this goal and describes a course of action, involving programs under its jurisdiction and those under the Energy Commission's authority to achieve it.

Recognizing that standards are the most cost-effective means to achieve energy efficiency, the Energy Commission is committed to pursuing more aggressive lighting standards and load management standards. As a result of the AB 2021 assessment, the Energy Commission is recommending that the statewide goal for energy efficiency is 100 percent of economic potential. Achieving maximum energy savings as the primary strategy for greenhouse gas emission reductions builds on California's long history of embracing all of these fundamentally cost-effective strategies; however, it will also require even more innovative strategies to compel all Californians to participate to the fullest.

To capture 100 percent of cost-effective efficiency, the Energy Commission recommends:

- Enlisting publicly owned utilities in a collaborative relationship to further their efforts in aggressively ramping up energy efficiency programs. Publicly owned utilities need to

[9] Proportional to the estimated volume of emissions that the electricity sector emitted in 1990.

use their local conditions and customer knowledge to craft new program ideas. In doing so, sufficient incentives must be provided.

- Pursuing legislation that would require energy audits and a cost-effective level of efficiency improvements at the time of sale of a building. Diagnostics and measure verification can be completed while homes or buildings are empty, providing the opportunity for upgrading major building systems such as windows; insulation; lighting; heating, ventilation, and air conditioning systems; and water heating.
- Enacting appliance standards to improve efficiency of appliances sold in California, including standards to increase the efficacy of general service lighting.
- Increasing the efficiency levels of the building standards so that buildings are net zero energy by 2010 for residences and 2020 for commercial buildings.
- Supporting behavioral and other social science research applied to customer decision making in energy efficiency.
- Investigating market-based approaches to energy efficiency, such as "white tags" or "white certificates" (also known as energy efficiency certificates or credits), the analog to renewable energy credits.

Renewables

Renewable resources are an essential tool for reaching AB 32 goals; however, with renewables comprising only 11 percent of the state's resource mix as of 2006, we clearly face some program adjustments in order to reach Renewable Portfolio Standard goals of generating 20 percent of the state's electricity from renewable resources by 2010 and 33 percent by 2020. Two main considerations drive the need to achieve those RPS goals:

- The critical imperative to reduce greenhouse gas emissions
- Management of the cost and risk borne by ratepayers for electricity generation

As this *2007 IEPR* reports to the Governor[10] in Chapter 4, achieving 33 percent renewables by 2020 is feasible with certain changes to the structure of the Renewable Portfolio Standard and with a concerted effort by and coordinated support from government, industry, and the public. The ability to achieve the RPS goals depends on successfully implementing the following changes:

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[10] In 2005, the Legislature passed Assembly Bill 1585, which would have required the Energy Commission to include "a review of the feasibility of increasing the RPS to 33 percent by 2020." However, the law was to go into effect only if Senate Bill 107 of the 2005-06 regular session was also enacted and became operative on January 1, 2006. SB 107 was enacted in September 2006 and went into effect January 1, 2007. In signing AB 1585 into law, the Governor directed the Energy Commission to conduct the review even though SB 107 did not go into effect on the date required.

- Strengthening and streamlining of the planning and permitting processes for transmission
- Expansion and upgrade of the transmission grid and distribution system to access and deliver renewable resources
- Resolution of operational issues associated with integrating large volumes of intermittent resources into the system
- Redesign of the market price referent/SEP mechanism to allow developers to obtain lower-cost financing and encourage expansion of equipment production for renewable energy

Distribution System Planning/Distributed Generation

Electric distribution systems throughout California still use designs, technologies and strategies that were developed to meet the needs of mid-20th century customers. These large and complex systems have historically provided reliable electric power to tens of millions of customers throughout the state; however, aging infrastructure coupled with modern demands is starting to erode this capability. Today, about 90 percent of all customer interruptions and outages are caused by distribution problems. In four days in early September 2007, 645,000 Southern California Edison customers suffered distribution-caused outages.

California's commitment to distributed renewable energy, combined heat and power, demand response, and reduced production of greenhouse gases requires a change in the design of these distribution systems to accommodate the integration and full use of these new resources. Ideally, an automated 21st century distribution grid would allow grid operators to see and manage the grid in real time, provide for rapid two-way information exchange between utilities and customers, and allow for the seamless integration of the full spectrum of 21st century technologies. To do so, California must:

- Fund distribution research through the Energy Commission's PIER program to develop and demonstrate technologies that will accelerate the transformation of the distribution grid into an intelligent and sustainable network
- Develop state policy that will articulate and support modernizing the state's distribution system and establish a Distribution Program with adequate staff to assess distribution system adequacy and provide leadership in the area of distribution system modernization
- Establish a transparent process that integrates distribution planning with other resource procurement processes in a manner that supports the use of new low-carbon resources—renewables, demand response, efficient CHP, distributed generation, energy storage, advanced metering infrastructure, and plug-in hybrid electric vehicles

- Develop new rate designs that will encourage consumers and utilities to invest in promising technologies and participate in programs that provide value to them and the state (premium power quality, critical-peak and real-time pricing)
- Base a portion of each utility's profit on criteria related to performance, achievement of designated goals, service reliability, and customer support and assistance to achieve greater efficiency of electricity use
- Require utilities to demonstrate that they have considered investments in advanced grid technologies before allowing investments in the alternatives
- Recover the remaining book-value costs of equipment rendered obsolete by the deployment of a qualified smart grid system

Distributed Generation

Distributed generation (DG) and combined heat and power (CHP) are valuable resource options for California. The need to reduce greenhouse gas emissions as part of AB 32 goals elevates the importance of keeping DG capacity in the system. CHP in particular offers low GHG emissions rates for electricity generation, taking advantage of fuel that is already being used for other purposes. DG can also play an important role in helping to meet local capacity requirements. The California ISO has encouraged the CPUC to include local capacity requirements in its procurement to replace power plants that must operate, even if uneconomically, to preserve system reliability.

The Energy Commission has proposed policies to encourage development of DG resources, including CHP projects, since the late 1990s and continues today through collaborative efforts with the CPUC to address barriers to DG development. Yet significant issues facing DG developers persist. In the *2005 Integrated Energy Policy Report*, the Energy Commission reported that, despite many years of articulated policy preferences, DG and CHP in California continue to struggle with major barriers to market entry in the context of traditional utility cost-of-service grid management. The *2005 IEPR* reiterated that California needs to improve access to wholesale energy markets and streamline utility long-term contracting processes so that CHP owners can easily and efficiently sell their excess electricity to their local utility. Availability of the wholesale market continues to be a significant consideration in encouraging DG.

Because the Energy Commission continues to believe that DG, and especially CHP applications, provide significant system and efficiency benefits to California's distribution system, it recommends the following:

- The CPUC's self-generation program incentives should be based on overall efficiency and performance of systems, regardless of fuel type.
- The CPUC should complete a tariff structure to make DG projects "cost and revenue neutral," while granting owners' credit for system benefits, such as reduced congestion.
- The CPUC and the Energy Commission should work cooperatively to eliminate all non-bypassable and standby reservation charges for DG.

- The CPUC should continue the work of the "Rule 21" industry/utility collaborative working group to refine interconnection standards, provide third party resolution of interconnection issues, and streamline permitting
- The CPUC should develop a DG portfolio standard for electric utility procurement plans. Alternatively, the utilities could be required to treat DG like efficiency programs.
- The CPUC should adopt revenue-neutral programs that would place high efficiency CHP on an equal footing with bulk power from utilities.

Natural Gas

Over the last 30 years, as California worked to reduce its petroleum dependence, natural gas evolved as a critical element of California's energy system. Today, it provides more than a third of the state's total energy requirements. While California's demand for natural gas is increasing, it is not increasing at the same rate as in the rest of the United States and most of eastern Canada, where shifts from coal-based electricity generation to natural gas-based generation will increase competition for this important resource. That competition combined with projected flat production of natural gas in North America will likely increase the price of natural gas.

Natural gas will continue to be a major fuel in California's supply portfolio and must be part of a complementary strategy to reduce greenhouse gas emissions. Imports of liquefied natural gas are expected to supplement conventional supply sources and help stabilize prices. However, with only a single liquefied natural gas facility under construction on the West Coast, the issues surrounding the siting of future terminals may deter or delay the arrival of additional gas supplies.

To maintain an adequate and reliable supply of natural gas, the Energy Commission makes the following recommendations:

- The Energy Commission advocates policies that allow California to secure alternative and diverse sources of natural gas to meet growing demand and energy security options, including support of liquefied natural gas facilities on the West Coast that can be licensed to meet environmental and public health and safety standards.
- The Energy Commission supports all cost effective energy efficiency measures for natural gas including replacement of aging power plants with new efficient power plants, especially those operated in a combined heat and power configurations.
- The Energy Commission encourages renewable sources of energy to generate electricity, as well as sources—such as solar for water and space heating—that directly displace natural gas.
- The Energy Commission will continue to incorporate new analytical tools such as Scenario Planning and Portfolio Analysis in assessing and forecasting the state's natural gas supplies and demand to meet reduced greenhouse gas emission targets. The Energy

Commission will encourage the Public Utilities Commission to participate in these analytic efforts.

- As the Energy Commission has determined that there are uncertainties in forecasting natural gas production, demand, and price, we will pursue the following actions in the 2009 Integrated Energy Policy Report cycle.
  - Conduct a rigorous verification of the models used to forecast natural gas supply and price by evaluating the reasonableness and economic and physical likelihood of the model results based on a range of factors including number of new wells, initial rates of production, depletion rates, and other variables
  - Develop probabilities and quantify outcomes for demand scenarios to gain better insight into natural gas demand, including a) scenarios that assume an expanded consumption of preferred resources, b) adoption of electricity as the best fuel strategy, c) displacement of new coal plants with natural gas plants in the Western Electricity Coordinating Council and the eastern United States, and d) levy of a carbon charge on the use of coal to generate electricity.
- The Energy Commission must pursue energy efficiency improvements through increased natural gas research and development.

Meeting Transportation Needs

Decreasing California's reliance on petroleum fuels is critical. By 2020, at current trends, more than 44 million Californians will consume more than 24 billion gallons of gasoline and diesel fuel each year. Supplying this fuel for California's transportation sector poses two significant challenges: meeting demand while reducing carbon emissions and addressing infrastructure capacity. Transportation contributes more than one-third of California's greenhouse gas emissions, and reducing our transportation-related carbon emissions will require alternative fuels, alternative vehicles, new standards and the imagination of California citizens. The anticipated population growth and the cars and emissions that accompany that growth will not make it easy to reduce our carbon footprint, yet it is possible.

The Energy Commission was tasked with developing a plan to reduce the state's petroleum use and greenhouse gas emissions and increase the use of non-petroleum transportation fuels in California. As part of Assembly Bill 1007 (Pavley, Chapter 371, Statues of 2005) proceeding, the Energy Commission has published a draft plan to be considered for adoption by the Commission in October.

Results of the plan's full fuel cycle ("Wells-to-Wheels") analysis demonstrates that alternative fuels can provide substantial greenhouse gas reduction benefits, when used in mid-size passenger cars and urban buses. Depending on the fuel pathway chosen, fuels such as ethanol, natural gas, liquefied propane gas, electricity, and hydrogen have decided advantages over conventional gasoline and diesel fuels.

The plan concludes that regulations alone cannot achieve the state's multiple policy goals; California requires a portfolio of alternative, low-carbon fuels to meet the state's multiple goals of petroleum reduction, greenhouse gas emissions reduction, and increasing biofuels production. The plan recommends multiple strategies that combine private capital investment, financial incentives, and technology advancement approaches.

Achieving the state's petroleum reduction, climate change, and biofuels goals will require substantial investment in fueling infrastructure, production facilities, vehicle components, and commercial development of "second generation"[11] alternative fuels and advanced technology vehicles.

Californians used almost 16 billion gallons of gasoline and over 4 billion gallons of diesel in 2006, and a growing population is feeding that demand. The state cannot reliably meet its increasing fuel demand without a robust petroleum infrastructure that includes refineries, storage, pipelines, distribution terminals, and marine facilities.

Over 60 percent of the oil used by California-based refineries to make these transportation fuels and 10 percent of the refined and finished petroleum products come from outside the state through marine terminals. No pipelines bring crude oil or petroleum products into California; all imports arrive by ship. The marine terminals, specifically those in Los Angeles and Long Beach, are congested and near their berth and storage capacity.

As the demand for transportation continues to grow, California's 21 refineries have responded by increasing the capacity to process crude oil. In 2005, California refineries processed 674 million barrels (1.8 million barrel per day) of crude oil. In addition to supplying California transportation fuels, the state's refineries also supply all of Nevada's needs, 60 percent of Arizona's, and 35 percent of Oregon's. Based on increased future transportation fuel consumption in California and neighboring states, demand is growing faster than the ability of refineries to produce those fuels. Importing increasing quantities of finished petroleum products adds pressure on already-congested marine terminals.

Over the next several decades California must pursue multiple complementary strategies that increase fuel efficiency, expand non-traditional fuel use, and ultimately realign consumer preferences to reduce demand for all transportation energy use as well as reduce trips and vehicle miles traveled. In the near term, California must further expand its marine terminal capacity, marine storage and the pipelines connecting these facilities with the refineries and other pipelines if we are to meet our rising fuel demand.

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[11] "Second generation" alternative fuels refer to those biofuels that are under development and often called "advanced" or "emerging." For example, British Petroleum is conducting research and development on biobutunol, which is an ethanol substitute produced from cellulose---they refer to this as a "second generation" fuel.

Land Use

California's land use patterns shape energy use and the consequent production of greenhouse gas emissions. With nearly 40 percent of California's greenhouse gas emissions coming from the transportation sector, significant efforts are necessary to reduce vehicle miles traveled to meet the state's emission reduction goals. California must not only slow the current 3 percent annual growth rate of vehicle miles traveled, but reduce it. Research shows that increasing a community's density and its accessibility to job centers are the two most significant factors for reducing vehicle miles traveled through design.

Planning for land use and fewer vehicle miles traveled can reduce greenhouse gas emissions and energy use by encouraging walking, mixed use, and energy-efficient housing design. Existing tax policies, largely developed in response to Proposition 13, encourage commercial sprawl at the expense of smart growth strategies.

Issues such as housing, transportation planning, and local greenhouse gas reduction planning require a regional approach. California's metropolitan planning organizations are involved in long-range planning efforts to develop transportation plans that better incorporate land use considerations. These plans are expected to reduce projected energy and climate impacts in the regions. The state-sponsored Blueprint Planning Program has engaged nearly all of the state's metropolitan planning organizations in a long-range planning effort that will have many of them adopting plans to better coordinate land use and transportation development. The plans accommodate housing needs, reduce vehicle miles traveled, and identify priority planning areas. The plans are in early stages of implementation and may need technical, financial, and regulatory assistance to achieve their goals.

While the state has limited land use authority, it does have some key leverage points (California Environmental Quality Act, housing elements, and others) that it can use to assist local governments in reducing energy use and greenhouse gas emissions that result from land use planning choices.

The passage of the Governor's Strategic Growth Infrastructure Bond package represents an opportunity to influence the energy efficiency and environmental friendliness of communities and new growth through project funding criteria. In addition, utilities are playing a small but growing role in collaborative planning efforts with local governments. The potential for mutual benefit from planning efforts between these groups is great, but may need regulatory relief to achieve.

The body of research on the impact of land use on energy and climate is relatively small but receiving significantly more attention with the growing interest in climate change. The California Energy Commission is dedicating significant resources to studying opportunities and barriers to integrated energy planning.

To encourage adoption of land use planning, the Energy Commission recommends the following:

- The state should adopt a statewide growth management plan that is built from required local regional plans and that aligns state planning, financing, infrastructure, and regulatory land use policies and programs with the plan.
- The state should require regional transportation planning and air quality agencies to adopt 25-year and 50-year regional growth plans that provide housing, transportation, and community services for expected population increases while reducing greenhouse gas emissions to state-determined climate change targets.
- State infrastructure financing should encourage development that is consistent with the state's greenhouse gas emission and energy consumption goals.
- The state should expand efforts to provide technical and financial assistance to regional agencies and local governments to facilitate climate-friendly and energy efficient planning and development.
- State government should be a model for climate friendly and energy efficient development patterns.
- The state should determine the extent to which state and local tax policies affect and guide land use practices and correct polices that encourage growth inconsistent with the state's growth management plan.
- California's utilities should play an active role in regional and local government planning and development efforts at both the plan and project level to encourage climate friendly and energy efficient development in their service areas.
- The state should work with its congressional delegation to ensure that future federal highway and other transportation and land use related legislation and programs include energy reduction and climate stabilization considerations.

Moving Forward in a Carbon-Constrained World

Meeting the mandate of AB 32 will require aggressive and immediate action on the part of all Californians—government and private entities and individual citizens. This *2007 Integrated Energy Policy Report* (*IEPR*) reviews many aspects of California's energy system to assess how we can continue to meet the state's energy needs while restraining our carbon emissions. The report was prepared in response to Senate Bill 1389 (Bowen), Chapter 568, Statutes of 2002, which requires that the California Energy Commission prepare a biennial integrated energy policy report that contains an integrated assessment of major energy trends and issues facing the state's electricity, natural gas, and transportation fuel sectors and provides policy recommendations to conserve resources; protect the environment; ensure reliable, secure, and diverse energy supplies; enhance the state's economy; and protect public health and safety

(Pub. Res. Code § 25301[a]). It was developed under the direction of the Energy Commission's 2007 Integrated Energy Policy Report Committee (Committee).

CHAPTER 1: Meeting California's Energy Needs in a Carbon-Constrained World

Available, affordable, reliable, technologically advanced, and environmentally sound energy drives California's successful economy. Threatening California's environmental quality and robust economy is the scientific consensus that temperatures in the state are expected to increase during this century and precipitation patterns are predicted to change drastically. Even a small average annual three-degree temperature rise will have widespread consequences – worsening air pollution, intensifying heat waves, increasing coastal floods, reducing farmland productivity, increasing wildfires and pest infestations, decreasing fish populations and reducing snowpack, which means less hydropower and possible water shortages. California heeded the wake-up call.

Last year, Republican Governor Arnold Schwarzenegger and a Democratic legislature took collective action to pass the California Global Warming Solutions Act of 2006 (Assembly Bill 32, Nuñez, Chapter 488, Statutes of 2006), capping California's greenhouse gas emissions at the 1990 emissions level by 2020. Achieving that goal requires about a 29 percent[12] cut in emissions below projected 2020 levels. The Governor's long-term target is far more ambitious and calls for a reduction in emissions to 80 percent below 1990 levels by 2050. This is the level of worldwide reduction believed necessary by many climate scientists to limit global temperature gains this century to 2-3 degrees Celsius.

> *"The debate is over. We know the science. We see the threat. And we know that the time for action is now."*
>
> ***Governor Arnold Schwarzenegger***[1]

AB 32 is the definitive climate change legislation and places reducing greenhouse gas emissions front and center on government and business agendas. With the carbon reduction writing on the wall obvious, businesses are eager to show their greenness but require a clear, specific course of action if they are to help reach the state's goals. With AB 32, California is primed and its progressive energy policies must now also include reducing the state's "carbon footprint"[13]

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[12] Reduction of greenhouse gas emissions from a business as usual 2020 level as projected by the Climate Action Team based on 174 million metric tons CO2 equivalent. This number is an increase from the previous estimate of 145 million metric tons CO2 equivalent.

[13] "Carbon footprint" refers to the carbon dioxide emissions that result from burning fossil fuels for electricity and transportation and that are the primary culprit in trapping gases in the atmosphere and causing the "greenhouse effect" and hence global warming.

and stepping up the intensity of existing programs, standards and regulations is obligatory to achieve aggressive CO2 reduction. More must be achieved from business as usual.

California at the Forefront

From the rim of a thousand miles of spectacular Pacific Ocean coastline to the lip of the jagged Sierra Nevada mountain range, Californians live in an extraordinary environment that nurtures an imaginative, determined and forward-thinking population. For more than 150 years, California has represented the land of opportunity – and has been a land of challenges to overcome.

The Gold Rush of 1849 brought a flood of adventurous immigrants seeking better lives. A remote, wild California, geographically separated from the rest of the United States and the world, forced early settlers to solve problems in independent and innovative ways.

Our mild climate and fertile soil, coupled with some of history's most imaginative water projects at the time, earned California the reputation of the bountiful breadbasket to the nation, while discovery of oil made us an energy pioneer. As early as 1910, our state was producing almost 78 million barrels of oil a year[14], 22 percent of the entire world's oil production at the time.

Despite our early remoteness from most of the population centers in the United States, California has grown to become the most populous state in the union and the seventh largest economy in the world. Our diverse, mobile, dynamic and creative population has put us at the forefront of environmental, economic, technological, political, social and cultural development.

Guiding Energy Policy

The California Energy Commission was signed into law as the state's principle energy planning organization by then-Governor Ronald Reagan in 1974 to meet the energy challenges facing the state in response to the 1973 Oil Embargo. Five basic responsibilities guide the Energy Commission as it implements state energy policy: forecasting statewide electricity needs, licensing power plants to meet those needs, promoting energy conservation and efficiency measures, developing renewable energy resources and alternative energy technologies and planning for and directing state response to energy emergencies.

The Governor appoints the five members of the Commission to five-year terms that require Senate approval. The Commissioners represent the fields of engineering and physical science, economics, environmental protection, the public and the law. The Energy Commission is unique among most governmental entities as all business is conducted in a public forum. A Public Adviser, also appointed by the Governor, ensures that the public and all interested parties are adequately represented at all Commission proceedings.

The Energy Commission receives its funding from an electricity consumption surcharge collected by the electric utilities through customers' utility bills, then transferred to the state's treasury. The surcharge is 2/10 of a mil, or a $0.0002, per kilowatt hour of electricity consumption or about 12 to 14 cents per month on an average bill.

With a current population exceeding 37 million and projected to grow to 42 million by 2020, California's already over-burdened infrastructure—roads, pipelines, ports, refineries, power plants and transmission lines—will be strained further to meet increasing demand for energy. Most of the population growth is occurring in the hotter interior areas of the state, increasing

[14] *Oil and Gas Production: History in California*, Department of Conservation, Division of Oil and Gas, ftp://ftp.consrv.ca.gov/pub/oil/history/History_of_Calif.pdf

the demand for air conditioning. California's limited mass transit options, particularly in the inland areas, and the historic tendency toward suburban "sprawl" cause residents to rely more heavily on their cars, increasing individual vehicle miles traveled (VMT) and energy demand.

Environmental consciousness is not new to California. In 1947, Governor Earl Warren signed the Air Pollution Control Act, creating an air pollution control district for every county. And for over 30 years, the California Energy Commission has focused the state's energy policy on finding the most cost-effective, reliable, efficient resources while minimizing the environmental impacts of anticipated growth.

California leads the nation in the lowest electricity use per person. While the United States increased per capita electricity consumption by nearly 50 percent over the past 30 years, California's per capita electricity use remained almost flat; due in large part to a variety of cutting-edge energy efficiency programs and cost-effective building and appliance efficiency standards. The state also changed the way it generates electricity. Before the oil crisis of the 1970s, petroleum was the fuel source for over half of the state's electricity. Today, cleaner-burning natural gas fuels over 41 percent of the state's electricity and renewables account for almost 11 percent.

Other than for use in power plants to generate electricity, California's use of natural gas has also decreased on a per capita basis. Our building and appliance standards have reduced the need for gas space heating and water heating for each home or business in the state.

Despite its passion for the automobile, California adopted stringent tailpipe emission standards as early as 1966 and in 1971 adopted the first automobile nitrogen oxides standards—both the first such standards in the nation. The California Smog Check Program, which assured the effectiveness of vehicle emission control systems, went into effect in 1984. In 1992, the first of many phases of reformulated clean burning gasoline came to California, and in 1993 the state enacted new standards for cleaner diesel fuel.

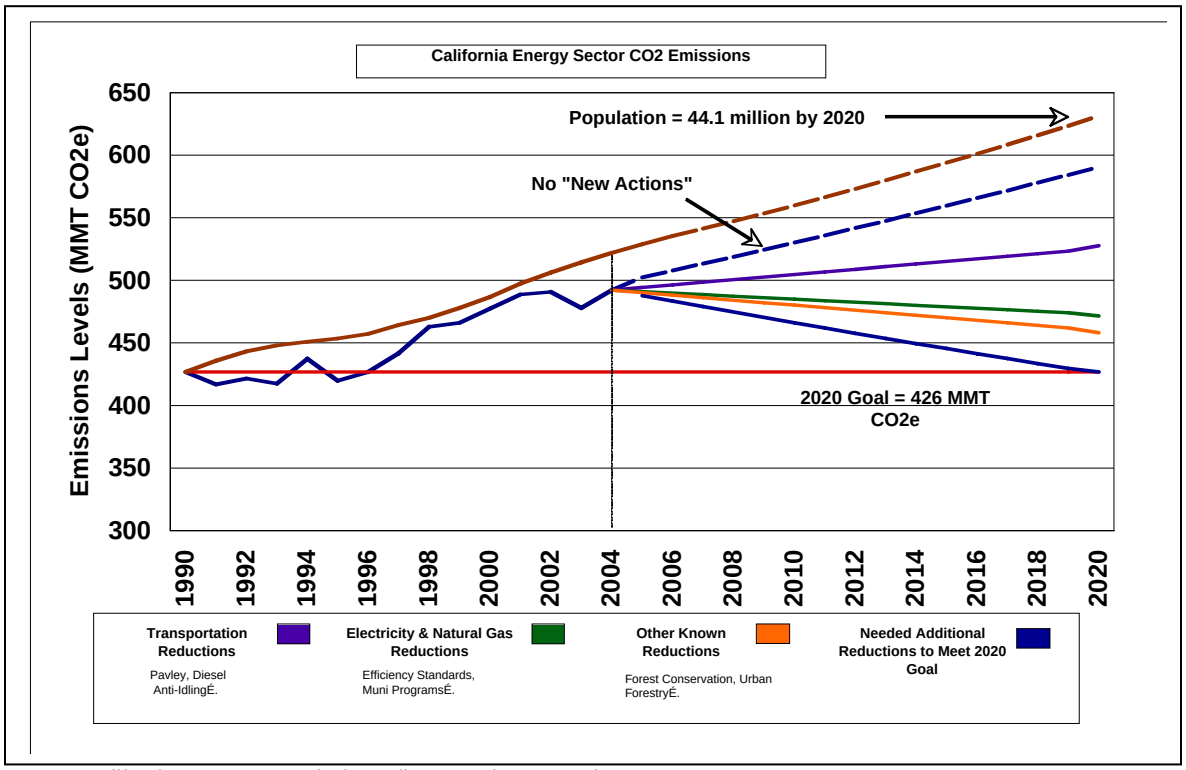
Improving vehicle fuel efficiency offers potentially dramatic reductions in petroleum demand and, hence, emissions; however, California's hands are tied by federal fuel efficiency standards that pre-empt state authority. The state has adopted regulations that limit the amount of greenhouse gases emitted by its vehicle stock but has not been able to implement those regulations pending federal government approval of a waiver. The prospect of a prolonged litigation battle looms large.

Regardless of the federal response, California has continued to move forward. Assembly Bill 1007 (Pavley, Chapter 371, Statutes of 2005) which directed the Energy Commission, in partnership with the Air Resources Board (ARB), to develop and adopt a state plan to increase the use of alternative fuels in the transportation sector. The plan describes strategies; highlights market penetration growth; and recommends new standards, requirements, financial incentives, and other policy mechanisms to address petroleum reduction, greenhouse gas reduction, and in-state biofuels production and use goals. The plan's first phase, a full fuel cycle analysis, forms the technical basis for the ARB's Low Carbon Fuel Standard that is designed to

increase the use of transportation fuels that emit lower quantities of greenhouse gas emissions on a life-cycle basis.

Yet, the sheer volume of California's projected population increase will overwhelm whatever gains existing efforts have made and continue to make in reducing its air emissions. California

Figure 1-1: Reaching for the AB 32 Target



Source: California Energy Commission, Climate Action Team data

currently emits 500 metric tons of greenhouse gases, 22 percent from electricity generation and over 39 percent from transportation. Even using every emission-saving technique in its substantial repertoire for transportation and electricity, California may still require a significant step-up in efforts to reduce greenhouse gases in 2020, to the levels mandated by the AB 32 goals (Figure 1-1).

Current Strategies to Reduce Emissions

Addressing these climate change goals requires meeting energy needs as much as possible with zero or low-carbon energy sources. Since 2003, California's energy policy has relied on the "loading order[15]" to meet growing energy needs, first, with energy efficiency and demand

[15] The "loading order," adopted as the state's energy policy, is the accepted protocol that describes the priority sequence for actions to address increasing energy needs.

response, second, with renewable energy and distributed generation, and third with clean fossil-fueled sources and infrastructure improvement. This strategy has had the benefit of reducing our carbon emissions and diversifying sources of energy supply.

California's Building and Appliance standards have saved consumers more than $56 billion in electricity and natural gas costs since 1978 and avoided the need to build the 30 large power plants that would otherwise have been necessary to meet electricity needs. It is estimated the standards will save an additional $23 billion by 2013.

Senate Bill 1078 (Sher, Chapter 516, Statutes of 2002), introduced a Renewable Portfolio Standard (RPS) requiring annual increases in energy generation from renewable resources equivalent to at least 1 percent of sales, with an aggregate goal of 20 percent by 2017. The 2003 *Energy Action Plan* adopted by the Energy Commission and the California Public Utilities Commission (CPUC) accelerated this target to 1020. Since 2004, the Energy Commission has recommended a further goal of 33 percent renewables by 2020. This enhanced target was endorsed by the CPUC and Governor Schwarzenegger in 2005, and its codification is currently pending before the Legislature.

The RPS was designed to address California's growing dependence on natural gas for electricity generation and set the stage for long-term power purchase contracts that financial institutions require of renewable energy companies that intend to build generation projects. Hampered by complex rules, inconsistent application among retail sellers, and a lack of transparency in its application, the state's efforts to meet the RPS goals have not kept pace with the mandate. In this report and previous Integrated Energy Policy reports, the Energy Commission has recommended a number of corrective measures to increase the role of renewals in our electricity mix.

As the second largest consumer of gasoline in the world (behind the United States as a whole)—more than 16 billion gallons of gasoline and nearly 3 billion gallons of diesel each year—California would like to replicate its success with electricity efficiency in transportation fuels. But federal law prohibits states from setting the minimum number of miles per gallon new cars and light trucks must achieve. Earlier this decade, the Energy Commission and the California Air Resources Board spent several years reviewing the technical and economic aspects of a major reduction in the petroleum dependence of California's transportation sector.[16] Based on this research, in 2005, Governor Schwarzenegger appealed to the United States House of Representatives "to establish new fuel economy standards that double the fuel efficiency of new cars, light trucks and SUVs."[17] In June 2007, the United States Senate voted to raise the fuel efficiency standard for cars to 35 miles per gallon by 2020. As of October 2007, the House had

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[16] California Energy Commission and the California Air Resources Board *AB 2076 Report*, adopted 2003.

[17] May 13, 2005 letter from Governor Arnold Schwarzenegger to Pete Domenici, chairman, Energy and Commerce Committee of the U.S. House of Representatives and Jeff Bingaman, member, Energy and Commerce Committee, U.S. House of Representatives.

taken no action. The proposed 35 mile per gallon standard pales in comparison to Japan's current standard of 45 miles per gallon and Europe's more than 50 miles per gallon by 2012 and may ultimately be too little, too late to rescue American automobile manufacturers.

The California legislature also took advantage of a federal Clean Air Act provision that allows states to set their own emission standards (with a waiver from the United States Environmental Protection Agency (EPA))[18] and passed California's Clean Car Law (Assembly Bill 1493, Pavley, Chapter 200. Statues of 2002), the first such regulation in the United States, to limit greenhouse gas emissions from passenger cars and light trucks. The Clean Car Law would cut greenhouse gas emissions by 30 percent by 2016 from all cars sold in California starting in 2009. As allowed under federal law, 11 other states have adopted these California standards pending receipt of the EPA waiver. Unfortunately, the EPA has sat on California's waiver request for nearly two years, declaring it lacks the authority to regulate greenhouse gases—a declaration rejected by the United States Supreme Court in their recent decision which states that EPA has the authority to regulate CO2 emissions and should reconsider its refusal to do so.

For the *2007 Integrated Energy Policy Report*, the first in the more complex post-AB 32 world of carbon constraints, staff has developed the Scenario Analysis and the Portfolio Analysis. These two new approaches analyze in more depth the uncertainties that affect our ability to meet our future energy needs. Scenario Analysis examines the implications of energy policies that could be necessary to achieve AB 32 goals. Portfolio Analysis seeks to understand how different mixes of resource additions economically perform, better taking into account the probability distributions of key variables like fuel prices.

In addition, staff revitalized and refined its cost of generation model—a classic levelized cost analysis—by collecting detailed information about actual power plant development costs and more systematically collecting and presenting information about new generating technologies that have limited track records. Making sound decisions to prefer one technology to another is impossible without reliable information about the cost and performance differences of these technologies, and a better understanding of the magnitude of uncertainties associated with such assumptions. The low fuel prices of the 1990s allowed insensitivity to financial risks that is unsuitable for today's decision making.

Pay A Little More Now or Pay A Lot More Later

Reducing California's carbon footprint to the levels envisioned in AB 32 will not be achieved without costs. However, near-term costs are dwarfed by the long-term costs that the fabric of California's economy would endure if we fail to adequately anticipate and respond to climate change. At the heart of the state's economic well-being is the need for all Californians to accept the slightly higher current costs that may come with greater investments in advanced and smarter efficient energy measures, cleaner renewable sources of energy, and critical

[18] <http://www.greencarcongress.com/2007/04/us_epa_opens_co.html> The EPA has historically granted all 53 such waivers previously sought by California.

infrastructure improvements. In the past, California pursued such strategies to enhance the state's economic welfare. This public policy direction taken over 30 years ago has been a "choice" that brought major environmental and economic benefits to the state. The specter of a changing climate that threatens California's economic well-being will require similar choices, but on an appreciably expanded scale to insure against the risks of higher environmental and economic costs in the future.

The Role of the *2007 Integrated Energy Policy Report*

Energy use and global climate change are fundamentally intertwined. The burning of fossil fuels, such as coal, gasoline, diesel and natural gas, to meet our electricity and transportation needs put millions of tons of carbon dioxide and other gases into the atmosphere, trapping heat and creating global climate change. The environmental and economic effects of these greenhouse gas emissions are a worldwide problem, and one that represents a significant risk to quality of life and economic well-being.

Californians historically have felt a responsibility to protect the environment for future generations. We have a similar responsibility to protect its economy. If we do nothing to abate carbon emissions, global warming will have profound effects—reducing our economic growth, damaging our world-class coastline and forest, altering the pattern of water supply so that it no longer meets our water conveyance systems and endangering public health, and presenting other myriad statewide environmental challenges.

California's Energy System: Powering a Nation

Today one in eight Americans or over 37 million people live in the Golden State.

Our state has doubled its population since 1965, a growth rate faster than any other developed region in the world and is already larger than Canada's (33 million) and Australia (21 million).[19] If we were a nation our population would rank 33 in the world. In fact, California's population exceeds the combined populations of our western neighbors – Oregon, Colorado, Wyoming, Montana, Nevada, Arizona, Idaho, Washington, Nevada, Arizona, Utah, New Mexico, Alaska, Hawaii, Yukon and British Colombia. The state Department of Finance predicts that California will add another 5 million people in the next decade moving toward 60 million residents by 2050. The challenge we face is continuing to provide a quality environment, and reliable energy services to support a world-class economy.

To maintain this economic output and meet the energy service demands of its citizens, California requires a significant amount of energy. Energy represents nearly $100 billion in expenditures each year. More importantly, California with the passage of AB 32, has a stringent

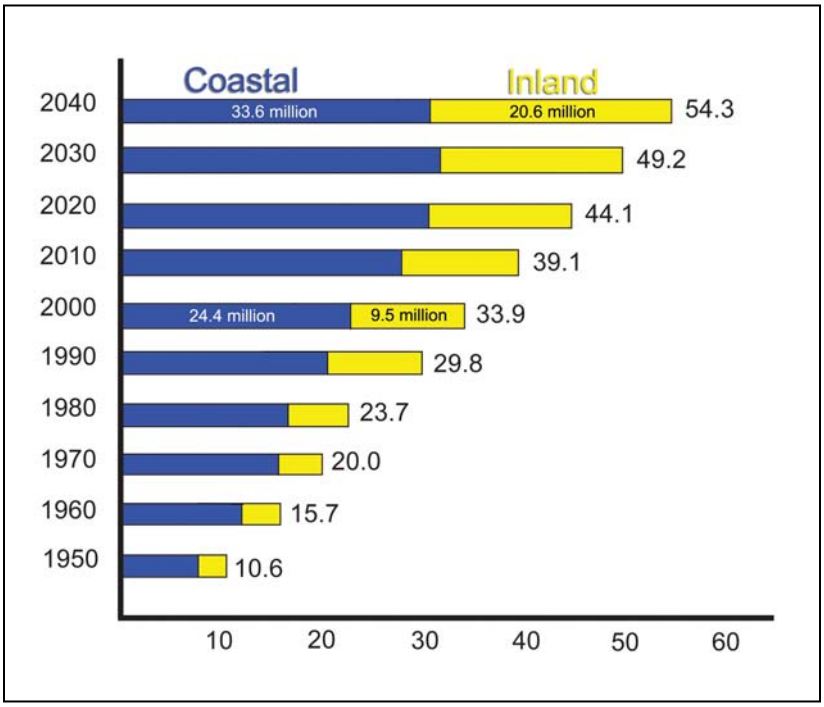
[19] Western City Magazine, How Should California Grow? Dr. Hans Johnson, July 2007.

mandate to significantly reduce greenhouse gas emissions requiring government, consumers and businesses to take a hard look at exactly how energy is used in the state and ways to focus on choosing a system that is less carbon intensive. At the core of this energy system is a policy that the state's economy and environment are best served by energy efficiency measures and demand response programs first, then by renewable energy sources and a diversity of energy supplies. This approach has resulted in California using less electricity per person than any other state from the world's most diverse electricity generation supplies. Unfortunately our success in electricity has not been reflected in our transportation sector.

Inland Population Climbs

Ensuring energy supplies and an infrastructure to keep pace with such dynamic growth has been an ongoing challenge, but California planners must take more than just additional population into account. While today nearly 70 percent of the state's population lives in what is described as coastal California, the inland areas – the San Joaquin Valley, the Southland's Inland Empire, and the Sacramento area – are growing faster than the coastal areas. (Figure 1-2) By 2040 almost 40 percent of the state's population or over 20 million will reside inland. This inland population growth drives demand for more electricity, but it also changes the energy use patterns for transportation fuels. Compared to the more temperate coastal zone, the inland climate is more extreme. In the summer, hotter inland areas require more air conditioning than coastal areas, which increases peak electricity use even faster than it pushes the overall demand for electricity.

Figure 1-2: California's Inland Population



Source: California Department of Finance, Demographic Research Unit projections and Public Policy Institute of California

The Inland Empire and the northern San Joaquin Valley are two of the fastest growing metro areas in the United States. These cities often serve as bedroom communities for workers in the Los Angeles basin and the San Francisco Bay area. Growth in these inland areas means that transportation patterns change as more commuters

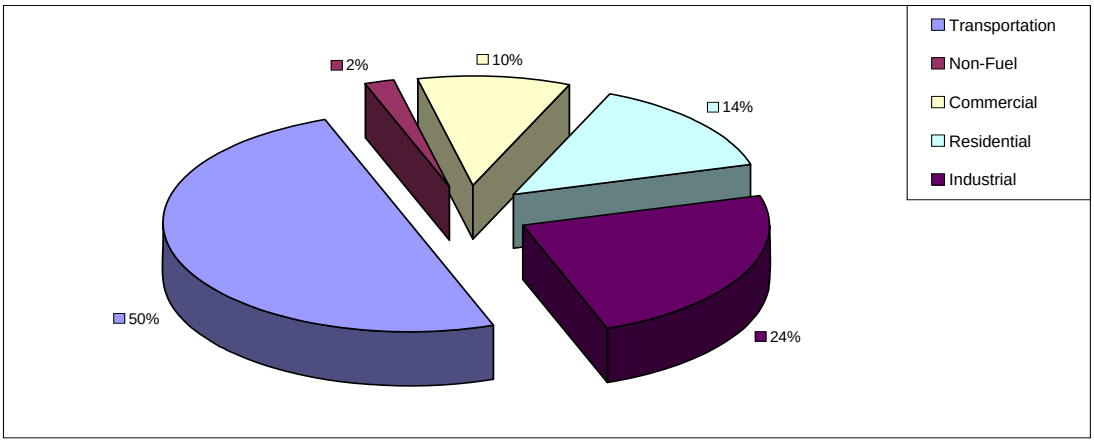
drive more miles and longer distances to work each day, increasing the demand for transportation fuels.

Inland growth also increases environmental problems. The San Joaquin Valley and the Inland Empire already have some of the worst air quality in the nation, and as California's growing population continues its inland trek, growth will only make the situation worse. In 2040 there are more people projected to live in the California's inland areas then the state's total 1970 population.

Energy Consumption

California's overall energy consumption continues to be dominated by transportation. Half of all energy consumed in the state is used to move people and goods – and almost all of this energy is derived from petroleum. (Figure 1-3)

Figure 1-3: Energy Use by Sector 2006



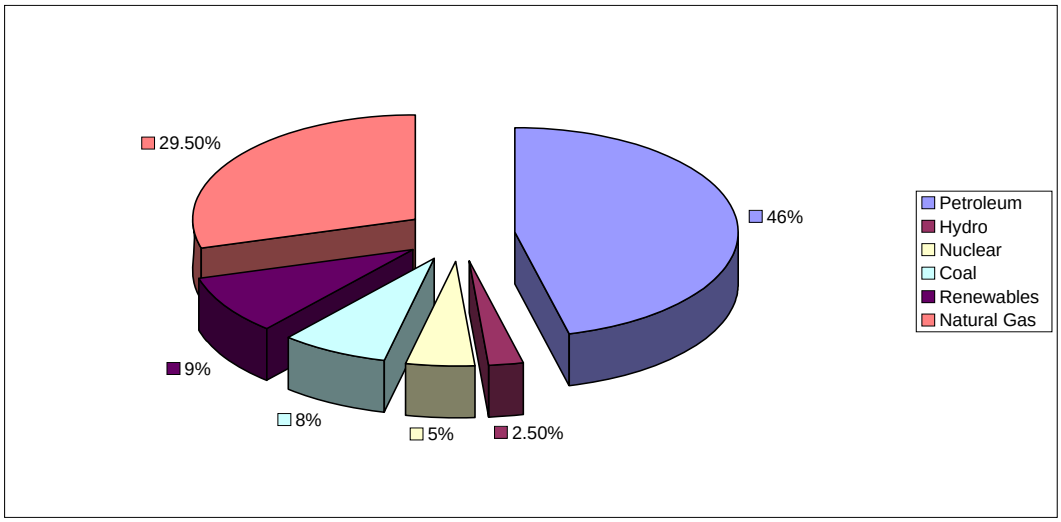
*Non-fuel is asphalts and other road oils.
Source: California Energy Commission 2006

Despite California diversifying the mix of energy resources used to generate electricity, over 90 percent of the energy consumed in the state still comes from fossil fuels. This continuing dependence combined with continuing population growth places at risk California's economic and environmental well being.

Energy Supply

To understand the challenges California faces in cutting back on greenhouse gases, it important to examine where the state gets its energy. Two primary fuels drive California's energy system: petroleum and natural gas. (Figure 1-4) These resources are used in the transportation sector, to generate electricity, or for heating buildings and water, or cooking.

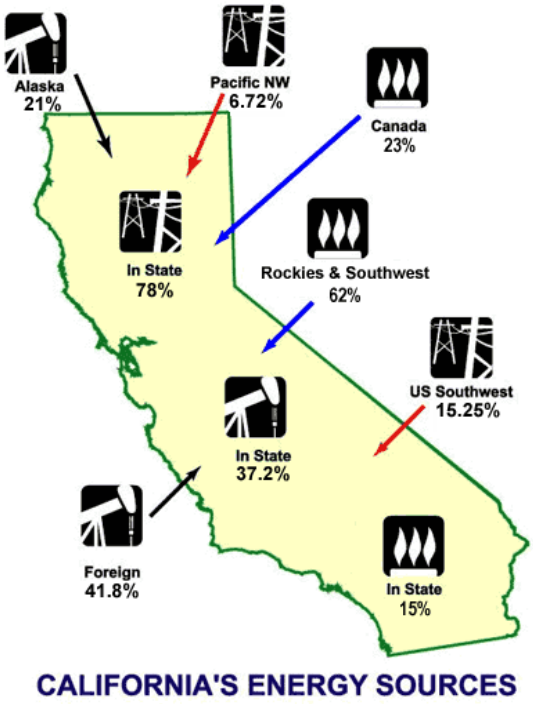
Figure 1-4: California's Energy Sources 2006



California Energy Commission 2006

The state produces about 15 percent of the natural gas it uses, 37 percent of the petroleum and over three quarters of the electricity. The remaining amounts are electricity and natural gas purchases from other states and Canada and crude oil imports from Alaska and foreign sources. (Figure 1-5) Importing energy means exporting state dollars. Energy efficiency can reduce these expenditures as well as conserve finite resources.

Figure 1-5: California's Big Picture



Source: California Energy Commission

Electricity

Many Californians remember the electricity crisis of 2000-2001, when electricity seemed to be in short supply and prices skyrocketed. Rampant market manipulation by companies like Enron that occurred as a result of California's 1998 restructured electricity market has been controlled.

New power plants licensed by the Energy Commission have added almost 13,000 megawatts of additional power to the state's grid since 1998 and new policies have stabilized the market. Virtually all of these new power plants burn natural gas. In 1991, a third of California's electricity came from natural gas fired power plants. By 2006, this amount had increased to 41.5 percent.

Summer Demand

On hot summer afternoons, from peak hours of 3 pm to 7 pm, as temperatures soar into the high 90s and low 100s, statewide electricity demand can be as high as 48,000 to the record high 64,000 megawatts in 2006. Compared to moderate summer afternoon (85 degrees rather than 100 plus) statewide electricity demand ranges between 45,000 to 50,000 megawatts. Yearly round demand averages about 40,000 megawatts.

The lessons of the electricity crisis and the growing dependency on natural gas reinforce California's need to pursue a portfolio approach to electricity generation. Relying on a single fuel source for generation can be risky, as generators learned even before the 2000-2001 electricity crisis. At the time of high oil prices and tight supplies in the 1970s, oil-fired power plants supplied over half of the state's electricity. Today none of

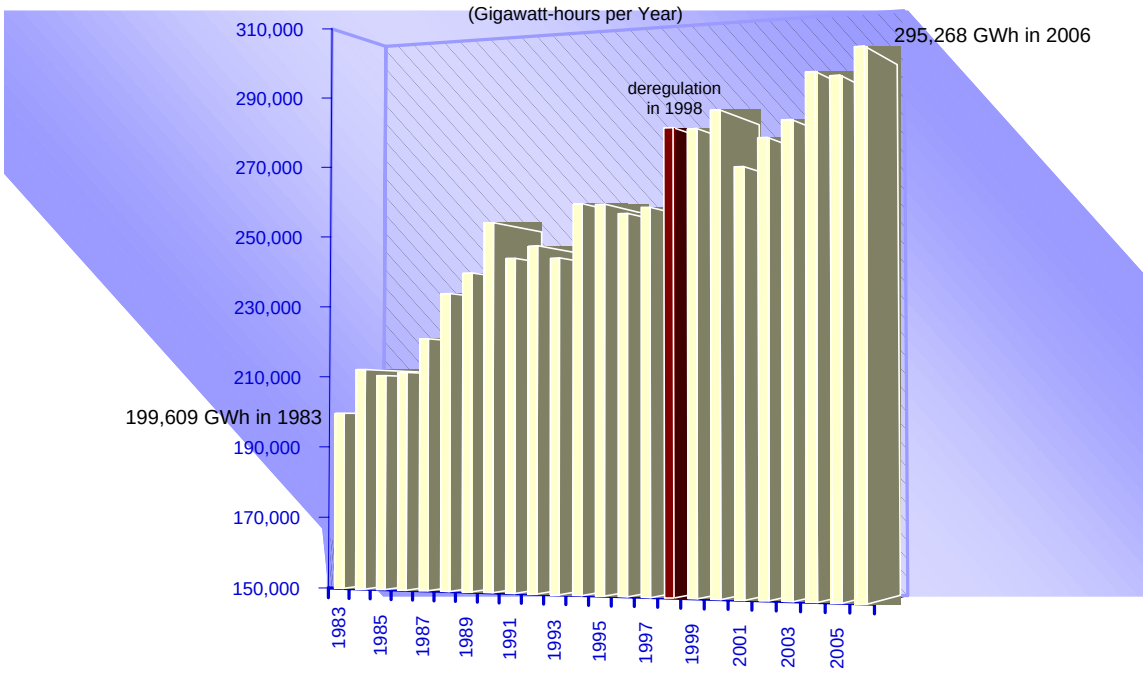
California's electricity comes from petroleum as the state turned to cleaner, less expensive sources of power. The California electricity generation system is massive. After a period of flat to slow growth on the heels of the 2001 electricity crisis, California's demand is now on the rise, fueled by population growth and a robust economy. (Figure 1-6) Electricity consumption is dominated by the commercial sector followed closely by residential. (Figure 1-7)

In an effort to diversify our electricity mix and reduce our output of greenhouse gases, California chose to significantly increase the amount of its electricity generation by renewable energy sources. The state adopted a Renewable Portfolio Standard (RPS) with a mandate of generating, by 2010, 20 percent of our power from renewable sources like biomass, geothermal, small hydro, solar and wind. In 2006, renewables supplied about 11 percent of our electricity, and even with almost 400 new megawatts of renewables added to the system, we are well below where the state must be to meet its goals. (Figure 1-8)

Governor Schwarzenegger, the Public Utilities Commission and the Energy Commission have called for 33 percent of our state's electricity to be from renewables by 2020, a daunting goal in light of current progress.

Wind farms, geothermal power plants and large solar facilities are often located well away from population centers where the electricity so cleanly generated is to be used. The state is upgrading its nearly 32,000 miles of transmission lines to bring more renewable energy to market.

Figure 1-6: California's Electricity Generation 1983-2006



Source: California Energy Commission

Figure 1-7: Electricity Consumption by Sector 2006

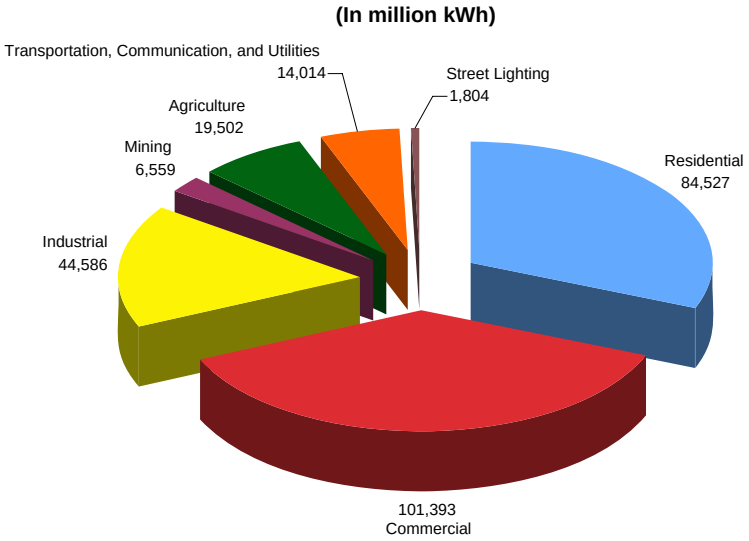
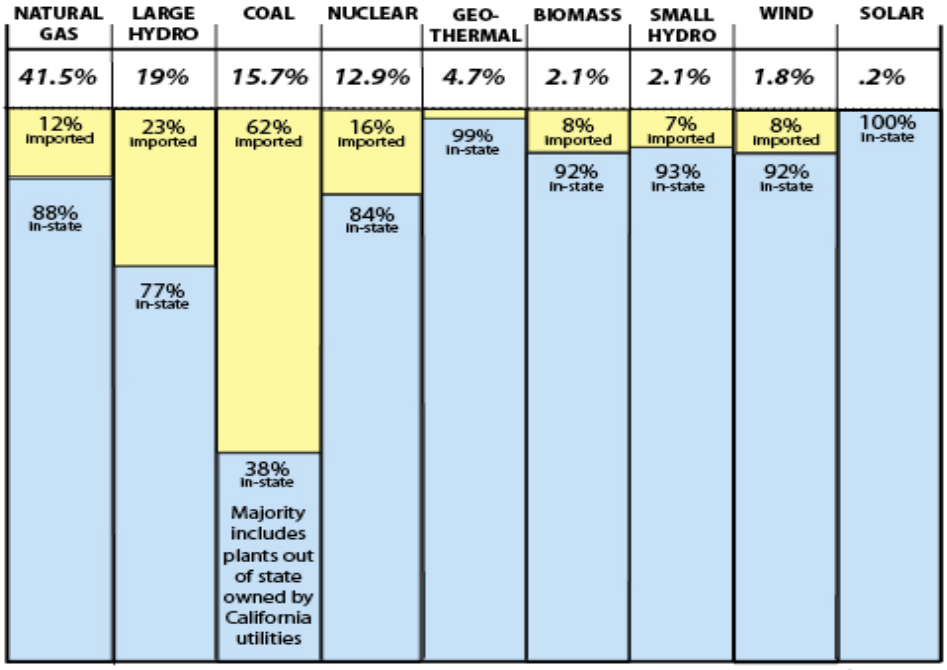


Figure 1-8: California's Electricity Mix - 2006



COAL: The in-state coal-fired generation includes electricity generated from several out-of-state coal-fired power plants that are owned by and reported by California utilities. There are other out-of-state generation facilities that are owned by California utilities, which are reported as imports.

California Energy Commission, Gross System Power Report 2006

Five major utilities provide about 80 percent of all electricity consumed in California: Pacific Gas & Electric, Southern California Edison, San Diego Gas & Electric (investor owned) and Los Angeles Department of Power and Water, and Sacramento Municipal Utility District (publicly owned). (Figure 1-9)

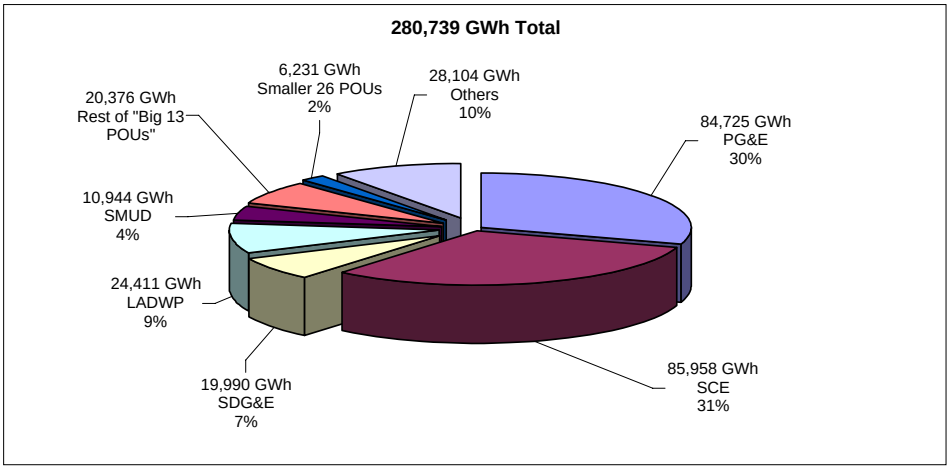
The remaining 20 percent is provided by three smaller investor-owned utilities (Bear Valley, Pacific Power and Sierra-Pacific Power) and 24 municipal utility districts; three rural cooperative; about 12 irrigation or water districts and one state and one federal water agencies (electricity is used for pumping water).

Under deregulation, the California Independent System Operator (California ISO) was formed to reliably and fairly control the electricity transmission system, or grid, meeting electricity demand and acting as the link between power plants and the utilities that provide electricity to customers. The California ISO controls electricity transmission for the majority of the state: the major investor owned utilities and two small city utilities – City of Vernon and City of Pasadena. Although the utilities still own transmission lines, the California ISO ensures equal access to power lines formerly under private control.

Almost 22 percent of the electricity used in the state is imported, coming from sources in 11 western states, Canada and Mexico. To avoid "exporting" California's power plant greenhouse

gas emissions to other states, in 2006, California enacted SB 1368, a law prohibiting utilities from making long term commitments for power generated by plants that create any more CO2 emissions than clean-burning natural gas plants. Similar requirements have been adopted by Washington state. The law has discouraged the construction of new, dirty coal-fired plants in the West, and serves as another example of how California's clean energy decisions can drive the market in other states and other regions of the country.

Figure 1-9: Investor and Publicly Owned Utility Shares of California's Electricity Consumption - 2006



Source: California Energy Commission

Natural Gas

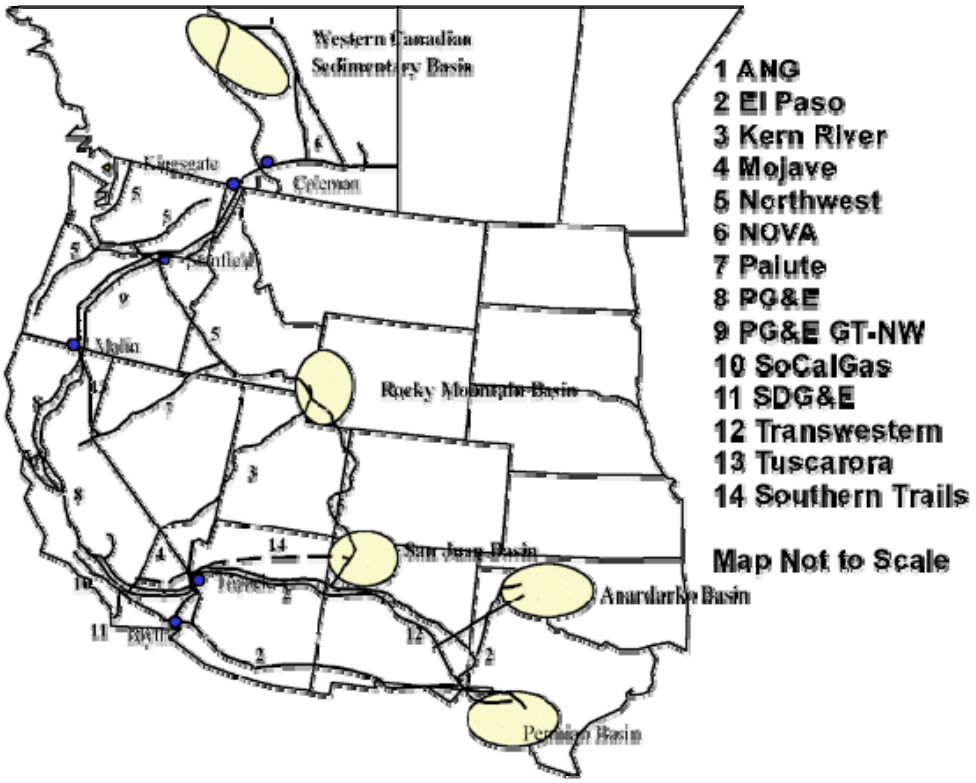
Only 15 percent of the natural gas California uses comes from in state production; the rest by pipelines from several production areas in the western United States and western Canada. California's location puts it at the end of those pipelines forcing us to compete with other states for supplies (Figure 1-10). Once the gas arrives in California, it is distributed by the state's three major gas utilities—San Diego Gas and Electric, Southern California Gas Company, and Pacific Gas and Electric Company – that provide a collective total of 98 percent of the state's natural gas. Palo Alto is the only municipal utility in California that operates city-owned utility services for natural gas customers.

The largest user of natural gas is electrical generation, using about half of all natural gas in the state. The residential sector uses 22 percent of the natural gas. Of that amount, 88 percent is used by space and water heating.

Natural gas has become an increasingly important source of energy since more and more of the state's power plants rely on the fuel. While California's successful efficiency programs and our reliance on renewable sources of electricity should keep demand for natural gas growing slower here than in other parts of the nation, competition for supply is increasing. Our reliance on imported gas leaves us vulnerable to price shocks and supply disruptions.

Importing liquefied natural gas (LNG) by ship from foreign sources has the potential of furnishing new supply, but so far no LNG receiving terminals have been approved in California. A newly constructed Mexican facility in Ensenada, Baja California, however, is expected to begin operation in early 2009. While 30 to 50 percent of the Sempra-owned plant is contracted for use in Mexico, the remainder should be available to California markets.

FIGURE 1-10: Natural Gas Resource areas and Pipelines



Source: California Energy Commission

Since 1970 the number of households in California has almost doubled from 6.5 million to 12.5 million pushing total residential natural gas consumption from about 5,500 million therms in 1970 to about 6,700 million therms in 2007. However, the average annual gas consumption per household has dropped over 36 percent, from 845 therms to 538 therms.

Petroleum

The early discovery of oil made California an energy pioneer. As early as 1910, our state was producing 73 million barrels of oil a year, 22 percent of the entire world's total oil output. Production in the state reached an all-time high in 1985 before beginning a gradual but steady decline. In 2004, California oil fields produced approximately 250 million barrels, a drop to levels not seen since the 1940s.

California is currently ranked fourth in the nation among oil producing states, behind Louisiana, Texas, and Alaska, respectively.

California's sources of crude oil have changed dramatically since the early 1990s. At that time the state imported 48 percent of its crude oil from Alaska and only five percent from foreign sources. Today, foreign imports – primarily Saudi Arabia, Ecuador, Iraq and Mexico – contribute almost 42 percent of crude oil supplies and Alaska imports have declined to 21 percent as the North Slope oil field production declines.

With 60 percent of the oil used by California-based refineries and 10 percent of the refined petroleum products coming from outside of the state, marine facilities are a vital part of the state's petroleum infrastructure. Because no pipelines bring crude oil or petroleum products into California, all crude supplies must arrive by ship.

These marine facilities include terminals with docks for unloading both crude oil and finished petroleum products into storage tanks, through a network of pipelines. The same facilities are also used to export petroleum products to other states along the West Coast and to foreign destinations.

Facilities for importing or exporting crude oil and refined fuels are available at 46 marine terminals in California, 39 are located in the two major refining centers, Los Angeles and San Francisco Bay. The other seven marine terminals -- in San Diego, Ventura, and Humboldt counties -- are not directly linked to refineries, but are used to ship and receive products in areas not served by pipelines.

The network of pipelines within the state are another important component of the petroleum supply system, bringing California crude from import terminals and both onshore and offshore oil fields to refineries, and distributing finished fuels like gasoline, diesel and jet fuel to over 70 distribution terminals scattered throughout the state. Trucks deliver gasoline and diesel from these distribution centers to local stations.

Pipelines also help put California at the center of a regional petroleum market. Our refineries supply Nevada with almost 100 percent of its transportation fuels. Arizona gets over 60 percent of its fuel from California, while Oregon depends on our refiners for 35 percent of its fuel.

Currently, 21 petroleum refineries operate in California. Their combined crude oil distillation capacity totals more than 1.9 million barrels per day, ranking the state the third highest producer of transportation fuels in the nation. Ten of these refineries are located in the Los Angeles Basin and 5 in the Bay Area. Between them, these two refining centers process over 90 percent of California's crude oil input. Of the remaining six refineries, three operate in Bakersfield, two in Santa Maria, and one in Oxnard. Just 14 of the 21 refineries produce California Air Resources Board (CARB) reformulated gasoline and diesel, while the remainder produces such non-fuel products such as lubricants and asphalt.

Until the mid-1990s, California refineries kept pace with the demand for gasoline and diesel fuel, but since then refiners have had to import more and more finished products. Californians

used almost 16 billion gallons of gasoline in 2006, making us the second largest consumer in the world, behind the entire United States.

Demand for gasoline and diesel is normally expected to increase by 1 to 2 percent each year as a growing population registers more vehicles and drives more miles. While national demand did grow by 1.5 percent in the first half of 2007 according to American Petroleum Institute figures, consumption in California actually dropped. Californians used nearly 1 percent less gasoline in April 2007 -- 10.5 million fewer gallons of gasoline than the previous April, according to figures released by the California Board of Equalization. This was the fourth straight quarter in which Californians have used less gas than they did during the same period the year before.

Greenhouse Gas Emissions

Climate change is the most important environmental and economic challenge of this century and greenhouse gas emissions are the largest contributor to global warming. In fact, a recent ABC News, Washington Post and Stanford University survey[20] found that one third of Americans believe climate change is the biggest environmental problem facing the world.

California's greenhouse gas emissions are huge and growing. In 2004, we produced about 492 million metric tons of carbon dioxide (greenhouse gas emission equivalent) - the second largest emitter of greenhouse gas emissions in the United States after Texas and about twelfth in the world.

The transportation sector is the single largest category of California's greenhouse gas emissions, producing over 39 percent of the state's total emissions in 2004. (Figure 1-11) Most of California's greenhouse gas emissions or 81 percent, are carbon dioxide produced from fossil fuel combustion, 2.8 percent were from other sources of CO2, 5.7 percent were from methane, and 6.8 percent were from nitrous oxide.

Another poll, sponsored by the William and Flora Hewlett Foundation, surveyed 2,500 of California's adult residents. A majority of them correctly identified vehicle emissions as the major contributor to regional air pollution, and reported they did not believe governments are doing enough to support clean air, manage droughts or prevent climate change.[21]

Electricity generation is the second largest category of greenhouse gas emissions after transportation. In particular, out-of-state electricity generation has higher carbon intensity than in-state generation. While imported electricity is a relatively small share of California's electricity mix, ranging from 22 to 32 percent of total electrical energy used, out-of-state electricity generation sources contribute 39 to 57 percent of the greenhouse gas emissions associated with electricity consumption in California.

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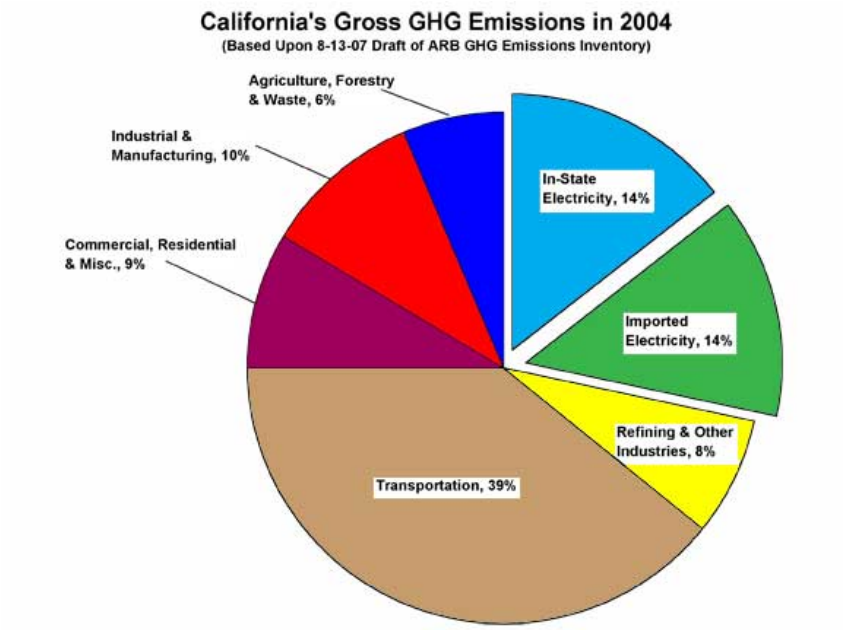
20 ABC News/Washington Post/Stanford Poll: The Environment. April 20, 2007

[21] Athens News (Ohio), August 2, 2007, http://www.athensnews.com/issue/article.php3?story_id=28918

Figure 1-11: California Greenhouse Gas Emissions in 2004



Source: California Air Resources Board, *Draft Greenhouse Gas Emissions Inventory*, August 2007

Electricity imported to California from the Southwest has a significant percentage that is coal-based generation, while imports from the Pacific Northwest have a significant portion that is hydroelectricity.

California's immense amount of greenhouse gas emissions is not surprising considering our nation-sized population; however what is remarkable has been that greenhouse gas emissions per capita are one of the lowest in the United States. In 2001, California ranked fourth lowest of the 50 states in carbon dioxide emissions per capita from fossil fuel combustion and fifth lowest of the 50 states in carbon dioxide emissions from fossil fuel combustion per unit of gross state product. Emission trends per unit of gross state product are encouraging; most states have reduced their emissions per unit of gross state product over the 1990 to 2001 period.

California's ability to slow the rate of growth of greenhouse gas emissions is largely due to the success of its energy efficiency and renewable energy programs, and a commitment to clean air and clean energy. In fact, the state's programs and commitments lowered its greenhouse gas emissions rate of growth by more than half of what it would have been otherwise.[22] And California's energy programs and policies have had multiple benefits that include reducing greenhouse gas emissions, lowering energy demand and improving air quality and public health.

[22] NRDC comments to the Energy Commission, April 5, 2005.

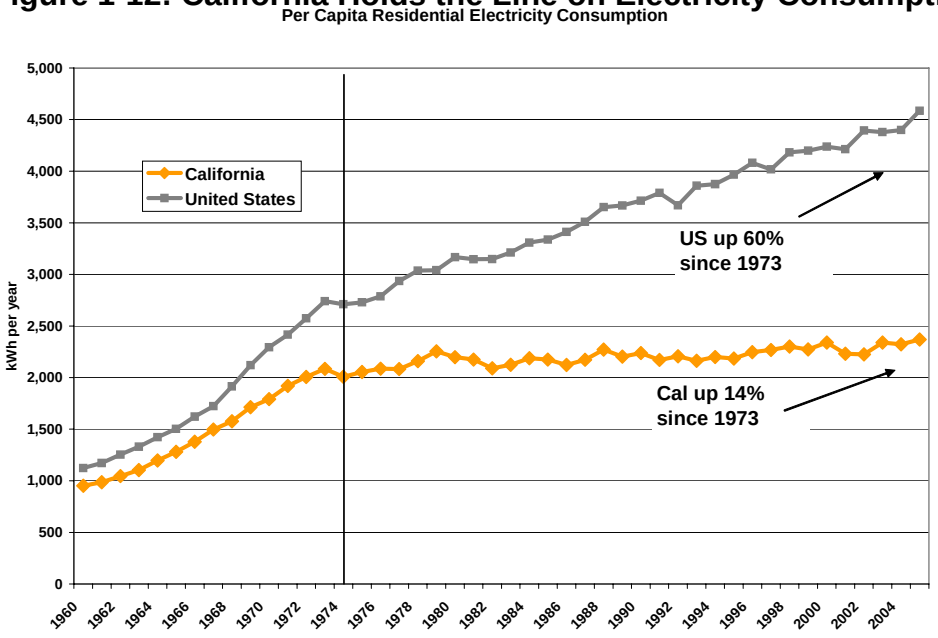
Preferred Resources Are Key

California's **loading order** provides the blueprint to priority sequence actions addressing increased energy requirements and may be the state's single most effective "weapon" to reduce carbon emissions. The loading order identifies energy efficiency and demand response as the state's preferred means of meeting growing energy needs, followed by renewable resources, affordable and reliable clean generation and fuels, and finally infrastructure improvements.

Energy efficiency is the cornerstone of California's energy strategy. While the United States increased per person electricity consumption by nearly 50 percent over the past 30 years, California's electricity use per person remained almost flat; due in large part to a variety of cutting-edge energy efficiency programs and cost effective building and appliance efficiency standards. (Figure 1-12) When compared to other states per person, we rate first in the efficient use of electricity, and third in the efficient use of total energy.[23] Since 1978, energy efficiency measures have saved consumers more than $56 billion in electricity and natural gas costs. California long ago decoupled Gross State Product from energy use per unit and proved that there is no longer a direct correlation between energy used and economic value.

At the same time, by reducing overall energy use, we avoided building 30 large power plants. Energy efficiency is more than just conserving energy and saving money. It is also the lowest cost alternative to reducing greenhouse gas emissions. The cost of improving energy efficiency is less than investing in new sources of power.

Figure 1-12: California Holds the Line on Electricity Consumption



[23] Energy Information Administration, Annual Energy Review 2007, http://www.eia.doe.gov/emeu/states/_seds.html

Source: Commissioner Art Rosenfeld, California Energy Commission

The transportation sector is ripe to replicate the successes and improvements achieved in new buildings and appliances through energy efficiency regulations such as increased Corporate Average Fuel Economy (CAFE) standards. Current CAFE standards are 27.5 miles per gallon for new cars and 22.2 miles per gallon for light trucks, minivans and sport utility vehicles.

One of the reasons our state is more energy efficient than most others may be our high gasoline and diesel prices, which routinely average 20 to 25 cents higher than the national average. But Californians also have an environmental ethic – by mid-2007, 280,000 fuel-efficient hybrid automobiles have been purchased by California drivers, and our state has a higher percentage of more fuel-efficient cars than other states. Californians seem to be making choices that will save money in the long run and be better for the environment. A poll released in late July 2007 by the Public Policy Institute of California found that a majority of Californians is considering buying a hybrid or electric car as their next vehicle.

Powering the Future

As the world's eighth largest economy,[24] second largest consumer of gasoline, and twelfth largest emitter of greenhouse gases, California must be a leader in and a major portion of the solution to reduce greenhouse gases and slow global warming. Clearly the state requires an energy system that provides for its growing population in a way that is economically achievable within the rigorous environmental parameters mandated by state law.

This *2007 Integrated Energy Policy Report* recommends energy policies that recognize this responsibility.

[24] California Department of Finance, Top Countries Ranked by its Gross Domestic Product, California's World Ranking 2006. http://www.dof.ca.gov/HTML/FS_DATA/LatestEconData/FS_Misc.htm

CHAPTER 2: Meeting California's Electricity Needs

Any disruption in the flow of electricity brings the entire California economy to an abrupt standstill and costs millions of dollars to the state as well as to individual commercial and personal enterprises. *The California Electricity Crisis: Causes and Policy Options,*[25] commented regarding the 2000 – 2001 energy crisis that "Although total energy costs for wholesale power were $7.4 billion in 1999, they were about $27 billion per year from 2000 through 2001, burdening California consumers and businesses with almost $40 billion in added costs. Thus, conservatively, the total costs can be placed around $40 billion to $45 billion or around 3.5 percent of the yearly total economic output of California."

AB 32 forces California to determine how to generate and use energy in a way that leaves an ever-shrinking "carbon footprint." Electricity generation accounts for 22 percent of California's greenhouse gas emissions. Through the 1990s, California successfully kept pace with electricity demand—which increased a manageable 2 percent each of the last dozen years—without construction of major power plants and/or infrastructure by relying on a variety of energy efficiency measures and diversity of energy resources. Those same strategies helped California buck the national trend: while per capita consumption increased nationally by 50 percent over the past 30 years, California's per capita electricity consumption remained almost flat. California has not been as successful controlling "peak" demand—those exaggerated spikes in electricity demand on the hottest days. However, demand forecasts suggest that increased energy efficiency will be unable to reduce per capita electricity consumption as the sheer volume of continued population growth—specifically the inland location of that growth—creates greater demand.

Although the Energy Commission had already begun exploring new analytical tools, AB 32 escalated the need. The Scenario Analyses and Portfolio Analysis Projects explored methods of analyzing resource data to inform decision makers on ways to satisfy demand and address related concerns such as cost, greenhouse gas emissions, and criteria pollutants. Staff also overhauled the traditional cost of generation model, creating a more accurate, user friendly, flexible, transparent, and better documented model for comparing alternative electricity generating technologies.

Conventional fossil generation, which accounts for some 70 percent of California's electricity supply, presents challenges to California's ability to meet the AB 32 mandate:

- Consideration of carbon capture and sequestration from coal-fired generation and of nuclear generation as cleaner technologies than fossil fuel generation, but recognition of their inability to contribute to AB 32 goals by 2020.
- A tendency for utilities to favor short-term rather than long-term contracts.

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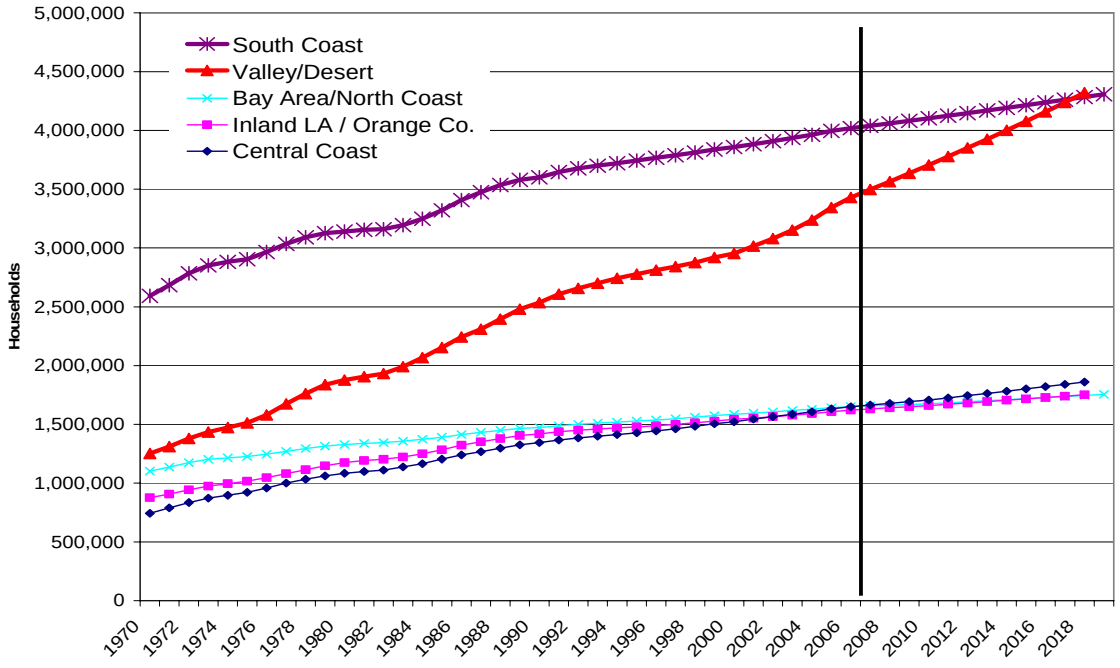
[25] *The California Electricity Crisis: Causes and Policy Options,* Christopher Weare, Public Policy Institute of California, 2003, pp. 3 – 4.

- A fleet of power plants that has reached its optimal output—efficiency improvements for the same fuel type exceed efficiency of the aging fleet by 20 to 30 percent.
- Threats to the potential of once-through cooling as a renewable resource.
- An infrastructure constrained by age, capacity, lack of funding, and permitting challenges.

Forecast for Electricity Demand

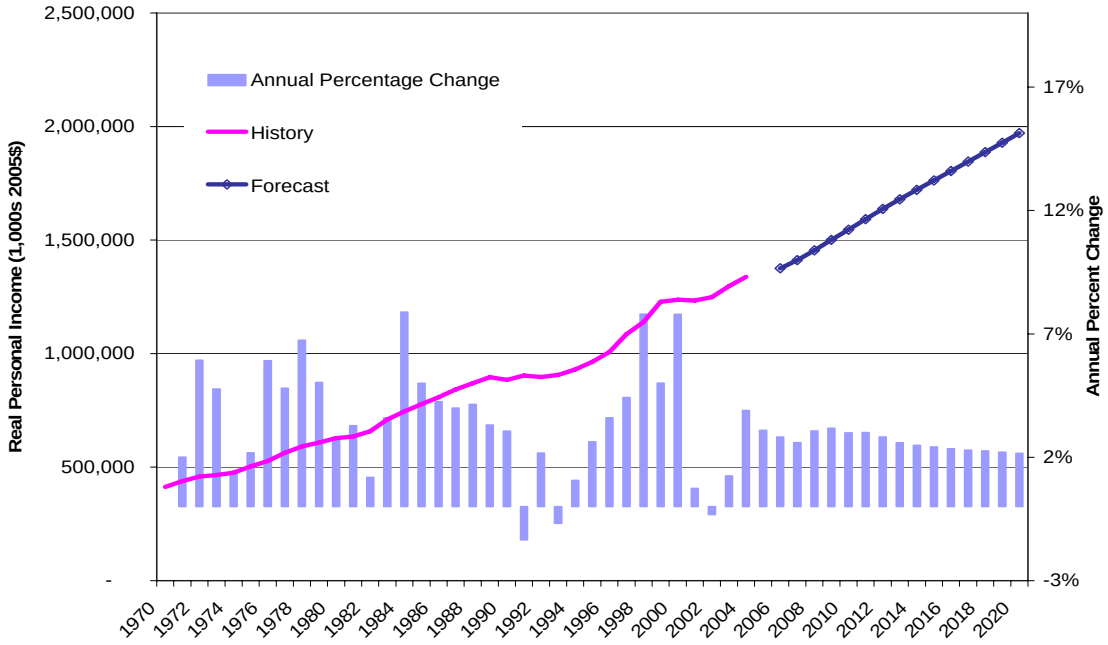
Reliable assessments of the amount, location, and timing of electricity demand growth are essential to system operators and policy makers in evaluating future infrastructure needs and resource options. The pattern of electricity use reflects evolving trends in where and how people live and do business. Population growth is a key driver for residential energy demand, as well as for commercial growth and demand for water pumping and other services. While the California Department of Finance (DOF) projects the *rate* of population growth will slow to 1.2 percent annually over the next 10 years (compared to average annual growth of 1.8 percent over the previous quarter century), the cumulative growth is immense, and that growth is increasingly occurring in hotter areas of the state. As Figure 2-1 shows, an increasing proportion of the population is located in the Central Valley and desert regions, and DOF expects this trend to continue.

Figure 2-1: Number of Households by Region



Source: Department of Finance (July 2007) and California Energy Commission

Figure 2-2: Statewide Personal Income ($2005)



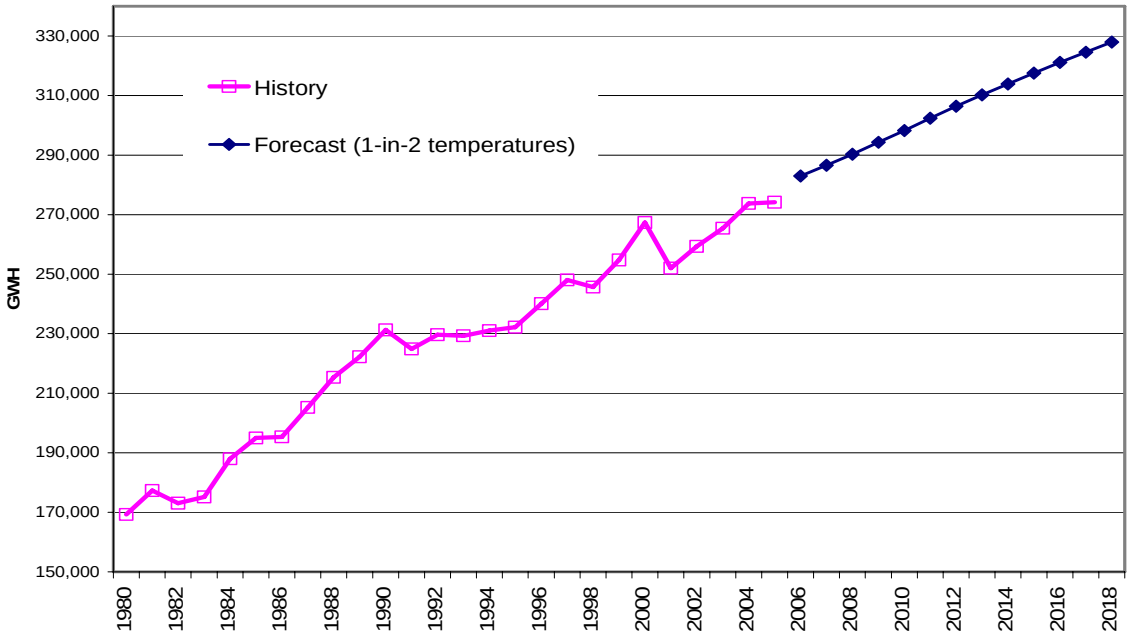
Source: Economy.com

The Energy Commission uses DOF population projections, along with projections of economic trends, demand-side program impacts, and temperature response, to forecast electricity demand throughout the state. Figure 2-2 presents statewide personal income, which is used to forecast growth in residential and commercial demand. In its May 2007 projections used for this forecast, Economy.com projects that personal income will grow at 2.7 percent annually, comparable to average annual growth since 1990.

Figure 2-3 shows historic and forecast annual electricity consumption. The historic data are actual consumption, while the forecast assumes average, or 1-in-2 temperatures. To account for the effects of temperature on residential and commercial electricity use, the forecast adjusts for both summer cooling and winter heating effects in each of the 16 climate zones used for forecasting. The 1-in-2 temperatures are calculated as the average over the last 30 years.

While trends in population growth are relatively stable, economic trends are more cyclical and can drive swings in annual usage. Electricity use sharply increased in 1999 and 2000 during the technology boom but rapidly diminished with the 2001 energy crisis and recession. In 2005 and 2006, electricity use returned to pre-energy crisis levels. In the forecast period (2008–2018), statewide energy consumption is expected to grow at an average of 1.4 percent. This forecast includes the projected effects of currently adopted building and appliance standards in place and current energy efficiency programs plans for 2006–2008 approved for the investor-owned utilities.

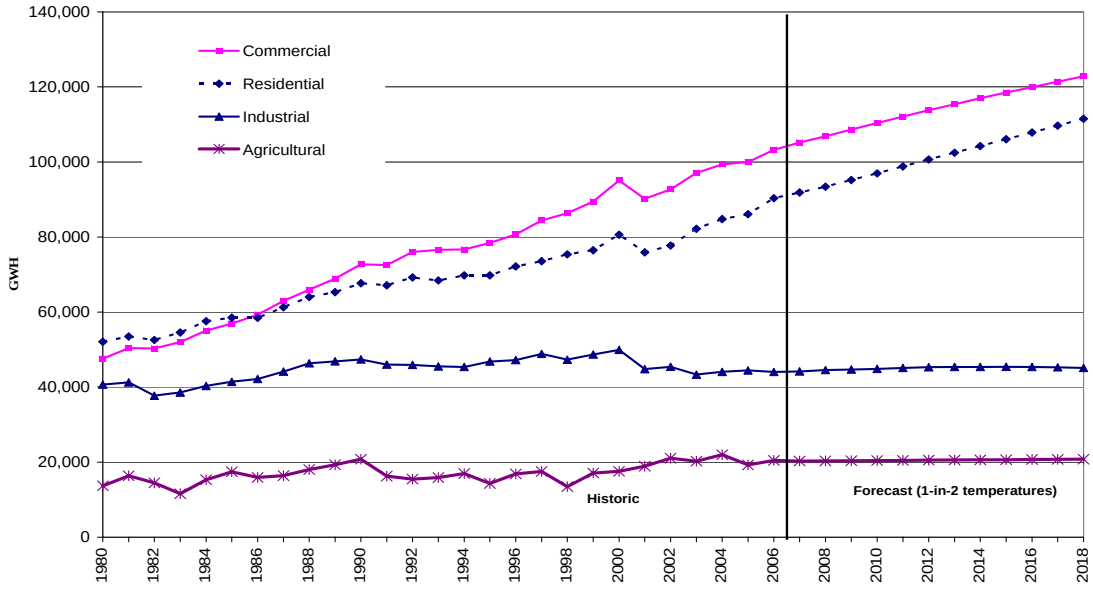
Figure 2-3: Statewide Annual Electricity Consumption (gWh)



Source: California Energy Commission *California Energy Demand 2008–2018* , #CEC-200-2007-015SD

Figure 2-4 shows the forecast of electricity consumption by the major economic sectors. Over the historic period, the commercial sector has had the highest growth rate, followed by the residential sector. In the forecast period, the residential sector continues to grow at the historic rate (1.7 percent), while the commercial sector slows slightly to 1.4 percent annual growth. Electricity use in the industrial sector is relatively flat, although the economic value of output is projected to continue to increase at 0.8 percent annually.

Figure 2-4: Annual Electricity Consumption by Sector

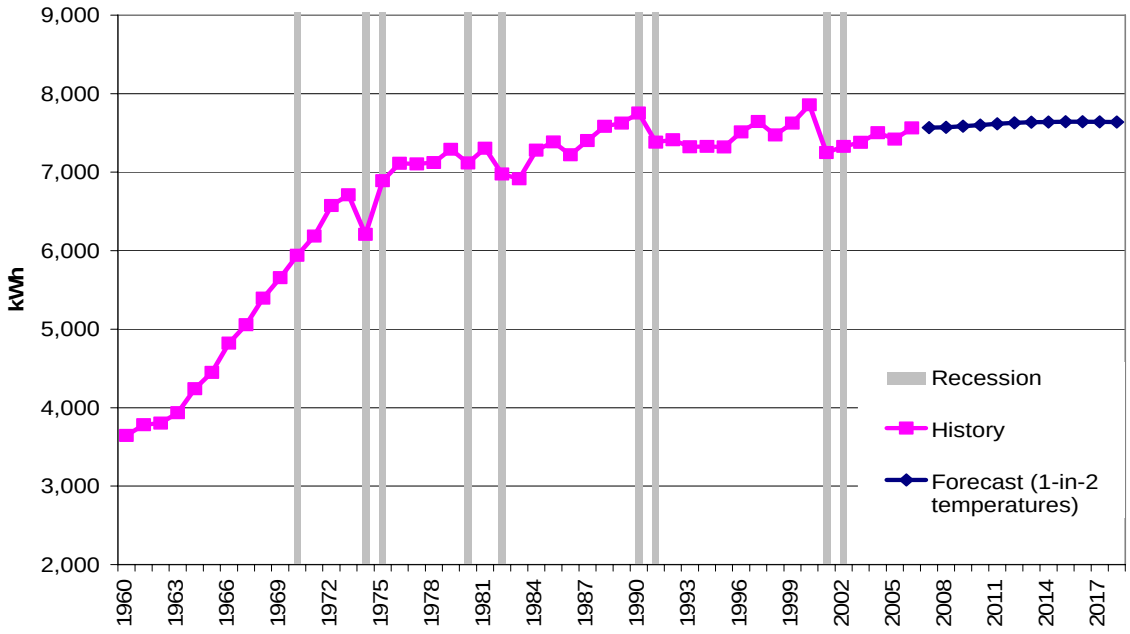


Source: California Energy Commission *California Energy Demand 2008–2018*, #CEC-200-2007-015SD

Overall, improvements in how efficiently we use electricity have helped to offset growth, so that per capita use has grown very slowly. As Figure 2-5 shows, since the initiation of energy efficiency standards and programs in the mid-1970s, per capita use has been essentially constant, fluctuating between 7,200 and 7,800 kilowatt hours (kWh) per person, depending on economic and annual temperature conditions. Building and appliance standards have offset rising usage from the increase in the number of different types of equipment that use electricity in homes and business.

The shaded bars in Figure 2-5 show the effect of economic conditions on usage. Since 1976, per capita use declined on average by 2 percent during recessions, while in non-recession years use typically increased by .05 percent. In the forecast period, this trend of relatively constant use per capita is projected to continue at just below 7,500 kWh per person.

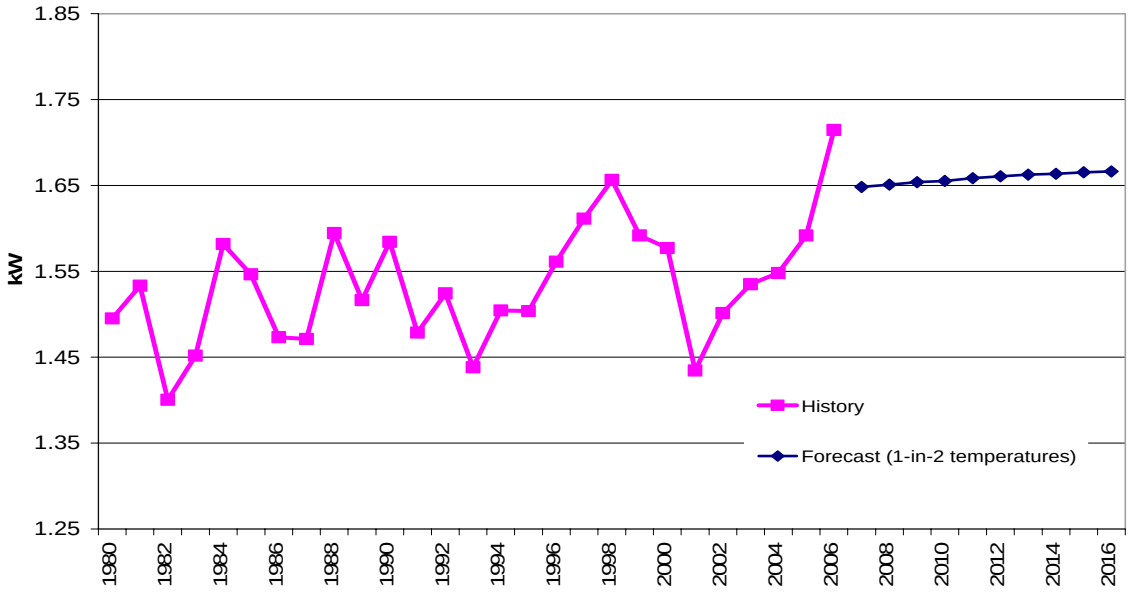
Figure 2-5: Annual Electricity Consumption per Capita



Source: California Energy Commission *California Energy Demand 2008–2018* , #CEC-200-2007-015SD

Peak demand per capita, shown in Figure 2-6**,** grows slightly faster than energy use per capita. The greater volatility of per capita peak demand reflects its sensitivity to temperature conditions. The temperature response of peak demand reflects the amount of installed cooling equipment in an area. To account for the effect of temperature on demand, daily temperatures from area weather stations, weighted by the distribution of residential air conditioning, are used to estimate response in each utility area. The 1-in-2 peak demand forecast assumes average annual maximum temperatures—the annual maximum temperatures that have a 50 percent (1-in-2) chance of being reached in any given year. Because 2006 was hotter than normal, the starting point of the 1-in-2 forecast is lower than actual demand in 2006.

Figure 2-6: Peak Demand Per Capita



Source: California Energy Commission *California Energy Demand 2008–2018* , #CEC-200-2007-015SD

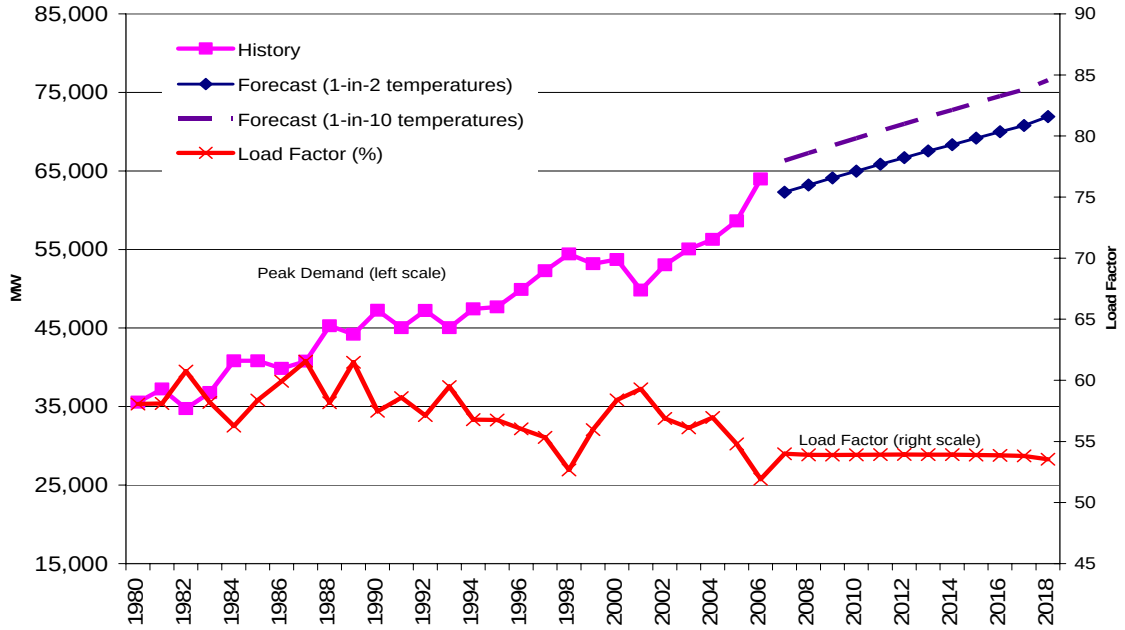
Statewide annual peak demand, shown in Figure 2-6, is projected to grow on average 850 MW per year for the next 10 years, or 1.6 percent annually. The effect of the population growth in the drier, warmer areas of the state increases peak demand—the highest hourly demand in each year—more than it increases annual energy consumption. Another reason for the higher growth rate of the peak demand forecast compared to the electricity consumption forecast is the forecast's assumption that the 2005 federal air conditioning standards have no impact on peak because of their inefficacy in reducing California peak demand. The seasonal energy efficiency ratio (SEER) performance metric is based on outdoor temperatures far below the average annual maximum temperatures experienced in California and on more humid indoor conditions. Therefore, while the electricity consumption forecast accounts for the 2005 standard's change to SEER 13, impacts from the 2005 standards are not included in the peak demand forecast.

The growth in peak demand is somewhat offset by projected increases in the load served by self generation, reflecting the effects of the California Solar Initiative (CSI), the New Solar Homes Partnership, and the Self-Generation Incentive Program. The peak demand forecast represents the net amount of load the electric grid must serve so that demand by self-generation reduces the electric system peak. In the forecast, the growth in photovoltaic and other self-generation installations is assumed to reduce peak demand by 650 MW by 2018, based on current costs and program performance; if the installed cost of photovoltaic systems declines rapidly, this projection could easily by exceeded.

Resource planners and system operators also need to know how much demand will increase under extreme temperature conditions. The Energy Commission applies its estimates of temperature response—how much peak demand rises as temperature increases—to develop demand forecasts for varying degrees of hotter-than-average temperatures. In the 1-in-10

temperature scenario, shown in Figure 2-7, which has a 10 percent chance of occurring in any year, demand is increased by 6.5 percent in any given year.

Figure 2-7: Statewide Coincident Peak



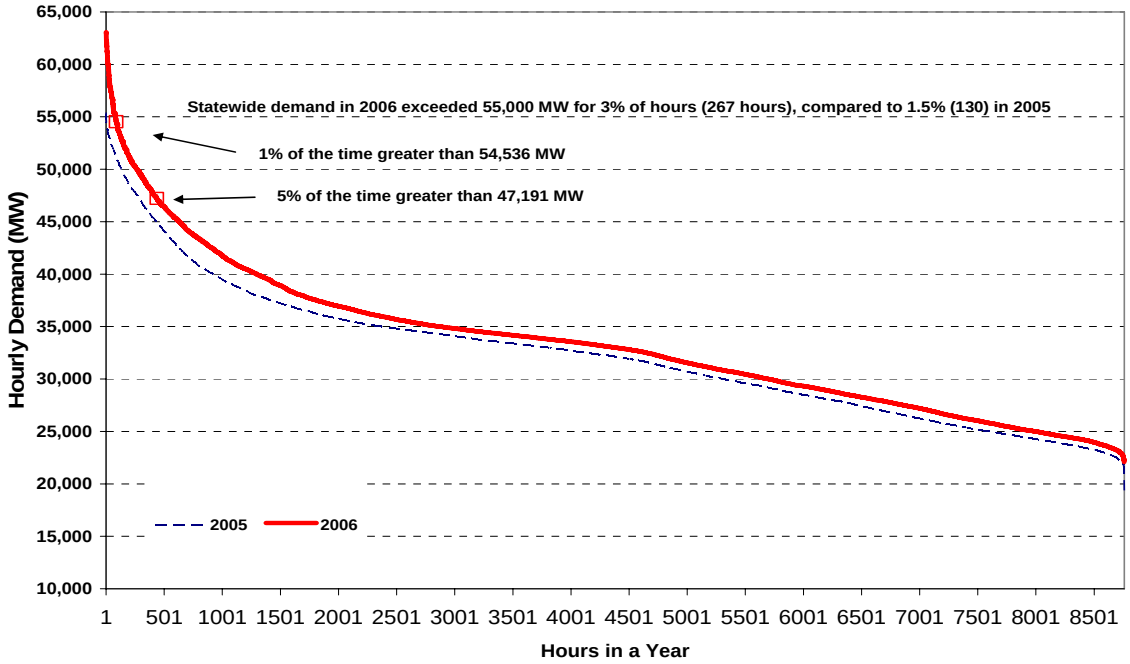
Source: California Energy Commission *California Energy Demand 2008–2018* , #CEC-200-2007-015SD

Figure 2-7 also shows the historic and forecast load factor. The distribution of load over the course of the year is an important characteristic of demand. System operators must plan for sufficient capacity to meet peak demand, but in off-peak hours only some fraction of that capacity will be used. The load factor, defined as average demand relative to peak demand, measures the extent to which capacity is being used. A load factor of 100 percent would mean demand is constant in all hours, so there is no unused capacity in any hour. Conversely, a low load factor means much of the resources needed to meet demand in the peak hour sit idle in other hours. Load factors vary from year to year depending on weather, as shown in Figure 2-7. For example, 1998 was a very cool year except for a brief hot spell, so average hourly demand was much less than the peak hour, resulting in a load factor of only 52.7 percent. In 2001, the load factor reached 60 percent as businesses and consumers chose to use less air conditioning in response to the energy crisis. In 2006, unusually hot weather simultaneously in Northern and Southern California produced a load factor of 52.

While year-to-year variation in temperature causes swings in the load factor, the systematic decrease over time (both historically and in the forecast) reflects a number of continuing trends: a greater proportion of homes in warmer areas and thus more homes and businesses with central air conditioning; higher saturations of cooling equipment even in mild climates; and a higher proportion of economic activity in the commercial rather than the industrial or agricultural sectors. Finally, many energy efficiency measures, such as more efficient residential lighting, can also contribute to the declining load factor by reducing overall energy use while having less of an impact on peak. The hourly demands shown in Figure 2-8 illustrate the effects

of these patterns on hourly demand and resource needs. Statewide demand in 2006 exceeded 55,000 MW for only 3 percent of the hours in that year (267 hours), compared to 1.5 percent (130 hours) in 2005, as shown on the load duration curve in Figure 2-8. The shift up from 2005 to 2006 represents both warmer temperatures and load growth in 2006.

Figure 2-8: Load Duration Curve 2006



Source: FERC Form 714 data compiled by Energy Commission staff

To support transmission planning studies, supply/demand assessments, and other analyses of the electricity system, staff disaggregates its planning area forecasts to correspond to control areas[26] and congestion zones.[27] Table 2-1 shows the forecast of peak demand by control area and congestion zone. The areas outside California ISO control, other than the Los Angeles Department of Water and Power (LADWP) with their loads in the desert and Central Valley, are the fastest growing areas.

[26] A "control area" refers to the area controlled by an independent system operator that is the day-to-day operations manager of the electric system.

[27] A "congestion zone" is an area within a control area that has some physical constraints in its ability to import resources. Such an area requires a distinct load forecast because of its constraints. California ISO has two major congestion zones: north of Path 15 and south of Path 15.

Table 2-1: Peak Demand (MW) by Control Area

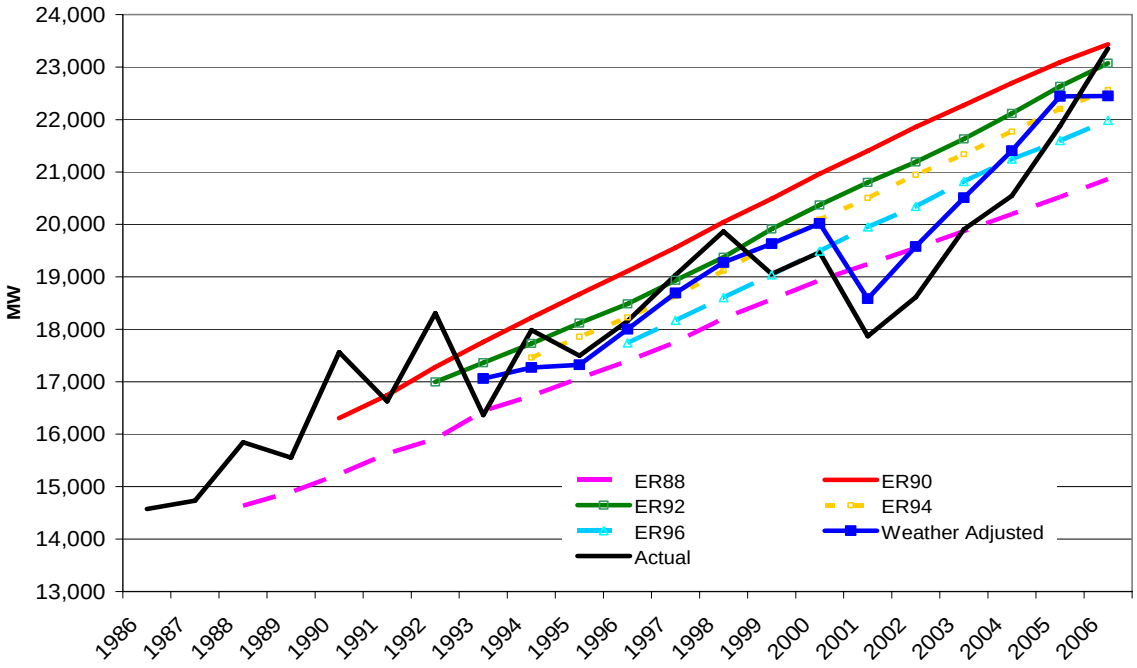
	North of Path 15	South of Path 15	California ISO Total	Turlock Irrigation District Control Area	SMUD/ Western Control Area	LADWP Control Area	Imperial Irrigation District Control Area	State
2000	20,862	23,473	41,933	322	3,765	5,859	753	53,661
2005	21,441	26,756	45,668	396	4,239	6,305	874	58,602
2008	23,269	28,515	49,011	582	4,726	6,480	935	62,935
2018	26,465	32,262	55,597	663	5,799	6,743	1,109	71,275
Annual Growth Rates								
2000-2005	0.55%	2.65%	1.72%	4.22%	2.40%	1.48%	3.03%	1.78%
2005-2008	2.76%	2.15%	2.38%	13.68%	3.69%	0.92%	2.26%	2.41%
2008-2018	1.30%	1.24%	1.27%	1.31%	2.07%	0.40%	1.73%	1.25%

Source: Preliminary figures from California Energy Commission, *California Energy Demand 2008–2018*, #CEC-200-2007-015SD.

How reliable are these forecasts? The long run economic and demographic projections used to forecast demand typically cannot predict the timing or magnitude of changes in the business cycle. So even if the predicted trend proves to be accurate over the forecast horizon, the forecast for any given year may be significantly inaccurate. Figure 2-9 illustrates this for the Southern California Edison (SCE) planning area, the utility area for which staff has the most comparison points. The Energy Commission's forecast of SCE peak demand for the 1994 Electricity Report (ER 94) has had an average error of 2.9 percent over its forecast horizon, including the energy crisis years of 2001 and 2002, which motivated a large amount of voluntary demand curtailment (the forecast error in 2001 was 10 percent). In 1999–2000, the forecast error was less than .05 percent, but in 2003, the ER 94 forecast was 4 percent too high, most likely reflecting the lingering effects of the recession associated with the bursting of the "dot-com bubble." By 2005, the forecast error declined to 1 percent.

For the five forecasts of demand in the SCE planning area adopted by the Energy Commission from 1988 to 1996, the average annual absolute error over the 5 to 12 year forecast horizon was 4 percent. This is the error when compared to weather-adjusted demand (what staff estimates demand would have been under average temperature conditions) and includes 2001.

Figure 2-9: Forecasted versus Actual Peak Demand in the SCE Planning Area



Source: California Energy Commission

Resource Adequacy

Reliable electricity service requires that the state have enough generation capacity to cover load and reserves at peak demand times. Beginning with D.04-01-050, the CPUC established resource adequacy requirements. To resolve ambiguities over state authority to establish requirements that sufficient capacity is available, in September 2005, the Legislature passed and the Governor signed AB 380 (Nuñez, Chapter 367, Statutes of 2005) which requires the CPUC to establish resource adequacy requirements for all load serving entities under its jurisdiction, including all investor-owned utilities and retail electricity service providers. The California ISO has established similar requirements for the publicly owned utilities located in its control area. These requirements have evolved over time to establish separate methods to address local capacity requirements, and zonal procurement restrictions that recognize the transmission limitations within the California ISO control area. For all publicly owned utilities, whether or not in the California ISO control area, AB 380 directs publicly owned utilities to prudently plan for and procure adequate resources to meet their respective planning reserve margins. It also requires them to provide the information necessary for the Energy Commission to evaluate and report progress made by publicly owned utilities to ensure resource adequacy in future Energy Reports.

Effectively, public utilities are not required by legislation or tariff requirements to buy, build, or contract with a specified amount of capacity (for example, an amount equal to 115 percent of their forecasted load during the summer peak in 2007), unless they are in the California ISO

control area, which has raised the question of whether formal requirements should be legislated.

Pursuant to the authority established by AB 380, the Energy Commission staff collected loads and resource information from all known publicly owned utilities throughout the state. This information was reviewed to determine whether individual publicly owned utilities appear to satisfy the requirements AB 380 established for all publicly owned utilities. Staff's assessment finds that generally the utilities have resources adequate to meet their anticipated demands for the next several years. Staff perceives that the public utilities police themselves and sees no need at this time to develop resource adequacy requirements that are the same for all publicly owned utilities, including the 18 outside California ISO control, because the utilities are so diverse. Even those 18 public utilities that are not in the California ISO control area are generally adhering to self-imposed standards that are in many ways as rigorous as those imposed by the California ISO.

Scenario Assessments

Overview

The Energy Commission undertook the Scenario Analyses Project to assess major expansion of the key policy strategies that are important for the electricity system. At this juncture, the greatest need is to develop a better understanding of the actions necessary to achieve major reductions in greenhouse gases for the electricity sector and the consequences of these actions. Rather than focusing on the range of uncontrollable external forces affecting the energy industry, staff developed scenarios that focused upon the broad policy options available to decision makers. Thus, the scenario approach in this IEPR cycle explores what happens if California adopts increasingly aggressive levels of carbon-free resources to curtail greenhouse gas emissions. The resulting "policy-driven" scenario analyses demonstrate the economic and greenhouse gas emission consequences of the scenarios. They provide a contextual framework to understand the consequences of the efforts now underway by the ARB, the CPUC, and the Energy Commission to establish regulatory requirements for specific load-serving entities.

Energy Commission staff examined the implications of resource plans featuring very high penetrations of energy efficiency measures and renewable energy generation (both rooftop solar photovoltaic and supply-side generating technologies) in California and the Western Interconnection.[28, 29] Among the variables of interest is the effect of a reduction in greenhouse

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[28] *Scenario Analyses of California's Electricity System: Preliminary Results for the 2007 Integrated Energy Policy Report*: Staff Draft Report, June 2007, CEC-200-2007-010SD.

[29] The Western Electricity Coordinating Council (WECC) encompasses 35 control areas, or balancing authorities, which are charged with maintaining system and voltage within narrow tolerances. Frequently these are closely aligned with a major utility within each one encompassing several smaller utilities. Modeling the detailed arrangements of hundreds of utilities is unwieldy, and for these policy

gas emissions compared to what might be expected from resource plans with more conventional resources. The greenhouse gas reduction potential demonstrated here is limited to CO_2 reduction because the greenhouse gas reductions modeled are associated with reductions in fossil-based electricity generation. In addition, the study investigated consequences for generation mix to support load, system and production costs of generation, fuel consumed in power generation, criteria pollutant emissions, and transmission additions needed in each scenario. The staff effort did not attempt to devise the optimal penetration of preferred resources, but rather, explored how combinations of increases in penetrations in California and the West affect greenhouse gas emissions, resource requirements, transmission requirements, and incremental costs in those geographic areas.

The study builds upon previous efforts by the California Energy Commission, the California Public Utilities Commission, the Clean and Diversified Energy Advisory Committee to the Western Governors Association, and others to identify the implications of various strategies to rely more on efficiency and renewables in the electricity sector. Rather than duplicating these efforts, this study attempts to complement those earlier efforts by investigating:

- The interaction between increased penetration of preferred resources and the associated transmission and fossil generation requirements needed to maintain system reliability at an inter-transarea (transmission zone) level of analysis
- The interaction between increased penetrations of preferred resources in California and increased penetrations in the West, especially on the dispatch of fossil power plants
- The greenhouse gas emission implications of high penetrations of the preferred resource types
- The effects of the interaction between increasing penetrations of renewables and the natural gas market
- The relative cost effects of increasing penetrations of preferred resources in California and the West

The study used standard production cost models to simulate the results for a variety of scenarios composed of differing levels of preferred resources—energy efficiency, roof top solar photovoltaic (PV), and supply-side renewable generating technologies—both for California and the balance of the Western Interconnection (Rest-of-WECC). The simulations were conducted out to year 2020 to correspond most closely to the target year of AB 32 in California that many other states have also identified for their greenhouse gas reduction goals. The production cost model was configured to use transmission zones (transareas) that modeled most of the major utility systems separately, but more detail was followed for California than for the Rest-of-WECC. The study addressed transmission in terms of the transfer capacity between transareas

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assessment purposes, unnecessary. The topology of the production cost model used 29 transareas, which was judged to be a reasonable balance.

and modeled expansion of the transmission system when necessary in each of the scenarios. All production cost model analyses develop considerable detail on fuel costs, other variable operations and maintenance costs, and so forth, but this analysis also estimated the capital and fixed operations and maintenance costs of generation and transmission.

While staff developed nine basic scenarios to evaluate the preferred resource strategies, it examined more than 50 cases for the entire Western Interconnection by evaluating sensitivities for high and low fuel prices, plus high and low hydro-electric generation. This range of thematic scenarios allows preferred resource plans to be compared to what might be expected from resource plans with more conventional resources.

The staff reports and presentations at four workshops emphasized numerous modeling limitations and uncertainties that could not be investigated. Most stakeholders wanted additional cases evaluated or desired additional, more nuanced analyses, but these comments did not directly contradict staff's analysis or its interpretations of the results.

Study Design and Scenario Definitions

Staff's study was designed to focus upon the broad implications of high levels of preferred resource additions. It was limited to the electricity sector and did not investigate measures like electrification of transportation or industrial processes that, while attractive to reducing greenhouse gas emissions in those sectors, would necessarily increase emissions in the electricity sector as resources were added to accommodate increased loads. The study was limited to an analysis of the physical system and did not link loads and resources to specific load-serving entities. The study investigated the following thematic scenarios using both deterministic production cost modeling as well as sensitivity assessments for some of the variables thought to materially affect the results:

- Case 1 — Current conditions extended into the future implying minimal penetration of preferred resources
- Case 1B — Compliance with current requirements for preferred resources, both in California and in Rest-of-WECC
- Case 2 — Utility industry resource decisions reflecting high sustained natural gas and coal prices, but minimal policy requirements from regulators
- Case 3A, D, E — Three levels of increased energy efficiency, in California only, otherwise the assumptions of Case 1B
- Case 3B, C — Two levels of increased energy efficiency, throughout the West, otherwise the assumptions of Case 1B
- Case 4A — High levels of rooftop solar PV and supply-side renewable generating technologies, in California only, otherwise the assumptions of Case 1B

- Case 4B — High levels of rooftop solar PV and supply-side renewable generating technologies, throughout the West, otherwise the assumptions of Case 1B
- Case 5A, D, E — Three levels of increased energy efficiency (Case 3A, 3D, and 3E) and a high level of renewables, in California only, otherwise the assumptions of Case 1B
- Case 5B — High levels of energy efficiency (Case 3B) and renewables (Case 4B) throughout the West.

Of these, Case 1B is the closest to reflecting the current energy efficiency goals, Renewable Portfolio Standard (RPS) requirements, and rooftop photovoltaic objectives both within California and across the West. In some respects it reflects continuation of recent policies without the incremental emphasis resulting from climate change concerns. The additional cases made use of the highest level of efficiency or renewables or PV that was developed in prior studies. The individual energy efficiency or renewables scenarios and especially the combination scenarios were intended to allow quantification of the greenhouse gas implications of these very high levels of penetration.

Source of Inputs

To focus upon the analysis of the implications of high penetrations of the preferred strategies, the Scenario Analysis Project adapted and used as inputs information about each of the three strategies from various existing studies. Table 2-2 identifies the principal source of information for each strategy both for California and for Rest-of-WECC. Especially for Rest-of-WECC information, this project used the task force studies and reports developed by the Clean and Diversified Energy Advisory Committee (CDEAC) formed in response to the Western Governors Association (WGA) adopted in June 2004 to pursue clean and diversified technologies.[30]

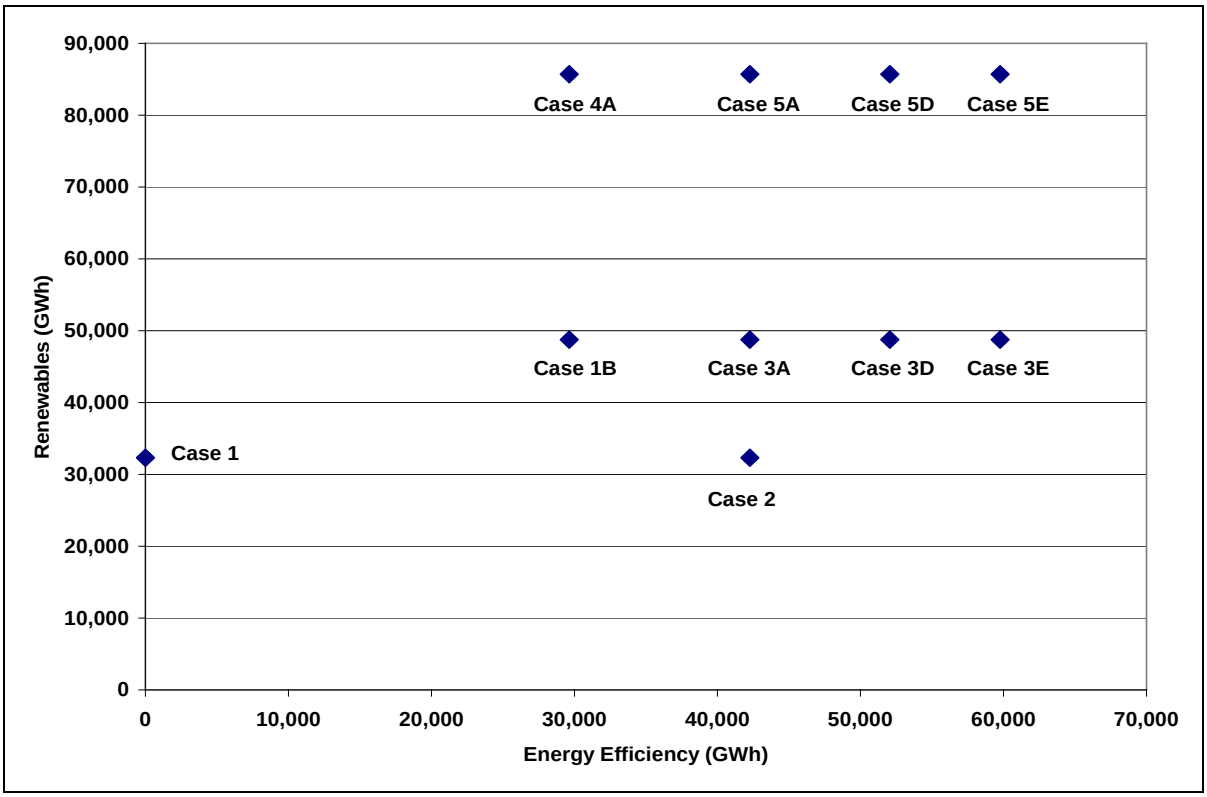
Figure 2-10 summarizes the relative differences among the 10 California-based scenarios in terms of their reliance upon energy efficiency and renewables (both rooftop PV and supply-side renewable generating technologies) in California.

[30] The Clean and Diversified Energy Advisory Committee submitted its report to the Western Governors Association in May 2006, and the Western Governors Association adopted policy Resolution 06-10 endorsing the effort and its recommendations in June 2006.

Table 2-2: Source of Preferred Resource Assumptions

Region	Energy Efficiency	Rooftop PV	Supply-Side Renewables
California	2006 Itron Study for economic potential with emerging technologies treated separately	PIER Funded PV Study which developed three different penetration scenarios	PIER funded Intermittency Analysis Project, 33% in 2020 amounts and locations of renewable capacity
Rest-of-WECC	CDEAC energy efficiency recommendations on "best practices" less the "current activities"	Navigant Consulting work for this project, and a separate Navigant project for the Arizona Corporation Commission	CDEAC Transmission Report, High Renewables Scenario for amounts and locations of approximately 16,000 MW of capacity

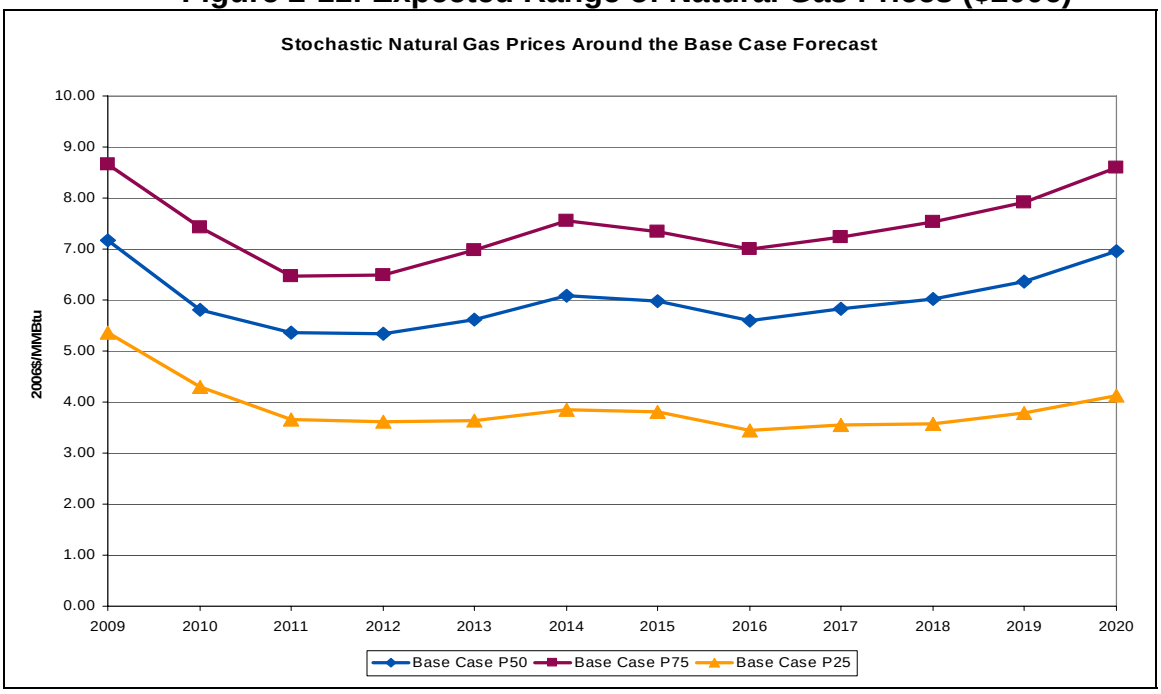
Figure 2-10: Preferred Resource Composition of California Thematic Scenarios in 2020



Source: California Energy Commission Scenario Project

Natural gas and coal fuel prices are a key input to any production cost modeling effort. Figures 2-11 and 2-12 report the baseline projections used in the deterministic assessments and the alternative views used to investigate the consequences of higher or lower fuel prices.[31]

Figure 2-11: Expected Range of Natural Gas Prices ($2006)



Source: Global Energy

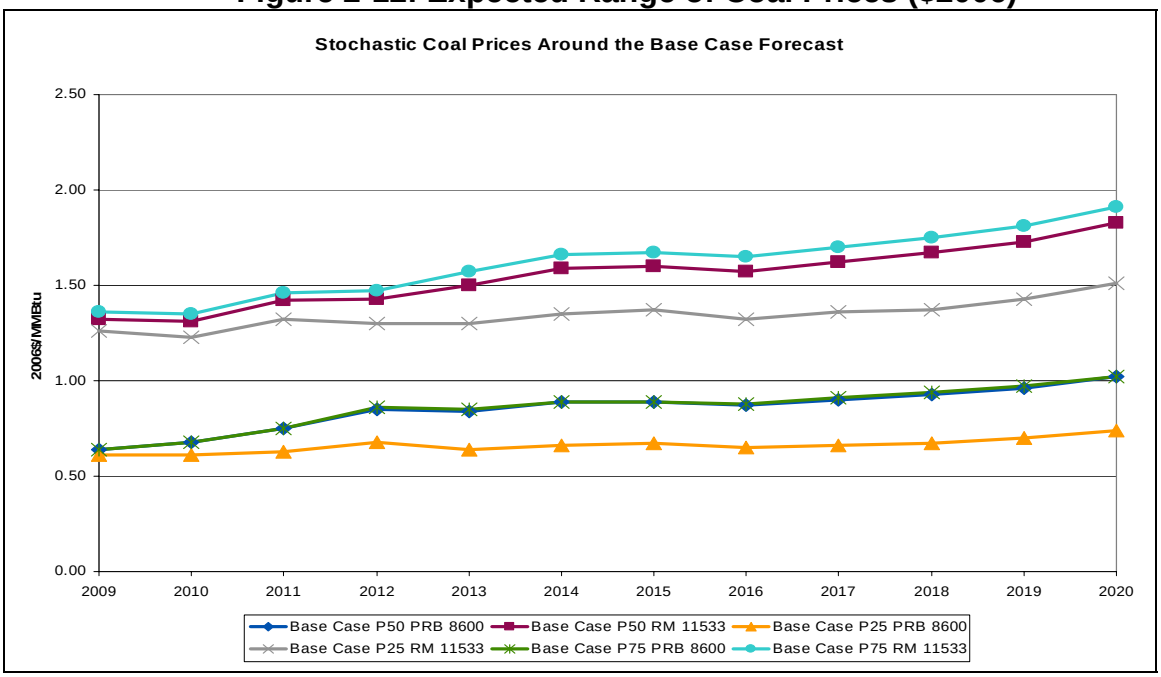
Results of the Analyses

The results can be examined from multiple perspectives—generation by fuel type/technology, GHG emissions, power plant fuel use, reliability, corresponding transmission additions, and cost. Staff evaluated the 13 scenarios using a baseline set of assumptions. The baseline results assumed average or most likely conditions, while an extensive sensitivity assessment provided further insight as to the variation in the results for the variables tested. An effort to assess reliability implications was inconclusive. In response to workshop comments, staff assessed the implications of a carbon dioxide cost adder on the dispatch of the fleet of plants in two of the

[31]*Scenario Analyses of California's Electricity System: Preliminary Results for the 2007 Integrated Energy Policy Report*: Staff Draft Report, June 2007, CEC-200-2007-010SD, pp. 97–99. Global Energy describes these alternative projections as encompassing the 50 percent of the likely range, so that the high alternative exceeds 75 percent of the expected values while the low alternative exceeds only 25 percent of the expected values.

scenarios to assess the level of dispatch cost increase needed to alter reliance upon these existing coal facilities.

Figure 2-12: Expected Range of Coal Prices ($2006)



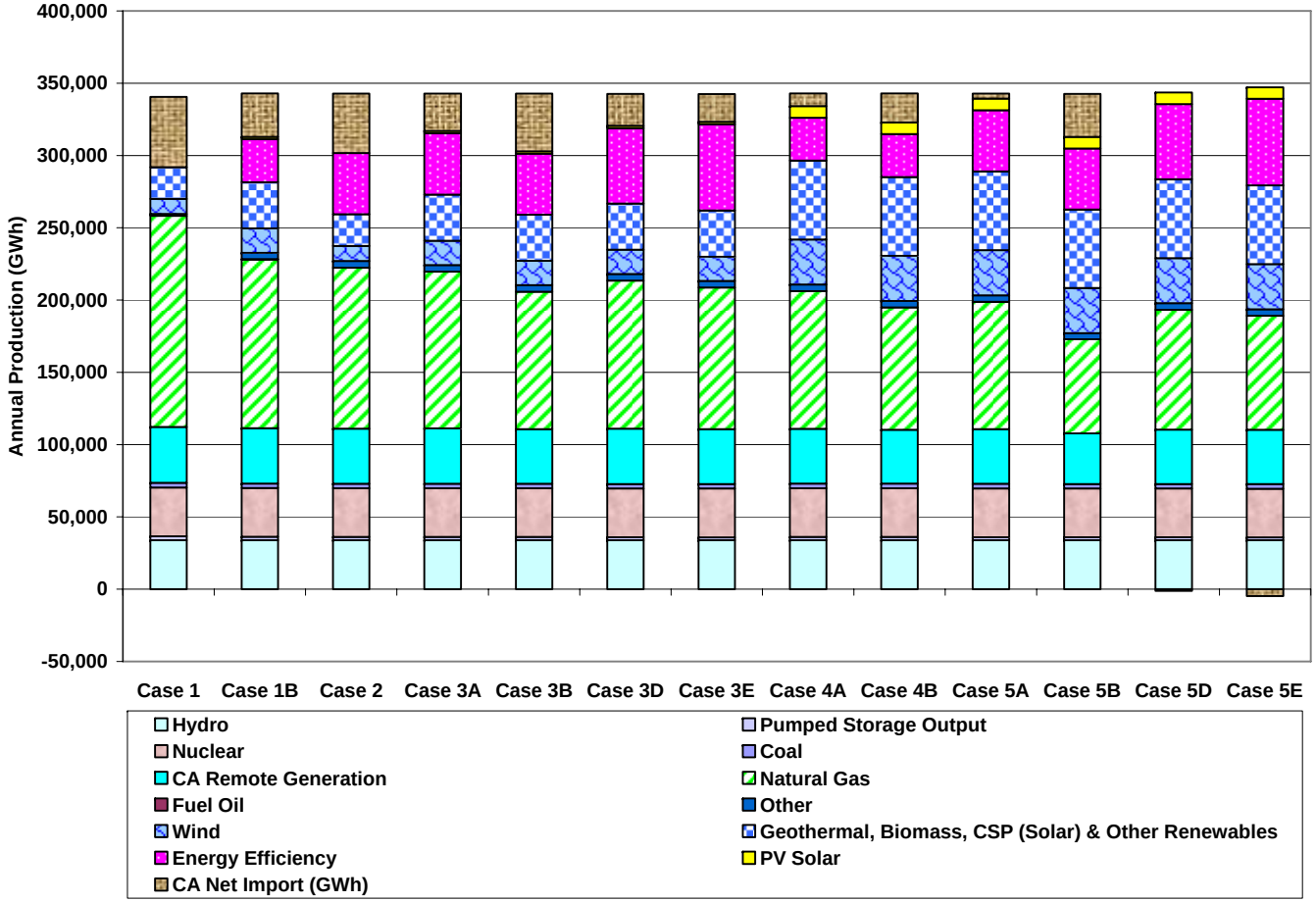
Source: Global Energy

Generation Mix

Figure 2-13 uses a stacking bar format to describe the generating resource output for California that corresponds to each of the same thematic scenarios for year 2020.[32] The conventional resource scenario on the left has a much larger proportion of generation from natural gas than the scenario furthest to the right, which presumes a large increase in energy efficiency and supply-side renewable generation. Clearly, as the scenarios are designed, the increasing role of the preferred resources diminishes the generation from conventional power plant technologies. In California, natural gas generation is the principal source of instate greenhouse gas emissions, and it is displaced as the preferred resources are added. Even in 2020, which affords the most time for the assumptions of Case 5B (the highest levels of both energy efficiency and renewables) to unfold, Figure 2-13 shows that natural gas is still the largest single source of the electricity consumed in California in 2020. Hydro, nuclear and some other fuel types/technologies are essentially unchanged across all scenarios.

[32] To simplify comparisons, incremental energy efficiency and roof top solar PV will be classified as resources, even though individual end-users might perceive the impact of these technologies to be load reductions and/or utility bill reductions.

Figure 2-13: Composition of California Resource Mix in Year 2020



Source: California Energy Commission Scenario Project

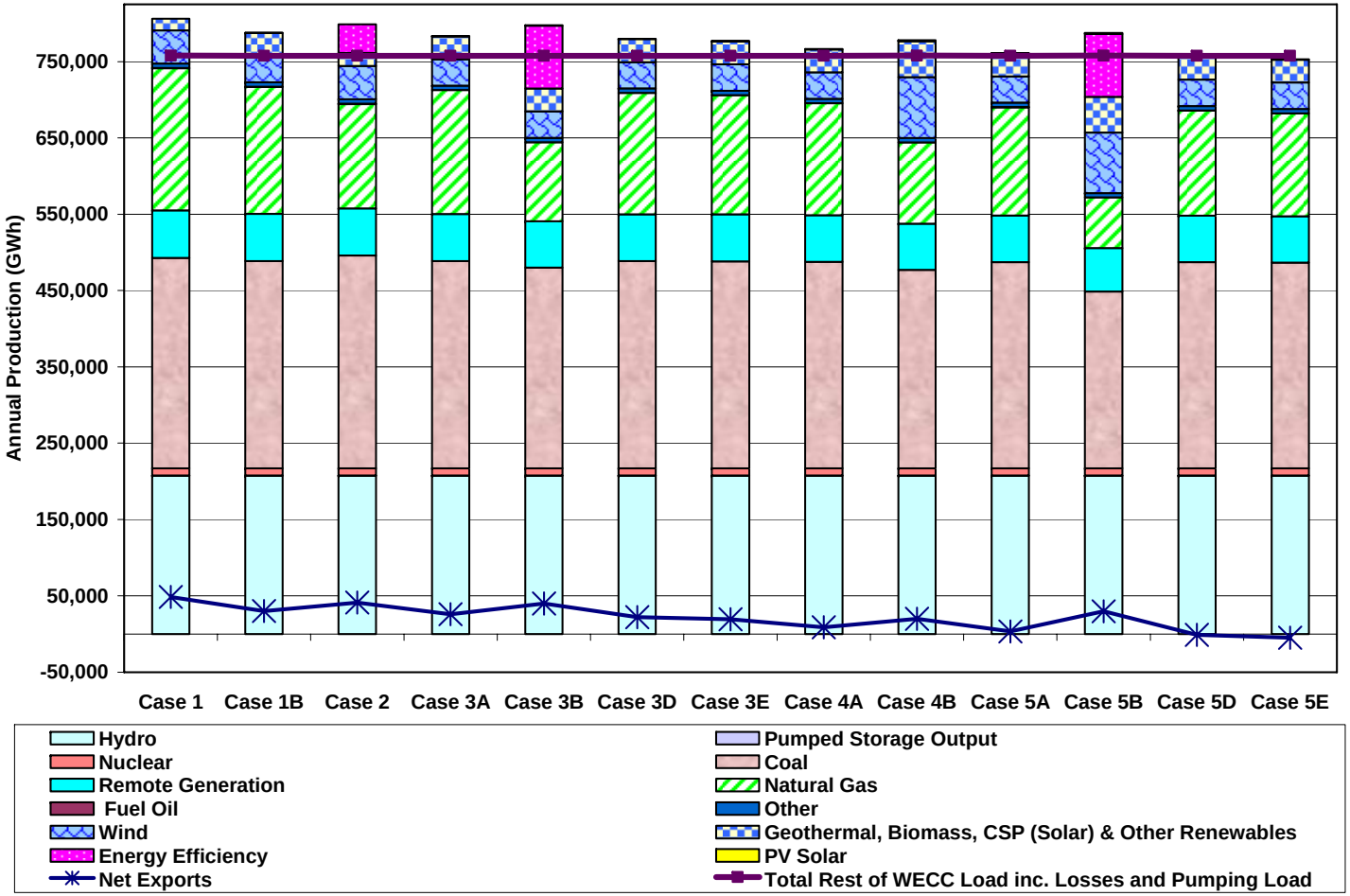
An important result of the analysis is the wide difference in level of imports (top of each bar) into California across these scenarios. As will be discussed in more detail later, these imports are limited to short-term market purchases that cannot necessarily be tracked to any specific generating plant.[33] Because of the influence of coal in supporting imports, both components of imports ("remote" plants and short-term market purchases) play a disproportionately large role in GHG emissions.[34]

Figure 2-14 provides a glimpse of the results for Rest-of-WECC in the same format as for California. Several things are notable. First, the large proportions of hydro-electric generation and coal generation for Rest-of-WECC compared to California power plants. Further, the output from hydro-electric and coal is practically unchanged across all of the scenarios, no matter how large the level of preferred resources. What is displaced as preferred resources are added is natural gas power generation, just as is the case for California power plants. What may be surprising, however, is that the degree of change in natural gas generated power is even larger in Rest-of-WECC than it is for California natural gas-fired power plants. This results from the higher operating costs of natural gas-fired plants, making their output the first to be displaced as preferred resources are added. Although power generated in Rest-of-WECC that is imported to California is a noticeable share of California's electricity power sources, such "exports" from Rest-of-WECC are not very important in the much larger Rest-of-WECC electrical system.

[33] The implications of these short-term market purchases have been discussed extensively in the AB 32 implementation processes, especially the joint proceeding between the CPUC and Energy Commission, because of the difficulties this sort of import creates for tracking and compliance systems.

[34] The physical system study design on which this analysis was conducted omits LSE-specific transactions, thus making it impossible to determine whether the limitations on baseload coal generation required by SB 1368 have been satisfied in all scenarios. Since only limited coal facilities are added in the entire Western Interconnection through 2020, the general intent to limit new coal contracts appears to be satisfied.

Figure 2-14: Composition of the Rest-of-WECC Generation in 2020



Source: California Energy Commission Scenario Project

Greenhouse Gas Emissions

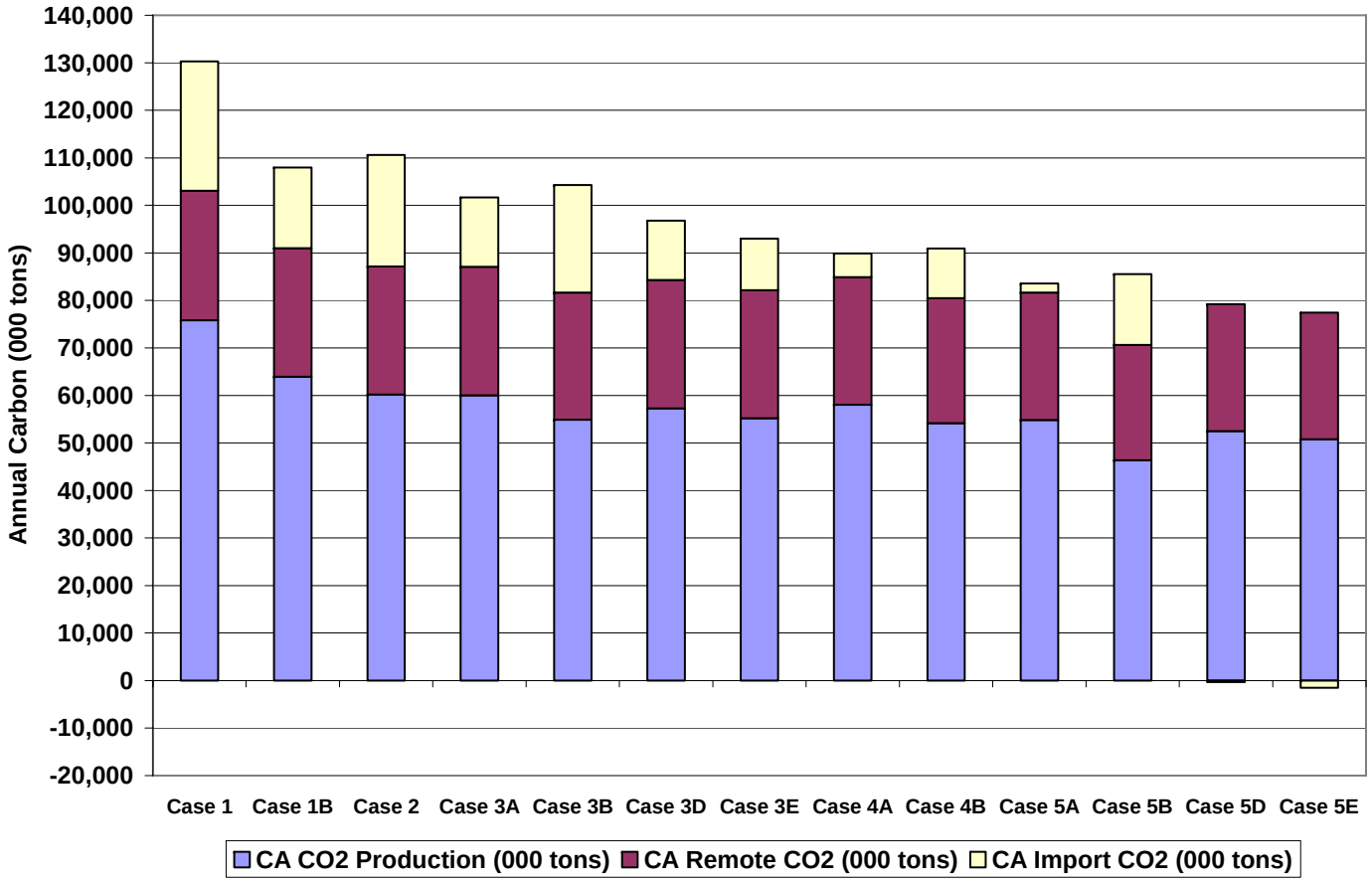
Staff's analysis of greenhouse gas impacts focused exclusively on carbon dioxide. In the electricity sector, greenhouse gas inventories are almost entirely carbon dioxide; therefore, this simplifying assumption makes no material difference in what would be a considerably more complex analysis if other greenhouse gas constituents had to be addressed.

Each generating unit modeled was assigned an emission rate for CO_2, and the simulation results recorded CO_2 amounts based on the fuel burn of each unit. The total carbon dioxide emissions across the cases change as the energy generation changes across the cases. The California responsibility for carbon consists of three categories: (1) power plants located in California, (2) power plants owned by or under long-term contract to California load-serving entities, and (3) emissions from power plants located outside California that correspond to "spot purchases." Similarly, the Rest-of-WECC carbon emissions consist of the plants located in Rest-of-WECC serving Rest-of-WECC loads as well as the share of the remote plants serving Rest-of-WECC loads. Power plants located in California and "remote" power plants located out of state but controlled by California have exact calculations of their emissions, but for "spot purchases" this portion of overall imports into California are allocated CO_2 based on the average carbon profile of the annual average generation mix for Rest-of-WECC.[35]

Figure 2-15 illustrates the change in California carbon responsibility for year 2020 among the scenarios assessed. A conventional resource mix on the left has higher carbon emissions than the one on the right, with the largest amount of energy efficiency and renewables across the West. Even though the resource mix of the two rightmost scenarios is quite different between the amounts of natural gas consumed in California versus power imported into California, the level of carbon dioxide emission shown on Figure 2-15 is nearly the same. Each of the pairs of cases—3A and 3B, 4A and 4B, and 5A and 5B—show slightly higher total emissions, from a California responsibility perspective, in the B version because of higher imports. This conclusion suggests that as long as power plant dispatch decisions continue to follow least-cost principles, and as long as carbon and other GHG constituents remain unpriced attributes of electricity generation, the sourcing of California's carbon emissions is substantially affected by the relative resource mix and cost differentials between power plants in California versus those in the Rest-of-WECC, that is, all of the Western Interconnection other than California.

[35] There are numerous methods for estimating the GHG profile of "imports" into California. Methods that are workable for estimating historic emissions can rely upon historic energy transactions, to the extent such data are available. Methods for projecting future emissions are necessarily unable to utilize methods applicable to the historic period since transactions are not modeled. More aggregated system characteristics data must be used to estimate future emissions for imports.

Figure 2-15: Comparing California Carbon Dioxide Responsibility in Year 2020



Source: California Energy Commission Scenario Project

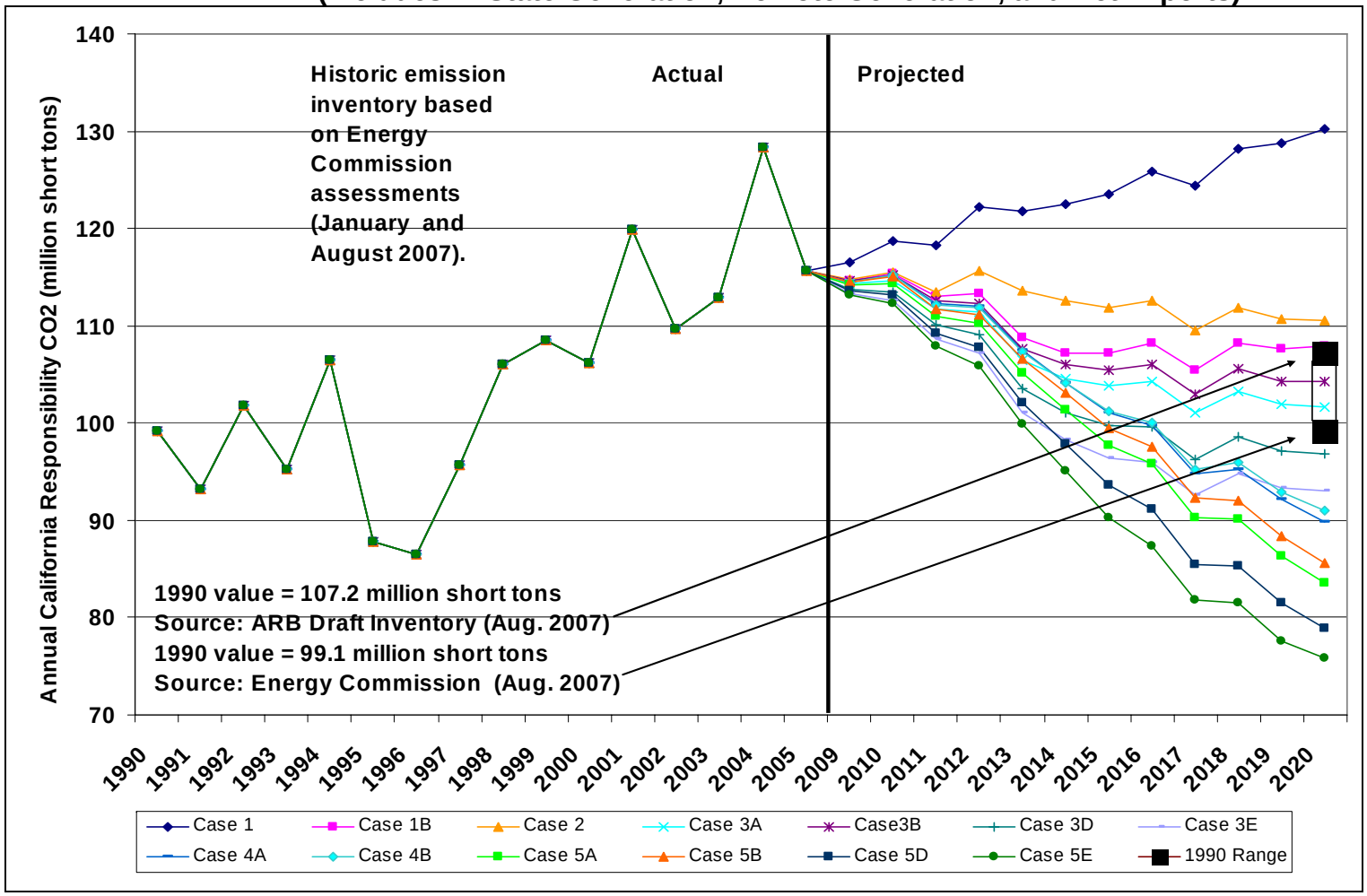
The change over time of California in-state power plant carbon dioxide production is largely based on the change in natural gas-fired generation as was summarized in Figure 2-13. Since coal and oil are negligible sources of generation in California, only natural gas really matters as a GHG source for power plants located in California. The "remote" power plants (in its inventory ARB refers to these as "specified imports") located outside California but built for or contracted to serve California loads hardly change in any scenario. Only spot market purchases (in its inventory ARB refers to those as "unspecified imports") are markedly reduced in the various preferred scenarios. GHG emissions from imports are reduced because imports are reduced, not because the emission characteristics of imports from Rest-of-WECC make any great change.

Figure 2-16 plots the California Responsibility for GHG through time for all cases. In Case 1, Current Conditions, natural gas-fired generation is added to meet future load growth while renewables and energy efficiency are only added in small nominal amounts. As a result, the carbon production for Case 1 increases at a higher rate than any of the other cases with more preferred resources added. At the other end of the spectrum, Case 5E is comprised of a high level of energy efficiency and renewables in California. In this case, California in-state carbon emissions are the lowest and noticeably lower than in Case 5B (a high energy efficiency and high renewables throughout the West.) This figure also identifies how these electricity sector projections compare with two estimates of 1990 GHG emissions. Since the ARB has not finalized its inventory, we have reported two values as a range. In making this comparison, we are not assuming ARB applies the statewide AB 32 greenhouse gas emission reduction goal proportionally to each of the five major emitting sectors. ARB will not make that decision until late 2008. There was no attempt to create an additional level of energy efficiency beyond Case 5B for Rest-of-WECC, because no source of data to guide such a scenario was available.

It is instructive to see the difference between Case 1(Current Conditions) and Case 1B (Current Preferred Resource Requirements). Case 1B reflects staff's interpretation of what would happen if current requirements for the three preferred strategies would unfold through time. While these strategies have been pursued for reasons other than greenhouse gas emission reduction, they clearly have a profound effect. In fact, according to the analysis, the Case 1 to Case 1B differential has a much larger effect than the incremental effect of further pursuit of these strategies. What is not clear from these charts is the level of energy efficiency embedded within the load forecasts that are common to all of the scenarios investigated. These loads forecasts, both for California and Rest-of-WECC, are clearly lower than they would otherwise have been as a result of decades of building and appliance standards, utility programs, and other factors.

It is clear that several strategies pursued individually can satisfy the range of 1990 values (estimates prepared by Energy Commission and ARB), if that is what ARB establishes as a goal for the electricity sector. Combinations of the preferred strategies at the levels investigated would reduce emissions below this range if ARB determines that the electricity sector should be controlled to a greater or lesser degree than some other sectors.

Figure 2-16: California Carbon Dioxide Responsibility through Time by Case (Includes In-State Generation, Remote Generation, and Net Imports)



Source: Global Energy Decisions, Inc. and California Energy Commission

In addition, the volatility exhibited within the historic portion of Figure 2-16 makes clear the degree to which hydro-electric variations can shift emissions from one year to the next. As noted in the staff analyses, any GHG compliance system has to recognize this volatility that is an inherent consequence of the generally beneficial use of hydro-electric generation in the Western electricity system.

Power Generation Fuel Use

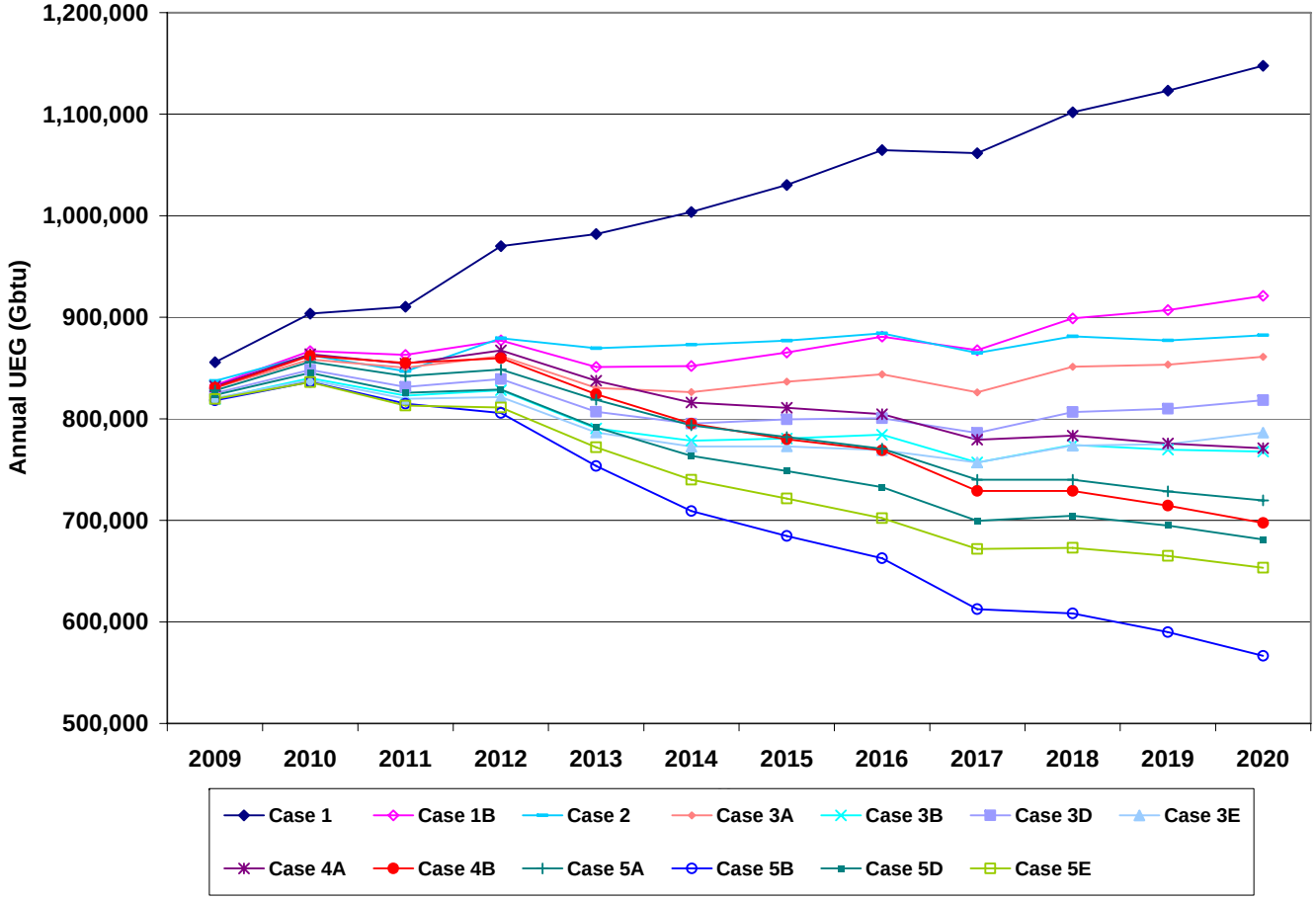
Figure 2-17 portrays the change in prospective natural gas demand as a power generation fuel in California. A comparable analysis was undertaken for all WECC-wide natural gas-fired power generation. California and Rest-of-WECC use of gas for power generation are comparable in volumes even though it is proportionally much more important in California. Gas consumption continues its historic increase in several scenarios, and only the ones involving more aggressive levels of both energy efficiency and renewables cause any decrease from current consumption levels.

Staff sponsored an assessment of the impact on natural gas prices of major reductions in natural gas demand from the scenario preferences leading to reductions in power generation natural gas demand.[36] Staff's sponsorship of two projects (one by Global Energy and one by Altos) clearly revealed differences both in methodological approach and in the assumptions used. Global found sizeable downward price impacts, while Altos did not. Neither analysis was convincing, yet this is an important topic that requires further examination and development of greater analytic consensus.

Figure 2-18 provides the WECC-wide coal consumption for power generation resulting from the scenario assessment. In all scenarios but Case 5B (both high energy efficiency and high renewables on a West-wide basis) coal consumption continues to rise through time. Even in Case 5B WECC-wide coal consumption only decreases back to current consumption levels. Although coal power plant development has increased somewhat in recent years, this effect is still modest, and the great majority of coal use stems from operations of existing coal plants. The coal prices described in Figure 2-12 are 5 to 10 times lower on a dollar per mmbtu basis than the corresponding natural gas prices shown in Figure 2-11. Absent a carbon cost adder affecting dispatch, an actual carbon tax on usage, and/or explicit constraints on coal usage, coal power generation prices are so much lower than natural gas prices that coal will continue to be dispatched irrespective of resource additions promoted by policy makers.

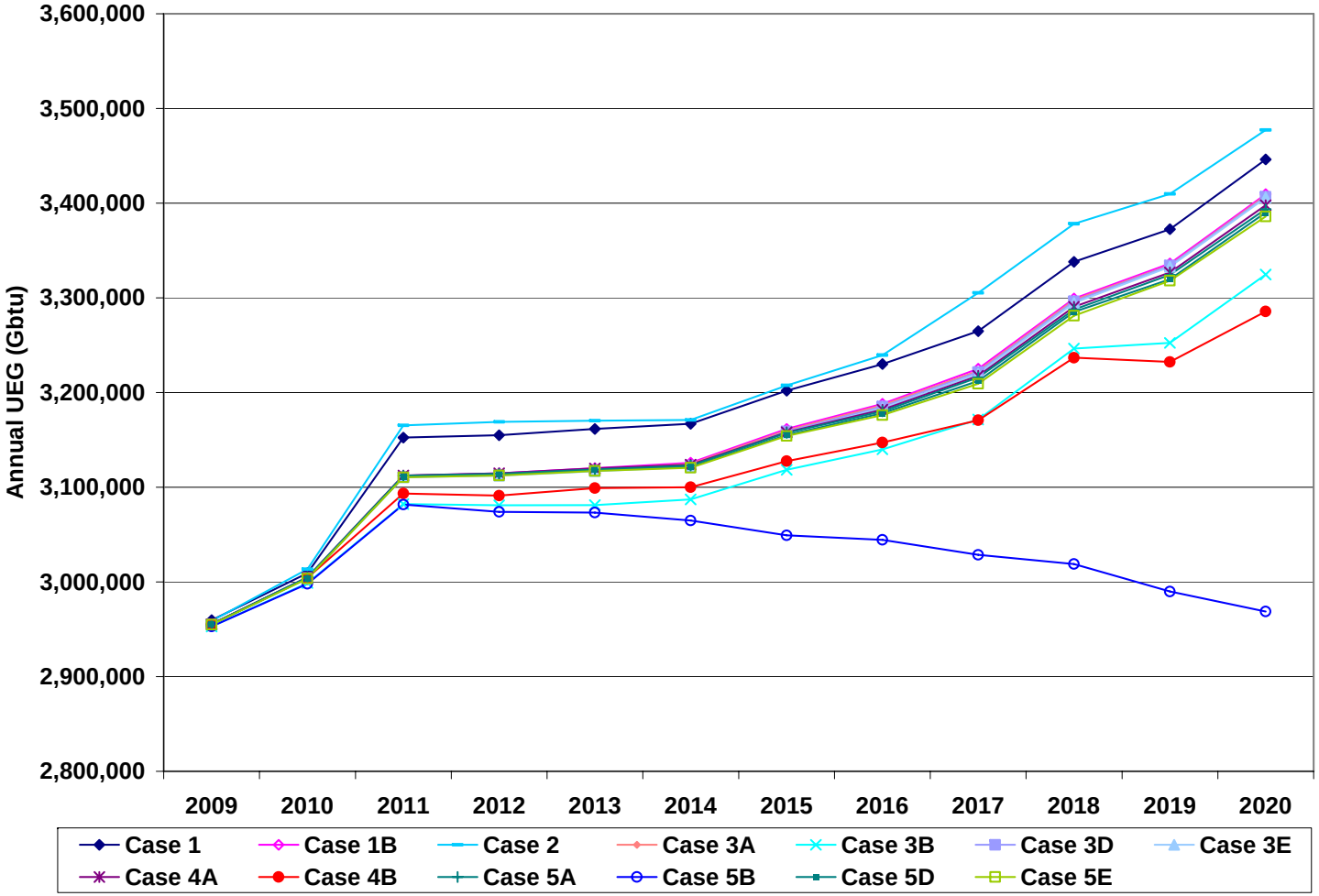
[36] Second Addendum Report, Appendix C prepared by Global Energy.

Figure 2-17: Total California Gas Consumption (GBTu)



Source: California Energy Commission Scenario Project

Figure 2-18: Total WECC Coal Consumption (GBTu)



Source: Global Energy

Reliability

Because of the large amounts of non-dispatchable capacity added in several scenarios, reliability was built into the design of the scenarios and tested. Staff used a simplified version of California's resource adequacy requirements to assure that each control area satisfied a 15 percent planning reserve margin while using dependable capacity values for wind and solar without backup. When dispatchable resources failed to satisfy the 15 percent threshold, combustion turbines were added or additions in transmission line capacity were made.

Staff tested reliability using standard loss of load techniques in Scenario 4B (the one most likely to confront these issues because of its reliance upon high levels of renewables and high loads through no increased preference for energy efficiency), but found no expected unserved energy.[37] Further examination of the results showed that actual resources exceeded planning reserve margin targets in all years, since the dependable capacity of the resources added exceeded the capacity of the generic resources removed when the scenarios were constructed.[38] This result suggests that adding renewable resources in the manner of Case 4A or Case 5A, even though they are not dispatchable, does not itself create reliability problems. Staff's supplemental analyses of retiring aged power plants in Southern California, while problematic from the perspective of assessing retirement rather than repowering, found that some dispatchable capacity could be retired and not replaced and still satisfy reliability standards, if appropriate transmission upgrades were made to allow renewables to be more effective.[39]

Utilities remain concerned about operational issues, especially those connected to retirement of aging power plants and replacement with renewables located at a distance from load centers, and whether the full set of transmission line additions needed to support this pattern of resource build out has been adequately assessed.[40] As further discussed in Chapter 4, the Energy Commission supports further studies of the operational issues associated with renewables development. The Commission believes such studies are critical to either dispel outdated concerns or to identify real problems with renewable development of the scale examined by these scenarios.

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[37] Expected unserved energy measures the annual amount of electricity consumption that end-users desired, but could not receive, through generation or transmission outages.

[38] Third Addendum Report, Chapter 4, and Appendix D.

[39] Second Addendum Report, Chapter 2, and Appendix A.

[40] SCE, "Aging Plant Retirements", August 16, 2007 IEPR Committee Workshop.

Table 2-3: Summary of Transmission Additions by Scenario

		Case 1 Addition		Case 1B Addition		Case 4A Addition		Case 4B Addition		Case 5B Addition	
From Trans. Area	**To Trans. Area**	**Year**	**Increase (MW)**	Year	Increase (MW)	Year	Increase (MW)	Year	Increase (MW)	Year	Increase (MW)
Alberta N	Alberta S	2007	200	2007	200	2007	200	2007	200	2007	200
Alberta N	Alberta S	2009	1,200	2009	1,200	2009	1,200	2009	1,200	2009	1,200
PV	Arizona	2007	1,200	2007	1,200	2007	1,200	2007	1,200	2007	1,200
PV	Devers#2	2009	1,200	2009	1,200	2009	1,200	2009	1,200	2009	1,200
Alberta S	Montana			2008	300	2008	300	2008	300	2008	300
Alberta S	Montana			2014	500	2014	500	2014	500	2014	500
Alberta S	BC			2016	500	2016	500	2016	500	2016	500
Arizona	S. Nevada			2009	1430	2009	1430	2009	1430	2009	1430
BC	Northwest			2009	500	2009	500	2009	500	2009	500
IID	SCE			2009	1000	2009	1000	2009	1000	2009	1000
Imperial	SDG&E			2010	1150	2010	1150	2010	1150	2010	1150
Montana	Northwest			2011	500	2011	500	2011	500	2011	500
Montana	Northwest			2013	500	2013	500	2013	500	2013	500
SCE	SCE			2012	Tehachipi upgrades	2012	Tehachipi upgrades	2012	Tehachipi upgrades	2012	Tehachipi upgrades
SCE	SCE			2012	Pisgah upgrade #1	2012	Pisgah upgrade #1	2012	Pisgah upgrade #1	2012	Pisgah upgrade #1
Wyoming	Idaho			2010	700	2010	700	2010	700	2010	700
Wyoming	Utah			2011	500	2011	500	2011	500	2011	500
Wyoming	Idaho			2012	800	2012	800	2012	800	2012	800
Wyoming	Utah			2013	500	2013	500	2013	500	2013	500
IID	SCE					2015	500	2015	500	2015	500
SCE	LADWP					2015	500	2015	500	2015	500
SCE	SCE					2017	Pisgah upgrade #2	2017	Pisgah upgrade #2	2017	Pisgah upgrade #2
IID	IV-NG*					2015	700	2015	700	2015	700
Idaho	N Nevada							2018	500	2018	500
Montana	Wyoming							2018	500	2018	500
New Mexico	Arizona							2018	1600	2018	1600
Northwest	Idaho							2015	500	2015	500
Wyoming	Utah							2013	1200	2013	1200
Wyoming	Colorado (E)							2015	500	2015	500
Wyoming	Colorado (W)							2017	500	2017	500
New Mexico	Arizona									2013	900
Wyoming	Utah									2015	500

Transmission Additions

Load growth, merchant generation development patterns, and supply-side renewable generating technology policy preferences imply various levels and configurations of transmission development. The scenario project identified necessary transfer capacity upgrades as part of each scenario. Table 2-3 summarizes these upgrades.

The emphasis on renewable generating development in Case 1B compared to Case 1 indicates that significant upgrades are needed between various transareas around the West and to a lesser extent within California. Despite its attractiveness from many perspectives, energy efficiency does not displace the need for these transmission additions. As an example, the two additions required in Case 5B are in addition to those of Case 4B because generic power plant additions still included in Arizona and Utah in Case 4B can be displaced by imports from New Mexico and Wyoming with the additional transmission upgrades.

While the specific projects identified in Table 2-3 should not be put forward for definitive planning studies, the variations on the chart reveal the strong interaction between generation development and transmission development. The Energy Commission is not the originator of this concept, but the Commission since its *2003 Integrated Energy Policy Report* has emphasized the need for increased attention to coordination among the entities responsible for transmission planning to make efforts to understand the nature of the generation build out framing transmission needs. Where there is clarity, transmission planning can proceed rapidly. Where there is ambiguity about generation development, multiple scenarios explicitly linking generation build out assumptions and complementary transmission needs must be prepared and provided to decision makers. The precise nature of the methodologies used to perform this linked analysis is less important than the need for linkage to be examined and understood.

Costs

Achieving these greenhouse gas emission reduction benefits is not without cost. Figure 2-19 provides the results of the analysis on levelized system costs for the scenarios under the control of California policy makers. These results presume that technology cost and performance stay constant through time, except for rooftop solar photovoltaic that is assumed to decrease by 50 percent.[41] With this significant caveat, total system costs tend to increase as greater proportions of renewables satisfy electricity requirements. Production costs tend to decrease as energy efficiency plays a larger role. The modeling

[41] The Scenario Analyses project used capital and other fixed cost estimates by technology, except for coal generation, from the Cost of Generation Study, which is the most recent study available. That study found significant cost increases in recent years for a wide range of generating technologies. In part the cost increases are attributed to the competition among generation developers for renewable technologies in the face of limited manufacturing capacity.

results clearly reveal a capital cost versus production cost tradeoff that reflects total cost reductions for energy efficiency and total cost increases for renewables.

On a levelized cost basis, the three scenarios defined by higher energy efficiency are slightly less expensive than the current requirements case, but when the renewable component is added there is a noticeable increase in system costs per unit compared to what it would have been under current policies. This result stems from the implied assumption that the least costly energy efficiency measures and the most transmission-accessible renewables have already been developed, and that more expensive increments are needed (absent dramatic technology breakthroughs). It should be noted, however, that the normal formula for computing levelized cost is a misleading metric for energy efficiency and end-user renewable technologies because these activities reduce sales. Figure 2-19 has been prepared considering energy efficiency and solar PV as resources, which make the comparison more direct.[42]

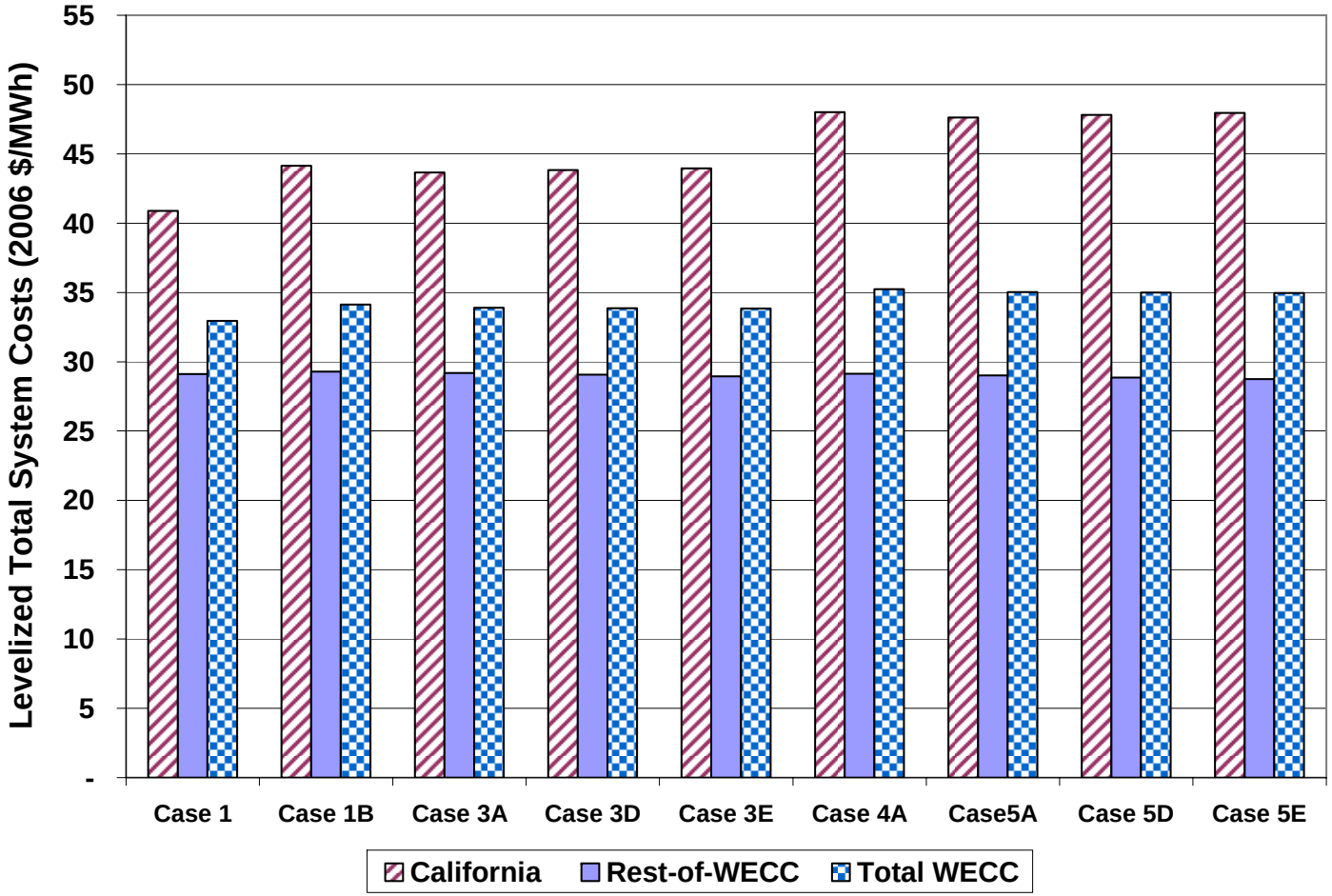
Sensitivities Revealing Implications of Uncertainty

Staff has rightly cautioned that many uncertainties affect the results. Most of them were not investigated for lack of time, resources, and data. However, staff believes the fundamental uncertainties that were addressed—fuel prices and hydro-electric generation—are sufficient to demonstrate that the results are sensitive to input assumptions.

Table 2-4 provides a concise summary of the sensitivity of cost and greenhouse gas emissions relative to fuel price and hydro-electric generation. The fuel price alternative projections were shown in Figure 11 to be asymmetric, with more room to go down than to go up (at least in the middle segment of the probability distribution). The hydro-electric generation range that staff examined is as extreme as it could be, the WECC-wide generation maximum corresponding to high hydro conditions and the lowest generation corresponding to adverse hydro conditions. Intuitively, costs are more sensitive to fuel price variations from baseline projections, while greenhouse gas emissions are more sensitive to the change in expected hydro-electric generation resulting from very dry or very wet precipitation patterns. A GHG emission reduction program must accommodate itself to the sort of swings in GHG emissions shown in the right panel of Table 2-4.

[42] Third Addendum Report, Table 8, p. 26.

Figure 2-19: Levelized System Costs ($2006/MWh)



Source: California Energy Commission Scenario Project

Table 2-4: Summary of California System Costs and Carbon Emissions for Year 2020

Thematic Scenarios		Calif. System Costs			Calif. Carbon Emissions		
		Low NG	Base	High NG	Low NG	Base	High NG
Case 1 - Current Conditions	High Hydro		16,164,681			69,142	
	Base	12,265,962	16,684,128	19,177,074	74,630	75,803	76,034
	Low Hydro		16,875,608			79,968	
Case 1B - Current Requirements	High Hydro		15,945,868			58,866	
	Base	13,004,270	16,354,098	18,224,842	63,100	63,907	63,850
	Low Hydro		16,507,640			67,441	
Case 3A - High EE in Calif. Only	High Hydro		15,299,757			55,124	
	Base	12,617,673	15,701,704	17,434,336	59,156	60,032	60,221
	Low Hydro		15,843,813			63,401	
Case 3B - High EE West-wide	High Hydro		15,077,660			49,691	
	Base	12,569,545	15,576,942	17,257,192	55,004	54,868	54,762
	Low Hydro		15,757,903			57,804	
Case 4A - High Renewables in Calif. Only	High Hydro		18,617,701			53,438	
	Base	16,452,327	18,935,010	20,318,987	57,233	58,078	58,338
	Low Hydro		19,039,752			60,914	
Case 4B - High Renewables West-wide	High Hydro		18,501,518			49,585	
	Base	16,443,014	18,904,156	20,272,379	53,804	54,172	54,268
	Low Hydro		19,055,587			56,826	
Case 5A - High EE and Rewables in Calif. Only	High Hydro		18,121,512			50,467	
	Base	16,184,232	18,407,604	19,636,497	54,047	54,836	55,030
	Low Hydro		18,491,545			57,592	
Case 5B - High EE and Rewables West-wide	High Hydro		17,799,534			42,429	
	Base	16,145,825	18,238,302	19,369,073	46,848	46,356	46,068
	Low Hydro		18,450,465			49,318	

Source: California Energy Commission

Initial Examination of Carbon Dioxide Cost Adder

Some stakeholders expressed frustration with the staff's project design in not directly addressing use of a carbon dioxide cost adder of some level to displace fossil generation.[43] These concerns were raised again when the preliminary results were reviewed in a public workshop. At the IEPR Committee's request, staff conducted an abbreviated analysis of the impact of a carbon dioxide adder on the dispatch of a known resource mix. Such an analysis, of course, is not the comprehensive assessment of a carbon adder or carbon tax on the build out of the electricity system.

[43] January 29, 2007 Workshop comments of NRDC and CEERT.

Figures 2-20 and 2-21 provide an overview of the degree to which resources are re-dispatched when a carbon dioxide cost adder of various levels affecting unit commitment and dispatch is imposed upon a given resource mix. Carbon dioxide cost adders from $10/short ton to $60/short ton were investigated. There are only very slight responses when the carbon cost adder is at levels of $10 and $20/short ton. Both figures show that meaningful displacement of coal generated power begins when the adder reaches $30 to $40 per short ton of CO_2.[44] Both the conventional resource mix (Case 1) and a resource mix with high levels of energy efficiency and renewables (Case 5B) show that natural gas-fired power plants increase generation to replace coal-fired generation.

Perhaps more importantly, since it once again illustrates the interconnectedness of the electricity system in WECC, natural gas plants in California are a principal means to displace generation from coal plants in Rest-of-WECC in this redispatch analysis. As natural gas plant usage increases in California, this would increase both greenhouse gas and criteria pollutant emissions from such plants. Staff's initial analysis of this issue for year 2020 shows that even in Case 5B (high energy efficiency and high renewables throughout the West) that California natural gas plants would supply more than half of the entire increase in generation displacing more expensive coal.

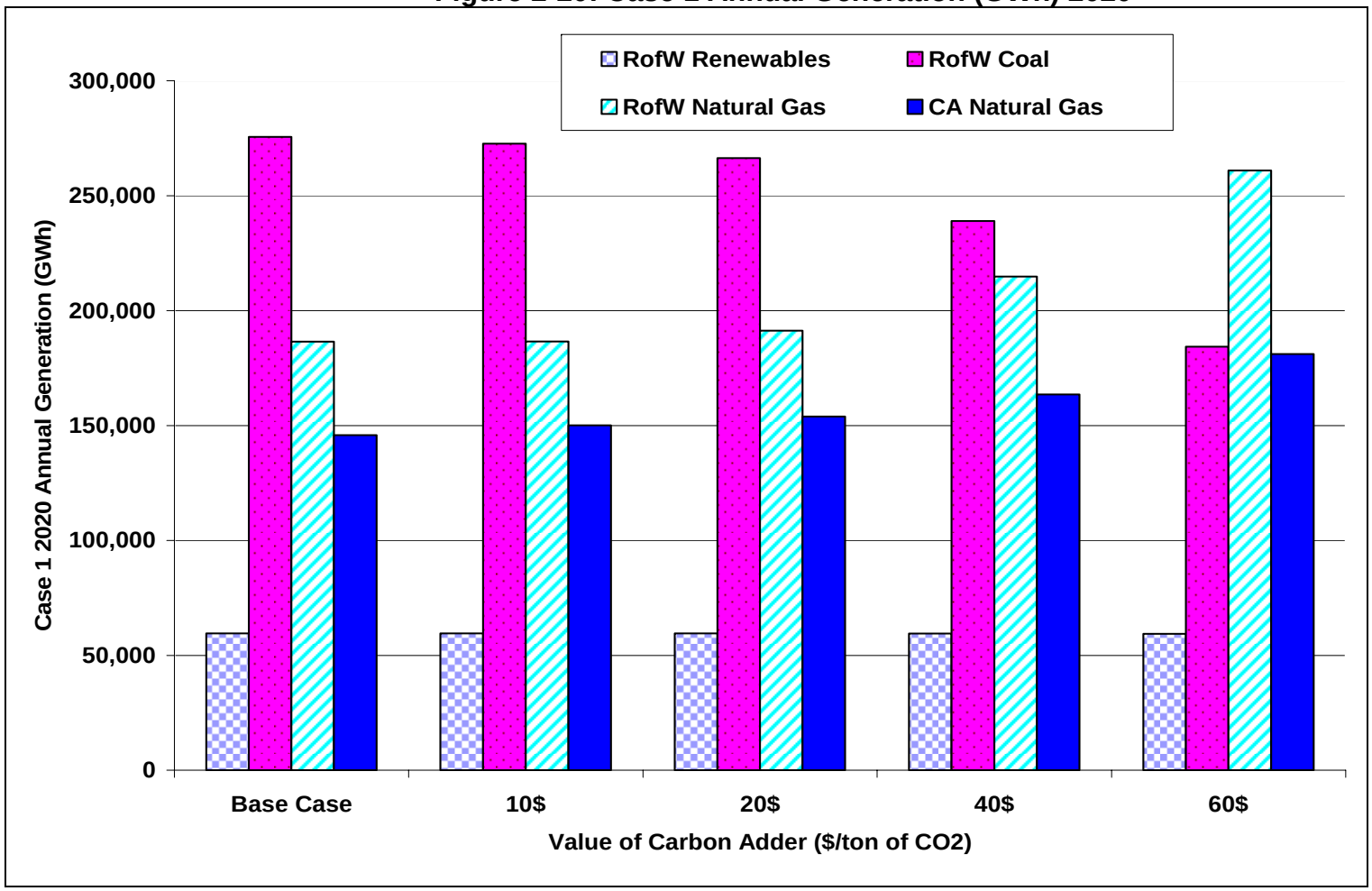
This initial result requires considerably more analysis, beyond the timeframe of the 2007 IEPR, but it illustrates one of the themes flowing from the staff's assessment—that is, California cannot hope to accomplish its greenhouse gas emission reduction goals in the electricity sector in isolation from Rest-of-WECC. The Energy Commission should both communicate these initial results to the ARB and CPUC and undertake additional studies to better understand the implications of various prices attached to CO_2 emissions in the future.

Implications of the Results

Table 2-5 provides an overview of the incremental effects of those cases that California policy makers could pursue alone (Cases 3A, 3D, 3E, 4A, 5A, 5D, and 5E) compared with Case 1B—essentially business as usual. Case 1B reflects staff's expectations of load-serving entity compliance with current requirements or current practice. All of the remaining cases compared to Case 1B reflect the cost and performance differences of these additional emphases on energy efficiency and renewables. Table 2-5 also computes a simple statistic of effectiveness. It measures greenhouse gas emission reductions per thousand dollars of expenditure.

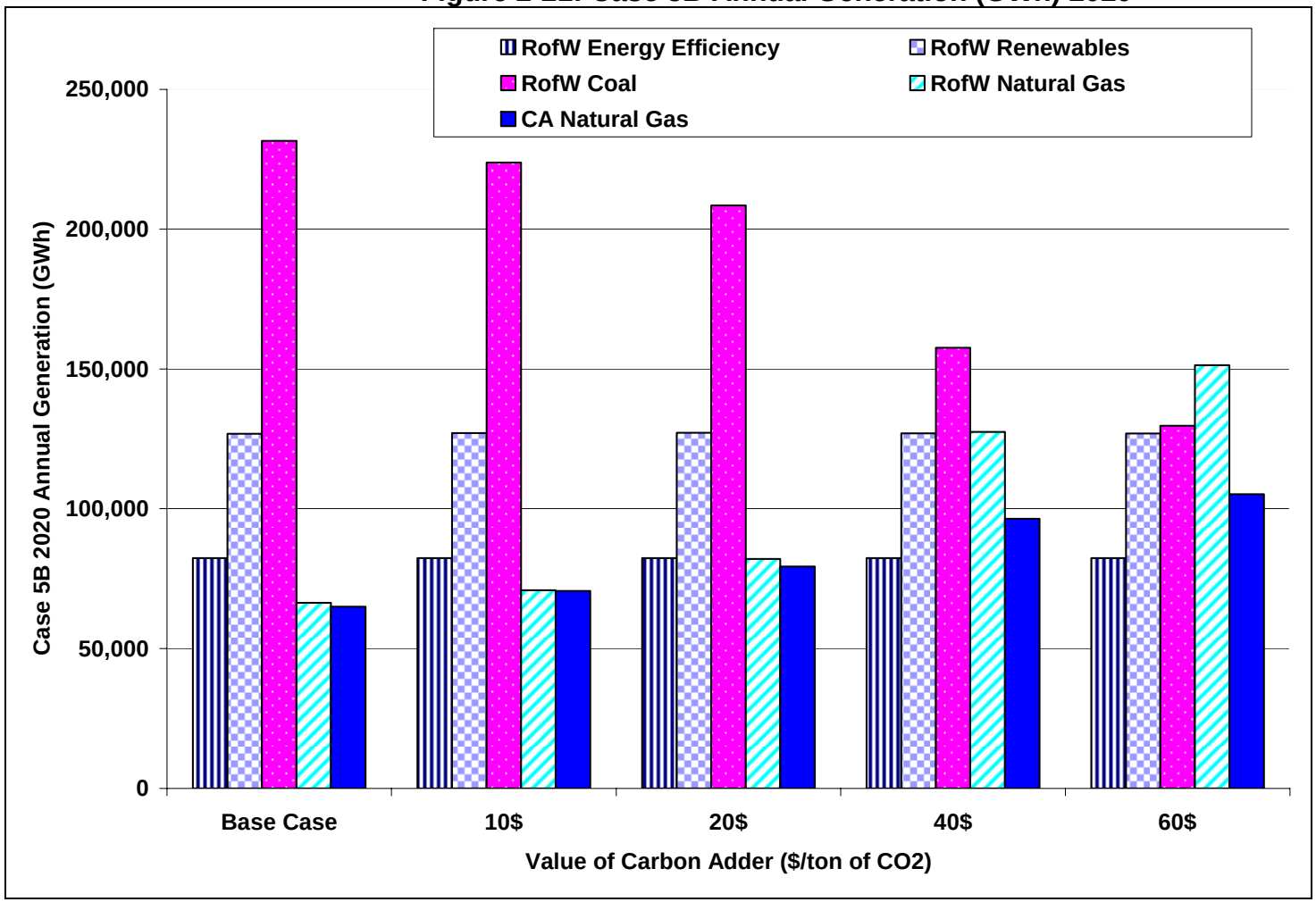
[44] Third Addendum Report, Chapter 3.

Figure 2-20: Case 1 Annual Generation (GWh) 2020



Source: Global Energy Decisions

Figure 2-21: Case 5B Annual Generation (GWh) 2020



Source: Global Energy Decisions, Inc.

Table 2-5: Measuring Cost Effectiveness of Strategies by Assessing Differences from Case 1B

	2020 System Cost Difference	2020 GHG Instate Emission Difference	2020 Reduction ($/ton)	2020 GHG California Responsibility Emission Difference	2020 Reduction ($/ton)
Case 1B	-	-	NA	-	NA
Case 3A	(652,394)	(3,876)	(168.34)	(6,324)	(103.17)
Case 3D	(1,172,584)	(6,624)	(177.01)	(11,196)	(104.73)
Case 3E	(1,569,955)	(8,691)	(180.63)	(14,994)	(104.71)
Case 4A	2,580,912	(5,829)	442.75	(18,085)	142.71
Case 5A	2,053,506	(9,071)	226.37	(24,429)	84.06
Case 5D	1,554,921	(11,411)	136.26	(29,105)	53.42
Case 5E	1,164,144	(13,140)	88.59	(32,100)	36.27

Source: Global Energy Decisions, Inc.

The three levels of energy efficiency (Cases 3A, 3D, and 3E) reflect successively increasing levels of greenhouse gas reduction by 2020. The cost per unit of greenhouse gas reduction from alternative levels of energy efficiency is relatively constant. Most importantly, the cost is

negative, meaning that society is better off with these higher levels than without them even without a carbon cost adder being included. Energy efficiency is less costly than the generating resources it displaces, so not only does it provide a public good in emission reductions, it provides a collective good to the ratepayers funding the activities by saving more in direct fuel expenses and deferred capital cost recovery than the costs of the programs.

A renewables strategy (Case 4A) is clearly more costly per unit of greenhouse gas reduced than is an energy efficiency strategy alone. Here, the rooftop solar photovoltaic costs and benefits are combined with supply side renewable generating technologies. The combined cases (Cases 5A, 5D, and 5E) blend the reduced expenditures for electricity customers with the increased outlays of Case 4A to get both higher total greenhouse gas reductions as well as lower increases in aggregate electricity costs than those from Case 4A alone. From this perspective, Cases 5D and 5E are also preferred to Case 5A since the increased levels of energy efficiency dilute the out-of-pocket costs to electricity consumers while achieving greater aggregate greenhouse gas emissions reductions.

Table 2-5 also illustrates the distinction between instate power generation versus the broader view of California's responsibility for all generation that supports California loads. The California Responsibility columns of Table 2-5 always show much lower $/ton of savings results than the instate generation columns because the same expenditures needed for the preferred measures affect both instate and out-of-state generation. For example, the Case 4A result for renewables measures GHG savings just for instate power plant GHG reductions costs over $400/ton, while taking total power generation emission reductions into account reduces this cost per ton to only $140/ton. Similar effects are shown for all of the cases in varying degrees, because the preferred strategies always have both instate and out-of-state power generation GHG emission reductions.

Limitations of Staff's Analysis

Numerous data and analytic limitations should be considered in interpreting these results. This study has not sought to identify the optimal level of energy efficiency or renewables or the best policy for attaining specific greenhouse gas levels. Due to its design, the study provides broad indications of results from "what if" assumptions that may not be feasible at the cost, or in the timeframe, assumed.[45] Supplemental studies of energy efficiency or supply-side renewable generating technology to devise, and cost out, implementation programs consistent with the scale of the "what if" assumptions are needed. The results are not readily translatable to requirements for any specific load-serving entity.

[45] For example, at the same workshop where the final results of the most aggressive energy efficiency measures for this study were presented by staff, numerous public utilities asserted that such aggressive energy efficiency levels were not possible, at least in their utility's circumstances.

Findings of the Assessment

Although staff's study improves upon weaknesses of previous studies, the results indicative rather than determinative. The study findings are only indicative because of scientific, technological, and institutional uncertainties. Despite staff's caveats, the following findings of this study are sufficiently robust to communicate as part of this IEPR:

- Each of the policy-driven cases which increases the investment in efficiency and renewables beyond current requirements seems likely to fall within the range of 1990 CO_2 emissions. The more intensive preferred resource scenarios would enable a higher contribution to AB 32's 2020 goals than merely attaining 1990 levels.
- Reductions in fossil generation that result from increased penetrations of efficiency and renewables are attributable to the displacement of production from some existing fossil-fueled generation facilities as well as the deferral or elimination of some anticipated fossil facilities.[46]
- Unless costs affecting power plant dispatch are revised, natural gas is found to be the swing fuel in nearly all cases, with coal-based electric generation little affected by simply increasing the levels of energy efficiency and renewables in the resource mix, either in California or Rest-of-WECC.[47]
- Given the assumptions inherent in this Scenario Analyses Project, existing coal generation will be affected by the imposition of a carbon dioxide "adder," whether by cap and trade or tax, but meaningful reductions (10 percent or greater) do not occur until the value reaches $30 to $40 per short ton of carbon dioxide.[48] The displaced coal generation would be replaced by higher generation from natural gas-fueled power plants, both in California and Rest-of-WECC.[49]
- Increased penetration of preferred resources that significantly reduces natural gas usage compared to the overall market can drive down natural gas market-clearing prices, but the magnitude of this result is sufficiently uncertain to be unreliable at this time.[50]
- Assuming a fixed set of technology characteristics and costs, increased penetrations of renewables may increase total system costs as the capital cost additions of these resource types outweigh the production costs savings.[51] The degree of this "penalty" shrinks if natural gas prices increase, but increases if natural gas prices decrease. The uncertainties

[46] Results Report, Chapter 7.

[47] Results Report, p. 120.

[48] Third Addendum, p. 30.

[49] Third Addendum, p. 29.

[50] Second Addendum, p. 30.

[51] Second Addendum, pp. 27 and 31.

about technology cost and performance were not adequately investigated to understand the sensitivity of this conclusion.[52]

Conclusions about Scenario Analyses

The staff's Scenario Analyses Project has the implications for the loading order preferences that have anchored California's electricity policies since 2003. The project has helped to provide a solid basis for understanding the extent to which these strategies need to be intensified if they are to be the means of achieving major greenhouse gas emission reductions for the electricity sector. The degree to which this intensification is successful will determine whether the electricity sector can disproportionately contribute to AB 32's 2020 goals, making up for potential shortfalls in other sectors.

This study has not identified all of the steps necessary—it is a first step in the process of recalibrating our thinking about the level of efficiency and level of renewables needed to achieve major greenhouse gas reductions. We have only limited information about the step-by-step feasibility of developing energy efficiency programs or of achieving the high levels of renewables examined here, much more work must be done to determine the most appropriate methods of implementation.

The results have driven home the reality of interconnectedness of California to the rest of the Western Interconnection that is too easily forgotten in enthusiasm over greenhouse gas emission reduction strategies. Of critical importance in the near term will be solidifying the regional framework initiated by Governor Schwarzenegger with other western states and Canadian provinces. The Energy Commission welcomes the formation of the Western Climate Initiative (WCI) as noted in the recent joint decisions by the CPUC and Energy Commission implementing AB 32. The decisions that California makes unavoidably affect other parts of the West and vice versa.

The ARB process for implementing AB 32 should be grounded in the type of analysis conducted in this project. The CPUC modeling project that intends to identify a specific set of measures that individual load-serving entities can use to comply with the goals established for them by ARB appears to be making use of the analysis and implications developed here. Staff should make every effort to develop cooperative working relationships with ARB and CPUC that can routinely illuminate the California-wide and WECC-wide consequences of greenhouse gas emission reduction strategies. This project and its successor editions complement the more emitter-specific analyses those regulatory agencies will conduct.

[52] Results Report, pp. 226-227.

Portfolio Analysis

Electricity industry restructuring, along with the changes in regulatory requirements and the financial and economic considerations it has affected, has greatly increased risks and added to the uncertainties that utilities and regulators must consider. In the days prior to industry restructuring, investor-owned electric utilities could construct, own, and operate new capacity to match their generation and reliability needs. Utility ownership of both generation and transmission, combined with a guaranteed rate of return, limited their financial risks. Although fuel costs could be a significant portion of total costs, they were relatively low and less volatile than they are today.

Today's environment calls for an electric resource planning process that includes the variety of options, risks, and uncertainties that utilities must consider in evaluating potential resource additions. Choosing a resource addition based on current lowest-cost projections is no longer adequate if the potential for dramatically higher prices is ignored. As Graves, et al., point out in their paper *Resource Planning and Procurement in Evolving Electricity Markets*:

> In particular, the old IRP (Integrated Resource Planning) model generally did not incorporate risk management considerations akin to those now central to utility planning. Perhaps a few scenarios were evaluated, but there was no need to measure and manage dynamically shifting probability distributions for future market prices or utility costs.[53]
>
> The new procurement and planning problem combines traditional least-cost goals with new risk-management objectives. Least-cost planning involves developing a portfolio of resources that has the lowest expected future cost (that is, on average), subject to achieving a given quality of service…Risk management, on the other hand, involves ensuring that the portfolio of power plants, contracts, and financial risk management instruments reduces foreseeable variance (or more generally, uncertainty) around the future expected cost.[54]

Current Investor-Owned Utility Practices

The CPUC recognizes the importance of managing risk by requiring investor-owned utilities to prepare risk reports for their existing portfolios based upon Value at Risk methods. However, these methods address primarily the level of short-term fuel-related risk to which the investor-owned utilities' existing portfolios are exposed and are used to provide guidance regarding the need for additional hedging activities over the short to mid term. They are not used for

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[53] Graves, Frank C., James A. Read, and Joseph B. Wharton, The Brattle Group. 2007. *Resource Planning and Procurement in Evolving Electricity Markets*, p. 19. Prepared for Edison Electric Institute, January 21, 2007.

[54] Ibid., p. 21.

constructing and analyzing a variety of portfolios over the longer term, with the goal of providing guidance regarding the efficiencies of those portfolios and the acquisition of new resources.

As the *2005 IEPR* pointed out, investor-owned utilities currently use opaque least-cost, best-fit criteria to select bids from their solicitations, and the criteria ostensibly focus on ensuring that selected bids match the baseload, peaking, and other physical characteristics of system needs. Filing of procurement plans is required at the CPUC every two years. The plans describe planning and procurement activities the investor-owned utilities will undertake over the succeeding 10-year period. While these plans conform to general requirements specified by Assembly Bill 57 (Wright), Chapter 835, Statutes of 2002, and CPUC orders, they vary greatly in their methodologies and assumptions.

Each investor-owned utility has developed its individual methods to calculate and weigh the criteria, including resource or market value, portfolio fit, credit, viability, transmission impact, debt equivalence, and non-price terms and conditions. Consequently, the criteria are not universally transparent and require a high degree of subjective interpretation and judgment.

As one example of the varying assumptions used by the different investor-owned utilities in their planning processes, Table 2-6 presents their estimates of the 95th percentile natural gas price from 2010 – 2016. In the relatively near term (2010), investor-owned utility estimated natural gas prices vary by as much as 67 percent. By 2016, projected prices vary by 84 percent. Investor-owned utility estimated gas price trends from 2010 to 2016 ranged from a decrease of 15 percent to an increase of 16 percent over the period.

Table 2-6: Reported Natural Gas Prices (95th Percentile, Nominal $)

	2010	2013	2016
PG&E	$17.09	$16.30	$17.21
SCE	$10.21	$10.61	$11.87
SDG&E	$11.06	$9.90	$9.36

Source: Investor-Owned Utility Long-Term Procurement Plans filed with the CPUC December 11, 2006.

The difference in the investor-owned utilities' estimated natural gas prices may reflect different methodologies or input assumptions (for example, historical period used for data, functional form) or, to a small extent, actual differences in the volatility of the gas price faced by each utility. Nevertheless, it is unrealistic that individual utilities could be exposed to such differences in the long-run cost of natural gas, one of the more fundamental planning assumptions; nor is such a wide divergence helpful in formulating statewide energy policy. Additionally, investor-owned utility gas costs are normally passed along to ratepayers; unexpectedly high prices do not unduly burden shareholders. The corrosive influence of "moral

hazard," where financial decisions are made by entities that do not bear the consequences of those decisions, should be obvious.

The impact of longer-run changes in the price of natural gas cannot be mitigated using traditional financial instruments, nor do longer-run changes have the predictability of short-run changes. The price of natural gas over the longer term will depend upon technological, economic, and political factors whose joint impact cannot be easily ascertained. Long-run natural gas price volatility will likely increase over time for several reasons, including increased reliance on remote resources and the risk that consumption in the eastern U.S. could rise dramatically from the curtailment of coal-fired generation due to greenhouse gas concerns, which could further strain the tight U.S. natural gas supply.

If the underlying probability distributions for key drivers of ratepayer costs vary significantly by utility, these variations can be incorporated into an analysis of each utility's portfolios. For example, small differences in expected gas prices can be assumed if indicated, but the broader range of gas prices over which portfolios are evaluated should be similar for each utility. This will not only provide policy makers with a basis for comparing the performance of each portfolio under a common set of futures, but will encourage development of a wider range of portfolios to analyze. While the resource planning process should provide an opportunity for utilities to present evidence about the likely cost of a preferred resource, requiring a range of costs for that resource should facilitate the development and consideration of portfolios suggested over that range.

State-of-the-Art Practices

Over the past year, Energy Commission staff investigated utility resource planning methods and reviewed selected plans to seek information on the state-of-the-art. The resulting report[55] describes planning and evaluation methods used by the three major investor-owned utilities in California as well as other out-of-state utilities and entities.

Energy Commission staff found that a portfolio analytical approach based on Modern Portfolio Theory is a better way to explicitly consider risk when analyzing different combinations of actions that utilities can take to meet future demand. Portfolio analysis enables a decision maker to assess the potential changes to an existing portfolio's risks and costs brought about by adding assets with their own individual risk and cost profiles. The resultant risks and costs of various combinations of assets can then be quantified, and the most efficient portfolios recognized, on a curve referred to as the "efficient frontier." That is, for any given level of risk, decision makers can determine the least expensive portfolio. Conversely, for any given level of cost, they can determine the portfolio associated with the least risk. This method allows consideration of different risk preferences and the examination of various tradeoffs among risks and costs. Both

[55] California Energy Commission. *Portfolio Analysis and Its Potential Application to Utility Long-Term Planning*. CEC-200-2007-012-SF. August 2007.

the cost and risk of an efficient portfolio cannot be simultaneously lowered; costs can only be lowered with an increase in risk. Similarly, one cannot reduce the risk of an efficient portfolio without increasing costs. Indeed, without the explicit consideration of both metrics, it is not possible to forecast the effect of adding the lowest expected cost resource to a portfolio.

As part of its investigation, Energy Commission staff reviewed the long-term procurement plans filed by California investor-owned utilities—Pacific Gas and Electric Company (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E)—at the CPUC on December 11, 2006, and subsequently amended. Staff also reviewed resource plans for 12 western utilities. In most of those cases, candidate resource portfolios were constructed by hand and featured resources that are regionally available and have passed initial cost or performance screening tests.[56] Though this selection of candidate portfolios may simplify the modeling process, it also allows human bias to influence the outcome by limiting the universe from which the optimal portfolio emerges.

Finally, staff also reviewed the Fifth Northwest Electric Power and Conservation Plan (May 2005 update) developed by the Northwest Power and Conservation Council, an "interstate compact" agency comprising the states of Idaho, Montana, Oregon, and Washington. The plan was developed from a regional model that is rooted in portfolio analytical-based techniques. The Council's approach to developing the plan was to test a wide variety of possible resource development plans (portfolios) against 750 futures (scenarios) that describe the behavior of key sources of uncertainty during the planning period. The Council calls this approach to resource planning "risk-constrained least-cost planning." Given any level of risk tolerance, there should be a least-cost way to achieve that level of risk protection.

Resource Planning and Policy Targets

The ideal planning process would begin by considering a wide range of available resource options so that a large number of portfolios designed to meet long-term needs could be constructed and examined. From the most efficient of these, the portfolio that best meets appropriate risk/cost requirements could be chosen. However, a number of existing legal and regulatory constraints and requirements currently either specify resources to include or limit the scope of alternatives that can be considered in constructing long-term plans. These include requirements for minimum amounts of renewables and energy efficiency, as well as limitations on the use of technologies based on coal and nuclear power. A central question in resource planning relates to the extent to which existing requirements and limitations should influence the construction of future portfolios. As pointed out by SDG&E in various forums, for example, its resource planning activities consist to some extent of simply "filling in the boxes."

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[56] Bolinger, Mark and Ryan Wiser. August 2005. *Balancing Cost and Risk: The Treatment of Renewable Energy in Western Utility Resource Plans*. Lawrence Berkeley National Laboratory Report LBNL-58450, p. 20.

An inherent danger in requiring resource plans to assume that targets for preferred resources are met, especially those for individual classes of preferred resources (energy efficiency, demand response, renewable energy), is that the set of portfolios evaluated is then often limited to those that exactly meet the stated targets.

If a balance can be struck between competing common resource planning assumptions, then a similar resource planning balance could perhaps be considered between striving to provide a common set of futures over which to develop and evaluate resource portfolios and acknowledging differences across utilities. Fixed policy targets may fail to adequately recognize that utilities may face, for example, different costs for classes of preferred resources. But even if the possibility of utility-specific targets is considered, portfolios need to be evaluated over a sufficiently wide range of assumptions to provide policy makers with information regarding the potential costs of meeting underlying policy goals under varying circumstances.

A resource planning process also benefits from being informed both by individual utilities' analyses of their portfolio choices and of the larger market by other entities. The latter serves to not only inform policymakers of the potential state- and region-wide impacts of their choices, but also to inform input assumptions made by utilities in the assessment of their individual portfolios.

Implementation Issues

There are numerous issues regarding the details of the specific planning method that could ultimately be implemented, such as the level at which such planning should occur (for example, investor-owned utility service area, regional, statewide), cost parameters to include, how risk should be measured, time frame of the analysis, method and rate of discounting future cost and price streams, wholesale gas and electric price projections, and a host of other elements. Determining the precise method and assumptions required for the actual analysis is properly the subject of a series of workshops or hearings that would bring together a broad representation of stakeholders and regulatory agencies. Many details must be worked out, however. The substantial uncertainty surrounding future gas prices, emission costs, technological advances, and other issues has implications for the efficacy of a process intended to evaluate the risks associated with different utility portfolios and guide future policy decisions. Broader, more general issues must be considered prior to the detailed issues noted above.

Historically, utilities and regulators largely considered cyclical risks in their planning processes, focusing on the cost and reliability consequences of plant outages, low hydro years, near-term fluctuations in demand, and increases in the natural gas price that were, if only implicitly, assumed to be transient. A key characteristic of these risks is their ready application to quantitative evaluation, using historical data. This fact allowed parties to reach consensus on the modeling of these risks, and thus their perceived magnitude.

The long-term risks that should be assessed may be different from those experienced in the past. For example, global climate change may alter precipitation patterns, making historical data incomplete or not applicable. Such a phenomenon might not be important in the 10-year time horizon of an investor-owned utility, but critical in the 50-year time horizon of state's greenhouse gas reduction strategies. Further, risks that are important to a specific investor-owned utility or load-serving entity may not be risks at all from a statewide perspective. For example, loss of bundled service load from an investor-owned utility shifting to an electricity service provider if direct access were to be reauthorized does not change total load, only load attribution to specific load-serving entities. So the perspective of the portfolio assessment can differ depending upon whether it is being conducted for an individual investor-owned utility or for the state of California as a whole.

Recommendations for Common Planning Assumptions and the Resource Planning Process

Any regulatory planning mechanism designed to achieve state policy goals must recognize meaningful differences in the relative costs of preferred resources across utilities. Doing so, however, requires confidence on the part of regulators that the values used by the utilities themselves truly reflect the actual underlying differences in the costs of preferred resources and not other factors (which might include differences in the methodologies and assumptions used in forecasting their future costs).

Costs that should be considered are not only the variable costs of plant operation such as fuel costs, but those associated with the environmental impact of operation. Potential future costs of meeting future greenhouse gas reduction goals must also be considered in near-term commitments to generation choices. Resource planning assessments should, at the least, evaluate the implications of committing to greenhouse gas-emitting resources during the near term for the ability to realize reductions over longer periods.

Resource planning methodologies can illustrate the potential trade-offs between cost and risk for a set of efficient portfolios, but policy makers must decide the appropriate balance between different levels of costs and the associated risks. In light of the potential of portfolio analysis to better inform the supply portfolio choices made by electric utilities and approved by their regulators, the Energy Commission recommends the following:

- The Energy Commission should continue to develop an analytical planning and evaluation method whereby investor-owned utility resource additions can be analyzed using an explicit accounting of risks and costs, such that the resulting portfolio is efficient (given existing constraints of the existing portfolio) and reflects the state's interests in addressing risk and uncertainty. Further, the analytical method should be suitable for providing guidance regarding (1) state energy policy goals and their associated costs and risks as well as (2) the overall construct of investor-owned utility portfolios and methods whereby their efficiencies may be maximized while meeting future energy needs and state policy goals.

- A core function of future *Integrated Energy Policy Reports* should be to provide periodic independent analyses of resource portfolios using the analytical methodology developed. Such analyses would be at various levels: that is, investor-owned utility specific, regional, or statewide, as necessary.
- The Energy Commission should sponsor a series of workshops and hearings that would include a broad representation of stakeholders and regulatory agencies in order to formulate the specific details of an analytical planning and evaluation method.

AB 57 requirements, as augmented by CPUC regulations and other requirements of state law, specify many aspects of utility planning. Thus, any planning-related changes must take existing requirements into account. Within consideration for those legal regulations, the Energy Commission makes the following recommendations:

- The staffs of the Energy Commission and CPUC should collaborate to integrate the analytical method into the Long-Term Procurement Planning process so that it can provide the basis for formulating and reviewing investor-owned utility portfolios.
- The CPUC should revise the long-term procurement plan procedures to explicitly incorporate portfolio analysis techniques. Publicly owned utilities should follow suit as they pursue procurement of resources.
- The CPUC should recognize that state energy policymaking and the transparency of the associated analytical process is best served by a method using common assumptions to the maximum extent practicable. While taking into account minor regional variations in costs, risks, and prices that may exist among different regions or investor-owned utilities, there should not be major variations in important risk drivers such as the underlying probability distributions for natural gas price trends, carbon costs, and renewable technology costs, for example.

Cost of Generation

As a step to improve the planning process for comparing alternatives and to increase the transparency of such analysis, the Energy Commission substantially overhauled its cost of generation model and input data. The Cost of Generation Model[57] uses capital, financing, and operational cost data to calculate levelized[58] costs of generation for various traditional and

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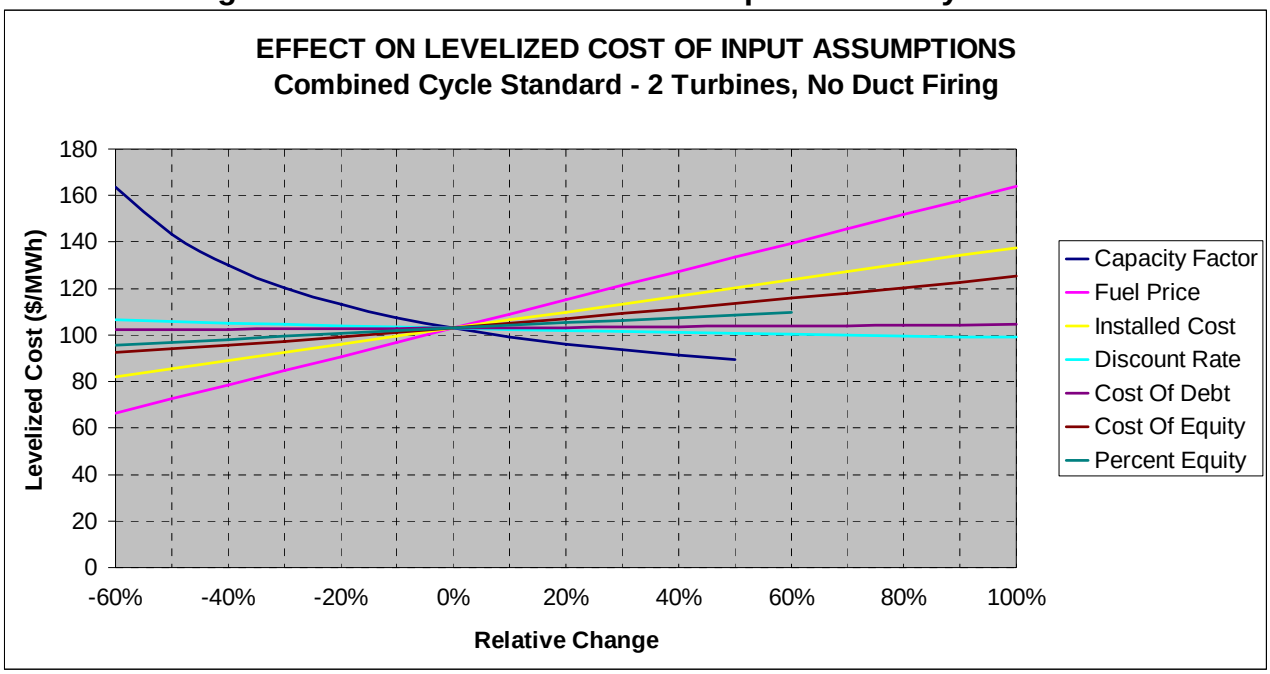
[57] *Comparative Costs of California Central Station Electricity Generation Technologies (2007 Update)*, draft staff report, June 2007, CEC-200-2007-011-SD provides a description of the cost of generation model, summarizes the calculated levelized costs, and provides the supporting data and a description of how that data was collected and processed.

[58] Levelized cost is the constant annual cost that is equivalent on a present value basis to the actual annual costs, which are themselves variable.

alternative electricity generating technologies. First introduced in the *2003 IEPR*, the cost of generation model has been extensively revised for the *2007 IEPR* to make it more accurate, user friendly, flexible, transparent, and better documented. The model has reasonable accuracy for gas-fired technologies (less information is available for renewable technologies), except for the extraordinary uncertainty of fuel price forecasts. Figure 2-22 demonstrates the sensitivity of the updated cost of generation model. The principal weakness of even the revised model, however, remains its inability to determine how technology costs will evolve through time. This is a research-intensive and judgmental task that was beyond the scope of staff's resources in the 2007 IEPR cycle. Because of the increasing role that newer technologies—especially in the renewables sector—are likely to play in California's future generation mix, the Energy Commission commits to using the 2009 IEPR cycle to extensively refine the input data used for developing technologies and to establish a process, working with industry and academic experts, to properly update technology costs over time.

Figure 2-22: Cost of Generation Sample Sensitivity Curve



Source: California Energy Commission

The Role of Conventional Resources in Meeting Demand and AB 32 Goals

Conventional generation resources that use natural gas, coal, and nuclear energy currently account for about 70 percent of California's electricity supply.[59] Even if California could achieve the maximum potential energy efficiency and renewable development opportunities identified to date, for the foreseeable future, the state will continue to rely heavily on these resources. However, each of these resources faces its own challenges.

Natural Gas

Since California's electricity market was deregulated in 1998,[60] the Energy Commission has licensed 62 power plants totaling nearly 24,000 megawatts of new capacity. During that same period, another 2,600 megawatts of electric capacity was licensed by local agencies. Nearly all of this capacity (99 percent) will be fueled by natural gas. If built and operational, this new generation would be enough to supply more than 40 percent of the state's peak demand. However, as shown in Figure 2-23, only 36 plants—12,910 megawatts—have come on line, with an additional 2,278 megawatts currently under construction. Although 13 plants, totaling 8,361 megawatts, have been approved, they have not moved forward with construction because they lack power purchase agreements needed to obtain their financing. The problems created by continued sluggishness in utility long-term procurement were a focal point of the *2005 IEPR*.

Natural gas is cleaner than other petroleum-based fuels and has become the market's fuel of choice for most new power plants because of its environmental benefits. It now provides more than 41 percent of the state's electricity. At the same time, volatility in natural gas prices can have severe financial impacts on California's economy because the regulatory process does not adequately value the price risk associated with natural gas in its electricity portfolio. Portfolio analysis conducted for this IEPR suggests a strong tendency for utilities to under-invest in supply options like efficiency and renewables, which can hedge this gas price exposure over the long term. As the state's use of natural gas continues to increase, the tension between reducing the environmental impacts of electricity generation and reducing California's overwhelming dependence on a single fuel also increases.

Coal

California gets nearly 16 percent of its electricity from coal, almost exclusively from out-of-state facilities. Although coal power is cheap, it also emits large quantities of carbon dioxide (CO_2). As required by Senate Bill 1368 (Perata), Chapter 568, Statutes of 2006, the state has set a

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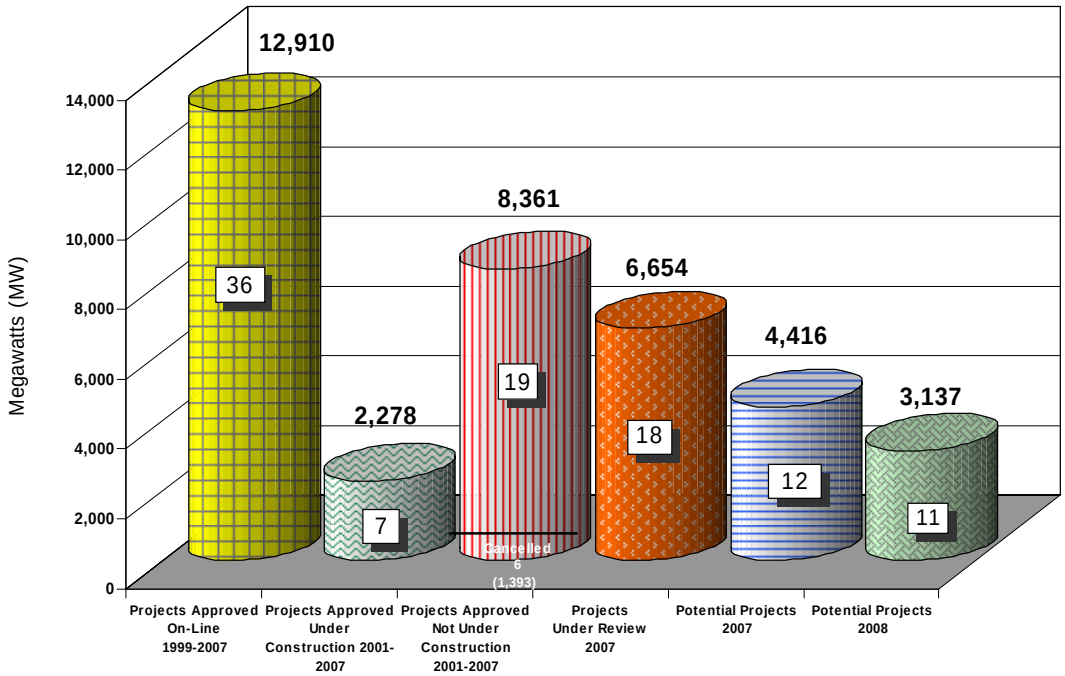
[59] California Gross System Power, 2006. The remaining 30 percent comes from renewables (11 percent) and large hydroelectric (19 percent).

[60] Assembly Bill 1890 (Brulte), Chapter 854, Statutes of 1996.

greenhouse gas emission performance standard for all new long-term investment in or purchases of baseload electricity generation by utilities. SB 1368 precludes new reliance on power plants with carbon emissions greater than those of a modern natural gas combined cycle plant: 1,100 pounds per megawatt-hour.

Figure 2-23: Power Plant Application Status 1999–2008



Source: California Energy Commission.

The most likely way for coal plants to meet this standard is through the use of advanced coal technologies[61] combined with geologic carbon sequestration, where carbon emissions are captured and stored underground in geologic formations for hundreds of years. However, sequestration has not yet been demonstrated at a commercial scale and investor confidence in this technology appears low, making it unlikely that plants using this technology will be able to contribute to California's AB 32 goals for 2020.

AB 1925 (Blakeslee), Chapter 471, Statutes of 2006, requires the Energy Commission and Department of Conservation to develop "recommendations for how the state can develop parameters to accelerate the adoption of cost-effective geologic sequestration strategies for the long-term management of industrial carbon dioxide." In October 2007, the Energy Commission

[61] Plant types considered "clean" include integrated gasification combined cycle; pulverized coal with "ultra-supercritical" main steam conditions, like a thermodynamic state well above the pressure and temperature of the critical point of water; and circulating fluidized-bed combustion plants with supercritical main steam conditions.

released *Geologic Carbon Sequestration Strategies for California: The Assembly Bill 1925 Report to the California Legislature.*[62]

The report finds that while there is generally a large storage resource potential, more detailed site-specific study will be needed in many areas. Because of the need for appropriate infrastructure and expertise, it is likely to be more economic for carbon capture and sequestration projects to be affiliated with CO_2 enhanced oil recovery projects in oil and gas fields than for carbon to be isolated simply for long-term storage purposes.

Two new power plants in California — the proposed BP-Rio Tinto-Edison Mission Energy petroleum coke gasification project in Carson (Los Angeles County) and the Clean Energy Systems oxy-combustion plant in Kimberlina (Kern County) — include designs for CO_2 capture, with the prospect that the CO_2 could be sold for commercial purposes, including use in enhanced oil recovery.

Elsewhere in the U.S., the Department of Energy has ongoing projects to facilitate carbon capture and sequestration, including seven regional partnerships that include about 40 states. These partnerships are conducting small scale sequestration demonstrations and providing assessments and databases of large emission sources and candidate storage sites within the U.S.[63] The WESTCARB partnership, led by the Energy Commission, includes California, Nevada, Oregon, Washington, Arizona, and Alaska, as well as British Columbia.

In addition, the FutureGen Project, the first project to combine coal gasification for electric power and hydrogen generation with carbon sequestration at a commercial scale, has recently completed its Environmental Impact Statement and risk assessments of candidate construction sites in Illinois and Texas.

Advanced coal technology with carbon sequestration is considered by some as a promising future low carbon source. This is particularly important to regions like the eastern United States or portions of the European Union with a high dependence on coal. Developing economies, like China and India, which intend to greatly expand their use of coal, may find it impossible to control their CO_2 emissions without breakthroughs in advanced coal technologies. However, investor confidence in these alternatives is presently low because sequestration technology is still under development and has not yet been demonstrated at a commercial scale. The inability of nascent carbon markets to establish a sufficiently high and sufficiently stable price for carbon complicates these prospects. Because an uncertain payment stream raises the cost of borrowing capital, uncertainty in the carbon markets can raise the cost of capital for cleaning up fuels with high greenhouse gas emissions.

Citibank recently downgraded its assessment of coal stocks, in part because of slow industry progress toward clean coal technologies. In its July 18, 2007, *North American Metals & Mining*

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[62] California Energy Commission, CEC-500-2007-100-SD, September 2007.

[63] http://www.netl.doe.gov/technologies/coalpower/futuregen/EIS/.

Newsletter, Citigroup noted ". . . prophesies of a new wave of coal-fired generation have vaporized, while clean coal technologies such as IGCC [integrated gasification combined cycle] with carbon capture and coal-to-liquids remain a decade away, or more" and "We expect anti-coal politics to intensify, with carbon constraints almost certain to pinch." Coal stock prices dropped after HSBC and Citigroup downgraded.[64]

It is challenging to accurately assess the economics of carbon capture and sequestration because no policy exists to establish a price for CO_2 in the marketplace. Preliminary estimates for CO_2 capture and compression — by far the largest part of the entire cost of carbon capture and sequestration — are $50 to $90 per metric ton of CO_2 removed. This does not include the cost of transporting CO_2 to the sequestration site. Other issues that could significantly increase costs include permitting, monitoring, acquiring property rights, and liability.

However, economists' estimates of the carbon price needed to stabilize CO_2 concentrations at 550 parts per million, higher than the 450 parts per million levels recommended by the Intergovernmental Panel on Climate Change,[65] range from $5 to $30 per metric tonne by 2025. The Intergovernmental Panel on Climate Change came out with similar figures of $20-$50 per tonne in 2020-2030. A $20 per tonne carbon price could raise electricity prices in the U.S. by 14 percent, while a $50 per tonne carbon price could raise prices by 35 percent.[66]

Because of the technological, economic, and regulatory barriers facing commercial-scale application of carbon capture and sequestration, the Energy Commission does not believe advanced coal with carbon sequestration will yield a significant amount of electric generation in the 2020 timeframe. It remains an important national, and international, research and commercialization priority, however. The Energy Commission's detailed findings and recommendations on the topic are available in its report *Geologic Carbon Sequestration Strategies for California: The Assembly Bill 1925 Report to the California Legislature*.[67]

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[64] John Hill, *Coal: Missing the Window. Downgrading on Stubborn Stockpiles, Hostile Politics.* Citigroup, July 18, 2007. See also *UPDATE: Coal Stocks Tumble on Sweeping Citigroup Downgrade.* <http://money.cnn.com> accessed July 20, 2007.

[65] The Intergovernmental Panel on Climate Change reports a 450 ppm CO_2 equivalent as substantially reducing the expected magnitude, impact, and rate of climate change from business as usual scenarios. IPCC, 2007. Climate change 2007: Mitigation. Contribution of Working group III to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change [B. Metz, O. R. Davidson, P. R. Bosch, R. Dave, L. A. Meyer (eds)], Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA. http://www.ipcc.ch/SPM040507.pdf, pp. 22-25.

[66] Richard Newell, Duke University, as cited in Economist.com, *The Final Cut,* May 31, 2007 <http://www.economist.com/surveys/displaystory.cfm?story_id=9217868>.

[67] California Energy Commission, CEC-500-2007-100-SD, September 2007.

Nuclear

Nuclear power provides nearly 13 percent of California's electricity supply from three plants: the Diablo Canyon and San Onofre nuclear power plants in California, and the Palo Verde nuclear power plant in Arizona. Nuclear power has lower greenhouse gas emissions than fossil fuels. Because fuel represents a small portion of their costs, nuclear plants are also largely insulated from fuel price volatility, making them relatively inexpensive to operate.

The U.S. is currently experiencing what has been called a "nuclear renaissance" as this technology is increasingly seen as a mitigation strategy for global climate change. Spurred by federal regulatory initiatives, financial incentives in the Energy Policy Act of 2005, increased volatility of fossil fuel prices, and continuing growth of energy demand, nuclear power is gaining greater visibility. About half of the nuclear power plants in the U.S. have received renewals to extend their operating licenses by 20 years, and some U.S. utilities and merchant generators have expressed interest in building new nuclear plants.

However, nuclear power still faces a number of barriers, including high capital costs, regulatory risks associated with the use of once-through cooling, and potentially severe effects from accidents, acts of nature, or terrorism. Within California, development and construction of any new nuclear power plants in the state are legally contingent upon the demonstration and approval of the technologies needed to reprocess or dispose of the spent fuel generated in nuclear reactors.[68] In the *2005 IEPR*, the Energy Commission reaffirmed its finding made in 1978 that "a high-level waste disposal technology has been neither demonstrated nor approved." The report also found that "reprocessing remains substantially more expensive than waste storage and disposal and has substantial adverse implications for the U.S. effort to halt the proliferation of nuclear weapons."

Although California consumers have paid over $1 billion to support federal efforts to develop a permanent repository for spent nuclear fuel at Yucca Mountain, Nevada, the repository is not expected to open until 2021, if at all.[69] In the absence of a federal repository, California must plan for the continued accumulation and interim storage of high-level radioactive waste at existing reactor sites, even though none of the sites were originally designed for such long-term use. California needs a comprehensive assessment of the implications of indefinite reliance upon at-reactor interim spent fuel storage and should evaluate the viability of centralized interim fuel storage proposals.

Reprocessing of spent fuel is more expensive than waste storage and disposal and continues to have implications for U.S. nonproliferation efforts. While the federal government has proposed a major new reprocessing initiative (GNEP), significant questions remain regarding reprocessing technologies available today and those GNEP proposes.

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[68] California Energy Commission reports related to this legislation are available on its website: http://energy.ca.gov/2007_energypolicy/documents/index.html#06252807

[69] Ibid.

Another barrier to the development of nuclear power is cost. Ironically, the recent surge in interest has prompted a sharp increase in the price of nuclear fuel in anticipation of a large worldwide increase in demand. In addition, while nuclear plants are relatively cheap to run, they cost a lot to build and in the past have required extraordinary ratepayer guarantees to cover interest costs during construction. Development costs for new nuclear plants are uncertain, as very little reactor development has occurred in the U.S. for the past 20 years. However, the Watts Bar project in Tennessee, which began operations in 1996, took 23 years to complete at a cost of $6.9 billion.[70] Internationally, the Areva nuclear plant in Finland continues to experience delays — most recently announcing that on-line operations may be postponed from 2009 to 2011 — and is thought to be nearly $1 billion over budget.[71]

Unlike natural gas and coal power plants, which use modular components built at a factory and trucked to the site for assembly, reactor projects are built on site and require large capital investments and very long lead times. Developers of new plants could face extreme cost overruns comparable to the rapid inflation recently experienced in the construction industry which nearly doubled the price of building a coal plant between 2002 and 2006. Some developers and utilities, however, believe that new technologies, federal subsidies, standardized reactor designs, revised federal licensing procedures, and relatively low interest rates will combine to keep costs down.

Assembly Bill 1632 (Blakeslee, Chapter 722, Statutes of 2006) poses another challenge to the development of new nuclear power plants in California and perhaps to the license extensions for existing plants. The bill requires that the Energy Commission determine the potential vulnerability of existing large baseload generation facilities—1,700 megawatts or greater—to a major disruption due to plant aging or an earthquake. The bill's 1,700-MW threshold applies to California's two operating nuclear power plants. It further directs the Energy Commission to assess the state and local costs and impacts from the accumulating waste at California's nuclear plants in the absence of a long-term, permanent federal waste disposal solution for these wastes.

In light of the obstacles involved in developing new nuclear power plants, the Energy Commission does not expect significant contributions from this generation source toward the state's AB 32 goals by 2020, and makes the following recommendations regarding nuclear energy:

- The state should take an active role in the Yucca Mountain licensing proceeding, currently planned to begin in June 2008, to ensure that California's interests are protected.

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[70] "Atomic Renaissance," The Economist, September 8th-14th, 2007, p. 71.

[71] Energy Business Review, August 13, 2007, "Areva-Siemens Consortium Announces Delay of Finnish Nuclear Reactor," http://www.energy-business-review.com/article_news.asp?guid=80B1249C-4590-4A5A-A624-AC9AD3901FA2.

- The state should challenge the U.S. Department of Energy's (DOE) inadequate response to potential impacts identified by California during the Yucca Mountain Environmental Impact Statement and review process.
- The Energy Commission should continue to participate in DOE and regional planning activities for nuclear waste shipments.
- The Energy Commission should work with federal and state regulators, nuclear plant owners, and Institute of Nuclear Power Operations (INPO) to develop a means to usefully incorporate INPO reviews and ratings of reactor operations into a meaningful public process while maintaining the value of the INPO reviews as confidential and candid assessments.
- Southern California Edison and San Diego Gas & Electric should, as part of their long-term procurement plans, develop a contingency plan to replace generation from Palo Verde should it be shut down for an extended period.
- The Energy Commission should continue to assess the reliability implications for California's operating nuclear plants of federal and state once-through cooling regulations.

Southern California Faces Unique Challenges

As the state's demand for electricity increases, Southern California in particular continues to be vulnerable to supply shortages. Southern California utilities continue to rely on electricity purchased from aging power plants under short-term contracts, threatening reliability in the area. In addition, 13 of the state's 19 coastal power plants – which face challenges from their use of ocean water for cooling – are located in the southern part of the state. Southern California air basins also have some of the worst air quality in the nation, resulting in stringent local air quality requirements and short supplies of emission credits for new electricity generators. This shortage will be exacerbated by the California ISO's Southern California local capacity requirements – enough generation to ensure uninterrupted service in all hours even if a major power plant or transmission line fails – which have increased such that in 2008, the Los Angeles Basin is required to meet nearly half of its electrical load with local generating capacity.

Aging Power Plants

As part of its *2004 IEPR Update*, the Energy Commission identified a study group of older power plants to evaluate the impacts of those aging plants on the state's resources. More than 80 percent of the plants identified in the study were located in the southern part of the state. In the *2005 IEPR*, the Energy Commission urged the state's utilities to undertake long-term planning and procurement to allow for the orderly retirement or repowering by 2012 of the aging plants in that study group.

However, to date only Pacific Gas and Electric (PG&E) has submitted a long-term procurement plan that contains enough new generation and transmission investments to avoid relying on aging plants after 2012. In contrast, Southern California Edison (SCE) relies on these plants

through 2016, and San Diego Gas and Electric's (SDG&E) plan relies on operation of the aging Encina facility throughout its planning period (although the Encina owner has announced plans to replace the old plant with a modernized design better suited to evolving loads and dispensing with ocean water cooling).

The Energy Commission submitted comments in the CPUC's long-term procurement proceeding recommending that the CPUC direct SCE and SDG&E to file an assessment of regional need that assumes the phased retirement of the aging plants identified in the *2005 IEPR's* Transmittal Report to the CPUC, with the CPUC revising its range of need accordingly. Further, the Energy Commission recommended that the CPUC direct SCE and SDG&E to either (1) conduct solicitations aimed at replacing these aging plants or (2) identify transmission, demand response, energy efficiency, or renewable resources to replace or offset the generation needed from these plants.

In its Scenario Analyses Project, the Energy Commission evaluated specific retirements and replacements of older plants in the SCE service area. The results identify which specific plants might be more logical to repower, how replacement plants interact with the preferred loading order resources necessary to achieve the state's greenhouse gas goals, and what transmission upgrades are needed to eliminate some facilities altogether.[72] Both SCE and the California ISO endorsed the assessment as a reasonable first step, but identified additional elements needing further study.

The California ISO has also proposed a study related to reducing the state's reliance on aging plants and those that use once-through cooling technologies. The goal of the study is to develop plans that take into consideration a variety of scenarios to facilitate retirement and replacement of these facilities as well as alternative solutions such as transmission, distributed generation, and load management programs.[73] This study will need to carefully consider issues surrounding once-through cooling and restrictions on emission credits in Southern California, discussed in more detail below.

Once-Through Cooling

Nineteen coastal power plants in California use once-through cooling, the use of seawater to recondense superheated steam after it has been used to generate power. This practice can have significant impacts on marine organisms and ocean habitat.

In recognition of these impacts, the U.S. Environmental Protection Agency (U.S. EPA) in 2004 issued its 316 (b) Phase II rule to regulate once-through cooling systems for existing large power

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[72] Second Addendum Report, Appendix A.

[73] *Mitigation of Reliance on Old Thermal Generation Including Those Using Once-Through Cooling Systems*, presentation by Larry Tobias, California ISO, September 21, 2007, http://www.caiso.com/1c5e/1c5edff632c50.pdf.

plants. The regulations established a series of "best technology available" options that created flexibility for facility owners to comply with the new regulations. The same year, the California Legislature enacted the Ocean Protection Act, which created an Ocean Protection Council to coordinate actions of state environmental regulatory agencies to improve the state of ocean ecosystems.

The *2005 IEPR* directed the Energy Commission to work with other state agencies to address once-through cooling issues in the broader context of protecting the state's fragile coastal marine ecosystem. Also in 2005, the State Water Resources Control Board (SWRCB) initiated a proceeding regarding the U.S. EPA's 316(b) regulations, followed in 2006 by a proposed SWRCB policy to strengthen regulation of cooling water intake structures.[74] SWRCB and the Ocean Protection Council have initiated their own studies of the fleet of power plants using ocean water for cooling, focusing principally on the aging power plants in Southern California studied by the Energy Commission in its policy on repowering/retirement and by the South Coast Air Quality Management District for emissions cleanup.

In 2007, the Second Circuit Court of Appeals approved a challenge to the 316(b) regulations in *Riverkeeper v U.S. Environmental Protection Agency*, saying that regulations for existing large power plants did not conform to the Clean Water Act.[75] The court upheld U.S. EPA's interpretation of "adverse environmental impact[s]" from once-through cooling and affirmed that the Clean Water Act requires such impacts to be minimized through the use of "best technology available." The decision also found that off-site restoration, cost benefit tests, and other exemptions to the technology requirements did not meet the intent of the Clean Water Act. As a result of this ruling, the U.S. EPA suspended its 316(b) regulations for large existing power plants and advised the states to use "best professional judgment" on specific permit renewals and new applications, with a new rulemaking planned to begin in late 2007.[76]

Some progress has been made in reducing the use of once-through cooling in the state. Five of the 19 power plants that use once-through cooling have proposed switching from once-through cooling: El Segundo, Encina, Gateway, Humboldt, and South Bay.

California's policy makers want to encourage retirement of the remaining steam boiler plants in California and encourage development at those sites of cleaner, combustion-based technologies that operate at higher efficiency and thereby reduce the demand for natural gas. However,

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[74] *Scoping Document and Proposed Statewide Policy on Clean Water Act 316(b) Regulations,* California State Water Resources Control Board, June 13, 2006. http://www.waterboards.ca.gov/npdes/docs/cwa316b_scoping.pdf.

[75] http://www.ca2.uscourts.gov:8080/isysnative/RDpcT3BpbnNcT1BOXDA0LTY2OTItYWdfb3BuLnBkZg==/04-6692-ag_opn.pdf#xml=http://10.213.23.111:8080/isysquery/irl981e/1/hilite

[76] "Discharge Permits: EPA Suspends Cooling Water Rule in Response to Second Circuit Decision," vol. 38, Env't Rep. (BNA), No. 27, at 1481 (July 6, 2007).

planning for investment in capital-intensive projects like new power plants must incorporate the risk that applications could be substantially delayed or denied if once-through cooling is used.

Nuclear plants that use once-through cooling present special challenges. Because of their size, these facilities use more seawater than gas-fired plants use. The recently suspended 316(b) regulations for existing large power plants contain a safety exemption for nuclear plants that use once-through cooling. The court affirmed in *Riverkeeper II* that U.S. EPA had appropriately addressed the nuclear safety issue in *Riverkeeper I*, stating, "We defer to the EPA's determination that this compliance alternative ensures that any safety concerns unique to nuclear facilities will prevail over application of the general Phase II requirements." Nuclear Regulatory Commission officials testifying this summer at the Energy Commission's IEPR workshops on nuclear power indicated an intent to defer to determinations of the State Water Resources Control Board.

New Air District Rule Limits Use of Emissions Credits

In the South Coast Air Basin, the supply of emission reduction credits are limited which constrains the ability to either site new power plants or repower existing ones.[77] One option to address this constraint is the use of priority emission reserves—emission credits that have been set aside by the air district for use by entities that serve a public interest.

However, the South Coast Air Quality Management District (SCAQMD) recently adopted Rule 1309.1, which limits the use of priority reserve emission credits for power plants. The rule establishes stringent emission rates for nitrogen oxides (NOx) and coarse particulate matter (PM10) and a requirement that developers obtain a long-term (one year) power sales contract and a license from the Energy Commission before the SCAQMD board will decide whether to release priority reserve credits for that facility. In addition, municipal-owned plants will only be given credits enough to build projects that serve their native load. In addition to these constraints, the SCAQMD limited the total amount of credits available for in-district generation to 2,700 MW of generation, and requires each applicant to go before the board of directors prior to release of the credits.

The rule does allow the option for any power plant applicant to petition the SCAQMD board for a waiver of the requirement for a long-term contract or to go over the 2,700-MW limit provided the applicant can demonstrate that the power plant is needed in the Basin. In order to inform its decision-making, SCAQMD is funding its own study of supply/demand, potentially duplicating the Energy Commission's planning activities.[78]

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[77] SCAQMD severely limits the offsets a repowering facility can use to satisfy air quality permit requirements by only acknowledging the plant's recent operating history, not the permitted values for the original facility.

[78] The construct of SCAQMD Rule 1309.1 seemingly threatens the Energy Commission role in licensing power plants. Follow -p efforts are required to clarify SCAQMD intentions.

Grid Support/Local Capacity Requirements

Beginning in 2007, the California ISO placed additional resource adequacy[79] requirements, known as local capacity requirements,[80] on load-serving entities. These requirements are intended to provide sufficient capacity on call to the California ISO to address alleviate transmission or generation outages. For 2008 and beyond, the California ISO convinced the CPUC to endorse another load pocket in the Ventura/Big Creek area, which will require more existing (and aged) Southern California facilities to be contracted for capacity. In addition, Path 26 — a crucial link between SCE and PG&E electric grids — is now recognized as a constraint in resource adequacy. This further obligates entities serving loads in Southern California to contract with existing power plants located there, even if they are more expensive (and more polluting) than those located in Northern California. As a result of CPUC Decision 06-07-029,[81] beginning in 2008 additional emphasis will be placed on contracting with generators located within Southern California, highlighting the nexus between limited generation and transmission-constrained portions of the grid.

Next Steps

Conditions limiting generation development and technology choice in coastal areas of Southern California require coordinated decisions and actions between all agencies to avoid reliability problems. Some incumbent merchant generators understandably question the *2005 IEPR* policy and want "market forces" alone to drive decisions on retirement or repowering.[82] But as discussed earlier in this chapter, existing barriers (including regulatory inertia) can allow "market forces" to protect an exceptional level of economic inefficiency. The *2005 IEPR* described at length the economic cost to utility customers of relying on outdated and inefficient steam boilers. More study is proposed, and California ISO technical staff has formed a transmission study group encouraging the participation of all relevant stakeholders, but their work may not be complete for 18 months.

Concerted effort by the state's energy agencies is needed to ensure economic, reliable, and sufficient electric supplies in Southern California. At the same time, the state needs to step up its efforts to evaluate the impacts of retiring, repowering, or replacing aging generation

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[79] "Resource adequacy" includes generation requirements needed to satisfy system and local capacity reliability standards and load-serving entity acquisition of resources that can meet those requirements.

[80] These requirements replaced most direct reliability must run contracts between the California ISO and generators.

[81] California Public Utilities Commission, July 20, 2006, <http://www.cpuc.ca.gov/published/Final_decision/58268.htm>.

[82] Comments of Mirant California on the California Energy Commission's August 16th Workshop on Aging Power Plants (Docket No. 06-IEP-1M), August 31, 2007.

resources with resources compatible with the state's air, water, and greenhouse gas goals, as well as the economic interests of its utility customers.

Toward this end, the Energy Commission recommends the following:

- The Energy Commission, the CPUC, the California ISO, and other interested agencies such as State Water Resources Control Board and SCAQMD should work together to complete the studies needed to better understand the impacts of retiring, repowering, and replacing aging power plants, particularly in Southern California.
- As originally articulated in the 2005 IEPR, the CPUC should require that IOUs procure enough capacity from long-term contracts to allow for the orderly retirement or repowering of aging plants by 2012.

Retail Price Forecast

Retail prices are difficult to predict over time since they are subject to underlying costs and rate design choices made by regulators. Most retail price forecasts are simply current rate structures projected out over time and applied to forecasted changes in operating costs. The process of developing the 2007 IEPR retail price projection experienced the same over-simplification and misleading optimism that plagued the 2003 and 2005 IEPR cycles. Although virtually all utility submittals to the Energy Commission call for retail prices to fall, these forecasts do not consider the cost of infrastructure improvements and are premised on extremely optimistic assumptions about the price of natural gas. The Energy Commission will re-evaluate the wisdom of expending state and utility resources on a process so vulnerable to public relations instincts.

Transmission Expansion

The achievement of state greenhouse gas policy objectives by the electricity sector will depend to a large degree on the interconnection and integration of renewable resources into the state's transmission grid. California must overcome ongoing transmission planning, permitting, financing, and integration barriers to accelerate the transition to a carbon-constrained generation base. In addition, California utilities must ensure that transmission projects that meet traditional reliability, congestion management, and economic objectives are developed in a timely manner. Actions are underway at the state and federal levels to address these barriers. The joint IEPR/Electricity Committee draft *2007 Strategic Transmission Investment Plan* prepared in support of the 2007 IEPR proceeding describes the state's transmission challenges and provides recommendations to overcome them.[83] The report also makes recommendations regarding in-state transmission corridor planning and in-state transmission projects.

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[83] California Energy Commission, *2007 Strategic Transmission Investment Plan*, http://www.energy.ca.gov/2007publications/CEC-700-2007-018/CEC-700-2007-018-CTD.PDF

CHAPTER 3: Meeting Energy Needs with Efficiency and Demand Response

For the last three decades, California has led the nation in promoting and using energy efficiency programs. While the per capita electricity consumption in the rest of the country continues to escalate, California's per capita electricity consumption leveled off in the mid-1970's and has remained relatively flat, between 7,200 and 7,800 kilowatt hours (kWh) per person—a success attributable in large part to energy efficiency initiatives in the form of building efficiency and appliance efficiency standards and utility-sponsored incentive programs.[84]

Energy efficiency and demand response programs are key strategies for addressing climate change and meeting the AB 32 goals for GHG emissions. These programs can continue to reduce California's energy demand, make businesses more competitive, and allow consumers to save money and live comfortably. In addition, they play a major role in increasing the reliability of the current electricity system, as well as reducing the costs of meeting peak demand during periods of high temperatures.

California continues to experience declining load factors.[85] The general decline in the load factor over the last 20 years is caused, in part, by a greater proportion of homes in warmer areas and more homes and business with central air conditioning. Today, close to 95 percent of single family homes in the Sacramento area and many other parts of the Central Valley and the Inland Empire have central air conditioning. Forecasts suggest that most housing growth in California will continue to be in these hotter areas.

More temperate climates in California are also becoming increasingly dependent on air conditioning. The area around San Francisco, from Santa Rosa to San Jose, now has a central air conditioning saturation of nearly 50 percent, double previous estimates. More than 75 percent of new single-family homes in the area are projected to have central air conditioning. These trends foretell a continuing reduction in the state's load factor, and continuing concern about meeting peak energy needs.

Energy efficiency tops the list of strategies for accomplishing California's significant GHG reduction targets because it is a relatively fast and inexpensive solution. In fact, it has what is called "negative abatement value" – by carrying out energy efficiency actions, energy consumers would both cut emissions and save money.

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[84] Per capita consumption is consumption across all of the electricity-using sectors: residential, commercial, industrial, and agricultural – totaled and divided by the state's total population

[85] A load factor represents the relationship between average energy demand and peak demand: a low load factor means the peak is much higher than average hourly energy demand.

Using Efficiency to Meet California's Energy Needs

If energy efficiency is to play the critical roles envisioned for it under AB 32, the state needs to support expanded efforts in all programs. Scenario analysis has demonstrated that cost-effective efficiency programs can, when coupled with renewables development, allow us to achieve at least a proportional reduction of carbon emissions from the electric sector. This analysis highlights the need to capture *all cost-effective energy efficiency.* The September 17, 2007 Proposed Decision from the California Public Utilities Commission emphasizes this goal and describes a course of action, involving programs under its jurisdiction and those under the Energy Commission's authority, to achieve it.

Since the 1970s, the Energy Commission has had the responsibility to establish and enforce energy efficiency standards for buildings and appliances. All construction of new buildings and major building modifications must meet the Energy Commission's standards, which are regularly updated to capture improvements in technologies, such as lighting and heating, ventilation and air conditioning (HVAC) systems. In addition, the Energy Commission sets minimum efficiency standards for a range of appliances that use significant amounts of energy. The standards must, by law, be technically feasible and cost-effective.

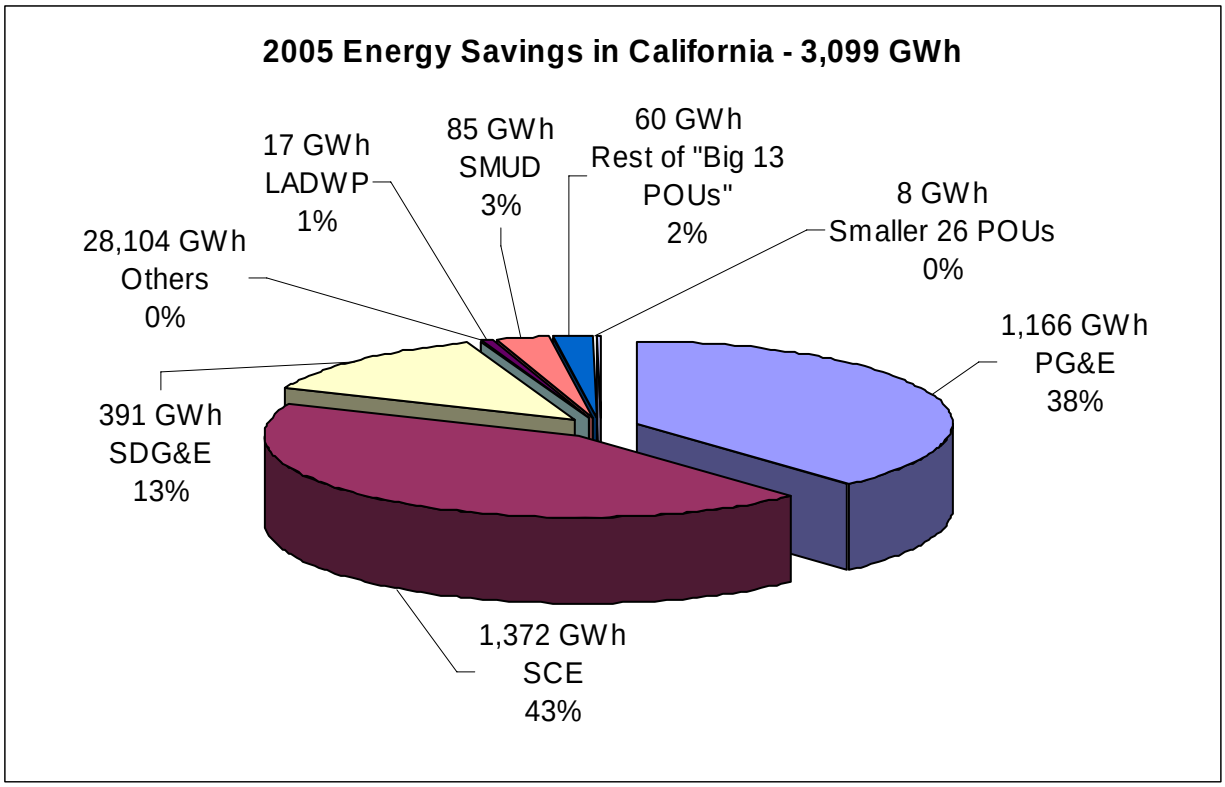
Besides the energy savings accumulated from these mandatory standards, since 1975, the IOUs in California have offered ratepayer-funded programs of incentives and rebates to encourage customers to participate in savings programs or purchase efficient appliances. Many of the POUs have offered similar programs for their customers although the significant differences in size among the POUs affect their level of program commitment.

By law, each IOU and POU customer pays a small public goods charge (PGC) to support public programs for energy efficiency, low-income services, renewable energy, and public interest research and development. A natural gas surcharge provides similar support on the natural gas side. Since 2004, additional funding has been made available through the IOUs' procurement proceedings to pursue energy efficiency beyond what is funded by the PGC. In the 2004-2005 energy efficiency program cycle, the IOUs reported energy efficiency savings of 4,670 GWh, 1,007 MW, and 80 million therms, with a budget of $965 million.

Like the IOUs, the POUs administer a variety of energy efficiency programs for their customers. During fiscal year 2005-2006, all POUs collectively spent over $54 million dollars on energy efficiency and saved over 170 GWh and 53 MW of peak electricity.

Figure 3-1 shows the electric energy savings reported for 2005 for both IOUs and POUs. Combined, the IOUs' programs command 95 percent of the savings. The two largest POUs in the state, Sacramento Municipal Utility District (SMUD) and LADWP, both of which have had programs as long as the IOUs, account for 3.2 percent of the statewide savings, but 60 percent of the POU savings. SMUD expended $22 million for energy efficiency, close to half of the entire amount spent for all 39 of the POUs which supplied expenditure data. LADWP spent the next highest amount for energy efficiency at $11 million.

Figure 3-1: IOU and POU Share of Electric Energy Savings in 2005



Sources: *2006 Energy Efficiency Annual Reports* for the investor-owned utilities. California Municipal Utilities Association (CMUA), *Energy Efficiency in California's Public Power Sector: A Status Report*, December 2006 for the publicly owned utilities.

Using Efficiency to Reduce GHG Emission Levels

Drawing on the efficiency potential described in a 2006 study from Itron[86], the Scenario Assessment Project examined the GHG implications of resource plans featuring high penetrations of energy efficiency measures and renewable energy generation (both rooftop solar photovoltaic and supply-side generating technologies) in California and the Western states. A base case (Case 1) included the IOU's 2004-2008 committed energy efficiency programs and the impacts of existing building and appliance efficiency standards, as accounted for in the Energy Commission's demand forecasts. No additional energy efficiency after 2008 was modeled in the base case. Four scenarios for energy efficiency were considered:

- Current practices (Case 1B) – For California, the energy efficiency resources reflect the goals summarized in the IOU 2006 procurement plans. For the rest of the Western states,

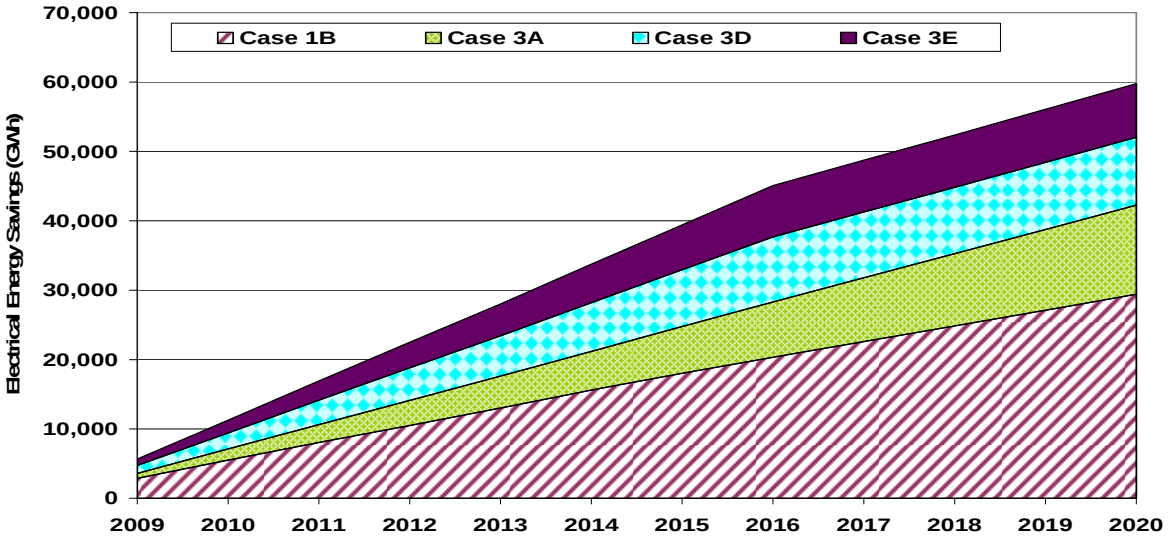
[86] Itron, *California Energy Efficiency Potential Study*, May 24, 2006. 3 vols. Available from http://www.calmac.org. This study projects electricity and natural gas efficiency potential through 2016 for the investor-owned utilities.

the current energy efficiency programs were assumed to be embedded in the load forecasts (that is the forecasts reflect sales net of reductions from energy efficiency programs).

- Aggressive development (Case 3A) – Reflects aggressive expansion of energy efficiency programs. In California, this is equivalent to all cost-effective energy efficiency (minus the portion of the economic potential attributable to emerging technologies) from the California Energy Efficiency Potential Study. (2006 Itron Study)
- Partial emerging technology deployment (Case 3D) – In addition to the aggressive energy efficiency included in Case 3A, approximately 55 percent of the economic emerging technology potential in California is included.
- Full emerging technology deployment (Case 3E) – Includes the entire economic emerging technology potential in California.

Figure 3-2 graphically depicts the four scenarios of energy efficiency through time.

Figure 3-2: Energy Efficiency through Time by Case

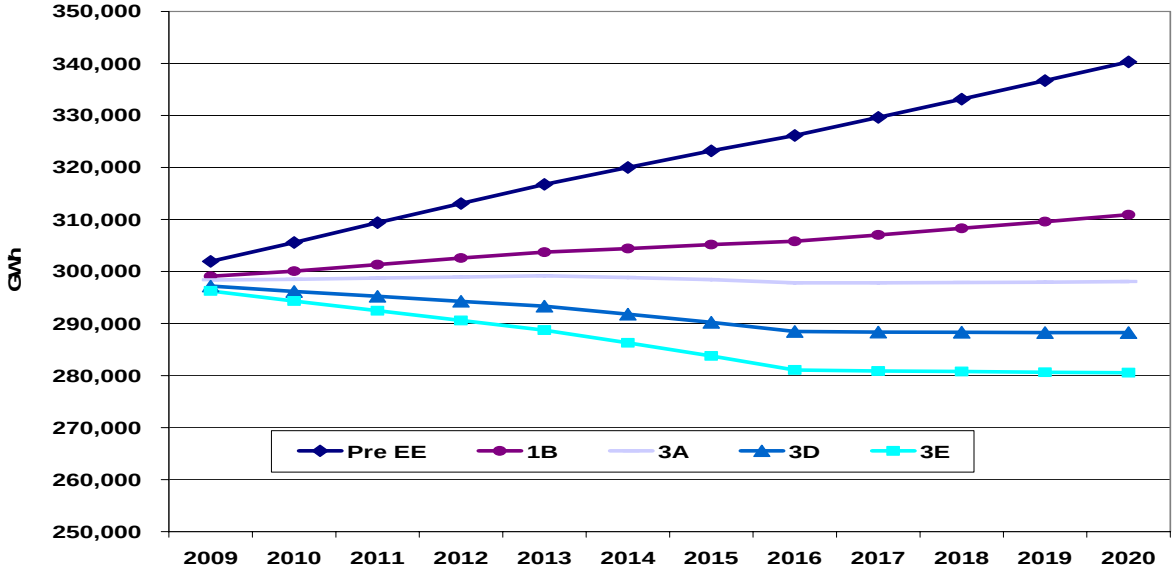


Source: Navigant Consulting, Inc.

The culmination of savings in each of the cases would be 30,000 GWh in Case 1B, 42,000 GWh in Case 3A, 52,000 GWh in Case 3D, and 60,000 GWh in Case 3E.

As depicted in Figure 3-3, California retail load becomes relatively flat between 2016 through 2020 after including the impacts of energy efficiency. The net effect of these energy efficiency savings is virtually no growth in California retail loads in Case 3A, a decline in retail loads in case 3D, and a further decline in retail loads in Case 3E as depicted in Figure 3-3. The average annual decline between 2009 and 2020 is -0.3 percent in Case 3D and -0.5 percent in Case 3E.

Figure 3-3: Projected Cumulative Impacts on Net Energy for Load



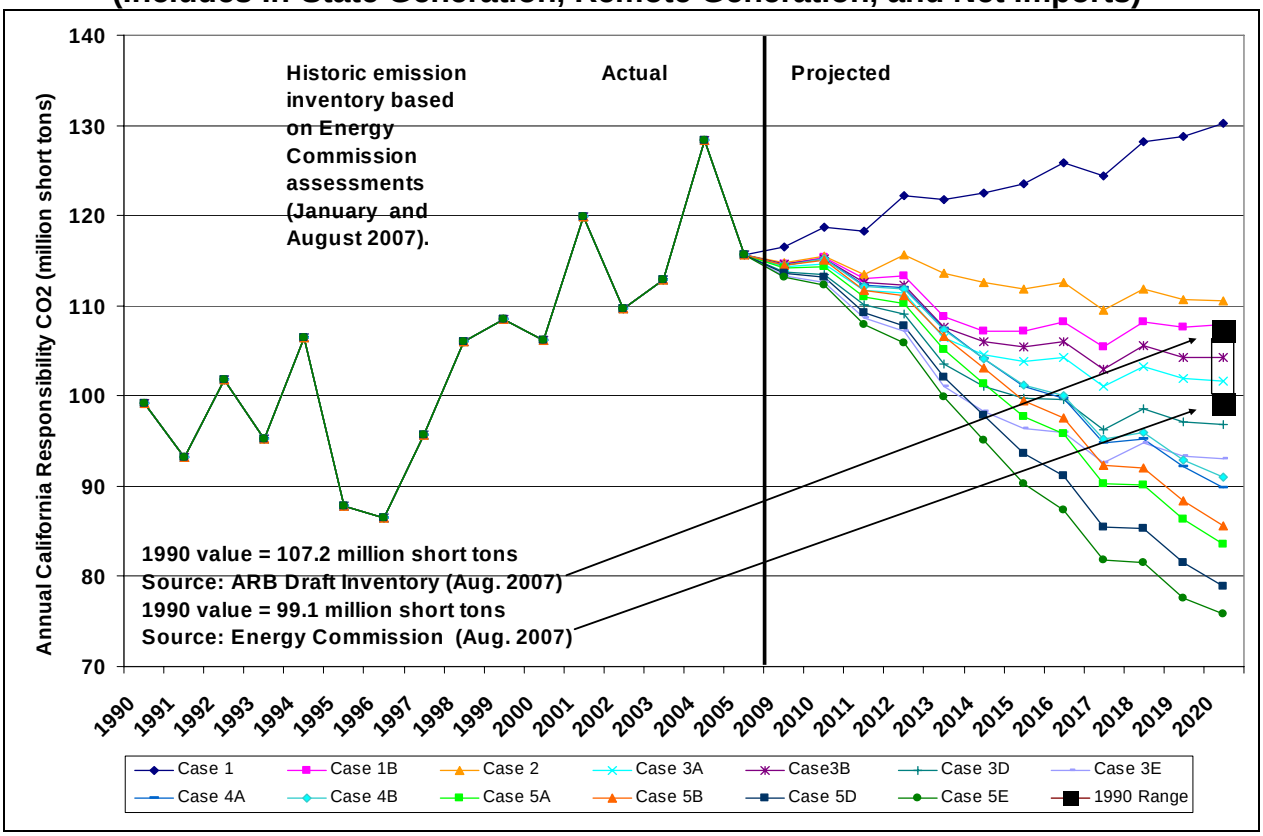
Source: Navigant Consulting, Inc.

The fundamental question is what impact the high efficiency cases will have on California's ability to reduce its overall greenhouse gas emissions to 1990 levels. Figure 3-4[87] shows the carbon emissions from the power generated to serve load in California, also known as the California Carbon Responsibility, for all thirteen scenarios modeled in the Scenarios Project. This figure also identifies how these electricity sector projections compare with two estimates of 1990 GHG emissions. The ARB will not determine until late 2008 whether the statewide AB 32 greenhouse gas emission reduction goal will be applied proportionally to each of the five major emitting sectors. Therefore, the two values are reported as a range.

The results show that even without significant contributions from renewable resources, the investment in energy efficiency within California included in Case 3A would reduce emissions below this range. Including the more aggressive energy efficiency investments envisioned in Cases 3D and 3E, the proportional contribution level is exceeded. Furthermore, all the cases with high renewables (Cases 4A and 4B) or high energy efficiency combined with high renewables (Cases 5A through 5E) exceed the proportional contribution, and in the highest contribution cases by a significant margin. The scenario results indicate that a more than proportionate contribution towards the AB 32 goals from the electricity sector is feasible, and may even be necessary if the overall goal is to be achieved.

[87] For an explanation and discussion of Cases 4A and 4B, which represent high renewables only, see California Energy Commission, July 2007, *Scenario Analyses of California's Electricity System: Preliminary Results for the 2007 Integrated Policy Report*, Staff Draft Report, CEC 200-2007-010.

Figure 3-4: California Carbon Dioxide Responsibility through Time by Case (Includes In-State Generation, Remote Generation, and Net Imports)



Cases 3A, 3D, and 3E reflect successively decreasing levels of emissions by 2020, as shown in Table 3-1. In them, the cost per unit of GHG reduction from alternative levels of energy efficiency is relatively constant, as shown in Table 3-2. Most importantly, the cost is negative, so society is better off with these higher levels of energy efficiency than without them. Energy efficiency is less costly than the generating resources it displaces, so not only does it provide a public good in emission reductions, it provides a collective good to the ratepayers by saving direct expenditures.

Table 3-1: Predicted GHG Emissions for California in 2020 (Thousand tons of carbon dioxide per year)

Annual CO2 (000 short tons)	Case 1B	Case 3A	Case 3D	Case 3E	Case 5A	Case 5D	Case 5E
Total California Responsibility	107,976	101,652	96,780	92,982	83,547	78,623	74,733

Table 3-2. Measuring Cost Effectiveness of Strategies by Assessing Differences from Case 1B

	2020 System Cost Difference	2020 GHG California Responsibility Emission Difference	2020 Reduction ($/ton)
Case 1B	-	-	NA
Case 3A	(652,394)	(6,324)	(103.17)
Case 3D	(1,172,584)	(11,196)	(104.73)
Case 3E	(1,569,955)	(14,994)	(104.71)

Source: Global Energy Decisions, Inc.

The enhanced efficiency cases also depend on utility program designs that can achieve essentially all of the economic energy efficiency potential identified in the *2006 Itron Study*. Numerous studies have found that *actual* energy efficiency savings tend to be less than those identified in the economic potential studies. It is essential that the CEC and CPUC combined efforts gain all cost-effective energy efficiency.

Achieving All Cost-Effective Energy Efficiency

Senate Bill 1037 (SB 1037, Kehoe, Chapter 366, Statutes of 2005) requires the California Public Utilities Commission (CPUC), in consultation with the Energy Commission, to identify all potentially achievable cost-effective electric and natural gas energy efficiency measures for the investor-owned utilities, set targets for achieving this potential, and review the energy procurement plans of the IOUs to ensure the use of cost-effective supply alternatives. SB 1037 also requires all POUs, regardless of size, to report investments in energy efficiency programs annually to their customers and to the Energy Commission.

Under Assembly Bill 2021 (AB 2021, Levine, Chapter 734, Statutes of 2006), the Energy Commission, in consultation with the CPUC and the POUs, must produce a statewide estimate, for both the IOUs and the POUs, of "all potentially achievable cost-effective electricity and natural gas efficiency savings and establish statewide annual targets for energy efficiency savings and demand reduction over 10 years."

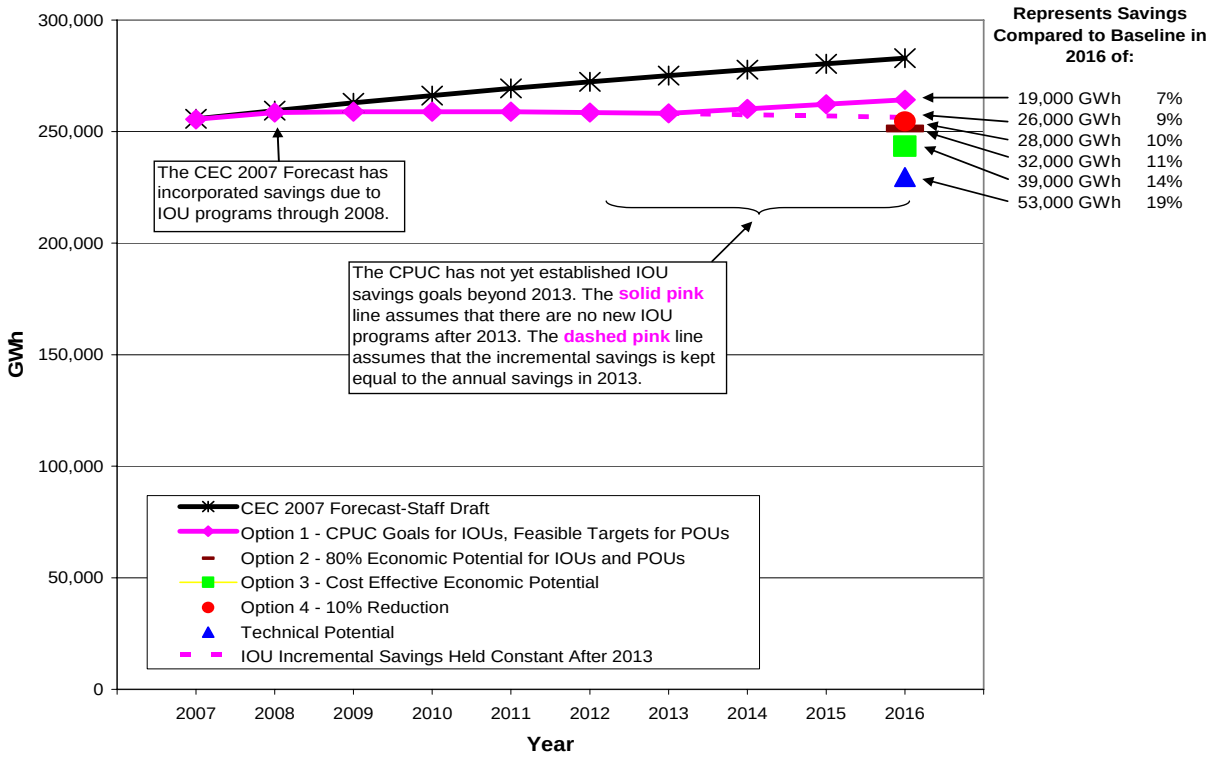
Based on the *2006 Itron Study*, the remaining economic potential in 2016 for the IOUs and the POUs is estimated to be 39,472 GWh, 6,569 MW and 749 million therms, **excluding** the potential that might be available from emerging technologies. These values are indicated by a green square on the next series of figures and are roughly equivalent to Scenario Case 3A. The emerging technologies represent an additional 12,000 GWh. In total, the savings targets proposed by the IOUs and POUs for 2016 are 26,491 GWh, 5,568 MW, and 490 million therms.

With their current programs, the IOUs are expected to achieve 71 percent of their electric economic potential by the end of the 10 years. This ratio assumes that the CPUC will direct the investor-owned utilities to achieve savings at a rate at least equal to the annual savings in 2013, the last year covered by D.04-09-060, the governing decision.

Based on their targets proposed to the Energy Commission in June 2007, the POUs intend to achieve 56 percent of their electric economic potential by 2016. On a statewide basis, the IOUs and the POUs, combined, are expecting to achieve 67 percent of their economic efficiency potential if they meet their ten-year savings targets.

Figure 3-5 illustrates the impact of four possible savings targets on reducing forecasted statewide electricity consumption.

Figure 3-5: IOU and POU Electric Energy Consumption 2007–2016

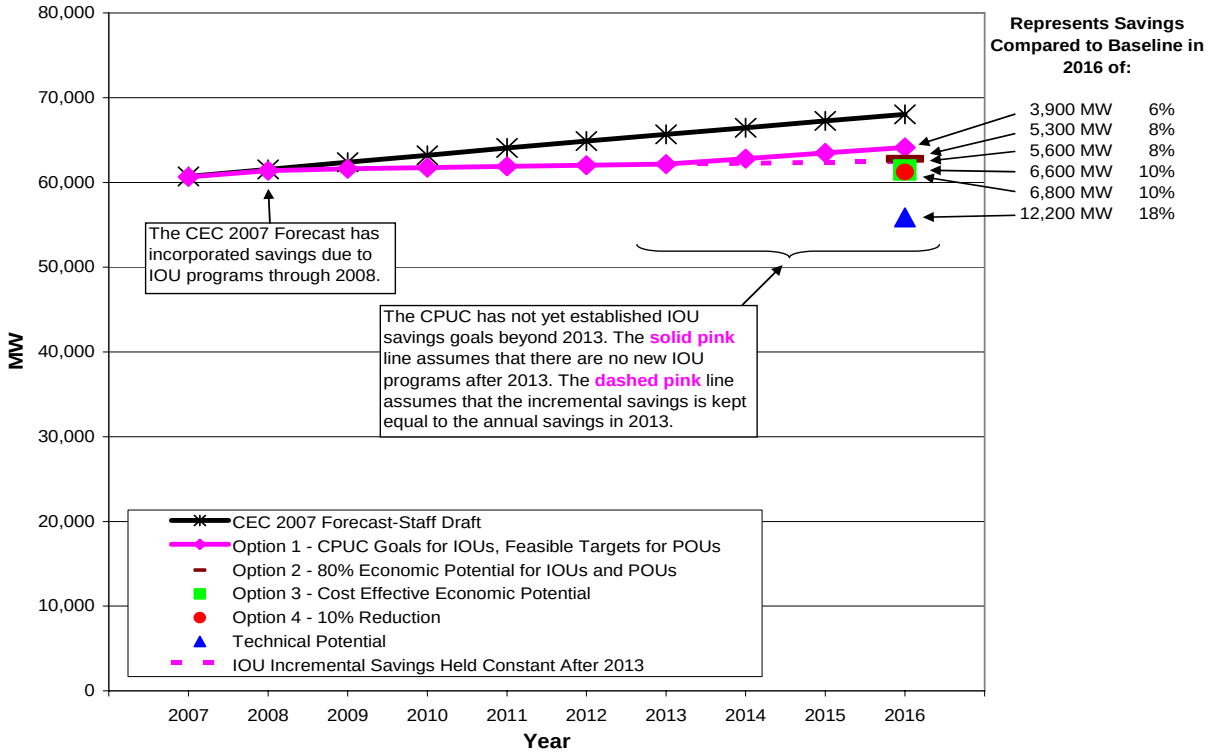


The top line shows the projected demand for electricity absent the effects of IOU or POU programs, for the period 2007-2016 (2009-2016 for the IOUs). The dashed line shows the resulting statewide consumption if both the POUs and IOUs are successful in meeting the

energy savings targets proposed by the POUs to the Energy Commission and adopted by the CPUC for the IOUs (and extended at the incremental 2013 rate through 2016) (Option 1). The other lines and symbols on this graph show the potential impact of achieving the higher savings goal of the IOUs and POUs obtaining 80 percent of their economic potential (Option 2), IOUs and POUs achieving all cost-effective economic potential (Option 3), obtaining a 10 percent reduction in consumption in 2016 (Option 4), and achieving the total technical potential. Emerging technologies are not included.

Figure 3-6 illustrates the same cases for peak demand. For peak electrical demand, the IOUs would achieve 95 percent of the economic potential, while the POUs are projecting to achieve 62 percent. Combined, the IOUs and POUs would achieve 85 percent of the remaining economic potential for peak electricity demand savings by 2016, excluding emerging technologies. This would reduce peak demand growth by 6 to 8 percent in 2016 depending on the IOU goals, or, put another way, meet 70 percent of the expected growth over the next 10 years.

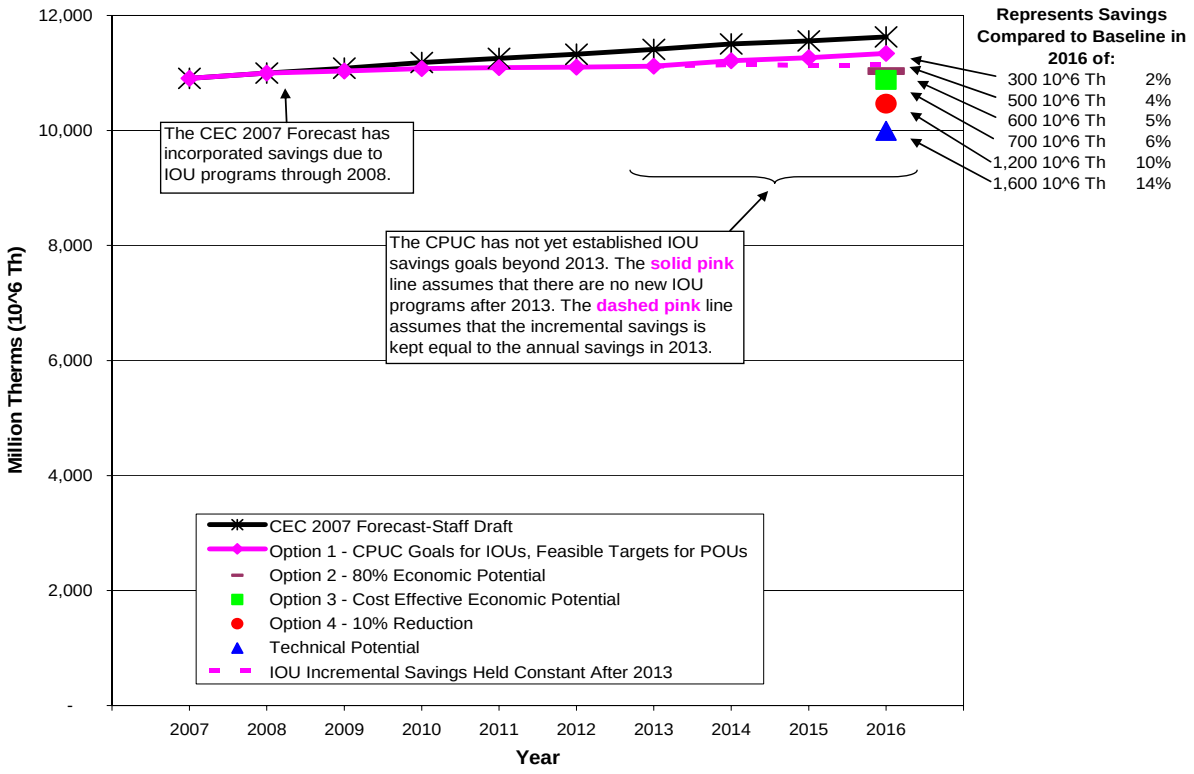
Figure 3-6: IOU and POU Peak Demand 2007–2016



Natural gas efficiency targets are proposed in Figure 3-7 that capture a smaller percentage of the economic potential than the electric efficiency. The IOUs would achieve 65 percent of the economic potential and the POUs 21 percent. Since the overwhelming portion of the natural gas consumption is represented by the IOUs, the combined percentage is also 65 percent of the economic potential.

For natural gas, proposed savings targets (predominantly IOUs) will reduce forecasted consumption by two to four percent in 2016 and capture 68 percent of the growth between 2007 and 2016.

Figure 3-7: IOU and POU Natural Gas Consumption 2007-2016



The POUs have made considerable progress in developing estimates of economic potential but there remains a wide variation in the proposed targets and program ramp-up rates. Thirteen of the 39 POUs account for 93 percent of the consumption. Using a metric of savings to sales (consumption) ratio averaged over 10 years, these utilities group into three natural clusters: one lower group clustering around 0.2 to 0.3 percent, a middle group clustering near 0.4 to 0.6 percent, and a higher group clustering between 0.7 and 1.5 percent. Year-to-year ramp-up rates in some cases exceed anything historically achieved by the IOUs. Given that other POUs have experience with efficiency and know their customer base and local conditions well, the Energy Commission supports those setting aggressive ramp-ups.

Comments from the September 17, 2007 workshop indicated utility support for using the sum of the IOU and POU targets as proposed for a statewide target, but setting an annual 1 percent reduction in consumption, or 50 percent of economic potential as a minimum threshold for each utility. For some, this would require close collaboration with the Energy Commission to help them succeed in meeting these significantly increased energy targets. Many of the POUs should be able to double their savings to sales ratios. Increasing the IOU trajectory after 2013 is a

desirable goal. As the IOUs move into non-traditional programs, such as on-bill financing or solar/efficiency combinations, and enter into wider collaborative and regional efforts, additional savings should be available.

AB 2021 gives the Energy Commission authority to make recommendations for improvements in efficiency program strategies or targets if necessary in the intervening years. We intend to do so. The Energy Commission also expects to specifically describe acceptable evaluation measurement and verification techniques and define both methods and metrics for tracking progress toward the targets and reporting them.

A "gap" still exists between the utilities' proposed efficiency targets and the estimated economic potential. Making up this gap will require more than "business-as-usual" utility programs from both POUs and IOUs. This needs to be a major near-term focus of the Energy Commission and the CPUC if we are to meet the greenhouse gas goals for the electricity sector.

New market-based approaches, such as "white tags" or "white certificates," which are the equivalent of renewable energy credits, should be considered. Each certificate would represent 1 MWh of energy savings and its associated carbon reduction. Renewable credits are tied to creating renewable generation and are measured by meter readings. "White tags" are created by reductions in energy use and are measured through software and control technology, but they can be sold or traded just as the renewable energy credits in a carbon market. This approach has not been extensively considered for California at this point but should be explored as an AB 32 compliance strategy. The Energy Commission and the CPUC should carefully study the role voluntary market instruments like "white tags" can play in closing the gap between utility programs, mandatory standards, and economic potential.

Other avenues, such as more expansive and stringent building standards, legislation requiring energy improvements at the time of a building's sale, local ordinances or codes, emerging technologies, programs combining efficiency with renewables, new federal and state appliance standards, and improved compliance mechanisms will obviously be needed. Efficiency standards for buildings, in particular, offer significant potential for savings. The CPUC's September 17, 2007 Proposed Decision advocates the use of utility efficiency program funds to support the Energy Commission's building standards efforts to achieve zero net energy residential buildings by 2020 and commercial buildings by 2030. The Energy Commission endorses these ambitious goals and will, with support from the CPUC and the utilities, strive to achieve them through successive cycles of the building standards and appliance standards.

Energy Savings from Building Standards

The Energy Commission is in the process of developing the 2008 building standards. Some of the efficiency features that are expected to be in the final version of the standards include updated lighting and mechanical measures, cool roofs for residential applications, better controls for central hot water distribution, residential programmable communicating thermostats and nonresidential demand shedding controls for demand response capabilities, a

new optional compliance tier for photovoltaic systems, and updated nonresidential outdoor lighting requirements.

The Energy Commission has coupled energy efficiency with promotion of solar photovoltaic systems through its New Solar Homes Partnership. To qualify for a PV incentive, the new home has to 'beat' the Title 24 building efficiency code by a minimum of 15 percent. This efficiency-first philosophy allows the PV system to cover more of the building's electric load. Builders are encouraged to beat the code by 35 percent. These levels were selected so the builders could qualify for efficiency incentives from the utility programs.

For the building standards to reach the aggressive goals described in the various policy reports, initiatives and legislation, the Energy Commission will need to consider vigorous efficiency coupled with technologies like solar photovoltaic systems. The Commission has recently initiated the investigative process required by SB 1 to determine whether solar photovoltaic systems should be mandated in future building standards.

Several bills were introduced this legislative session to encourage or mandate green building practices in the residential, commercial and state building sectors. Both the Department of Housing and Community Development (for residences) and the California Building Standards Commission (for all building sectors) have become engaged in the goal of creating a green building guideline to publish in the California Building Code.

In view of the importance that expanded efficiency efforts will play in achieving the AB 32 goals, the Energy Commission will pursue legislation to require an on-site audit and an appropriate level of cost-effective efficiency improvements in existing buildings at time of sale. Absent that legislative authority at this point, the Commission issued a booklet directed at homebuyers that provides information about home energy audits and rating programs and is marketing this information with home warranty company websites.

Energy Savings from Appliance Standards

The Energy Commission is considering what appliances may be covered in the next round of appliance standards. The most recent round of standards improved efficiency for a variety of consumer audio and video equipment, power supplies for a variety of consumer equipment, and residential lighting, among other appliances. The next round of standards is likely to cover battery chargers, commercial lighting systems, and – most importantly, residential lighting efficiency.

Improving the efficiency of electric lighting in California offers a cost-effective path to significantly reducing energy use and greenhouse gas emission. The greatest opportunity for saving lighting energy in California residences lies in addressing the continuing prevalence of incandescent lamps. That is already done, in part, by the building standards for new and renovated housing, but that affects a small proportion of all houses each year. The majority of sockets in existing houses are still occupied by incandescent lamps, which have an efficacy (amount of light provided per amount of electrical power consumed) in the region of 10-17

lumens per watt (lm/W). When compared with the 45-70 lm/W of currently available compact fluorescent lamps (CFLs), incandescent lamps are clearly very inefficient.[88]

The efficacy of incandescent lamps could be increased by 30% with technology presently available, such as using halogen capsules with infrared coatings. These technologies, while cost-effective in most uses, are significantly more expensive than standard incandescents. Furthermore, industry experts suggest that, with some technological improvements, incandescent efficiency could even exceed 40 lm/W. Meanwhile, emerging light-emitting diode (LED) sources achieve 40 lm/W at the moment, could achieve 60 lm/W in a few years and even reach 100 lm/W some time in the next decade.[89] These sources currently cost significantly more than alternatives, but also have significantly longer lifetimes.

In residential construction, the Energy Commission's 2005 Building Standards significantly increased requirements for fluorescent-level lamp efficiency in kitchens, and required either high-efficiency or sensor-controlled lights in bathrooms, laundries, garages, and utility rooms. In addition, the Energy Commission's latest Title 20, appliance regulations require more efficient lamps for general purpose uses. These standards removed the least efficient incandescent general service lamps from circulation in 2006. In 2008, the next tier of requirements will take effect, reducing wattages of general service incandescent lamps by approximately 5%, encouraging manufacturers to pursue improvements in efficiency. The Energy Commission has committed in the Climate Action Team's early action report to updating its lighting standards by January 1, 2010 to address the challenge of further reducing greenhouse gas emissions.

Legislation currently before the Governor for signature, Assembly Bill 1109, would require the Energy Commission to develop regulations to reduce the average energy used for residential general service lighting by 50 percent by 2018. Lighting industry support for this bill carries a potent message about the level of efficiency gain prudently achievable.

Other states have taken action to address lighting energy efficiency as well. In Nevada, a bill (AB.178) banning lamps under 25 lm/W after 2012 was signed by the governor in June, 2007. Connecticut, Minnesota, New York, New Jersey, North Carolina, South Carolina and Rhode Island have all introduced bills that in one way or another restrict or ban the sale of incandescent lamps.

The National Electrical Manufacturers Association (NEMA) has proposed federal legislation to increase the minimum efficacy standards for incandescent lamps, corresponding to an efficacy increase of approximately 28 percent, to be gradually phased-in until 2018. This would be accomplished by adopting halogen capsules, infrared coatings, and other technologies to provide similar light output with lamps that are required to have lower wattage.

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[88] "Efficiency Opportunities for Edison-Based Luminaires, Fernandez, California Lighting Technology Center (CLTC) , Sept. 12, 2007 p. 3

[89] Ibid, p. 3

Both the U.S. Senate and House of Representatives are considering legislation to improve the efficiency of residential, general purpose lighting. In the Senate, S.2017 ("Energy Efficient Lighting for a Brighter Tomorrow Act") would establish wattage caps for ranges of lumen output, and deadlines for manufacturers to comply with the caps. The wattage caps in the current version match those of the NEMA proposal, with earlier implementation deadlines. S.2017 also includes a 'second tier' of standards to be adopted by 2017 that would require general service lamps to achieve efficiencies of 50 lumens/watt by 2020.

The House of Representatives version of the energy bill (HR.3236) takes a similar approach. It requires minimum efficacies for several lumen ranges, phased in between 2012 and 2014. It also includes a 'second tier' standard that would achieve efficiencies of about 45 lumens/watt after 2020, and it prohibits the sale of 100 watt incandescent lamps after January 1, 2012, unless their efficacy is at least 60 lm/W.

While both bills include preemption of state standards to improve general service lighting efficiency, HR 3236 provides more flexibility than S. 2017. Specifically, the House bill would allow states to modify their standards to reflect the provisions in federal law with earlier enforcement dates.

Either of these approaches would improve the efficiency of residential lighting. The accompanying preemption provisions, however, are poor policy. Reasonable state standards do not present an undue burden to industry on a national level. Industries already routinely ship and distribute appliances with different performance characteristics to different regions of the country. In fact, the lighting market is an international marketplace, with a variety of standards efforts in progress addressing general service lighting.

The federal proposals would not provide sufficient savings, by themselves, to achieve California's AB 1109 targets by 2018.[90] Achieving the goals of that legislation would require a concerted effort to increase the efficiency of existing incandescent technologies, as well as increase the use of the most efficient options. Customer education and information, lamp appliance standards, incentives to encourage use of efficient technologies and stricter building codes are all tools that could be employed to achieve these goals.

In February of this year, Australia put forth a proposal to impose stricter efficacy standards for the majority of general service lamps. Beginning in 2008, standard general service lamps in Australia must meet an efficiency curve that is about 18-22 lm/W, depending on lamp wattage. By 2014, other lamps such as candle shaped and round shaped lamps must meet the same standard. Australia would then consider a second tier of standards to become effective in 2016.

The Canadian government announced last April that it intended to phase out inefficient lighting by 2012, using non-technology-specific national standards. These standards are

[90] Op cit. CLTC, p.36

currently being developed, taking into account the potential effects on the Canadian lighting market.

In the European Union, under a 2005 European Commission directive to regulate products that have an energy and environmental impact, a study is ongoing to develop standards for office lighting (linear fluorescent and non-integrated CFL), and a new study targeting residential lighting has been launched this summer. The standards are to be ready in 2008 and 2009, respectively. Meanwhile, the European Lighting Council – a European counterpart to NEMA – has made public a proposal for Europe-wide regulation which, although divided into two stages of increasing stringency, is quite similar to the NEMA proposal in the United States, with slight differences in timing and efficacy levels. Independently of EU-wide activity, individual European countries have proposed or taken measures to curb the least efficient types of lamps.

IOU Efficiency Programs

In September 2004 the CPUC adopted the 10-year savings goals shown in Table 3-3 for the state's three electric and three natural gas IOUs. The CPUC is currently considering whether to update these goals for 2009–2013 and how to extend them to 2020.

Table 3-3: Approved 2004–2013 CPUC Goals for IOUs

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Total Annual Electricity Savings (GWh/yr)	1,838	1,838	2,032	2,275	2,505	2,538	2,465	2,513	2,547	2,631
Total Cumulative Savings (GWh/yr)	1,838	3,677	5,709	7,984	10,489	13,027	15,492	18,005	20,552	23,183
Total Peak Savings (MW)	379	757	1,199	1,677	2,205	2,740	3,259	3,789	4,328	4,885
Total Annual Natural Gas Savings (MMTh/yr)	21	21	30	37	44	52	54	57	61	67
Total Cumulative Natural Gas Savings (MMTh/yr)	21	42	72	110	154	206	260	316	377	444

Source: CPUC Decision 04-09-060, September 23, 2004 - *Interim Opinion: Energy Savings Goals For Program Year 2006 And Beyond*

The goals are based on a 2002 perspective on technologies, utility program designs, and price levels, and may therefore significantly understate the amount of future potential available in 2007. The adopted cumulative 2013 goal captures 91 percent of the "achievable" potential and 68 percent of the economic potential thought to be available based on the 2002 study. The 2002 potential studies that were used to set the existing goals, however, showed total economic potential to be less than 65 percent of the technical potential, and the achievable potential through utility incentive programs as less than 40 percent of the economic.[91]

For the 2004–2005-program cycle, the IOUs planned energy efficiency savings of 4,600 GWh, 757 MW, and 42 million therms and a total expenditure of $965 million. The IOUs spent approximately $672 million of the $965 million planned for 2004-2005 programs. For the 2006–2008 efficiency program cycle, the IOUs budgeted a total of $2 billion for three years of

[91] Kema-Xenergy, *California's Secret Surplus: The Potential for Energy Efficiency, Final Report*, submitted to Energy Foundation and Hewlett Foundation, September 23, 2002.

efficiency programs for projected savings of 6,800 GWh in reduced annual electricity consumption, 1,000 MW in peak demand reduction and 111 million therms of natural gas. As of July 2007, the IOUs have spent approximately $747 million of their $2 billion budget, with another $200 million in commitments.

Figure 3-8 compares the 2004-2007 program electric energy savings accomplishments to the goals. The utilities exceeded their goals in 2005, but did not meet their goals in 2004 or 2006. Slow program-start-up likely contributed to the failure to meet the goals in 2004 and 2006, each year being the first year in a new program cycle. Utilities did better in 2005 as the programs matured and savings committed in 2004 were actually installed. In fact, electricity savings in 2005 increased by more than 68 percent on average over savings achieved in 2004. 2005 represents the last year utilities were allowed to count commitments to install in a future year as part of their current year's reported savings. This change in rules contributes to sharp drop-off in 2006, but may enhance the credibility of claimed savings levels. Program savings in 2007 are through July.

Figure 3-8: IOU Electricity Goals Compared to Actual Savings (2004-2007)

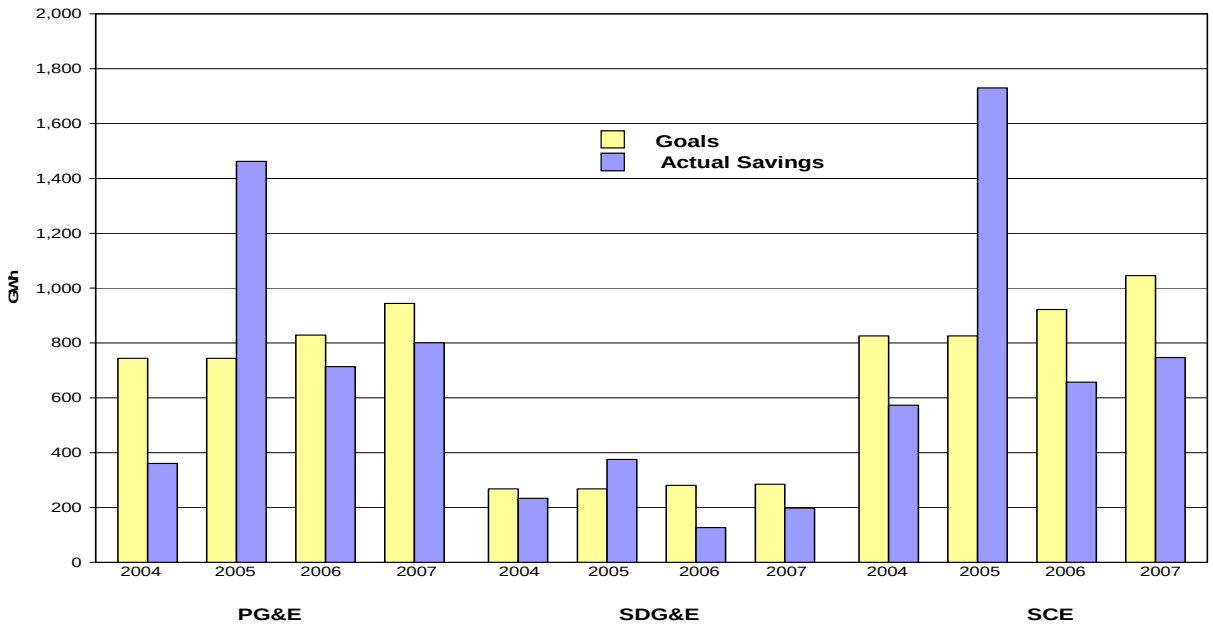


Figure 3-9 compares the IOU yearly peak demand savings goals to their yearly reported accomplishments. None of the IOUs met their demand savings goals in 2004 or 2006, but all utilities exceeded their goals in 2005, the second year of a program cycle. Combining the two program years of 2004-2005, SCE exceeded its goals by nearly 60 percent. The 2006-2008 program cycle exhibits a similar increased rate of savings in the second year.

Figure 3-9: IOU Peak Demand Goals Compared to Actual Savings (2004-2007)

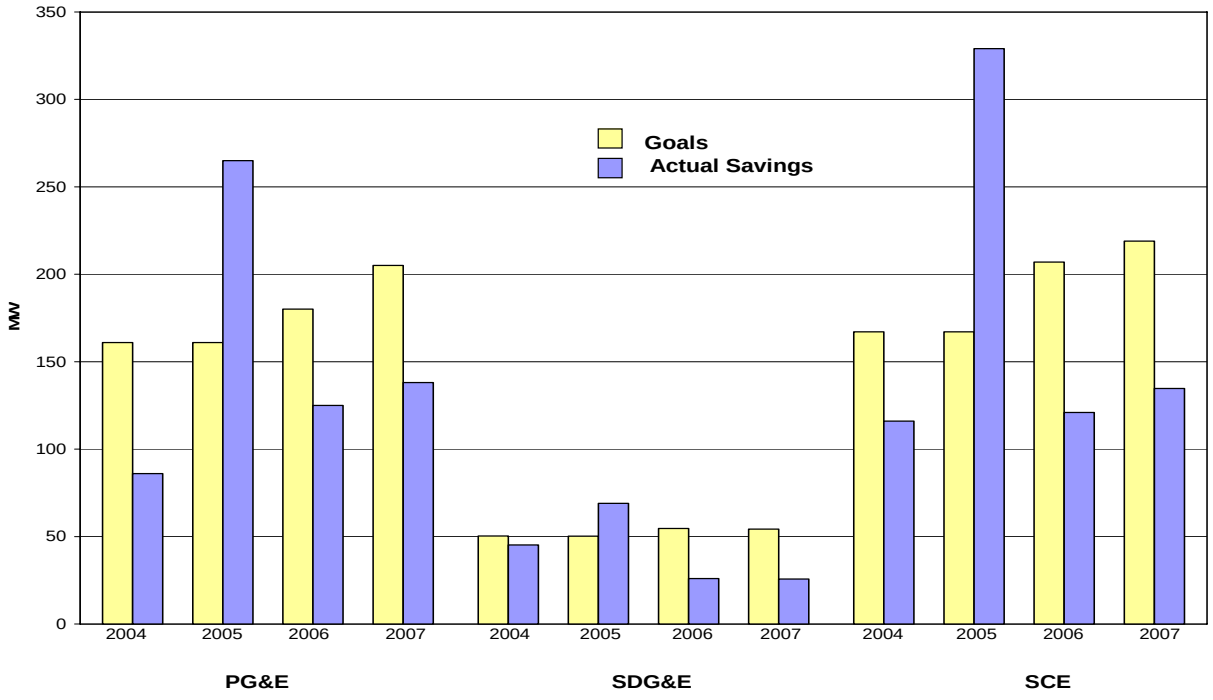


Figure 3-10 illustrates first-year reported therm savings compared to IOU goals. All three gas utilities met their goals in 2004 and 2005, while none met their goals in 2006.

In 2004-2005, at least nearly half of reported GWh savings came from lighting measures not already included in the Title 24 building standards. This share is as large as 80 percent in the residential sector, with the commercial sector being about half that amount. The smaller commercial share may reflect high commercial lighting accomplishments prior to this program cycle.

The decline in the new construction and HVAC shares largely reflects changes in reporting rules; utilities are no longer allowed to record savings until measures are actually installed. Lead times for savings are longer in these two program areas.

Figure 3-10: IOU Therm Goals Compared to Actual Savings (2004-2007)

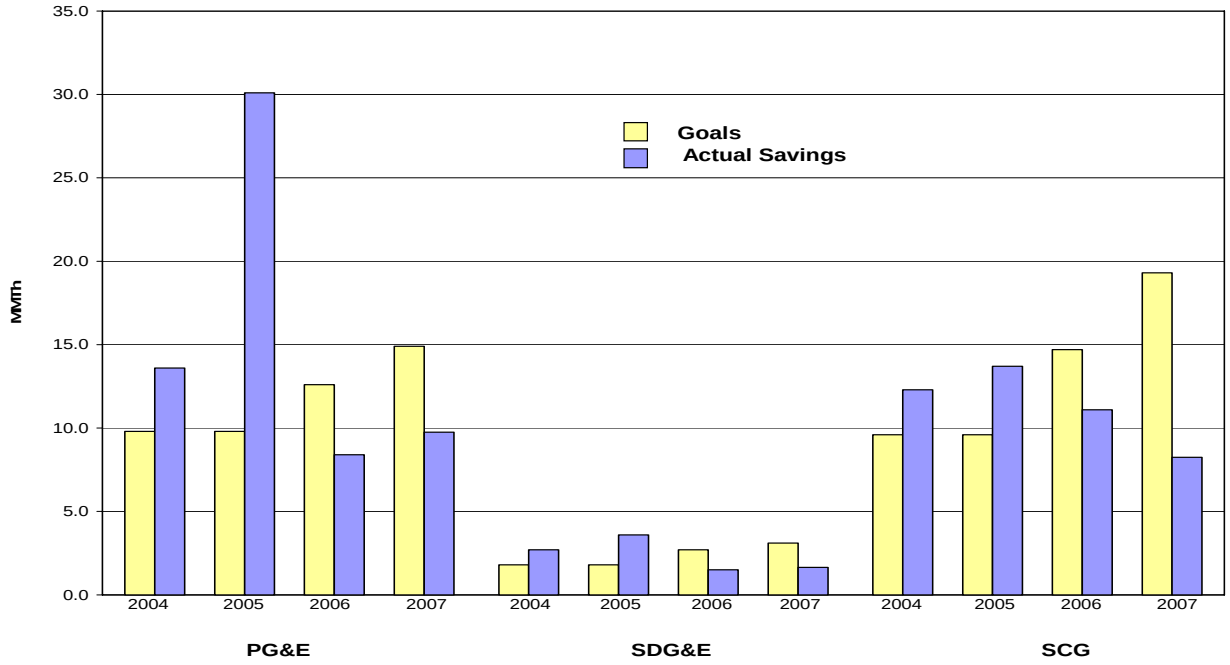
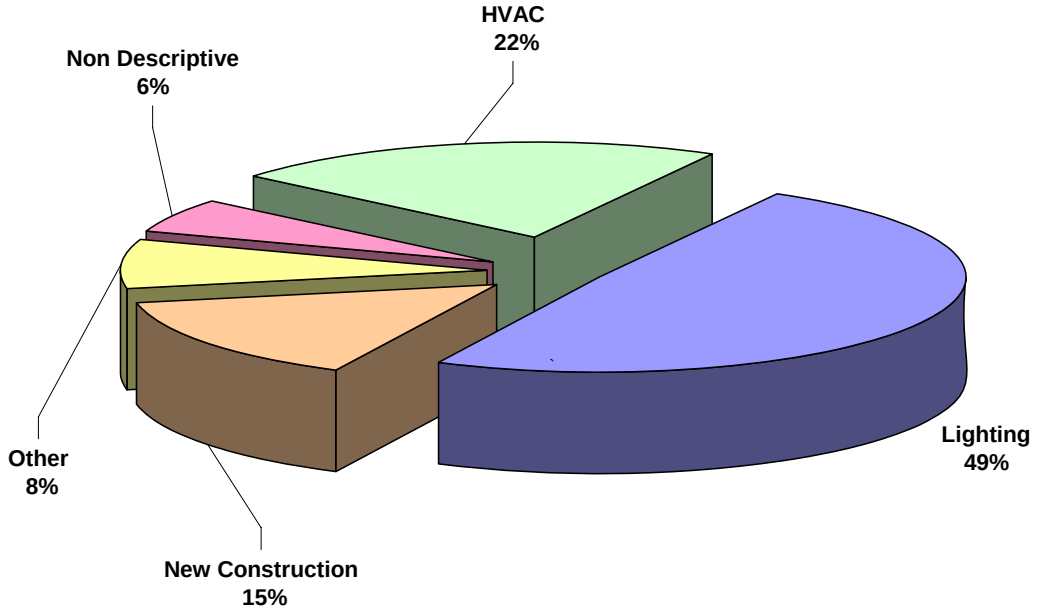


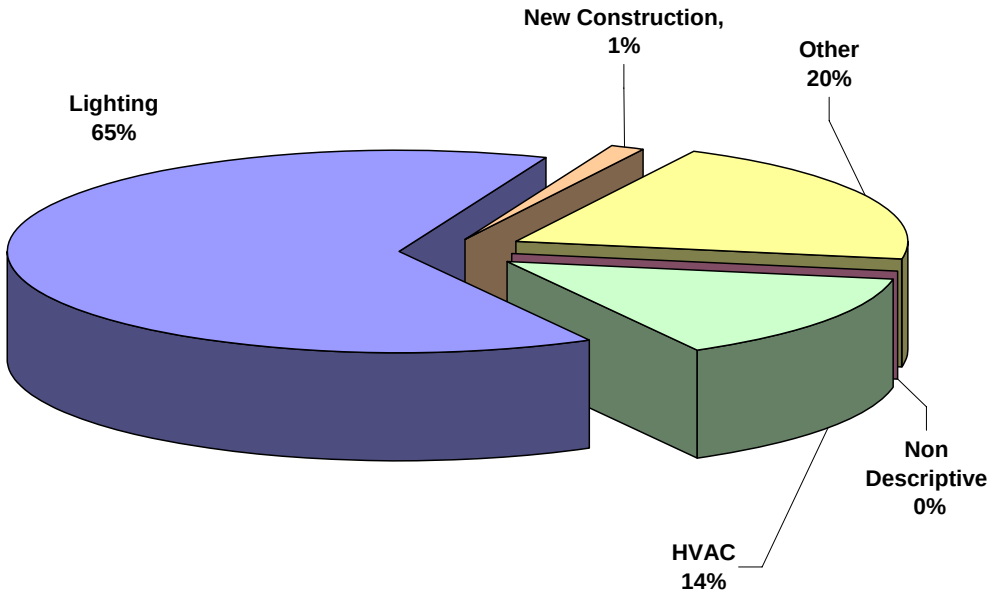
Figure 3-11: IOU Reported Savings by End Use 2004-2005 (MW)



Looking at demand savings in Figure 3-11, lighting accounted for only a slightly smaller share than in energy savings – 49 percent in 2004-2005 -- and continues to be the largest contributor in the next program cycle, rising to 60 percent of reported savings in the 2006-2008 portfolio. Commercial peak savings from lighting is nearly twice the size of residential savings.

Peak savings from HVAC programs averages out to 22 percent of the 2004-2005savings, but in the current program cycle, HVAC share has dropped to 14 percent of total peak savings as of July 2007. The lighting share of peak demand savings continues to increase. This is illustrated in Figure 3-12.

Figure 3-12: IOU Reported Savings by End Use 2006-2007(MW)



On September 20, 2007, in D.07-09-043, the CPUC adopted a risk/reward incentive mechanism for IOU energy efficiency programs. The system will require each utility to achieve at least 85% of the adopted energy and peak savings targets for the period 2007-2008 before being eligible for performance- based incentives. All calculations of net benefits and savings are to be independently verified and will be based on cumulative achievements for the program cycle.

Earnings would be shared between shareholders and ratepayers and begin to accrue at 9 percent once 85 percent of the savings is verified. If 100 percent or more of the goal is reached, the earnings rate increases to 12 percent. This means, for example, if a utility achieves 100 percent of the 2006-2008 savings goal, 88 percent of the verified net benefits or "performance earnings basis" (resource savings minus total portfolio costs) goes to ratepayers and 12 percent goes to shareholders.

Utilities achieving below 65 percent of the goals would be subject to penalties (reductions in shareholder earnings) assessed at 5 cents/kWh, 45 cents/therm and $25/kW. No earnings or penalties apply to performance greater than 65 percent and less than 85 percent of goal achievements. This system is similar to the previous incentive system in place from 1992 to 1998, but provides much a much lower incentive to the utility than previously when shareholders received 30 percent of the benefits and ratepayers received 70 percent. Earnings and rewards would be capped at $500 million dollars for each program cycle.

Lack of critical evaluation feedback and progress on foundational studies is severely hampering the 2009-2011 program planning cycle. Assumptions in the *Database for Energy Efficient Resources* used to estimate program savings and calculate cost-effectiveness badly need updating. Re-examination of the avoided cost components is also needed, especially the value placed on peak demand reductions, generation costs, and the carbon adder. The Total Resource Cost test calculation is also being criticized for recent interpretations that appear to bias program choice against all programs that are not traditional customer rebate programs.

Problems notwithstanding, evidence suggests that sufficient potential remains for utilities to achieve higher levels of savings. A dearth of new program ideas to achieve them has been the principal constraint.

The CPUC proposed decision of September 17, 2007 directs the IOUs to prepare a "single comprehensive statewide long-term energy efficiency plan." Three programmatic initiatives form the centerpiece of an expanded "next generation" efficiency effort:

- All new residential construction in California will be zero net energy by 2020,
- All new commercial construction in California will be zero net energy by 2030, and
- Heating, ventilation and air conditioning will be reshaped to ensure optimal equipment performance.

Using Demand Response to Meet Electric System Peaks

Demand response (DR) could play a critical role as a resource in California's electricity planning mix. Price-responsive DR, coupled with advanced metering infrastructure (AMI), improves the level of service provided to electricity customers and has the potential to cost-effectively avoid incremental generating capacity costs, energy production costs, and transmission and distribution (T&D) capacity costs. Despite its many advantages, price responsive DR is expected to reduce peak demand by only 2.2 percent in the summer of 2007, which is less than half of the goal of five percent laid out in the *Energy Action Plan II*.[92]

[92] If reliability-triggered programs are included as well, the utilities are expected to achieve a 5.7 percent reduction in peak demand. However, reliability-triggered programs are not part of the five percent target. This is elaborated upon in *The State of Demand Response in California*, by Ahmad Faruqui and Ryan

In addition, reliability-triggered DR promotes system reliability by providing the California Independent System Operator (CAISO) with tools to manage demand during peak days, as well as preventing brownouts and blackouts during emergency situations.

Potential Savings from DR

The potential reduction in peak demand that can be achieved through price-responsive DR programs depends on the amount of coincident demand that is reduced per customer and on the number of participating customers. As with energy efficiency programs, it is normal practice to assess three types of demand impacts: technical potential, economic potential, and market potential.[93]

- *Technical potential* measures the outcome if all customers use the best available DR technology. In the residential class, this is the gateway system, which allows homeowners to automatically manage electricity consumption at several points of end-use, including stereos, appliances, and air conditioning units. The gateway system has the potential for lowering peak demand by 43 percent, as demonstrated by the advanced demand response system (ADRS) sub-set of the statewide pricing pilot (SPP). In the commercial and industrial classes, automated DR programs that control multiple end-use loads and leverage the energy management control system that is installed in most facilities are projected to reduce demand by 13 percent, as demonstrated by work carried out by the Demand Response Research Center. A weighted average over all customer classes leads to an estimate of roughly 25 percent for the technical potential of demand response.[94]
- *Economic potential* measures what would happen if all customers used a cost-effective combination of technologies rather than the best available technologies. This produces an estimate of the economic potential for demand reduction through DR programs of approximately 12 percent. To illustrate this computation for the residential class: customers in the California experiment without an enabling technology lowered their peak usage by 13 percent. Those with a smart thermostat lowered it by 27 percent and those with the gateway system lowered it by 43 percent. If 70 percent of the customers chose no enabling technology, 20 percent chose the smart thermostat and 10 percent

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Hledik, Draft Consultant Report prepared for the California Energy Commission, April 2007. That document is hereafter referenced as *State of DR*.

[93] It should be noted that these projections are in addition to the current peak reductions achieved through reliability-triggered demand response. For a description of the distinction between price-responsive DR and reliability-triggered DR programs, see pp. 8-9 of *State of DR*.

[94] Much higher responses are possible in specific facilities that have time-flexible production processes, energy storage systems and back-up generation. Since these are highly facility-specific, they have not been included in our estimate of technical potential.

chose the gateway system, this would yield a weighted average estimate of approximately 19 percent for the residential class. Corresponding values for the commercial and industrial classes are roughly seven percent and nine percent.

- *Market potential* (or "achievable potential") measures what would happen if a cost-effective combination of technologies is accepted by a realistic number of customers in the market place. It differs from economic potential, which assumes that all customers accept dynamic pricing. Thus, the key unknown in estimating market potential is the number of participating customers. This, of course, depends on the conditions under which dynamic pricing is offered to customers. It is also contingent on the availability of advanced metering infrastructure (AMI) which is currently limited to customers above 200 kW but is likely to be deployed for all customers in the state during the next five years. Under that assumption, if dynamic pricing is made the default rate (as it has been made in restructured states for large customers), a larger fraction of customers would be expected to stay on it than if it is offered on an optional basis. The limited literature on the topic suggests that about 80 percent would stay on dynamic pricing if it is offered as the default rate and that a substantially smaller number, perhaps 20 percent, would select in on a voluntary basis. In its initial analysis, the staff assume that the actual number is likely to be somewhere in the middle. This yields an estimate of approximately five percent. Obviously, programs that achieve greater customer participation will yield greater savings.

If California were to achieve a five percent peak demand reduction, there would be several types of benefits. Three of these can be quantified in a preliminary projection. The first and most significant benefit is the reduction in needed peaking generation capacity. This is a long run benefit and consists of the sum of avoided capacity and energy costs. It can be readily estimated based on the capacity cost of a combustion turbine. The second benefit is the avoided energy cost that is associated with the reduced peak load. Third is the reduction in needed transmission and distribution capacity.

To quantify the avoided capacity cost, the amount of capacity that would be avoided by a five percent reduction in peak demand was quantified and valued. A five percent reduction in California peak demand of approximately 61,008 MW amounts to 3,050 MW of avoided peak demand. The amount of peaking capacity that is needed to meet this peak demand can be computed by allowing for a reserve margin of 15 percent and line losses of eight percent. This amounts to 3,789 MW or roughly the output of 50 combustion turbines.[95] A conservative value

[95] These turbines come in sizes generally ranging from 50 MW to 100 MW.

of the avoided cost of generation capacity is $52/kW-year.[96] Thus, the total value of avoided generation capacity costs would be roughly $200 million per year.

Using the relationship that was observed between annual generation capacity and energy benefits in a recent PJM analysis of demand response, the annual value of avoided energy costs is estimated at around $20 million.[97]

In addition, there would be a reduction in transmission and distribution capacity needs. While these are system-specific and depend on the coincidence between system and local area peaks, they are unlikely to be zero. A conservative estimate is 10 percent of the savings in generation capacity and energy costs. Using this estimate, would yield an estimate of roughly $20 million per year for savings in transmission and distribution costs.

Most of the barriers to adopting demand response measures are related to rate design issues, such as the need to deal with constraints created by the AB 1X residential rate freeze and the need to ensure that the rates reflect cost-based pricing principles There are also analytical issues in this area, such as the need to modify existing cost-benefit methodologies for evaluating demand-side programs, develop protocols for measuring demand response impacts and develop innovative rate designs that incorporate the risks of outages and high peak generation costs. Current efforts by the utilities and commissions to develop workable dynamic rate designs and effective protocols for measuring demand response impacts are steps toward solving these problems.

Additionally, there is a dearth of customer understanding of the potential benefits from broad adoption of time-varying and dynamic rates, the impacts on their electricity costs from such a change and the options they have for responding. In fact, the $3 billion calculated earlier as the present value benefit of a 5 percent DR program can just as easily be seen as a measure of the hidden subsidies which in the present time – insensitive rate structure provides to that 5 percent of peak demand. With well-designed rate designs in place, the focus must shift to overcoming the technological barriers to DR. First is the need to install advanced metering infrastructure (AMI) throughout the state. This is likely to happen over the next five years. To get the most out of the AMI investment, it may be necessary to equip the customer with enabling technologies and automation to facilitate reducing demand during critical-peak times. The use of existing technologies that automate demand response should be integrated into program and tariff offerings, while further development of such technologies should continue.

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[96] In R.02-06-001, the CPUC specified a value of $85/kW-year. That value is widely accepted throughout the mainland United States. However, once the revenue stream associated with energy sales from the operation of the turbine is subtracted, a value of $52/kW-year is obtained.

[97] Sam Newell and Frank Felder, "Quantifying Demand Response Benefits in PJM," Study Report Prepared for PJM Interconnection, LLC and the Mid-Atlantic Distributed Resources Initiative (MADRI), January 29, 2007.

Additionally, rates need to be designed with an understanding of the level of response that customers are capable of providing. Research has shown that customers provide a significantly higher level of demand response when equipped with enabling technologies that automate the response and facilitate the control of electricity consumption at multiple end-use points. Ultimately, these enabling technologies need to be adopted on a large scale for California to approach its potential for demand response.

Since the 1970s the Energy Commission has had the authority to establish and enforce Load Management Standards for the state. They were created to provide the Energy Commission with the ability to develop programs for reducing peak demand and reshaping utility load duration curves. The Commission specifically is authorized to consider the following load management techniques, but its authority is not limited to these three:

- Adjustments in rate structure to encourage use of electrical energy at off-peak hours or to encourage control of daily electrical load. Compliance with those adjustments in rate structure are subject to the approval of the Public Utilities Commission in a proceeding to change rates or service.
- End-use storage systems which store energy during off-peak periods for use during peak periods, such as thermal storage, pumped storage, and other storage systems.
- Mechanical and automatic devices and systems for the control of daily and seasonal peak loads.

The Energy Commission's load management authority would be a valuable policy tool for the state to bridge the gap between the current level of DR in California and its full cost-effective potential. In a joint IEPR and Electricity Committee workshop on demand response efforts on June 5, 2007, EnerNoc, Ice Energy, and Strategen Consulting encouraged the Energy Commission to use its load management authority to better achieve the state's DR objectives. At the same workshop, Southern California Edison, San Diego Gas and Electric Company, and Pacific Gas and Electric Company all indicated support for the Energy Commission's effort to invoke its load management authority.

There are two areas in which this policy tool may be particularly effective. One is modifying the default tariff, which could be changed to a dynamic tariff that reflects the higher cost of using electricity during critical peak hours and provides an incentive for lowering peak demand. The other is the adoption of technologies that enable customers to respond to the opportunities created by dynamic pricing tariffs.

Three illustrative load management proposals have been developed. One calls for replacing the default rate design with a dynamic pricing tariff, while the other two call for deploying enabling technologies directed at residential and non-residential customers.

In a scenario in which no load management standards are in place, dynamic pricing would probably be offered on an opt-in basis by the utilities as AMI is rolled out to customers.[98] Once

[98] As proposed by PG&E.

AMI has been fully deployed, dynamic pricing becomes feasible, but on an opt-in basis may not achieve a participation rate greater than 20 percent. In this scenario, customers would probably not be equipped with enabling technologies such as a smart thermostat. Under these assumptions dynamic pricing could achieve a reduction in system peak demand of around three percent, representing over $1 billion in financial benefits over the next 20 years.[99]

In a second case in which a dynamic pricing standard is adopted in California, requiring that some form of dynamic pricing be offered as the default rate, 80 percent of customers are likely to stay on dynamic pricing, with the other 20 percent opting back to their old rate. Assuming that these dynamic pricing customers are not equipped with enabling technology, the peak demand reduction could increase to some 10 percent, representing financial benefits of nearly $6 billion. The incremental benefit of the dynamic pricing standard would be the difference between this and the previous calculation: an increase in peak demand reduction of roughly 7 percentage points and incremental financial benefits of around $4 billion.

Now, if on top of the default dynamic pricing standard, another standard was imposed that required the installation of programmable communicating thermostats (PCT) in all residential dwellings, the potential benefits would rise even further. The standard could require that all residential customers be equipped with PCTs that can receive price signals from the utilities and/or the Independent System Operator (CA ISO) so their temperature setback would be raised by a few degrees during critical-priced periods. With this technology installed, the estimated peak reduction potential might increase incrementally by roughly 8 percentage points to around 18 percent.[100] The present value of the benefits would increase incrementally by around $5 billion to $10 billion.[101]

Finally, an automated demand response standard could be included with the PCT standard and the dynamic pricing standard. This could equip commercial and industrial customers with system-wide automation, allowing them to leverage existing energy management control systems and automatically manage lights, air conditioning, and other sources of load during peak times. With this addition, the estimated peak reduction potential could increase incrementally by roughly 2 percentage points to approximately 20 percent. The present value of the benefits could increase incrementally by around $1 billion to $11 billion.

These approximate estimates of the benefits of new load management standards are summarized in Figure 3-13.

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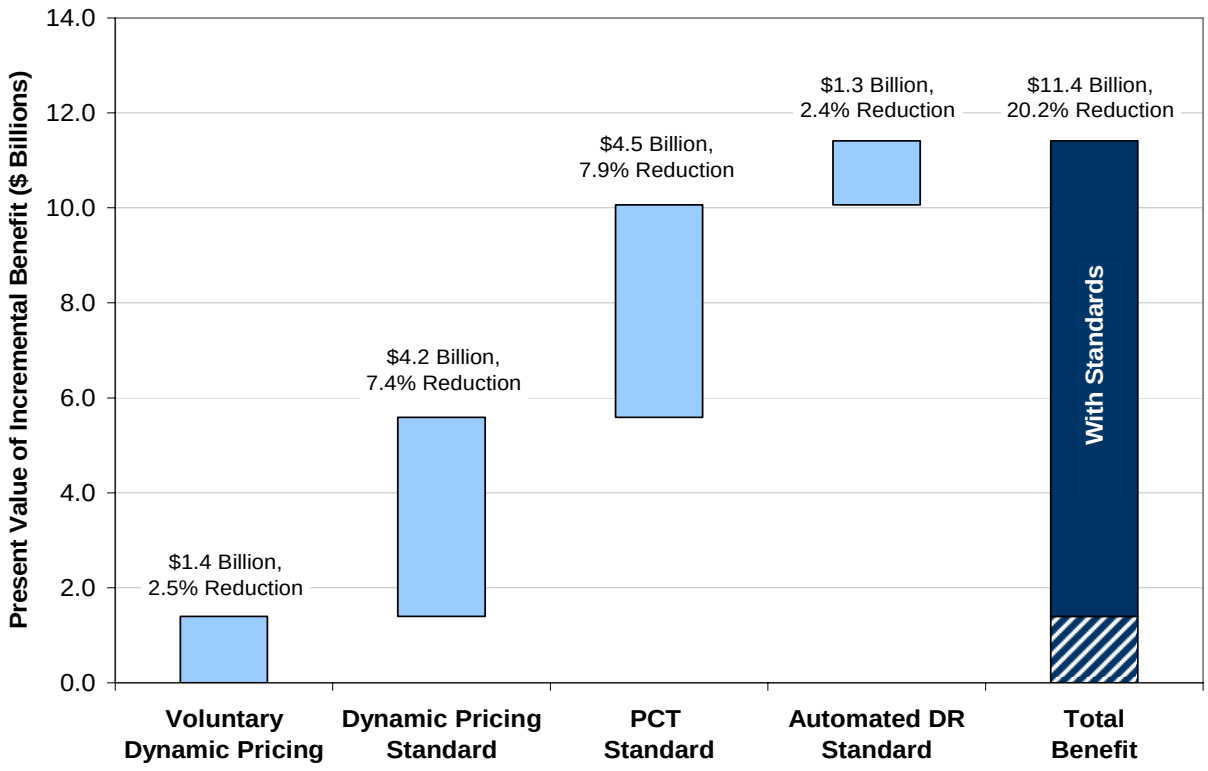
[99] For the methodology behind these computations, consult Sidebar 1. Additionally, Monte Carlo simulations were performed to better understand the range of uncertainty around these estimates. For details, see Appendix A.

[100] Note that this estimate assumes that these benefits will accrue over a 20 year period during which all residential customers have PCTs installed in their homes. There would be an initial period during which the PCTs would need to be rolled out to customers.

[101] Note that some of the figures may not add up due to rounding.

Figure 3-13: Incremental Benefits of Load Management Standards



Recommendations

- Adopt statewide energy efficiency targets for 2016 equal to 100 percent of cost-effective efficiency.
- Enlist POUs in a collaborative relationship to aggressively ramp up energy efficiency programs. POUs need to use their local conditions and customer knowledge to craft new program ideas. In doing so, sufficient incentives need to be provided.
- Pursue legislation that would require energy audits and a cost-effective level of efficiency improvements at the time of sale of a building. Diagnostics and measure verification can be completed while homes or buildings are empty, providing the opportunity for upgrading major building systems such as windows, insulation, lighting, HVAC and water heating.
- Initiate a formal rulemaking process in 2008 to pursue the adoption of load management standards under its existing authority.
- Enact appliance standards to improve efficiency of appliances sold in California, specifically targeting standards to increase the efficacy of general service lighting.

- Increase the efficiency levels of the building standards so that buildings are net zero energy users by 2010 for residences and by 2020 for commercial buildings.
- Support behavioral and other social science research applied to customer decision making in energy efficiency.
- Investigate market-based approaches to energy efficiency such as the "white tag" or "white certificate," also known as energy efficiency certificates or credits – the analog to renewable energy credits.

CHAPTER 4: Using Renewable Resources to Meet Energy Needs

Introduction

California is a national leader in the development of renewable resources. Over the past 30 years, the state has built one of the largest and most diverse renewable generation portfolios in the world. In 2002, California established its Renewable Portfolio Standard program, with the goal of increasing to 20 percent by 2017 the percentage of the state's electricity that is sold to retail customers and derived from renewable resources. Legislation accelerated that target date to 2010, and the *2004 Integrated Energy Policy Report (IEPR) Update* recommended increasing the target to 33 percent by 2020. The *2005 IEPR* and *2006 IEPR Update* both reinforced that recommendation.

Two main considerations drive the state's goals to achieve 20 percent renewable energy by 2010 and 33 percent by 2020:

- The critical need to reduce greenhouse gas emissions
- Management of the cost and risk borne by ratepayers for electricity generation

Increasing renewable energy to 20 percent of electricity sales by 2010 and 33 percent by 2020 is an essential part of reducing California's greenhouse gas (GHG) emissions. The Governor's long-term target is to reduce GHG emissions to 80 percent below 1990 levels by 2050, which is consistent with the global reductions necessary to substantially reduce the expected rate, magnitude, and impact of climate change.[102] The AB 32 GHG emissions limit of 1990 levels by 2020 is an important milestone for achieving these longer term reductions.

Given this context, California's progress to date in achieving its renewable energy goals is too slow. Barriers in the short and longer term include:

- Lack of legislative authority to require renewable procurement beyond 20 percent by 2010.

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[102] This level of reduction is consistent with the global reductions needed to achieve a GHG concentration stabilization level of about 450 ppm CO_2 equivalent. The IPCC reports a best estimate of about 2 degrees to 2.4 degrees Celsius above preindustrial levels for 450 ppm CO_2 equivalent, substantially reducing the expected magnitude, impact, and rate of climate change from business as usual scenarios. IPCC, 2007. Climate change 2007: Mitigation. Contribution of Working group III to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change [B. Metz, O. R. Davidson, P. R. Bosch, R. Dave, L. A. Meyer (eds)], Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA. http://www.ipcc.ch/SPM040507.pdf, pp. 22-25..

- Lack of adequate transmission to renewable-rich resource areas, both in-state and out-of-state.
- Challenges with integrating large quantities of intermittent resources.
- Complexity, lack of transparency, and undervaluing of renewables in the RPS program.
- The need for greater clarity regarding the treatment of GHG emissions displaced by renewable energy procured to meet California's renewable energy targets.
- Pending federal legislation that, if inadequately designed, could preempt or negatively affect California's RPS targets.

These barriers will almost certainly delay accomplishment of the 2010 goal by several years and must be overcome for California to meet its goal of 33 percent renewables by 2020.

California must determine how to meet its renewable and GHG emission reduction goals while minimizing costs and risks borne by electric ratepayers. Assembly Bill 1585 (Blakeslee, Chapter 579, Statutes of 2005), which directed the Energy Commission to prepare an evaluation of the impacts of the 33 percent goal, was passed subject to the passage of Senate Bill 107 (Simitian, Chapter 464, Statutes of 2006) in 2005. However, because SB 107 did not pass until 2006, AB 1585 did not become law. Nevertheless, the Governor's signing statement for AB 1585 directed the Energy Commission to prepare and incorporate into the *IEPR* a report addressing the following topics related to the 33 percent goal:

- Needed transmission
- System reliability and dispatchability impacts
- Long-term planning requirements identified in electrical corporations' 2006 procurement plans
- Potential impacts on electric rates

In addition, the Energy Commission is directed to report on progress made by California's public and private utilities and other entities that provide retail electricity in meeting the 20 percent by 2010 goal.

Meeting the 33 percent goal in 2020 is feasible, but will require coordinated efforts in transmission and generation planning, as well as bold initiatives to ensure that state-of-the-art technology is used to create a more flexible and integrated electricity system; including several transmission initiatives; moving forward with feed-in tariffs;[103] and streamlining permitting , contracting, and construction.

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[103]A long-term contract providing a fixed price or a fixed premium above market prices for electricity generated from eligible renewable energy resources or fuels.

Key Drivers for Renewable Energy and Recent Legislation

This section provides background on the two major policies driving renewable energy development—reducing greenhouse gas emissions and managing cost and risk to ratepayers—as well as an update on recent state legislation affecting renewable energy and a discussion of federal legislation that could preempt California's renewable energy programs.

Reducing Greenhouse Gas Emissions

As part of the state's loading order for electricity, renewable energy is essential to meet California's greenhouse gas emission reduction goals. In support of the state's efforts to coordinate with neighboring states and international partners to reduce greenhouse gases, this section summarizes recent trends in California, other states, and Europe, including the following topics:

- The California Global Warming Solutions Act of 2006 (AB 32)
- Market Advisory Committee's view that renewable energy should not create offsets[104]
- Need to separate RPS from a future carbon market for California

The California Global Warming Solutions Act of 2006

In consultation with other state agencies and with programs in other states, cities, regions, and countries, by January 1, 2009, the California Air Resources Board (ARB) must prepare a scoping plan "for achieving the maximum technologically feasible and cost-effective reductions in greenhouse gas emissions from sources or categories of sources of greenhouse gases by 2020" as defined by AB 32 (Health and Safety Code Section 38561 [a]). The plan must be updated at least every five years.

AB 32 requires the ARB to adopt a statewide GHG emissions limit to achieve 1990 levels by 2020. The ARB must adopt the limit and "emission reduction measures by regulation" by January 1, 2011, to be effective by January 1, 2012. The law requires that reductions pursued through any market-based compliance mechanism must be "in addition to any greenhouse gas emission reduction otherwise required by law or regulation, and any other greenhouse gas emission reduction that otherwise would occur."

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[104] Offsets refer to greenhouse gas emission reductions from a source in a sector or location that is not included in a cap- and-trade program. For more information, see http://www.climatechange.ca.gov/documents/2007-06-29_MAC_FINAL_REPORT.PDF, p. 61-62.

AB 32 makes clear the intent of the Legislature to continue GHG emission reductions beyond 2020, maintaining the limit established in AB 32 and directing the ARB to recommend further actions to the Governor (Section 38551). The Governor's Executive Order S-3-05 underscores that long-term commitment, establishing a goal of 80 percent below 1990 levels by 2050.[105] Led by CAL EPA, the California Climate Action Team prepares reports to the Governor recommending strategies to achieve the state's GHG emission reduction targets, including the target for 2050.

Market Advisory Committee: Renewables Should Not Create Offsets

The Governor created a Market Advisory Committee tasked with preparing a report for ARB on designing a market-based compliance program. In its report released on June 30, 2007, the Market Advisory Committee explained that renewable energy for electricity should not create offsets for a cap-and-trade[106] system for GHG emissions because that simply reduces the demand for allowances from regulated sources and does not provide additional reductions in GHG emissions.[107]

Furthermore, the report explains that a cap-and-trade system addresses the lack of a price signal for reducing greenhouse gas emissions but does not address other impediments. A cap-and-trade system is best used to complement standards and incentives that address other impediments, such as the risk of a step-change in technology, fragmented supply chains, and high discount rates for investment by consumers. "By itself, a cap-and-trade program alone will not deliver the most efficient mitigation outcome for the state. There is a strong economic and public policy basis for other policies that can accompany an emissions trading system."[108]

Separating the Renewables Portfolio Standard from a Future Carbon Market for California

The California Climate Action Team report identified achieving 33 percent renewable energy by 2020 as one of the key strategies for reducing GHG emissions in California. To ensure the maximum contribution of this renewable energy target to GHG emission

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[105] Office of the Governor, Executive Order S-3-05, signed June 1, 2005.

[106] Cap-and-trade refers to a market-based compliance mechanism to lower allowable greenhouse gas emissions over time to achieve a specified limit. Each regulated source of greenhouse gas emissions gets a specified number of emission credits for each compliance period (e.g., per year). If a source finds it has more emission credits than emissions, it may sell the excess credits.

[107] http://www.climatechange.ca.gov/documents/2007-06-29_MAC_FINAL_REPORT.PDF, accessed July 27, 2007.

[108] Ibid, p. 19.

reduction, the number of allowances distributed under any future cap-and-trade system must exclude the amount of fossil-fuel energy displaced by achieving the RPS target.

As part of implementing AB 32, ARB will determine what quantity of GHG emissions is equivalent to the GHG emission reduction goal of 1990 levels by 2020. The ARB will also consider whether to establish a cap-and-trade system and to allow offsets from entities in sectors not covered by the trading system. The quantity of allowances to be distributed under a cap-and-trade system will not be equivalent to the 1990 emissions level because all sources are not likely to be included within the system. At issue is what portion of the annual emissions target will be included in any allowance-based trading system. It is widely believed that an emissions trading system can be an efficient means of creating a price signal that encourages investment in additional GHG-reducing alternatives to meet California's growing energy demand.

The contribution of the 33 percent renewable goal to GHG emission reductions may not be clear if the expected carbon reductions that will emerge from this goal are not subtracted from the number of allowances distributed in a cap-and-trade system. The mechanism for reducing GHG emissions in a cap-and-trade system is a gradual reduction in the number of allowances. Adding renewable energy, without reducing the number of allowances distributed, will reduce the demand for allowances, but will not lower the total number of allowances. If the reductions were not subtracted, then if one utility reduced its GHG emissions by adding renewable energy to meet the 33 percent by 2020 target, it would be able to sell its GHG allowances to another utility, producing no net GHG emission reduction. To avoid this perverse effect, any expected GHG emissions reductions from achieving the state's renewable energy goals should reduce the pool of available GHG allowances.

In addition, using renewable energy credits (RECs) in a situation where they may actually result in no net GHG emission reduction could affect the value of the RECs.[109] Although some states allow the GHG emissions attribute to be separated from a REC used for their RPS programs, California's RPS does not. As defined by Public Utilities Code Section 399.12(g)(2):

> "Renewable energy credit" includes all renewable and environmental attributes associated with the production of electricity from the eligible renewable energy resource, except for an emissions reduction credit issued pursuant to Section 40709 of the Health and Safety Code and any credits or payments associated with the reduction of solid waste and treatment benefits created by the utilization of biomass or biogas fuels.

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[109] As defined in California, a renewable energy credit is a certificate of proof that one unit of electricity was generated and delivered by an eligible renewable resource. For further information, see the RPS Eligibility Guidebook, http://www.energy.ca.gov/renewables/documents/index.html#rps.

However, the exact quantification of these environmental attributes has not been assessed. Their value depends on the regulatory environment and the electricity that is displaced by the REC.

In written comments for the March 13, 2007, IEPR workshop on wind repowering and best practices for coordinating the RPS with carbon market design, APX warned, "If renewable energy is managed outside the Cap and Trade mechanism and if the Cap is set without taking renewable energy emissions reductions into account, then it would significantly weaken any emission reduction claims of REC purchases, whether for state RPS compliance or for voluntary green power programs."[110]

In a situation where RECs are used in such a way that they do not result in net GHG emissions reductions, the value of the REC would depend on the supply of RECs, other low-GHG resources, and GHG emission allowances in a trading system. For example, an increase in renewable energy use by one utility could allow the utility to sell some of its allowances, enabling an increase in fossil fuel use by another utility. This could yield no net greenhouse gas emission reduction and potentially cause an over-supply of allowances. As was evident in the first phase of the Emissions Trading System (ETS) of the European Union (EU), the excess supply of annual emissions allowances combined with the lack of carryover into Phase II of the EU ETS led the trading price to fall from 33 Euro to less than 1 Euro.[111]

In contrast, if RECs are taken off the top of the number of allowances, an increase in the use of renewable energy leads to a decrease in GHG emissions.[112] In this case, the amount of GHG emissions contained in a REC would be a function of the electricity displaced by the generation of the renewable energy creating the REC.

Taking 33 percent renewables by 2020 "off the top" of the quantity of allowances distributed under a cap-and-trade system reduces uncertainty and would create a price

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[110] California Energy Commission, Integrated Energy Policy Report Committee Workshop on Incentives for Wind Repowering and Best Practices for Coordinating RPS with Carbon Market Design, March 13, 2007, Automated Power Exchange written comments.

[111] For reviews of the EU ETS see: http://ec.europa.eu/environment/climat/emission/review_en.htm and http://www.openeurope.org.uk/research/etsp2.pdf.

[112] Although combustion of biomass releases CO_2, it displaces the methane that would have been released through decay of the biomass. The greenhouse gas effect of methane is many times stronger than the effect of carbon dioxide. For further discussion, see Morris, G. 1999. The Value of the Benefits of U.S. Biomass Power. NREL/SR-570-27541. Golden, Colorado: National Renewable Energy Laboratory. In addition, Senate Bill 1368 (Perata), Chapter 598, Statutes of 2006 prohibits long-term financial obligations, including ownership and contracts five years or longer, with power plants, including biomass and biogas power plants, that exceed the state's greenhouse gas performance standard.

incentive for utilities to increase the pace of their investments in these long-standing, high priority alternatives.

Managing Risk and Cost to Ratepayers

California continues to be at risk from the potential for sustained high natural gas prices. In 2006, dependency on natural gas for electricity was 41 percent, up from 36.5 percent in 2002. California's growing dependence on natural gas for electricity generation has been a major theme of the *Integrated Energy Policy Reports* since 2003.

Another source of price risk associated with California's generation mix is the potential future cost of carbon emissions. The European Union instituted trading of carbon emissions allowances as part of its efforts to meet the Kyoto Protocol. In implementing AB 32, California will adopt various strategies to limit greenhouse gas emissions, and fossil fuel generation is likely to incur costs based on such emissions.

In addition to the economic risk posed by volatile fuel prices and unknown emissions costs, global warming presents serious risks to public health and safety in addition to costs associated with the consequences of climate change. Increasing renewable energy generation is critical in mitigating these risks.

Renewable resources are also subject to technology price risk, including investment cost risk, operations and maintenance risk, and risks associated with the intermittency of some technologies such as wind and solar. However, the volatility of the costs associated with these risks is much less than the volatility of the price of natural gas.[113]

Two important questions determine how we approach these risks. First, what portfolio of generation assets has the best combination of risk and expected cost for California's ratepayers? Second, what kind of premium is justified to accelerate renewable development in light of the dangerous effects of climate change?

To address the first question, the Energy Commission examined the use of portfolio analysis. Portfolio analysis allows the presentation of a range of portfolios, each with a different combination of expected cost and risk, allowing decision makers to choose one which matches the desired risk tolerance. The level of risk exposure is a policy decision. As discussed in the *2006 IEPR Update*, the current standard of comparison is based on stand-alone incremental engineering calculations of the future expected cost of electricity from a new baseload natural gas-fired combined cycle generation plant.

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[113] Bates White, A Mean-Variance Portfolio Optimization of California's Generation Mix to 2020: Achieving California's 33 Percent RPS Goal, Draft Consultant Report, July, 2007, CEC-300-2007-009/CEC-300-2007-009-D.PDF.

The resulting market price referent (MPR),[114] however, fails to properly consider the risk of price volatility. In the *2006 IEPR Update*, the Energy Commission discussed the weakness of relying on a particular natural gas forecast that represents a snapshot of potential future costs. Costs for most renewable generation (other than biomass) are independent of fuel price volatility and depend primarily on capital investment during project development. Thus, renewable generation has value as a hedge against fuel price volatility. However, in the current IOU solicitation process for long-term RPS contracts, SDG&E states that renewable energy developers tend to increase their bids if natural gas prices rise.[115] SCE is concerned that the demand for renewable energy is outpacing the supply and anticipates that prices for renewable energy will be 25 percent higher as the state moves to 33 percent by 2020. To avoid these results, changes in the structure of the RPS program could be designed to de-link prices paid for renewable energy from natural gas and thereby avoid a shortage of renewable energy. One way of doing so is through feed-in tariffs, discussed later in this chapter.

Investors in stocks and other assets know that diversification can mitigate or reduce risk. Increasing diversity by adding a less volatile asset reduces risk, more so when the values of the different assets are not perfectly correlated. A similar approach, focusing on expected costs and risk, should be used in determining the generation mix of most value to California's ratepayers. Modern portfolio analysis shows that adding higher cost assets can result in lowering total portfolio risk.

In addressing the second question, the cost of carbon emissions represents an additional risk that is difficult to estimate. In 2005, the CPUC directed the large IOUs to use a carbon adder[116] for resource planning and bid evaluation of $8 per ton of CO_2, escalating at 5 percent per year. However, other estimates of CO_2 emissions costs range from $0 to $58 per ton.[117] A recent Synapse report estimates that in 2020 CO_2 emission costs will be $10 to $33 per ton,[118] indicating that the $8 per ton figure may be too low. A CPUC draft

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[114] A proxy for the market price of various electricity products, used to compare renewable products to meet a retail seller's Renewable Portfolio Standard obligations. Contracts with renewable generators at or below the market price referent are deemed reasonable with costs recoverable in rates.

[115] SDG&E 2007-2016 LTPP Vol 1 part 2 p. 211.

[116] A price per ton of carbon used by utilities when evaluating options to meet future electricity demand. The adder is used for planning purposes as a proxy for potential future greenhouse gas emission reduction costs.

[117] 2006 IEPR Update, page 55. See footnotes for sources of various estimates.

[118] Synapse Energy Economics, Inc, "Climate Change and Power: Carbon Dioxide Emissions Costs and Electricity Resource Planning," prepared by Lucy Johnston, Ezra Hausman, Anna Sommer, Bruce Biewald, Tim Woolf, David Schlissel, Amy Rocshelle, and David White, June 8,

resolution scheduled for consideration on October 4, 2007, adds carbon adders to the MPR, with values ranging from 0.354 to 1.211 cents per kWh ($3.54 to $12.11 per MWh) depending on the contract length and contract start year.[119] These values are based on CPUC Decision 04-12-048, which says: "Consistent with established Commission policy, and the positions of several parties, including PG&E, we adopt a range of values to explicitly account for the financial risk associated with greenhouse gas emissions (which we call a "GHG adder"), of $8 to $25 per ton of CO2, to be used in the evaluation of generation bids."

Legislation Affecting Renewables in California

State Legislation

Three recently enacted bills affect California's RPS program: Senate Bill 107,[120] which made significant modifications in California's RPS program; Assembly Bill 1969,[121] which requires IOUs to set a tariff to purchase renewable generation from small facilities operated by public water and wastewater agencies; and Assembly Bill 1585,[122] which requires the Energy Commission to evaluate the feasibility of the 33 percent by 2020 renewable goal.

- **SB 107**: This bill codifies the 20 percent by 2010 goal set by the Governor and State energy agencies. Several provisions of SB 107 serve to incorporate publicly owned utilities (POUs) more fully into the RPS. POUs are now required to report to the Energy Commission the resource mix they use to serve their customers using the categories defined as eligible for the RPS for the state's IOUs, electric service providers (ESPs), and community choice aggregators (CCAs). A summary of the data submitted by the POUs this year in response to this requirement is provided later in this chapter.

  SB 107 also established a process that may lead to allowing unbundled renewable energy certificates to count toward meeting the RPS requirement, provided "the electricity is delivered to a retail seller, the Independent System Operator, or a local publicly owned electric utility."[123] Further, SB 107 continued the trend to

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2006. Available at: http://www.synapse-energy.com/Downloads/SynapsePaper.2006-06.0.Climate-Changeand-Power.A0009.pdf.

[119] CPUC, revised Draft Resolution E-4118, September 24, 2007, at http://www.cpuc.ca.gov/PUBLISHED/COMMENT_RESOLUTION/73147.htm.

[120] Senate Bill 107 (Simitian), Chapter 464, Statutes of 2006

[121] Assembly Bill 1969 (Yee), Chapter 731, Statutes of 2006.

[122] Assembly Bill 1585 (Blakeslee), Chapter 579, Statutes of 2005.

[123] Public Utilities Code Section 399.16(a)(3).

relax deliverability requirements for renewable energy generated out of state. It allows electricity generated by an RPS-eligible[124] resource to be considered delivered "regardless of whether the electricity is generated at a different time from consumption by a California end-use customer."[125] This makes it possible for out-of-state wind and other intermittent resources that cannot normally be scheduled across control areas to meet deliverability requirements and count toward a utility's RPS target.

However, under SB 107, before the CPUC can authorize the use of RECs for RPS compliance, the CPUC and Energy Commission must jointly determine that a REC tracking system is operational and "can ensure that renewable energy credits shall not be double counted by any seller of electricity within the service territory of the Western Electricity Coordinating Council [WECC]."[126] The Energy Commission and other WECC entities developed the Western Regional Energy Generation Information System (WREGIS), which began operating in June 2007, to track renewable energy used for RPS programs in the WECC to prevent double counting.

Although the CPUC may determine that RECs may be used to comply with the RPS, SB 107 stipulates that supplemental energy payments (SEPs), intended to cover the above-market costs of complying with California's RPS, may not be used for RECs.[127] Also, a retail seller may purchase RECs from a POU only if the Energy Commission has determined that the POU is on track to meet its own RPS that is comparable to the standard applied to retail sellers.

- **AB 1969:** The purpose of AB 1969 is to bring in additional RPS-eligible energy from facilities that are too small to participate in utility RPS solicitations, either because they fail to meet minimum size requirements or because the process is too complex. In implementing AB 1969, the CPUC ordered IOUs to set a tariff under which qualifying generation from public water and wastewater facilities up to 1.5 megawatts is purchased at the MPR used for the RPS, until a statewide cap of 250 megawatts is reached under the program. Furthermore, the CPUC

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[124] For information on RPS eligibility, see the RPS Eligibility Guidebook, http://www.energy.ca.gov/renewables/documents/index.html#rps.

[125] Public Resources Code § 25741(a).

[126] Public Utilities Code Section 399.16(a)(1).

[127] Supplemental Energy Payments are incentive payments made by the Energy Commissions New Renewable Facilities Program to cover the above-market cost of procuring energy from an eligible renewable energy resource for the Renewable Portfolio Standard. For more information, see the RPS Eligibility Guidebook, http://www.energy.ca.gov/renewables/documents/index.html#rps.

instituted a parallel program for about 230 megawatts that is open to customers other than public water and wastewater agencies.[128]

- **AB 1585:** In 2005, the legislature passed AB 1585, which would have required the Energy Commission to include "a review of the feasibility of increasing the RPS to 33 percent by 2020." However, the law was to go into effect only if SB 107 of the 2005-06 regular session was also enacted and became operative on January 1, 2006. SB 107 was enacted in September 2006 and went into effect January 1, 2007. In signing AB 1585 into law, the Governor directed the Energy Commission to conduct the review even though SB 107 did not go into effect on the date required. The Energy Commission's response to the Governor's direction is provided in this chapter.
- **SB 451 (pending):** SB 451 expands the concept of AB 1969 and creates a standard tariff for facilities of all customers of up to 1 megawatt. The statewide cap is 1,000 megawatts.
- **SB 1036 (pending):** SB 1036 switches the responsibility for administration of funds above-MPR costs of renewable energy from the Energy Commission to the CPUC. By March 1, 2008, unencumbered funds from the New Renewable Resources Account of the Renewable Trust Fund will be returned to the utilities and held in accounts to be used for above-market costs of RPS generation. Funds will be allocated proportionally by load share to the utilities whose customers pay into the renewable public goods charge. Use of the funds must be approved by the CPUC through the advice letter and contract approval process currently used for RPS contracts.

Federal Proposed Legislation

As of August 2007, legislation was pending in Congress that could negatively affect California's RPS program. While a federal RPS could help stimulate investment in renewable energy if it were designed as a minimum requirement, it would not serve this purpose if it effectively prevented states from increasing renewable energy beyond the federal standard, or allowed the higher standards in some states to 'offset' procurement to the federal standard in other states.

A minimum standard could help overcome underinvestment in renewable energy resulting from a misallocation of risk. Utility procurements, as well as deregulated markets, tend to systematically under-invest in renewables and efficiency because the

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[128] California Public Utilities Commission, July 26, 2007, "Decision 07-07-027: Opinion Adopting Tariffs and Standard Contracts for Water, Wastewater and Other Customers to Sell Electricity Generated from RPS-Eligible Renewable Resources to Electrical Corporations," Rulemaking 06-05-027, http://www.cpuc.ca.gov/WORD_PDF/FINAL_DECISION/70660.PDF, accessed August 6, 2007.

cost of fuel price volatility on customers is ignored.[129] A minimum federal standard would also require those electricity suppliers in the 25 states without a state RPS to meet certain minimum renewable energy purchase requirements, therefore expanding the nation's use of renewable electricity.

Also, a minimum standard would allow state and regional initiatives to take advantage of the diversity of resources across the states, allowing each state to decide how to meet electricity needs beyond the minimum standard. The Western states are rich in renewable resources, but the resource mix likely to be developed in the next 10 years varies widely from state to state. For example, the Western Governors' Association Clean and Diversified Energy Advisory Committee's Transmission task force developed a scenario of renewable resources that are likely to be economically feasible to meet the WGA goal of 30,000 MW of clean and diversified energy by 2015, as shown in Figure 4-1.

The range of policies and requirements among the states in the West is readily accommodated in the Western Generation Information System (WREGIS), which can track renewable generation of member facilities in the WECC interconnect. To be eligible for the California RPS, generators must join WREGIS.

As discussed in Chapter 2, the Energy Commission published a study[130] showing the impact of a range of scenarios, including one scenario assuming about 30 percent renewable energy in California and a second scenario holding that amount of renewable energy in California constant while adding high levels of renewable development in the West, similar to the CDEAC scenario shown in Figure 4-1. The study suggested that high renewable energy development in the West displaces some new conventional generation additions and frees up some existing conventional generation. The study also finds that there may be increased levels of low-cost, high GHG-emitting resources into California. How to attribute GHG characteristics of power plants located out-of-state within the regulatory construct is one of the major unresolved challenges of GHG policy implementation. However, out of state renewable generation may also help California realize its goals at lower cost to ratepayers.

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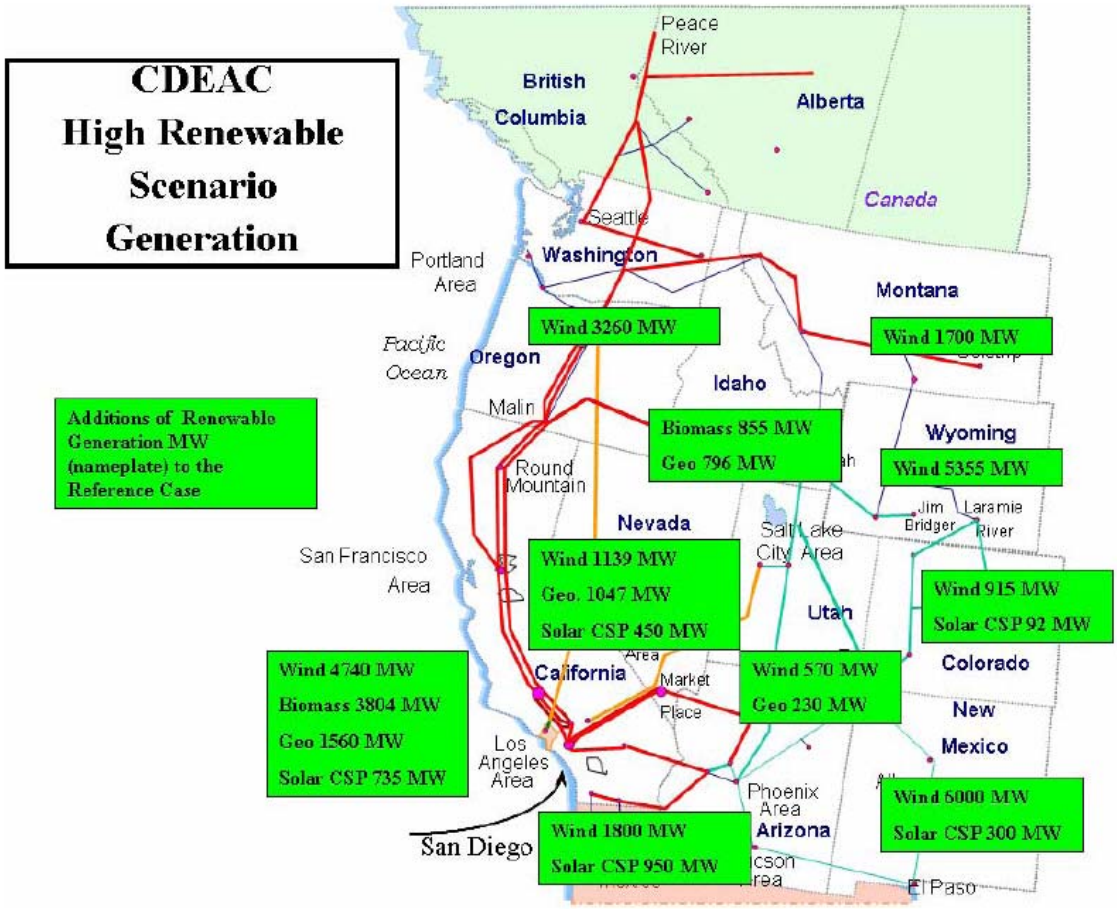
[129] For a detailed discussion, see California Energy Commission, July 2007, A Mean-Variance Portfolio Optimization of California's Generation Mix to 2020: Achieving California's 33 Percent Renewable Portfolio Standard Goal, DRAFT CONSULTANT REPORT, CEC-300-2007-009-D. http://www.energy.ca.gov/2007_energypolicy/documents/index.html#071107, p. 1.

[130] California Energy Commission, July 2007, Staff Draft Report: Scenario Analyses of California's Electricity System; Preliminary Results for the 2007 Integrated Energy Policy Report, Addendum, CEC-200-2007-010-AD1, http://www.energy.ca.gov/2007publications/CEC-200-2007-010/CEC-200-2007-010-AD1.PDF, p. 4-5.

Figure 4-1. Clean and Diversified Energy Advisory Committee Transmission Task Force High Renewables Scenario for 2015



Source: http://www.westgov.org/wga/initiatives/cdeac/TransmissionReport-final.pdf

Feasibility of 33 Percent by 2020: AB 1585 Review

Governor Schwarzenegger directed the *2007 Integrated Energy Policy Report* to review the feasibility of 33 percent renewable energy in California by 2020. The CPUC currently has legislative authority to require investor-owned utilities to purchase 20 percent renewable energy by 2010, provided supplemental energy payments are available for above-market costs. To extend that authority to 33 percent will require additional legislation. Six topics identified in AB 1585[131] and related issues will affect the state's ability to achieve 33 percent renewable energy by 2020.

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[131] California, Office of the Governor, Signing statement for AB 1585 (Blakeslee), Chapter 579, Statutes of 2005: " … Unfortunately, this measure was joined to another measure requiring concurrent enactment and that measure did not pass the Legislature. By signing this measure I

- Deliverability of electricity from eligible renewable energy resources to end users and any needed additions or upgrades to the transmission grid system
- Dispatchability of electricity from eligible renewable energy resources and the consequences for the reliability of the electrical system
- Long-term planning requirements identified in the 2006 procurement plans for electrical corporations approved by the Public Utilities Commission pursuant to Section 454.5 of the Public Utilities Code
- Potential impacts upon the rates of electrical corporations and whether or not a renewable energy public goods charge is necessary to fund the above-market costs of electricity generated from eligible renewable energy resources
- The progress made by electrical corporations toward meeting the goal of procuring 20 percent of the electricity sold to retail customers per year by the year 2010, and the results of electrical corporation bid solicitations pursuant to a renewable energy procurement plan approved by the Public Utilities Commission pursuant to Section 399.14 of the Public Utilities Code
- The progress made by all load-serving entities other than electrical corporations, including the progress made by local publicly owned electric utilities as defined in subdivision (d) of Section 9604 of the Public Utilities Code, toward meeting the goal of procuring 20 percent of the electricity sold to retail customers per year by the year 2010

Deliverability and Transmission Upgrades Needed

The first topic in AB 1585 that affects the state's ability to achieve the 33 percent by 2020 goal is the need for transmission additions or upgrades to deliver renewable electricity. This section provides an overview of the status of new transmission to access areas rich in renewable resource potential, including:

- Delays facing key transmission projects
- FERC support for transmission to multi-user location-constrained resources
- Potential involvement of the California ISO to facilitate equitable cost allocation of renewable generation through expanded feed-in tariffs
- In-state planning processes for renewables transmission
- Transmission to bring renewable energy from out of state
- Renewable Energy Certificates and deliverability

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am directing the appropriate agencies to include the review required by this bill in the next update of the Integrated Energy Policy Report even though this measure will not be enacted." http://www.governor.ca.gov/govsite/pdf/press_release_2005/AB_1585_signing.pdf, accessed June 21, 2007.

- Need for a "smart" transmission-distribution system (potential solutions are discussed in the *Dispatchability and Reliability* section below.)

Additional information and recommendations regarding transmission planning are provided in the *2007 Strategic Transmission Investment Plan*.

Delays Facing Key Transmission Projects

Key transmission projects to access the renewable resources in the Tehachapi Mountains and Imperial County are facing delays.

SCE is planning to build new transmission to allow up to 4,500 MW of wind from the Tehachapi Wind Resource Area to interconnect to the transmission grid. As of July 2007, the projected completion date is winter of 2013.[132] Segments capable of exporting 700 MW of wind from the area are scheduled to be completed by the end of 2009.[133]

LADWP is expanding its transmission lines in the Tehachapi Wind Resource Area to accommodate at least 500 MW of wind and other renewables as part of a larger project that will add 1,150 MW of transfer capability for renewables and other transmission needs.[134] The Energy Commission encourages LADWP to coordinate its plans with Southern California Edison to avoid duplicative transmission development.

The Sunrise-Powerlink transmission project would provide access to about 1,000 MW of renewable energy.[135] The project has been delayed by debate regarding the path the transmission line should take from Imperial County to San Diego County.[136] In response

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[132] Southern California Edison, Updated July 2007, *Fact Sheet: Tehachapi Renewable Transmission Project*, http://www.sce.com/NR/rdonlyres/96270562-668A-49F8-BCD4-B96A9D8E3F9E/0/TRTPFSJuly07.pdf, accessed July 20, 2007.

[133] Southern California Edison Company, December 11, 2006, 2006 Procurement Plan Volume 1B (Public Version), https://www.pge.com/regulation/LongTermProcureOIR/Testimony/SCE/2006/LongTermProcureOIR_Test_SCE_20061211-02.pdf, p. 95

[134] Department of Water and Power, City of Los Angeles, April 17, 2007, Renewable Transmission, presentation at April 17, 2007, IEPR workshop, Slide #5, accessed July 20, 2007, <http://www.energy.ca.gov/2007_energypolicy/documents/2007-04-17_workshop/public_comments/16%20Randy%20Howard%20LADWP.pdf>. LADWP's transmission plans are further described in its March 30, 2007, data response to the Energy Commission's Transmission Related Data Request.

[135] CPUC, SDG&E's Proposed Sunrise Powerlink Transmission Project, http://www.cpuc.ca.gov/static/hottopics/1energy/a0512014.htm, accessed July 20, 2007.

[136] California Public Utilities Commission, San Diego Gas & Electric Company's Sunrise Powerlink Project(Applications A.05-12-014 and A.06-08-010), http://www.cpuc.ca.gov/environment/info/aspen/sunrise/sunrise.htm, accessed July 20, 2007. See

to public comments, alternative paths have been proposed. The Committee has no position regarding the path the line should take, but urges the parties to find a workable solution as the Sunrise-Powerlink transmission project appears necessary for SDG&E to achieve the state's renewable energy goals of 20 percent by 2010 and 33 percent by 2020.

The Green Path Coordinated Projects, involving LADWP, IID, Citizens Energy, and SDG&E, would provide access to more than 2,000 MW of new renewable energy resources in the Imperial Valley. The Energy Commission supports this project for its contribution to achieving the state's RPS goals. However, the Imperial Irrigation District has raised concerns that may delay completion of this project.[137]

The proposed transmission development for the Tehachapi Wind Resource Area would capture much of the estimated economic potential for renewable energy development in that region, but the proposed transmission lines into the Imperial Valley could potentially need further expansion to accommodate the full renewable energy development of that region. Studies published by the Energy Commission's PIER-renewables staff identify potential renewable energy in Tehachapi by 2020 as about 8,000 MW of wind, with 4,500 MW included in a scenario achieving 33 percent by 2020.[138] Estimates for Imperial County total more than 3,700 MW of near-term potential for new renewables, including about 1,000 MW of wind, about 2,400 MW of geothermal (1,900 MW more than existing), and large amounts of potential concentrating solar power. [139] RPS contracts have been signed for more than 800 MW of solar in Imperial County requiring new transmission.[140]

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also, J. Harry Jones, January 26, 2007, Public can weigh in on Sunrise project, San Diego Union Tribune, http://www.signonsandiego.com/news/northcounty/20070126-9999-1mi26sunrise.html, accessed July 20, 2007.

[137] Jesse Montano, July 10, 2007, "Phase 1 Direct Testimony of Jesse Montano on Behalf of Imperial irrigation District, Before the CPUC, Application No. 06-08-010, In the matter of the application of SDG&E Company for a CPCN for the Sunrise Powerlink Transmission Project.

[138] http://www.energy.ca.gov/pier/notices/2007-02-13_workshop/presentations/04_2007-02-13_DAVIS+DAHMAN+PATTEN.PDF, p. 85.

[139] Wind estimates are from http://www.energy.ca.gov/2007publications/CEC-500-2007-014/CEC-500-2007-014.PDF, p. 13. Geothermal estimate is from http://www.energy.ca.gov/2005publications/CEC-500-2005-070/CEC-500-2005-070.PDF, p. 8. For estimates of technical potential for concentrating solar power, see http://www.energy.ca.gov/2005publications/CEC-500-2005-072/CEC-500-2005-072-D.PDF, p. 19.

[140] California Energy Commission, April 6, 2007, Database of Investor-Owned Utilities' Contracts for Generation, Contracts Signed Towards meeting the California Renewable portfolio Standard Target. http://www.energy.ca.gov/portfolio/contracts_database.html, accessed July 20, 2007.

FERC Support for Transmission

Since the *2006 IEPR Update*, the FERC has approved a concept proposed by the California ISO to provide a new financing mechanism for interconnecting location-constrained, multi-user resources, such as renewables, to the transmission grid. Under this concept, each generator that interconnects would be responsible for paying its pro rata share of the going-forward costs of using the line, but until the line is fully subscribed, all users of the grid would pay the cost of the unsubscribed portion of the line through the California ISO Transmission Access Charge. Once the facilities are built, generators would be allowed to interconnect and contract for unsubscribed capacity.[141] To implement this concept, the California ISO is preparing a tariff amendment, which it will file to FERC later this year for approval.[142] The Committee supports implementation of this concept as a needed mechanism for transmission to access renewable resources.

Connection between Transmission Options and Need for Cost Allocation Mechanism for Expanded Feed-In Tariffs

In Europe, feed-in tariffs typically offer a fixed, long-term price for renewable energy based on specific technologies.[143] In a number of European countries, the tariff levels are set to cover the cost of each eligible renewable technology plus a profit. The tariff can be designed to favor early actors, with generations coming on-line in later years receiving a lower price. The tariff also can be varied by technology. Germany's tariffs are designed to favor both early actors and specific technologies.

This approach has benefits compared to California's SEP process and ad-hoc contract-by-contract subsidy decisions by the CPUC. As discussed below, funding for SEPs can be "borrowed" by the state Legislature, introducing risk that the payments may not be available. Developers are concerned that this uncertainty will raise their cost of borrowing capital. By reducing uncertainty in a project's income stream, feed-in tariffs help developers obtain lower-cost financing and stimulate investment in a domestic renewable energy market.

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[141] Federal Energy Regulatory Commission, April 19, 2007, Order Granting Petition for Declaratory Order, Docket No. EL07-33-000, 119 FERC 61,061.

[142] In late July, a draft of the proposal to be submitted to FERC is available on the California ISO website for discussion at a stakeholder workshop. See http://www.caiso.com/1816/1816d22953ec0.html.

[143] European legislation requires renewables to be given priority in interconnection, but interconnection in some countries can be difficult. Spain and Ireland are two examples. In Germany there is an obligation to interconnect renewables.

In countries that offer feed-in tariffs, a strong home market has enabled renewable energy markets to show strong growth. This type of market is unlikely to develop from case-by-case decisions to allow above-market RPS contracts to be rolled into IOU rates without SEPs. A number of other countries in Europe offer a feed-in premium on top of the electricity price, or a feed-in premium that varies with the market price to provide a set tariff to renewable projects. The former enables coexistence with a competitive market, but introduces market volatility to renewable developers, which could increase their costs. The latter removes this market volatility, while reducing the potential cost of feed-in tariffs.

To succeed on a statewide scale, the costs of feed-in tariffs need to be fairly distributed. One criticism of feed-in tariffs is that they cannot function in tandem with a competitive retail electricity market. The primary concern in this context is the lack of an obvious party to bear the electricity purchase obligation without destabilizing or skewing the competitive market landscape. Imposing an open-ended purchase obligation on competitive suppliers is not compatible with a market structure under which such suppliers contract to sell at fixed prices for varying terms to non-captive customers.

On the other hand, placing the obligation instead on just the regulated "provider of last resort" would not only burden a subset of customers disproportionately with the cost premium of supporting renewable energy, but could also accelerate customer migration to competitive alternatives, stranding the costs with an ever-shrinking subset of customers. As Wiser et al. point out, "feed-in laws are only competitively neutral if applied to regulated elements of the industry or if a cost recovery and sharing mechanism is developed." [144]

In Europe, governments have developed mechanisms through which the costs of feed-in tariffs can be evenly redistributed.[145] In Germany, for example, regional transmission authorities evenly redistribute feed-in costs among national rate payers. In the U.S., Letendre suggests that a similar redistributive role could be played by regional transmission authorities or independent system operators.[146]

There are significant differences between the role played by the California ISO and that of European regional transmission authorities (transcos). In both Spain and Germany,

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[144] Wiser, R., Hamrin, J., & Wingate, M. (2002). Renewable energy policy options for China: A comparison of renewable portfolio standards, feed-in tariffs, and tendering policies. San Francisco, CA: Center for Resource Solutions. Prepared for the Center for Renewable Energy Development, Energy Research Institute, State Development Planning Commission.

[145] Muñoz, M., Oschmann, V., & Tàbara, J. D. (in press). Harmonization of renewable electricity feed-in laws in the European Union. Energy Policy.

[146] As quoted in Wilson Rickerson and Robert C. Grace, February 2007, The Debate over Fixed Price Incentives for Renewable Electricity in Europe and the United States, http://www.boell.org/docs/Rickerson_Grace_FINAL.pdf, p. 12-13.

grid access is guaranteed for generators responding to feed-in tariffs.[147] Germany's 2000 Ernueerbare-Energien-Gesetz (EEG) established a "countrywide compensation scheme . . . to help balance the costs [of renewable electricity] between the different electricity providers."[148] In 2004 the EEG was amended and the equalization providing for connection costs to be paid by plant operators, and grid upgrade costs to be paid by the grid operator. In Germany, "The equalization provision in the EEG is aimed at the operators of transmission grids. (This is a small group with a limited number of players who will easily be able to handle the transactions associated with the equalization scheme, and will also be able to monitor each other.)"[149] In contrast, the California ISO has limited responsibility in allocating costs except for ancillary services.

However, given potential benefits of having a transmission agency guarantee renewable interconnection and play a role in cost equalization, the California ISO should consider its potential, as the control agency for transmission, to further accommodate and provide for equitable cost allocation of generation purchased should feed-in tariffs be adopted.[150] A Transco model, similar to that adopted in some European countries, was considered by Energy Commission staff during deregulation planning in the mid-1990s. Aspects of such a model may be adapted to California's current or potential electricity system to better integrate renewable generation, interconnection, transmission development and scheduling of renewable electricity.

Several options should be evaluated as part of a joint Energy Commission-CPUC proceeding on feed-in tariffs to determine how best to allocate these costs. One option would be to allocate the costs through CPUC distribution rates. Another option would be to put in generation rates that allow stranded cost recovery from retail providers, as is currently done for QF renewable contracts. For additional discussion of feed-in tariffs, see *33 Percent by 2020 is Feasible with Changes in Program Structure* near the end of this chapter.

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[147] Ragwitz, M. and Huber, C. *Feed-in systems in Germany and Spain: A comparison*, Fraunhofer Institure: Systems and Innovation Research, 2004, source for Table 5.1, page 54 in Mendonca, Miguel *Feed-In Tariffs: Accelerating the Deployment of Renewable Energy*, World Future Council, London, 2007.

[148] Mendonca, Miguel *Feed-In Tariffs: Accelerating the Deployment of Renewable Energy*, World Future Council, London, 2007, page 32.

[149] Ibid, page 35.

[150] Menanteau, P., D. Finon, and M.-L. Lamy, Prices versus quantities: Choosing policies for promoting the development of renewable energy. Energy Policy, 2003. **31**(8): p. 799-812. See also, Lewis, J. and R. Wiser, Fostering a renewable energy technology industry: An international comparison of wind industry policy support mechanisms. 2005, Lawrence Berkeley National Laboratory: Berkeley, CA. http://eetd.lbl.gov/ea/emp/reports/59116.pdf.

In-State Planning Processes for Transmission to Renewable Resources

One of the most important issues identified in the *2007 Strategic Transmission Investment Plan* is ensuring that transmission corridors are available to support the state's GHG emission reduction and RPS goals. Designating corridors can help streamline the transmission permitting process, building on improvements put in place by the CPUC and California ISO.

The Energy Commission, CPUC, California ISO, and publicly owned utilities have also created a new statewide inter-agency initiative, the California Renewable Energy Transmission Initiative (CRETI). The CRETI will assess competitive renewable energy zones in California, and possibly in neighboring states, to identify which zones can be developed most cost effectively and with the least environmental impacts. The CRETI will identify top-priority renewable energy zones and conceptual transmission plans for those zones, and initiate the permitting processes for projects identified in CRETI transmission plans.[151]

Noting the "land rush" in the Mojave Desert for potential concentrating solar energy development, the *2007 Strategic Transmission Investment Plan* recommends programmatic environmental impact reports/environmental impact statements (EIR/EIS) for California, led by the Energy Commission and the Bureau of Land Management, with full participation from other state and local regulators. The programmatic EIR/EIS would formalize a roadmap of preferred renewable energy resource zones and the transmission needed to interconnect those areas to the electricity grid for permitting purposes, including both federal and non-federal land.

Another important part of the transmission investment process is the interconnection studies conducted by the California ISO to evaluate and allocate the transmission impacts of interconnecting new projects. The California ISO assesses renewable energy and other generation projects seeking interconnection to the transmission grid serving the state's investor-owned utility service areas and the service areas of many publicly owned utilities. This assessment takes place according to a proposed project's place in the California ISO interconnection queue, although clustered interconnection requests with common upgrades may be assigned without consideration of the queue position.[152] For projects that are not part of a cluster, if a project near the front of the queue drops out, interconnection studies for projects later in the queue must be redone.

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[151] California Renewable Energy Transmission Initiative Mission Statement, July 11, 2007, http://www.ceert.org/ceert_reports/CRETI%20Mission%20-%20final.pdf, accessed July 24, 2007.

[152] California ISO, FERC Electric Tariff, Third Replacement Volume No. II, Original Sheet No. 1005A, Effective March 1, 2006. http://www.caiso.com/1bf0/1bf0e846437e0.pdf, accessed July 20, 2007.

Due to the California ISO's cost allocation procedures, it is financially difficult for projects to be interconnected ahead of other projects located in the same part of the transmission grid, unless they are considered as part of a cluster. As a result, a project that is delayed can hold up interconnection of other projects further down the queue. As of June 13, 2007, the wind projects in the queue total more than 17,000 MW, including more than 5,800 MW in Kern County alone, where much of the Tehachapi Wind Resource Area is located. Solar projects in the California ISO queue total more than 11,000 MW of concentrating solar power, including about 1,400 MW in Imperial County, 1,000 MW in Kern County, and more than 7,000 MW in San Bernardino County.[153] Most of the renewable energy projects in the current queue are fairly recent, although more than 700 MW of wind joined the queue before January 2004, including 300 MW of wind in Kern County that does not have an interconnection agreement.[154]

Transmission to Bring Renewable Energy from Out of State

The 2007 IEPR Committee is encouraged by the efforts of SCE and PG&E to develop transmission plans to bring renewable energy from out of state to California. The CPUC has authorized SCE to spend $4.5 million to assess resource zones in southeastern California, and close-in border areas in Arizona and western Nevada, and to participate in the CRETI process rather than perform those studies on its own.[155] PG&E received CPUC approval for $14 million in rate payer money to study options for a major transmission line to bring up to 3,000 MW of renewable and other energy to Northern California. The earliest on-line date for the transmission line would be no earlier than 2013. Please see the *2007 Strategic Transmission Investment Plan* for discussion of additional renewable generation-transmission studies underway.

Renewable Energy Certificates and Deliverability

As of August 5, 2007, 55 of 64 new, repowered, or restarted RPS contracts signed since 2002 (about 80 to 85 percent of new, repowered, or restarted RPS capacity, depending on options exercised) are priced below the Market Price Referent, providing a significant economic benefit if this capacity becomes operational. Although out-of-state renewables have been eligible from the beginning of the RPS program, they have played a small part so far. As California moves to 33 percent RPS-eligible renewable energy, the state can

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[153] The latest update of the California ISO queue is available from http://www.caiso.com/docs/2002/06/11/2002061110300427214.html.

[154] The latest update of the California ISO queue is available from http://www.caiso.com/docs/2002/06/11/2002061110300427214.html.

[155] California Public Utilities Commission, Energy Division, Resolution E-4052, approved August 23, 2007.

maintain downward pressure on costs through a broad range of potential supplies in the WECC interconnection.

It is in California's interest to have better interconnection with other regions in the West. Such interconnection broadens the range of resources available to help meet California's GHG and renewable energy goals. As we move to a carbon-constrained economy, there will likely be a higher value on environmental attributes of renewable energy without regard to location.

Recent changes to California's RPS are expected to encourage the development of out-of-state resources throughout the West. Although the California RPS currently requires retail sellers to procure renewable attributes and energy together as a "bundled" commodity — such that RPS-eligible energy is "delivered" to California consumers — these requirements have been made more flexible to make it easier to meet delivery requirements. However, renewable attributes, also referred to as "renewable energy credits" or "renewable energy certificates" (RECs), that are sold separately from energy are termed "tradable" or "unbundled" and currently cannot be used to meet California RPS procurement requirements. To the extent unbundled RECs become eligible in the future, customers of the purchasing LSE will likely forego any supply diversity or price stabilizing benefits from the purchase because the LSE will still need to acquire a commensurate amount of conventional energy.

Provisions in SB 107 effectively allow "banking and shaping" of renewable energy by allowing RECs associated with out-of-state RPS-eligible facilities to be bundled with energy imported into California from electricity produced at a different time and from a different location. Previously, the Energy Commission required delivery to be scheduled directly from the RPS-eligible facility located out-of-state. The changes in the delivery requirements are expected to reduce the cost of importing RPS-eligible electricity, largely because of the flexibility in navigating transmission constraints. Further, these provisions allow intermittent resources to "shape" delivery with other resources and offer a firm product instead of energy "as available."

Another important amendment in SB 107 is allowing tradable RECs associated with energy produced from RPS-eligible resources to qualify toward RPS procurement requirements in the future once certain conditions have been met. Tradable RECs may be allowed for RPS compliance after the CPUC and Energy Commission conclude that the Western Renewable Energy Generation Information System (WREGIS) is operational, capable of independently verifying delivery of renewable energy to a retail seller, and can assure that RECs are not double counted by any seller within the WECC. Also, the CPUC may limit the amount of tradable RECs that a retail seller may procure to satisfy its RPS requirements. The CPUC is addressing RECs and other RPS

implementation issues in its Rulemakings 06-05-027 and 06-02-012, and in subsequent RPS Rulemakings.[156]

Allowing tradable RECs for RPS compliance, including out-of-state RECs, could help increase the development of renewable energy WECC-wide, reducing the GHG emissions of system power. Also, it could encourage early action to build renewable energy that may otherwise be delayed by congestion on existing transmission lines bringing electricity into California, if that renewable energy can be effectively used locally.

Dispatchability and Reliability

AB 1585 also requires the Energy Commission to examine the consequences to electric system reliability from increased levels of renewable energy. This section discusses the impact of 33 percent renewable energy on the changing dynamics of reliable electricity supply in California. Intermittent renewable technologies, such as wind and solar, are a challenge to traditional reliability planning. The challenges must be addressed in part by changes in scheduling and services that support rapid changes in load and supply, such as improving the ability of system-wide and local capacity to ramp up and down rapidly.

Most existing baseload fossil fuel and nuclear plants and some recently built baseload plants cannot ramp up and down as rapidly as needed to meet the increased peakiness of the California's electricity load and the expected increased use of intermittent and must-take renewables to achieve 33 percent renewable electricity by 2020. At the same time, residential air-conditioning demand is increasing. In California, the population is growing fastest in areas of the state with hot summer temperatures. In addition, a growing number of coastal homes are being retrofitted with air conditioning. To meet the growing demand for air-conditioning, California needs greater quantities of electricity supply that can ramp-up quickly.

As part of the 2007 IEPR proceeding, the Energy Commission published two reports assessing "stress" scenarios of the potential impact of expanded use of renewable electricity in California's 2020 generation mix:

- The *Scenario Analyses of California's Electricity System* report (Scenario Analysis Report) focused on scenario analysis in California and throughout the WECC region, creating scenarios that integrated high renewables and high levels of

[156] California Energy Commission, *Renewables Portfolio Standard Eligibility Guidebook*, March 2007, http://www.energy.ca.gov/2007publications/CEC-300-2007-006/CEC-300-2007-006-CMF.PDF, p. 3.

energy efficiency.[157] Some scenarios in this report used a resource mix of about 30 percent renewable energy in California.

- The *Intermittency Analysis Project Report* (IAP) analyzed renewable electricity scenarios for 2010 and 2020 and used a resource mix of 33 percent by 2020.

The Scenario Analysis Report divided the entire WECC area into 29 transmission zones, including 10 zones within California, to model transmission constrained production costs. This analysis also used reserve margins as developed and required by the CPUC. More detail about the results of the Scenario Analysis Report is contained in Chapter 2.

The IAP studied the impacts of a 33 percent by 2020 scenario on system reliability and dispatchability in California and focused on using in-state renewables using a more fine-grained approach than the Scenario Analysis Report, enabling study of the impacts of 33 percent renewable energy on local transmission requirements. Additional objectives of the IAP included quantifying both positive and negative impacts of a mix of 33 percent renewable technologies on transmission reliability and congestion. The study also attempted to develop a common perspective for evaluating different technologies, both fossil and renewable, that compete for limited system resources. The project was designed to provide a forum in which investor- and publicly-owned utilities, developers and regulators could work together to identify barriers, opportunities and benefits of strategically located renewable technologies.

The IAP relied on a systematic approach to identify statewide generation, transmission, and operations scenarios that satisfied 2010 and 2020 policy goals, beginning with developing a 2006 base case. The study accounted for grid-friendly technology changes by looking in detail at the electrical characteristics of modern state-of-the-art wind turbines and their impacts on performance, reliability, power quality and transmission system operation.[158] The study also used emerging wind and solar technologies and performance in selecting resource types and locations.

In contrast to the Scenario Analysis Report, which used current 2006 cost of generation estimates from the Cost of Generation model with no assumed change in cost over time, the IAP study based future costs of renewables on present-day costs of energy and industry forecasts by entities such as the Electric Power Research Institute and Navigant. The economic analysis also accounted for the maturity of the technology and the length of time needed for development of a renewable energy project using that technology.

The resource mix developed for the IAP is shown in Table 4-1.

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[157] California Energy Commission, Scenario Analyses of California's Electricity System: Preliminary Results for the 2007 Integrated Energy Policy Report, Staff Draft Report, http://www.energy.ca.gov/2007publications/CEC-200-2007-010/CEC-200-2007-010-SD.PDF

[158] California Energy Commission, Impact on Past, Present and Future Wind Turbine Technologies on California Grid, CEC 500-2006-050, May 2006.

Table 4-1. Resource Mix Scenario for Intermittency Analysis Project (33 Percent Renewable Energy by 2020)

	2020
Peak California Load, MW	74,300
Peak California ISO Load, MW	61,200
Total Geothermal, MW	5,100
Total Biomass, MW	2,000
Total Concentrating Solar, MW	3,100
Total PV Solar, MW	2,900
Total Wind, MW	12,700
Wind in Tehachapi Region, MW	5,800
Intermittent Penetration in CA	25%
Intermittent Penetration in California ISO	31%

Source: California Energy Commission Intermittency Analysis Project[159]

In preparing this scenario, the IAP team and stakeholders considered transmission upgrades, options for voltage reactive support (to protect equipment from voltage spikes and drops), and operational improvements to maintain local reliability. Investment will be needed in transmission, generation, and operations infrastructure to maintain reliability as the electricity system moves toward 33 percent by 2020.

The IAP was designed to quantify in MW and MWh the potential impact of the 2010 and 2020 renewable energy goals on state-wide system operations. As part of the scenario analysis, IAP estimated the indirect costs of integration for regulation and load following for wind to be $0.69 per MWh. and reported that emerging grid-friendly wind turbine technologies may reduce integration issues and costs.[160] Also, benefits of

[159] Porter, K. and Intermittency Analysis Project Team. 2007. *Intermittency Analysis Project: Summary of Final Results*. California Energy Commission, PIER Research Development & Demonstration Program. CEC 500 2007 081. , http://www.energy.ca.gov/2007publications/CEC-500-2007-081/CEC-500-2007-081.PDF, Tables 2-2 on page 18.

[160] Impact on Past, Present and Future Wind Turbine Technologies on California Grid by BEW Engineering, CEC 500-2006-050, May 2006. As reported in Porter, K. and Intermittency Analysis Project Team. 2007. *Intermittency Analysis Project: Summary of Final Results*. California Energy

incorporating state-of-the-art wind energy forecasting techniques across the system were estimated to be $4.37/MWh.

The IAP did not focus specifically on estimating costs such as unit commitment or cost adders. The unit costs to manage and procure the MW and MWh variability created by increased renewable energy deployment will vary depending on the size of the utility service area and mix of resources. However, a joint project of the Northwest Power Planning Council (NWPPC) and other contributors reviewed several northwest utility studies of integration costs. The utility studies estimated costs from about $3.20 to $9.75 per MWh for 10 percent wind penetration, about $6 to $11.70 for 20 percent penetration, and about $8.85 to $16.15 for 30 percent penetration.[161] These estimates include additional incremental reserves needed to compensate for intermittency at a local utility planning scale, in addition to the costs of load following, regulation, and unit commitment. The NWPPC study states that the cost of wind integration depends primarily on the following factors:

- Size of the control area from which such services are procured relative to the amount of wind being integrated.
- Geographic diversity of wind sites and resulting generation patterns.
- Amount of flexibility available to the power system.
- Access to robust markets for control area services and storage and shaping products.[162]

The IAP final report estimates the number, type, and location of transmission upgrades needed for the report's renewable energy scenarios. These estimates do not include detailed land use or right-of-way costs, which could significantly increase costs. However, the IAP analyzed only in-state renewable resources. In reality, out-of-state resources are likely to provide significant portions of California's RPS requirements, and these would imply different transmission upgrades and costs.

In addition, the transmission analysis of the scenarios studied in the IAP suggests that "wind variability may contribute to transmission congestion under certain renewable

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Commission, PIER Research Development & Demonstration Program. CEC-500-2007-081. , http://www.energy.ca.gov/2007publications/CEC-500-2007-081/CEC-500-2007-081.PDF, p. 3.

[161] Northwest Power and Conservation Council, *Northwest Wind Integration Action Plan,* pre-publication version, March 2007 at http://www.nwcouncil.org/energy/Wind/library/2007-1.pdf, p. 8

[162] Northwest Power and Conservation Council, *Northwest Wind Integration Action Plan,* pre-publication version, March 2007 at http://www.nwcouncil.org/energy/Wind/library/2007-1.pdf, p. 8.

energy dispatch scenarios, and that transmission congestion patterns are more difficult to predict as the penetration of variable renewable energy resources increases."[163]

Regarding the technical feasibility of 33 percent by 2020, the IAP reached the conclusion that California can incorporate that amount of renewables, provided appropriate infrastructure, technology, and policies are in place. Specifically, this successful integration will require investment in transmission, generation, and operations infrastructure to support the renewable additions, appropriate changes in operations practice, policy and market structure, and cooperation among all regulatory participants. f[164]

Another issue identified in the IAP 33 percent by 2020 scenario is the shape of California's overall wind generation profile, which is capable of producing large amounts of energy during low demand times. The combination of wind generation needed to meet RPS goals and existing baseload "must-run" plants such as qualifying facilities with must-run contracts and nuclear plants can contribute to an over-generation problem at these times. The IAP found that pumped hydro storage, better coordination of pumping by the State Water Project to increase load during low demand times, and other potential storage technologies discussed below can help accommodate low marginal cost wind.

The IAP suggests that there are opportunities to better use existing pumped storage to modify and increase load during off peak times and provide ancillary services. New pumped storage, such as the proposed Lake Elsinore Advanced Pump Storage (LEAPS) facility in rapidly growing Riverside County and the Iowa Hill facility being considered by the Sacramento Municipal Utility District (SMUD) may provide further assistance for "storing" renewable energy generated on windy nights.[165][166]

In addition to the ability to ramp up or down on an hourly basis, the IAP suggests that an electricity mix for 2020 that includes 33 percent renewables will need a relatively modest average increase in regulation control resources (20 MW), such as automated demand response technologies, variable speed pumped hydro, and flywheel energy

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[163]Ibid.

[164]Ibid, p. 3.

[165] Porter, K. and Intermittency Analysis Project Team. 2007. *Intermittency Analysis Project: Summary of Final Results*. California Energy Commission, PIER Research Development & Demonstration Program. CEC-500-2007-081, http://www.energy.ca.gov/2007publications/CEC-500-2007-081/CEC-500-2007-081.PDF, p. 34-35.

[166] Confluence Newsletter, Summer, 2007, at http://hydrorelicensing.smud.org/IowaHill/News/Confluence%20News_Sumr07.pdf . See also SMUD's project description at http://hydrorelicensing.smud.org/IowaHill/iowa/Iowa_PD.pdf

storage.[167] The IAP 33 percent by 2020 scenario also suggested a need for significant amount of volt-amperes reactive (VAR) compensation to maintain voltage stability.[168]

2006 Long-Term Procurement Plans for Investor-Owned Utilities

AB 1585 also requires the Energy Commission to discuss the long-term planning requirements for the state's IOUs. The CPUC directed PG&E, SDG&E and SCE to develop 2006 Long-term Procurement Plans (LTPP) to meet EAP II targets of 20 percent renewable by 2010 and 33 percent by 2020.[169] The CPUC stated that it "will not approve plans that lack realistic and implementable provisions for meeting the EAP II targets."[170]

However, as described below, the utilities' procurement plans contain considerable uncertainty about their ability to procure the amount of renewable energy equal to 20 percent by 2010. PG&E's 2006 LTPP did not include a scenario that would put the utility on track to meet 33 percent by 2020, and whether SDG&E's plan does so is subject to some debate. SCE did include such a scenario, but argued against adopting it.

The CPUC requires utilities to achieve 20 percent by 2010. This procurement requirement is defined as 20 percent of 2009 retail sales.[171] To be on track to achieve 33 percent by 2020, adding 1.3 percent per year to 20 percent in 2010, the Energy Commission estimates the need for 28 percent of retails sales in 2016, the end of the planning period covered by the 2006 LTPP.

Pacific Gas and Electric

PG&E's 2006 LTPP reports renewable energy in 2007 to be between 10,487 GWh and 10,498 GWh, 13.3 percent of the retail sales for 2006.[172] PG&E expects to have total retail

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[167] Porter, K. and Intermittency Analysis Project Team. 2007. *Intermittency Analysis Project: Summary of Final Results*. California Energy Commission, PIER Research Development & Demonstration Program. CEC 500 2007 081. , http://www.energy.ca.gov/2007publications/CEC-500-2007-081/CEC-500-2007-081.PDF, p. 5.

[168]Ibid, p. 27.

[169] http://www.energy.ca.gov/energy_action_plan/2005-09-21_EAP2_FINAL.DOC

[170] CPUC, Scoping Memo on the Long-Term Procurement Phase of Rulemaking R.06-02-013. http://www.cpuc.ca.gov/EFILE/RULC/60186.htm, p. 17.

[171] CPUC, October 19, 2006, Decision 06-10-050, in Rulemaking 06-05-027, *Opinion on Reporting and Compliance Methodology for Renewables Portfolio Standard* Program, http://www.cpuc.ca.gov/WORD_PDF/FINAL_DECISION/61025.DOC.

[172] Pacific Gas and Electric Company, 2006 Long-Term Procurement Plan, Vol. 1, public version, Tables IVC-7 and IVC-8.

sales between about 75,000 GWh and 85,000 GWh in 2010.[173] PG&E used 20 percent of 2009 retail sales to calculate the total renewable energy it needs to meet the 20 percent by 2010 target, about 15,000 GWh to 17,000 GWh with a renewable resource mix between 980 and 1,000 MW in size. PG&E used 25 percent of 2015 retail sales, forecast to be about 19,000-23,000 GWh as a proxy for 33 percent by 2020, with between 2,800 MW and 5,000 MW of renewable resource capacity.[174]

PG&E's plan anticipates achieving about 18 to 19 percent renewable deliveries in 2010 and 20 percent in 2011 or 1012, depending on the scenario. Three of four of the scenarios prepared by PG&E do not achieve 28 percent of renewables by 2016. [175]

Assuming a 50 percent capacity factor to convert from energy (GWh) into capacity (MW), the Energy Commission estimated PG&E's scenarios are short of achieving 20 percent renewables by 2010 by between 823 GWh to 1611 GWh (188 – 368 MW). Assuming 28 percent by 2016 is needed to be on track to achieve 33 percent by 2020, PG&E's scenarios are short by from 4,548 GWh (1,038 MW) to 1,764 GWh (403 MW).[176]

PG&E's LTPP recognizes that transmission is "increasingly becoming a critical element in meeting the state's RPS goals," and that most proposed renewable development is remote from PG&E's load centers.[177] PG&E assumes development of 2,400 MW of wind and 200 MW of geothermal resources which require transmission development and notes that there is "significant uncertainty regarding the availability of transmission capacity and consequent effect on wind [and geothermal] resource deliveries."[178]

To address the need for transmission, PG&E describes short-term (one to five years), medium-term (next 5-10 years), and long-term (next 10-15 years) actions critical to support its procurement plan. The short-term projects are typically upgrades to existing facilities or transmission lines needed to reduce congestion such and expand PG&E's ability to deliver new renewable power from remote locations.[179] PG&E also identifies three-medium term projects with their schedules, recognizing that the timing may change depending on the results of environmental and technical studies: (1) Midway-

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[173] Ibid, p. IV-31.

[174] Ibid, p. IV-31.

[175] California Energy Commission, Prepared Direct Testimony of Heather Raitt on Behalf of the California Energy Commission Regarding the Issue of Renewable Energy Procurement Strategy as Addressed in the Long-Term Procurement Plan of Pacific Gas and Electric, pp. 16-17.

[176] Ibid, pp. 19-20.

[177] Pacific Gas and Electric Company, 2006 Long-Term Procurement Plan, Vol. 1, public version, p. V-49)

[178] Ibid, p. IV-34 for wind, p IV-35 for geothermal.

[179] Ibid, p. V-50.

Gregg 500 kV Line by 2012; (2) Bay Area 500 kV Station by 2013; and (3) Vaca Dixon-Fulton Connection by 2015.

For the long-term, PG&E states that it will continue to participate in regional planning efforts to access renewable resources in the Pacific Northwest. PG&E is contributing to a feasibility study for the Frontier Line, a proposed interstate, high voltage line to deliver renewable and coal energy throughout the West.[180] Also, PG&E has received approval from the CPUC to spend up to $14 million to study the feasibility of developing transmission to access renewable resources in British Columbia. Although PG&E did not include potential capacity from British Columbia in its forecasts of pending additional research,[181] it estimates that almost 9,900 MW of renewable resources—wind, hydro (including "medium" hydro which is not eligible for the California RPS), biomass, and geothermal—could be developed in British Columbia.[182]

PG&E states that it "…is planning to procure all available renewable resources, subject to market and transmission constraints until it meets its RPS targets, even if they are priced above market price. Once PG&E meets its RPS targets, it will implement the EAP loading order by pursuing all cost-effective renewable energy resources…".[183]

San Diego Gas & Electric

The Energy Commission's analysis determined that SDG&E's 2006 LTPP exceeds the 2010 RPS goal by approximately 334 GWh (76 MW) in 2010, but is short of a trajectory towards 33 percent in 2020 by approximately 880 GWh in 2016 (201 MW).[184] SDG&E contests these findings and states that its plan is on a trajectory to meet the 33 percent target as discussed below.[185]

SDG&E's 2006 LTPP states that it has contracts for 16.4 percent renewable energy under contract for delivery in 2010 and that it plans to procure the remaining approximately 3.6 percent needed to reach 20 percent (based on 2009 forecasted retail sales in accordance with the methodology approved by the CPUC in D.04-06-014).[186]

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[180] Ibid, p. V-49.

[181] Ibid, pp. IV-33-34.

[182] Ibid, p. IV-37.

[183] Ibid, p. IV-27.

[184] California Energy Commission, Prepared Direct Testimony of Heather Raitt on Behalf of the California Energy Commission Regarding the Issue of Renewable Energy Procurement Strategy as Addressed in the Long-Term Procurement Plan of San Diego Gas & Electric, p. 19.

[185] SDG&E Opening Brief, pp. 82-83.

[186] SDG&E 2007-2016 LTPP Vol. 1 part 2 p. 190-191.

According to SDG&E, it plans to have 507 MW of renewable capacity in 2010 and 840 MW in 2016. SDG&E states that these resources would allow it to provide about 22 percent of its energy needs in 2010; it would then continue to increase its procurement of renewable energy over time. SDG&E cautions that the ability to meet the targets will depend on the availability of transmission.[187] SDG&E explains:

> There is some risk of contract failure associated with a number of power contracts, particularly those that are contingent on transmission additions. Should any of the signed contracts not materialize, then SDG&E would need to replace the power from an additional source with similar characteristics.[188]

The Energy Commission has expressed concern that SDG&E's margin of safety is not large enough to ensure that it meets the 20 percent by 2010 goal and has encouraged SDG&E to procure, through contracted or development of utility-owned facilities, RPS energy equivalent to 20 percent by 2010 plus a 20 to 30 percent margin of error. SDG&E has responded by noting that if all negotiations with a portfolio of counterparties were to be completed successfully, this could take SDG&E well beyond the recommended 30 percent safety margin if circumstances dictate a need for greater contracting. SDG&E has requested that the CPUC recognize that it is prudent to contract with renewables in excess of the 20 percent mandate to allow for unexpected contract failures or delays in the approval and construction of new transmission or renewable generation. SDG&E envisions contracting for 24-26 percent of 2010 retail sales to be delivered from renewable resources.[189]

For 2016, SDG&E's plan calls for 840 MW of renewable capacity.[190] SDG&E states that it currently has renewable energy contracts for 19.5 percent of forecasted 2016 retail sales, explaining that actual growth in delivered renewable energy is likely to be "lumpy" and may be changed if the CPUC allows SDG&E to use unbundled RECs for the RPS, which SDG&E supports.[191]

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[187] SDG&E Vol. 1 Part 1, p. 169.

[188] SDG&E, December 11, 2006, 2007-2016 Long-term Procurement Plan, Volume 1, Public Version, https://www.pge.com/regulation/LongTermProcureOIR/Testimony/SDGE/2006/LongTermProcureOIR_Test_SDGE_20061211-01.pdf, p. 168.

[189] SDG&E Opening Brief, pages 83-84. LTPP [Staff to provide complete reference]**

[190] SDGE 2007-2016 LTPP Vol. 1 part 1, p. 178.

[191] SDG&E 2007-2016 LTPP Vol. 1 part 2 p. 191-192.

The Energy Commission's testimony concluded that SDG&E's plan does not meet the 28 percent required to be on track to achieve 33 percent by 2020.[192] SDG&E, however, states that its plan actually shows reaching 29.4 percent renewable by 2016, consistent with reaching a 33 percent goal by 2020.[193]

Regarding transmission, SDG&E states that it needs the Sunrise Powerlink transmission project to achieve 20 percent by 2010 and "higher percentages in future years."[194] The Sunrise Powerlink would allow SDG&E to import an additional 1,000 MW from Imperial Valley to San Diego.[195] The Energy Commission supports this project as critical to SDG&E's ability to meet the 2010 RPS goal, ensure system reliability, and reduce congestion costs.[196]

Southern California Edison

The Energy Commission's analysis determined that SCE's 2006 LTPP exceeds the 2010 RPS goal by approximately 765 GWh (175 MW) in 2010, but is short of a trajectory towards 33 percent in 2020 by approximately 1358 GWh in 2016 (310 MW). These results reflect SCE's scenario that incorporates the Energy Commission's load forecast into SCE's "Best Estimate Plan," and the Energy Commission's assumption that renewable resources will have an average capacity factor of 50 percent.[197]

SCE's 2006 LTPP meets the 20 percent by 2010 RPS goal, with about 15,000 GWh of renewable energy.[198] For 2006, SCE anticipated having 16.5 percent of its retail load met by output from eligible renewable resources.[199] In its LTPP, SCE states it may not be able to achieve 20 percent by 2010:

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[192] California Energy Commission, Prepared Direct Testimony of Heather Raitt on Behalf of the California Energy Commission Regarding the Issue of Renewable Energy Procurement Strategy as Addressed in the Long-Term Procurement Plan of San Diego Gas & Electric, pp. 12-13, 15, 18.

[193] Ibid, pp. 82-83.

[194] SDG&E 2007-2016 LTPP Vol. 1 part 2 p. 192.

[195] Ibid, p. 204.

[196] California Energy Commission, Prepared Direct Testimony of Heather Raitt on Behalf of the California Energy Commission Regarding the Issue of Renewable Energy Procurement Strategy as Addressed in the Long-Term Procurement Plan of San Diego Gas & Electric, p. 16.

[197] California Energy Commission, Prepared Direct Testimony of Heather Raitt on Behalf of the California Energy Commission Regarding the issue of Renewable Energy Procurement Strategy as Addressed in the Long-Term Procurement Plan of Southern California Edison, p. 22.

[198] SCE's 2006 Procurement Plan, Volume 1B, public version, p. 78

[199] Ibid, p. 76.

> … many uncertainties could potentially hamper the viability of this forecast, such as: potential fluctuations in load growth due to customer migration; potential fluctuations in renewable output resulting from resource depletion and contract attrition at levels higher than the 10% attrition rate assumed for the 33% scenario; delays in obtaining State or local transmission permits; missed milestones by project developers; and other unanticipated causes.[200]

To meet the 20 percent by 2010 goal and 33 percent by 2020 goal, SCE assumes the following transmission will be built:[201]

- Tehachapi (Phase I) 700 MW in 2010
- Tehachapi (Phase 2/3) 1,700 MW in 2013
- Tehachapi (Phase 4) 2,100 MW in 2015
- San Bernardino County 2,000 MW every two years starting in 2015 up to 10,000 MW
- Salton Sea 1,300 MW in 2017
- North of Lugo 975 MW in 2020

SCE's 2006 LTPP includes a Required Plan to put SCE on a path to achieving 33 percent renewables by 2020. SCE's scenario assumes a "chunky" development path, coming-on line as new transmission is built, showing about 25,000 GWh in 2016, providing close to 33 percent of retail sales under the CEC Load Scenario, and about 30 percent of retail sales under the SCE load scenario.[202] For comparison, SCE's 20 percent planning scenario shows about 20,000 GWh of renewable energy in 2016.[203]

SCE identified new transmission to the following renewable resource areas as essential to achieving 33 percent by 2020: Western Nevada, Inyo County, the Salton Sea area in Imperial County, and Eastern San Bernardino County.[204]

However, SCE does not recommend this plan, stating that it would be expensive because of the transmission required to achieve this goal and increased demand for renewables.[205] In this Required Plan, for resources procured beyond the 20 percent plan, SCE assumes renewables will be priced at 25 percent above the MPR, arguing that "increasing demand by elevating the overall goal of the RPS program to 33 percent in a

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[200] Ibid, pp. 85-86.

[201] Ibid, p. 77.

[202] SCE's 2006 Procurement Plan, Vol. 1B, public version, p. 85, 127.

[203] Ibid, p. 78.

[204] Ibid, p. 82.

[205] SCE's 2006 Procurement Plan, Vol. 1A, public version, page 5, lines 18-27.

market already demonstrating resource shortages and consequently higher prices will likely lead to higher overall costs for the RPS program."[206] To avoid the expense, SCE asks the CPUC to approve its Best Estimate Plan, which does not meet 33 percent by 2020, stating "the Best Estimate Plan is the only plan that is realistically achievable and cost-effective." [207]

SCE's view of the cost of renewable energy is not supported by publicly available data from RPS solicitations. From the beginning of the RPS program in 2002 to August 2007, more than 80 percent of the new, repowered, or restarted renewable energy capacity and more than 90 percent of projected RPS energy deliveries contracted with IOUs is priced below the market price referent. Whether future costs remain below the MPR depends in part on whether manufacturing of wind turbines expands to meet demand; transmission is built to access renewable-rich areas; existing contracts (particularly for large amounts of solar) come on-line as planned; the future price of natural gas goes up or down, on average, compared to current prices; and the SEP/MPR structure is revised to incorporate modern portfolio theory and incorporate an appropriate greenhouse gas adder, or is changed to a feed-in tariff.

In addition, SCE assumes carbon regulation will cost $8 per ton of carbon dioxide. There is substantial risk that the value may be much higher. The *2006 IEPR Update* cited a study by Synapse Energy Economics forecasting a range of $8.5 to $30.8 per ton (p. 55). A July 2007 press release from Deutsche Bank anticipates carbon for 2008-2020 in Europe may be in the range of 35 Euro (about $48).[208] 2008 allowances have been trading at about 20 to 30 Euro per metric tonne CO2 in the European Union Emission Trading Scheme.[209]

Potential Impact on Rates and Public Goods Charge

AB 1585 requires the Energy Commission to report on the potential impacts on electric rates of the 33 percent renewable goal. In November, 2005, the CPUC published a report prepared by the Center for Resource Solutions assessing the feasibility and cost impacts of a 33 percent renewable energy target. The report found 33 percent to be technically and economically feasible and slightly lower cost than business-as-usual in the long

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[206] SCE's 2006 Procurement Plan, Vol. 1B, public version, p. 87-88.

[207] SCE's 2006 Procurement Plan, Vol. 1A, public version, page 5.

[208] Deutsche Bank, July 25, 2007, The European Union wants to cut Carbon Emissions by 20% by 2020, Deutsche Bank significantly upgrades Carbon Price Forecast, http://www.db.com/presse/en/content/press_releases_2007_3588.htm.

[209] 5 July 2007, EU carbon down, but solid above 20 Euros, http://www.carbonpositive.net/viewarticle.aspx?articleID=98 . See also, http://www.carbonpositive.net/viewarticle.aspx?articleID=137.

term. The report found an average rate impact of plus 0.57 percent over the 2011-2020 period. However, extending the analysis to 2011-2030, the report found the 33 percent by 2020 target was likely to provide a net savings.[210]

As part of the 2007 IEPR proceeding, the Energy Commission published several studies investigating potential impacts of 33 percent renewable energy on rates and public goods charge funds. Detailed findings from these studies are discussed later in this section.

The results of the Scenario Analysis Report show that a 2020 scenario with about 30 percent renewable energy may be achievable without a significant upward impact on rates.[211] As mentioned earlier, this study did not analyze potential changes in renewable technology costs over time. In addition, much of the increase in system costs in the high renewables scenario is associated with customer-funded distributed generation competing economically with retail rates, not contributing to them. In particular, the analysis of Case 4A showed a total increase of about $10 per megawatt-hour for both demand-side rooftop solar PV and total utility generation mix. This Scenario Analysis Report used total societal costs, including both rebates and PV purchase costs paid by homeowners and businesses. For that reason, and the fact that PV is more expensive than utility scale renewables, the expected $10 increase in total economic cost is consistent with a minimal or negligible increase in costs of utility generation that becomes part of the rate base.

A second, portfolio analysis, study[212] suggests that there may be statewide generation portfolios with renewable content in excess of 33 percent by 2020 that provide lower or equivalent cost and lower risk for California ratepayers than maintaining 20 percent renewable energy. For example, the study models a generation mix with 45 percent renewables that has costs equivalent to a 20 percent renewable "business as usual" portfolio.

There is a wide range of uncertainty regarding forecasts of future electricity rates, which depend on future natural gas prices, generation costs in general, and upgrades to the transmission and distribution grids, among other factors. Major investments in

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[210] Center for Resource Solutions, November 2005. *Achieving a 33% Renewable Energy Target*. Prepared for the CPUC. http://www.cpuc.ca.gov/word_pdf/misc/051102_FinalDraftReport_RenewableEnergy.pdf. p. 99-101.

[211] California Energy Commission, Scenario Analysis of California's Electricity System: Preliminary Results for the 2007 Integrated Energy Policy Report, CEC-200-2007-010-SD, June 2007

[212] Bates White, A Mean-Variance Portfolio Optimization of California's Generation Mix to 2020: Achieving California's 33 Percent RPS Goal, Draft Consultant Report, July, 2007, CEC-300-2007-009/CEC-300-2007-009-D.PDF.

transmission infrastructure will be needed to maintain system reliability and serve increasing electricity demand as California's population grows. Much of this investment would be needed even if the state were not committed to 33 percent renewable generation by 2020. Geographically, the areas with the most growth in housing are in the central valley and the southeastern counties.

Beyond the uncertainties affecting electricity rates in general, a different set of factors affects the future costs of renewable electricity. For example, there is currently a shortage of wind energy turbines, which is likely to drive up the price of energy from new wind facilities until manufacturing capacity expands to meet demand. The potential impact of 33 percent on rates and public goods charge funds also depends on the price mechanism used to contract for the additional renewable energy.

At this time, while there is considerable uncertainty regarding future costs of reaching California's renewable goals, preliminary analyses indicate that rates may not be greatly impacted. The Scenario Analysis Project found a clear tradeoff between higher capital cost and lower production costs with generation portfolios weighted towards renewables. In balance, a modest total cost increase seems probable. However, several possible futures resulting in sustained very high natural gas prices could result in high renewable generation mixes that are less costly than mixes with more conventional generation. For example, county-wide turn away from high GHG-emission coal generation could put unprecedented upward pressure on gas prices.

Mean-Variance Portfolio Analysis Findings

In addition to the scenario analysis described above, the Energy Commission published a report using mean-variance portfolio analysis to assess potential future generation portfolios.[213] These scenarios suggest potential cost and risk impacts of at least 33 percent renewables by 2020. The report demonstrates how mean-variance portfolio analysis can be used to generate an "efficient frontier" of resource mixes for electricity generation. The mixes on this frontier indicate the least expensive options for a given amount of risk and the least risky options for a given cost.

This approach, commonly known as portfolio analysis, has been used by investors for decades. Investors typically seek a diversified portfolio that balances higher risk stocks with low risk assets such as government bonds. One reason that diversified portfolios have lower risk is that the likelihood of all assets declining in value at the same time is low. For example, expected returns for stocks are higher than for bonds; however, because stock prices are more volatile, bonds are a less risky investment. Studies of portfolio performance show that when bonds are added to a stock portfolio, the

[213] Bates White, A Mean-Variance Portfolio Optimization of California's Generation Mix to 2020: Achieving California's 33 Percent RPS Goal, Draft Consultant Report, July, 2007.

expected value of net returns of the portfolio over time increases. Just as a diversified portfolio of investments can increase returns, a diversified portfolio of generation assets can reduce overall electricity costs paid by ratepayers.

The main findings of the portfolio analysis report include:

- Compared to a "business as usual" portfolio with 20 percent renewable resources in 2020, other portfolios exist that are less risky, less expensive, and that substantially reduce $C0_2$ emissions and dependence on energy imports.
- An optimal generating portfolio for California includes greater shares of renewable technologies that may cost more on a stand-alone basis.
- Adding a non-fossil, fixed-cost technology such as wind to a risky generating portfolio lowers expected costs at any level of risk. Adding too much renewable generation increases portfolio risk, but those levels are substantially greater than 33 percent in 2020.

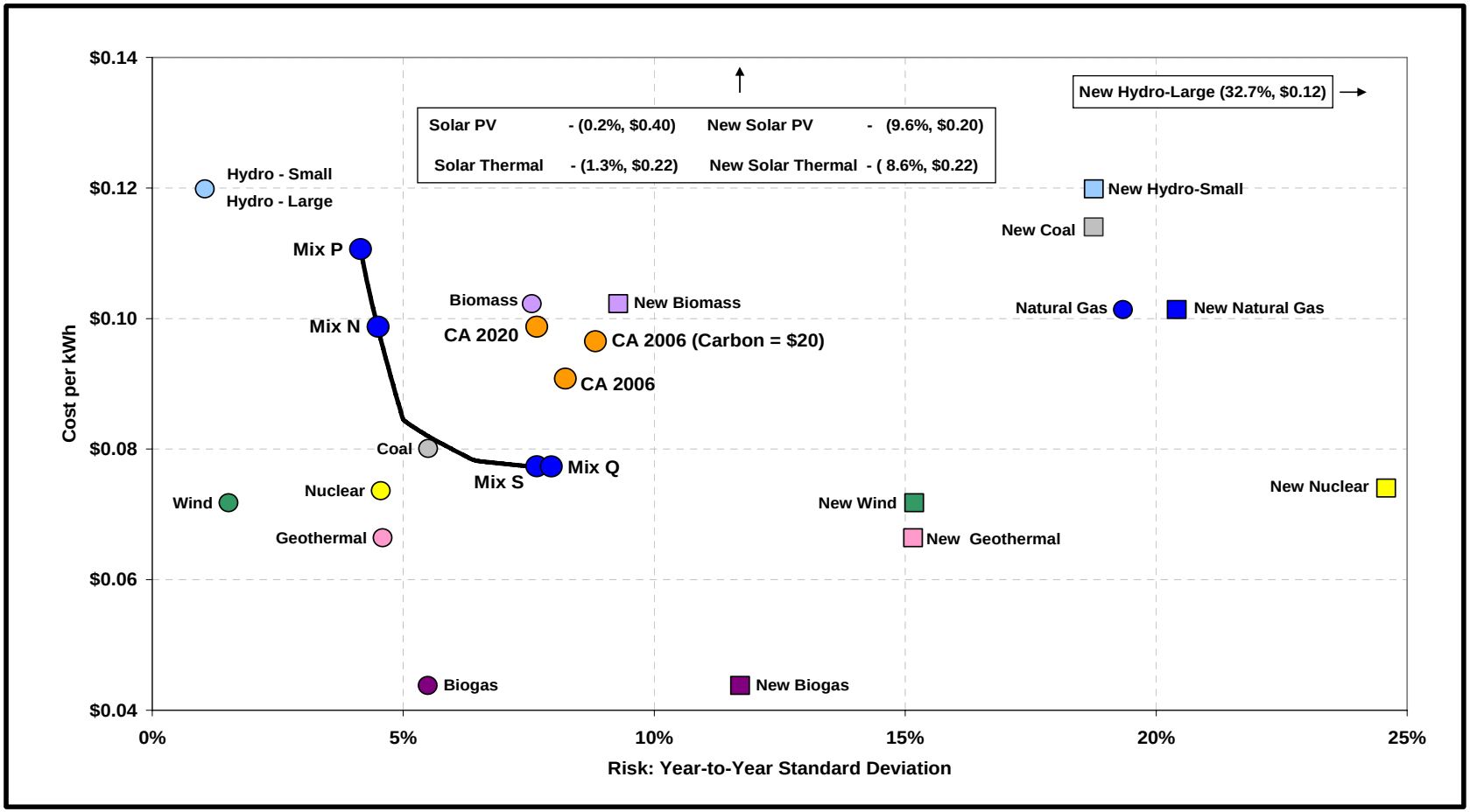
The authors of the report noted a number of caveats and limitations associated with these findings:

- Realistic constraints on the amounts (upper and lower bounds) for each renewable and conventional technology type must be substituted for the proxy assumptions used in the report.
- A more complete analysis is needed that considers transmission and integration constraints, to regional and local levels.
- It may be difficult to constrain estimates of future volatility and covariance.
- The analysis ignored certain risks including wind resource intermittency and transmission stability issues and geothermal steam resource constraints
- Mean-variance portfolio analysis assumes that risks are symmetric, and that variance captures all risk attributes; however, risks associated with future generation costs may well not be symmetric.

Given these caveats, the report's results in terms of costs and risks associated with various portfolios are illustrative. Further analysis is needed to apply the concepts of portfolio analysis to models using more complete sets of inputs, such as those used in the Scenario Analysis Report and the IAP. Ultimately, integrating portfolio analysis concepts into state and utility long-term planning could be combined with other improvements that address the need to achieve state GHG goals while controlling ratepayer costs. Figure 4-2 shows the results from the preliminary portfolio analysis discussed in the report.[214] The vertical axis shows total portfolio electricity generation

[214] Adapted from Bates White, Figure 8, p. 28. http://www.energy.ca.gov/2007publications/CEC-300-2007-009/CEC-300-2007-009-D.PDF

Figure 4-2. Risk and Cost in Portfolio Analysis of California Business as Usual 2020 Generation Resources



Source: Bates White, A Mean-Variance Portfolio Optimization of California's Generation Mix to 2020: Achieving California's 33 Percent RPS Goal, Draft Consultant Report, July, 2007.

cost, while the horizontal axis shows portfolio risk. In the figure, the curve connecting "Mix P" to "Mix Q" shows the location of portfolios with the best cost-risk combinations, indicating that the "business as usual" portfolio mix is not on the frontier.

Table 4-2 shows portfolios that fall on the efficient frontier shown by the curve in Figure 4-2. The proportions of each renewable technology in Portfolio N appear to be more practical than those in Portfolios S and Q. In addition to exceeding the 33 percent renewable generation goal, Portfolio N has lower risk, equivalent costs, and results in significantly less CO2 emissions than the business-as-usual case.[215]

Table 4-2. Portfolio Mix Details for Portfolios P, N, S, and Q shown in Figure 4-2.

	CA-2020 (BAU)	Portfolio P	Portfolio N	Portfolio S	Portfolio Q
RISK	7.7%	4.2%	4.5%	7.7%	8.0%
COST: cents/KWh	9.9	11.1	9.9	7.7	7.7
CO2: Mil-tonnes/Yr	78	47	47	19	19
Generating Resource	Generating Shares				
Coal	15%	15%	15%	5%	5%
Natural Gas	34%	5%	5%	5%	5%
Nuclear	12%	12%	12%	12%	11%
Hydro	20%	20%	20%	15%	15%
Wind	4%	2%	5%	22%	23%
Geothermal	7%	5%	11%	29%	29%
Biomass	3%	12%	12%	1%	1%
Biogas	1%	10%	10%	10%	10%
Solar Thermal	3%	10%	6%	0%	0%
Solar PV	0%	8%	4%	0%	0%
Renewables Share	20%	41%	45%	64%	64%

Source: Bates White, A Mean-Variance Portfolio Optimization of California's Generation Mix to 2020: Achieving California's 33 Percent RPS Goal, Draft Consultant Report, July, 2007.

[215] BW, p. 25-30.

In written comments on the portfolio analysis report, the IOUs indicated that they believe the report is based on too many simplifying assumptions. SDG&E states, "…we believe that the situation facing the utilities and the state in resource planning is far more complex than has been captured in the illustrative analysis presented as an example.[216]" PG&E echoes the concern: "Conclusions suggested by the Bates-White report are premature due to its methodological issues.[217]"

SCE articulates a similar position: "SCE believes the analysis is a reasonable starting point for understanding the potential effects that a limited set of risk factors would have on the future costs and emissions of various hypothetical portfolios. However, the [Energy Commission's] analysis contains omissions in input data, risk factors, peer scrutiny, and other considerations that bring into question whether the results are a meaningful representation of the future outcomes."[218]

The Natural Resources Defense Council's (NRDC) written comments recognized the concerns voiced at the workshop regarding assumptions used in the report, but stated that, ". . . we believe that the value of portfolio analysis is clear." NRDC believes that the use of this approach is critical to "understand[ing] the important role that energy efficiency and renewable energy can play in reducing total system risk" and recommends that "the [Energy] Commission work with the CPUC and the state's utilities to incorporate portfolio analysis techniques in the development of the 2008 Long-Term Procurement Plans."[219]The workshop comments and the acknowledged caveats to the mean-variant portfolio analysis study indicate that further study is needed to bring the benefits of portfolio concepts into analysis with a more complete set of assumptions.

The scenario and portfolio analyses approaches, along with the methodology used in the IAP, each have their strengths and weaknesses. None of these studies alone can definitively answer the question of the effect of 33 percent renewables on rates. Collectively, however, they corroborate the feasibility and desirability of the 33 percent in 2020 objective.

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[216] SDG&E, Comments, July 11, 2007 Integrated Energy Policy Report Committee Workshop on the Use of Portfolio Analysis in Electric Utility Resource Planning

[217] PG&E, Comments, July 11, 2007 Integrated Energy Policy Report Committee Workshop on the Use of Portfolio Analysis in Electric Utility Resource Planning

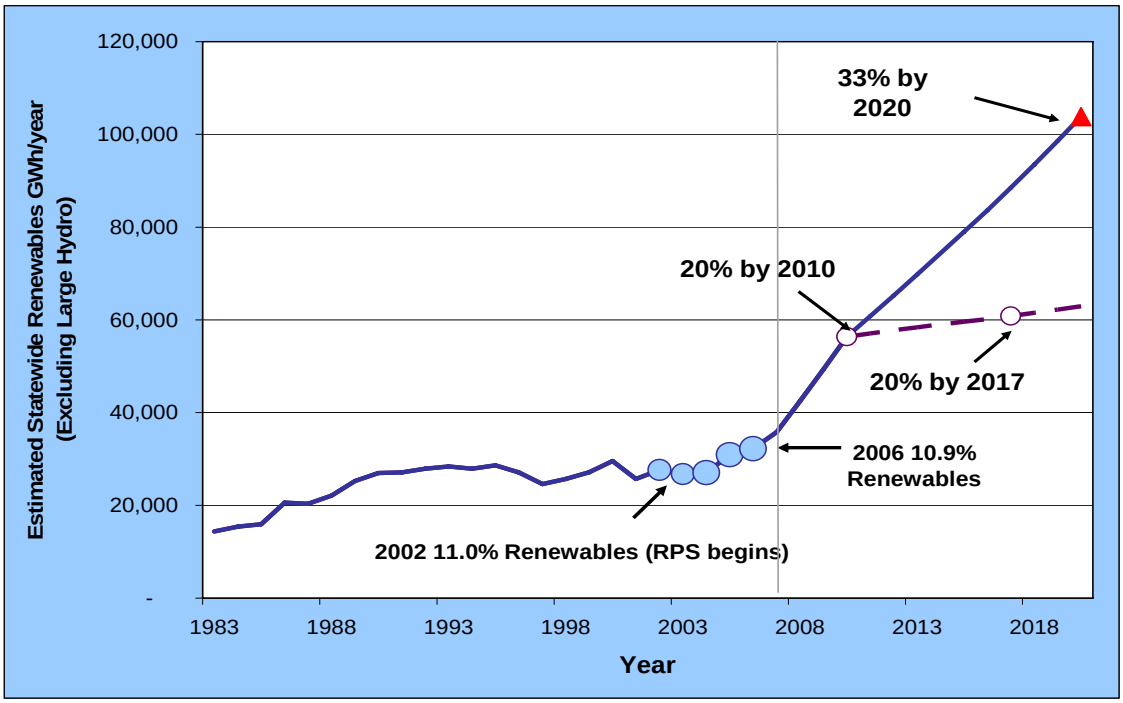
[218] SCE, Comments, July 11, 2007, Integrated Energy Policy Report Committee Workshop on the Use of Portfolio Analysis in Electric Utility Resource Planning

[219] Natural Resources Defense Council Comments, July 11, 2007 Integrated Energy Policy Report Committee Workshop on the Use of Portfolio Analysis in Electric Utility Resource Planning

Status of RPS Compliance: California Not on Track to Meet 20 Percent by 2010

AB 1585 requires the Energy Commission to evaluate the progress made toward the 20 percent renewable goal by all load serving entities. Four years after legislative enactment of the RPS, little progress has been made toward increasing the overall percentage of renewable energy deliveries in California's generation mix, as illustrated in Figure 4-3. Renewable generation in 2006, for all entities serving retail load, was at 10.9 percent, just below the percentage in 2002 before the RPS began.[220] While delivered renewable energy has grown, load has also continued to grow, and delivered renewable energy has essentially kept even, rather than increasing in percentage terms as required.

Figure 4-3. Progress Toward California's Renewable Energy Goals



Source: California Energy Commission.[221]

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[220] California Energy Commission, Gross System Power 1998-2005,

http://energy.ca.gov/electricity/gross_system_power.html. Gross System Power renewable percentages are based on total reported generation and allow for consistent comparison of renewable generation across multiple years. Renewable Portfolio Standard targets are defined as renewable generation as a percentage of retail sales. In 2006, renewable generation in California represented approximately 11.9 percent of retail sales.

[221] California Energy Commission, Gross System Power 1998-2005. Gross System Power renewable percentages are based on total reported generation and allow for consistent comparison of renewable

California's statewide RPS target of 20 percent by 2010 is defined as actual delivered renewable energy divided by retail sales. Although the percentage of renewable deliveries has been flat, there is a large amount of contracted renewable energy that is likely to come on line in the next 2 to 5 years as new transmission to the Tehachapi and Imperial Valley areas becomes available. Due to transmission constraints, growth of renewable energy is likely to be characterized by flat periods and periodic bursts of growth.

California's statewide targets are unlikely to be met without proportional contributions by all load serving entities, including IOUs, POUs and ESPs. Currently, mandatory RPS targets with consequences for noncompliance only apply to IOUs and ESPs, and rules for ESPs are less clear than for IOUs and have been only recently developed. POUs are "…responsible for implementing and enforcing a renewables portfolio standard that recognizes the intent of the Legislature to encourage renewable resources, while taking into consideration the effect of the standard on rates, reliability, and financial resources and the goal of environmental improvement.[222] Since the passage of SB 107, POUs will not be allowed to sell RECs in the future to IOUs unless they are on track to meet RPS targets comparable to those of the IOUs.[223]

Progress Made by Investor-Owned Utilities

Although IOUs have not sufficiently increased renewable deliveries since 2003, they have contracted for substantial quantities of renewable energy that they expect will become part of the generation mix soon after 2010. While an earlier discussion focused on the IOU's LTPPs and their expectations regarding future renewable deliveries, this section focuses on actual delivered energy.

Table 4-3 shows the verified renewable energy procurement of the three major IOUs in 2005 and the unverified data for 2006 reported by the IOUs.

Comparing 2006 renewable generation with actual 2003 renewable generation shows that while overall IOU renewable deliveries has increased, particularly for SDG&E, overall procurement as a percent of retail sales has decreased by almost one percent. This means that renewable energy deliveries are not keeping up with load growth.[224] To reach 20 percent in 2010, PG&E and

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generation across multiple years. Renewable Portfolio Standard targets are defined as renewable generation as a percentage of retail sales. In 2006, renewable generation in California represented approximately 11.9 percent of retail sales.

[222] Public Utilities Code Section 387, paragraph (a).

[223] Public Utilities Code Section 399.13, paragraph (d), as amended by SB 107 (Simitian), Chapter 464, Statutes of 2006, http://www.leginfo.ca.gov/pub/05-06/bill/sen/sb_0101-0150/sb_107_bill_20060926_chaptered.pdf.

[224] Use of 2003 for a comparison reflects the CPUC's Decision 07-03-046 under Rulemaking 06-05-027 (the March 2007 Baseline Decision) that revises the methodology used to calculate the IOUs' Initial Baseline Procurement Amounts.

SDG&E will need to increase renewable deliveries by approximately two and five per cent per year, respectively.

Table 4-3. Investor-Owned Utility Renewable Generation (2003-2006)

UTILITY	PG&E	SCE	SDG&E	Total
2003 Retail Sales (GWh)	71,099	70,617	15,044	156,760
2003 RPS Renewable Generation	8,828	12,496	550	21,874
2003 RPS Renewable Generation as % of Retail Sales	12.4%	17.7%	3.7%	14.0%
2005 Retail Sales (GWh)	72,727	75,302	16,002	164,031
2005 RPS Renewable Generation (GWh)	8,650	12,924	825	22,399
RPS Renewable Generation as % of Retail Sales	11.9%	17.2%	5.2%	13.7%
2006 Retail Sales (GWh)	76,692	78,863	16,847	172,402
2006 RPS Renewable Generation (GWh)	9,114	12,596	900	22,610
RPS Renewable Generation as % of Retail Sales	11.9%	16.0%	5.3%	13.1%

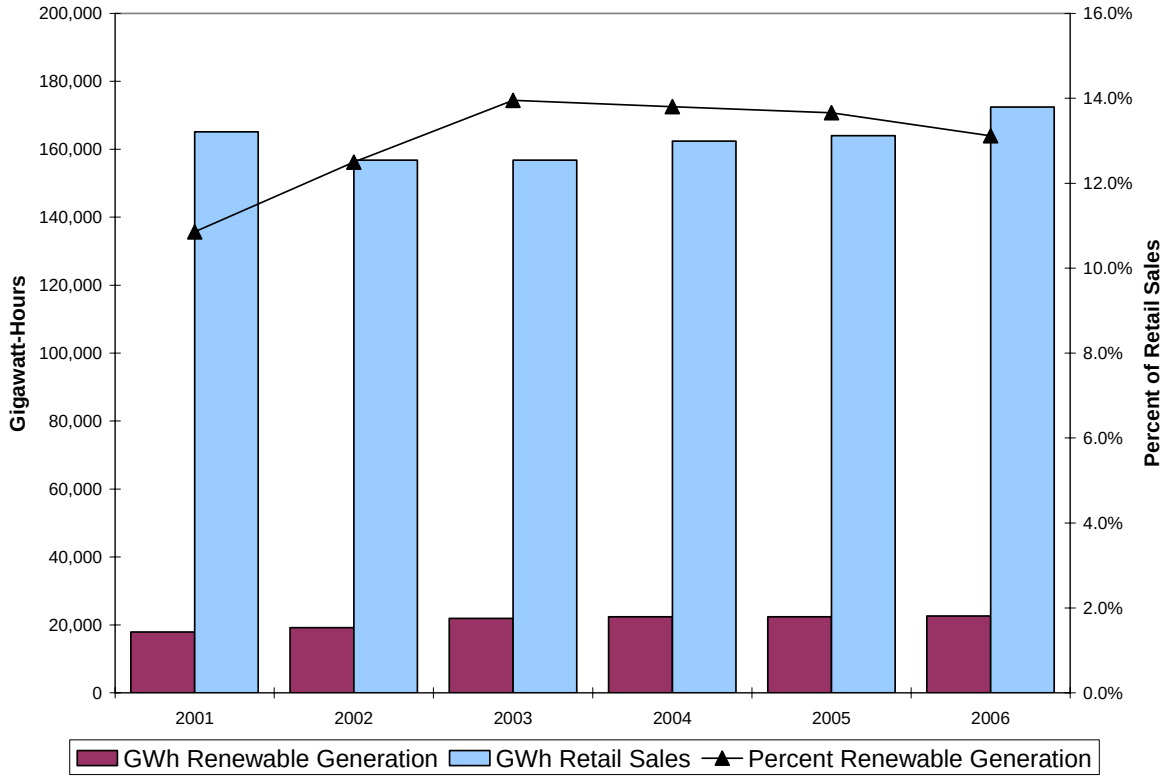
Source: Data for 2003 and 2005 from California Energy Commission 2005 RPS Verification Report (CEC-300-2007-001-CMF), except 2003 RPS Renewable Generation is from 2004 RPS Verification Report (CEC-300-2006-002-CMF). Data for 2006 submitted by IOUs in RPS Track Forms, to be verified in the forthcoming 2006 Verification Report

Figure 4-4 shows the progress of the three large IOUs toward the short-term RPS target of 20 percent renewable generation by 2010. The blue bars show combined total retail sales for PG&E, SCE and SDG&E, while the red bars show renewable generation. The yellow line shows renewable generation as a percentage of retail sales.

The three major IOUs added more renewable generation during each of the two years immediately preceding the start of the RPS at the beginning of 2003, although much of this added generation came from existing resources. Since 2003, the IOUs as a group have been going in the wrong direction. The trend since 2003 is increasing load growth without the required increases in the amount of renewable generation.

Figure 4-5 compares the three major IOUs' status. SDG&E, starting with only one percent renewable generation, has made the most progress but will need to increase much more rapidly to meet the goal. SCE continues to decline in renewable generation, and will need to achieve about 1.5 percent per year to hit the target. PG&E's performance has also been flat over the last four years.

Figure 4-4. Progress of Large Investor-Owned Utilities toward 20 Percent Renewable Energy by 2010 (GWh/year, Percent)

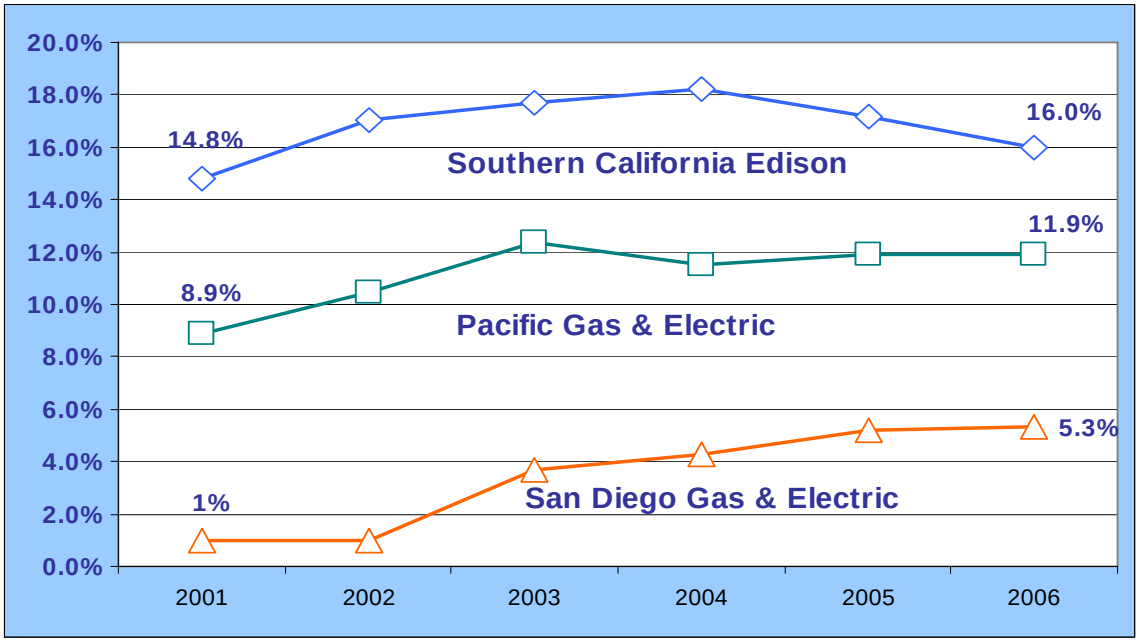


Source: California Energy Commission

The three major IOUs have contracted (or are close to receiving CPUC approval for contracts) for sufficient renewable generation to meet 2010 goals if all contracts were to perform on schedule. Figure 4-6 shows the amount of renewable capacity the IOUs have contracted for each year since the RPS legislation took effect. According to the CPUC's RPS Procurement Status Report, submitted to the legislature in July 2007, RPS contracts approved or pending approval will result in the IOUs achieving about 25,000 GWh of renewable deliveries in 2010, provided contracts are not delayed.[225] This is equivalent to about 14 percent of retail sales.

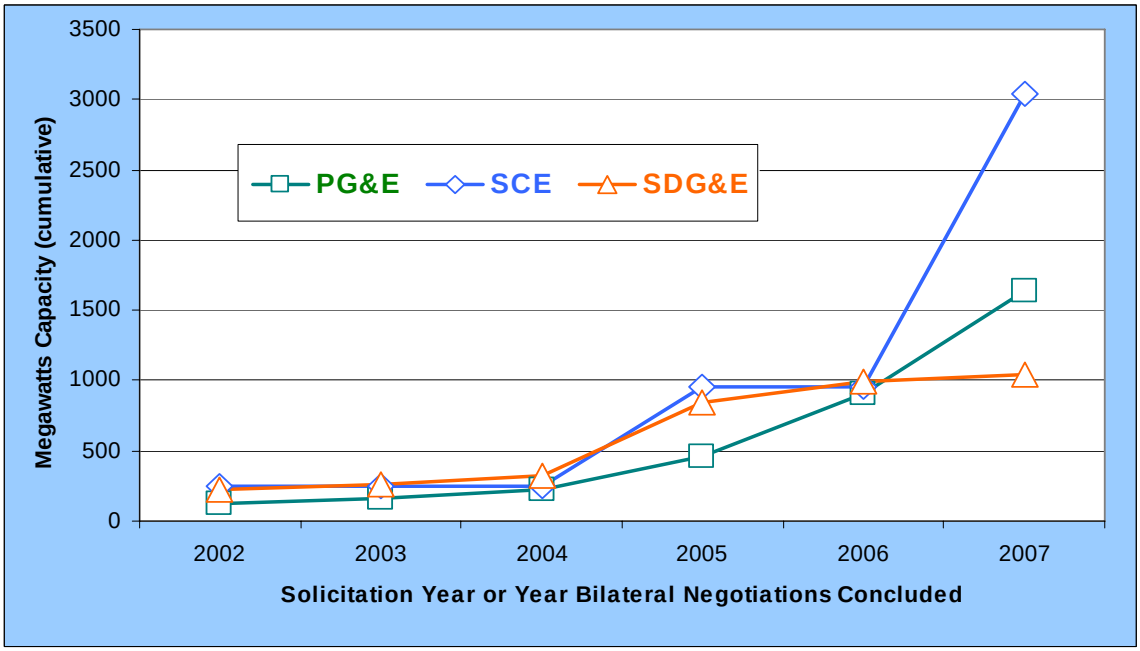
[225] CPUC, Progress of the California Renewable Portfolio Standard, July 2007, at http://www.cpuc.ca.gov/word_pdf/REPORT/69823.pdf. Quantities are based on Figure 1, p. 5.

Figure 4-5. Comparison of IOU RPS Progress 2001–2006



Source: California Energy Commission 2004 and 2005 RPS Verification Reports and data submitted for 2006 RPS Verification reports. 2002 data is from AB 1305 submittals and IOU reports to the CPUC.

Figure 4-6. Cumulative Contracted Renewable Capacity 2002–2007



Source: California Energy Commission, Contract Database at <http://www.energy.ca.gov/portfolio/IOU_CONTRACT_DATABASE.XLS>.

However, since June, the IOUs have requested CPUC approval for additional contracts that would deliver an additional 7,700 GWh by January 2011. These numbers are based on minimum quantities in the contracts in cases where there are options for additional build out. If all build-out opportunities were taken, there is sufficient energy contracted for the utilities as a group to meet the 20 percent goal. But the potential for contract failure and delay, discussed below, indicates that if current trends continue, the 20 percent target will be met after 2010.

IOU Contract Failure and Delay

The trend in failure and delay of IOU RPS contracts is not encouraging. As shown in Table 4-4 on the following page, as of March 2007, 50 percent of IOU RPS generation (GWh/year) under contract with new, repower, or restarted facilities was canceled or delayed. Since then, new contracts have been signed for large amounts of energy, bringing the failure rate to 25 percent. It is too soon to tell what portion of these new projects will be cancelled or delayed. Similarly, as of March 2007, about 33 percent of the number of contracts signed since 2002 had been cancelled or delayed. In August 2007, contract failure by this measure remained at 33 percent.

Table 4-4. New, Repower, Restart Facilities with IOU RPS Contracts

	Number of Contracts		Minimum Capacity (MW)		Energy (GWh/year)		Percent of Contracted Energy (%)	
	3/07	8/07	3/07	8/07	3/07	8/07	3/07	8/07
Canceled	8	9	162	207	724	1,039	9%	6%
Delayed	12 (4 of these on-line after delay)	15(4 of these on-line after delay)	1,248	1,234	3,415	3,323	41%	21%
Percent Canceled or delayed	33%	33%	62%	30%	50%	26%		
On schedule	39 (12 on-line)	49 (13 on-line)	860	3,364	4,093	12,147	49%	74%
Unknown	2	73	13	4,805	93	16,508	1%	100%
Total	61	9	2,283	207	8,325	1,039	100 %	6%

Source: Energy Commission, IOU RPS Contract Database (March and August 2007)

In terms of capacity, the March 2007 data show 1,410 MW of 2,283 MW, more than 60 percent of minimum capacity, was canceled or delayed. As of August 2007, 1,441 MW of 4,805 MW, about 30 percent of minimum capacity, was canceled or delayed.

Progress Made by Publicly Owned Utilities

POUs, including both municipal utilities and cooperatives, are required by state law to implement a renewables portfolio standard, but are given flexibility in developing specific targets and timelines.

This section describes efforts (through the end of July 2007) by the state's POUs in meeting their RPS requirements, including a summary of current POU RPS targets, progress towards achieving those targets, and recent contracts and solicitations. Despite some improvements to encourage more regular reporting of POU progress, the data that follow remain incomplete and somewhat uncertain in many respects.

Data Sources for Tracking POU RPS Activities

POUs are required to report annually to the Energy Commission on the status of their RPS implementation and to provide data on specific purchases of eligible renewable electricity. Data submitted in accordance with these requirements were used if available to verify current RPS goals and timelines and to determine energy supplied from specific, Energy Commission eligible and POU-qualifying resources.[226]

Many POUs, however, did not submit all required data for 2006. Thus, a variety of other data sources were used in lieu of, or as a supplement to, information submitted to the Energy Commission, including: power content labels, press releases, annual financial reports, city council and utility board documents, and integrated resource plans or other planning documents prepared by POUs. Many of these data sources also provided information about recent POU renewable energy contracts and solicitations.

Several comments are worth noting regarding how these data sources were used:

- The amount of energy supplied by "CEC-eligible" resources considers only resource eligibility criteria (e.g., no large hydro), but not deliverability-related eligibility criteria. That is, some renewable purchases indicated as "CEC-eligible" represent resources that would not be eligible under the California RPS as applied to IOUs because of geographic location (out-of-state) and/or product type (e.g., RECs).

[226] "POU-qualifying" resources include deliveries from renewable resources that are eligible under a POU's RPS target but that are not CEC-eligible (e.g., large hydro).

- Prior reports have presented data on each POU's supply of CEC-eligible and POU-qualifying resources in 2003.227 We re-calculated 2003 values based on data in the POUs' SB 1305 Annual Report Forms (if available) in order to maintain consistency with the 2006 values. In many cases, the re-calculated 2003 values were lower than those previously reported.
- If power content labels were used to determine the percentage of a POU's retail load supplied by CEC-eligible or POU-qualifying resources, the percentages reported on the labels were adjusted to remove the renewable content associated with non-specific purchases.

Finally, we note that not all details presented here have been formally verified with POUs, and feedback on the accuracy of the data presented here is welcomed.

Current POU RPS Targets

Table 4-5 lists current RPS targets and timelines of the state's 47 POUs. As shown, at least 29 POUs, representing 98 percent of statewide POU retail sales, have established some form of RPS commitment, although the details of their RPS policies vary considerably in terms of the target, timeframe, and resource eligibility rules. Some of these targets are equally or more aggressive than the RPS targets applied to the state's IOUs (20 percent by 2010), while others are less so. At least 19 POUs that have developed RPS targets allow some hydropower projects to qualify that are not otherwise eligible under the IOUs' RPS requirements.

A number of the state's larger POUs have recently adopted more aggressive RPS policies. At least four POUs – the Los Angeles Department of Water and Power (LADWP), Riverside, Palo Alto, and Redding – have accelerated their existing 20 percent renewable energy targets to 2010 or sooner, in line with the timetable established by SB 107 for the state's IOUs. In addition, at least three POUs have increased their overall targets to levels greater than 20 percent, including LADWP (35 percent by 2020), the Imperial Irrigation District (30 percent by 2020), and Palo Alto (30 percent by 2012 and 33 percent by 2015). Anaheim, the state's fourth-largest POU, raised its RPS goal from 15 to 20 percent, while moving its target date forward from 2017 to 2015.

Though rules for resource eligibility and other policy details differ, it is instructive to compare the POUs' RPS targets to those of the IOUs in terms of the incremental need for renewable energy. Relative to their eligible renewable energy deliveries in 2003, the state's IOUs will – in aggregate – have to supply an additional 6 percent of retail sales with CEC-eligible resources to meet their current 20 percent RPS target by 2010, and an additional 19 percent of retail load to meet the state's non-mandatory 33 percent goal by 2020.[228] In comparison, the 20 POUs for which data are available (representing 89 percent of statewide POU load) will have to increase

[227] KEMA, Publicly Owned Electric Utilities and the California RPS: A Summary of Data Collection Activities, November 2005, CEC-300-2005-023.

[228] KEMA, Publicly Owned Electric Utilities and the California RPS: A Summary of Data Collection Activities, November 2005, CEC-300-2005-023.

their supply of POU-qualifying resources by 20.5 percent of retail sales (on an average, load-weighted basis) to meet their ultimate targets.[229] The POU targets vary in target year and target percentage. As shown in Table 4-5, although large POUs including LADWP, IID and Palo Alto have set ultimate goals of 35, 30 and 33 percent by 2020 or earlier, respectively, most POUs have not yet set 2020 goals comparable to those of the IOUs.

Given POUs' widely varying compliance dates, however, it is also useful to compare the stringency of their goals relative to the IOUs' compliance dates in terms of average annual procurement needs, starting from 2003 levels. To meet their 20 percent target by 2010, the state's IOUs will need to have add, on average, an additional 2 percent of load each year from 2007 to 2010 from eligible resources; to meet the 33 percent by 2020 goal will require an increase of 1.3 percent of retail sales per year from 2010 through 2020.[230] In comparison, the 20 POUs for which data are available (representing 89 percent of statewide POU load) will have to increase their supply of qualifying resources by 1.5 percent of retail sales per year (on a load-weighted basis) to meet their collective targets. These comparisons are not definitive, given different resource eligibility rules and enforcement approaches. However, because POUs began with lower levels of renewables, they will need to continue to add renewable resources at a much faster average rate than the IOUs in order to fulfill their proportional share of the overall state target.

POU Progress in Increasing Renewable Energy Deliveries

Since enactment of the state's RPS, progress by POUs towards achieving their individual RPS goals has been uneven, but increases in renewable energy deliveries are apparent. Reasonably reliable data on deliveries by specific, CEC-eligible resources in both 2003 and 2006 are available for 21 POUs, representing 89 percent of total POU retail sales. Among these utilities, deliveries of specific, CEC-eligible resources increased by 3 percent of retail sales between these years, on a load-weighted average basis.[231]

Among these 21 POUs, deliveries of specific, CEC-eligible resources declined from 2003 to 2006 for 7 utilities that represent 9 percent of total POU retail sales. However, at least 14 POUs, representing 80 percent of statewide POU retail sales, saw an increase in deliveries from CEC-eligible resources over this timeframe equivalent to 3.5 percent increase per year. The following five utilities saw the largest percentage increases:

Palo Alto increased its CEC-eligible renewable percentage from 2.4 to 10.4 percent, primarily as a result of two new wind contracts (High Winds and Shiloh).

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[229] These 20 utilities consist of all those listed in Table 7 with available data on both RPS targets and POU-qualifying deliveries in 2003. Also included are Santa Clara and Healdsburg, both of which are considered to have no incremental need relative to 2003 levels.

[230] KEMA, Publicly Owned Electric Utilities and the California RPS: A Summary of Data Collection Activities, November 2005, CEC-300-2005-023.

[231] These 21 utilities consist of all those listed in Table 7 with available data on CEC-eligible deliveries in both 2003 and 2006.

Table 4-5. Publicly Owned Utility Renewable Energy Targets and Deliveries (2003, 2006)

Utility Name	Total Retail Sales 2005 (MWh)	CEC Eligible 2003 (%)	CEC Eligible 2006 (%)	POU Qualifying 2003 (%)	POU Qualifying 2006 (%)	RPS Target	Large Hydro Included	RPS Timeframe
Los Angeles	23,400,472	1.6	3.9	4.2	6.6	20/35	Partial	2010/2020
Sacramento	10,485,723	4.8	10.9	4.8	10.9	20	No	2011
Imperial	3,108,748	n/d	6.7	n/d	n/d	20/30	Only "low impact"	2010/2020
Modesto	2,582,599	0.0	6.6	0.0	6.6	20	No	2017
Anaheim	2,553,464	0.1	4.5	4.3	8.6	20	Yes	2015
Santa Clara	2,496,836	23.5	21.2	63.1	51.4	No Specific	n/a	n/a
Riverside	1,989,207	13.4	13.1	13.4	13.1	20	No	2010
Turlock	1,808,573	6.7	8.0	6.7	8.0	20	No	2017
Pasadena	1,175,585	0.6	1.9	4.9	6.2	10/20	Existing large hydro only	2010/2017
Roseville	1,159,937	8.8	10.2	40.9	54.0	20	Yes	2017
Vernon	1,137,854	n/d	n/d	n/d	n/d	5/20	n/d	2009/2017
Glendale	1,104,909	7.4	10.7	13.4	16.7	20	Yes	2017
Burbank	1,093,700	0.3	0.6	0.3	0.6	10/20	Only "low impact"	2011/2017
Palo Alto	958,571	2.4	10.4	2.4	10.4	20/30/33	No	2008/2012/2015
San Francisco	782,758	n/d	n/d	n/d	n/d	n/d	n/d	n/d
Redding	769,947	4.8	8.1	39.3	61.6	20	Yes	2010
Lodi	455,238	27.1	22.9	48.6	34.4	20	Yes	2017
Alameda	378,333	54.7	48.7	90.9	86.1	40	Yes	Through 2020
Merced	345,224	1.6	2.9	1.6	2.9	15	No	2012

Utility Name	Total Retail Sales 2005 (MWh)	CEC Eligible 2003 (%)	CEC Eligible 2006 (%)	POU Qualifying 2003 (%)	POU Qualifying 2006 (%)	RPS Target	Large Hydro Included	RPS Timeframe
Colton	342,569	2.3	4.0	2.3	4.0	15	No	2017
Azusa	251,266	2.2	6.1	2.2	6.1	20	No	2017
Shasta Lake	194,897	n/d	n/d	n/d	n/d	20	n/d	2010
Corona	163,745	n/d	n/d	n/d	n/d	n/d	n/d	n/d
Plumas-Sierra	153,368	n/d	n/d	n/d	n/d	20	Yes	2017
Banning	144,447	n/d	n/d	n/d	n/d	20	Yes	2017
Truckee Donner	135,919	n/d	n/d	n/d	n/d	21	Yes	2010
Lompoc	133,838	30.3	n/d	54.1	n/d	20	Yes	Purchases limited to funds, load growth, and replacing retired resources
Lassen	127,996	n/d	n/d	n/d	n/d	n/d	n/d	n/d
Ukiah	111,894	55.0	50.3	90.6	67.1	n/d	Yes	n/d
Trinity	83,401	n/d	n/d	n/d	n/d	Only renewables to meet growth beyond that provided by the Trinity River	Yes	n/a
Surprise Valley	76,147	n/d	n/d	n/d	n/d	n/d	n/d	n/d
Healdsburg	72,569	54.7	49.8	n/d	n/d	20	n/d	n/d
Needles	62,277	0.0	0.0	n/d	n/d	n/d	n/d	n/d
Anza	42,460	n/d	n/d	n/d	n/d	n/d	n/d	n/d

Utility Name	Total Retail Sales 2005 (MWh)	CEC Eligible 2003 (%)	CEC Eligible 2006 (%)	POU Qualifying 2003 (%)	POU Qualifying 2006 (%)	RPS Target	Large Hydro Included	RPS Timeframe
Gridley	32,033	n/d	n/d	n/d	n/d	20	Yes	As resources added
Tuolumne	26,413	n/d	n/d	n/d	n/d	n/d	n/d	n/d
Biggs	19,144	n/d	n/d	n/d	n/d	20	Yes	As resources added
Valley Electric	6,796	n/d	n/d	n/d	n/d	n/d	n/d	n/d
Escondido	18	n/d	n/d	n/d	n/d	n/d	n/d	n/d
Hercules	n/d	n/d	n/d	n/d	n/d	n/d	n/d	n/d
City of Industry	n/d	n/d	n/d	n/d	n/d	n/d	n/d	n/d
McAllister Ranch	n/d	n/d	n/d	n/d	n/d	n/d	n/d	n/d
Moreno Valley	n/d	n/d	n/d	n/d	n/d	n/d	n/d	n/d
Pittsburg	n/d	n/d	n/d	n/d	n/d	n/d	n/d	n/d
Rancho Cucamonga	n/d	n/d	n/d	n/d	n/d	n/d	n/d	n/d
Victorville	n/d	n/d	n/d	n/d	n/d	n/d	n/d	n/d
Port of Oakland	n/d	n/d	n/d	n/d	n/d	20 Goal, 40 Objective	Yes	2017

Note: n/d indicates no data available and n/a indicates not applicable.

Source: Form EIA-861; SB 1305 Annual Report Forms; Form CEC-POU-RPS; Power Content Labels; and information posted on utility and municipal websites, including annual financial reports, city council and utility board documents, and integrated resource plans or other planning documents

- Modesto increased its CEC-eligible renewable percentage from 0 to 6.6 percent of retail sales by adding three new wind contracts to its portfolio (High Winds, Shiloh, and Big Horn).
- SMUD increased its CEC-eligible renewable percentage from 4.8 to 10.9 percent as a result of new contracts for geothermal (Geysers), wind (High Winds), and small hydro (EBMUD) resources, and by expanding its owned wind project (Montezuma Hills).
- Anaheim increased its CEC-eligible renewable percentage from 0.1 to 4.5 percent, largely as a result of new wind (High Winds) and geothermal (Heber) contracts.
- Azusa increased its CEC-eligible renewable percentage from 2.2 to 6.1 percent as a result of a new wind project (High Winds).

LADWP, the state's largest POU, increased its CEC-eligible renewable deliveries by 2.3 percent between 2003 and 2006, from roughly 1.6 percent in 2003 to 3.9 percent in 2006. This increase is associated largely with several new contracts with small hydro facilities in the Pacific Northwest, as well as a new wind contract (Pleasant Valley).

The 3 percent load-weighted average increase in CEC-eligible renewable deliveries between 2003 and 2006 among the 21 POUs for which data exist can be compared to progress made by the three large IOUs over the same time period, as reported in the Energy Commission's 2004 and 2005 RPS Verification reports, and in RPS track reporting forms submitted by the IOUs that will be used in the 2006 RPS Verification report:[232]

- PG&E: Renewable deliveries as a percentage of retail sales from the same year decreased from 12.4 percent in 2003 to 11.9 percent in 2006 (a 0.5 percent decrease).
- SCE: Renewable deliveries as a percentage of retail sales from the same year decreased from 17.7 percent in 2003 to 16 percent in 2006 (a 1.7 percent decrease).
- SDG&E: Renewable deliveries as a percentage of retail sales from the same year increased from 3.7 percent in 2003 to 5.3 percent in 2006 (a 1.6 percent increase).

As a group, the IOUs have decreased CEC-eligible renewable deliveries as a percentage of retail sales by an average of 0.1 percent per year between 2003 and 2006, compared to the 3 percent load-weighted average increase of the 21 POUs for which data are available. Thus, clearly the POUs were more successful than IOUs from 2003 to 2006 in increasing CEC-eligible renewable energy deliveries.

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[232] IOU Compliance reports submitted to the CPUC look at compliance defined, in part, as one year's RPS generation divided by the prior year's retail sales. This analysis compares renewable generation as a percent of the same years' retail sales. Energy Commission, Renewables Portfolio Standard 2005 Procurement Verification, CEC-300-2007-001-CMF, August 2007 and Renewables Portfolio Standard Procurement Frication Report, CEC-300-2006-002-CMF, February 2006. [staff to review this footnote. Do we need to add more here to explain why we do this differently than the CPUC?]**

POU Contracts and Solicitations

Since the beginning of 2003, POUs have contracted for approximately 1,600 MW of renewable electricity capacity, 1,300 MW of which is from new resources that began, or are expected to begin, operation after passage of the state's RPS law in 2002. The 1,300 MW includes approximately 900 MW of wind, 200 MW of geothermal, and 200 MW of biomass (including 100 MW of MSW to be developed by LADWP).

As of July 2007, over 550 MW of the contracted new capacity was online and delivering energy to the California POUs, while only 324 MW of new, repowered or re-started RPS capacity contracted by the IOUs was on line as of early August.[233]As shown in Table 4-6, new POU wind projects make up almost all of this capacity, with the two largest projects located outside of California.

Table 4-6. New Renewable Projects Online (Publicly Owned Utilities)

Project	Technology	MW Under Contract to CA POUs	Location	Online	POUs Currently Receiving Deliveries
Big Horn	Wind	200	WA	2007	Modesto, Redding, Santa Clara
Pleasant Valley	Wind	127	WY	2003	Anaheim, Burbank, Glendale, LADWP
High Winds	Wind	104	CA	2003	Alameda, Anaheim, Azusa, Colton, Glendale, Merced, Modesto, Palo Alto, Pasadena, Roseville, SMUD
Shiloh	Wind	75	CA	2006	Modesto and Palo Alto
Montezuma Hills Phases I and II	Wind	39	CA	2003/ 2006	SMUD (owned-project)
Heber expansion	Geothermal	10	CA	2006	Anaheim, Banning, Glendale, Pasadena
Multiple projects	Landfill Gas	9	CA	2003-2006	Alameda, Burbank, Colton, Palo Alto, Riverside

Source: SB 1305 Annual Report Forms and information obtained through web searches, including press releases issued by utilities and project owners/marketers, annual financial reports, city council and utility board documents, and integrated resource plans or other utility planning documents

[233] See the Energy Commission database of renewable energy contracts signed by the IOUs under the state's RPS, at: http://www.energy.ca.gov/portfolio/contracts_database.html

Approximately 700 MW of new renewables projects are under contract (or in development) but not yet online. Included within this total are a number of contracts or projects announced since July 2006, including:

- The Milford wind project, located in Utah, for which contracts have been announced by Burbank (10 MW), LADWP (185 MW), and Pasadena (5 MW);
- Four municipal solid waste projects, totaling 100 MW, that LADWP has announced plans to develop;
- A 25 MW landfill gas project in Brea under contract with Anaheim Public Utilities; and
- A 25 MW biomass repowering project under contract with the Modesto Irrigation District.

Also since July 2006, at least seven solicitations have been announced through which the state's POUs are seeking additional renewable energy deliveries (see Table 4-7). New contracts have yet to be announced from most of these solicitations. However, based on the amount of capacity solicited, additional resources procured through these efforts may add substantially to POUs renewable deliveries in future years.

Table 4-7. Renewable Solicitations Issued by POUs since July 2006

Issued By	Date of Solicitation	Technologies Requested*	Capacity Solicited	Energy Solicited
Palo Alto	Jul-07	CEC Eligible	not stated	280 GWh/yr
SMUD	Apr-07	CEC Eligible	not stated	not stated
LADWP	Jan-07	CEC Eligible	not stated	2,200 GWh/yr
Turlock	Oct-06	CEC Eligible	not stated	260 GWh/yr
SCPPA	Sep-06	CEC Eligible	300 MW	not stated
NCPA	Sep-06	CEC Eligible	79 MW	not stated
SMUD	Aug-06	CEC Eligible	not stated	not stated

Notes: * Some of the RFPs do not explicitly identify CEC-eligible as a requirement, but define eligible technologies to be largely consistent with CEC rules. There are some modest exceptions. SCPPA's RFPs do not reference CEC eligibility, but indicate "any certifiable renewable energy." Many of the solicitations provide greater delivery flexibility, or even allow RECs.

Source: Press releases and solicitations issued by utilities, posted on utility websites.

Assuming that all contracts come to fruition, the 1,300 MW of new renewable sources currently under contract to the POUs is expected to meet 11 percent of 2003 POU load. This compares to roughly 4,640 to 6,330 MW of new renewable energy contracts signed by the state's IOUs as of July 2007, equivalent to 10 to 13.5 percent of aggregate IOU load in 2003. In other words, while POU progress in bringing new renewable energy projects on-line has so far exceeded the progress made by the state's major IOUs, projected future deliveries are similar if all contracts deliver as promised.

Progress Made by Electric Service Providers and Small and Multi-Jurisdictional Utilities

Although PG&E, SCE, and SDG&E began reporting their RPS procurement to the Energy Commission in 2005, the first year that other retail sellers were required to submit procurement data is 2007. The Energy Commission began collecting RPS data from ESPs and California's small and multi-jurisdictional utilities (SMJUs) in 2007, after the CPUC issued decisions establishing RPS rules for those entities.

In Decision 05-11-025 (p. 14), the CPUC ruled that electric service providers are subject to the following RPS requirements:

- Achieve 20 percent renewable energy by 2010.
- Increase renewable sales by at least 1 percent of sales per year.
- Submit reports to the CPUC.
- Use flexible compliance mechanisms if needed.
- Subject to penalties and penalty processes.

In 2006, CPUC Decision 06-10-019 further clarified RPS rules and targets for retail sellers. In general, the same RPS requirements that apply to ESPs also apply to SMJUs. Following on the CPUC's decisions bringing all retail sellers into the RPS, the Energy Commission's RPS Guidebook requires ESPs, CCAs, and SMJUs to report their RPS procurement for 2005 and 2006.

To date, ten of 15 ESPs have either provided required reports or provided a partial response to the Energy Commission. In addition, all but one of the five SMJUs have responded. Therefore, the following discussion of ESP and SMJU progress is based on incomplete, unverified data. This preliminary data includes most of the total load served by ESPs and SMJUs.

The *2006 IEPR Update* reported that ESPs as a group served only about 0.25 percent of their retail sales from renewable sources immediately prior to 2006. In 2006, ESPs as a group increased their renewable energy to two per cent of retail sales. As shown in Table 4-8, of the six ESPs that reported both retail sales and RPS-eligible renewable energy, APS Energy reported the most (4.8 percent); the lowest percentage reported was just under 1 percent. After a late start, ESPs have a long way to go to meet the 2010 goals.

Table 4-8. RPS-Eligible Energy as Percent of 2006 Retail Sales Reported by Electric Service Providers

Electric Service Provider	2006 RPS-eligible Renewable Energy as percent of 2006 retail sales
APS Energy Services	4.8
Calpine Power America	0.8
Commerce Energy, Inc	1.0
Pilot Power Group, Inc.	1.4
Sempra	2.4
Strategic Energy	1.0

Source: California Energy Commission

Two of California's five SMJUs are large utilities that serve bordering states as well as California, while three SMJUs are very small. Sierra Pacific Power, based in Nevada, reports procuring 31.8 GWh of renewable electricity in 2006 for its California load, or 5.9 percent of retail sales. PacificCorp reports 29.4 GWh of renewable energy, but has requested confidentiality for data on California retail sales. The state's three very small utilities have not provided complete reports, but represent only an extremely small portion of total state electric load.

Remaining Barriers to Renewable Energy Market Development

In addition to the issues discussed above, two additional barriers to renewable energy market development remain unresolved: a shortage of wind turbines; and the economic and permitting barriers to repowering and expanding existing wind facilities.

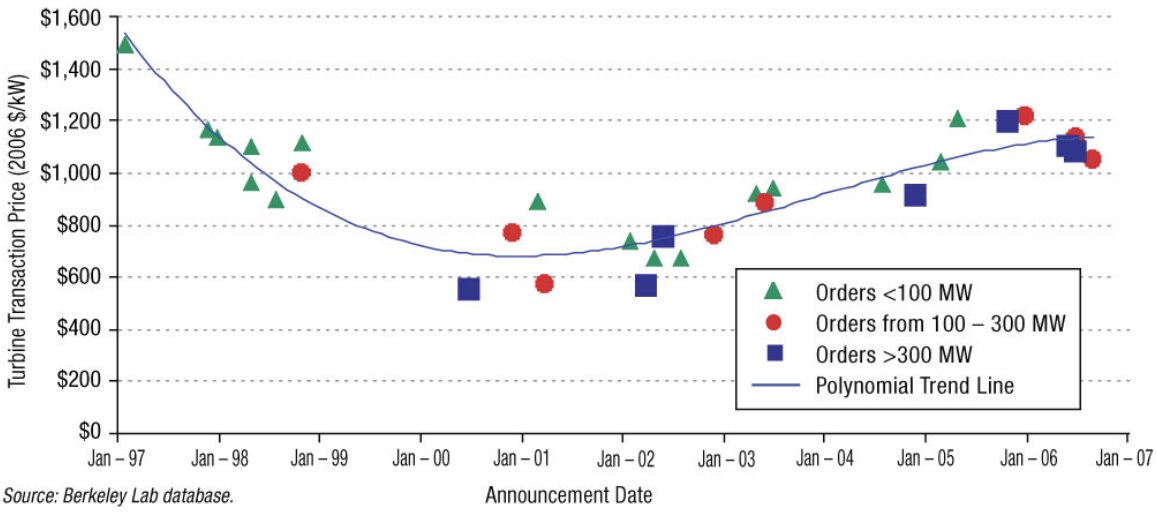
Shortage of Wind Turbines

Global demand for wind turbines has increased dramatically in recent years, with annual installations growing from 6,800 MW in 2001 to more than 15,000 MW in 2006. With this rapid growth, demand for wind turbines has exceeded supply, and manufacturers of turbines and turbine components have struggled to scale-up manufacturing capability.

To secure wind turbines in this new environment, project developers have been required to enter into large orders for future turbine delivery and front substantial commitment fees. Smaller wind developers who typically purchase turbines as-needed for individual wind projects are unable to compete for turbines in this environment, so much consolidation has occurred within the development community.

One result of these trends is that wind turbine prices, and installed wind project costs, have increased substantially. Data from Lawrence Berkeley Laboratory, for example, show an increase in average wind turbine prices delivered to the U.S. market of roughly $400/kW between 2002 and 2006 (see Figure 4-7). These increases have been caused by factors such as the declining value of the U.S. dollar relative to the Euro, increased materials and energy input prices, a general move by manufacturers to improve their profitability while demand exceeds supply, an up-scaling of turbine size (and hub height) and sophistication, and shortages in certain turbine components.

Figure 4-7. Wind Turbine Transaction Prices in the U.S. Market



Source: Wiser and Bolinger 2007.

In this turbine-limited environment, some project developers have been unable to move their projects to fruition, and those developers with access to turbines dedicate them to the most-profitable wind projects in their pipeline. The evolving pricing environment has also made it difficult for developers to accurately predict delivered wind prices in competitive solicitations, sometimes requiring price revisions to already-signed wind power contracts as has already been seen with IOU solicitations in California. In locations where the project development cycle is lengthy – such as California, where many of the best sites are transmission-constrained – developers have been reluctant to commit to long-term pricing based on uncertain future turbine costs.

Economic and Permitting Barriers to Repowering and Expanding Existing Wind Facilities

To achieve the state's renewable and GHG goals, existing as well as new renewable and transmission resources must be used efficiently. Some contracts have been signed to repower aging wind turbines, but more progress is needed.

An analysis by KEMA, Inc., on the economics of repowering estimated that replacing 1,000 MW of California's oldest existing wind projects with 1,000 MW of new wind turbines could result in more than 1,000 GWh/year of incremental wind power production, equivalent to about 350 MW of new (i.e., greenfield) wind capacity.[234] The study did not assess expanding capacity at existing wind facilities, only switching out older turbines and replacing them with fewer, larger, more-efficient wind turbines. The Energy Commission would prefer to see capacity expanded at these prime sites, many of which were originally developed with significant investment of public resources.

The study also provided indicated economic trade-offs facing owners of existing wind turbines when deciding whether or not to repower. These trade-offs include whether the revenue likely to be earned by the repowered facility can at least match the profitability of the existing facility, and whether the existing project owner would be better off deploying new turbines in a greenfield rather than repowered project. The answers to these questions depend heavily on the profitability of the existing project, which can vary widely from project to project and is most strongly affected by the operation and maintenance costs of the existing turbines and their operating efficiency (capacity factor).

For example, poorly performing projects with high operating costs (i.e., marginally profitable existing projects) may find it economically advantageous to repower under reasonable assumptions about the amount of revenue (i.e., from power and REC sales) available to a repowered project. Conversely, adequately performing projects with relatively low operating costs may find that the amount of revenue available to a repowered project is insufficient to make up for the foregone profitability of the existing project. Furthermore, in some cases the most profitable outcome could be to continue to operate the existing project and, rather than repowering, deploy the new turbines in a greenfield project.

Although over time an increasing proportion of existing wind projects will be in the first category which is conducive to repowering, the report suggests that in the near-term, an economic incentive may be needed to accelerate the pace of repowering. Given the varying degrees of profitability among existing wind projects, a "one-size-fits-all" incentive approach may overpay some projects and underpay others, relative to the revenue needed to induce repowering. Furthermore, economic incentives alone may not be sufficient to stimulate repowering, which faces time-consuming environmental review procedures, limited turbine availability, and contracting barriers.

The KEMA report does not consider the cost of any transmission network upgrades that may be required (particularly to interconnect greenfield projects). But it does suggest that greenfield projects are likely to be more expensive than repowered projects, due to the latter's ability to

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[234] California Energy Commission, (forthcoming 2007), Consultant Report: Scoping-Level Study of the Economics of Wind-Project Repowering Decisions in California, prepared by the following subcontractor team to KEMA, Inc.: Ryan Wiser, consultant; Ric O'Connell, Black & Veatch; and Mark Bolinger, consultant.

use existing infrastructure. That said, continuing to operate an existing project while simultaneously deploying new turbines in a greenfield project may result in a lower power price (for the new capacity) than would be required for a repowered project. This is because when a project owner repowers, it foregoes the remaining profitability of the existing project, and presumably needs to make up for that lost profit (to induce repowering) by earning "above-normal" revenue from the repowered project. Instead, if a project owner continues to reap the benefits of the existing facility while at the same time devoting the new turbines to greenfield development, then it need only earn "normal" revenue from the greenfield project, which may result in a lower required power price for the greenfield project than for the repowered project, even though the former is more expensive to build than the latter.

At the March 13, 2007, workshop on incentives for wind repowering, there was little support for special economic incentives for repowering wind energy. SCE stated that the amount of incremental energy that could be gained from repowering wind would be about 1,100 GWh/year (roughly consistent with the KEMA estimate mentioned above), stating that this amount "is helpful, but not significant that it warrants special attention." (SCE comments for March 13, 2007, workshop, p. 2) In its calculations, SCE assumed that the total amount of installed capacity would remain unchanged, but did not explain what prevented expansion of the MW of wind installed at currently developed wind sites or what would be needed to overcome these barriers. As indicated above, the Energy Commission believes an expansion of capacity at these prime sites is desirable.

SCE explained that "as existing contracts near termination, the project owners will have significantly more incentive to repower." They also explained that transmission upgrades are needed to make repowering possible in the Tehachapi area.[235]

PG&E agreed that lack of transmission limits the rate of wind repowering, along with environmental study requirements, and "allocation of limited equipment to projects yielding greater return on investment."[236] "[T]he most profitable application …would be Greenfield development, rather than brownfield development." (PGE, Comments for March 13 workshop, p. 7). This implies that building new transmission to remote areas far from load to develop new resources is more profitable than repowering and expanding premium, known wind resources close to load.

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[235] Southern California Edison Company, March 19, 2007, Southern California Edison Company's Written Comments on the Workshop on Incentives for Wind Repowering and Best Practices for Coordinating RPS with Carbon Market Design; Docket Nos. 06-IEP-1c and No. 03-RPS-1078. http://www.energy.ca.gov/2007_energypolicy/documents/2007-03-13_workshop/comments/, accessed June 29, 2007.

[236] Pacific Gas and Electric Company, March 19, 2007, Post Workshop Comments of Pacific Gas and Electric Company on Incentives for Wind Repowering and Best Practices for RPS-Carbon Market Design, http://www.energy.ca.gov/2007_energypolicy/documents/2007-03-13_workshop/comments/PACIFIC_GAS_+_ELECTRIC_2007-03-20.PDF, accessed June 29, 2007.

CalWEA's comments explain some of the circumstances that lead to this result. CalWEA explained that most existing wind projects have little economic incentive to repower, noting that 20-year old technology is functioning very well, transaction costs of a new contract are high because repower contracts are not standardized, and the permitting process is costly and time consuming.[237] CalWEA suggested a standard contract amendment that would allow repowered projects to be eligible for the federal production tax credit, removing "one of the main barriers to repowering."[238] Regarding transmission, CalWEA seeks a decision to ensure that repowered wind projects maintain existing interconnection rights if their generating capacity is not increased. Also, CalWEA states that avian issues in Alameda County and Contra Costa County are slowing repowers in the Altamont Pass, although at least one project is talking with PG&E about repowering.

The IEPR Committee encourages the repowering and expansion of existing wind energy sites to increase the efficient use of existing infrastructure and reduce environmental impacts.

As discussed below, the Committee supports efforts to reduce transaction costs for contract negotiation for all renewable energy, including repowered and expanded existing wind energy projects.

RPS Program Structure: Need for Greater Transparency, Less Complexity, and Full Valuation of Renewable Energy

As discussed in previous IEPRs, the RPS program structure needs greater transparency, less complexity, and full valuation of the system benefits of renewable energy. The following examples illustrate the need for change: Least-cost best-fit, supplemental energy payments, and the use of natural gas prices to calculate the market-price referent.

Least-Cost, Best-Fit Evaluation

The *2005 IEPR* noted that transparency is necessary to ensure that all parties can fully understand the rationale for allocation of public funds. Transparency is also needed so developers and transmission planners can know where renewable energy development has the greatest strategic and economic value. As noted in the discussion of the IAP, incorporating 33 percent renewables will require strategic placement of new generation and new transmission. The CPUC has taken some steps to increase transparency of the procurement process, including

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[237] California Wind Energy Association, March 14, 2007, Comments of the California Wind Energy Association on Wind Repowering, http://www.energy.ca.gov/2007_energypolicy/documents/2007-03-13_workshop/comments/CALIFORNIA_WIND_ENERGY_ASSOCIATION_2007-03-14.PDF, accessed June 29, 2007.

[238] Ibid.

a workshop held on December 15, 2006. Despite these efforts, the procurement process remains in need of greater transparency and is subject to delays that are not clear to the public.

Each utility uses its own approach to least-cost best-fit evaluation, within the latitude granted by the CPUC. For example, SCE's least-cost-best-fit evaluation compares a base case using "generic generation" to a base case using generic generation and an RPS project bid into a competitive RFP. SCE uses Global Energy Decisions' ProSym model to compare the total production costs of SCE's base resource portfolio ("project out") with the total production costs when each proposal is individually added to the base portfolio ("project in"). ProSym performs an hourly, least-cost dispatch with SCE's known resource portfolio and generic generation to meet customer demand. Because SCE's complete resource portfolio in the future is uncertain, generic generation is added to the portfolio to ensure that RPS and resource adequacy requirements are satisfied and customer load can be met. Each proposal is added to the resource portfolio as a no-cost, must-take hourly generation profile that is provided by the seller. The difference in total production costs between the "project in" and "project out" cases is the energy benefit for each proposal.[239]

SCE's analysis as described does not consider the combined effect of the RPS bids, or which combination of new bids and existing assets would best balance ratepayer costs and risk. So, the resulting mix may not, in fact, be the least cost portfolio at an acceptable level of risk, even if individual additions are declared to be "least-cost best-fit."

Without relying on the principles of modern portfolio theory as described in the portfolio analysis report, a portfolio cannot be judged to be efficient or inefficient; in the case of an inefficient portfolio, it may be possible to simultaneously lower both cost and risk, but without considering both, it is not even possible to tell.[240]

Supplemental Energy Payments

In addition to the least-cost-best-fit process, the SEP process adds another layer of uncertainty about the price a developer will receive for its renewable energy. Although the funds used for SEPs are continuously appropriated, the Legislature can borrow or use the funds for other purposes, causing doubt whether the funds will be available when needed.

Of the 64 active RPS contracts executed by the IOUs since 2002 for new, repowered, or re-started renewable energy projects, only 9 contracts are priced above the MPR. One additional

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[239] SCE, July 30, 2007, SCE's Written Description of RPS Bid Evaluation and Selection Process and Criteria ("LCBF Written Report"), CPUC Rulemaking 06-05-027, p. 3.

[240] California Energy Commission, July 2007, Portfolio Analysis and its Potential Application to Utility Long-Term Planning, Draft Staff Paper, http://www.energy.ca.gov/2007publications/CEC-200-2007-012/CEC-200-2007-012-SD.PDF, p. 11.

contract that would have needed SEPs was canceled.[241] The nine active contracts priced above the MPR include:

- One with a developer that submitted a SEP application and withdrew it.
- Two for which the procuring utility announced that SEPs are needed, but for which the Energy Commission has not yet received an application.
- Three for which the Energy Commission has received incomplete applications.
- One for which PG&E has requested full rate recovery of the MPR and the SEP-eligible above market costs from the CPUC.
- Two priced above the MPR that are not eligible for SEPs because they are bilateral contracts.

The six contracts that may seek SEP payments represent roughly 9 percent of the new, repowered, or restarted renewable energy capacity currently under contract with the state's IOUs from contracts executed since 2002. The nine contracts with above-MPR pricing, meanwhile, represent roughly 15 to 20 percent of the new, repowered, or restarted renewable capacity currently under contract.[242]

Natural Gas Prices and Market-Price Referent

The risk to ratepayers of continued reliance on natural gas is not shared by the IOUs since fuel costs are automatically passed through to ratepayers. The price of natural gas is one of the most volatile commodity prices. Linking the market-price referent to natural gas forecasts, rather than an estimate of fixed-cost conventional generation as required by law, does not adequately reflect the cost, risk, and carbon reduction value of renewable energy to the state's portfolio of generation resources. The CPUC in its draft 2007 MPRs has now included a carbon adder in the MPR.[243] The CPUC expects to consider in more detail carbon adders for future MPRs.

The CPUC calculates MPR values for a baseload proxy plant for use in RPS solicitations. The method of determining MPR values generally involves evaluating (discounting) all project costs at the weighted average cost of capital (WACC). Finance-based approaches reflect cost and market risk.

Starting with the November 17, 2006, draft CPUC inputs to the MPR, Bates White calculated MPR values using finance-oriented valuation principles, based on the Capital Asset Pricing

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[241] Letter to Sean Gallagher at the CPUC from Lee Schavrien at SDG&E regarding Withdrawal of SDG&E Advice Letter 1795-E, February 5, 2007.

[242] California Energy Commission, Database of Investor Owned Utilities' Contracts for Renewable Generation, Contracts Signed Towards Meeting the California Renewables Portfolio Standard Target, updated August 5, 2007.

[243] CPUC Resolution E-4118 rev. September 24, 2007.

Model (CAPM).[244] This approach relies on specific risk-adjusted discount rates for each project cost stream, as opposed to discounting all costs at the WACC as is done by the CPUC.

In this analysis, the CAPM-based approach assumed a baseload proxy plant could obtain a long-term natural gas fuel supply at a risk-free rate. This assumption treats natural gas fuel price risk quite favorably. It is likely that this price is less than what would be charged under long-term fixed price contracts, which are not available in practice. Tables 4-9 through 4-11 compare CPUC's WACC-based MPR values with CAPM-based MPR values. Despite this assumption, the CAPM model suggests higher MPR values than those used by the CPUC.

Table 4-9. Weighted Average Cost of Capital-Based 2006 MPR Values
(Nominal - dollars/kWh)

Resource Type	10-Year	15-Year	20-Year
2007 Baseload MPR	0.08046	0.08176	0.08424
2008 Baseload MPR	0.07979	0.08195	0.08482
2009 Baseload MPR	0.07925	0.08223	0.08548
2010 Baseload MPR	0.07929	0.08295	0.08652
2011 Baseload MPR	0.07890	0.08307	0.08688
2012 Baseload MPR	0.07961	0.08420	0.08820
2013 Baseload MPR	0.08072	0.08566	0.08981
2014 Baseload MPR	0.08229	0.08746	0.09167
2015 Baseload MPR	0.08435	0.08964	0.09468

Source: CPUC November 17, 2006, "2006 MPR Model Draft Resolution E 4049_Distrib_11_17_06.xls."

[244] Bates White analysis is based upon CPUC's MPR spreadsheet dated on November 17, 2006 ("2006 MPR Model_Draft Resolution E 4049_Distrib_11_17_06.xls"). Thus, the reported WACC-based MPR values are not exactly the same as the values reported in Resolution E-4049 dated on December 14, 2006.

Table 4-10. Capital Asset Pricing Model-Based 2006 MPR Values
(Nominal - dollars/kWh)

Resource Type	10-Year	15-Year	20-Year
2007 Baseload MPR	0.08371	0.08970	0.09610
2008 Baseload MPR	0.08299	0.09005	0.09584
2009 Baseload MPR	0.08241	0.08955	0.09687
2010 Baseload MPR	0.08244	0.09045	0.09828
2011 Baseload MPR	0.08192	0.09143	0.09977
2012 Baseload MPR	0.08260	0.09262	0.10335
2013 Baseload MPR	0.08370	0.09664	0.10510
2014 Baseload MPR	0.08699	0.09852	0.10707
2015 Baseload MPR	0.08928	0.10076	0.11143

Source: Bates White, August 2007.

Table 4-11. Difference Between WACC- and CAPM-Based 2006 MPR Values
(Nominal - dollars/kWh)

Resource Type	10-Year	15-Year	20-Year
2007 Baseload MPR	0.00325	0.00794	0.01186
2008 Baseload MPR	0.00320	0.00811	0.01102
2009 Baseload MPR	0.00316	0.00732	0.01139
2010 Baseload MPR	0.00315	0.00750	0.01176
2011 Baseload MPR	0.00303	0.00835	0.01289
2012 Baseload MPR	0.00299	0.00841	0.01515
2013 Baseload MPR	0.00298	0.01099	0.01529
2014 Baseload MPR	0.00470	0.01106	0.01540
2015 Baseload MPR	0.00493	0.01112	0.01675

Source: Bates White, August 2007.

33 Percent by 2020 Is Feasible with Changes in Program Structure

Thirty-three percent by 2020 is feasible technically and economically, but concerted and coordinated support is needed from government, industry, and the public to make it happen. Changes are needed in the following areas:

- Planning and permitting processes need to be strengthened and streamlined through programmatic environmental impact report/environmental impact statements for renewable energy generation in coordination with state and federal transmission corridor planning.
- The transmission grid and distribution system need to be expanded and upgraded to access and prepare for the resource mix needed to bring the electricity sector's greenhouse gas emissions to 1990 levels.
- The MPR/SEP payment mechanism should be redesigned to allow developers to obtain lower-cost financing and encourage expansion of equipment production for renewable energy.

The first two items are addressed in the *2007 Strategic Transmission Investment Plan*. The third can be addressed through the expanded use of feed-in tariffs, as discussed below.

Moving Forward with Feed-In Tariffs

Assembly Bill 1969 requires utilities to file tariff/standard contracts for renewable generation operated by a public water or wastewater facility. In July 2007, the CPUC adopted Decision 07-07-027 implementing this requirement. The decision requires that the standard contract use the appropriate MPR from the table of MPRs that are in effect on the date the contract is signed. However, in each solicitation year's table, the MPRs vary by start year. The decision requires that the actual MPR tariff paid be equal to the MPR for the start year during which the facility becomes commercially operational. Since MPRs used for a particular year's solicitation may trend up or down over the potential start years, either the utility or the generator, but not both, is at risk of the commercially operational date is delayed. Because for most solicitation years the MPR trends upward for later start years, the generator could have a small incentive to delay commercial operation.

Utilities are required to offer this tariff until they have purchased generation equal to a proportionate share of 250 megawatts, statewide. The CPUC expanded this program to require the same standard tariff for about 230 MW of additional "renewable resources from customers other than water and wastewater."[245]

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[245] California Public Utilities Commission, July 26, 2007, "Decision 07-07-027: Opinion Adopting Tariffs and Standard Contracts for Water, Wastewater and Other Customers to Sell Electricity Generated from RPS-Eligible Renewable Resources to Electrical Corporations," Rulemaking 06-05-027,

In May 2007, SCE started offering a set of standard contracts priced at the 2006 MPR for biogas and biomass generators as large as 20 MW. The 2006 MPR is equivalent to approximately 7.960 to 9.393 cents per kilowatt-hour, depending on contract length (10, 15, or 20 years) and start date. Actual prices paid will also be adjusted for time of delivery, with higher prices paid during peak demand periods.[246] The contracts are available until December 31, 2007 up to a maximum of 250 MW.

This offer was prompted by the Governor's executive order S-06-06, issued in April 2006, which encouraged IOUs to increase sustainable use of biomass and other renewable resources.[247] There are three standard contracts, divided by project size and location as follows:

- Less than 1 MW of generating capacity in SCE's service territory.
- 1 MW to 5 MW in the California ISO Control Area.
- Greater than 5 MW to 20 MW under the operational control of the California ISO.[248]

SCE set the cut-off at 20 MW because it found that biogas and biomass renewable energy projects this size or smaller have been unable to participate in its competitive RPS solicitations.

The Energy Commission applauds SCE's leadership in the use of standard RPS contracts set at the MPR, making participation in the RPS feasible for smaller generators that cannot easily participate in the standard RPS process. Following the example set by CPUC implementation of AB 1969, the contracts offered by SCE should be expanded to other RPS-eligible renewables. Based on SCE's rationale, the size cut-off could be for systems as large as 20 MW, but SCE and the other investor-owned utilities should impose no cap on the total amount to be contracted and renew the offer each year.

In general, feed-in tariffs can increase transparency, reduce complexity, and provide full valuation of renewable energy, addressing key problems of the current RPS structure. Feed-in tariffs can set different cost-based prices for different technologies, providing flexibility to

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http://www.cpuc.ca.gov/WORD_PDF/FINAL_DECISION/70660.PDF, accessed August 6, 2007. Attachment A, Item 11, and Conclusion of Law 25.

[246] California Public Utilities Commission, June 22, 2007, AB 1969 Workshop Documents (Summary Matrix on Standard Terms and Conditions, Pacificorp Comments, and 250 MW allocation, Rulemaking 06-05-027, http://www.cpuc.ca.gov/EFILE/PD/69606.htm, accessed June 28, 2007.

[247] Executive Order S-06-06 sets a target to increase the use of biomass for electricity to 20 percent of the state's renewable generation goals for 2010 and 2020, and directs the CPUC to encourage investor-owned utilities to pursue sustainable use of biomass and other renewable resources.

[248] Southern California Edison, SCE Biomass Standard Contracts – Protocol, p. 4-5, in California Public Utilities Commission, June 22, 2007, AB 1969 Workshop Documents (Summary Matrix on Standard Terms and Conditions, Pacificorp Comments, and 250 MW allocation, Rulemaking 06-05-027, http://www.cpuc.ca.gov/EFILE/PD/69606.htm, accessed June 28, 2007.

account for technology-specific market conditions. Rickerson and Grace[249] report that "well-designed feed-in tariffs have been highly successful in driving a large percentage of the new renewable energy capacity installed around the world since the 1990s."

The German feed-in tariff system is one of the most successful. Germany had 6.3 percent renewable electricity in 2000. In 2007, Germany met its goal for 2010 renewable electricity (12.5 percent) and states that new goals of 27 percent by 2020 and 45 percent by 2030 should be adopted.[250]

German feed-in tariffs are not linked to the cost of generation of wholesale electricity; rather, they are based on the cost of generation for each technology. The tariffs decline over time so facilities that begin operation in a future year receive a lower payment than facilities beginning operation in the current year.

Cost-based, technology-specific feed-in tariffs in Germany and other European countries have provided a mechanism to contain costs, while also lowering uncertainty to the developer, and stimulating expanded supply of renewable energy.[251]

Feed-in tariffs allow individuals, communities, and for-profit developers to generate renewable energy at a publicly known price. Feed-in tariffs are long-term and widely available, allowing developers to obtain financing at a lower cost.[252] In this supportive climate, equipment manufacturers can invest in expanded production.

At the Energy Commission's public workshop held on May 21, 2007 on this topic, participants supported further investigation of how best to tailor feed-in tariffs to California's renewable energy development goals, although the SCE and PG&E support continued use of the RFO process for large-scale renewable projects. Industry participants in the workshop supported cost-based feed-in tariffs, while SCE and PG&E recommended using an indicator of the wholesale market price for electricity considering the time-value of generation. SCE also

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[249] Wilson Rickerson and Robert C. Grace, February 2007, The Debate over Fixed Price Incentives for Renewable Electricity in Europe and the United States, http://www.boell.org/docs/Rickerson_Grace_FINAL.pdf, p. 7.

[250] German Federal Ministry for the Environment, Nature Conservation and Nuclear Safety (BMU), July 5, 2007, Draft report on the Renewable Energy Sources Act (EEG). Only in German. http://www.bmu.de/files/pdfs/allgemein/application/pdf/erfahrungsbericht_eeg.pdf, p. 4.

[251] Commission of the European Communities, July 12, 2005, Communication from the Commission: The support of electricity from renewable energy sources, Com(2005) 627 final, http://ec.europa.eu/energy/res/biomass_action_plan/doc/2005_12_07_comm_biomass_electricity_en.pdf

[252] Presentation by Hans Cleijne at the May 21, 2007 *Integrated Energy Policy Report* Workshop, http://www.energy.ca.gov/2007_energypolicy/documents/2007-05-21_workshop/presentations/Hans%20Cleijne-European%20feed-in%20tariffs%20without%20RPS.pdf, slide 11.

stressed the need for safeguards to ensure long-term performance and maintenance of equipment. AES, a company with both fossil and solar thermal generation facilities, also supported a feed-in tariff that reflects the time value of electricity, noting the importance of peaking power to California. AES suggested a demonstration/transitional feed-in tariff for the 2008-2010 timeframe before moving to large-scale use of feed-in tariffs.

In considering how to develop large-scale feed-in tariffs, state agencies should design feed-in tariffs to complement the state's plans to coordinate generation and transmission planning, through programmatic EIR/EIS, transmission corridor designation, and other measures discussed in the *2007 Strategic Transmission Investment Plan*.

Proximity to transmission can also affect the cost of renewable energy. The costs may differ among utilities, depending on the extent of new transmission needed to reach renewable resources. To address uneven impacts on ratepayers of the feed-in tariffs in Germany, the costs of the feed-in tariffs are distributed evenly to all ratepayers by the regional transmission authorities.[253]

Several options should be evaluated as part of a joint Energy Commission-CPUC proceeding on feed-in tariffs to determine how best to allocate these costs. One option to consider would be to allocate the costs through CPUC distribution rates.

Recommendations

To address the barriers to renewable development in the context of the state's GHG emission targets and the need to manage cost and risk to ratepayers for electricity, the Energy Commission makes the following recommendations:

- Building new transmission lines to renewable resource areas in California and the West is essential to achieving California's GHG and RPS goals. The CPUC has approved PG&E's transmission planning efforts in the Northwest, extending to British Columbia, Canada. In August 2007, the CPUC approved Southern California Edison's (SCE) request for transmission feasibility planning for renewable resources in Western Nevada, Southeastern California (Inyo, San Bernardino, and Imperial Counties), and Western Arizona. The Committee applauds the CPUC's support of these transmission planning efforts. To tie together the changing resource mix needed to meet California's GHG and RPS goals, utilities must incorporate new technologies into the transmission and distribution systems to create an electricity transmission/distribution system that accommodates a growing volume of intermittent renewable, distributed generation, and demand response technologies. This will require coordinated investment in generation, transmission, and support services. For additional recommendations related to

[253] Wilson Rickerson and Robert C. Grace, February 2007, The Debate over Fixed Price Incentives for Renewable Electricity in Europe and the United States, http://www.boell.org/docs/Rickerson_Grace_FINAL.pdf, p. 13.

transmission, refer to the *2007 Strategic Transmission Investment Plan, Draft Joint Committees Report*.[254] For recommendations related to the distribution system, refer to Chapter 6 of this document.

- Implement a feed-in tariff set, for the immediate future, at the MPR for all RPS-eligible renewables up to 20 MW in size, and begin a joint process with the CPUC to consider instituting feed-in tariffs for larger projects to accelerate renewable development in the next decade. This process should recognize the value of a diverse mix of renewables considering differential costs of different renewable technologies and incorporate these values and the applicable features of the most successful European tariffs. Also, the joint Energy Commission-CPUC process should consider how to evenly allocate costs for renewable energy feed-in tariffs.
- Until a feed-in tariff system is in place, continue to update the MPR protocols to more fully reflect risk and market costs of long-term fixed-price power. The MPR for 2007 will include a GHG adder, but still does not capture fully the benefits of renewables. The Energy Commission and CPUC should include the risk of price volatility and further develop GHG adders in the valuation of renewable energy.
- Coordinate the RPS with market-based compliance mechanisms for GHG emissions reduction. To be eligible for trade in any market-based compliance mechanism used to achieve the AB 32 emission GHG limit, AB 32 requires that GHG emission reductions be in addition to reductions required by existing policies. To avoid excess supply of tradable GHG emission reduction credits, this should be clarified to ensure that GHG reductions due to RPS and 33 percent by 2020 are quantified and taken out of any allowance system for cap-and-trade purposes.
- Ensure that California's RPS goals are not negatively affected by any federal targets that may be developed for renewable energy. Congress has been considering legislation that, if not carefully implemented could negatively affect California's RPS program. Though the Committee supports a federal renewable portfolio standard, it does so only if such a standard does not pre-empt the authority of states to implement higher standards within their own jurisdictions in a manner that does not allow inappropriate spillover in the federal obligation.[255]

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[254] California Energy Commission, CEC-700-2007-018 CTD, August 2007.

[255] John L. Geesman, Commissioner and Presiding Member, Renewables Committee, and Jackalyne Pfannenstiel, Chairman and Associate Member, Renewables Committee, June 18, 2007, Letter to the Honorable John D. Dingell, Chairman, Committee on Energy and Commerce and the Honorable Rick Boucher, Chairman, Subcommittee on Energy and Air Quality, U.S. House of Representatives. California Energy Commission, http://www.energy.ca.gov/papers/2007-06-18_CONGRESSMAN_DINGELL_LETTER.PDF, accessed July 20, 2007.

CHAPTER 5: California's Electric Distribution System

California's electric distribution system is essential to deliver power to consumers. Distribution systems transfer high-voltage power from the transmission grid through substations, where the voltage is reduced. From the substation, distribution lines transfer power to customers.

Electric distribution systems throughout California still use designs, technologies and strategies that were developed to meet the needs of mid-20th century customers. These large and complex systems have historically provided reliable electric power to tens of millions of customers throughout the state, although aging infrastructure coupled with modern demands is beginning to erode this capability. With California's strong commitment to distributed renewable energy, combined heat and power, demand response, and reduced production of greenhouse gases, the design of these systems will have to change to accommodate the integration and full use of these new resources.

Ideally, the much more automated 21st century distribution grid should allow grid operators to detect and respond to problems quickly by being able to see and manage the grid in real time. It should provide for rapid two-way information exchange between utilities and customers. It should allow the use of distributed resources to support grid operation. And it should allow for the seamless integration of the full spectrum of 21st century technologies.

As California utilities invest billions of dollars to expand and replace aging distribution infrastructure in the next five to ten years, it is critical to develop a framework to guide these investments. Without a transparent planning process, the state will not realize the full benefits of these resources.

This chapter discusses the challenges facing California's distribution system along with the barriers to integrating distributed resources into that system.

Existing Distribution Infrastructure in California

Each utility service territory is physically different and has its own unique challenges. Some utilities have large concentrations of urban customers and others serve rural areas. Some systems are relatively new, while others have served customers for more than a century.

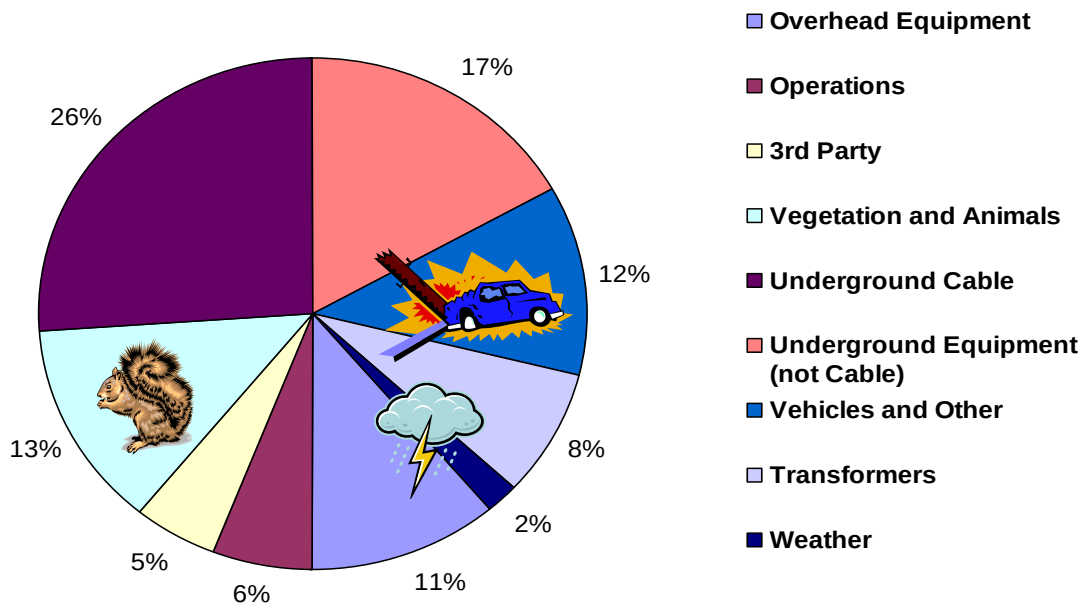
Of the state's three major investor-owned utilities (IOUs), Pacific Gas & Electric (PG&E) has the largest service area and serves approximately 15 million electric and natural gas customers in dramatically varying climate and weather conditions.[256] Serving 12 million people, Southern California Edison (SCE) provides electric service to central, coastal, and southern California,

[256] http://www.pgecorp.com/corp_responsiblity/reports/2006/company_overview.html.

including larger urban population centers.[257] San Diego Gas and Electric (SDG&E) is the smallest of the three IOUs, with 4,100 square miles of service territory, serving 1.4 million electricity customers in San Diego and southern Orange counties to the Mexican border.[258] One of the biggest challenges each of these utilities face when planning into the future is unprecedented load growth in the hot inland areas of their service territories.

Today, about 90 percent of all customer interruptions and outages — both within California and throughout the U.S. — are caused by distribution problems or "events." In four days in early September of 2007, an unprecedented 645,000 SCE customers suffered distribution-caused outages. Some of these events can occur when poles or lines are impacted by people, equipment, high temperatures, balloons, or vegetation. Service can also be interrupted by weather related events such as wind and lightning. Another significant cause of outages is equipment malfunction and failure. Figure 5-1 shows the breakdown of distribution failures by cause.

Figure 5-1. Distribution Failures



When interruptions do occur, it is often the customer who first alerts the utility. Utilities and researchers are working to improve problem detection and response and to develop sensors, smart meters, communications, and controls to enable them to detect problems and restore power quickly anywhere on the system.

[257] http://www.sce.com/AboutSCE/CompanyOverview/territorymap.htm.

[258] http://www.sdge.com/aboutus.

Addressing California's Distribution Infrastructure Challenges

On May 10, 2007, the California Energy Commission's Integrated Energy Policy Report (IEPR) Committee and the Electricity Committee held a joint workshop to provide stakeholders and parties the opportunity to bring forward and discuss issues and challenges facing California's electricity distribution system.[259] During the workshop, presentations and discussions covered distribution challenges, San Diego Smart Grid Study research technologies, and research program activities.

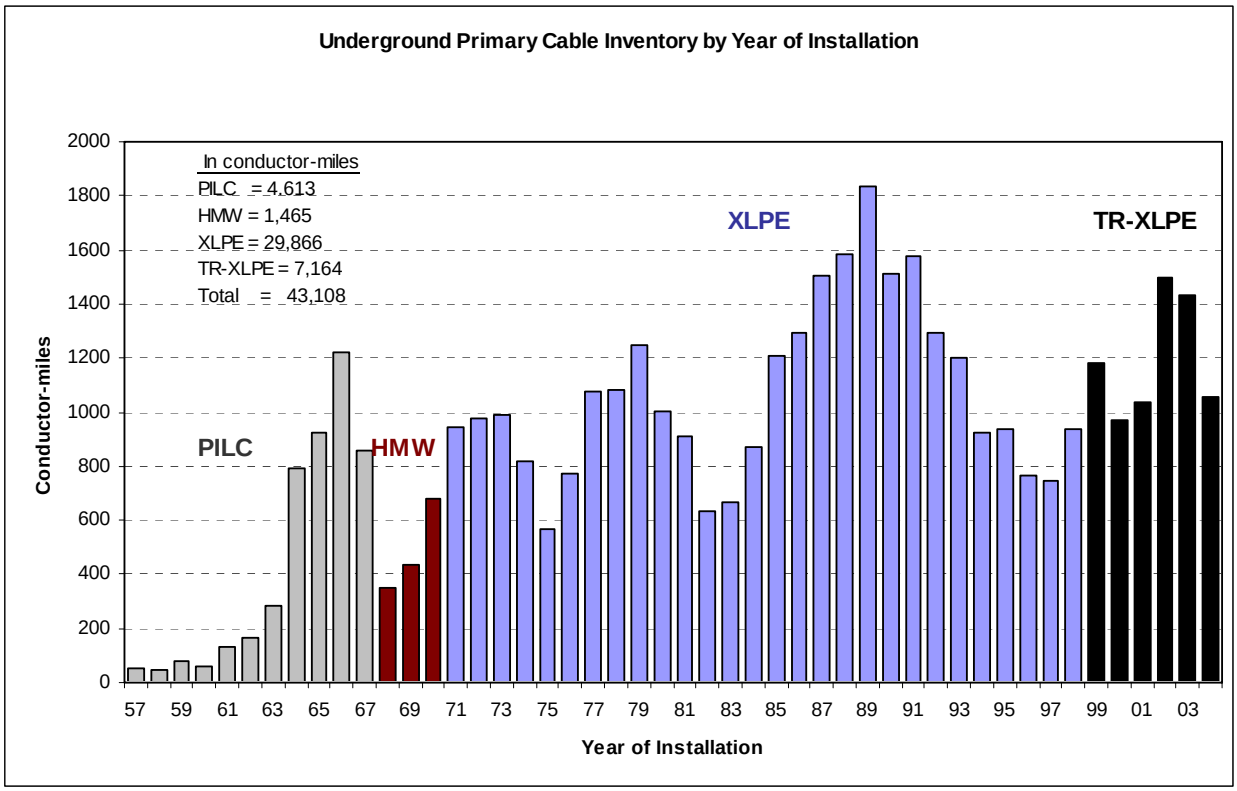
Presentations by PG&E, SCE, and SDG&E at the workshop described in detail the operational challenges California's distribution utilities face on a daily basis. One issue highlighted at the workshop was the age of the existing underground cable system. Customer preference for underground cables is so high that the California Public Utilities Commission (CPUC) authorizes utilities to replace portions of overhead cable in areas of their service territory with underground cable every year.

As shown in Figure 5-2, throughout the 1970s and 1980s SCE installed increasing amounts of underground cable, much of which is approaching the end of its design life. It will therefore need to be replaced in the near future to avoid failures. Depending on the amount and age of underground cable in their service territories, utilities report replacing underground cable at rates of 40 to 70 miles per year. Based on 43,108 miles of such cable, this is unlikely to prove an adequate replacement cycle. Even if the rate of replacement is increased, it is clear from the figure that in the SCE service territory, cable failures due to age are likely to measurably increase in the next 5 to 10 years, impacting reliability.

At the May 10 workshop, PG&E acknowledged that with 26,000 miles of underground cable and current replacement efforts at 70 miles per year, their efforts are equivalent to a 371-year replacement cycle.

[259] California Energy Commission, Joint Committee Workshop on Addressing California Distribution Infrastructure Challenges, May 10, 2007.

Figure 5-2. SCE Underground Primary Cable by Year of Installation[260]



One way to deal with this problem is to determine which lines are at greatest risk of failing and replace them first, since some older underground cables are still capable of performing reliably for some years into the future. However, an inexpensive and reliable diagnostic technique that can accurately determine the condition and remaining life of underground cables does not currently exist. With this type of diagnostic, utilities could prioritize the replacement of cable, rather than simply replacing them based on age. At the workshop, PG&E indicated that the average cost to replace one foot of underground cable for PG&E is $120. By determining what cables actually need to be replaced and when, substantial savings could be achieved without eroding reliability. These issues are not unique to California, as other utilities throughout the U.S. are struggling with the same reliability and technical challenges.

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260 260 PILC: Paper Insulated Lead Cable, old style cable with copper conductors wrapped in oil soaked paper covered in lead sheath. HMW: High Molecular Weight polyethylene cable, an early form of poly cable. XLPE - Cross Linked Polyethylene cable, the more modern form of poly insulation. TR-XLPE: Tree Retardant XLPE, where trace chemicals are added to XLPE to retard the growth of "trees," cracks in insulation due to moisture and voltage stress.

In spite of interest in automation and smart grid technologies, California utilities have very little regulatory incentive to design and build "smart" distribution infrastructure that can do more than simply assure that power is reliably delivered from distant central station power plants. The goal should be to encourage investment in technology that supports flexibility. Utility engineers are clearly interested in designing new infrastructure that will meet the needs of their customers in the future, but the current regulatory approval process is not designed to allow the transparent side-by side evaluation of new technologies and traditional investments. Without regulatory approval, utilities will be reluctant to introduce new technologies into their systems.

Another issue that was highlighted in the workshop by SDG&E is the aging utility workforce and the inability of utilities to attract both new operational and engineering talent. As a career field, power engineering does not attract many students and the number of universities and colleges at which it is taught is declining. Attracting and keeping skilled field and construction staff are also issues. Over the next five years, this issue is expected to worsen and will impact the ability of utilities to rebuild their distribution systems and provide reliable service in the future. New technologies including automation, sensors, and controls will assure that staff resources are used as efficiently as possible.

At the workshop, the customer perspective was provided by the San Francisco Community Power Cooperative representative who indicated that the role of customers passively receiving and paying for electricity is changing. New laws and programs in California are providing incentives to customers to install renewable solar generation at their homes and businesses to meet some of their energy needs. A range of new technologies, tariffs (such as time-of-use and Critical Peak Pricing), and programs are being developed that will also encourage customers to control the amount of power they use during different times of the day. It can be expected in the coming years that, as new advanced metering infrastructure is installed throughout the state, this infrastructure will enable other technology applications and support the growth of a California customer-centric resource pool throughout the state. Customers will increasingly be in a position to provide valuable energy resources and services to utilities if the right programs and incentives are developed.

PG&E indicated that utilities are also working to understand and develop strategies to manage and utilize the growing penetration of customer resources on the distribution system. The utilities are addressing issues like the technical challenges and how the design of the distribution system should change to accommodate and optimize the use of emerging resources. Beyond the technical changes —for example, integrating automation and communications technologies into the existing power delivery system to coordinate new resources — it is critical to begin today to explore what must be done to encourage utilities and customers to work together to develop a more integrated and lower-carbon energy network that better meets everyone's needs in the future.

Distribution System Investments

Utilities spend approximately three-fourths of their total capital budgets on distribution assets, with about two-thirds spent on upgrades and new infrastructure in most years. These investments will be with us for 20-30 or more years. As utilities throughout the state plan to build new distribution assets and replace old assets, the magnitude of these investments suggests that we must understand what they are investing in and whether these investments will result in a distribution system that will serve customers in the future without becoming obsolete. Planning for investment in these assets should include requiring utilities, before undertaking investments in non-advanced grid technologies, to demonstrate that alternative investments in advanced grid technologies that will support grid flexibility have been considered, including from a standpoint of cost-effectiveness.

California's energy policies are shifting how the state will meet energy demand in the future. Legislation and new laws, as well as the state's Energy Action Plan, have made strong statements that new energy demand in California must increasingly be met by energy efficiency and demand response, the use of alternative fuels, and low carbon distributed generation resources such as solar, combined heat and power (CHP), and wind. With the advent of new advanced metering infrastructure, along with the increasing focus on distributed generation technologies and the high priority for demand response, the state needs a distribution grid that facilitates two-way communication while easily detecting problems and automatically adjusting for them. "Business as usual," where customers passively receive energy from utilities, must change. During the next 10 years, a whole range of new energy tariffs and programs will have to be developed to encourage utilities, customers and businesses to use new information and energy technologies through the distribution system so they can benefit from greater choice and lower costs.

As the goals of state law are met over the next decade, the distribution system will be called on to integrate and efficiently use all the distributed energy resources that will be installed in California customers' homes and businesses. As California moves towards that utility investment should be channeled into appropriate technologies and equipment that will lead to the development of a modern and smart network. Utilities will be spending billions of dollars over the next 10 years rebuilding and expanding their distribution systems. It is essential that this massive capital flow be directed to where it can be most effective.

Today, distribution systems continue to be designed and built to accommodate one-way flow of power. Figure 5-3 illustrates the typical "one direction" distribution system that is currently in place.

California continues, through legislation and regulation, to support its commitment to increased penetrations of renewable and highly efficient distributed generation, a trend likely to intensify as priority is placed on aggressively reducing greenhouse gas emissions. To assure maximum reliability and leverage benefits from these new distributed resources, the design of the electric distribution system must also evolve. Through increased use of distribution automation and

communications and controls, utilities will no longer have to wait for customers to let them know there is a problem. New technologies, including Advanced Distribution Automation (ADA), will give distribution grid operators the ability to detect and respond to problems quickly and safely. Being able to see and manage the grid in real time will allow utilities to better assure grid reliability, security, efficiency, affordability and power quality. These new systems will feature the free exchange of information between the utility and the customer and the customer and the utility. Figure 5-4 illustrates how a modern distribution system would look and illustrates possible new relationships between customer and the utility.

Figure 5-3. Typical Distribution System

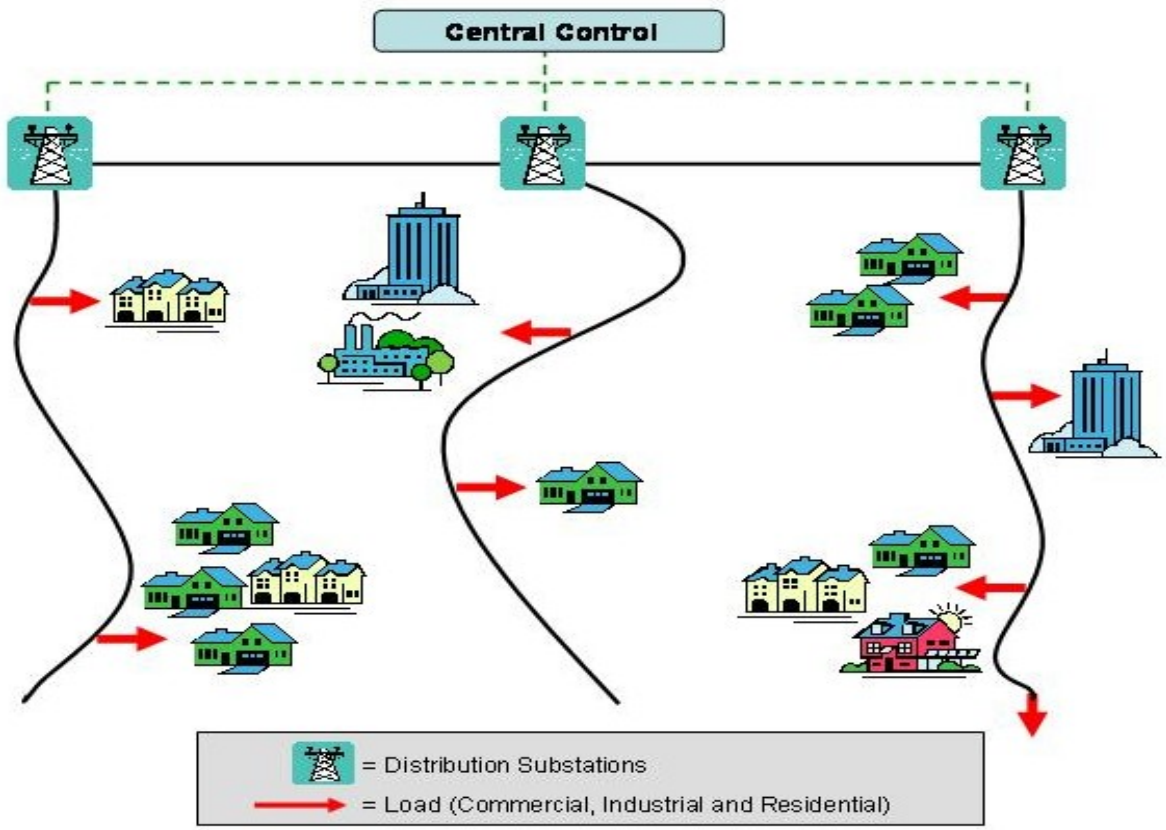
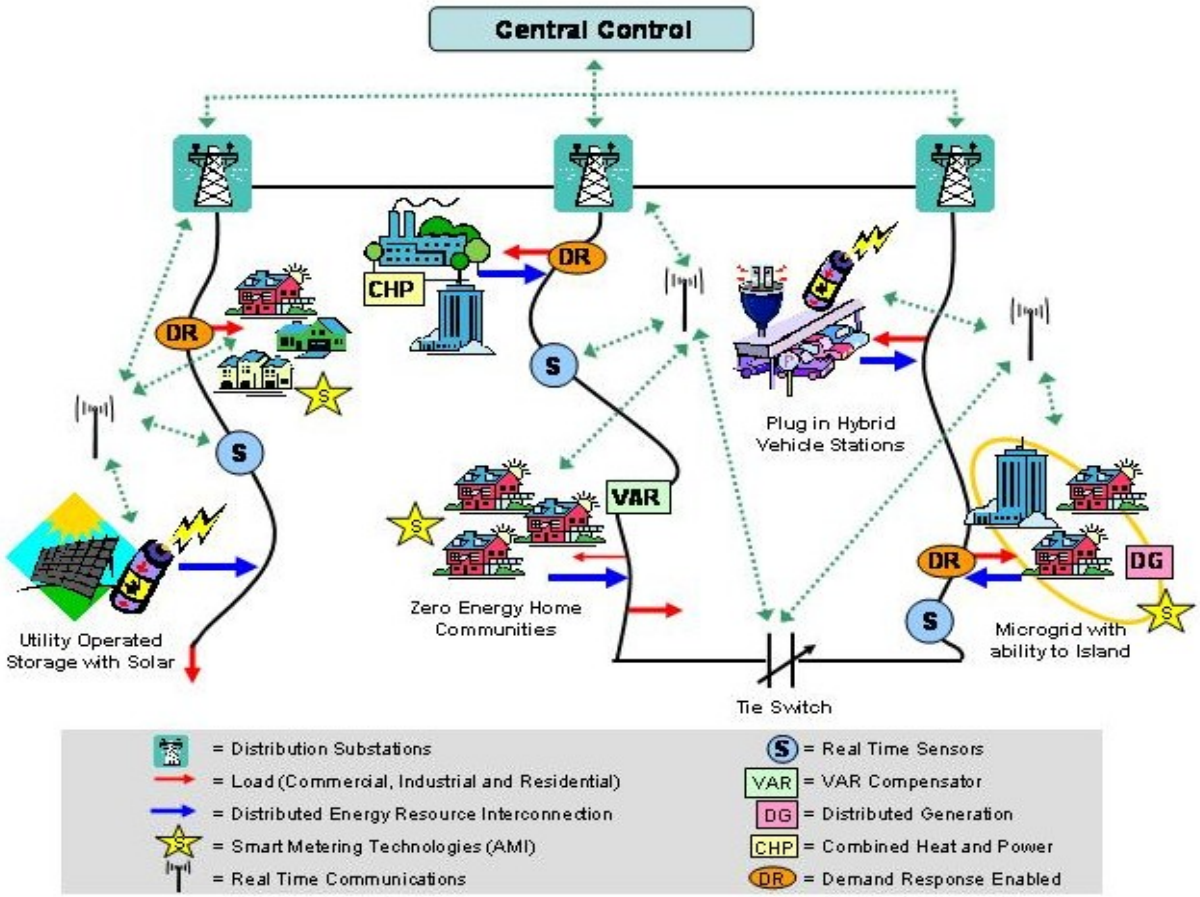


Figure 5-4. 21st Century Distribution System



Distribution Research Program

The distribution system will play an increasingly important role in dealing with energy issues and challenges that California will face in the near future. The following issues and their solutions will require research to develop distribution level technologies, planning tools, models and business cases.

- Capacity Constraints: Transmission and environmental constraints, along with continuing population growth, suggest that distributed generation will play an increasing role in meeting future capacity needs. Because these resources will be dispatched and used through the distribution system, this will require the distribution system to shoulder an increasing burden for meeting California's capacity needs.
- Integrated distributed energy resources: Integrating and leveraging these resources, including photovoltaics, CHP, and energy storage, is a critical challenge that California must overcome to meet its environmental and energy reliability needs.

- End-Use Technologies: The development of increasingly diverse and sophisticated end-use technologies — including smart appliances, Plug-in Hybrid Electric Vehicles and demand response — will require a vibrant and modern distribution system .
- Energy Efficiency: The distribution system accounts for a higher share of delivery losses than transmission, and may offer a significant opportunity for improvements in efficiency.
- Transparent Planning: Customers are likely to play a greater role in meeting their own energy needs, and current approaches to planning may limit the potential benefits.

The Energy Commission's Public Interest Energy Research Program (PIER) has developed a Distribution Research Program intended to develop technologies that provide efficient, reliable and affordable energy to customers through a low-carbon energy network, and to bring those technologies to market.

The Distribution Research Program completed a comprehensive assessment that identified critical research gaps. A program roadmap was then developed to identify milestones needed to reach target program goals. The program includes a Program Advisory Committee comprised of representatives from California's three major IOUs, a large out-of-state utility, DOE, and the customer and manufacturing sectors which provides advice and expertise to program managers. After careful analysis and study, the program developed a project portfolio emphasizing technologies which support reductions in greenhouse gases, improve distribution reliability and capability, and enable renewable energy resources, demand response and energy storage.

Currently, the program is developing and funding several projects to support integrating distributed energy resources, enable the optimization of these resources to improve and support reliability, reduce greenhouse gases and reduce costs to customers. Areas addressed by these projects are Advanced Distribution Automation, microgrids, distribution models and planning tools, and sensors.

Advanced Distribution Automation Research

Advanced Distribution Automation (ADA) has been identified as a focus area for the program due to the critical role it will play in establishing a modern distribution system. To support the development and deployment of ADA, the program has been conducting research to determine how ADA provides value to utilities, customers, and society. Two studies were commissioned to accomplish this. The first, "Value of Distribution Automation Applications,"[261] looks at the ways ADA has been applied by state, national and international utilities. This work provides a foundation for understanding how ADA adds value for improving operational efficiency, peak load management, and system restoration after failures. The second study, "The Value of

[261] California Energy Commission, *Value of Distribution Automation Applications*, PIER Final Project Report, Prepared by: Energy and Environmental Economics, Inc. and EPRI Solutions, Inc., April 2007, CEC 500-2007-028.

Distribution Automation,"[262] presents an analytical framework that determines the potential value that ADA could provide if fully deployed in the service territories of California's investor owned utilities. This study is nearing completion and will be available in the fall of 2007.

In parallel with these two studies, the DRP has been actively engaged with leading distribution experts from industry to fully vet and appropriately focus research in this area. As part of the first study, a large group of experts representing utilities, equipment suppliers and researchers held a workshop to discuss the ADA topic. The workshop reinforced the complexity of the distribution automation value proposition, and there was general agreement that a deeper understanding of the value of automation is needed to more fully use these types of technologies.

It is clear that ADA adds significant value for California stakeholders by increasing service quality (reliability), improving resource efficiency (including reducing energy losses), and reducing the cost of distribution service. It is also important to specifically note ADA's contribution to increasing the penetration of distributed generation, including PV. By understanding how various ADA functions benefit stakeholders, Distribution Research Program managers can make strategic decisions to support R&D that answers the following key questions:

- How can we develop ubiquitous, low-cost sensors that can monitor the distribution network at a resolution sufficient for ADA?
- How can we ensure that a wide variety of new and legacy equipment can communicate reliably and operate in a coordinated fashion?
- How can we manage the large quantity of data associated with a full-scale deployment of ADA, and convert the data to useful information and databases that are actionable?
- How do we balance autonomous local control with central or regional coordination?
- How do we reduce the cost of ADA technologies to promote full-scale deployment?

The effective deployment of ADA technologies will be key to developing the distribution system of the future. By integrating and adding ADA technologies, utilities will be able to increase the reliability, efficiency and flexibility of the distribution system to respond to the evolving needs of customers. ADA will also make vital contributions to meeting California's energy challenges in the coming years, including integrating high penetrations of distributed generation, reducing greenhouse gases, and creating new approaches to infrastructure planning and development.

Microgrid Research

A microgrid is an integrated energy system consisting of interconnected loads and distributed energy resources which, as an integrated system, can operate in parallel with the grid or in an

[262] California Energy Commission, *The Value of Distribution Automation*, PIER Final Project Report, Prepared by: Navigant Consulting, Inc., September 2007.

intentional island mode. The Energy Commission's PIER Program and DOE have been researching and developing this technology since 2000 to allow the safe operation of microgrids. Some of the value propositions for microgrid applications include:

- Reducing the cost of energy and managing price volatility
- Improving reliability and power quality
- Increasing the resiliency and security of the power deliver system by promoting (allowing) the dispersal of power resources
- Helping to manage the intermittency of renewables and promoting the deployment and integration of energy-efficient, environmentally friendly technologies
- Assisting in optimizing the power delivery system, including the provision of services
- Providing different levels of service quality and value to customers segments at different price points.

If it can be demonstrated that microgrids can operate safely, a whole range of new opportunities, and value propositions like those described above will become available for both customers and utilities. In particular, microgrids offer the opportunity for customers to develop "micro" systems that use clean generation technologies and support California's low carbon objectives. Working jointly with the Distributed Energy Resources Integration Program, the Distribution Research Program is developing major research demonstrations of microgrid technology that will feature innovative integrations of suites of clean technologies and energy storage. The research will focus on documenting the value of these integrated resources to provide local load reductions of at least 15 percent on utility distribution feeders and to efficiently coordinate generation and customers' resources.

Distribution Models and Planning Tools

California's distribution operators have limited ability to assess the benefits of distributed energy resources on the distribution system. Traditional power flow models and analysis have not been able to process system data on large distribution circuits. Some new distribution operational models are becoming available and can help operators better manage segments of their system, but distribution data challenges remain difficult.

This lack of system visibility also impacts the overall planning process and makes it difficult to assess and rank what additions or investments provide the maximum value. The Distribution Research Program currently has a contract with New Power Technology (Contract #) to develop a methodology using Optimal Technology's AEMPFAST to assess and rank system changes to improve operational efficiency. This tool will also be used to rank, from an operational perspective, the value of distributed energy resource additions. This research project has successfully processed huge amounts of distribution data into a working model for one of the largest systems within the SCE service territory. The model will recommend system reconfigurations and optimization strategies that will be applied and monitored to validate projected benefits. These types of models, which are routinely used to model transmission systems, have not been widely used to assess distribution systems. This research will validate

the use of distribution planning models to determine high value locations for distributed resources and support a more transparent distribution planning process. DOE is funding a complementary financial study that will compare the value of distributed resource options identified in the New Power Technology analysis to traditional utility capital investments (e.g. substation upgrades and other equipment replacements).

Sensors

Sensors are critical to determining the condition of equipment. Because communicating sensors remain relatively expensive and the distribution system is so expansive, developing small and extremely cheap communicating sensors using new technology would provide a whole range of new opportunities to better monitor the distribution system for faults and equipment failure. The Distribution Research Program will be issuing a Research Opportunity Notice in 2008 to explore innovative technologies to develop new applications for small inexpensive communicating sensors.

Sensors are also the focus of a unique research effort that is being managed through the Center for Information Technology Research in the Interest of Society at the University of California, Berkeley. The researchers will be developing a diagnostic tool or sensor that can reliably determine the remaining life of a distribution cable buried in the ground. The team and California utilities will use innovative and new scientific instruments and scopes to understand the reason for cable failure and explore new technologies that can sense and relay the condition of the cable to utility engineers without interrupting service on the cable. A conference to bring engineers and scientists from around the country and world to discuss possible solutions to this vexing problem will be held in Berkeley in January 2008. Failing underground cable is one of the most critical problems faced by utilities in California and the U.S. If new diagnostics are not developed, distribution system reliability will be negatively impacted because current rates of replacement of old cable will not be able to keep up with increasing age-related failures.

Integrating Distributed Generation

Distributed generation (DG) and CHP are valuable resource options for California. The Energy Commission has proposed policies to encourage development of DG resources, including CHP projects, for many years, beginning in the late 1990s with the formation of the California Alliance for Distributed Energy Resources and continuing with collaborative efforts with the CPUC to address barriers to DG development.

Despite these efforts, significant issues facing DG developers persist. In 2002, the Energy Commission developed a Distributed Generation Strategic Plan, noting:

> "…regulatory uncertainty in California continues to be a major concern for those considering the deployment of distributed generation. Utility rate design is confusing at best, including issues surrounding standby charges, interconnection fees, exit fees, and grid management charges. The timing of legislative mandates regarding rate

design and the ultimate implementation of those policies also carry confusion and uncertainty to DG stakeholders."[263]

Both the 2003 and 2005 *Integrated Energy Policy Reports* recognized that focused policy direction would be needed for successful long-term deployment of DG and CHP. The *2003 IEPR* recommended that California "Create a transparent electricity distribution system planning process that addresses the benefits of distributed generation."[264] As part of the 2005 IEPR process, the Energy Commission assessed California's CHP market.[265] In that assessment, potential project developers indicated the policy options most likely to increase the likelihood of a CHP project going forward were:

- modifying the CPUC's Self Generation Incentive Program to allow larger, natural gas fired projects that meet customers' requirements to participate; and
- allowing CHP owners to sell excess power to the grid.[266]

Opening the wholesale market for CHP projects was seen as the most important policy change for increasing the penetration of CHP, and for increasing societal benefits.[267] By allowing large CHP projects to find customers for their excess generation and to export power at wholesale prices, more than 2,400 megawatts of CHP generation output could be available for export. Because this reflects generation that is matched to facilities' heat loads, it is an efficient use of fossil fuel, mainly natural gas. The carbon-reduction paradigm established by AB 32 should place particular value on achieving these efficiencies rather than meeting electric and thermal loads separately.

In the 2005 assessment, some project developers suggested that the state consider measures to incent IOUs to support rather than oppose CHP development.[268] Developers felt that CHP is seen as competing with the local utility, and the lack of incentives to encourage utility cooperation could result in utility foot-dragging.

Through a research project involving the Electric Power Research Institute (EPRI), California investor-owned utilities (IOUs), and other states, the Energy Commission investigated the

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[263] California Energy Commission, *Distributed Generation Strategic Plan*, publication no. 700-02-002, June 2002, p. 16.

[264] California Energy Commission, *2003 Integrated Energy Policy Report*, publication no. 100-03-019, December 2003, p. 16.

[265] *An Assessment of California CHP Market and Policy Options for Increased Penetration*, CEC-500-2005-173, 2005.

[266] Ibid, p. XIII.

[267] Ibid, p. 4-25.

[268] Ibid, p. 3-21.

possibility of utility ownership of DG facilities, particularly CHP projects.[269] The goal was to develop a pilot application, testing alternative, "win-win" regulatory treatment of DG projects. However, utilities showed no interest in owning non-renewable projects. This result is consistent with findings of a 2007 Department of Energy (DOE) study[270] which concluded:

> There are several economic and institutional reasons why electric utilities have not installed much DG. For example, the economics of DG are such that financial attractiveness is largely determined on a case-by-case basis, and is very site-specific. As a result, many of the potential benefits are most easily captured by customers so that the incentives for customer-owned DG are often far greater than those for utility-owned DG. This has led to the current situation where standard business model(s) for electric utilities to invest profitably in DG have not emerged.

In the *2005 Integrated Energy Policy Report*, the Energy Commission found that, despite many years of articulated policy preferences, DG and CHP in California continues to face major barriers to market entry in the context of traditional utility cost-of-service grid management.[271] The *2005 IEPR* reiterated that California needs to improve access to wholesale energy markets and streamline utility long-term contracting processes so that CHP owners can easily and efficiently sell their excess electricity to their local utility. Availability of the wholesale market continues to be a significant consideration in encouraging DG.

As part of the 2007 IEPR process, on May 7, 2007 the 2007 IEPR Committee held a joint workshop with the Energy Commission's Electricity Committee to discuss staff's proposed "Combined Heat and Power Policy Roadmap." The roadmap was developed to provide a long-term perspective for DG and cogeneration policy. The Roadmap includes a 2020 DG and Cogeneration Vision and a Pathway with detailed actions and milestones for implementing policies.

Oral and written comments from the workshop raised the same issues which have characterized past discussions. Testimony by municipal utilities suggests that they welcome DG resources in their systems, but there is a continuing gulf between the perceptions of the IOUs and those of DG advocates regarding the risks and value of DG projects to those systems.

IOUs continue to show little interest in accepting energy from customer-owned DG projects or in developing utility-owned DG or CHP projects. As a result, these options continue to struggle with major barriers to market entry. As noted in the *2005 IEPR*, many of the state's operating,

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[269] California Energy Commission contract number 500-02-014, WA #121.

[270] "The Potential Benefits of Distributed Generation and Rate-Related Issues that May Impede Their Expansion, a Study Pursuant to Section 1817 of the Energy Policy Act of 2005". U.S. Department of Energy, February 2007.

[271] California Energy Commission, *2005 Integrated Energy Policy Report*, CEC-100-2005-007-CMF, November 21, 2005, p. 76.

large-scale CHP systems continue to run under the terms of generation contracts signed during the early 1980s. As these contracts expire, as much as 2,000 MW could shut down by 2010.[272]

However, the importance of keeping this DG capacity in the system is elevated by the state's need to reduce greenhouse gas (GHG) emissions as part of AB 32. CHP in particular offers low GHG emissions rates for electricity generation taking advantage of fuel that is already being used for other purposes. These systems use waste heat for either process or electricity generation needs which results in very efficient use of fossil fuels. Large CHP units appear to offer the greatest fuel efficiency of available DG technologies. Because CHP systems are located close to the load, transmission and distribution line losses are minimized, further reducing GHG impacts.

As regulations for AB 32 compliance are finalized, the benefits of DG for the electricity system will become more quantifiable. This will reinforce the need to make DG projects a higher priority in utility resource mixes.

DG can also play an important role in helping to meet local capacity requirements. The California ISO has encouraged the CPUC to include local capacity requirements in its procurement to replace "reliability must-run" (RMR) capacity that must operate, even if uneconomically, to preserve system reliability. This change lowers the costs of California ISO services and allows longer term contracts (more than one year).

Under the RMR contracts, plants had to be larger than one MW to participate. With the local utility now responsible for this reliability hedge, smaller plants, such as DG facilities, may participate, subject to utility and/or CPUC approval, improving local reliability and system efficiency.

The CPUC is beginning to act on the need for contracts that provide DG developers with the certainty needed to undertake projects. In October 2006, the CPUC approved SCE's request for approval of 61 fixed price energy agreements with existing renewable QFs for a five-year period through April 30, 2012.[273] The CPUC also adopted the PG&E/Independent Energy Producers Settlement Agreement in which 121 power projects entered into either a fixed or variable energy price agreement with PG&E. The power deliveries associated with the settlement agreement "represent over half of generation deliveries from all QFs [qualifying facilities] currently under contract with PG&E." [274]

In April 2007, the CPUC released a proposed decision that would provide for contract terms as long as 10 years for DG projects that fit as qualifying facilities. The proposed decision has been

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[272] California Energy Commission, *2005 Integrated Energy Policy Report,* CEC-100-2005-007-CMF, p. 77.

[273] Ibid, p. 4.

[274] *Opinion on Future Policy and Pricing for Qualifying Facilities*, D.06-07-032, ALJ Halligan, April 24, 2007, p. 4.

scheduled for approval at a number of CPUC meetings, but each time was postponed. A revised proposal is currently circulating, with an alternate decision proposed by Commissioner Grueneich. When this decision is finally made, it could remove the major barrier of uncertainty that has helped to stall development of new distributed generation, especially combined heat and power projects.

However, this opening of longer-term, firm capacity contracts is offset by the possible imposition of as-yet-undetermined nonbypassable charges for departing load related to DG and CHP projects. Comments filed during the Energy Commission's DG workshop noted the uncertainty generated by CPUC-proposed, unquantified departing load charges to be assessed on DG projects.[275] While the option for longer-term contracts reduces uncertainty for project developers, this future nonbypassable charge has the opposite effect.

Given the expected growth in electricity demand in each procurement period along with the cyclical nature of the procurement process, it is possible to adjust resource procurement to load changes over time. It is not reasonable to subject one source of load changes to these charges, while ignoring the impacts of other sources of change, such as increased efficiency. This use of nonbypassable charges chills the market for DG projects, undermining the potential benefits these projects offer both to the environment and California's electricity system.

Recommendations

To address the challenges facing California's distribution system, the Energy Commission recommends the following:

- Developing state policy that will articulate and support modernizing California's distribution system
- Establishing a transparent distribution planning process that is integrated with other resource procurement processes to assure that the intelligent electrical and communications infrastructures that will be required to support the integration and use of new low-carbon resources — renewables, demand response, efficient CHP, distributed generation, energy storage, advanced metering infrastructure, and plug-in hybrid electric vehicles — is developed during the same timeframe.
- Establish a Distribution Program, similar to the Energy Commission's Transmission Program, with adequate staff to assess distribution system adequacy and provide leadership in the area of distribution system modernization.

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[275] Comments Of The Cogeneration Association Of California And The Energy Producers And Users Coalition On The Distributed Generation And Cogeneration Policy Roadmap For California, May 3, 2007.

- Funding distribution research through the PIER program that develops and demonstrates technologies that will accelerate the transformation of the distribution grid into an intelligent and sustainable network.
- Developing policies and research to develop open data architecture that will support interoperability from transmission to generation, distribution, and customers and their meters and appliances.
- Developing new rate designs that will encourage consumers and utilities to invest in promising technologies and participate in programs that provide value to them and the state (premium power quality, critical-peak and real-time pricing).
- Basing a major portion of each utility's profit on criteria related to performance, achievement of designated goals, service reliability, and customer support and assistance to achieve greater efficiency of electricity use, rather than basing that profit exclusively on investing in infrastructure that supports a high volume of electricity sales.
- Requiring utilities, before undertaking investments in non-advanced grid technologies, to demonstrate that alternative investments in advanced grid technologies have been considered, including from a standpoint of cost-effectiveness.
- Recovering in a timely manner the remaining book-value costs of equipment rendered obsolete by the deployment of a qualified smart grid system, based on the remaining depreciable life of the obsolete equipment.
-

The Energy Commission continues to believe that DG, and especially CHP applications, provide significant system and efficiency benefits to California's distribution system and therefore recommends the following:

- The CPUC's self-generation program incentives should be based upon overall efficiency and performance of systems, regardless of fuel type.
- The CPUC should complete a tariff structure to make DG projects "cost and revenue neutral", while granting owners' credit for system benefits, such as reduced congestion.
- The CPUC and the Energy Commission should work cooperatively to eliminate all non-bypassable and standby reservation charges for DG.
- The CPUC should continue the work of the "Rule 21" industry/utility collaborative working group to refine interconnection standards, provide third party resolution of interconnection issues and streamline permitting
- The CPUC should develop a DG portfolio standard for electric utility procurement plans. Alternatively, the utilities could be required to treat DG like efficiency programs.
- The CPUC should adopt revenue-neutral programs that would place high efficiency CHP on an equal footing with bulk power from utilities. These programs could include:
    - Requiring utilities to procure natural gas for combined heat and power plants at customer sites on the same basis they do for central power plants.

- Counting combined heat and power plant output toward energy efficiency goals for utilities.
- Providing a portfolio standard with steadily increasing requirements for combined heat and power plant generation.

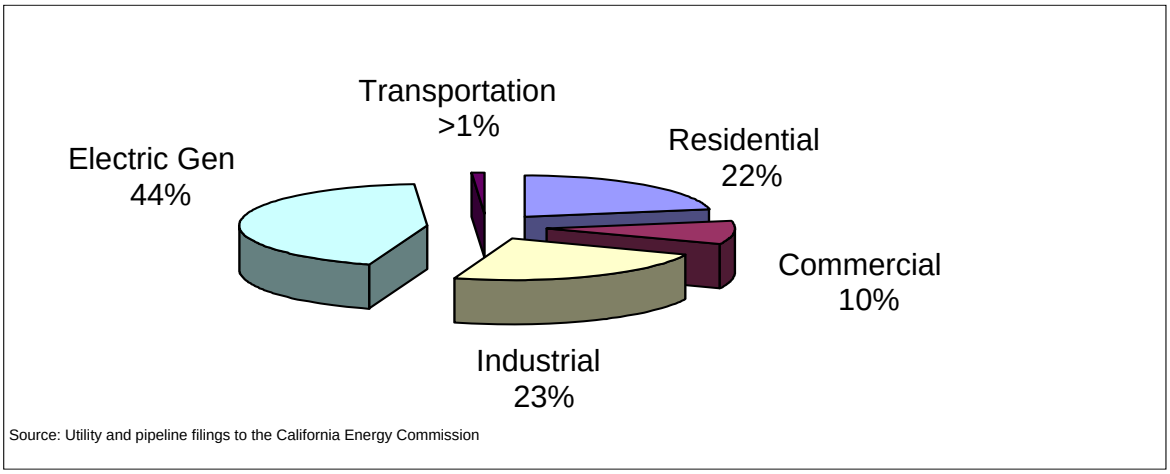
CHAPTER 6 - Meeting Natural Gas Needs

Almost 30 years ago, California's serious air quality problems placed natural gas as the fuel of choice for electricity generation. In the late 1970s for air quality and cost benefits, California moved away from petroleum, nuclear and out-of-state coal to natural gas for generating electricity. Natural gas was cleaner burning, relatively cheap and helped diversify our electricity generation system. Now, with global warming recognized as a serious world environmental concern, the rest of the United States, Canada and Mexico are following California's lead with a similar shift from an oil and coal-based electricity system.

California faces a more difficult challenge. Natural gas contributes to greenhouse gas emissions and state policy now mandates that California's greenhouse gas emissions must be reduced to 1990 levels by 2020. This reduction must be balanced with the understanding that natural gas is the criteria pollutant fossil fuel of choice and will likely play an even more important role in California's energy future, despite policymakers' emphasis on efficiency and renewables. As discussed in the description of the scenario analysis in Chapter 3, increased natural gas fired generation in the California is a possible outcome of displacing coal generation in other western states. The magnitude of any such increase will depend on the amount of efficiency and renewables across the Western Electric Coordinating Council (WECC), but in each scenario less coal requires more natural gas and visa versa.

Natural gas is critical to California's energy system, providing more than a third of the state's total energy requirements. Over 44 percent of the natural gas consumed in the California is used to generate electricity. More importantly, natural gas is the primary and most efficient fuel for residential cooking, space and water heating and cooking, and industrial processes (Figure 6-1).

Figure 6-1. California Natural Gas Use in 2006



Almost 85 percent of our natural gas supplies are from sources outside of the state. This dependency poses an ongoing challenge in securing adequate and reliable supplies of natural gas at reasonable prices. This occurs, in part, because natural gas well productivity is declining and California is literally at the end of the interstate pipeline system, competing with a growing North American demand.

In fact, natural gas, like petroleum, has become a global commodity and California, which is currently competing with the Mid-West and East Coast for natural gas supplies, will be in direct competition with Western Europe and Asia Pacific importers in a world market for natural gas supplies and at prices that are likely to continue increasing.

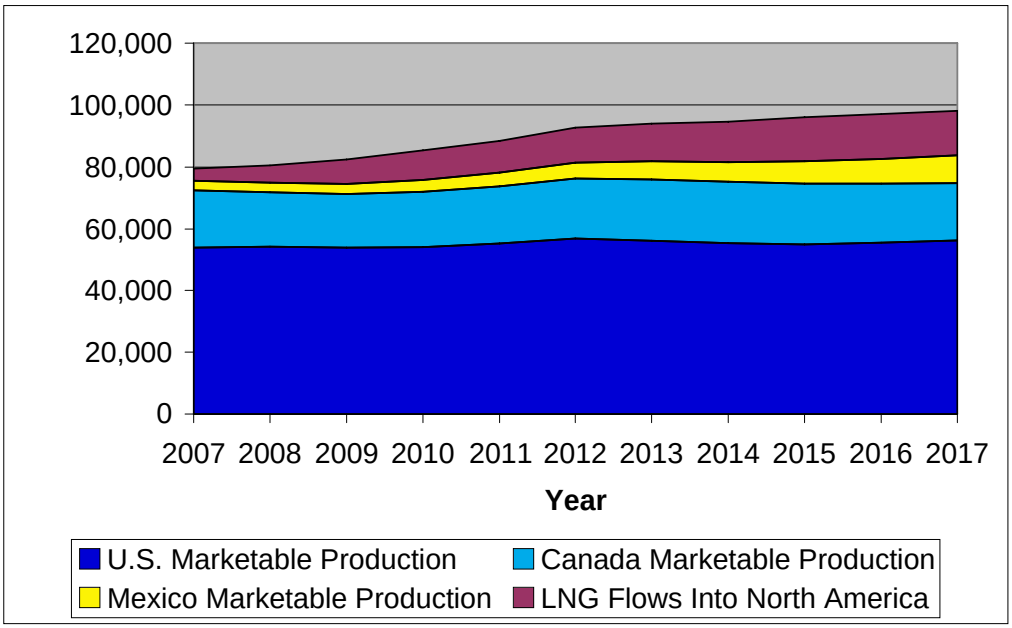
Natural gas demand in the power generation sector for the United States is projected to increase by 5.5 percent per year, putting pressure on California's ability to obtain stable supplies without paying more. Most of this projected growth is occurring in the states east of the Mississippi as they shift more from coal-based electricity generation to cleaner natural gas-fired generation to help reduce criteria pollutant emissions.

Over the past several years, instate and interstate natural gas pipelines and storage facilities have been improved, strengthening the state's ability to bring in, store and distribute more supplies to reduce price volatility and meet demand. However, because California imports large volumes of natural gas by pipeline, we are vulnerable to weather related events throughout the United States that can either disrupt production as in the case of hurricanes or increase demand with cold temperatures. In either case supplies can be constrained, causing prices to spike. Cold winters in the East can drive up natural gas prices for California and hurricanes in the Gulf region can wreak havoc on natural gas production and distribution.

New natural gas supplies in the continental United States are more difficult to find and produce as cheaply as before. Despite more drilling activity, declining well productivity, shorter production life, smaller fields and more drilling regulations have all combined to keep North American production relatively flat and increase prices.

The decline in well productivity creates a widening gap between United States demand and domestic supplies. Additionally, the United States can rely less on pipeline imports from Canada as its own domestic natural gas demand increases and field production declines. To fill this gap the Energy Information Administration (EIA) projects significant imports of natural gas from worldwide sources to increase over the next 20 years and shipped as liquefied natural gas (LNG) by tanker, not pipeline, requiring additional infrastructure. By 2017, 15 percent of North American natural gas supplies could be LNG (Figure 6-2).

Figure 6-2. Origins of Natural Gas Supply for North American



Source: California Energy Commission

North American production cannot keep up with growing demand and this widening gap could be filled with imported LNG.

The state's energy efficiency programs and the use of renewable energy for electricity generation have helped keep California's growing natural gas demand in check even though our population continues to climb by a half million people each year. California's overall natural gas demand is projected to grow at less than one percent per year, mostly for electricity generation. Lacking similar national efficiency and renewable standards, the comparable United States annual growth rate for natural gas to generate electricity is twice California's 2.1 percent.

While California's average wholesale natural gas price is lower than some regions in the United States, it has increased appreciably from $3.82 per thousand cubic feet in 2002 to $6.68 per million cubic feet in 2006 (2006 dollars). California consumers spent $18.8 billion for natural gas in 2006, double what they spent in 2002. As demand throughout North America grows, natural gas prices are likely to continue the upward trend. The impact on the economy is compounded because higher natural gas prices also lead to higher electricity prices.

Even with the uncertainties of domestic supplies and prices, California most likely will continue to build new natural gas power plants for years to come. Since 1998, the Energy Commission has approved over 23,000 megawatts of natural gas-fired facilities with about 13,000 megawatts of that amount generating and an additional 7,500 megawatts of gas-fired power currently in the review process. Newer natural gas power plants are more efficient than the existing aging natural gas power plants. They also have the ability to ramp up and shut down more quickly to provide electricity to meet peak demand and use less natural gas for more electricity output. Natural gas power plants are also the best complement to renewable resources since they have the ability to come on line quickly when wind or solar resources lose output due to lack of wind

or sunshine. Despite numerous energy efficiency programs in California, electricity demand is expected to grow due to population increases in the hotter, inland areas that have high air conditioning loads. Natural gas power plants have proven to be reliable providers of electricity for California. They are also superior options to nuclear and coal-fired plants until those technologies resolve their environmental problems of waste disposal and carbon sequestration. As discussed in Chapters 2 and 5; however, the high price volatility for natural gas and the tendency of electric utilities to be insensitive to fuel cost pass-through, has made California's increasing reliance on gas-fired electric generation problematic from a ratepayer perspective.

A Paradigm Shift in Analysis

Mark Twain was correct when he said, "Prophesy is a good line of business, but it is full of risk." Attempting to forecast California's future natural gas demand, supplies and prices is laden with uncertainties. Clearly, the natural gas price forecasts developed by Energy Information Administration have been wildly inaccurate (Figure 6-3). There is no magic measuring stick that shows exactly what volume of natural gas reserves exist in North America or what the cost of these supplies will be. And one of the biggest unknowns is how many LNG facilities will be built in the United States and whether the United States will compete with developing economies in Asia for those remote supplies of natural gas.

The scenario analysis work performed for the *2007 Integrated Energy Policy Report* was designed to expand the pinpoint analysis done in past years to address broader energy policy dynamics. This modeling approach addressed those measures that would meet carbon reduction goals.

What happens to natural gas demand if new environmental policies drive the United States, Canada and Mexico to switch from coal and oil for some or most of their electricity generation to reduce greenhouse gas emissions? How will these policies impact available natural gas supplies and prices?

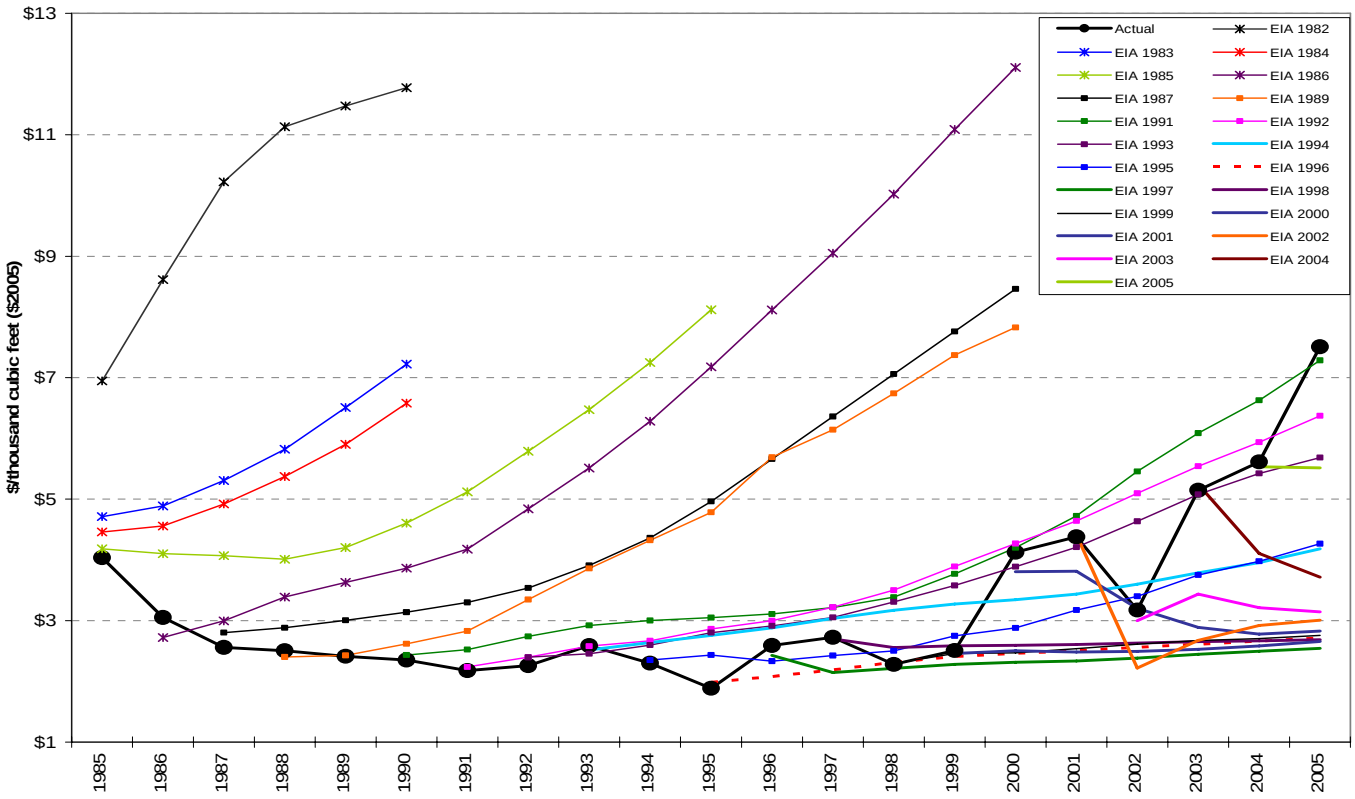
How can we determine increasing natural gas use, if California decides that electricity is the "clean" fuel strategy of choice and replaces stationary diesel motors with electricity? Will plug-in hybrid vehicles grab the lion's share of the vehicle market? That would reduce gasoline consumption, but increase electricity demand, and subsequently increase natural gas demand to an unknown extent. Does following the European model by encouraging the use of compressed natural gas vehicles make sense?

Or can tankless water heaters be the solution to the continuous high temperature storage feature of current natural gas water heaters? What role will solar water heating, or space heating, play in the future?

These questions challenge the traditional forecasting methodology because they do not provide the flexibility to quantify the uncertainties and risks the state is facing with new energy policies. AB 32 shifts how California considers its natural gas future and challenges how we look at the consequences of our energy choices. Cutting greenhouse gas emissions means that the *business as usual* mode of using natural gas less efficiently for electricity generation and industrial

processes will no longer allow us to meet our environmental policy. These necessary and difficult choices require new tools that help design a California future that uses natural gas in its most efficient way such as eliminating wasteful electricity generation from aging power plants and encouraging uses that meet the state's environmental goals.

Figure 6-3. Natural Gas Price Forecasts by Year Issued



Source: Department of Energy, Energy Information Administration, *Annual Energy Outlook Retrospective Review*, March 2007, DOE/EIA-0640(2006).

Rethinking Forecasting Methods

The California Energy Commission's Scenario Analyses Project took the first step in moving towards exploring a carbon-constrained future by expanding how we consider our energy choices from a policy-driven perspective and which combination of resources will help reduce greenhouse gases. Scenario Analyses Project examined the implications of using various amounts of energy efficiency, rooftop solar photovoltaic (PV), and renewable electricity generating technologies to determine which of these known strategies could satisfy AB 32's goal for the electricity sector. One of those variables evaluated in this assessment was natural gas

used in electric power generation. Staff studied these implications in a number of conventional and non-conventional scenario futures.

As expected, the more conventional scenario produced a California natural gas demand for power generation similar to the staff's most recent natural gas forecast. Natural gas demand would rise slowly as natural gas becomes a larger share of electricity generation. Although this scenario is the closest to meeting current efficiency goals and RPS requirements, it does not notably reduce greenhouse gases.

More significant were the results from the scenario that combined both high amounts of energy efficiency and renewables. This scenario concluded that employing very high levels of energy efficiency and renewables could substantially reduce 2020-projected natural gas used for power generation in California and drive down greenhouse gas emissions extensively below 1990 levels. More importantly, if the rest of the West pursued these preferred resources as aggressively as California; then natural gas demand for power generation could fall 51 percent from what it would otherwise be in 2020. This aggressive scenario future relies heavily on energy efficiency and renewables; and natural gas plants only where needed for reliability.

Rather than asking which of these views of the future is most likely, California and western states decision-makers should ask which one is preferable? California has already embarked on a process to answer that question with AB 32. Five other states and two Canadian provinces have signed a Memorandum of Understanding to pursue a major decrease in greenhouse emissions. These policy debates, and their implications for substantial change compared to current energy use patterns will dominate analyses of demand for and supply of natural gas for several years to come.

Even with AB 32 demanding significant reductions in greenhouse gases, natural gas use will remain a major fuel in California's supply portfolio over the next several decades, and if California adopts an electricity as the best fuel strategy, natural gas use will likely increase until displaced by renewables, carbon-sequestered coal, or nuclear generation.

Natural Gas Supplies and Dependence on Imports

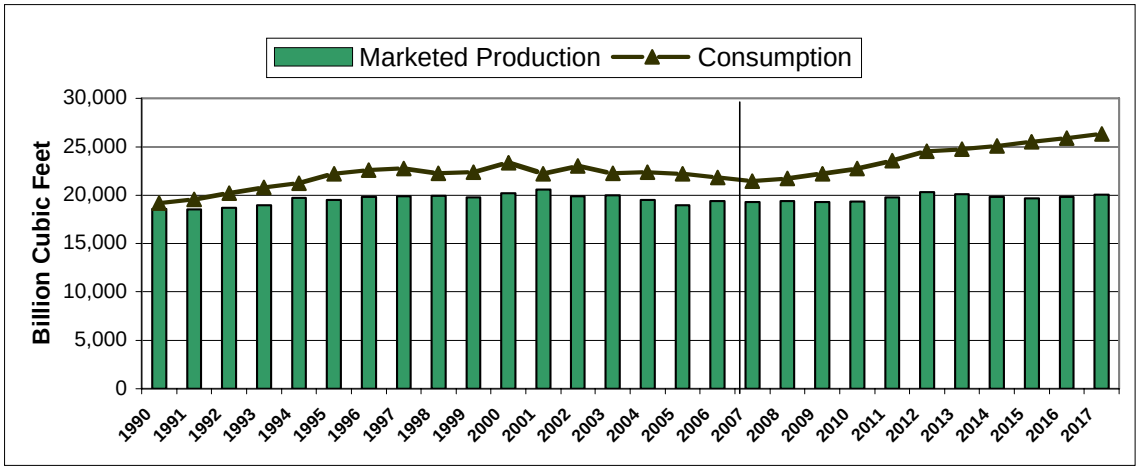
Starting in the late 1970s California altered the state's electricity generation system by switching to a cleaner burning fuel – natural gas. Driven by deteriorating air quality and an oil embargo, the state's utilities invested in cleaner burning natural gas. With only about 15 percent of California's supplies coming from in-state production, billions of cubic feet each year were imported to a hungry California electric generation market from the Southwest, Rocky Mountains and Canada. Suppliers were eager to get paid for gas that had no other market. Competition from other states was minimal and California effectively cornered the market for gas as a generation fuel and cornered it rather cheaply. Unfortunately, that's not the case today. The state no longer has a lock on natural gas supplies and California must compete with the rest of North America as demand increases and supplies become tighter. As natural gas becomes the fuel of choice for electricity generators to reduce criteria air pollutants, competition for natural

gas will only intensify as concerns about greenhouse gas emissions grow across the United States.

California's natural gas supplies are tied to North American production with about 1.7 trillion cubic feet per year of natural gas imported to meet the state's demand. Because in-state production peaked several years ago and is slowly declining, and in-state natural gas demand continues to grow slowly but steadily, natural gas imports will have to increase to keep up.

Gas producers across the United States and Canadian are struggling to keep pace with growing demand. Although large volumes of natural gas have been discovered worldwide and production is increasing, United States production has been relatively flat since 1990 and most conventional domestic and Canadian natural gas production from mature basins is declining.

Figure 6-4. United States Production and Consumption 1990-2017



Source: Energy Information Administration

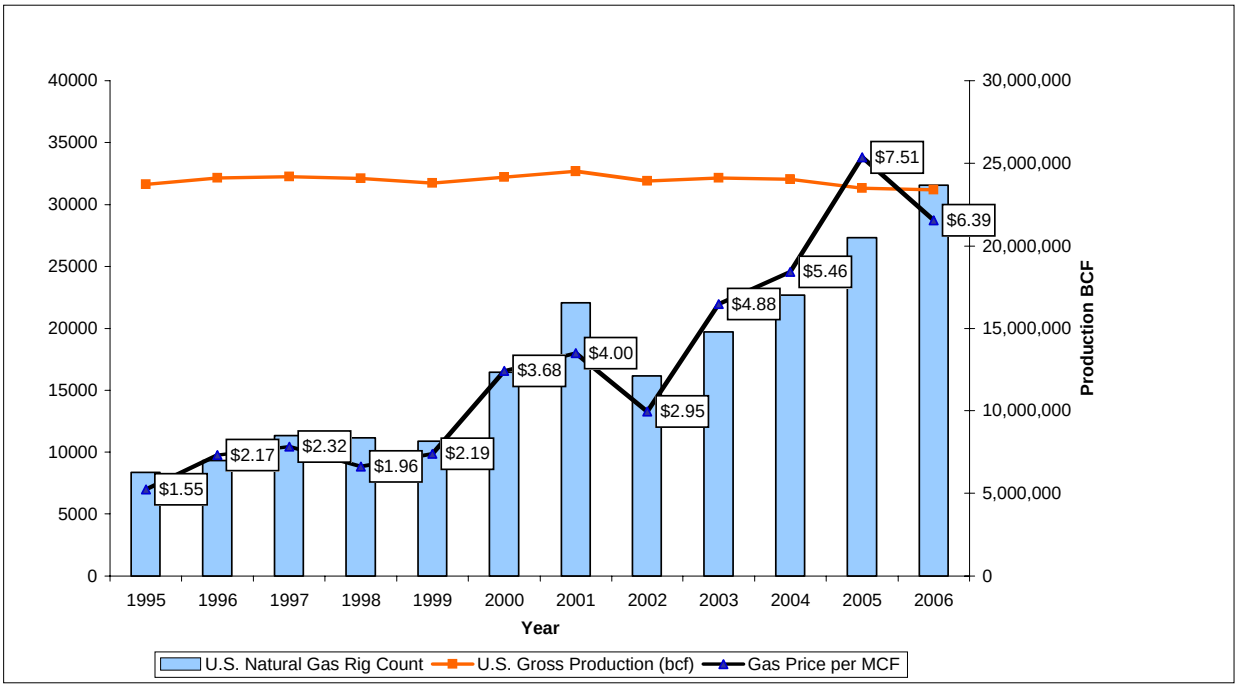
As natural gas production in the United States flattens and demand increases, the gap will be made up with more LNG imports.

United States production is expected to remain around 53 billion cubic feet per day (20 trillion cubic feet annually) over the next decade (Figure 6-4). Growth in natural gas production from the Western Canadian Sedimentary Basin, the largest natural gas producing region in North America, has slowed considerably over the last five years and is expected to slightly increase from about current levels of about 18 billion cubic feet per day to only about 19 billion cubic feet per day by 2012, remaining flat afterwards. Supplies in North America are not able to meet growing demand despite high prices and higher levels of drilling.

Since 1995, the number of natural gas wells completed in the United States has almost tripled from 8,400 to 31,000 wells in 2006. Had production per new well remained constant, this would have resulted in huge volumes of natural gas produced. Instead, despite intensive drilling, production increased only modestly and the easier-to-produce, less expensive supplies are

dwindling. Nine years ago it took 15,427 wells to produce the same amount of gas that today requires 27,414 wells to produce.

Figure 6-5: United States Natural Gas Production, Price and Wells Drilled



Source: California Energy Commission

Although higher natural gas prices have spurred more drilling, production has not increased and drilling costs are higher (Figure 6-5). If declines in productivity per new average well continue at the four percent per year rate experienced from 2000 to 2006, then 60,000 more new wells would have to be drilled in 2017 to satisfy demand in that year – a number that is not economically or physically likely.

Newly found fields are usually smaller and more costly to develop and, over time, more effort is required to produce the same amount of gas. Advances in drilling technology allow producers to increase a well's first-year performance; but by extracting the gas more quickly, the well's annual production declines more rapidly in the following years. Also as developers move to increased reliance on unconventional gas fields, the productivity per well continues to fall even as costs and prices continue rising.

Producers are on a treadmill of drilling just to keep pace with current demand and they will soon reach a point where they will no longer be able to maintain this level of output without extraordinary price increases or technological advances.

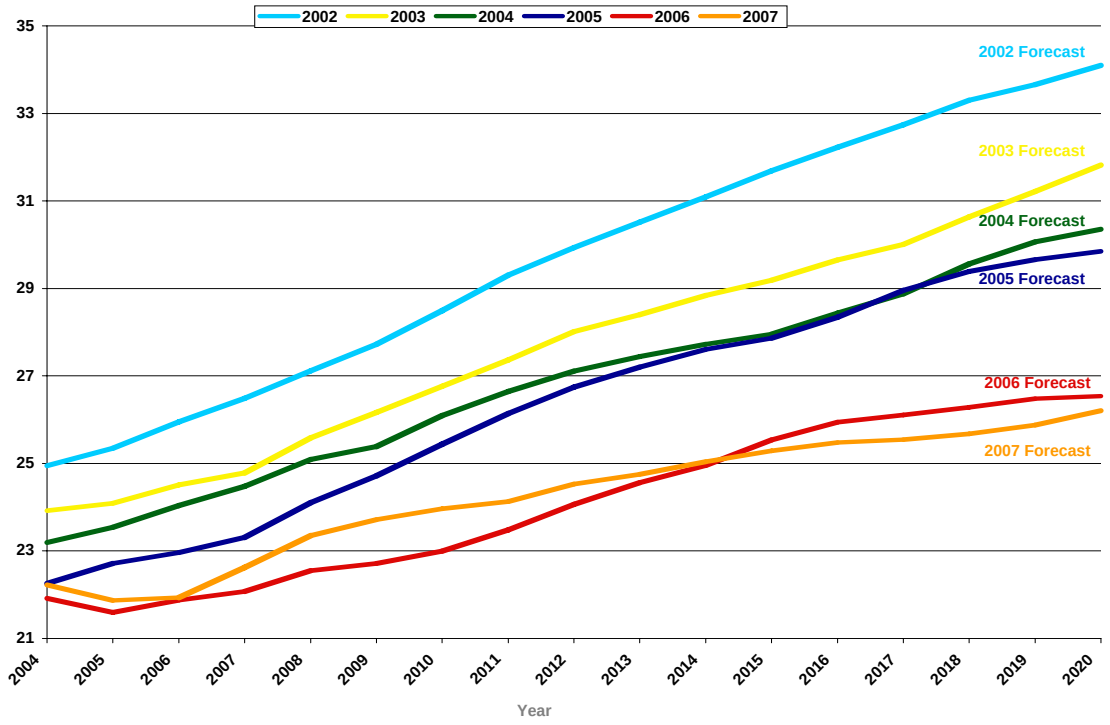
Although earlier forecasts projected rising gas production, the reality of falling production per well means that even by drilling more wells we can achieve only slight increases in production over the next several years. And despite earlier optimism, natural gas resources previously

slated for delivery from Artic Canada (Mackenzie Delta) and Alaska's North Slope into the North American gas market are not likely to be available until at least 2020.

Supply Uncertainty

The Energy Information Administration publishes an annual projection of natural gas production for North America (Figure 6-6). The annual forecast of North American natural gas production has decreased each year since 2002, a difference of about eight trillion cubic feet a year. These forecasts have been unreliable and reflect a change in trends that the models were unable to capture. The modelers expected natural gas prices to stay cheap and abundant at $2 per thousand cubic feet but conventional resources went into decline and North America had to turn to more costly unconventional supplies.

Figure 6-6. DOE EIA Natural Gas Supply Forecasts in North America 2002-2017



Source: Energy Information Administration

Over time the forecasts finally started incorporating the industry's inability to produce additional North American natural gas, despite ever increasing drilling. Given the challenges in producing North American natural gas, we expect more downward adjustments in future forecasts. PG&E has publicly commented that they believe that western Canadian natural gas production will be less than predicted while Sempra/SoCalGas believes that several supply basins will produce less than forecasted.

The natural gas industry continues looking for more supplies – supplies that are more difficult and more expensive to produce. Production from newer supply basins in the Rocky Mountains,

east Texas and in the Gulf of Mexico deep water has helped to slow this decline. Supplies from some of these areas; however, are produced from unconventional resources such as coal bed methane, tight sands gas, shale gas, or in very deep water, all which cost more to develop and raise the relative costs of natural gas across North America. Based on the number of applications to construct liquefied natural gas (LNG) terminals in North America, some in the natural gas industry believe that it is more profitable to develop stranded natural gas supplies in remote corners of the world and ship it as LNG.

Alternative Natural Gas Sources

LNG – A Controversial Supply

Being at the end of a long pipeline network with little in-state production, California must have access to a variety of stable sources. LNG is one potential supply of natural gas. LNG is natural gas that has been chilled, reducing it to a liquid form, condensing its volume by 600 percent. This significant reduction in bulk allows natural gas to be shipped worldwide by tankers before the liquid gas is re-vaporized back into its gaseous state.

LNG is already a natural gas supply source for North American users and is currently imported into the United States through five receiving and re-gasification terminals. None of these terminals is on the west coast, although Sempra's Costa Azul facility in Baja California will provide some United States supplies when it comes on-line in 2008. Bringing natural gas into California as LNG will require infrastructure improvements including a re-gasification terminal.

LNG imports to the United States are expected to increase 14 percent annually by 2017 to about 14 billion cubic feet per day, according to Energy Commission staff. Staff only included facilities that fall into the following three categories: currently operating (with any scheduled expansion), currently under construction, and currently permitted (high probability of construction).

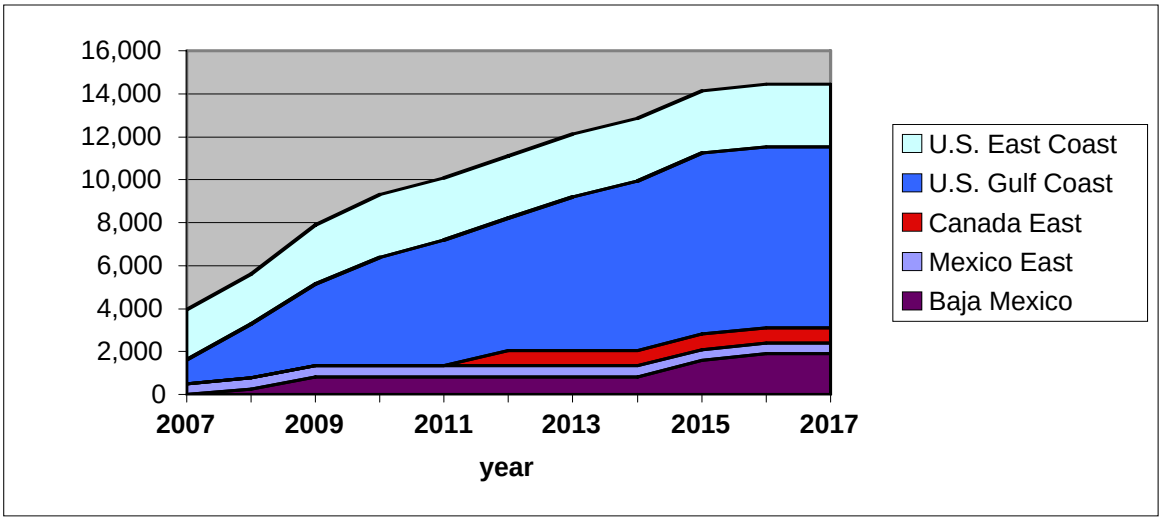
Although much of these supplies will be shipped into the United States' Gulf Coast region, it will help meet California's additional natural gas needs by increasing overall domestic supplies (Figure 6-7).

In its *2003 and 2005 Integrated Energy Policy Reports*, the Energy Commission found the construction of LNG import facilities important to natural gas supplies and infrastructure in North America. These facilities will increase natural gas supplies available to the United States over the next 10 years and help meet California's additional natural gas needs. The *2003 and 2005 Energy Reports* also highlighted the need to develop these facilities and their associated infrastructure to better serve the natural gas needs of California and the western United States.

Twelve applications to build LNG re-gasification facilities are in various stages of review on the West Coast including four in California, four in Oregon, three in British Colombia and one in Mexico. California has already engaged in the LNG debate by participating in direct discussions with the Federal Energy Regulatory Commission, which manages the environmental review

process for on-shore LNG facilities, and the Coast Guard, which is responsible for the offshore review. In addition, the Energy Commission coordinates the activities of the LNG Interagency Working Group, composed of the federal, state and local agencies responsible for overseeing the licensing of LNG facilities in California. It is the mission of the Energy Commission, and the LNG Working group, to help ensure that any LNG development is consistent with the state's interest in balancing environmental protection, public safety and local community concerns to ensure protection of the state's population and coastal environment.

Figure 6-7. LNG Imports into North America



Source: California Energy Commission

By 2017 LNG imports could supply almost 15 percent of North American natural gas demand.

Currently, staff analysis anticipates receiving about 500 million cubic feet a day of natural gas from the almost completed Costa Azul facility on Mexico's west coast starting early in 2008. The Costa Azul facility is projected to import an average of roughly 800 million cubic feet per day when it reaches commercial operation. About 300 million cubic feet per day will serve electric power plants in Mexico and up to 400 million cubic feet per day will flow to San Diego through the SDG&E lines. The rest will flow through the North Baja line to Blythe and then north into California. Almost all the Mexican natural gas entering California will displace domestic Southwest supplies that currently come to California.

Even before the Costa Azul facility is completed, the North Baja pipeline provides natural gas to Baja. The California State Lands Commission recently approved the necessary permits for the pipeline to cross the Colorado River, which could allow the reverse the flow of the North Baja pipeline to import supplies to southern California from Costa Azul. However, if the Costa Azul facility expands from 800 million cubic feet per day to double that amount, for California to access more natural gas from Mexico, additional or modified pipeline infrastructure will be required. If the expansion takes place, as much as an additional 1 billion cubic feet per day could enter southern California through the North Baja pipeline. There is no guarantee,

however, that Costa Azul will expand. Another LNG facility may be built on the west coast instead. Market conditions and environmental review of the proposed sites will determine the outcome.

Although, there is also no assurance that west coast LNG projects will lower natural gas prices to California, staff's modeling work has provided an important insight: LNG delivered to the United States is cheaper, on a cost basis, than the high-cost elements of newer North American production and keeps prices lower than they would be if no LNG came to North America. Additional supplies, no matter where they come from, can help stabilize California's supplies and prices.

Biogas

Diversifying the state's natural gas supply sources is important especially if it increases in-state biogas production facilities. California has a large amount of biomass resources that are suitable as feedstock for gasification technologies.[276] Natural gas produced from landfills in the state is growing and agricultural waste can be converted to synthetic natural gas. Greater use of combined heat and power systems fueled by biomass could also reduce demand for natural gas in process and industrial heat and cooling operations, helping to increase overall energy efficiency and reduce carbon impacts of the state. By 2050, nearly 100 billion cubic feet of biomethane per year could contribute to the state natural gas supplies.

The Energy Commission has invested almost $94 million over the last five years in renewable facilities and agriculture biomass projects to help over come some of the economic barriers and environmental impacts.

Natural Gas Infrastructure – A Vital Resource

The natural gas infrastructure system is critical to California's ability to provide a stable and reliable supply of gas since only 15 percent of our natural gas supplies are produced in state. Just as California looks for adequate supplies of natural gas, it must also ensure that its infrastructure can move and store supplies.

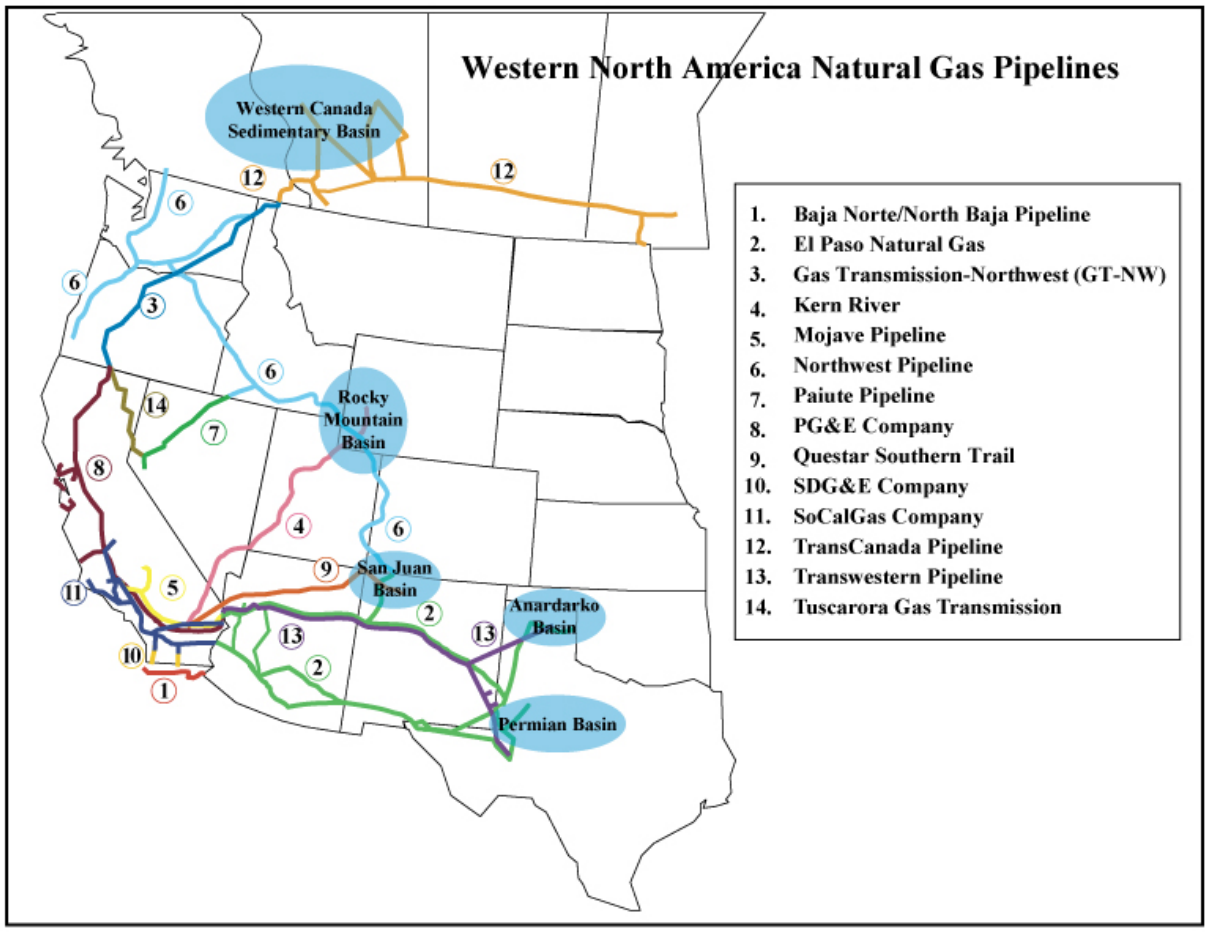
An extensive pipeline network, linking the state to several supply basins in North America, can satisfy California's average demand of over two trillion cubic feet of natural gas annually. (Figure 6-8) Since the 2001 electricity crisis, delivery capacity to California has expanded about 18 percent by 2006, climbing to about 9.2 billion cubic feet per day and ensuring that we will have adequate capacity for the next decade. The demands of residential, commercial, industrial and power generation customers sometimes display wide variation from month to month, even day to day. As has happened in the past, sustained cold winter days makes it difficult to satisfy all demand requirements by pipeline capacity. In these cases the state's storage facilities supply

276 *Bioenergy Action Plan for California.* The Bioenergy Interagency Working Group, July 13, 2006.

additional natural gas. As noted earlier, there will be two pipelines bringing natural gas from an LNG facility in Costa Azul, Baja Mexico into southern California.

If the Costa Azul LNG facility and the North Baja pipeline are expanded to import more natural gas into California, a surplus will occur at the southern California border. Competition between additional supplies from Wyoming delivered by the Kern River pipeline system and from the Southwest delivered by the Transwestern and El Paso pipeline systems will cause the price of natural gas at the Southern California border to drop below the price of natural gas in Northern California. If the price of this natural gas is 20 cents to 50 cents below the northern California gas price then most likely one of these three options will occur. Since the existing south to north pipeline – Line 300 – is owned by PG&E and would be full, PG&E could expand the line; however, this option would take several years. Options 2 and 3 include either expanding the Kern Mojave and Mojave pipelines to allow additional natural gas supplies to move north, or power plant developers wanting access to the less costly gas will try to locate their power plants in the southern region.

Figure 6-8. Western North American Pipelines and Supply Basins



Source: California Energy Commission

Even though staff assumes Costa Azul will expand, PG&E suggested that other supply options could develop to the north of California, most likely brought to North America as LNG. According to PG&E, "California and in particular Northern California, see significant benefits in terms of price, extended use of installed capacity, and far lessened pressure to expand PG&E's Baja path."[277]

There are also concerns that when Sempra's Rocky Mountain Express Pipeline goes into operation in 2009, natural gas supplies currently transported to California could be shifted to the East. The original staff assessment estimated 1.5 billion cubic feet per day of natural gas capacity; however, this potential has increased as the Rocky Mountain Express Pipeline sponsor has reportedly received commitments from shippers for 1.8 billion cubic feet per day of capacity. A more detailed analysis of the Rocky Mountain Pipeline expansion will be provided in the *2009 Integrated Energy Policy Report* cycle.

California's natural gas storage has been instrumental to help guard against interruptions or severe weather changes, ensuring adequate supplies and making some contributions to more stable prices. Over the last several years, the state has added storage bringing total capacity to about 256 billion cubic feet. These storage facilities allow sustained additional gas withdrawals of about 4.9 billion cubic feet per day during peak demand periods.

Natural Gas Demand

Natural gas is critical in meeting the state's energy demand. California's growing population requires more natural gas for residential heating and cooking, industrial processing and - the big driver - electricity generation. Electric motors and other measures such as plug-in hybrids in transportation may also play a larger role in future demand.

California Depends on Natural Gas

California's demand growth for natural gas in residential, industrial and commercial sectors has remained slow, with each sector expected to grow less than one percent each year in the next decade (Figure 6-9).

Electricity generation demand is growing about 1.4 percent each year through 2017 and will continue to fuel the largest increased use of natural gas over the next decade. Before 1997, natural gas consumption for electricity averaged 500 billion cubic feet each year (1,400 million cubic feet per day); however, future demand is anticipated to average 2,500 million cubic feet each day.

California no longer has the luxury to view natural gas from a "California demand only" perspective but must examine how the demands from our competitors are changing – the western states, Canada as well as the eastern United States.

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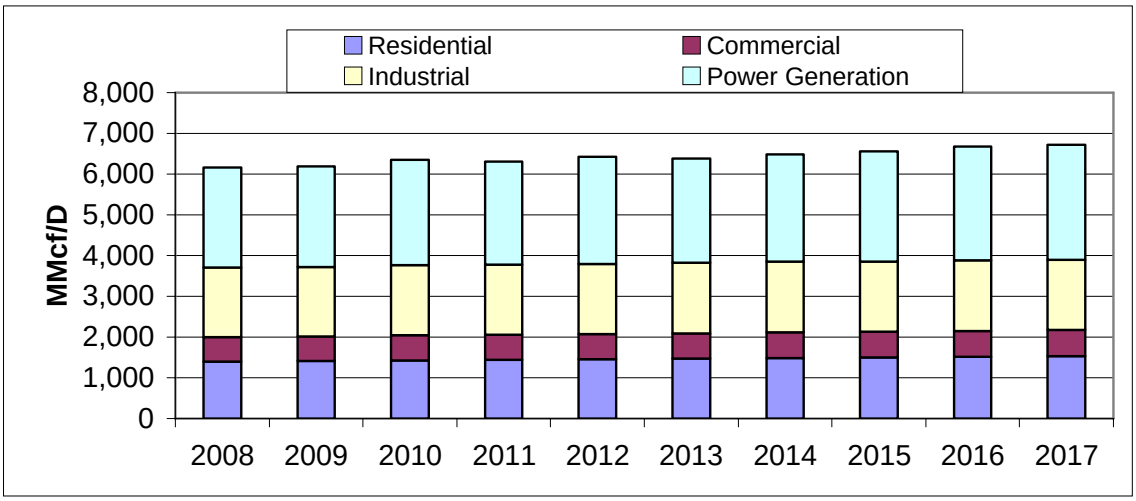
[277] Pacific Gas & Electric Company letter commenting on the August 16, 2007 IEPR Workshop.

Figure 6-9. Projected California Demand by Sector 2008-2017



Source: California Energy Commission

California's demand for natural gas will slowly increase over the next decade with the electricity sector being the largest driver

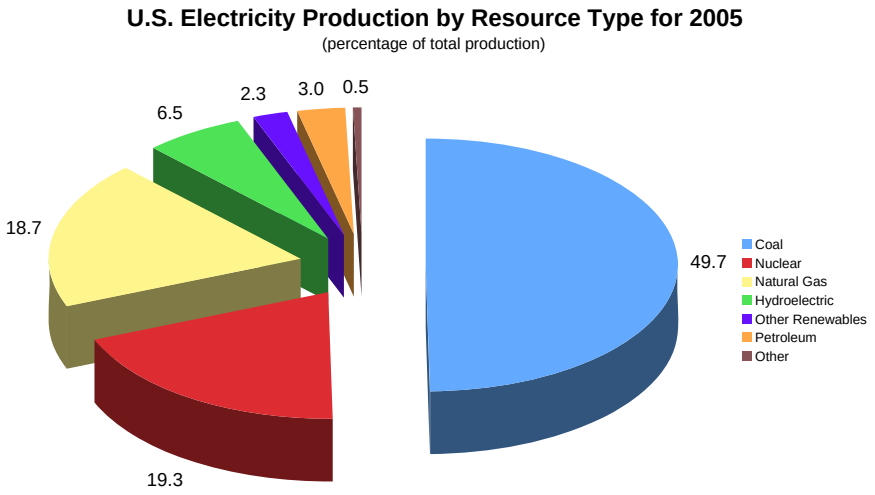
Currently the United States, Canada and Mexico consume about 74.5 billion cubic feet of natural gas each day. This demand is expected to increase 2.3 percent each year, reaching over 89 billion cubic feet per day by 2017. Although the United States is the dominant consumer of natural gas, at 83 percent of total demand, it could experience the slowest growth rate of 2.1 percent each year over the next 10 years when compared to Canada and Mexico's combined demand growth at 3.1 percent each year.

Electricity Generation - the Driver Behind Robust Demand

Today coal makes up almost 50 percent of the United State's electricity generation (Figure 6-10). As more states follow California's lead and substitute natural gas in the electricity generation sector to cut criteria pollutant and greenhouse gas emissions, this demand growth for natural gas will only continue. Electric power generation in North America is projected as the fastest growing end use for natural gas at 5.7 percent each year. By 2017, daily natural gas consumption for electricity generation will almost double from the current 17 billion cubic feet daily to 30 billion cubic feet each day.

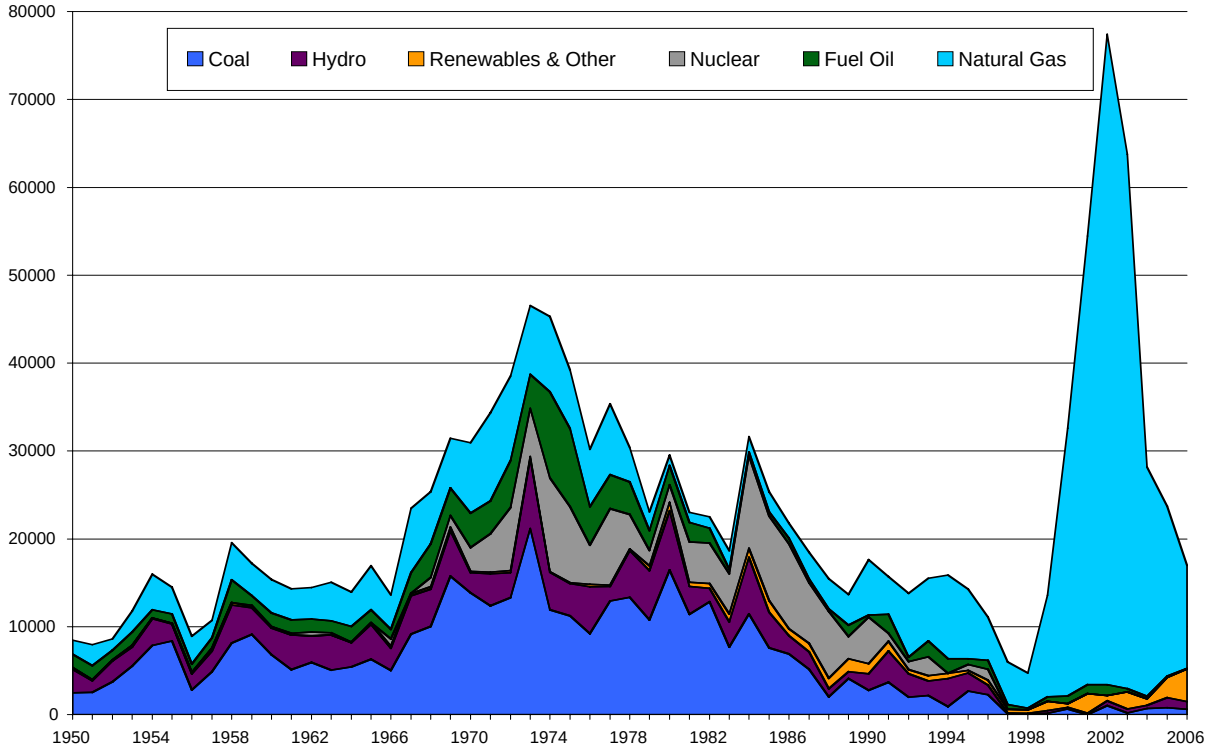
If the eastern United States and Canada adopt more aggressive strategies to reduce greenhouse gas, demand will rise even faster as their coal plants are replaced with cleaner burning natural gas fired ones. More than 100,000 megawatts of merchant owned natural gas-fired generation facilities were constructed throughout North America over the last 10 years (Figure 6-11). Currently these facilities are using less than their full generating potential, increasing the possible likelihood for quick, large jumps in natural gas demand if a shift from coal and oil occurs. From 1998 to today, when North America constructed the majority of natural gas fired generating capacity, California added almost 13,000 megawatts of gas-fired generating capacity.

Figure 6-10. United States Electricity Production by Resource for 2005



Source: U.S. Energy Information Administration, Form EIA-880, "Annual Electric Generator Report."

Figure 6-11. North American Capacity Additions Since 1950 in Megawatts



2007 Energy Information Administration Data

Construction of natural gas facilities skyrocketed in 2002 driven by merchant financing. Most of these facilities are not operating at their potential capacities leaving room for increased natural gas use when North America moves from coal supplied generation.

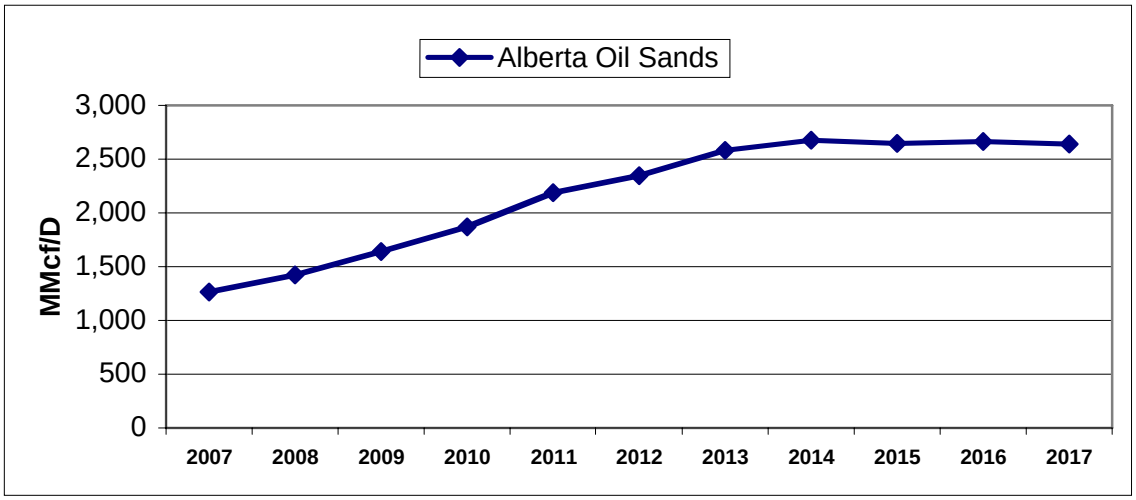
Even with this extra electricity generation potential there is still not enough capacity to meet growing demand in North America. The rest of the United States must begin choosing from a mix of coal, natural gas and renewable resources to meet their growing electricity demand. Facing the anticipation of more stringent environmental regulations, more utilities coast to coast are abandoning their plans for coal plants because conventional coal plants are too dirty and the cost of cleaner facilities too high. Decisions made 25 years ago by the rest of the country as to what they chose as the fuel for their electricity generation system did not affect California. Today these decisions do. And California has helped push those choices towards natural gas, with SB 1368 which prohibits California utilities from renewing or entering into new long-term contracts with out-of-state generators that are not providing electricity from plants as clean as natural gas-fired power plants. Given the national supply constraints, the more natural gas other states use, the less is available for California and the more prices could increase.

Although demand throughout North America impacts California, natural gas demand in the western United States and western Canada influences California more. Expected natural gas demand in the western states and Canadian provinces has a direct influence on gas prices and the ability for California to secure its necessary supplies. By 2017, the western United States and western Canada will be consuming over 1.6 billion cubic feet more of natural gas each day to meet the growing needs of residential, commercial, industrial and electricity users. Most of this new demand will be to generate electricity.

Alberta Oil Sands Production Uses More Natural Gas

Western Canada accounts for roughly 98 percent of Canada's gas supplies. Production for the Western Canadian basin is expected to decline slightly over the next decade so any increase in demand for natural gas in Canada reduces available gas exports to the United States, which has a direct impact on California's supplies and prices.

Figure 6-12. Alberta Oil Sand Production Increases Natural Gas Demand



Source: California Energy Commission, 2006 Natural Gas Staff Assessment

Natural gas demand doubles in the next decade as soaring oil prices push Canadian oil sands production.

Currently, Alberta oil sands are consuming approximately six percent of the natural gas produced in western Canada. Producing oil from these sands is costly and requires large quantities of natural gas; however, even in the $35 per barrel range, it is profitable to extract. With current oil prices hitting $80 per barrel, every effort is being made to produce as much as possible. More oil production means more natural gas from the western Canadian sedimentary basin consumed locally and less available for exporting. By 2017, the oil sands are projected to consume approximately 2.6 billion cubic feet per day or about 15 percent of the forecasted gas production in the basin. (Figure 6-12)

The Ontario region of eastern Canada is anticipating increased natural gas demand as coal-fired generation is curtailed to meet recent greenhouse gas reduction requirements.

This increase in natural gas demand in western and eastern Canada impacts the amounts of natural gas Canada will have available to export to the United States. The United States will have to either seek additional LNG imports or prices will have to increase enough to encourage more unconventional North American production.

Demand Impacts Natural Gas Prices

Natural gas prices ebb and flow with demand and supply availability - and demand for natural gas is increasing throughout North America. Even though the record-breaking prices of $14 to $16 per thousand cubic feet caused by Hurricanes Katrina and Rita in 2005 have declined, wholesale prices are still much higher than five years ago. Natural gas prices that were expected to go back to pre-hurricane and pre-energy crisis levels have stayed high. Declining rates of finding new North American natural gas supplies, uncertainty over LNG imports, proposed carbon controls to reduce greenhouse gas emissions and a growing population has continued to push national prices higher. Natural gas is not immune to wide price swings but it seems unlikely prices will return to the 1990s era of cheap natural gas.

As noted earlier there is basically one natural gas market in North America; however like any commodity, there are regional price variations that reflect different levels of demand, supplies and pipeline capacities. The Energy Commission staff estimates national wholesale prices ranging from $4.50 to $6.25 per thousand cubic feet in 2007 to increase 30 to 40 percent over the next 10 years to $6.75 to $8.25 per thousand cubic feet.

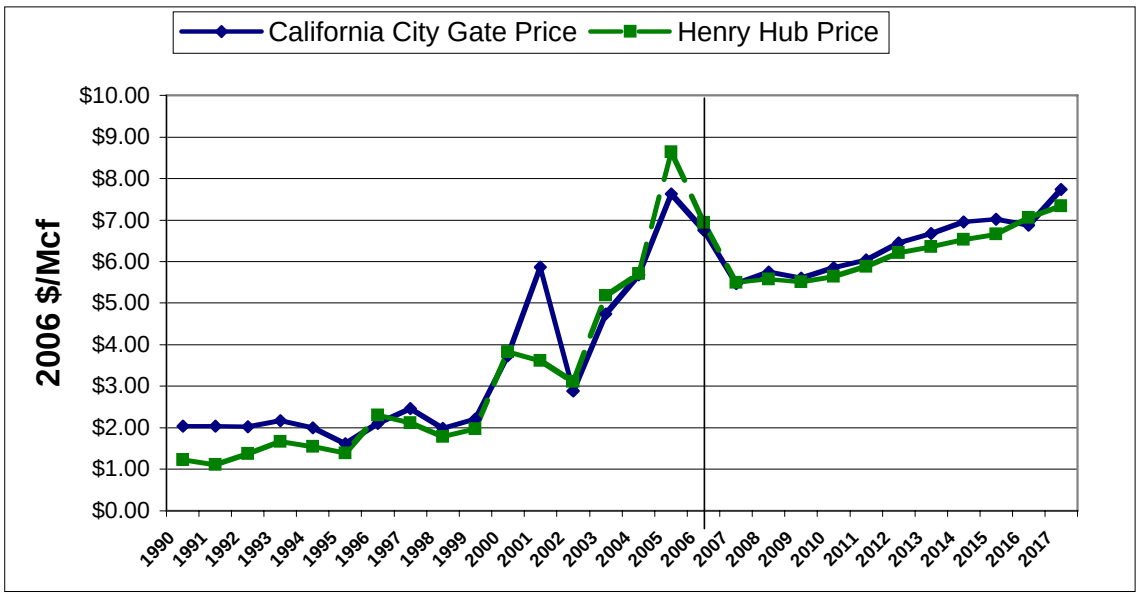
Higher natural gas prices can mean higher gas bills for customers if consumption stays the same, especially for those using natural gas to meet their heating needs. At the wholesale level, higher natural gas prices also mean higher costs to generate electricity, which translate into higher costs for electricity ratepayers.

The California City Gate Price, or price paid by the utilities before the gas is distributed, was very stable during the 1990s. But in recent years this price has become much more volatile as

the state faces more competition for natural gas from its traditional supply sources just as many of the major producing basins in the west have peaked in their ability to increase production.

The forecast indicates an increasing California city gate price. Over the forecast period the City Gate price is expected to increase at a rate of 3.5 percent annually, slightly higher than the forecast annual increase for the Henry Hub price of 2.9 percent. (Figure 6-13) The Henry Hub is the wholesale price for natural gas processed in the Gulf Coast that serves the eastern United States.

Figure 6-13. Wholesale Natural Gas Prices – California compared with Henry Hub (National)



Source: California Energy Commission

California market behavior has effectively no influence over short-term national natural gas market prices. Even when California's own demand is moderate, in-state prices can spike in response to extreme weather conditions in other parts of the country. Although natural gas prices could decline slightly in the near term with the introduction of newer supplies into the market, Energy Commission staff projects a slow increase in national natural wellhead gas prices over the next decade as conventional sources are replaced by more expensive unconventional ones. This slow rise reflects the growing difficulty of producing natural gas in North America conventional production areas; however, it does not account for market volatility and short-term price spikes.

Over the next 10 years, the Energy Commission estimates that residential gas prices will fluctuate between $9.90 and $12.70 per thousand cubic feet or 99 cents and $1.27 per therm. Based on staff's forecast, this increase could be as much as $150 annually for the average residential household's gas bill. However, the impact will be reflected in electricity bills as well.

According to a 2006 California Natural Gas Study Advisory Committee[278] report, if natural gas prices rose to $1 per therm, the average California household would experience a combined increase of $339 annually for natural gas and electricity.

Commercial customers can expect to pay between $8.90 and $11.70 per thousand cubic feet over the same period, depending on the service territory. Natural gas prices for industrial customers track similar trends as those for other California customers but at lower levels. Industrial customers usually purchase their gas directly, reducing delivery and storage costs for the utilities and could expect to pay between $7.10 and $9.80 per thousand cubic feet over the next decade. If the cost of doing business becomes too high for gas-intensive industries like fertilizer and chemicals to earn a profit, they may move their operations to other countries where costs are more affordable.

California's electricity generators are estimated to pay between $5.10 and $8.60 per thousand cubic feet through 2017 and prices vary based on whether or not the generator is served by a natural gas utility or takes its fuel supplies directly from another source, such as an interstate pipeline or local gas producer.

Unanticipated weather or political events that might influence demand are not considered in the Energy Commission's price projections. The model is based on long-term market fundamentals that drive the supply-demand balance in a normal, well-functioning market.

What Happens to Price if Production Drops?

What happens to price if the gas industry is not able to stay on the production treadmill and maintain supplies to meet current demand? Most experts agree that North American natural gas production will decline as well productivity continues to drop. And as discussed, it is difficult to imagine that the industry can complete the necessary 50,000 to 60,000 wells in 2017 for production to keep pace with demand. Staff examined a *scarcity case* that assumed that natural gas production would fall by 35 percent below the forecasted levels (Figure 6-14). The results show natural gas prices increase over 50 percent in each year from 2009 to 2020 and by 2015 the prices increase from $5.99 to $10.13 per thousand cubic feet. This scenario is not meant to predict but rather describe the consequences if a decline in North American natural gas production occurs. The case requires further adjustments and evaluation on the demand side of the model used before a complete understanding of the impact of low domestic natural gas supply is understood.

Given the consequences for California, the Energy Commission will monitor North American natural gas production for signs of decline or production difficulties. Unless the productivity of new natural gas wells stops deteriorating, the number of wells required just to maintain production will exceed what is likely to be economically or physically possible.

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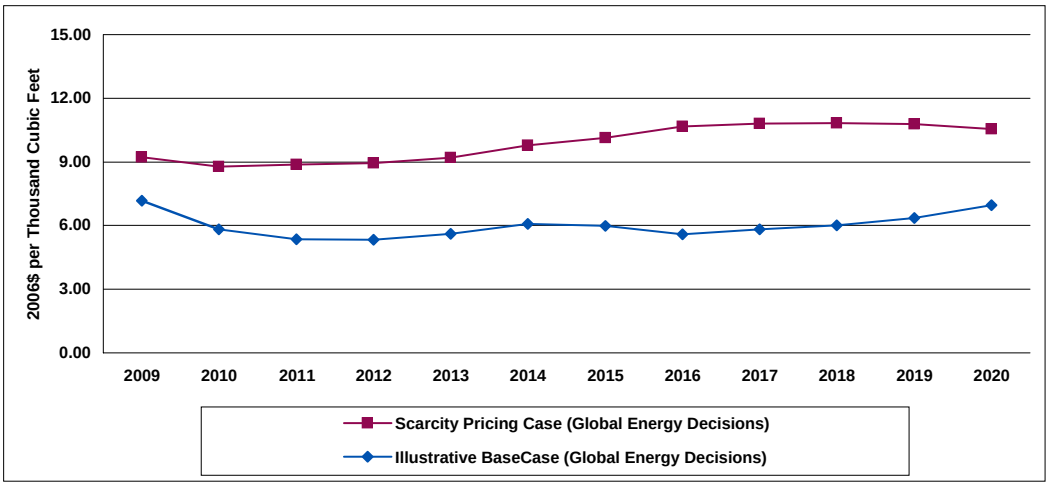
278 *The Impacts of Natural Gas Prices on the California Economy* by Global Insight, 2006

It is time to recognize that alternatives to North American natural gas are essential, and will likely require increased amounts of the preferred resources of energy efficiency combined with renewables and other natural gas sources such as LNG.

Figure 6-14: Illustrative Scarcity Price Compared to Illustrative Base Case



Source: California Energy Commission

Natural Gas Demand and AB 32

Energy Efficiency

Energy efficiency has always been the most effective way to reduce demand and still increase productivity. It has played a major role in establishing California as one of the lowest per capita energy users in the nation. Even though today's homes are larger and have more appliances, California households use almost half the natural gas that households used in 1977. California's Building and Appliance Energy Efficiency Standards are the foundation of the state's energy efficiency policy and have been instrumental in helping to reduce natural gas use. The CPUC in recent years has authorized an additional $300 million for funding utility natural gas efficiency programs, setting aggressive goals to double annual natural gas savings by 2008 and triple savings by 2013.

Efficient Natural Gas-Fired Generation

New natural gas-fueled electricity generation technologies offer efficiency, environmental and other benefits to California, specifically by reducing the amount of natural gas used and with less natural gas burned, fewer greenhouse gas emissions. Older combustion and steam turbines use outdated technology that makes them less fuel- and cost-efficient than newer, cleaner plants. They waste two-thirds of the natural gas they use to make electricity – they are only 33 percent efficient. The state has about 16,000 megawatts of aging natural gas-fired electricity generating capacity, many of these units are between 26 and 62 years old and reaching the end of their assumed operational lifetimes. Because these facilities take too long to ramp up to

provide electricity when needed, they are idled during the low demand season, burning natural gas and emitting greenhouse gas emissions but producing no electricity. Yet, as electricity demand grows, California remains dependent on these older plants for summertime peak power. California must take serious steps to retire these aging facilities that are being misused as peakers and replace them with newer technology that can more effectively provide electricity when needed without added emissions.

Today's natural gas-fueled electricity generation technology offers more efficient and reliable generation with about one and a half times increased efficiency, reducing the amount of natural gas consumed by 50 percent. These combined heat and power facilities can be particularly efficient when a heat recovery steam generator to power a conventional steam turbine in a combined cycle configuration captures waste heat from the gas turbine. They can also be run in a cogeneration configuration: the exhaust is used for space or water heating, or drives an absorption chiller for cooling or refrigeration. This type of cogeneration configuration can be over 90 percent efficient.

Combined heat and power facilities must provide a larger role in meeting California's electricity supply needs. The *2003 and 2005 Energy Reports* noted that the state could help reduce natural gas consumption for electric generation by taking steps to retire older, less efficient natural gas power plants and replace or repower them with new, more efficient combined heat and power facilities.

Natural gas efficiency is also a priority in the Energy Commission's natural gas research, development and demonstration program. In the last two years the Energy Commission established a Public Interest Energy Research Program on Natural Gas. With a 2007 budget of $18 million, this program has focused half of its funding on energy efficiency projects linked to the state's natural gas efficiency programs. Future reports will have more specific information on natural gas efficiencies from this program.

Renewables in Electricity Generation

Today California generates almost 11 percent of its electricity from renewable resources – solar, wind, geothermal and biomass. Meeting California's Renewable Portfolio Standard (RPS), which requires that 20 percent of California's electricity supplies must be from renewable energy by 2010, is essential in reducing the growth in natural gas use for electricity generation and help in meeting the AB 32 goals. The state also has a goal of achieving 33 percent renewables by 2020. For the most part, the investor owned utilities have been slow to embrace the RPS and less than 400 megawatts of renewable resources have been brought on-line in the five years since the RPS was enacted, although nearly 5,000 megawatts of new contracts have been signed.

Coupled with expanding energy efficiency and demand response programs, California could reduce projected electric generator natural gas demand by 37 percent in 2020 if preferred energy efficiency and renewable resources are increased as described in Scenario 5A. And if the same assumptions were applied to California and the Western Electricity Coordinating Council

(WECC) under Scenario 5B, California could reduce electric generator gas demand by 51 percent from projected 2020 levels.

The Effect on Natural Gas Prices by Reducing Demand

What happens to natural gas prices if demand for natural gas is reduced? Previous studies have found that reducing electricity demand through increased amounts of preferred resources lowers natural gas prices. This conclusion could help drive public policy to choose preferred resources over other conventional fuels. Staff's analysis looked at two models[279] from the Scenario Analysis Project; Case 1 using just enough efficiency and renewables to meet the RPS goals and Case 5B using high levels of efficiency and renewable energy in the WECC electricity resource mix. Results showed that the difference in natural gas demand for the electricity sector between Case 1 and 5B *averaged* a 36 percent decline from 2009 to 2020, as more preferred resources were incorporated into the WECC region's electricity supplies. The region's total natural gas demand for all sectors, including residential, commercial and industrial, decreased 2 percent in 2009 to 26 percent by 2020. And North American demand declines ranged from 0.2 percent in 2009 to 2.5 percent in 2020.

What did this mean for prices? The staff used two different models to answer this question. By lowering natural gas demand, the average wholesale (Henry Hub) price forecast for the WECC declined an average of 15 percent from $5.92 to $5.15 per thousand cubic feet in the first model compared to an average of just over 2 percent in the second model. Both these studies concluded that increasing energy efficiency and renewables in the electric sector reduces natural gas demand and may bring downward pressure on natural gas prices for all customers.

Natural Gas as a Complementary Strategy to Meet Greenhouse Gas Emission Reductions

As our population continues to grow, California manages to keep natural gas demand for residential, commercial and industrial customers to less than one percent growth each year respectively. Higher gas prices and aggressive efficiency and renewables programs have helped to slow demand, even in the electricity generation sector. Compared to the East Coast's projected growth rate of 6.4 percent each year for electricity generation, California's slower annual 1.4 percent increase in the electricity generation demand seems slight. However, electricity generation combined with the other sectors will add 827 million cubic feet more each day to California's already enormous natural gas demand – a total of almost seven billion cubic feet daily by 2017.

Growth in natural gas used to generate electricity may exceed even these estimates under certain greenhouse gas reduction measures. For example, scenario analysis calculated that if a

[279] Altos and Global Energy natural gas demand; Scenario Analysis Project - *Second Addendum Report*

$60 per ton of carbon price were attached to CO2 emissions, projected levels of coal-generated electricity in the WECC would decline by about 30 to 40 percent in 2020. As a result, natural gas burned to generate electricity in California would increase by about 20 to 70 percent depending on the amount of preferred resources. Natural gas consumption in the WECC would increase between 35 to 127 percent.

Reducing the amount of coal used to generate electricity with a combination of preferred resources and natural gas and in the context of $60 per ton of carbon charge increases natural gas use in California and throughout the WECC.

Natural gas is and will remain the major fuel in California's supply portfolio and must be used prudently as a complementary strategy to reduce greenhouse gas emissions. Not only does the state have a mandate to cut greenhouse gas emissions, we also have a responsibility to provide a reliable and affordable fuel source for home and business use.

Recommendations and Action Steps

- The Energy Commission advocates policies that allow California to secure alternative and diverse sources of natural gas to meet growing demand and energy security options, including support of liquefied natural gas facilities on the West Coast that can be licensed to meet environmental and public health and safety standards.
- The Energy Commission supports all cost effective energy efficiency measures for natural gas including replacement of aging power plants with new efficient power plants, especially those operated in a combined heat and power configurations.
- The Energy Commission encourages renewable sources of energy to generate electricity, as well as sources—such as solar for water and space heating—that directly displace natural gas.
- The Energy Commission will continue to incorporate new analytical tools such as Scenario Planning and Portfolio Analysis in assessing and forecasting the state's natural gas supplies and demand to meet reduced greenhouse gas emission targets. The Energy Commission will encourage the Public Utilities Commission to participate in these analytic efforts.
- As the Energy Commission has determined that there are uncertainties in forecasting natural gas production, demand, and price, we will pursue the following actions in the 2009 Integrated Energy Policy Report cycle.
    - Conduct a rigorous verification of the models used to forecast natural gas supply and price by evaluating the reasonableness and economic and physical likelihood of the model results based on a range of factors including number of new wells, initial rates of production, depletion rates, and other variables
    - Develop probabilities and quantify outcomes for demand scenarios to gain better insight into natural gas demand, including a) scenarios that assume an expanded consumption of preferred resources, b) adoption of electricity as the best fuel

strategy, c) displacement of new coal plants with natural gas plants in the Western Electricity Coordinating Council and the eastern United States, and d) levy of a carbon charge on the use of coal to generate electricity.

- The Energy Commission must pursue energy efficiency improvements through increased natural gas research and development.

CHAPTER 7: Meeting Transportation Needs

Californians have had a love affair with the automobile and the open road since the 1920s. Perhaps no other population in the world has embraced the automobile as passionately as Californians and probably no other state is defined as much by the car as California.

Cars give Californians the individual freedom and autonomy we crave. But, this freedom comes with a high price, both to the environment and consumer pocketbooks. Vehicles are the major contributor to global warming pollution. Almost 40 percent of carbon dioxide (CO_2) and other greenhouse gas emissions in California are caused from burning transportation fuels, mainly gasoline and diesel in cars and trucks. We must change our relationship with automobiles and the way we view transportation—at a personal as well as a state policy level.

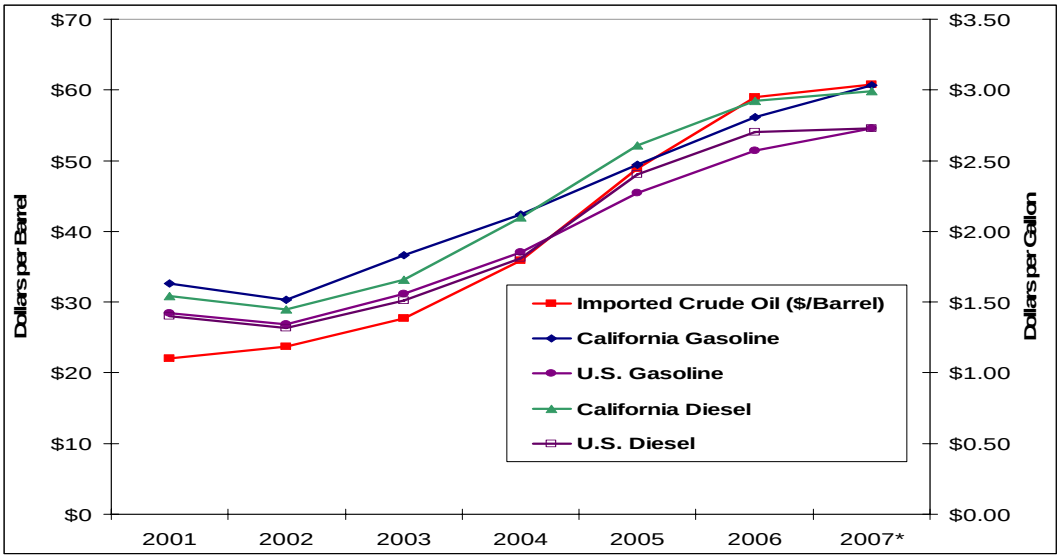
Transportation dominates California's overall energy consumption. Almost half of all energy used in the state moves people and goods – and nearly 100 percent of fuel demand is met by petroleum. The state's nearly 26 million registered vehicles consume about 380 million barrels of gasoline (over 16 billion gallons) and almost 100 million barrels of diesel (over 4 billion gallons) each year. California is the second largest consumer of gasoline in the world, behind the entire United States and just ahead of Japan.

Sustaining California's economic vitality in the short term depends on ample supplies of gasoline and diesel fuels at stable prices. California has neither.

California's gasoline prices, due to high oil prices as well as in-state refinery maintenance problems and breakdowns, reached a record high of $3.46 per gallon during May 2007 (Figure 7-1). In addition to reducing the real income of consumers forced to pay higher fuel prices, increases in crude oil prices drive up the average cost of production of goods and services throughout the economy. This negatively affects the state's economy and gross state product. Major petroleum price hikes; such as those experienced in 1973-74, 1979-80, and 1990; all led to national recessions.

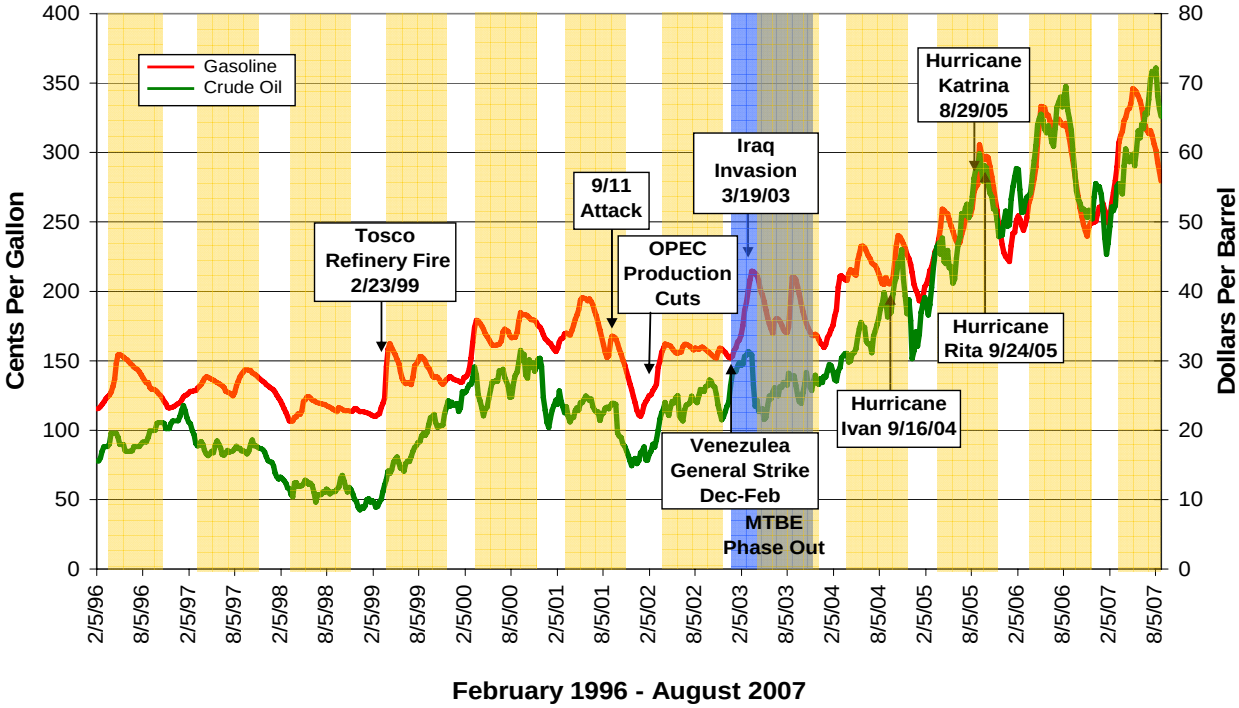
Crude oil is the single largest cost component in producing gasoline and diesel, accounting for between 42 and 56 percent of the price of regular gasoline in the last year. World oil prices have more than *doubled* since 2004. Skyrocketing demand in China and other developing nations, along with current world conflict, particularly in Nigeria and the Middle East, are exacerbating the situation. Other factors such as weather and geopolitical events also affect crude oil and gasoline prices (Figure 7-2).

Figure 7-1: Gasoline, Diesel and Crude Oil Prices



Source: California Energy Commission

Figure 7-2: California Gasoline and World Crude Oil Prices



Source: California Energy Commission

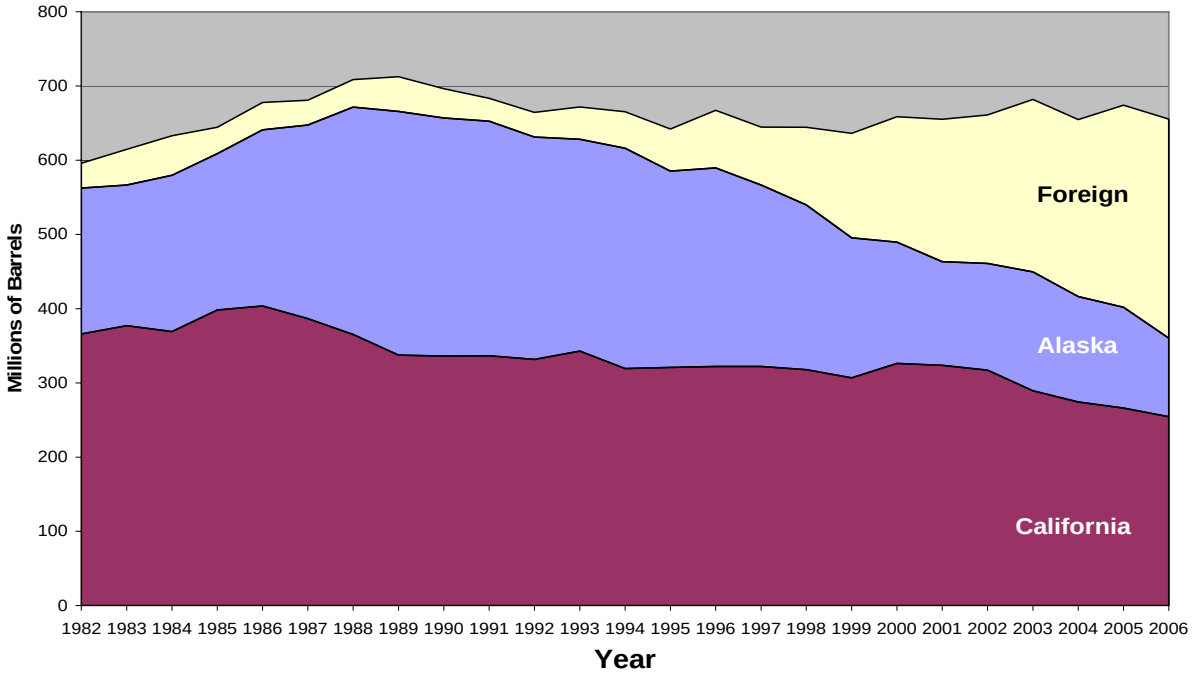
Notes: Shaded Regions represent periods of summer gasoline blends, produced from February through October in Southern California and from March through October in Northern California. California became a gasoline net importer sometime in the late 1990s. Oil prices triple between January 1999 and September 2000 due to strong oil demand and OPEC oil production cutbacks

By September 2007, crude oil prices had exceeded $80 per barrel. Crude oil, regardless of its origin, is pegged to world oil prices, and these price trends emphasize the importance of reducing our growing dependence on foreign oil sources.

Twenty-five years ago, California received 94 percent of its crude oil supplies from in-state production and Alaskan imports, with foreign sources contributing little (Figure 7-3). By 2006, the situation had reversed, with foreign imports making up 61 percent of the crude oil refiners use. Declining in-state production and limited refining capacity means that California has to import ten percent of its refined blending components and finished gasoline and diesel to meet growing demand.

Adding further challenges, California's petroleum infrastructure operates at near capacity and the volume of imports is constrained by limited storage capacity and marine terminal capabilities at Southern California ports.

Figure 7-3: California's Crude Oil Sources



Source: California Energy Commission

Breakdowns and outages at in-state refineries and pipeline facilities quickly tighten gasoline and diesel supplies, creating price spikes. California is not directly connected by pipeline to other domestic refining centers, and in-state refiners cannot readily procure gasoline, diesel, and other blending components when outages occur. Relying on imports of petroleum and

finished product coming into this constrained infrastructure environment creates a market conducive to extreme price volatility. This contributes to higher and more prolonged price spikes, as we have experienced over the last several years.

Transportation Fuel Demand Trends

In the past 20 years, California's population has increased at an annual average rate of 1.7 percent per year and personal income has increased at 1.58 percent per year. Over the 2005 to 2030 time period, projections forecast a slowing of growth for both population and income, to 1.04 percent and 1.08 percent per year, respectively.[280] Nevertheless, California's population is estimated to exceed 44 million by 2020. Even if not climbing at historic high rates, the total growth will be considerable and result in substantial increases in transportation fuel demand for the state.

Besides population growth, California's transportation fuel demand is affected by many other factors, including economic growth, fuel prices, and consumer behavior such as vehicle purchasing and driving habits. Energy Commission staff developed several demand forecasts with different levels of transportation fuel consumption and several variable factors such as fuel prices, technology developments, and greenhouse gas reduction regulations. For petroleum supply and imports, staff developed cases that varied according to assumptions about crude oil production, refinery and pipeline expansion projects, port and marine terminal capacities, and California and neighboring state fuel demand.

Increasing demand is one factor that drives gasoline prices (Figure 7-4). Potential growth for both gasoline and total transportation fuel demand (gasoline, diesel, and jet fuel) is illustrated for the High Demand Case and the Base Demand Case (Figure 7-5). Gasoline use in California will increase steadily at an average annual rate of 0.76 to 1.63 percent through 2012. From 2012 to 2020 gasoline demand declines at an average annual rate of 0.07 to 0.98 percent. This downturn in the rate of growth of gasoline demand occurs in both cases because more hybrid-electric and diesel light-duty vehicles are assumed to enter the fleet. In the Base Demand Case, greenhouse gas standards and higher fuel prices also reduce fuel demand growth.

While gasoline demand is expected to peak and then fall, total transportation fuel demand will continue to increase through 2020. Total gasoline, diesel, and jet fuel demand increases at an average annual rate of between 0.96 and 1.61 percent by 2020, growing from 553 million barrels per year in 2005 to between 638 - 702 million barrels per year.

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[280] Based on population projection series from the Department of Finance's July 2007 report, *Population Projections by Race / Ethnicity for California and Its Counties 2000–2050* (population growth rate of 26% for the 2005-2030 timeframe) and demographic data obtained from California Energy Commission Demand Analysis Office.

Figure 7-4: Projected California Gasoline Prices

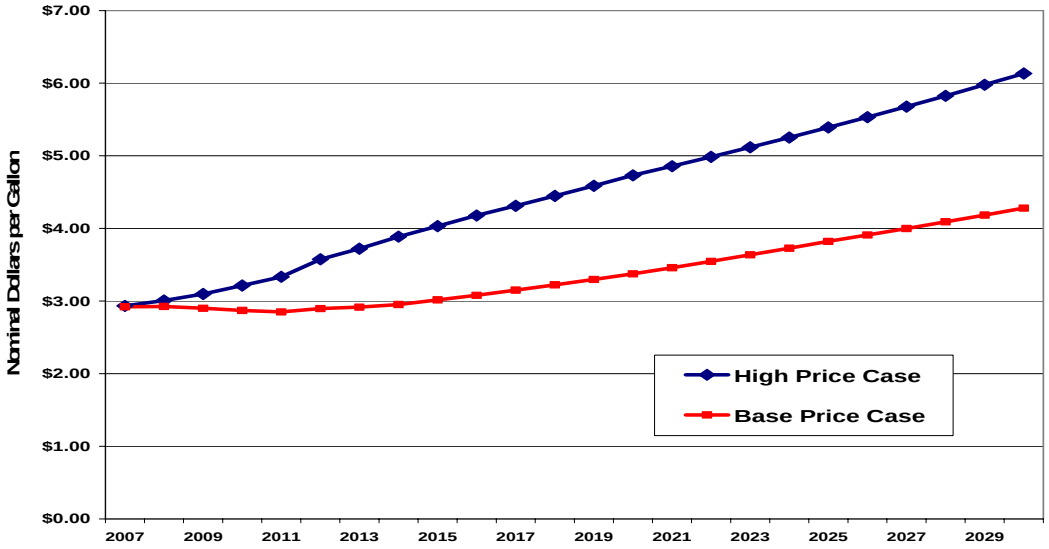
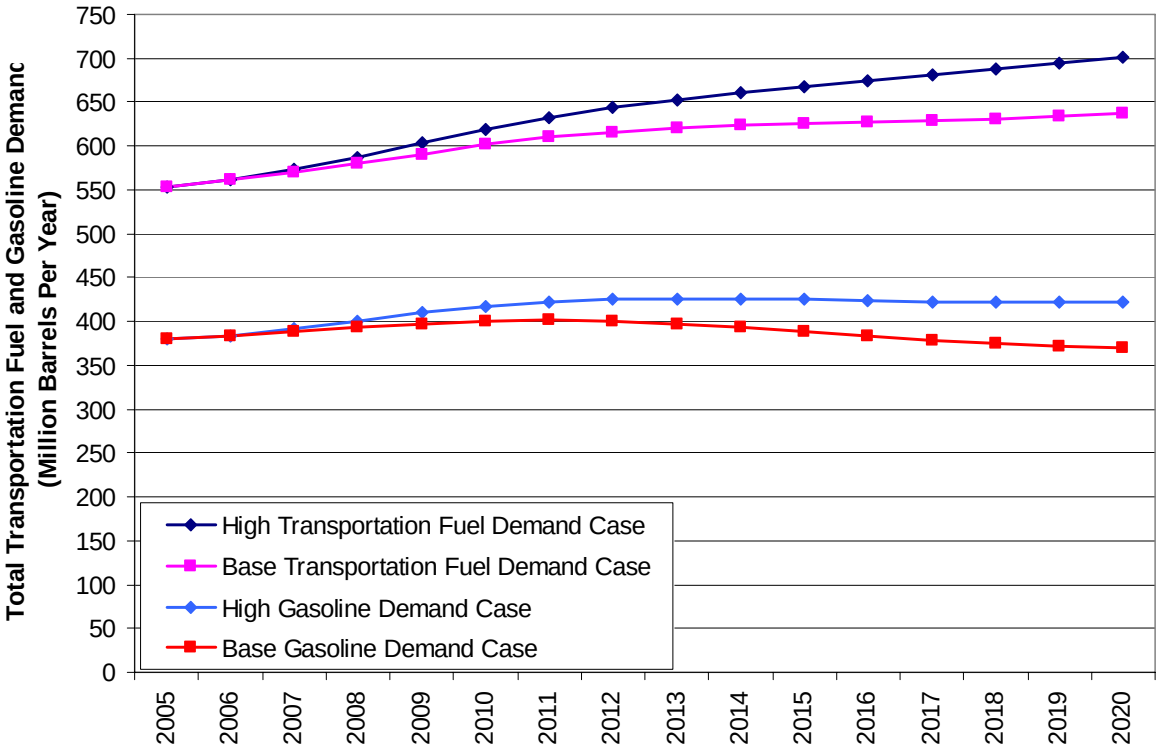


Figure 7-5: Transportation Fuel Demand



Source: California Energy Commission

Diesel fuel is expected to steadily increase its share of the transportation fuel market. Diesel consumption in freight, transit, and off-road uses is expected to continue to grow with

population and economic growth. In these sectors, diesel use will also be largely insulated from dramatic changes in vehicle fuel efficiency. At the same time, diesel is poised to make major penetrations in the light-duty vehicle market because of its marked fuel efficiency advantages compared to gasoline vehicles. Total state diesel use is projected to grow at an annual average rate of 3 percent to 3.5 percent per year through 2020.

Commercial jet fuel use in California is estimated to grow at an annual average rate of 2.9 percent to 3 percent. Future commercial jet fuel use is calculated by using forecasts of the number of passengers boarding each plane and depends on population growth and projections of revenue per passenger mile. Different paths for future jet fuel prices may cause airlines to change the quantity of jet fuel used. However, federal projections of airport capacity at Los Angeles International, San Francisco International, and San Diego International airports indicate that constraints largely limit growth so that demand levels in the High and Base Demand cases do not differ very much through 2020. In addition, fuel prices are around 25 percent of total airline expenses, so the price signals that might otherwise alter demand are dampened.

California has been called an "island" in terms of petroleum markets, but is in fact an integral part of the larger West Coast and Pacific market regions. In addition to being partially integrated with refinery operations in Washington, California supplies virtually all of Nevada's transportation fuels and over 60 percent of Arizona's, as neither of these landlocked states have any refineries (Figure 7-6). California refineries also provide 35 percent of Oregon's fuels. These refineries export petroleum products via pipelines that are linked to distribution terminals located in Reno, Las Vegas, and Phoenix. This network of interstate pipelines is owned and operated by the Kinder Morgan Pipeline Company (KMP). Demand for transportation fuels in each of these states is increasing rapidly. To meet this growing demand, pipeline exports from California to Nevada will increase at an average annual rate of 2.1 to 2.9 percent per year and exports to Arizona will increase at a rate of 2.4 to 2.6 percent per year from 2006.

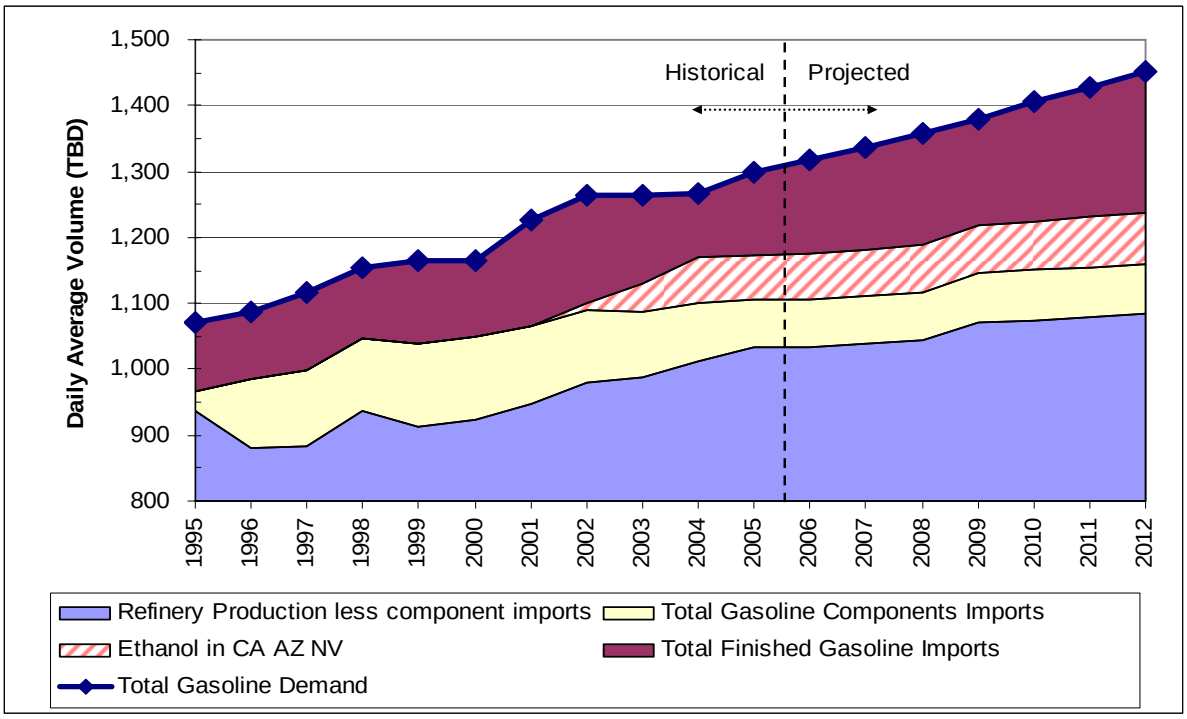
California Ethanol Demand

Currently, substantial volumes of ethanol are blended into the gasoline pool. In the near future, California ethanol demand is expected to increase primarily from changes to California's gasoline regulations and other efforts to increase the use of alternative fuels (such as the Low Carbon Fuel Standard). Energy Commission staff believes the majority of California's gasoline market will contain E-10 by 2012. As such, ethanol demand in the state under the Base Case gasoline demand scenario is expected to jump from almost 23 million barrels in 2006 to approximately 40 million barrels in 2012, a 10 percent annual average rate of growth.[281] The

[281] In the high gasoline demand and limited in-state ethanol production scenario, incremental imports of ethanol could grow to 35 million barrels per year by 2020 compared to 2006 import levels of 22 million barrels. Assuming lower gasoline demand and higher in-state ethanol production, ethanol imports could actually decline to 21 million barrels by 2020.

additional imports needed to meet this anticipated growth will depend on how many additional California ethanol production facilities are constructed over the next few years.

Figure 7-6: Regional Gasoline Supply Demand for California, Arizona and Nevada



Source: California Energy Commission; *2006 Price Spike Report*

As of July 2007, California had an ethanol production capacity of 1.8 million barrels per year. Based on additional projects already under construction, in-state ethanol production capacity is estimated to increase to at least 5.5 million barrels per year by 2009. If other projects in advanced stages of planning and financing are also pursued to completion, conventional ethanol annual production capacity could reach 16 million barrels by 2012.

The Energy Commission expects California's future transportation fuel demand to increase regardless of which price scenario and regulatory conditions are assumed. However, the magnitude of future contributions from various emerging alternative transportation fuels and technologies is unknown. Potentially, these emerging fuels, such as ethanol and biodiesel, can displace significant amounts of petroleum, which may change the mix of required infrastructure enhancements in the future. However, many of these alternative fuels, in particular renewable fuels, may also require their own additional segregated import facilities, including pipelines and storage tanks.

California must continue to meet its growing transportation fuel needs and must further consider the impacts of these needs while meeting the targets of reducing greenhouse gas emissions. To meet these needs the state must address to major areas of concern: the

constrained petroleum infrastructure and options to reduce petroleum dependency – alternative fuels, emission and vehicle standards – that trims down our carbon footprint.

California's Petroleum Infrastructure

California cannot reliably meet its increasing fuel demand without a robust petroleum infrastructure that includes refineries, storage, pipelines, distribution terminals and marine facilities. The *2005 Integrated Energy Policy Report* noted that although there had been some necessary improvements made to portions of the infrastructure, California must further expand its marine terminal capacity, marine storage and the pipelines connecting these facilities with the refineries and other pipelines if we are to meet our rising fuel demand.

Little has changed since the *2005 Integrated Energy Policy Report*; in fact, the outlook for the marine infrastructure has worsened. Staff projects that overall fuel demand will continue to grow, increasing imports through a marine infrastructure that is already congested and that exceeds infrastructure capacity expansions currently under construction or to which the industry is committed.

Whether California consumers and businesses have adequate supplies of transportation fuels over the forecast period will be determined by existing spare capacity, magnitude and timing of marine terminal expansion activity, and demand projections. Several conclusions from the *2005 Integrated Energy Policy Report* are applicable today:

- Important segments of the state's existing fuels infrastructure are already being used at or near their capacity.
- The current capacity of existing marine infrastructure, particularly in the Los Angeles and Long Beach marine terminals, could decline as a result of pressure to remove petroleum facilities from port areas and from requirements to meet seismic standards implemented by the State Lands Commission.
- Petroleum marine terminal capacity, marine storage, and gathering pipelines that connect marine terminals with refineries will have to expand to meet expected demand for fuels. Most of this expansion would occur in the Los Angeles Basin.
- Expansion of transportation fuel marine infrastructure will become more difficult in the Los Angeles Basin as available land becomes increasingly scarce and subject to competing uses and because residents, community groups, and local authorities have expressed substantial resistance to such expansion.

Effects of Competition for Existing Terminal and Storage Capacity

As transportation fuel demand and imports increase, facilities to accommodate the increased number of vessels carrying cargoes of crude oil, gasoline, diesel, and jet fuel must also expand. Without an adequate import infrastructure there will not be ample transportation fuels for the state. Marine terminals are naturally limited in their ability to operate at their theoretical

maximum capacity since it is difficult to precisely calculate a tanker's travel time and arrival (because of changing sea conditions) and unexpected delays in unloading cargo (lengthy inspections, processing delays in paperwork, and interruption of pumping operations during cargo discharge) automatically reduce the number of vessels a terminal can manage. Most marine terminals operate at 50 to 70 percent of their capacity, which is considered at or near maximum economic and safe operating levels. Having tankers wait at anchor in the harbor is impractical from both economic and safety perspectives and costly from the tanker owner's perspective.

Vessels unable to unload cargoes, despite an immediate need for the product, not only impact the tankers' owners with delays costs of $30,000 to $100,000 per day but consumers also pay a price for this congestion with increased retail costs. A 10-cent per gallon increase in gasoline, diesel, and jet fuel prices means over $6 million per day increased direct consumer expenditures on these fuels, depending on demand levels.

Congestion also leads to additional tankers at anchor in the port or nearby, which raises risk of serious accidents and even spills, and possibly increased emissions. Many harbors and waterways in California already have a significant amount of marine vessel traffic.

Over the past 15 years approximately six million barrels of storage tank capacity has been removed from Southern California. The potential loss of more existing marine terminal capacity from voluntary business decisions, involuntary forced closure due to current lease termination of or refusal by a lease holder to renew an exiting marine terminal operating lease erodes the ability to meet California's transportation fuel demand. Constrained storage capacity also limits increased imports of alternative fuels, in particular biofuels necessary to meet the state's goals for reducing petroleum use.

Challenges to Developing Additional Capacity

Efforts to expand existing or create additional petroleum infrastructure, specifically in the San Pedro Harbor, have been met with stiff resistance from some local community members, elected officials, and port representatives. Objections include concerns over increased air pollution, increased truck traffic, visual aesthetic opposition to the sight of storage tanks, perceived safety threats to nearby communities, and competition for diminishing spare land that is coveted by community members for park/recreational development and by port representatives for expansion of cargo container handling facilities.

Dredging and Maintenance Standards

Unlike facilities in the Los Angeles Basin, San Francisco Bay marine petroleum terminals face sizeable limitations caused by the relatively shallow depths of their shipping channels. The draft or depth that a vessel sits on the water, of modern very large crude carriers (VLCC) exceeds the depth of these shipping channels. This requires either more shipments by smaller tankers or transferring, called lightering, of loads from larger tankers that anchor in areas outside the constrained channels into smaller vessels that continue to the terminals. Lightering is strictly regulated by the Department of Fish and Game's Office of Spill Prevention and

Response and the United States Coast Guard and incurs extra costs, inefficiencies, time delays and risks that would be avoided by more direct access. In some cases, water depths near marine terminals are difficult to maintain at depths adequate for even smaller tankers.

Timely and reliable dredging of the Pinole Shoal sufficient to support marine shipments into the Carquinez Straits is an ongoing challenge. Environmental rules limits the time allowed when dredging activities can take place and where dredging spoils can be deposited. Most terminals in the San Francisco Bay area also require periodic maintenance dredging to offset silt deposits in nearby lanes. These logistical and permitting requirements do not prevent crude oil and transportation fuels deliveries but can lead to higher costs for producers and consumers. It is important that federal funding for Pinole Shoals dredging receive continuous high priority to ensure adequate shipping depths through the Carquinez Straits to upstream refinery marine terminals.

All California petroleum marine terminals are under a new set of regulations known as the Marine Oil Terminal Engineering and Maintenance Standards (MOTEMS), approved by the State Lands Commission in 2004. MOTEMS are a comprehensive standard for the design, construction, maintenance, inspection and repair of petroleum marine terminals. These standards primary purpose is to prevent crude oil and petroleum product spills. Since the average age of most of these marine terminals is more than 50 years, the design and configurations have not been updated to accommodate the growth in vessel size or structures. Applying the MODEMS will extend the life spans of these aging facilities and reduce their seismic, mooring and berthing vulnerabilities.

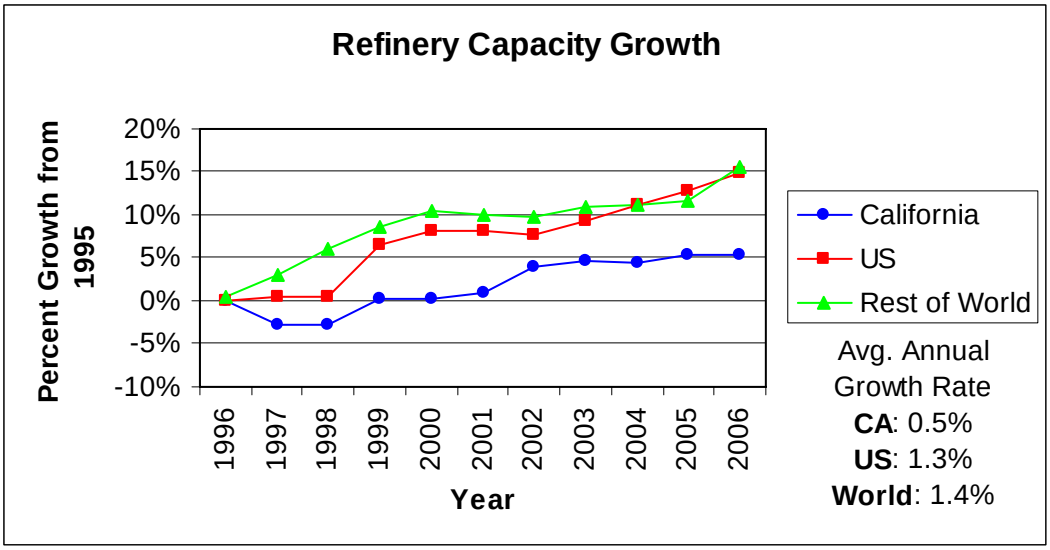
Some of the state's marine terminal network, especially in Southern California, will require substantial upgrades to meet these standards. These costly investments may cause short operational disruptions; however, some terminals in the San Francisco Bay have already performed these seismic and structural upgrades on a much larger scale. The MOTEMS regulations include compliance flexibility and an implementation schedule with flexibility dependent on annual funding limits, environmental restrictions and any other permit permitting or regulatory compliance issues. With some thought and good engineering, there should be almost no operational disruptions or fuels price impacts caused by MOTEMS compliance. It is important that Energy Commission staff continue to monitor progress toward compliance with MOTEMS as well as the actions by the ports to terminate leases to oil terminals to determine any potential impacts to the flow of crude oil and transportation fuels of these standards.

Refining and Storage Capacity

As the demand for transportation continues to grow throughout the world, refiners have responded by increasing the capacity to process crude oil. In 2005, California refineries processed 674 million barrels (1.8 million barrel per day) of crude oil; however, the state's refinery capacity is expanding at a slower rate than in the United States or the rest of the world (Figure 7-7). Based on increased future transportation fuel consumption in California and neighboring states, staff found that demand grows faster than the ability of refineries to

produce those fuels. California refinery capacity growth, known as refinery creep, is relatively low and only expected to increase at an annual average rate between 0.4 and 0.98 percent per year through 2020.

Figure 7-7: Refinery Capacity Growth for U.S., California, and the World



Source: California Energy Commission; *2006 Price Spike Report*

Even this small, expected refinery growth requires more tankers than at present to bring in refined products, congesting marine terminals, as well as requiring more marine port storage capacity. Coupled with the state's steadily declining crude oil production, even low refinery capacity growth rates will require growing levels of crude oil imports and increased crude oil storage capacity. Imports of crude oil into California are expected to rise at an annual average rate between 1.7 to 2.7 percent per year by 2020.

Additional storage tank capacity necessary to meet California's product storage requirements by 2020 ranges from 5.4 million and 13.1 million barrels and the additional crude oil storage capacity needed ranges from five to 17 million barrels.

Assuming planned storage capacity is built, crude oil import capacity in the Los Angeles Basin should be sufficient through 2015, but in the higher imports case, more capacity would be required by 2020. The Crude Oil Import Marine Facility project at Pier 400 in the Port of Los Angeles has been significantly delayed and this facility is a critical element of this assumption of adequate capacity through 2015. Further delay by the Port of Los Angeles could put at risk the oil industry's ability to import sufficient quantities of crude oil to operate their refineries.

Crude oil tankers are considerably larger than product tankers - an average crude oil tanker load is about 700,000 barrels while an average product tanker load is around 300,000 barrels. By 2020, the number of additional crude oil tanker arrivals to California ports is estimated from between 167 to 291 per year, depending on assumptions about state oil production and refinery

capacity additions. And additional product tanker arrivals per year could range from as few as 214 to as many as 519, again depending on assumptions about product demand.

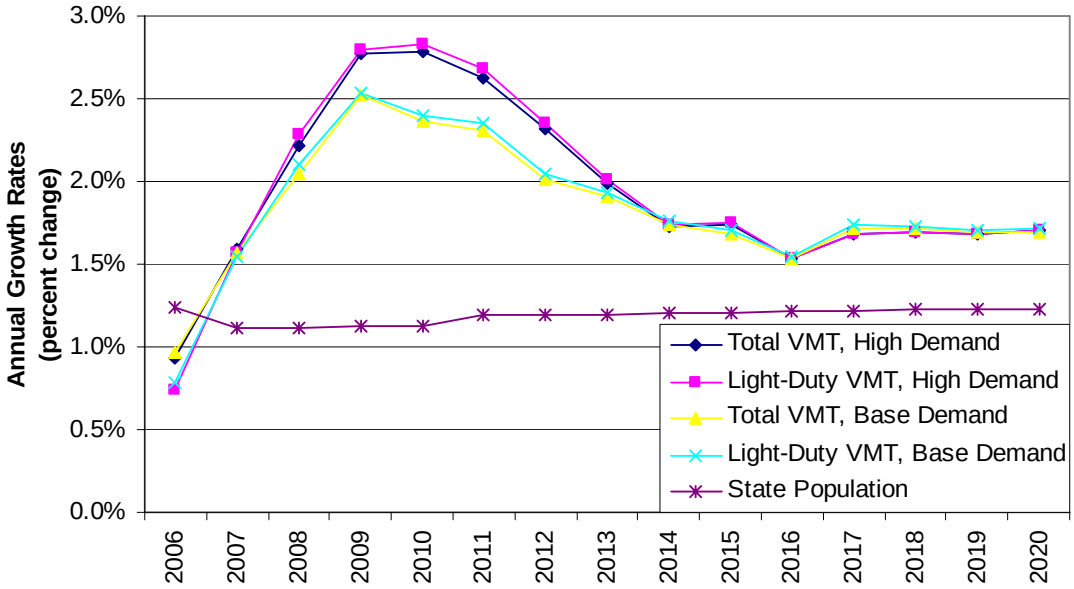
The relative contribution of criteria pollutants by various marine vessels from petroleum tanker emissions are marginally less than emissions from container ships per port visit. Overall, emissions from marine tankers in 2001 represented between 1.2 and 8.2 percent of air pollution from all sources in the Port of Los Angeles, depending on type of pollutant.

Providing Transportation Options

Californians require mobility to conduct their everyday lives and attend to their business needs. For the most part, this mobility is achieved through use of a petroleum-fueled vehicle, typically with a single occupant, and is measured as vehicle miles traveled. Figure 7-8 shows the narrow range of future travel demand expected under differing future conditions of fuel prices and fuel efficiency standards. Travel demand is essentially a fixed requirement for individual consumers of transportation goods and services in a state as physically expansive as California, where distances are large and most metropolitan areas extensive and poorly served by public transit. Reducing this public access to work, recreation, and other travel cannot be accommodated at present without disruption and economic loss. Moreover, population growth translates directly into increases in aggregate travel demand.

Consumers must have a broader set of choices to simultaneously reduce the environmental, social, and economic costs of transportation energy use while maintaining their mobility. Although conventional petroleum fuels will be the main source of transportation energy for the foreseeable future, over the next several decades California must pursue multiple complementary strategies that increase fuel efficiency, expand non-traditional fuel use, and ultimately realign consumer preferences to reduce demand for all transportation energy use as well as reduce trips and vehicle miles traveled (VMT).

Figure 7-8: A Population on the Move



Source: California Energy Commission

Government mandates, policy directives, incentives, and increased concerns over the negative environmental and economic consequences associated with global climate change are all aligned to increase the use of alternative fuels in California. The increased use of fuels with a lower carbon intensity than conventional petroleum fuels can help meet the mobility requirements of consumers while reducing the economic and environmental impacts of continued petroleum dependence. However, increased availability of alternative refueling infrastructure and changes in vehicle procurement processes needs to support a broader concept of transportation choices under AB 32.

Even though fuel efficiency and greater use of alternative fuels can contribute to lower petroleum consumption, California cannot meet its long-range goals of reducing greenhouse gas emissions without fundamental changes to the way we meet our mobility needs. Changing the patterns that cities take as they grow so that destinations are closer to people's homes and channeling urban growth so that public transit can assume a larger burden of travel demand are elements of the longer-term strategy that the state must develop if gains made in other policy areas are not to be overwhelmed by future population growth.

While California must address its petroleum infrastructure problems and act prudently to secure transportation fuels to meet the needs of our growing population, this should be viewed as a complementary strategy to allow for time for the market and consumer behavior to make the adjustment to alternative fuels and transportation choices. During this transition, California must be innovative and aggressive in finding more ways to make increased efficiency, greater renewable fuel use, and smart land use planning the most desirable consumer options.

Changing the Future

Decreasing California's reliance on petroleum fuels is critical. By 2020, at current trends, over 44 million Californians will consume more than 24 billion gallons of gasoline and diesel fuel each year. The consequences are quite clear: major investments in petroleum refinery and delivery infrastructure expansions, more dependency on foreign energy supplies, and decreased environmental and public health quality.

California's energy policy - the loading order - identifies energy efficiency, renewables and new infrastructure improvements as the state's priorities in meeting growing energy demand. These strategies also apply to transportation. Improved efficiency of transportation energy use, in large part through vehicle standards, is the most effective and sustainable strategy for reducing our demand for transportation fuels. Applying these preferred strategies to transportation focuses first on the pursuit of maximum achievable energy efficiency. Efficiency improvements can be made in vehicle energy use, individual vehicle miles traveled, and goods movement.

Corporate Average Fuel Economy (CAFE) Standards

The average, on-road fuel economy of cars and light-duty trucks in California increased from 12.6 miles per gallon (mpg) in 1970 to 20.7 mpg in 1985 as a result of federal standards. These standards have not substantively changed in 22 years. Fleet averaged, on-road fuel economy has deteriorated steadily as consumers purchased more light trucks, especially sports utility vehicles (SUVs), which meet a lower miles per gallon CAFE standard. With the implementation of small increases in CAFE requirements for light-trucks as described below, this trend began to reverse in 2004 and the combined fleet's fuel economy has gradually improved by about 2 mpg.

The goal of the original 1977 federal CAFE standards for passenger cars was to double new car fuel economy to 27.5 mpg by model year 1985. Congress did not specify a target for the improvement of light truck fuel economy. Instead, it directed that they be established administratively, at the maximum feasible level for model year 1979 and each year after. The act gave the exclusive authority for establishing fuel economy standards to the federal government. The National Highway Traffic Safety Administration (NHTSA) is responsible for establishing and amending the light-truck CAFE standards.

In April of 2003, NHTSA adopted new, "reformed" light-truck CAFE requirements, now based on size (distance between front and rear axles times average wheel track width) with larger vehicles allowed to have lower fuel economy. The reformed light-truck CAFE requirements increase this requirement to 21.0 mpg in 2005, 21.6 mpg in 2006 and 22.2 mpg starting in 2007. These values assume the same market shares by vehicle size as previous sales. Additionally, the reformed CAFE requirements apply to medium-duty passenger vehicles (rated at 8,501 to 10,000 pounds gross vehicle weight).

Because CAFE standards have been largely unchanged until the modest improvements in 2003, most technological improvements to engines and vehicles have been used to increase

performance and overcome weight gains from the larger vehicles, especially trucks and SUVs, rather than to improve fuel economy.

National experts, such as the National Research Council of the National Academy of Sciences and the American Council for an Energy Efficient Economy, have identified multiple pathways to achieve an on-road fleet average fuel economy of 30 to 45 mpg. Their analysis shows that, in most instances, increasing fuel economy creates consumer fuel savings that exceed the increased cost of the more fuel-efficient vehicle. In addition, society benefits from improvements to the environment and energy security.

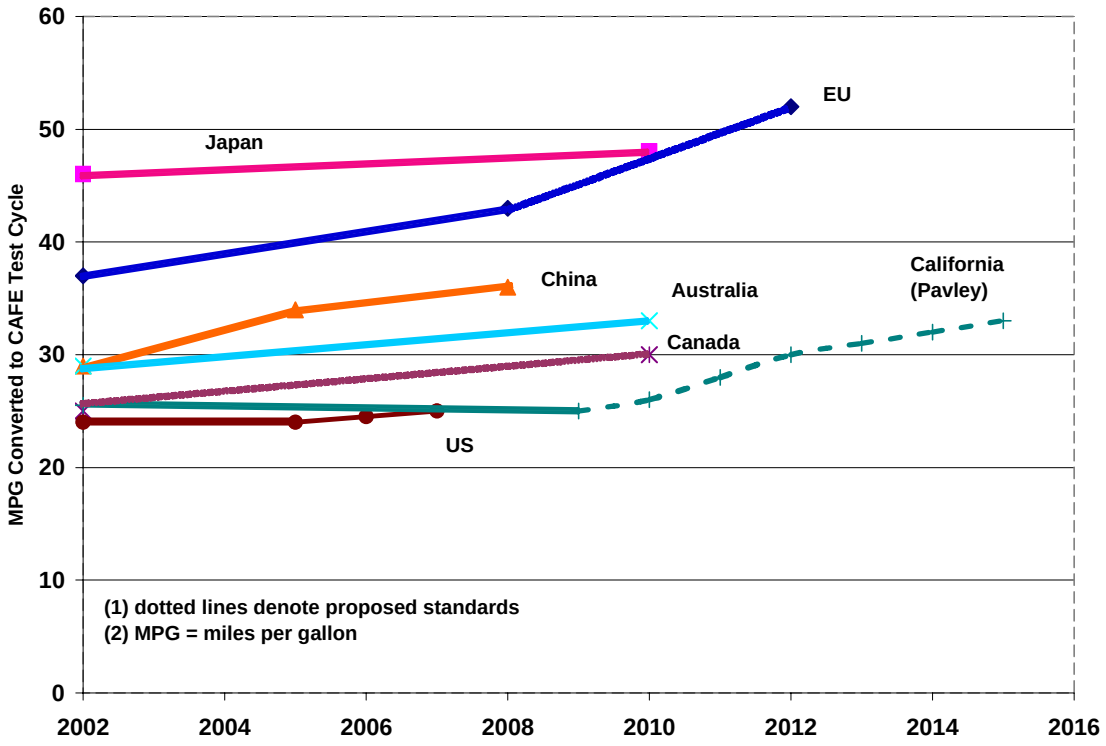
Requiring vehicle manufacturers to improve fuel economy, however, is the sole domain of the federal government. The challenge for California policy makers is to work effectively with the federal government to improve new vehicle fuel economy.

In June 2007 the United States Senate voted to raise fuel efficiency standard for cars to 35 miles per gallon in 2020. As of July 2007, no action has been taken by the House of Representatives and the fate of any legislation to modify CAFE remains uncertain. This proposed legislation is a step in the right direction because United States manufacturers individually have only recently begun to see the value of improving their vehicles' fuel economy as they lost market share to other companies. The federal government can help automobile manufacturers by requiring them to meet improved CAFE standards. By instilling "fuel economy discipline" through more demanding CAFE requirements, United States auto manufacturers will be better able to compete with international companies in the world market. A recent analysis by the University of Michigan's Transportation Research Institute has concluded that adopting size-based CAFE requirements similar to those adopted for light-trucks would improve the competitive position of U.S. automobile manufacturers and workers.[282] Additionally, CAFE improvements do not have to reduce vehicle safety or compromise performance; hybrid-electric vehicles are proof of this.

Japan, the current leader in the auto industry, has a fuel economy standard equivalent to 45 mpg. Europe has recently passed legislation to raise its fuel economy standards to more than 50 mpg by 2012 and even China and Australia have higher fuel economy than California and United States. (Figure 7-9)

Figure 7-9: Comparison of Fuel Economy of Passenger Vehicles

[282] Walter S. McManus, PhD. Director, Automotive Analysis Division, University of Michigan Transportation Research Institute, Ann Arbor, Michigan, July 2007, page 5.



Source: Pew Center on Global Climate Change, *Comparison of Passenger Vehicle Fuel Economy and Greenhouse gas Emission Standards Around the World*, December 2004

A study by Union of Concerned Scientists found that a 35 mpg fleet would create as many as 170,800 jobs in 2020 — including 22,300 in the auto industry — and save consumers nearly $25 billion on gasoline with average prices at $2.55 per gallon. The increase in fuel efficiency would also save Americans close to 2.5 million barrels of oil per day.

Since over 39 percent of California's greenhouse gas emissions come from transportation (on-road gasoline use is 27.7 percent, on-road diesel use is 5.8 percent and railroad, marine and aviation make up the remainder), it is important to address this problem at its source.

The *2003 Integrated Energy Policy Report* stated that California should work to build a coalition with other states and stakeholders to influence Congress and the U.S. Department of Transportation to once-again double the fuel economy of new passenger cars and light trucks. Three proposals now active in Congress would implement reformed CAFE requirements for both passenger cars and light-duty trucks and would require the overall United States market to improve from a 2005 base of 23.7 mpg to 32 to 35 mpg.[283] The modest improvements seen to

[283] Same as above, Table ES-2.

date, and even the more aggressive targets in pending legislation, suggest that coalition building must continue.

The recommendation to double fuel economy as called for in the *2003 Integrated Energy Policy Report* was based on results of a joint Energy Commission/Air Resources Board study of options to reduce petroleum use, as directed by AB 2076 (Chapter 936, Statutes of 2000). This recommendation was by far the most significant and cost-effective single petroleum reduction strategy resulting from this joint study, which was based upon technologies either already on the market or judged to be ready to enter the market.

Fuel Substitution Options - Alternative Fuels

Governor Schwarzenegger, in his response to the *2003 Integrated Energy Policy Report*, called upon the California Energy Commission (Energy Commission) to craft a workable long-term plan to increase the use of alternative fuels. Recent legislation, Assembly Bill 1007 (Pavley, Chapter 371, Statutes of 2005), directs the Energy Commission, in partnership with the California Air Resources Board (Air Resources Board), to develop a State Alternative Fuels Plan (Plan) to increase the use of alternative fuels, without adversely affecting air pollution, water pollution, and public health.

Assembly Bill 1007 specifically requires the State Alternative Fuels Plan to:

- Evaluate alternative fuels using a full fuel cycle analysis.
- Set goals to increase alternative fuels in 2012, 2017, 2022.
- Recommend policies, such as standards, financial incentives, research and development programs, to stimulate the development of alternative fuel supply, new vehicles and technologies, and fueling stations.

Satisfying the bill's requirements was accomplished through an open and public process, involving one-on-one meetings with key stakeholders and public workshops conducted over the past year. The Plan, developed in partnership with the Air Resources Board, has been released in draft and is scheduled for approval by both agencies during October.

The Plan recommends a combination of regulations, incentives, and market investments to achieve increased penetration of alternative and non-petroleum fuels. In addition, to accomplish a longer term vision for the year 2050, vehicle efficiency improvements, and significant reductions in vehicle miles traveled are needed. The Plan describes strategies, highlights actions, and recommends mechanisms to concurrently address multiple state policies in an integrated fashion:

- Petroleum reduction: joint recommendations by the Energy Commission and the Air Resources Board in response to Assembly Bill 2076 (Chapter 936, Statutes of 2000).[284]
- GHG reduction: Governor's Executive Order S-3-05 on Climate Change (2005), Assembly Bill 32, the Global Warming Act (2006), and Governor's Executive Order S-1-07 on the Low Carbon Fuels Standard.
- In-state biofuels production and use goals: California Bioenergy Action Plan and the Governor's Executive Order S-06-06 on Biomass.

It concludes that regulations alone cannot achieve the state's multiple policy goals; the State needs a portfolio of alternative, low-carbon fuels to meet the state's multiple goals of petroleum reduction, greenhouse gas emissions, and biofuels production. The plan recommends multiple strategies which combine private capital investment, financial incentives, and technology advancement approaches.

Achieving the state's petroleum reduction, climate change, and biofuels goals will require substantial investment in fueling infrastructure, production facilities, vehicle components, and commercial development of "second generation" alternative fuels and advanced technology vehicles.

Federal incentives, augmented by state incentives, will be needed to complement mandates, standards and regulations, and must be sustained and consistent over the 20 to 30 year period. More importantly, substantial capital investment by the private sector must be directed toward advanced technology and infrastructure.

Figure 7-10 shows the greenhouse gas and petroleum reduction performance of new light-duty vehicles on a well-to-wheels (WTW) basis for selected alternative non-petroleum fuels as a function of feedstock, compared to Phase 3 Reformulated Gasoline (RFG3). The figure clearly shows the greenhouse gas emissions are dependent on feedstock origins and production pathways.

Results of the Plan's full fuel cycle (Wells-to-Wheels) analysis demonstrates that alternative fuels can provide substantial greenhouse gas reduction benefits, when used in mid-size passenger cars and urban buses. Depending on the fuel pathway chosen, fuels such as ethanol, natural gas, liquefied propane gas (LPG), electricity, and hydrogen have decided advantages over conventional gasoline and diesel fuels.

Assembly Bill 1007 goals for each fuel were developed using a scenario approach. Each scenario has a Business-As-Usual (BAU), Moderate and Aggressive case. The cases differ by the assumptions made about technology maturity, vehicle and infrastructure availability, fuel supply and fuel type. Alternative fuel and vehicle goals were not simply based on desired reductions in petroleum use and emissions, but were derived from assessments about the potential market expansion of each alternative fuel, informed by substantial research and

discussions with the alternative fuel industries. Fuel use goals were determined by several approaches appropriate to the data available for the Assembly Bill 1007 candidate fuel or an appropriate analog for the fuel and vehicle technology combination.

Figure 7-10: Vehicle GHG and Petroleum Reduction Performance of Alternative Fuels for Light-duty Vehicles as a Function of Feedstock

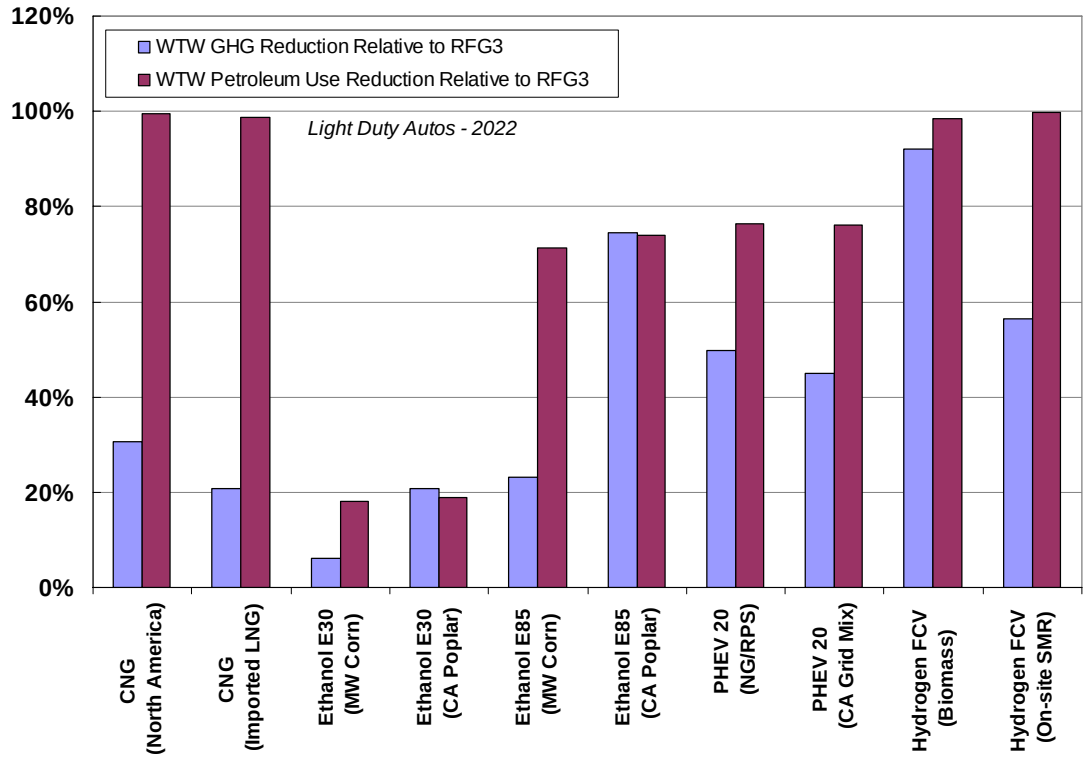


Figure 7-11. Alternative Fuels Use Goals (mm gge)

Alternative Fuels Case	Milestone Year 2012	2017	2022
Business as Usual	1,434	1,713	2,106
AB 1007 Goals (Moderate Case)	2,360	3,565	5,220
Aggressive	2,943	6,772	11,298

Biofuels, produced from the state's agricultural, forestry, and urban waste residues, should be pursued in the short term, because of their petroleum reduction, waste reduction, and climate change benefits. Over the longer-term, advanced biofuels, hydrogen, and plug-in hybrid vehicles are expected to play a role in meeting California's Low Carbon Fuel Standard.

Certain biofuels can provide large greenhouse gas reductions (up to 75 percent compared to gasoline) because carbon dioxide emissions are recycled through plant photosynthesis. Changes in agricultural land can have a dominant impact on biofuels pathways, however, and the potential land conversion effects need to be better quantified.

Lastly, the Plan recommends a four-part strategy to achieve the state's petroleum reduction, biofuels and greenhouse gas reduction goals:

(1) promote alternative fuel blends with gasoline in the near term;

(2) maximize alternative fuels in early adopter market niches, such as heavy duty, fleets, off-road, and ports;

(3) optimize the use of alternative fuels in existing internal combustion engines in the near term, while advancing new vehicle technologies, such as electric drive and hydrogen fuel cells, in the mid-to-long term; and

(4) reduce Vehicle Miles Traveled and Vehicle Hours Traveled through a combination of travel demand reduction and sound land use planning measures.

Recommendations and Action Steps

To continue to meet California's growing transportation fuels needs while also complying with the directives of AB32, the Energy Commission makes the following recommendations:

- Energy Commission representatives should participate whenever possible in transportation-related workshops and public forums to provide information and stress the role of transportation energy infrastructure in the health of the California economy.
- The Energy Commission should involve local and other state agencies to a greater degree during the IEPR process in efforts to maintain and expand needed transportation energy infrastructure, including mitigating the impacts of lease denials.
- The Energy Commission should stress to local and state authorities the connection between infrastructure expansion requirements and measures that reduce demand for petroleum fuels, as shown in this report by the impact of the greenhouse gas regulations.
- To help ensure that independent traders are not unfairly denied access to the California fuels market, the Energy Commission should propose an arbitration mechanism for the state, backed by decision-making authority, to resolve market access issues.
- The Energy Commission should propose a new law that allows state appeals in the petroleum marine infrastructure lease renewal process at the Ports of Los Angeles and Long Beach.

- The Energy Commission should monitor the impact of the State Lands Commission Marine Oil Terminal Engineering and Maintenance Standards, especially on clean fuels marine terminals in the Ports of Los Angeles and Long Beach.
- The Energy Commission should press for a firm federal funding mechanism to maintain an adequate depth for tanker traffic in the Pinole Shoal in San Francisco Bay.

CHAPTER 8: Resolving Energy Needs with Smart Growth

The neighborhoods we live in and the cars we drive around them are major contributors to greenhouse gas emissions. Adding 24 million new California residents by 2050 will push greenhouse gas emissions from vehicle and home energy use even higher – in direct opposition to the goals of AB 32 and the Governor's Executive Order S-3-05.

The location and size of the average home in California have changed significantly in the past decades. Returning World War II veterans married and flocked to the suburbs. A thriving economy, increased automobile ownership, an expanded urban road network, and available land continued the trend. The result was a dispersed urban geography, often called sprawl, which characterized both suburbs of large cities and also whole cities like Los Angeles. More expensive housing and less developable land have pushed suburbs even more far-flung, with potential homeowners employing the mortgage option "drive 'til you qualify" in the hopes of finding affordable housing.

This 60-year legacy of suburban growth, increased auto use, and an inexpensive and reliable fuel supply has increased the miles we drive to work, to the grocery store, to soccer games, and social events. The resulting vehicle miles traveled (VMT) account for 27 percent of California's greenhouse gas (GHG) emissions and are increasing at a rate markedly faster than the population growth rate over the same period.

Residential home styles have changed as well. Nationally, single-family homes have doubled in size from just less than 1,000 square feet in 1950 to 2,265 square feet in 2000.[285] Residential use (electricity and natural gas) accounts for 14 percent of California's GHG emissions.[286] Studies have shown that the type of housing (such as multi-family) and the size of a house have strong relationships to residential energy use. Residents of single-family detached housing consume more than 20 percent more primary energy than those of multifamily housing and 9 percent more than those of single-family attached housing.[287]

California's efforts to reduce GHG emissions are leading the nation. Programs to reduce petroleum use with clean alternatives, reduce GHGs by requiring the sale of cleaner cars, and reducing the amount of carbon in our fuels are but some of the innovative leading edge policies

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[285] America's Housing 1900-2000, A Century of Progress. National Association of Homebuilders, http://www.nahb.org/assets/docs/files/v5_513200312545PM.pdf

[286] http://www.climatechange.ca.gov/policies/1990s_in_depth/page5.html.

[287] Rong, Fang, 2006, Impact of Urban Sprawl on U.S. Residential Energy Use, University of Maryland, http://hdl.handle.net/1903/3848.

the State is implementing to reduce the impact of transportation on our climate. But even these regulations are not enough to meet AB 32 goals due to the significant expected VMT growth. This growth is being caused by our community design choices. A new land use dynamic is needed. Planning for more compact and energy-efficient homes close to transit, work and services — smart growth — must be a state priority.

Role and Impact of Land Use in Energy Consumption, Production and Distribution

VMT is the 800 Pound Gorilla

Urban growth patterns have caused California's VMT to increase at a rate of over 3 percent a year between 1975 and 2004, markedly faster than the population growth rate over the same period. This VMT created 130.9 million metric tons of carbon dioxide (CO2) in 2004. The California Department of Transportation (Caltrans) estimates that VMT will continue to grow at nearly 3 percent into the foreseeable future. A continuing increase in VMT caused by California's expected growth is predicted to push CO2 emissions to 152.6 tons by 2020, a 16.6 percent increase without AB 1493 and the LCFS.

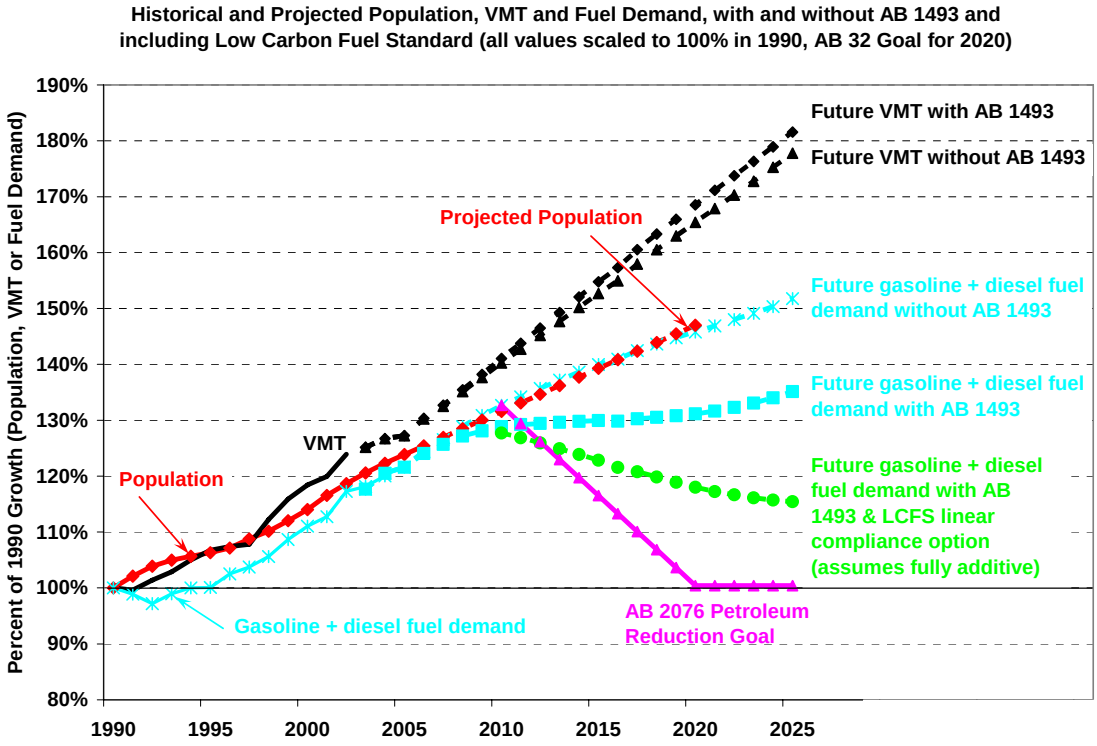
The degree to which transportation GHG emissions must be reduced is uncertain given the status of several approaches to reduce transportation GHG emissions. However, it is apparent that reduced VMT growth will be required to meet GHG reductions goals. It is imperative that land use planning and infrastructure investments place a high priority on reducing VMT growth. Meeting Executive Order S-3-05's long-term goal, which requires a reduction by 2050 to 80 percent below 1990 emissions levels, would certainly require nearly carbon-free transportation and strong actions to reduce VMT.

Figure 8-1 shows California's growth in VMT, population, and gasoline and on-road diesel consumption, all indexed to their 1990 value. Values plotted reflect growth from 1990. As stated above, this is the year that AB 32 GHG control measures are required to be met by 2020. Thus, Figure 8-1 can be used to view the historical growth in transportation fuel use (and associated GHG emissions) relative to the historical growth in population and VMT and the degree of reduction needed to return to 1990 levels. Also plotted in Figure 8-1 are projected gasoline and on-road diesel use, population growth, and VMT projected by Energy Commission staff for the *2005 Integrated Energy Policy Report*. Transportation fuel use is plotted both with and without the effect of the AB 1493 rule, and one line shows the result with AB 1493 and with the low-carbon

fuel standard, assuming it is entirely additive to reductions obtained by implementing AB 1493.[288]

[288] AB 1493 has an "alternative compliance option" that could include low-carbon fuel, and therefore, the low carbon fuel standard may not be entirely additive.

Figure 8-1: Historical and Projected Population, VMT, and Fuel Demand



Source: Energy Commission staff, 2007

Since GHG emissions from gasoline are such a large fraction of total state GHG emissions (27 percent), it is likely that these emissions will have to be controlled to meet the goals of AB 32. The goals have yet to be established for specific energy end-use sectors such as transportation, but the overall goal represents about a 29 percent reduction in projected 2020 emissions. This percentage can be used to compare the historical and projected gasoline demand. From Figure 8-1 it can be seen that the gallons of transportation fuel used in 2004 grew 20 percent above 1990 usage. Projected usage in 2020 is about 45 percent over 1990 consumption, if the AB 1493 rule is not approved by the courts, and about 31 percent if the rule is upheld and implemented on the schedule adopted by ARB.

Figure 8-1 also shows the effect of the LCFS, assuming implementation of the "linear" compliance schedule and assuming that these reductions are fully additive to fuel use reductions accomplished by AB 1493 and the Zero Emissions Vehicle Program. The LCFS technical report shows annually decreasing carbon intensity[289], but the effects of the LCFS are

[289] Table 2-2 of the LCFS technical report.

projected only to 2020. The additive effect of these strategies reduces future transportation fuel consumption such that by 2025, transportation fuel consumption is only about 15 percent above 1990 consumption. This indicates that even with AB 1493 and the LCFS, significant further efforts (roughly equivalent to the projected magnitude of AB 1493 or the LCFS) would be needed to reduce the transportation sector's fuel consumption and greenhouse gas emissions to their 1990 levels by 2020 as required by AB 32.

Land use patterns play a direct role in the rate and growth of VMT, influencing the distance that people travel and the mode of travel they choose.

A 2002 U.S. Environmental Protection Agency study[290] compared the impacts of compact and sprawling counties on transportation patterns. Sprawl was defined as:

- A population widely dispersed in low density residential development.
- A rigid separation of homes, shops, and workplaces.
- A lack of distinct, thriving activity centers, such as strong downtowns or suburban town centers.
- A network of roads marked by very large block size and poor access from one place to another.

Sprawl was measured for 83 of the nation's largest metropolitan areas. The research suggests that counties with an inverse proportion of the above sprawl characteristics had significantly less average vehicle ownership, daily VMT per capita, annual traffic fatality rate, and maximum ozone level days. At the same time, shares of work trips by transit and walk modes increased to a significant degree.

Of the many factors that can be used to quantitatively analyze development and transportation interactions, density may have the most significant relationship to travel and transportation outcomes. Controlling for other factors, the difference between low and high density U.S. metropolitan areas is more than 40 percent daily per capita VMT. A doubling of neighborhood density can be expected to result in approximately a 5 percent reduction in both vehicle trips and VMT per capita.

Accessible, highly dense, mixed-use communities result in shorter length of vehicle trips. Of particular note is the difference between centrally located developments and development along the outskirts of established areas. Areas of high accessibility—such as center cities[291]—seemed to produce substantially lower VMT than dense mixed-use developments in the

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[290] Ewing R., R. Pendall, and D. Chen, "Measuring Sprawl and Its Impact," Smart Growth America/ U.S. Environmental Protection Agency, Washington D.C., 2002.

[291] A city's downtown and adjacent neighborhoods.

exurbs.[292] Trip frequencies seem to depend mostly on socioeconomic and demographic factors, but overall VMT and vehicle trips declined as accessibility, density, and/or land-use mixing increased. As Dr. Reid Ewing noted in the June 26, 2007, Energy Commission workshop, "a smart growth development plan that increases average density by 30 percent, emphasizes infill, and mixes land uses to a high degree would be expected to reduce regional VMT by about 15 percent per capita over 30 years at an average metropolitan growth rate."

Unintended Tax Consequences

Land use patterns, and the VMT resulting from them, are influenced by the tax revenues available to local governments. One of the largest impediments to local governments' embracing of energy-efficient and climate-friendly growth patterns is the structure of local-government finance.

Proposition 13 significantly cut local tax revenue as compared to the prior period and altered the way local governments fund public services and infrastructure. In particular, it encouraged cities and counties to impose heavier exactions—sometimes known as developer fees or impact fees—to pay for roads, sewers, parks, and schools.

Local governments receive 1/7 of the state sales tax for sales in their local districts. So in addition to exacting fees on developers, local governments also started encouraging development that increased sales tax revenue, such as shopping malls, car dealerships, and hotels. By contrast, land uses that produce only property taxes and have a high public service cost, such as moderately priced housing, became less desirable. This caused counties and cities to favor sales tax-generating retail development rather than property-tax-bound residential uses, a circumstance commonly referred to as "the fiscalization of land use."

As a result of these tax policies, local land use planning and decision making may demonstrate a bias toward tax revenue-driven development. Such development often may pit one community against another in an effort to attract businesses that generate sales tax. Local competition for retail and auto malls rarely balances community housing needs with the benefits of non-retail business and industry and may exacerbate transportation and associated environmental problems.

The state should conduct a thorough review of the impact of tax policy on land use patterns in the California.

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[292] Prosperous rural communities beyond the suburbs that become commuter towns for an urban area.

Residential Energy Supply and Use Offer Additional Opportunities

To ensure a reliable and secure source of electricity, and reduce residential GHG emissions, land use planning must also consider energy demand, supply and infrastructure. Increasing on-site production of renewable energy, using distributed generation, orienting residences in relation to the sun, increasing shading, incorporating roofs that reflect heat, and installing energy efficient appliances would produce significant energy savings. Most developments, if they consider energy, do so in the context of building efficiency. However, much more is possible and necessary.

Local governments and utilities are joining forces to plan new communities from inception to full build-out. Military base closures and reuse present a particular opportunity to explore these concepts. For example, Southern California Edison and Southern California Gas Company have joined forces with the City of Irvine, Lennar Corporation, and energy and land use experts to develop a new energy infrastructure for the proposed Irvine Great Park. The Great Park will use energy efficiency and fuel diversity to meet a goal of net zero energy use. The target is homes that use 40 percent less energy than required by California Building Energy Efficiency Standards (Title 24) and non-residential facilities that use 30 percent less energy than is required by the code. In addition, the Great Plan will incorporate advanced metering infrastructure, solar photovoltaics, district heating and cooling, distributed generation, transportation strategies, lighting technology, waste to energy and grid islanding.[293]

The Road to Better Land Use Planning

Currently, land use planning, although linked to transportation and air quality planning, is not integrated with these activities. Opportunities exist at all levels of government for integrated planning that would reduce energy demand and greenhouse gas emissions as well as eliminate redundant or conflicting efforts. At the local level, general plans and zoning codes are incorporating more growth management and energy measures. At the regional level, hundreds of millions of dollars are spent annually on transportation, land use, and air quality planning and better coordinating these efforts will reduce energy demand, for example, by tying transportation funding to smart growth land use plans. At the state level, policies and plans (the California Environmental Quality Act, the California Transportation Plan, housing element updates, the California Water Plan, and stormwater plans) and the state's purse strings can be used as levers to effect land use patterns.

[293] Irvine Great Park Energy Subteam Update, November 2006.

Local Government Plans Need to Address Energy and Greenhouse Gas Emissions Reductions

The state has limited authority in direct land use planning, rather conducting activities that more indirectly influence land use decisions. Local governments hold the majority of land use authority in California and express their legally enforceable policies through required general plans and zoning codes. General plans set forth objectives, principles, standards, and proposals for development. State law requires these general plans to address land use, circulation, housing, open space, conservation, safety, and noise.

No specific state mandate requires that a general plan include an energy element — a part of the general plan that addresses energy demand and resource development of a community. Only about 10 percent of California's general plans include such elements, and over half of the state's jurisdictions have general plans more than 10 years old.[294]

Currently, there is no State guidance for how local governments should assess, report, avoid or mitigate GHG emissions resulting from their land use decisions.

The passage of SB 97 (Dutton, Statutes of 2007) requires the Governor's Office of Planning and Research to develop, and the Resources Agency to adopt, guidelines for the feasible mitigation of GHG emissions or the effects of GHG emissions. This will lead to local governments performing analysis of, and offering mitigation efforts for, the potential GHG emissions impacts of growth within their jurisdictions. This will require local governments to address GHG considerations in their general plan and other planning efforts.

Issues such as housing, transportation and congestion, economic development and air pollution and reducing GHGs lend themselves to, and in some cases require, a more regional approach. City and county boundaries and authority can limit an agency's ability to affect change as it may require collaboration from regional peers to effectively attain its policy goals. An example of this is the adoption of smart growth principles by a city attempting to reduce sprawl by limiting low-density development within its boundaries. If the city's regional partners do not support the city's efforts by adopting similar policies and allowing the same kind of low-density, sprawling development in its jurisdiction, then the region could still suffer from the negative impacts (congestion, GHG emissions, etc.) of the development.

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[294] Roberts, T. 2006. Remarks presented at Land Use and Energy Workshop, California Energy Commission, September 22, 2006

Regional Blueprint Planning Efforts Show Promise

California's Regional Blueprint Planning Program provides a model example of the potential benefits of regional planning. The program is based on the principles of regional collaboration, stakeholder involvement, more efficient land use patterns, and more housing and transportation choices. The Program provides funding to help regional governments create long term growth plans consistent with the above principles. The Blueprint Learning Network coordinates state and regional agencies to share experiences and best practices in making better infrastructure investment decisions. As a result, nearly all of the state's metropolitan planning organizations (MPOs) are developing long-range growth and transportation plans.

The program involves the proactive engagement of all segments of the population, as well as critical stakeholders in the community, business, academia, developers, construction, and environmental organization, to foster consensus on a vision and preferred land use pattern in a given region. the regional blueprint planning grants are intended to build capacity for regional collaboration and integrated planning that will in turn enable regions to plan to accommodate all their future growth, thereby reducing sprawl.

If implemented aggressively, blueprint planning could reduce future VMT. For instance, projections to 2050 showed that the scenario preferred by Sacramento stakeholders and adopted by the regional governing body could use 46 percent less new land, reduce VMT by 12.3 miles per household per day, and produce 15 percent less carbon dioxide and particulate matter per capita, as compared to the business-as-usual case (Table 8-1). However, even though VMT declines compared to the business-as-usual case, Sacramento total regional VMT per day grows from 43 million in 2000 to 53 million in 2050 because the number of households more than doubles during the timeframe.

Table 8-1: Key Statistics Comparing Sacramento Base Case Scenario 2050 and Regional Preferred Scenario 2050

PARAMETER	BASE CASE 2050	ADOPTED PLAN 2050	DIFFERENCE
VMT per household per day (excludes commercial vehicles)	47.2	34.9	12.3 fewer miles per household per day, a 25% reduction
People Living in Areas with Good Mix of Jobs and Housing	26%	53%	27% increase
Growth Near Transit	5% New Jobs	41% New Jobs	36% more new jobs near transit

	2% New Housing	38% New Housing	36% more new homes near transit
Additional Urbanized Land	666 square miles	304 square miles	362 fewer square miles urbanized
Daily Vehicle Minutes of Travel (per household per day)	81 minutes	67 minutes	14 fewer minutes per day (more than two 40 hour work weeks per year)
Per Capita Carbon Dioxide and Small Particulate Emissions from vehicles (includes commercial vehicles)	Set at 100%	85% of Base Case	15% less than the Base Case per capita

Source: SACOG, Blueprint Program, 2005.

A similar planning effort in the San Francisco Bay Area showed that the smart-growth land use scenario, as compared to the business-as-usual case, could reduce the urbanized footprint of the area by 16,000 acres (2 percent), reduce per capita water consumption by 50 gallons per day (17 percent), and increase the proportion of new affordable housing from 16 percent to 41 percent of all new units.

As important as blueprint planning, it only offers the pathway to lower the *rate of VMT growth*. Its implementation is unlikely to reduce *total VMT* once population growth is taken into account. In addition, the success of blueprint planning is ultimately defined by what percent of new land use development actually follows the blueprint plan.

The completed Blueprints are in early stages of implementation and may need technical, financial, and regulatory assistance to achieve maximum results.

These efforts are good but will not be sufficient to meet the state's energy and climate goals unless the state provides strong leadership in shaping how land will be used into the future and how land use impacts will be measured and tracked. A state growth plan, prepared in conjunction with regional and local interests, must be developed. A state plan should be composed of regional plans, developed by local governments, in a process facilitated by regional agencies, modeled on the Blueprint success. Once regional plans are adopted, the state should build a statewide growth management plan. Upon adoption of such a plan, state policies and programs should be modified to align with and support the plan. In order to allow for

programs and development projects to mature, while also keeping the state and regional plans up-to-date, the plans should be updated every 10 years.

The State's Regulatory Authority and Purse Strings should be used to Better Advantage

The state took a major step toward encouraging smarter growth with the passage of AB 857 (Wiggins, Chapter 1016, Statutes of 2002), which laid out three planning priorities for state agencies: promote infill development and social equity in existing communities; protect and conserve environmental and agricultural resources; and achieve more efficient use of land, transportation, energy and public resources outside the infill areas. Unfortunately, AB 857 has had little effect. While AB 857 provided the framework for guiding state agency land use practices, there is no consequence for agencies that do not comply. Currently, the Governor's Office of Planning and Research has authority to only collect annual reports of agencies self-reported compliance with the law.

While the state has limited land use authority, it does have some key leverage points (California Environmental Quality Act, housing elements, and others) that can be used to assist local governments in reducing energy use and greenhouse gas emissions that result from land use planning choices. Even though land use authority is nearly completely vested with local government, the state can use the disbursement of transportation and housing funds to motivate collaborative planning at a regional level that seeks to significantly reduce the community's GHG emissions. A common methodology for reporting and measuring GHG emissions contributions for communities is needed.

Infrastructure funding policies influence the design and use of local government infrastructure and development projects. California has a unique opportunity to direct infrastructure investments contained in the Governor's Strategic Growth Plan and approved by voters in November 2006 to those communities that reduce their GHG emissions associated with given projects. The Strategic Growth Plan contained a few programs to encourage energy-efficient, climate-friendly land use but project funding criteria (where they exist) currently contain no energy or climate considerations. The funding criteria ultimately developed for Propositions 1B, 1C, 1D, and 84 will determine the extent to which bond monies contribute to less energy-intensive land use and reduce VMT. The state should build upon the Governor's Strategic Growth Plan by requiring that all state financing for infrastructure incorporate energy use reduction strategies and climate considerations.

California Should Learn from Other States

Plans being developed in other states may be instructive to California. Oregon, New Jersey, and Maryland are conducting similar land use planning efforts, some of which are specifically targeted toward GHG emission reductions. Some of the states and regions within states have tied financial and technical assistance to smart growth planning areas. New Jersey has issued regulations that specifically integrate smart growth principles into utility service policies. Anyone building in State-determined non-smart growth areas must pay the full cost of utility line extensions. Some of the programs are already showing reductions in VMT: Portland residents decreased their daily per capita VMT by 11 percent between 1996 and 2002, while the nation and California both increased daily per capita VMT by 5.7 percent and 6.6 percent, respectively.

Utility Partnerships with Local Planning Efforts are Essential

While electric utilities have been instrumental in supporting local building energy efficiency measures, they have played only a limited role in local government planning. Planning for intrastate transmission lines is underway and must address local and regional issues if future infrastructure has any hope of being developed. As mentioned above, utilities are partnering with local governments to plan new residential and commercial developments. The state's investor owned utilities (IOUs) and municipal utilities need to play an even greater role in planning and development programs and projects. IOUs have stated that their ability to do so is hamstrung by current energy efficiency program time and funding constraints.

Research is a Critical Tool for Ensuring Future Success

Land use impacts on energy demand, energy generation, and transmission and on GHG emissions are in the early stages of exploration. Further research and development is necessary to explain and quantify the impacts land use has on energy systems. Research is needed to develop and update existing modeling and decision-support tools to allow the integration of energy considerations into future planning and development efforts. For example, differences in neighborhood characteristics result in differences in trip generation. Mechanisms to account for the 4 Ds — residential and employment **D**ensity, **D**iversity of land use types, walkable **D**esign, and access to regional **D**estinations — are needed. Many local governments and regional agencies state that access to information and a lack of funding prevent them from implementing climate-friendly and energy-efficient development plans and programs.

For all aspects of future land use and transportation, research and development remains critical to reducing energy use and VMT, and meeting climate change targets. The *2006 Integrated Energy Policy Report Update* charged the Energy Commission's Public Interest Energy Research (PIER) group with providing tools and conducting research to assist the energy and GHG reduction planning efforts of local governments. A number of currently funded projects support this charge. In the next year, over $2 million will be allocated for sustainable communities research. This funding will support initiatives designed to better understand the interaction between

energy demand and environmental design principles, to identify infrastructure design impacts on energy and the environment, and to identify design improvements that would reduce energy use in California. Land use modeling tools are critical to these initiatives.

Transportation research is also underway at PIER, with research designed to reduce petroleum consumption and GHG emissions through increased vehicle efficiency and lower carbon fuels. Creation of new, and validation of existing, transportation modeling tools used in these and similar research efforts are important elements. Understanding the role of smart communities—those that employ information technology to change how the community uses its physical space—in reducing VMT needs to be explored.

Caltrans is developing improved, more integrated transportation models that will allow for improved evaluation of smart growth and should continue to do so. Focused research is needed to maximize the benefits of smart growth and mode transfer from automobiles to mass transit. Technologies that facilitate this transfer need more research to determine the appropriate mix of strategies to reduce VMT.

Aggressive Steps are Needed for Land Use to Meet the State's Energy and Climate Goals

Recommendations

- The state should adopt a statewide growth management plan that is built from required local regional plans and align State planning, financing, infrastructure and regulatory land use policies and programs to the plan
- The state should require regional transportation planning and air quality agencies to adopt 25-year and 50-year regional growth plans that provide housing, transportation and community services for expected population increases while reducing greenhouse gas emissions to state-determined climate change targets.
    - The Air Resources Board should adopt regional greenhouse gas emission reduction levels to guide regional growth management plans in their AB 32 scoping plan. The Board should include in the scoping plan clear guidance on greenhouse gas emissions accounting for urban land use activities and a local government protocol for assessing and tracking greenhouse gas emissions in jurisdictions.
    - The Climate Action Team's Land Use Subgroup should convene a proceeding to develop recommendations for measuring and reducing vehicle miles traveled.
    - The Legislature should pass legislation that requires local governments to develop regional growth management plans that will accommodate 25-years and 50 years of housing, transportation and community service growth needs while meeting Air Resources Board-set regional greenhouse gas emission targets.

The legislation should:

- Require regional growth management plans to be adopted through a joint process between a region's Municipal Planning Organizations and/or Council of Governments (MPO/COGs) and the local air quality management district (AQMDs).
- Require local governments to adopt the portion of the regional plan and greenhouse gas emission reduction target that impact their jurisdiction into their General Plans. The plans should clearly identify areas where growth and development should and should not occur.
- Require MPO/COGs and AQMDs to incorporate the plan and targets into their planning, financing and regulatory programs.
- Require the Governor's Office of Planning and Research to collect the regional growth management plans and combine them to create a statewide growth management plan.
- Require state agencies to modify all programs and policies that affect land use, including but not limited to, planning, financing, capital outlay and compliance, to incorporate, and support, the statewide growth management plan. Colleges, universities and state buildings should also be required to be consistent with the growth management plan.
- Require that the regional and statewide plans, and the local governments, MPO/COGs and AQMDs adoption of them, shall be updated on ten-year schedule.

- State infrastructure financing should encourage development that is consistent with the state's greenhouse gas emission and energy consumption goals.
  - The Legislature should pass legislation for all remaining Strategic Growth Plan bond programs to incorporate climate change and energy consumption reduction measures.
  - If the state adopts growth management legislation as described above, all state infrastructure planning, financing and compliance programs should only allow resources, financial, technical or otherwise, to be spent for development of projects in identified growth areas.
  - The Legislature should pass legislation that requires that all state infrastructure planning, financing and compliance programs should only allow resources, financial, technical or otherwise, to be spent for development of projects in complete consistency with regional Blueprints.

- The Legislature should pass legislation that requires that all state infrastructure planning, financing and compliance programs not allow resources, financial, technical or otherwise, to be spent for development of projects in areas not consistent with existing regional Blueprint plans.

- The state should expand efforts to provide technical and financial assistance to regional agencies and local governments to facilitate climate-friendly and energy efficient planning and development.
  - The state should continue to fund the Blueprint Planning Grant program and Blueprint Learning Network to assist regional agencies and local governments in developing regional growth management plans. The Grant program should include energy consumption and greenhouse gas emission reduction as primary outcomes of the blueprints developed within the program.
  - Upon passage of the above described growth management legislation, the Grant program and Network should be modified to support development of the regional growth management plans as specified in the legislation.
  - The Legislature should pass legislation that implements the Proposition 84 Sustainable Communities Program. The Program should focus on assisting regional and local governments in developing, implementing and incorporating into existing policies the above mentioned growth management plans, Blueprints and climate action plans.
  - The Energy Commission should convene a group of stakeholders, both within and outside of State government, to update its Energy Aware Planning Guide to provide guidance for local governments attempting to adopt local growth management and climate action plans.
  - Using the Energy Commission's new Sustainable Communities research program and the California Department of Transportation's existing research efforts as the base, the state should convene a land use research group to identify research needs, carry out research and develop and disseminate tools and resources to land use stakeholders.

- State government should be a model for climate friendly and energy efficient development patterns.
  - The Legislature should pass legislation that builds upon AB 857's intentions by adding greenhouse gas emissions reduction and energy consumption as priority planning goals of the state. The legislation should require that state agencies engaging in or financing the development of infrastructure or capital outlay projects report on the project's compliance with state planning policies during each stage of its

administrative and legislative budget approvals. The legislation should require that projects that do not meet the state planning priorities should not be funded except in situations where compliance would be proven infeasible by the sponsoring agency.

- The Climate Action Team Land Use Subgroup should develop greenhouse gas emissions reduction and energy efficiency guidelines for state agency programs that affect land use. State agencies should adopt the guidelines to the greatest extent feasible.

- The state should determine the extent to which state and local tax policies affect and guide land use practices and correct polices that encourage growth inconsistent with the state's growth management plan.
  - The Governor's Office of Planning and Research, working with local governments, the building community, the university system and other stakeholders should conduct a study of the impacts of state and local tax policy on land use practices in the state. The report should contain recommendations for changing identified tax policy that leads to detrimental land use practices.

- California's utilities should play an active role in regional and local government planning and development efforts at both the plan and project level to encourage climate friendly and energy efficient development in their service areas.
  - The California Public Utilities Commission should allow utility-incentive and technical-assistance programs with longer lead times to enable greater collaboration by utilities with developers and local governments.

- The state should work with its Congressional delegation to ensure that future federal highway and other transportation and land use related legislation and programs include energy reduction and climate stabilization considerations.