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Governor

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Preface

The *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 (Public Resources 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 necessary 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

*"We can't solve problems by using
the same kind of thinking we used
when we created them."*

Albert Einstein

California's vibrant economy is dependent on reliable and affordable supplies of energy. Yet, fossil-based energy produces greenhouse gases that are the primary contributors to climate change. California's challenge, like that of the rest of the developed world, is how to maintain its growth and vitality while decreasing its contributions to global greenhouse gas emissions.

Responding to this challenge, Governor Arnold Schwarzenegger and the California Legislature placed reducing greenhouse gas emissions at the center of their agendas. Assembly Bill 32 (Núñez, Chapter 488, Statutes of 2006), the California Global Warming Solutions Act of 2006 (AB 32), mandates that California reduce its greenhouse gas emissions to 1990 levels by 2020.

In 2004, the state produced almost 500 million metric tons of carbon dioxide (CO₂). Reducing California's *greenhouse gas footprint* to meet AB 32 goals will require approximately a 29 percent¹ cut in emissions below the levels the state is currently projected to produce in 2020.

As the second largest emitter of greenhouse gases in the United States and about twelfth largest in the world, California's efforts to reduce its emissions will lead the way for other governments, as well easing the severity of environmental and economic impacts experienced this century.

AB 32 marks a significant change in California's energy policies. Before its passage, energy policy makers focused on stabilizing and/or minimizing energy costs, ensuring supply, limiting dependence on imports and fossil fuels, protecting the environment, and benefiting the state's economy.

AB 32 upped the ante: California is obligated to meet its previous energy goals, but it must do so while reducing the volume of CO₂ emissions. Slowing global warming requires meeting energy needs with zero- or low-carbon energy sources.

California has led the nation in effective action to improve air quality and has held the line on per capita consumption of electricity. But, with a growing population and economy, California must ensure that energy supplies keep pace with the growth while simultaneously reducing its greenhouse gas footprint.

Today one in eight Americans, more than 37 million people, lives 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, its population would make it the 33rd largest in the world. The state Department of Finance expects California will add another 7 million people in the next dozen years, growing to more than 44 million by 2020 and moving toward 60 million residents by 2050.²

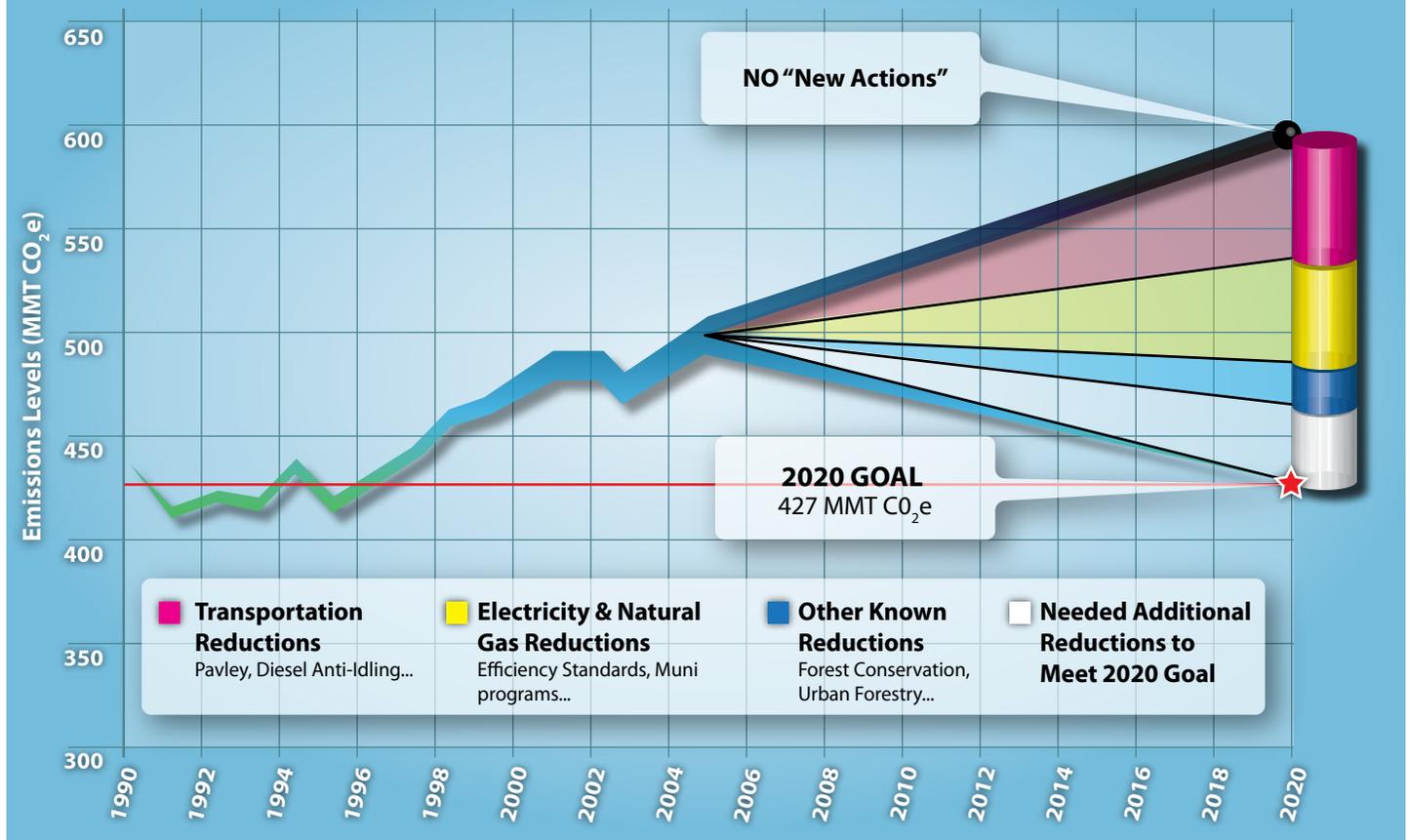
Affordable and reliable energy is essential to California's successful economy. Energy represents nearly \$100 billion in annual expenditures. Fossil fuels dominate the state's energy system — petroleum to serve the transportation sector and natural gas to heat homes and generate electricity. Most of California's greenhouse gases are carbon dioxide, which accounts for 89 percent of emissions. Methane (CH₄), nitrous oxide (N₂O), and other man-made gases contribute the remainder of the gases. Of those emissions, 25 percent results from electricity generation and 38 percent from transportation.³

1 The 29 percent reduction of greenhouse gas emissions from a business-as-usual 2020 level is based on 173 million metric tons CO₂ equivalent as adopted by the California Air Resources Board, December 6, 2007.

2 California Department of Finance, Demographic Research Unit, July 2007.

3 California Air Resources Board, *Greenhouse Gas Emissions Inventory*, adopted December 6, 2007.

Figure ES-1: California's CO₂ Emission Reduction Strategies



Source: California Energy Commission, Climate Action Team data.

The top line on Figure ES-1 shows the anticipated growth in emissions levels with no new strategies undertaken to reduce this growth. The figure also depicts the potential effects of AB 32-compliant actions. The effects of these strategies can be significant compared to the projected unmitigated growth in emissions.

The Electricity Sector

Electricity accounts for 28 percent of the state's CO₂ emissions and demand for electricity is forecasted to grow at a steady pace, fed by a projected increase in population. Even with a decrease in the rate of population growth, from 1.8 percent to 1.2 percent annually, the cumulative growth will

significantly affect statewide annual electricity consumption. In addition, tendencies toward larger houses and more and bigger appliances will increase expected growth in electricity demand. Projected effects of building and appliance standards and energy efficiency programs will mitigate some of this electricity growth, but overall electricity demand is still expected to increase an average of 1.25 percent annually.

California uses less electricity per person than any other state in the nation. 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 cost-effective building and appliance efficiency standards and other energy efficiency programs (Figure ES-2).

Figure ES-2: California Holds the Line on Electricity Consumption
(Per Capita Electricity Sales in Kilowatt Hours)



Source: California Energy Commission.

How California generates the electricity required to power its economy and support its growth has changed over the years. In the late 1970s, petroleum was the fuel source for over half of the state’s electricity. Today, cleaner-burning natural gas produces over 41 percent of the state’s electricity, and renewable resources account for about 11 percent.

Since 2003, California’s energy policy has defined a *loading order*⁴ of resource additions to meet the state’s growing electricity needs: first, energy efficiency and demand response; second, renewable energy and distributed generation; and third, clean fossil-fueled sources and infrastructure improvements. This strategy has had the benefit of reducing CO₂ emissions and diversifying our sources of energy.

Energy efficiency, which helped to flatten the state’s per capita electricity use, will continue to be the keystone of California’s energy strategy. California’s building and appliance standards have saved consumers more than \$56 billion in

electricity and natural gas costs since 1978 and averted building 15 large power plants. It is estimated the current standards will save an additional \$23 billion by 2013.

Overall electricity use in California is projected to grow at 1.25 percent annually; however, *peak*⁵ demand is growing at a rate of 1.35 percent (850 megawatts) per year. This increase in peak demand is the result of a population that is moving inland to the hotter areas of the state, prompting higher demand for electricity for air conditioning.

While nearly 70 percent of the state’s population currently lives along coastal California, it is the state’s inland areas — the San Joaquin Valley, Southern California’s Inland Empire, and the Sacramento area — 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 overall demand for electricity, it changes the pattern of energy use. The climate inland

⁴ 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.

⁵ *Peak* refers to the highest hourly demand for electricity. Summer demand peaks are mostly driven by increased air conditioning during the hottest hours of the day on the hottest days of the year.

is more extreme than along the coast. In the summer, inland areas require more air conditioning than coastal areas, increasing peak demand more dramatically than overall electricity demand.

With the pressure of increasing population growth in drier, hotter inland areas, energy efficiency and demand response programs become even more important. The California Energy Commission (Energy Commission) and the California Public Utilities Commission (CPUC) are collaborating to step up the state’s efficiency efforts. 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 investor-owned 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.” The Energy Commission concluded that the statewide targets should be set to achieve all of the state’s cost-effective energy efficiency. The CPUC supports this goal and has described a course of action focused on programs under its and the Energy Commission’s authority to pursue it.⁶

Scenario analysis indicates that these aggressive cost-effective efficiency programs, when coupled with renewables development, could allow the electricity industry to achieve at least a proportional reduction,⁷ and perhaps more, of the state’s CO₂ emissions to meet AB 32’s 2020 goals.

The Energy Commission strongly supports capturing all cost-effective efficiency savings potential and recommends that this agency:

- Adopt statewide energy efficiency targets for 2016 equal to 100 percent of economic potential, to be achieved by a combination of state and local standards, utility programs, and other strategies.

⁶ California Public Utilities Commission decision D.07-10-032 adopted October 18, 2007.

⁷ Proportional to the estimated amount of emissions that the electricity sector emitted in 1990.



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

- Enlist publicly owned utilities in a collaborative relationship to further their efforts in aggressively ramping up energy efficiency programs. Publicly owned utilities can use their knowledge of local conditions and customers to craft new program ideas.
- Pursue legislation that would require energy audits and a cost-effective level of efficiency improvements at the time of sale of a building.
- Initiate a rulemaking, involving the CPUC and the California Independent System Operator (California ISO), to pursue the adoption of load management standards under the Energy Commission’s existing authority.
- Enact appliance standards to improve the efficiency of appliances sold in California, including standards to increase the efficacy of general service lighting.

- Increase the efficiency standards for buildings so that, when combined with on-site generation, newly constructed buildings can be net zero energy by 2020 for residences and by 2030 for commercial buildings.
- Investigate market-based approaches to energy efficiency, such as “white tags” or “white certificates” (also known as energy efficiency certificates or credits), the companion to renewable energy credits.

Renewable resources are essential for reducing greenhouse gas emissions and reaching AB 32 goals. Over the last three decades, the state has built one of the largest and most diverse renewable generation portfolios in the world. Currently, about 11 percent of the state’s electricity is from renewable energy sources such as solar, wind, and biomass.

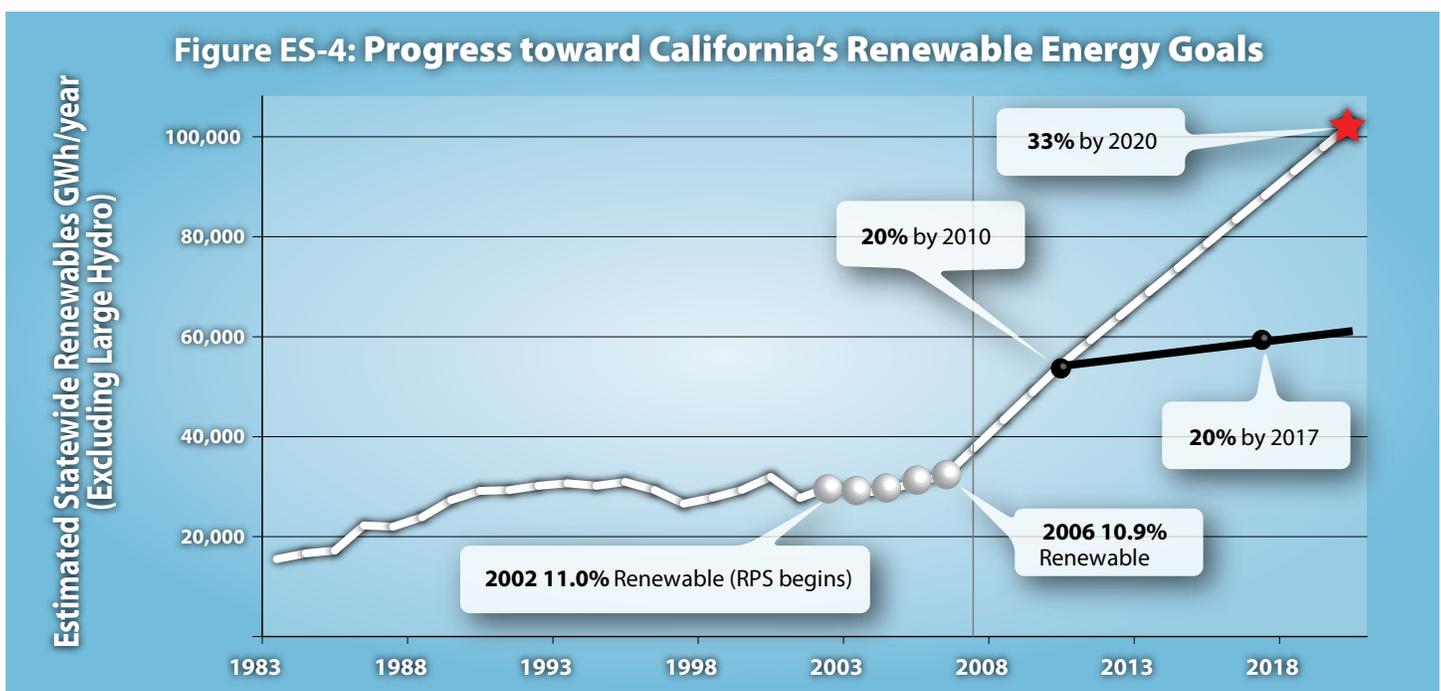
Senate Bill 1078 (Sher, Chapter 516, Statutes of 2002) introduced a Renewables Portfolio Standard (RPS) with the goal of increasing the portion of electricity derived from renewable resources and sold to retail customers to 20 percent by 2017. Initially designed to address California’s growing dependence on natural gas for electricity generation and encourage long-term power purchase contracts, the RPS is also

an important means for meeting the state’s AB 32 greenhouse gas emission reduction goals. Senate Bill 1250 (Perata, Chapter 512, Statutes of 2006) accelerated the 20 percent goal to 2010. The Governor, the Energy Commission, and the CPUC have endorsed an enhanced target of 33 percent renewables by 2020.

So far, however, the RPS results have not kept pace with its mandate due principally to insufficient transmission infrastructure and complex administration (Figure ES-4). The utilities are not expected to be able to serve 20 percent of their retail load with renewables by 2010, although they may have contracted for the necessary amount by that date. The 33 percent goal by 2020 is feasible, but only if the state commits to significant investments in transmission infrastructure and makes some key changes in policy.

The Energy Commission strongly supports renewable energy development to achieve the RPS targets and recommends that this agency:

- Leverage its power plant licensing and transmission corridor designation authority, its environmental expertise, and its transmission planning and policy experience to guide further renewable resource development in California.



Source: California Energy Commission.

- Establish a more cohesive statewide approach for renewables development that identifies preferred renewable generation and transmission projects in a “road map” for renewables.
- Implement a feed-in tariff, set initially at the market price referent, for all RPS-eligible renewables up to 20 megawatts in size.
- Collaborate with the CPUC to evaluate feed-in tariffs for larger projects. Such tariffs should incorporate the value of a diverse mix of renewables as well as features of the most successful European feed-in tariffs.
- Collaborate with the CPUC to establish an appropriate feed-in tariff for excess generation from customer-owned solar installations.

The Energy Commission also recommends that:

- The wind industry expand and repower existing wind sites to increase the efficient use of existing infrastructure.
- The CPUC revise the market price referent calculation to more fully reflect price volatility; market costs of long-term, fixed-price power; and appropriate greenhouse gas adders.
- The greenhouse gas reductions attributable to the RPS be removed from any cap-and-trade allowance system.

Even as California increases its use of preferred strategies of efficiency and renewable resources, conventional resources — natural gas, nuclear, coal, and large hydroelectric — will continue to be the mainstay of the state’s resource mix for the immediate future.

Non-renewable generation resources and large hydroelectric currently account for 89 percent of the state’s electricity supply. Even when California’s 33 percent renewable target is met, two-thirds of the state’s electricity will still come from conventional sources — the vast majority of which will be natural gas-fired.

Of the nearly 24,000 megawatts of new capacity licensed since 1998, 36 plants — 12,910 megawatts — have been

built and are in operation. An additional 2,278 megawatts are currently under construction, and 18 additional plants, totaling 8,361 megawatts, have been approved, but construction has not moved forward. Of these megawatts, 99 percent are fueled by natural gas and 1 percent by geothermal.

While nuclear and “clean” coal-fired generation offer the potential to generate electricity with lower CO₂ emissions, the Energy Commission does not expect them to contribute significantly to the state’s near-term AB 32 goals given the economic, environmental, and regulatory barriers these technologies face.

The Energy Commission supports the improved use of California’s electricity infrastructure and recommends that this agency:

- Conduct a public process including the CPUC, utilities, and other stakeholders to determine an effective method to better delineate the energy efficiency savings assumptions in the Energy Commission’s staff forecasts.
- Develop a common portfolio analytic methodology to clearly influence the long-term procurement plans filed by the investor-owned utilities.
- Refine in the *2009 Integrated Energy Policy Report* the input data used for developing technologies in the Cost of Generation Model and establish a process to regularly update changing technology costs over time.
- Include in the *2009 Integrated Energy Policy Report* a robust assessment of the effect of high levels of preferred resources on reducing natural gas prices.
- Ensure that California’s interests in the nuclear process are protected by taking an active role in the Yucca Mountain licensing proceeding; challenging the U.S. Department of Energy’s inadequate response to potential impacts identified by California; and continuing to participate in Department of Energy and regional planning activities for nuclear waste shipments.

- Incorporate Institute of Nuclear Power Operations (INPO) reviews and ratings of reactor operations into a meaningful public process while maintaining the value of the INPO reviews as candid assessments.
- Assess the reliability implications of federal and state once-through cooling regulations for California’s operating nuclear plants.

The Energy Commission also recommends the CPUC:

- Require investor-owned utilities to procure enough capacity from long-term contracts to allow for the orderly retirement or repowering of aging plants by 2012.
- Require Southern California Edison to develop, as part of its long-term procurement plans, a contingency plan to replace generation from Palo Verde should it be shut down for an extended period.

Electric distribution systems throughout California still mainly use designs, technologies, and strategies that were designed to meet the needs of mid-20th century customers. These large and complex systems have historically provided reliable electric power to millions of customers throughout the state; however, aging infrastructure coupled with modern demands is starting to erode this capability. About 90 percent of all customer interruptions and outages are caused by distribution problems.

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

The Energy Commission supports the development of a modern electric distribution system to incorporate new resources and recommends that the state:

- Integrate distribution planning with other resource procurement processes to support the use of new low-carbon resources and applications — renewables, demand response, efficient combined heat and power, distributed generation, energy storage, advanced metering infrastructure, and plug-in hybrid electric vehicles.
- Fund research to develop and demonstrate technologies that will accelerate the transformation of the distribution grid into an intelligent and sustainable network.
- Develop new rate designs that will encourage consumers and utilities to invest in promising technologies.
- Provide financial incentives for utilities to meet goals related to performance, achievement of designated goals, service reliability, and customer assistance to achieve greater efficiency of electricity use.
- Allow utilities to recover the remaining book-value costs of equipment rendered obsolete by the deployment of a qualified smart grid system.

Distributed generation and combined heat and power, regardless of size or interconnection voltage, are valuable resource options for California. Combined heat and power, in particular, offers low levels of greenhouse gas emissions for electricity generation, taking advantage of fuel that is already being used for other purposes. Distributed generation can also play an important role in helping to meet local capacity requirements. California ISO has encouraged the CPUC to include local capacity requirements in its procurement process to replace power plants that must operate, even if uneconomically, to preserve system reliability.

The Energy Commission has encouraged development of distributed generation resources, including combined heat and power projects, since the late 1990s and continues today through collaborative efforts with the CPUC to address

barriers to distributed generation development. Yet, significant issues facing distributed generation developers persist. In the *2005 Integrated Energy Policy Report (2005 IEPR)*, the Energy Commission reported that, despite many years of policy preferences, distributed generation and combined heat and power 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 must improve access to wholesale energy markets and streamline utility long-term contracting processes so that combined heat and power facility owners can efficiently sell excess electricity to their local utility. Accessibility to the wholesale market continues to be a major consideration in encouraging distributed generation.

The Energy Commission continues to support distributed generation and recommends that this agency:

- Work with the CPUC to eliminate non-bypassable charges for combined heat and power and distributed generation and punitive standby reservation charges for distributed generation.
- Develop a methodology for estimating distributed generation costs and benefits.

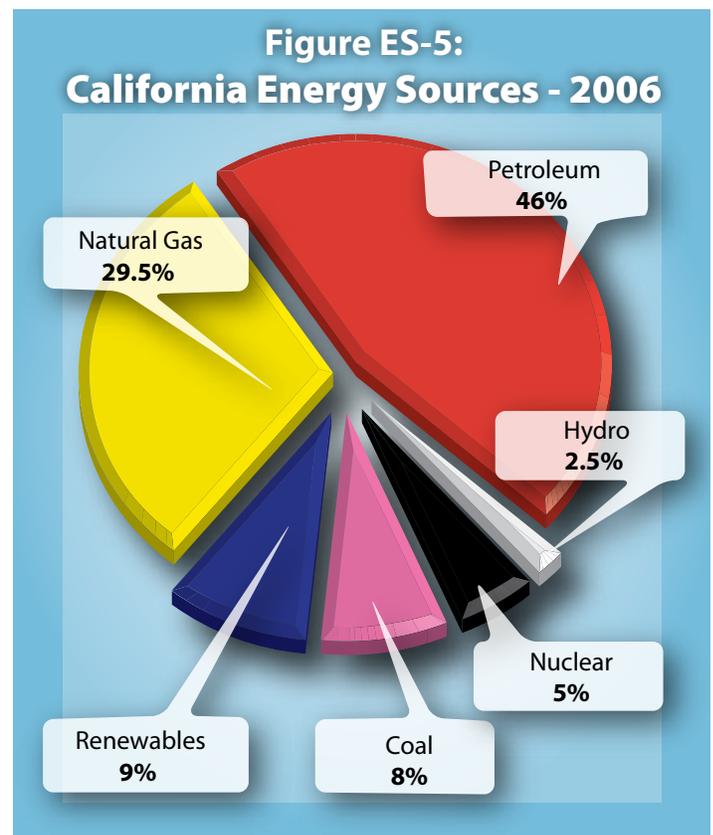
The Energy Commission also recommends:

- The CPUC 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 state adopt greenhouse gas reduction measures and regulations that fully reflect the benefits of combined heat and power.
- The CPUC adopt a tariff structure to make distributed generation projects “cost and revenue neutral,” while granting owners credit for system benefits, such as reduced congestion.

- The CPUC base self-generation program incentives on overall efficiency and performance of systems, regardless of fuel type.
- The CPUC adopt revenue-neutral programs that would allow high efficiency combined heat and power on an equal footing with bulk power from utilities.

The Natural Gas Sector

Almost 30 years ago, California’s serious air quality problems made natural gas the fuel of choice for electricity generation. Natural gas was cleaner burning, relatively cheap, and helped diversify the state’s electricity generation system. Today, natural gas provides almost a third of the state’s total energy requirements and will continue to be a major fuel in California’s supply portfolio (Figure ES-5).



Source: California Energy Commission.

Imports of liquefied natural gas are expected to supplement conventional supply sources and help stabilize prices.

With only a single liquefied natural gas facility under construction on the West Coast, however, the arrival of additional liquefied natural gas supplies may be delayed.

The Energy Commission recommends this agency take the following actions to maintain a reliable supply of natural gas:

- Improve the ability to forecast natural gas production, demand, and price, including:
 - Conducting a rigorous verification of the models used to forecast natural gas supply and price.
 - Developing probabilities and quantifying outcomes for demand scenarios to gain better insight into natural gas demand.
- Increase natural gas research and development for ways to advance energy efficiency for both consumers and power plants.
- Support displacing natural gas with renewable sources to generate electricity and alternatives such as solar for water and space heating.
- Establish with the CPUC an appropriate feed-in tariff for pipeline-quality biogas.

The Energy Commission also recommends:

- The state secure alternative and diverse sources of natural gas, including liquefied natural gas, through licensing facilities that meet stringent environmental and public health and safety standards.
- California's utilities adopt all cost-effective energy efficiency measures for natural gas, including replacement of aging power plants with new efficient power plants.

The Transportation Sector

Transportation is the single largest contributor to California's greenhouse gas emissions, producing 39 percent of the state's total emissions in 2004. California has long been regulating the criteria pollutants from automobiles. The state 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, California began the first of many phases of reformulated clean-burning gasoline, and in 1993, the state enacted new standards for cleaner diesel fuel. However, reducing greenhouse gas emissions is a new, more difficult challenge for a state so heavily dependent on automobiles.

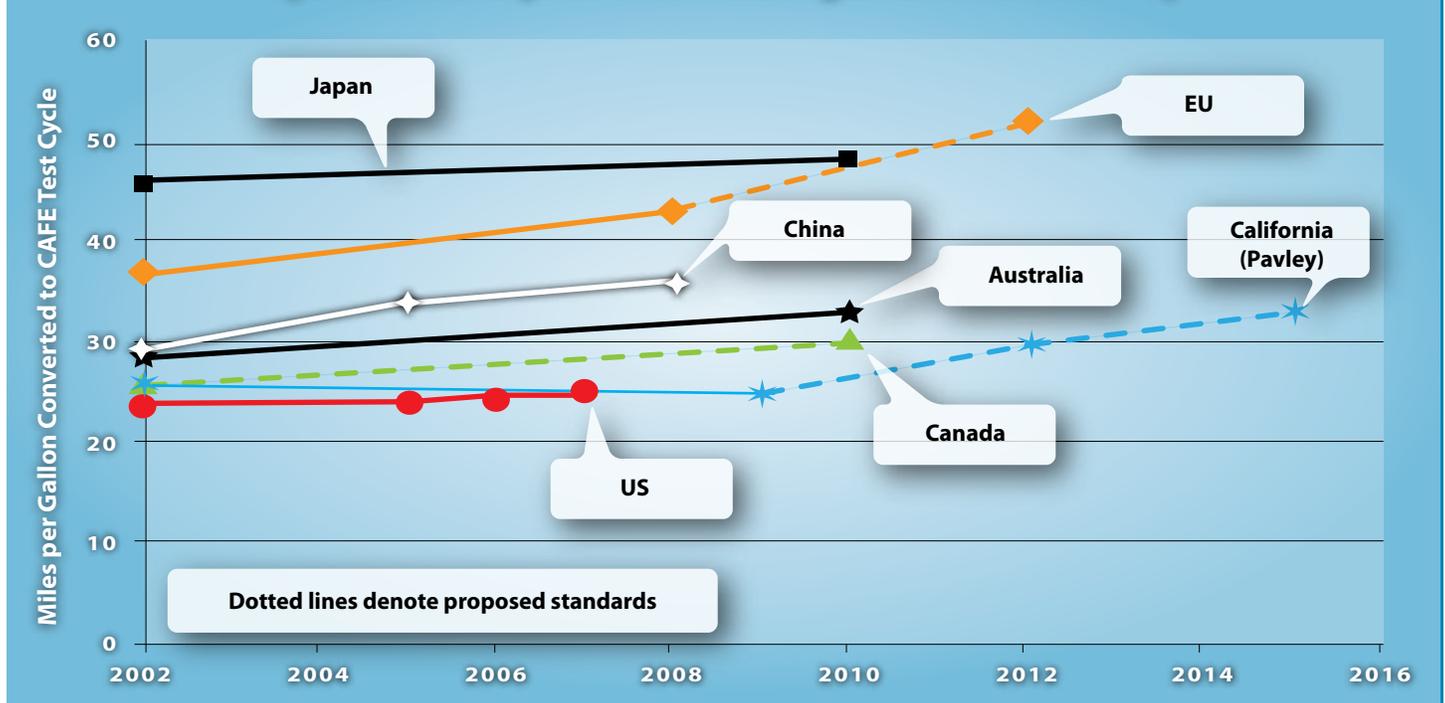
There is some good news. While national demand grew by 1.5 percent in the first half of 2007, according to the American Petroleum Institute, consumption in California actually dropped. Californians used more than 63 million *less* gallons of gasoline from January through August 2007 than during the same period in 2006.⁸ Despite these recent statistics, demand for gasoline and diesel is projected to increase in California by 1 to 2 percent each year as a growing population registers more vehicles and drives more miles.

As the third largest consumer of transportation fuels in the world (behind the United States as a whole and China) — almost 16 billion gallons of gasoline and more than 4 billion gallons of diesel used 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. In 2003, the Energy Commission and the California Air Resources Board (ARB) reviewed the technical and economic aspects of a major reduction in the petroleum dependence of California's transportation sector.⁹ Based on this research, in 2005, Governor Schwarzenegger appealed to the

⁸ California Board of Equalization, Net Taxable Gasoline Gallons, 2000–Present.

⁹ California Energy Commission and the California Air Resources Board, *AB 2076 Report*, adopted 2003.

Figure ES-6: Comparison of Passenger Car Fuel Economy



Source: Pew Center on Global Climate Change, *Comparison of Passenger Vehicle Fuel Economy and Greenhouse Gas Emission Standards Around the World*, December 2004.

United States House of Representatives “to establish new fuel economy standards that double the fuel efficiency of new cars, light trucks and SUVs.”¹⁰ 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-miles-per-gallon standard pales in comparison with Japan’s current standard of 45 miles per gallon and Europe’s more than 50-miles-per-gallon standard by 2012, and may ultimately be too little, too late (Figure ES-6).

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)¹¹ 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, 15 other states have adopted or are considering 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 affirming that the Environmental Protection Agency does have the authority to regulate CO₂ emissions.

Decreasing California’s reliance on petroleum fuels is critical. By 2020, at current trends, 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 CO₂ emissions and addressing infrastructure capacity and reliability. Transportation contributes nearly 40 percent of California’s greenhouse gases; reducing its transportation-related CO₂ emissions requires alternative fuels, alternative vehicles, new

10 May 13, 2005 letter from Governor Arnold Schwarzenegger to Senator Jeff Bingaman, chairman, and Senator Pete Domenici, member, Senate Energy and Natural Resources Committee, U.S. Senate.

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

standards, and advances in technology. Although the anticipated population growth will not make it easy to reduce our greenhouse gas footprint, it is essential that we find the means to do so.

Assembly Bill 1007 (Pavley, Chapter 371, Statutes of 2005) tasked the Energy Commission to develop a plan for reducing the state's petroleum use and greenhouse gas emissions and for increasing the use of non-petroleum transportation fuels in California. As required by the statute, the Energy Commission adopted the State Alternative Fuels Plan in October 2007. Results of the plan's full fuel cycle ("well-to-wheels") analysis demonstrate that certain alternative fuels can provide substantial greenhouse gas reduction benefits when used in mid-sized passenger cars and urban buses. Fuels such as ethanol, natural gas, liquefied propane gas, electricity, and hydrogen can have important 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 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. Substantial investment is also needed in fueling infrastructure, production facilities, vehicle components, and commercial development of *second generation*¹² alternative fuels and advanced technology vehicles. In 2007, Governor Schwarzenegger signed AB 118 (Núñez, Chapter 750, Statutes of 2007) into law, providing a much-needed funding source for incentives to encourage this investment.

More than 60 percent of the crude oil used by California-based refineries to make the state's transportation fuels is imported into the state. California's refineries also import 10 percent of the refined and finished petroleum products to meet demand. No pipelines bring crude oil or petroleum products into California; all of these imported products arrive

by ship through marine terminals. The marine terminals, specifically those in Los Angeles and Long Beach, are congested and near their maximum berth and storage capacity.

As the demand for transportation fuels continues to grow, California's 21 refineries have responded by gradually increasing their capacity. 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 as much as 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 California's refineries to produce those fuels. Importing increasing quantities of finished petroleum products puts more pressure on already congested marine terminals.

Over the next several decades, California must pursue strategies to increase fuel efficiency, expand non-traditional fuel use, and ultimately realign consumer preferences to reduce demand for all transportation fuels. In the near term, California must expand its marine terminal capacity, marine storage, the pipelines connecting these facilities with the refineries, and other distribution pipelines.

The Energy Commission recommends the following actions by this agency to meet California's growing transportation needs:

- Propose legislation that allows state appeals in the petroleum marine infrastructure lease renewal process at the Ports of Los Angeles and Long Beach.
- Assess the impact on infrastructure development 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.
- Advocate for a federal funding mechanism to maintain an adequate depth for tanker traffic in the Pinole Shoal in San Francisco Bay.

¹² *Second generation* alternative fuels refer to those biofuels that are under development and often called "advanced" or "emerging," such as biobutanol, which is an ethanol substitute produced from cellulose.

The Energy Commission also recommends:

- The state increase alternative fuels use to 9 percent by 2012, 11 percent by 2017, and 26 percent by 2022, to meet the AB 1007 goals that reduce petroleum fuels use and greenhouse gas emissions.

Land Use

Decisions affecting land use directly affect energy use and the consequent production of greenhouse gases, primarily because of the strong relationship between where we live and work and our transportation needs. Significant efforts are necessary to reduce vehicle miles traveled to meet the state’s emission reduction goals. California must begin reversing the current 2 percent annual growth rate of vehicle miles traveled. 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.

Housing, transportation planning, and local greenhouse gas reductions require local and regional approaches. California’s metropolitan planning organizations are involved in long-range planning efforts to develop transportation plans that incorporate improved land use decisions. These plans are expected to reduce energy and climate impacts in metropolitan 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 result in plans to coordinate land use and transportation development. The plans accommodate housing needs, reduce the rate of growth of vehicle miles traveled, and identify priority-planning areas. They are in early stages of implementation and may require 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, bond funding, 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. In

addition, the state can provide local governments with tools and technical assistance to help meet greenhouse gas emission goals.

The Governor’s Strategic Growth Infrastructure Bond package represents an opportunity to influence the energy efficiency and environmental friendliness of communities through project funding criteria. 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 require regulatory support to achieve.

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

The Energy Commission supports the adoption of efficient and effective land use planning and recommends that the state:

- Adopt a unified statewide growth management plan, based on local and regional plans, aligning state planning, financing, infrastructure, and regulatory land use policies and programs.
- 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 projected population increases while reducing greenhouse gas emissions to state-determined climate change targets.
- Expand efforts to provide technical and financial assistance to regional agencies and local governments to facilitate climate-friendly and energy-efficient planning and development.
- Model climate-friendly and energy-efficient development patterns.
- Determine the extent to which state and local tax policies affect and guide land use practices and revise policies that encourage growth that is inconsistent with the state’s growth management plan.

- Direct California's utilities to play an active role with regional and local governments to encourage climate-friendly and energy-efficient development in their service areas.
- Work with California's 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

Energy and the environment are inextricably linked. Meeting the mandate of AB 32 will require aggressive and immediate action from all Californians — government, private entities, and individual citizens. The *2007 IEPR* reviews the issues of California's energy system to assess how we can meet the state's growing energy needs while restraining greenhouse gas emissions.

The Energy Commission offers the *2007 IEPR* as a balanced and considered review of the major energy issues facing the state as it grapples with meeting the enormous challenge of reducing greenhouse gas emissions. A single state alone cannot stabilize the world's climate. But California has a reputation for innovation. Other states and countries follow our lead. If history is a predictor of a state's ability to make a difference on the world stage, California's actions on climate change will drive global progress.

Chapter 1



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

"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

Available, affordable, reliable, technologically advanced, and environmentally sound energy drives California's successful economy. Scientific consensus is that temperatures in the state are expected to increase during this century, and precipitation patterns are predicted to change — threatening California's environmental quality and robust economy.

This temperature increase will result in widespread environmental consequences — worsening air pollution, intensifying heat waves, increased coastal floods, reduced farmland productivity, increased wildfires and pest infestations, decreased fish populations and reduced snowpack, which means less hydropower and possible water shortages.

Last year, Republican Governor Arnold Schwarzenegger and a Democratic Legislature passed the California Global Warming Solutions Act of 2006 (Assembly Bill 32, Núñez, Chapter 488, Statutes of 2006), capping California's greenhouse gas emissions at the 1990 level by 2020. Achieving that goal requires about a 29 percent¹³ cut in emissions below projected 2020 levels. The Governor's long-term target is far more ambitious and calls for reducing emissions to 80 percent below 1990 levels by 2050. This is the level of worldwide reduction believed by many climate scientists as necessary to limit global temperature gains this century to 2 to 3 degrees Celsius.

AB 32 places reducing greenhouse gas emissions at the center of government and business agendas. 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's

progressive energy policies must now also include reducing the state's *greenhouse gas footprint*,¹⁴ and stepping up the intensity of existing programs, standards, and regulations is mandatory to achieve aggressive carbon dioxide (CO₂) reduction.

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.

Its mild climate and fertile soil, coupled with some of history's most imaginative water projects at the time, earned California the reputation as the bountiful breadbasket to the nation, while the discovery of oil made it an energy pioneer. As early as 1910, the state was producing almost 78 million barrels of oil a year,¹⁵ 22 percent of the entire world's oil production at the time.

13 The 29 percent reduction of greenhouse gas emissions from a *business-as-usual* 2020 level is based on 173 million metric tons of carbon dioxide equivalent as adopted by the California Air Resources Board, December 6, 2007.

14 *Greenhouse gas footprint*, often referred to as *carbon footprint*, is a measure of the impact of human activities on Earth's climate systems, directly or indirectly, as greenhouse gas emissions produced over the life cycle of a product, service, or activity. These gases trap outgoing radiation that heats the atmosphere, increasing the *greenhouse effect* or global warming. The measure is usually expressed as tons of carbon dioxide (CO₂) equivalent. CO₂ accounts for about 89 percent of human-caused greenhouse gas emissions in California. Methane (CH₄), nitrous oxide (N₂O), and other man-made gases contribute the remainder of the gases.

15 Department of Conservation, Division of Oil and Gas, *Oil and Gas Production: History in California*, <[ftp://ftp.consrv.ca.gov/pub/oil/history/History_of_Calif.pdf](http://ftp.consrv.ca.gov/pub/oil/history/History_of_Calif.pdf)>.

Guiding Energy Policy

The California Energy Commission was created as the state's principal 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. Six basic responsibilities guide the Energy Commission as it sets 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; research development and demonstration; 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 operational and administrative 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 \$0.0002 per kilowatt hour of electricity consumption – about 12 to 14 cents per month on an average bill.

Despite its 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 eighth largest economy in the world. Our diverse, mobile, dynamic, and creative population has put it at the forefront of environmental, economic, technological, political, social, and cultural development.

With a current population exceeding 37 million and projected to grow to more than 44 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 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 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 more than 30 years, the California Energy Commission has focused the state's energy policy on finding the most cost-effective, reliable, and 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 more than 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 (Figure 1-1).

The state also changed the way it generates electricity. By the late 1970s, petroleum was the fuel source for more than half the state's electricity. Today, cleaner-burning natural gas fuels more than 41 percent of the state's electricity, and renewables account for almost 11 percent.

Figure 1-1: California Holds the Line on Electricity Consumption
(Per Capita Electricity Sales in Kilowatt Hours)



Source: California Energy Commission.

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.

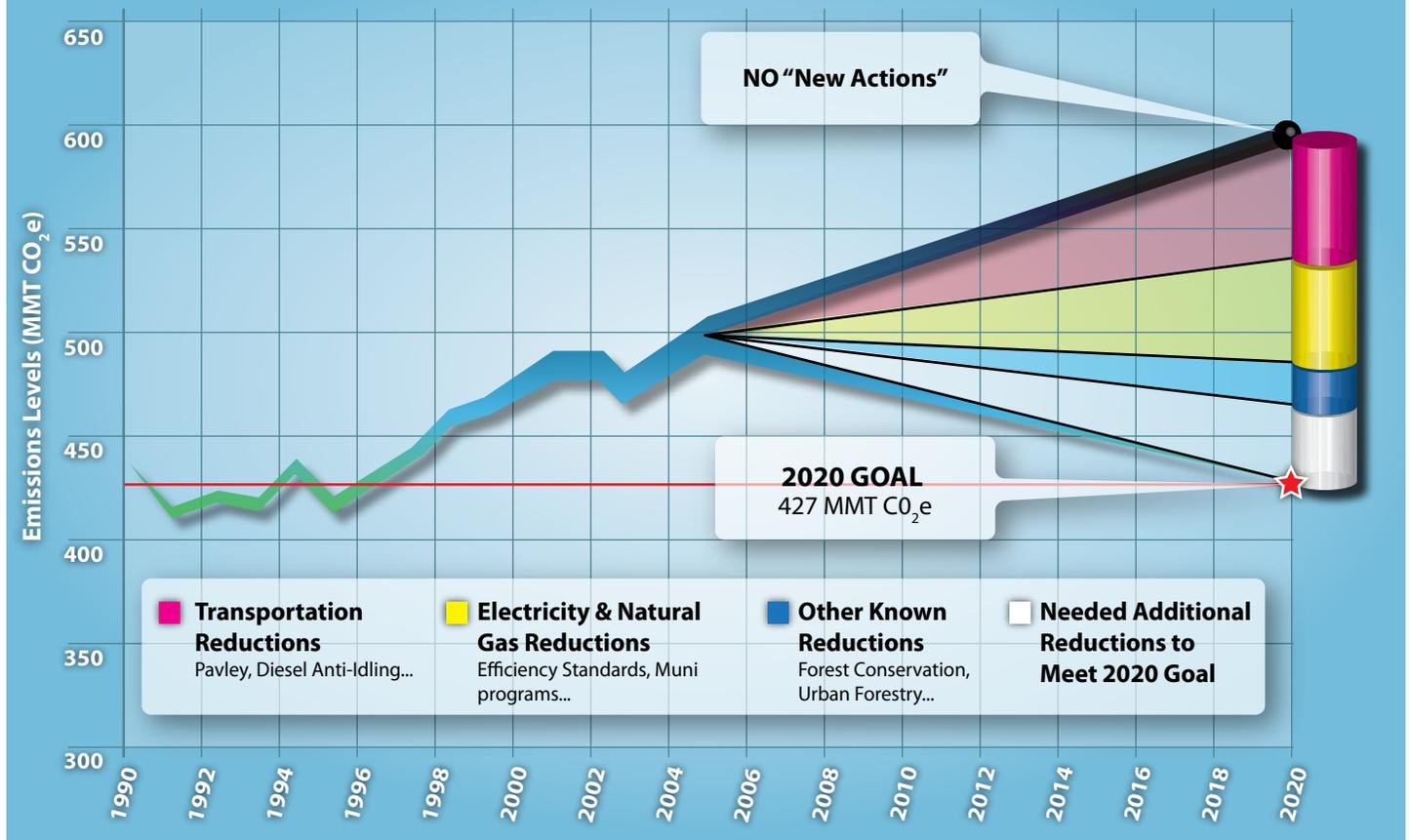
Despite its passion for the automobile, California adopted stringent tailpipe emission standards as early as 1966, and in 1971 adopted the first automobile nitrogen oxides standards — both the first such standards in the nation. The California Smog Check Program, which assured the effectiveness of vehicle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

Regardless of the federal response, California has continued to move forward. Assembly Bill 1007 (Pavley, Chapter 371, Statutes of 2005) directs the Energy Commission, in partnership with the California 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 and greenhouse gas reduction and in-state biofuels production and use goals, as articulated in the Governor’s Executive Order S-06-06. The Executive Order calls for California to produce a minimum of 20 percent of its biofuels — transportation fuels prepared from non-fossil feedstocks — within the state by 2010, 40 percent by 2020, and 75 percent by 2050. The plan’s first phase, a full fuel cycle analysis, forms the technical basis for the ARB’s Low Carbon Fuel Standard

Figure 1-2: Reaching for the AB 32 Target



Source: California Energy Commission, Climate Action Team data.

that is designed to increase the use of transportation fuels that emit lower quantities of greenhouse gases on a life-cycle basis.

Yet, California's projected population increase will offset whatever gains existing efforts have made and continue to make in reducing emissions. The state currently emits almost 500 million metric tons of greenhouse gases — 28 percent from electricity generation and more than 39 percent from transportation. California must step up efforts with every emission-saving technique in its substantial repertoire for transportation and electricity to reduce greenhouse gases in 2020 to the levels mandated by the AB 32 goals (Figure 1-2).

Greenhouse Gas Emissions

Climate change is the most important environmental and economic challenge of this century, and greenhouse gas

emissions are the largest contributors to global warming. California's greenhouse gas emissions are huge and growing. In 2004, California produced almost 500 million metric tons of CO₂ (greenhouse gas emission equivalent) — making the state the second largest emitter of greenhouse gas emissions in the United States after Texas and about twelfth in the world.

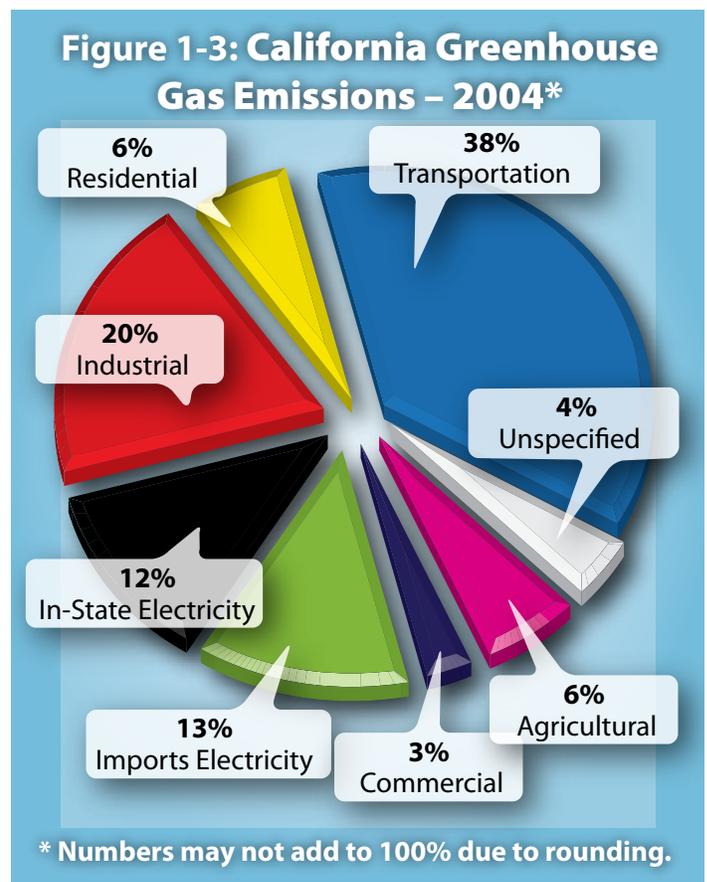
The transportation sector is the single largest source of California's greenhouse gas emissions, producing more than 38 percent of the state's total emissions in 2004 (Figure 1-3). Most of California's greenhouse gases, or 89 percent, are from CO₂, and the remaining gases include methane, nitrous oxide, and other man-made gases.¹⁶

¹⁶ The California Air Resources Board estimates that the distribution of greenhouse emissions in 1990, by contrast, was as follows: transportation, 35 percent; imported electricity, 14 percent; in-state electricity, 11 percent; industrial, 24 percent; residential, 7 percent; agricultural, 5 percent; and commercial, 3 percent.

Electricity generation is the second largest source of greenhouse gas emissions after transportation. Out-of-state electricity generation from coal has higher CO₂ emissions 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 electricity used, out-of-state electricity generation sources contribute 39 to 57 percent of the greenhouse gas emissions associated with electricity consumption in California.

A significant percentage of electricity imported to California from the Southwest comes from coal-based generation, while imports from the Pacific Northwest are primarily hydroelectricity.

California's high level of greenhouse gas emissions is not surprising considering its nation-sized population. What is remarkable, however, is that California's greenhouse gas emissions



Source: California Air Resources Board, *Greenhouse Gas Emissions Inventory*, November 2007.

per capita are one of the lowest in the United States. In 2001, California ranked fourth lowest in CO₂ emissions per capita and fifth lowest in CO₂ emissions per unit of gross state product. Nationally, 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 will largely depend on the success of its energy efficiency and renewable energy programs and its commitment to clean air and clean energy. In fact, the state's programs and commitments have lowered its greenhouse gas emissions rate of growth by more than half what it otherwise would have been.¹⁷ And California's energy programs and policies have had multiple benefits that include expanding energy diversity, lowering energy demand and improving air quality and public health.

¹⁷ National Resources Defense Council comments to the Energy Commission, April 5, 2005.

Meeting AB 32 Goals

Some have argued that a single dimensional approach, focusing on price such as a carbon tax or a cap-and-trade program, would be the simplest approach for California to meet its AB 32 greenhouse emission goals. Others argue that the state's existing programs for energy efficiency and demand-side management, along with the Renewables Portfolio Standard, should be expanded as these programs will provide the earliest and most reliable emission reductions.

The Energy Commission believes that the most prudent avenue for addressing California's climate issues is to pursue both a pricing and program approach. The state must aggressively pursue and expand its energy efficiency and demand-side management programs, as well as meet its 33 percent Renewables Portfolio Standard. These important programs will provide early greenhouse gas emission reductions and serve as a solid foundation for cap-and-trade or carbon tax pricing.

Current Strategies to Reduce Emissions

Addressing the state's climate change goals requires meeting energy needs with zero- or low-carbon energy sources to the extent possible. Since 2003, California's energy policy has relied on the *loading order*¹⁸ to meet 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 CO₂ emissions and diversifying sources of energy supply.

Senate Bill 1078 (Sher, Chapter 516, Statutes of 2002), introduced a Renewables 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 2010, and SB 107 (Simitian, Chapter 464, Statutes of 2006) put it in statute. Since 2004, the Energy Commission has recommended a further goal of 33 percent renewables by 2020, and in 2005, Governor Schwarzenegger and the CPUC endorsed this enhanced target.

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 renewables in the state's electricity mix.

As the third largest consumer of gasoline in the world (behind only the United States as a whole and China) — almost 16

billion gallons of gasoline and 4 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 that 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.¹⁹ 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.”²⁰ 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 standard of 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 [U.S. EPA])²¹ 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 from all cars sold in California starting in 2009. As allowed under federal law, 15 other states have adopted these California standards pending receipt of the EPA waiver.

Unfortunately, the EPA has not acted on California's waiver request for nearly two years, declaring it lacks the authority

18 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.

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

20 May 13, 2005 letter from Governor Arnold Schwarzenegger to Senator Jeff Bingaman, chairman, and Senator Pete Domenici, member, Senate Energy and Natural Resources Committee, U.S. Senate.

21 <www.greencarcongress.com/2007/04/us_epa_opens_co.html>. The U. S. Environmental Protection Agency has historically granted all 53 such waivers previously sought by California.

to regulate greenhouse gases — a declaration rejected by the United States Supreme Court in its recent decision which states that EPA has the authority to regulate CO₂ emissions and should reconsider its refusal to do so.

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.

For the *2007 Integrated Energy Policy Report*, the first in the more complex post-AB 32 world of carbon constraints, staff has developed scenario analyses and a portfolio analysis. These two new approaches analyze in more depth the uncertainties that affect California's ability to meet its future energy needs. The Scenario Analyses Project examines the implications of energy policies that may help achieve AB 32 goals. 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. The Portfolio Analysis Project studies how different resource additions perform economically and respond to changes in key variables such as fuel prices.

California's Energy System: Powering a Nation-State

Today one in eight Americans, or more than 37 million people, lives 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 already larger than the populations of Canada (33 million) and Australia (21 million).²² If California were a nation, its population would rank 33rd in the world. In fact, California's

population exceeds the combined populations of its western neighbors — Oregon, Colorado, Wyoming, Montana, Idaho, Washington, Nevada, Arizona, Utah, New Mexico, Alaska, Hawaii, the Yukon Territory, and British Columbia. The State Department of Finance predicts that California will add another 7 million people in the next dozen years, moving toward 60 million residents by 2050. The challenge California faces 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. Now, with the passage of AB 32, California has a stringent 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 at 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, the state's success in electricity has not been reflected in its 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, Southern California's Inland Empire, and the Sacramento area — are growing faster than the coastal areas (Figure 1-4). By 2040, almost 40 percent of the state's population, or more than 20 million, will reside inland. This inland population growth drives demand for more electricity, but it also changes the energy

22 Johnson, H., "How Should California Grow?" *Western City Magazine*, July 2007.

**Figure 1-4:
California's Inland Population Increases**



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

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.

The Inland Empire and the northern San Joaquin Valley are two of the fastest growing metropolitan areas in the United States. These areas 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.

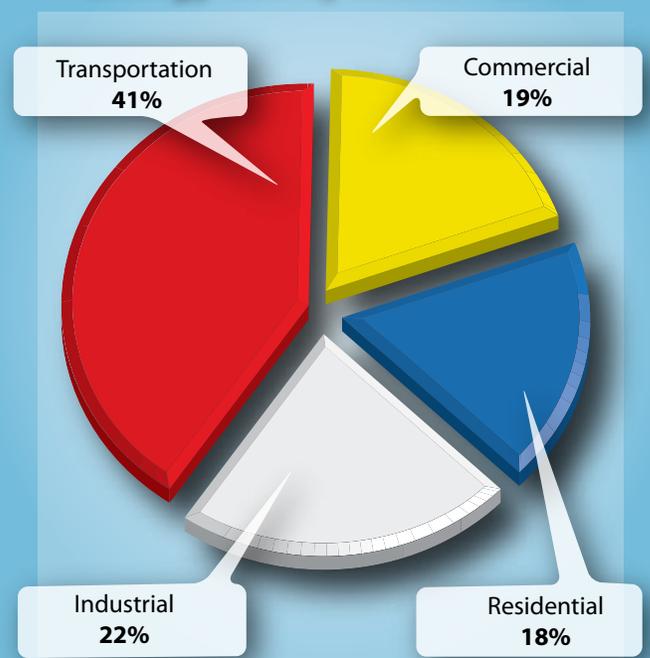
Inland growth also increases environmental problems. The San Joaquin Valley and the Inland Empire already have some of the worst air quality in the nation, and as California's growing population continues its inland trek, growth will only make the situation worse. By 2040, more people are projected to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

Energy Consumption

California's overall energy consumption continues to be dominated by transportation. More than 40 percent of all energy consumed in the state is used to move people and goods — and almost all of this transportation energy is derived from petroleum (Figure 1-5).

Despite diversifying the mix of energy resources used to generate electricity, more than 80 percent of the energy consumed in the state still comes from fossil fuels. This continuing dependence, combined with continuing population growth, places California's economic and environmental well being at risk.

**Figure 1-5:
Energy Use by Sector - 2006**



Source: California Energy Commission 2006.

Energy Supply

To understand the challenges California faces in cutting back on greenhouse gases, it is important to examine where the state gets its energy. Two primary fuels drive California's energy system: petroleum and natural gas (Figure 1-6). These resources are used in the transportation sector to generate electricity or for heating buildings and water.

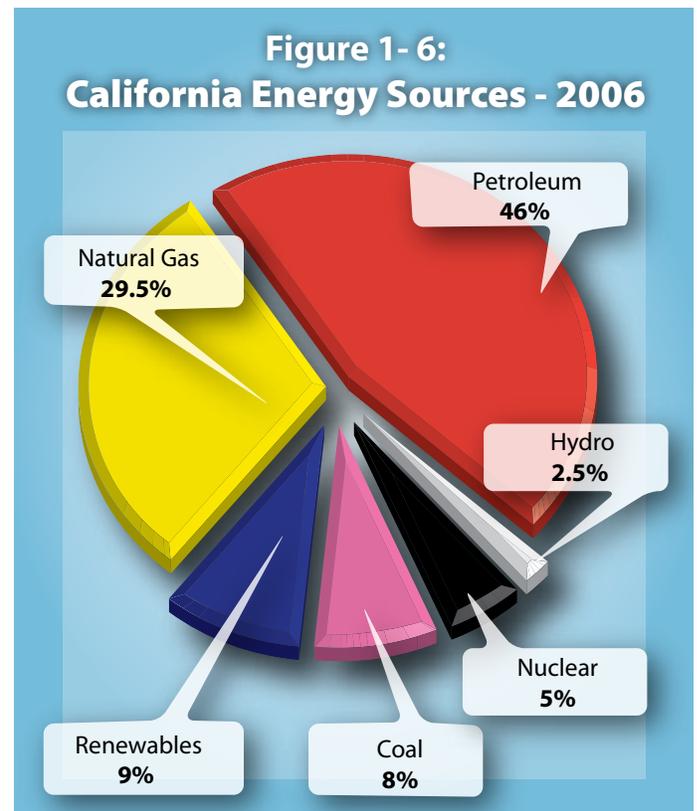
The state produces about 13.5 percent of the natural gas it uses, 39 percent of the crude oil, and more than three-quarters of the electricity. The remaining amounts are electricity and natural gas purchases from other states and Canada and crude oil imports from Alaska and foreign sources (Figure 1-7). Importing energy means exporting state dollars. Energy efficiency can reduce these expenditures as well as conserve finite resources.

Electricity

New power plants licensed by the Energy Commission have added almost 13,000 megawatts 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.

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 a time of high oil prices and tight supplies in the 1970s, oil-fired power plants supplied more than half the state's electricity. Today, none of California's electricity comes from petroleum as the state turned to cleaner, less expensive sources of power.

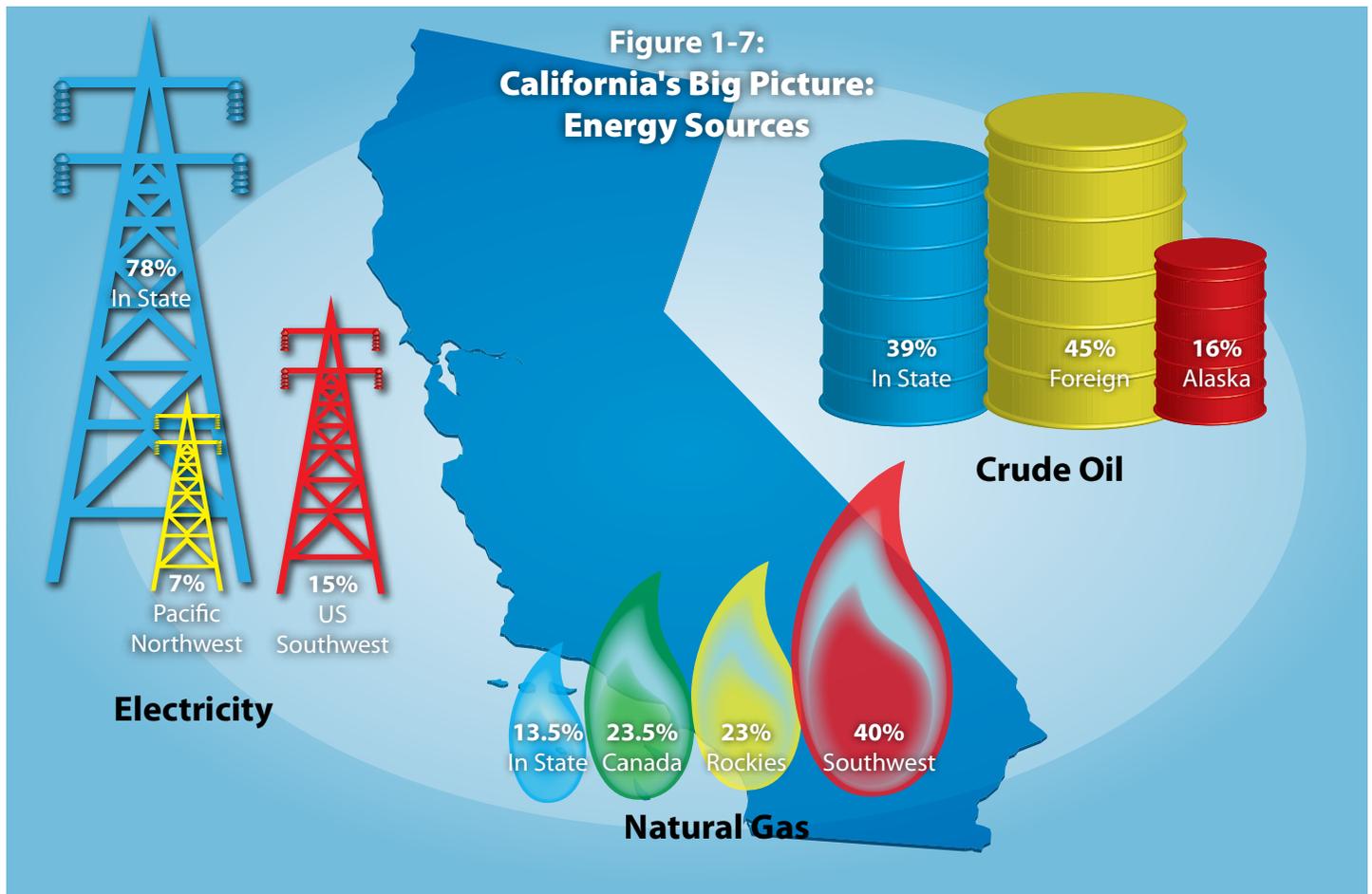
The California electricity generation system is massive (Figure 1-8). After a period of flat to slow growth on the heels of the 2001 electricity crisis, California's demand is now on the rise, fueled by population growth and a robust economy. Electricity consumption is dominated by commercial and the residential use (Figure 1-9).



Source: California Energy Commission 2006.

To diversify its electricity mix and reduce its output of greenhouse gases, California chose to significantly increase the amount of its electricity generation from renewable energy sources. The state adopted a Renewables Portfolio Standard with a mandate of generating, by 2010, 20 percent of its power from renewable sources like biomass, geothermal, small hydro, solar, and wind. Additionally, in Executive Order S-06-06, the Governor called for a 20 percent target within the RPS goals to be met with electricity from biomass and established the Bioenergy Action Plan to develop an integrated and comprehensive state policy on biomass. In 2006, renewable energy supplied about 11 percent of the state's electricity, and even with almost 400 new megawatts of renewables added to the system, load growth has matched these additions, and California remains at the same level (Figure 1-10).

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



Source: California Energy Commission 2006.

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.

Five major utilities provide about 80 percent of all electricity consumed in California: investor-owned Pacific Gas and Electric Company (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E), and the publicly owned Los Angeles Department of Water and Power (LADWP) and Sacramento Municipal Utility District (SMUD), (Figure 1-11).²³

The remaining 20 percent is provided by three smaller investor-owned utilities (Bear Valley, PacifiCorp, and Sierra-Pacific Power) and 24 municipal utility districts, three rural cooperatives,

about 12 irrigation or water districts, and one state and one federal water agency (electricity is used for pumping water).

Under electric industry restructuring, 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 generators 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 – the cities of Vernon and 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. In 2006, California enacted SB 1368 (Perata, Chapter 598, Statutes of 2006), a law prohibiting utilities from

²³ California Energy Commission, *California Energy Demand 2008–2018: Staff Revised Forecast*, November 2007, CEC-200-2007-015-SF2.

making long-term commitments for electricity generated by plants that create any more CO₂ than clean-burning natural gas plants create. 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.

Natural Gas

Only 13.5 percent of the natural gas California used came from in-state production in 2006; the rest was delivered by pipelines from several production areas in the western United States and western Canada.²⁴ California is at the end of those pipelines, forcing it to compete with other states for supplies (Figure 1-12). Once the gas arrives in California, it is distributed by the state's three major gas utilities — SDG&E, Southern California Gas Company, and PG&E — 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.

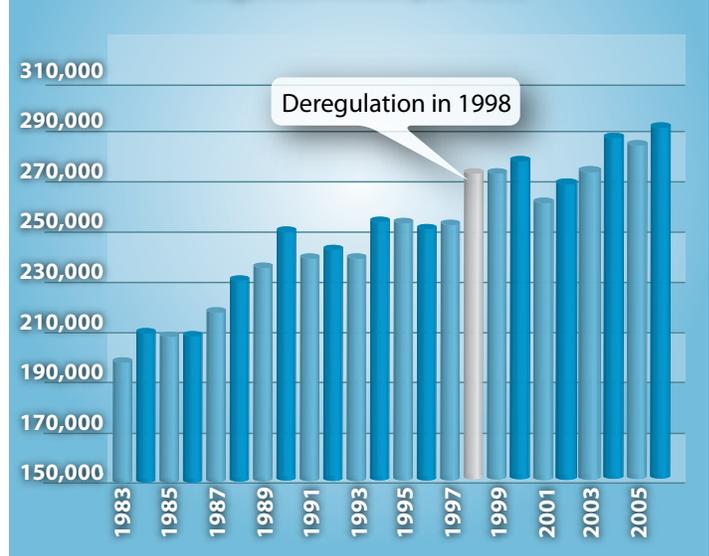
The largest user of natural gas is electricity generation, using about half of all natural gas in the state. The residential sector uses 22 percent of the natural gas. Of that amount, 88 percent is used by space and water heating.

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 its reliance on renewable sources of electricity should slow the demand for natural gas relative to the demand in other parts of the nation, competition for supply is increasing. Our reliance on imported gas leaves the state vulnerable to price shocks and supply disruptions.

Importing liquefied natural gas by ship from foreign sources has the potential to furnish new supply, but so far no terminals to receive liquefied natural gas have been

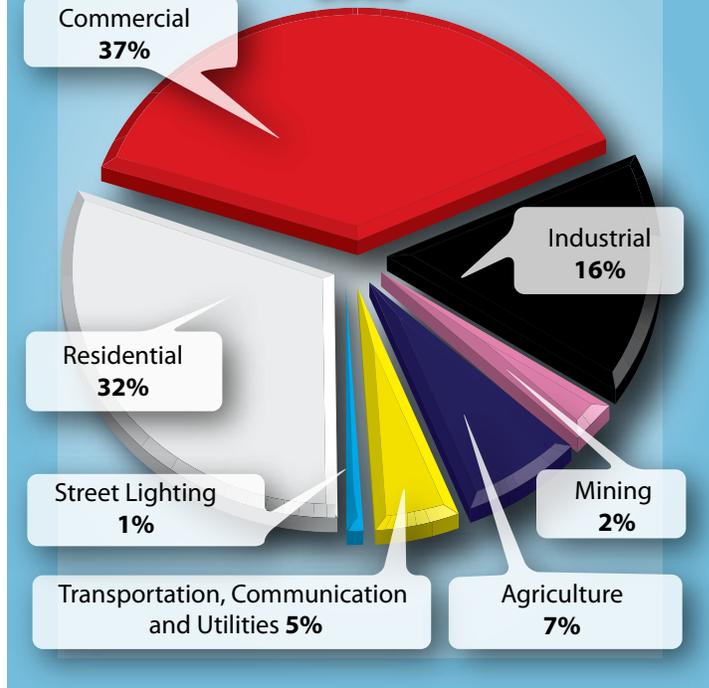
**Figure 1-8:
California's Electricity Generation
1983-2006**

(Gigawatt Hours per Year)



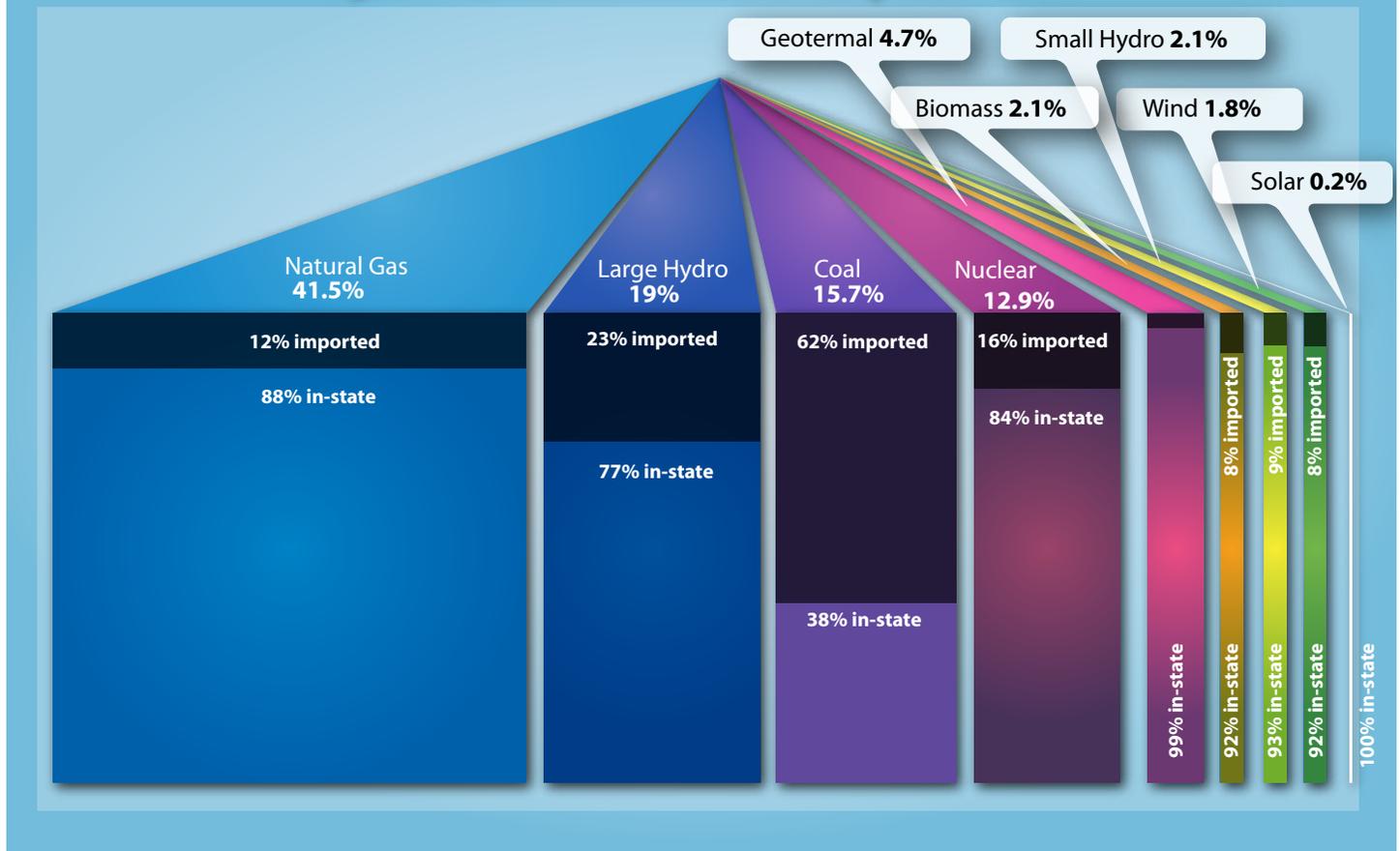
Source: California Energy Commission.

**Figure 1-9:
Electricity Consumption by Sector
2006**



Source: California Energy Commission.

Figure 1-10: 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.

Source: California Energy Commission, *Gross System Power Report 2006*.

approved in California. A newly constructed Mexican facility in Ensenada, Baja California, however, is expected to begin operation by the end of 2008. While 30 to 50 percent of this Sempra-owned plant is contracted for use in Mexico, the remainder should be available to California markets.

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 more than 36 percent, from 845 therms to 538 therms.²⁵

25 California Energy Commission, *Utility Annual Statistical Reports*, Federal Energy Regulatory Commission Form 2, and *Annual Report to the California Public Utilities Commission*.

Petroleum

The early discovery of oil made California an energy pioneer. As early as 1910, the 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.²⁶ 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.²⁷

26 California Department of Conservation, Division of Oil, Gas and Geothermal Resources, *Oil and Gas Production History in California*, p. 6. <ftp.consrv.ca.gov/pub/oil/history/History_of_Calif.pdf>.

27 Energy Information Administration, <tonto.eia.doe.gov/dnav/pet/pet_crd_crdpn_adc_mbbbl_a.htm>.

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 5 percent from foreign sources.²⁸ Today, foreign imports — primarily from Saudi Arabia, Ecuador, Iraq, and Mexico — contribute more than 45 percent of crude oil supplies, and Alaska imports have dropped to 16 percent as the North Slope oil field production declines.²⁹

With more than 60 percent of the oil used by California-based refineries and 10 percent of the refined petroleum products coming from outside 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 and products must arrive by ship.

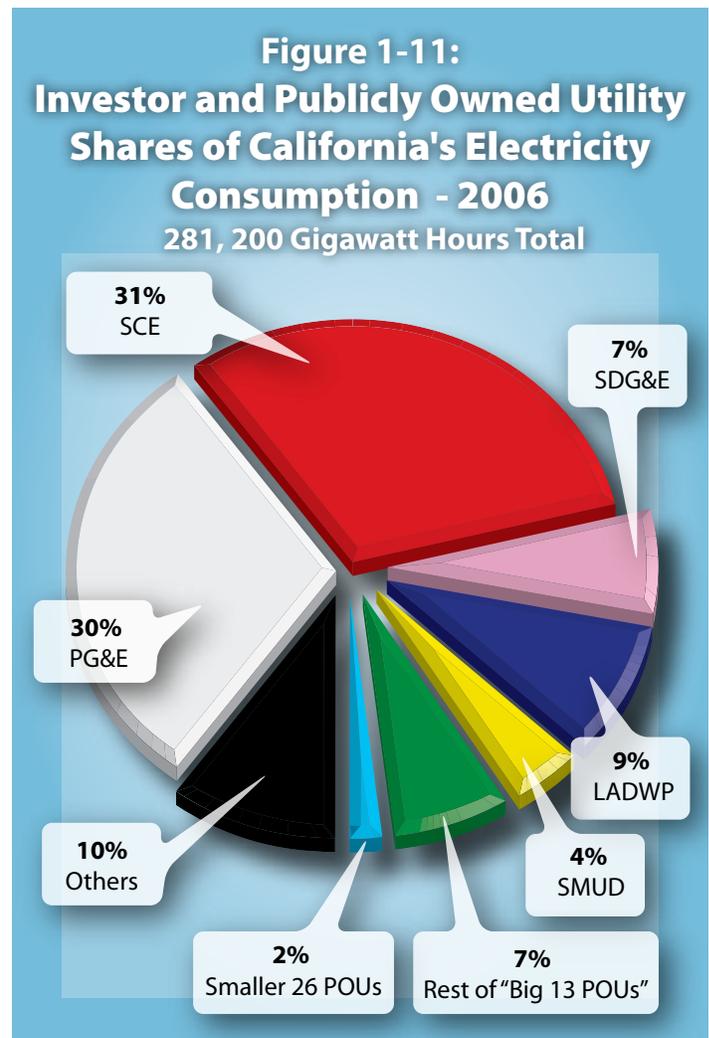
These marine facilities include terminals with docks for unloading both crude oil and finished petroleum products into storage tanks through a network of pipelines. The same facilities are also used to export petroleum products to other states along the West Coast and to foreign destinations.

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 refined 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 more than 70 distribution terminals scattered throughout the state. Trucks deliver gasoline and diesel from these distribution centers to local stations.

28 California Department of Conservation, Division of Oil, Gas, and Geothermal Resources, *2006 Annual Report of the State Oil & Gas Supervisor*, publication PR06, 2007, p. 3, <ftp.consrv.ca.gov/pub/oil/annual_reports/2006/0101summary1_06.pdf> and California Energy Commission analysis of Petroleum Industry Information Reporting Act monthly crude oil receipt data.

29 California Energy Commission analysis of Petroleum Industry Information Reporting Act monthly crude oil receipt data.



Source: California Energy Commission.

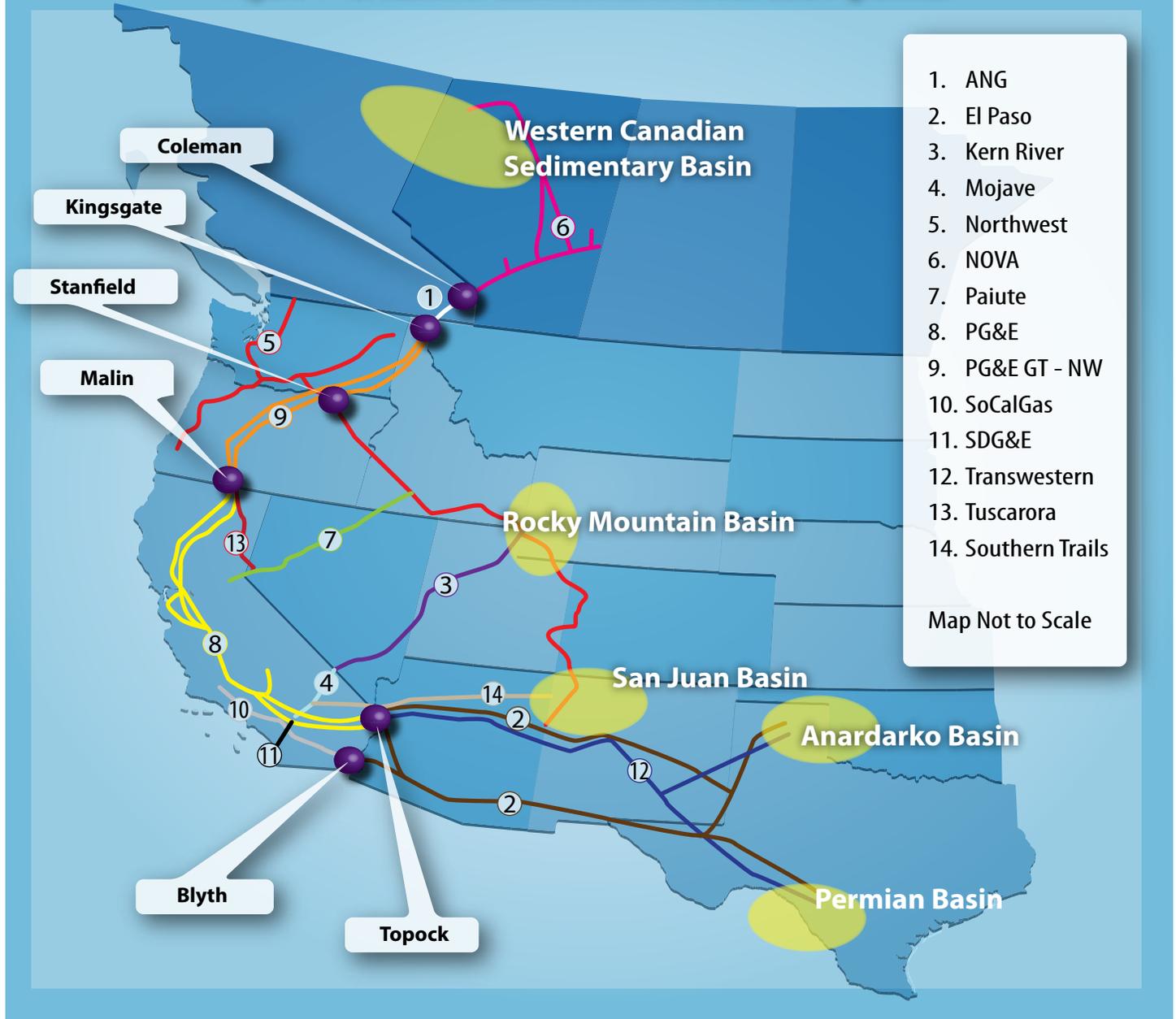
Pipelines also help put California at the center of a regional petroleum market. California refineries supply Nevada with almost 100 percent of its transportation fuels. Arizona gets more than 60 percent of its fuel from California, while Oregon depends on California's refiners for 25 to 35 percent of its fuel.³⁰

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

30 Arizona and Nevada estimates from California Energy Commission analysis of Kinder Morgan pipeline shipment information. Oregon estimate from California Energy Commission analysis of U.S. Army Corps of Engineers marine shipments information.

Figure 1-12: Natural Gas Resource Areas and Pipelines



Source: California Energy Commission.

and five in the San Francisco Bay Area. Between these two refining centers, more than 90 percent of California's crude oil input is processed. Of the remaining six refineries, three operate in Bakersfield, two in Santa Maria, and one in Oxnard. Just 14 of the 21 refineries produce ARB reformulated gasoline and diesel, while the remaining facilities produce

non-fuel products such as lubricants and asphalt.³¹

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 finished products. Californians used almost 16 billion gallons of gasoline

31 California Energy Commission analysis of Petroleum Industry Information Reporting Act data. A table listing the various California refineries and type of gasoline and diesel fuel production is available at <www.energy.ca.gov/oil/refineries.html>.

in 2006, making it the third largest consumer in the world, behind the entire United States and China.³²

Demand for gasoline and diesel is expected to increase 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 more than 63 million gallons of gasoline less from January through August 2007 than during the same period in 2006.³³ Despite these recent statistics, 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.

Bioenergy

California has large untapped biomass resources, including residues from forestry, urban, and agricultural wastes. Bioenergy cuts across all energy supply sectors because biomass can be used to create electricity, transportation fuels, and biogas.

Using biomass to produce energy can reduce the waste stream in California's forests, landfills, and farmlands and improve forest health while reducing the risk of catastrophic wildfires.

Because of the importance of this strategic fuel source, Governor Schwarzenegger issued Executive Order S-06-06 in April 2006 to establish specific biomass production and use targets for California. The Executive Order sets a target for biomass to comprise 20 percent of the state's Renewables Portfolio Standard for 2010 and 2020. In addition, the order states that California shall produce a minimum of 20 percent of its biofuels within the state by 2010, 40 percent by 2020, and 75 percent by 2050. The Executive Order also directed the Energy Commission to report on progress made toward achieving these targets in the *Integrated Energy Policy Report*.

Key issues that must still be addressed include regulatory

uncertainty and adequately valuing the public benefits of biomass energy. A number of state agencies have jurisdiction over aspects of biomass production and use. Overlapping or conflicting regulations make it difficult for any individual agency to evaluate the overall environmental impacts and benefits of proposed projects. At the same time, bioenergy provides unique benefits not currently quantified in the marketplace. Recognizing and properly valuing these benefits would compensate project developers and help the biomass industry meet the Governor's goal for bioenergy in California.

California's Bioenergy Working Group continues to evaluate strategies to remove barriers to meeting the Governor's bioenergy goals. The group is comprised of the ARB, the Energy Commission, the California Environmental Protection Agency, the Resources Agency, the California Department of Food and Agriculture, the California Department of Forestry and Fire Protection, the Department of General Services, the Integrated Waste Management Board, the CPUC, and the State Water Resources Control Board.

Bioenergy for Electricity Production

Biomass currently represents nearly 19 percent of the state's renewable resource requirements for 2010, close to the Governor's goal of 20 percent. Sustaining this progress beyond 2010, however, will require a concerted and coordinated effort by state government and the private sector. A number of these efforts are already underway:

- Under the Executive Order, the CPUC must initiate a new proceeding or build on an existing proceeding to encourage sustainable use of biomass and other renewable resources by the state's investor-owned utilities. A decision is pending in proceeding R06-05-027, under which the CPUC has asked parties to comment on how the unique benefits of biopower should be evaluated in resource procurement, particularly non-electric public benefits such as waste disposal, forest fire risk reduction, and cleaner air by avoiding open field burning.

32 Ranking based on the most recent set of complete data available, year 2004, from International Energy Agency. A complete listing is available at <www.energy.ca.gov/gasoline.statistics/gasoline_consumption_country.php>.

33 California Board of Equalization, Net Taxable Gasoline Gallons, 2000–Present.

- The CPUC has approved RPS biomass contracts totaling between 299 and 351 megawatts of new capacity since 2002. Meanwhile, the Energy Commission has supported 640 megawatts of existing biomass facilities with more than \$150 million in production incentives and has certified or pre-certified 117 biomass facilities as eligible for California's RPS. In addition, the Energy Commission expanded RPS eligibility to include electricity generated from biogas injected into a natural gas transportation pipeline.
- The CPUC is also implementing a Renewable Power Purchase Tariff for renewable generation operated by a public water or wastewater facility, making 250 megawatts of small-sized biomass pilot projects (for example, municipal wastewater treatment facilities, dairy digesters) eligible for the proposed tariff. In May 2007, Southern California Edison began offering a set of standard contracts for biogas and biomass generators as large as 20 megawatts.
- The CPUC's greenhouse gas emission performance standard for new long-term power contracts specifies a maximum rate of 1,100 pounds of CO₂ per megawatt hour and is consistent with the Energy Commission's proposed standard for municipal utilities that expresses a preference for low carbon sources of electricity, such as biomass-based power.
- The Energy Commission is funding an economic study of dairy digesters for the State Water Resources Control Board and has also installed 10 dairy digesters at sites throughout California with 2.5 megawatts of capacity. These efforts complement a memorandum of understanding signed on June 15, 2006, by the State of California with the government of Sweden, pledging cooperation on development of renewable energy and fuels, particularly biogas.
- California Department of Food and Agriculture (CDFA) Secretary A. G. Kawamura is working with 22 other states on the 25x25 Initiative, a coalition of states aimed at achieving the goal of 25 percent renewable energy from the nation's farms and forests by 2025. These efforts complement California's Renewables Portfolio Standard. Of particular interest to CDFA are efforts by California farmers to harness dairy and food wastes as a source of energy. CDFA has collaborated with the State Water Resources Control Board, Regional Water Quality Control Boards, and the farm community to strengthen water protection and discharge requirements for dairies, which can produce biogas while protecting water quality. CDFA has participated in the development of dairy digester reporting protocols by the Climate Registry, which will be adopted by ARB, and has worked with the CPUC to facilitate on-the-farm power sales and distribution.
- ARB is currently recommending emissions performance standards for the use of biomass and biofuels by local air districts in stationary sources, expected to be complete by mid-2008.
- California Integrated Waste Management Board (CIWMB) has completed its strategic plan that is intended to increase bioenergy production at landfills. As part of its strategic objectives, CIWMB has endorsed the goals to divert 10 percent of biomass wastes and 20 percent of organic residues from landfills by 2010, and 40 percent of waste and 60 percent of organic residues by 2020. As part of its statewide diversion strategy, CIWMB is also encouraging the production of landfill gas to biofuels at the state's waste disposal facilities. Statutory changes are needed to enable use of biomass residues through both combustion and non-combustion technologies, such as gasification, fermentation, and pyrolysis, in current waste conversion technologies.
- California Department of Forestry and Fire Prevention (Cal Fire) is planning a small biomass cogeneration project at the Parlin Fork Conservation Camp and is in the process of identifying the most efficient means of harvesting and collecting the biomass to fuel that facility. Cal Fire is collaborating with the Climate Registry on urban forestry climate accounting protocols that encourage "best practices" for both forest management and resource conservation, while maintaining the state's forest lands as carbon sinks. Cal Fire is also working with the Tahoe Conservancy to secure state funding for a forest biomass demonstration program in the Lake Tahoe Basin. This program would demonstrate the significant benefits of

reducing the risk of catastrophic wildfires and avoiding large fire suppression costs, while thinning the forests. Further, Cal Fire is partnering with the Energy Commission on the Western Carbon Sequestration Partnership to evaluate storing carbon in both geologic and terrestrial forms.

- Placer County released its strategic plan for biomass development based, in large part, on the Bioenergy Action Plan. Placer County has experienced four major forest fires since 2001 that have consumed more than 30,000 acres of forest. The county is seeking financial and technical support from federal, state, and private partners for its wildfire protection and woody biomass program. This program will improve air quality by avoiding forest fires and increase renewable energy production. If funding is secured, the county plans at least one forest biomass-to-energy project in the Lake Tahoe Basin.
- The State Water Resources Control Board is committed to protecting water quality during the harvesting of biomass and the operation of biomass facilities. In particular, it is working to resolve permitting uncertainties for dairy digester projects in collaboration with the Regional Water Quality Control Boards. The Central Valley Regional Board has increased staffing for addressing dairy issues from 7 to 14 fulltime positions. State Water Resources Control Board estimates that anaerobic digestion of manure at dairies could produce up to 1,530 gigawatt hours of electricity. As a first step in addressing the costs of mitigating air, water, and waste disposal impacts, the Board has arranged for an economic study of the effects of air and water quality regulation on proposed dairy digester projects in the Central Valley.

Bioenergy for Transportation

Biofuels are an essential component of California's petroleum reduction goals. The Governor's Executive Order calls for increasing amounts of California's biofuels to be produced in state. Activities underway to assist in meeting the Governor's goals include:

- In June 2007, the ARB adopted amendments to its

California reformulated gasoline regulations that favor the use of E10 (10 percent ethanol blends) using the California Predictive Model. As part of ARB's effort to develop the Low Carbon Fuel Standard, it is using \$2 million in research funding to evaluate the environmental impacts and emissions performance of a range of biofuels to establish fuel specifications for biodiesel blends ranging from 5 to 20 percent biodiesel.

- On October 31, 2007, the Energy Commission adopted its State Alternative Fuels Plan as directed by AB 1007. The plan, which was prepared in partnership with the ARB, includes a full fuel cycle analysis of the costs and benefits of various transportation fuels and also provides the analytic foundation for ARB's Low Carbon Fuel Standard. The Energy Commission has also awarded \$3 million for energy conversion technologies using biomass, including projects for brown grease recovery, demonstration of an integrated biofuels and energy production system, and California's first cellulose-to-ethanol biorefinery project. In addition, in 2007 the Energy Commission-funded California Biomass Collaborative developed *A Preliminary Roadmap for the Development of Biomass in California*, a comprehensive strategy to guide research and development, address regulatory and permitting issues, and recommend appropriate public education programs.
- The Energy Commission's Agricultural Loan Program provides approximately \$3 million in loan funds for the design, purchase, and installation of eligible biomass technologies. Funding is available for fuel production from agricultural and forest residue, urban waste, food and beverage waste, waste grease, and purpose-grown energy crops. The California Department of Food and Agriculture is also working to influence federal funding opportunities in the 2007 Federal Farm Bill for conversion of agricultural residues and specialty crops to biomass power and fuels.
- The Department of General Services continues to purchase large numbers of flexible fueled vehicles for the state fleet, having purchased more than 1,100 E-85 vehicles during the last two years. The department purchases roughly 7,000 new

state vehicles each year of the total 50,000 light and heavy duty vehicles in the state fleet. It plans to purchase more alternative fueled vehicles with the expectation that the state's fuel suppliers will establish the fueling infrastructure. To date, none of these vehicles are operated with fuels produced from biomass.

- The private sector and California universities have also contributed to the progress in reaching the state's bioenergy goals. Private industry, utilities, and venture capitalists have stepped up their efforts in California to finance the commercial development of biofuels projects, most notably, Pacific Ethanol's plant that is operating in Madera, California, and the proposed Blue Fire Ethanol project to be located at a Southern California landfill.
- Other private sector activities include British Petroleum's new global business unit, BP Biofuels, which is developing transportation fuels using petroleum and agricultural feedstock. The company is addressing the challenges of cost, availability, quality, and sustainability in pursuing technology solutions. Chevron, through its Biofuels Business Unit, is pursuing a two-phased approach, emphasizing ethanol blends in its first generation of biofuels development. Amyris Biotechnologies is leveraging its own proprietary technology to develop hydrocarbon biofuels that perform like conventional gasoline, diesel, and jet fuels. Conoco Phillips, an integrated energy company, is producing a diesel fuel substitute, using agricultural, forestry, waste oils, wood, grass, and cane. Neste Oil, an international fuel company with headquarters in Finland, is investing in renewable diesel fuel derived from vegetable oils or animal fats that can be used in today's engines.
- Close collaboration with private companies, the federal government, and California's universities has resulted in considerable research funding for development of advanced biomass conversion technologies, commercial development of at least one biomass-to-ethanol project, and the creation of research centers at University of California (UC), Davis and UC Berkeley on advanced biofuels. Other public/private research efforts include: a \$500 million private grant from

British Petroleum to UC Berkeley to establish the Energy Bioscience Institute; a \$125 million grant to UC Berkeley and UC Davis from the United States Department of Energy for a Joint BioEnergy Institute to develop environmentally friendly biofuels; and a \$25 million grant from Chevron Corporation to UC Davis for bioenergy research.

Powering the Future

As the world's eighth largest economy,³⁴ second largest consumer of gasoline, and twelfth largest emitter of greenhouse gases, California must be a leader in reducing greenhouse gases and a major participant in slowing 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.

34 California Department of Finance, Top Countries Ranked by Gross Domestic Product, California's World Ranking 2006. <www.dof.ca.gov/HTML/FS_DATA/LatestEconData/FS_Misc.htm>.

Chapter 2



Meeting California's Electricity Needs

"There are risks and costs to a program of action. But they are far less than the long-range risks and costs of comfortable inaction."

John F. Kennedy

California must provide a reliable supply of electricity for its citizens. A significant disruption in the flow of electricity would bring the California economy to an abrupt standstill, costing hundreds of millions of dollars to the state as well as to individual commercial and personal enterprises.

AB 32 forces California to determine how to meet its electricity needs in a way that leaves an ever-shrinking *greenhouse gas* footprint. Currently, electricity generation accounts for 28 percent of California's greenhouse gas emissions. Conventional generation natural gas and coal, which account for 57 percent of the state's electricity supply, present challenges to California's ability to meet the AB 32 mandate. Some of these challenges include:

- California's aging power plants are extremely inefficient compared to current technologies that are 20 to 30 percent more efficient; these plants must be either re-powered or retired and replaced with cleaner technologies that operate at higher efficiency to contribute to AB 32 goals.
- Existing power plants that use once-through cooling are facing legal challenges, and new plants proposing to use once-through cooling face the risk of permitting delays or denials as a result of more stringent regulations on this technology.
- Carbon capture and sequestration for coal-fired generation and nuclear generation both face economic, environmental, and regulatory barriers that make them unlikely to be able to contribute significantly to the state's AB 32 goals by 2020.

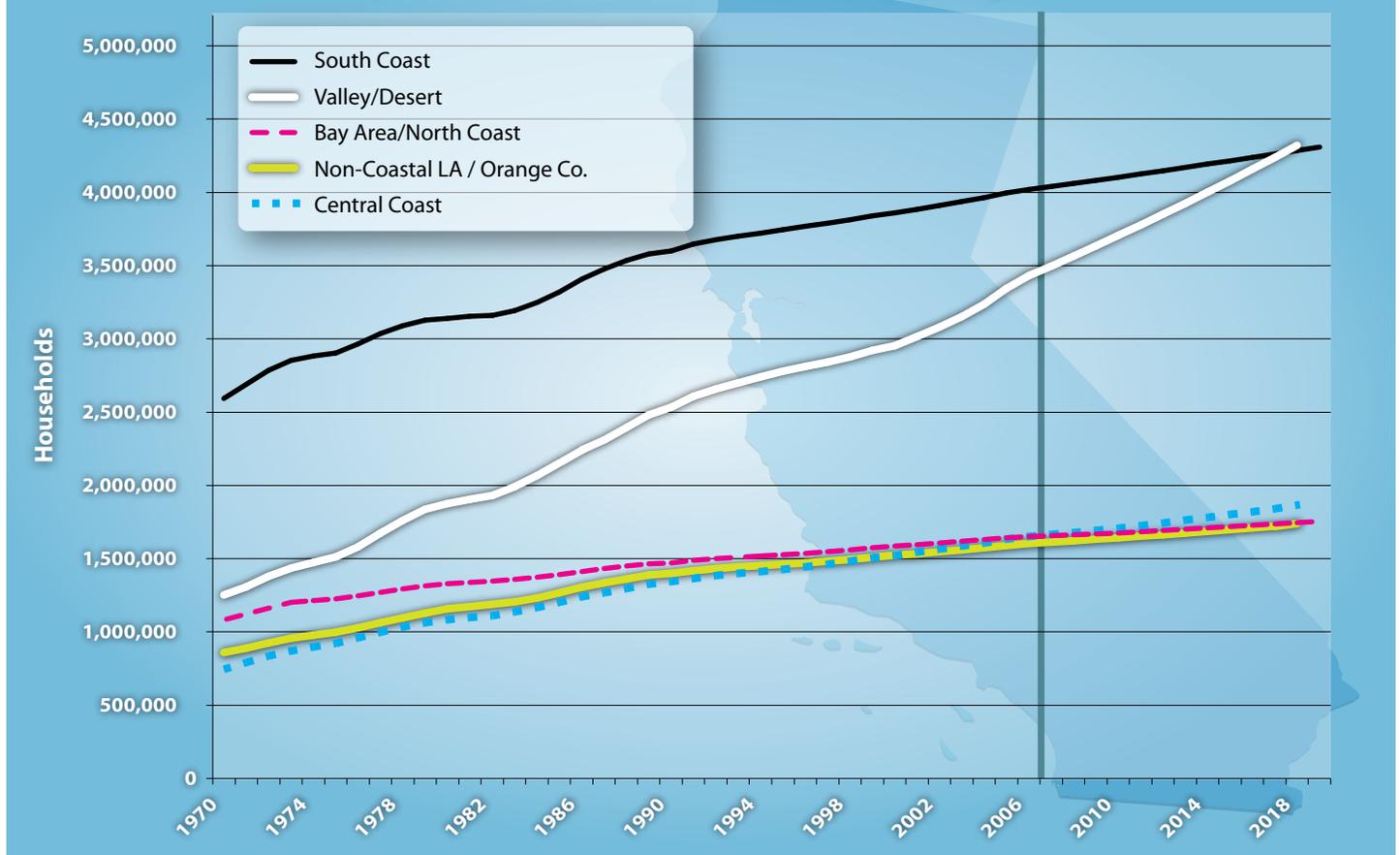
Forecast of Electricity Demand

Reliable and current assessments of electricity demand growth are essential to system operators and policy makers in evaluating future infrastructure needs and resource options. Electricity use patterns reflect evolving trends in where and how people live and do business. Population growth is a key driver for residential energy demand and for commercial growth and demand for water pumping and other services. Even though 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 more than the previous quarter century), the cumulative growth is significant, and that growth is occurring more in hotter areas of the state (the Central Valley and desert areas), pushing up the peak demand for electricity (Figure 2-1). DOF expects this trend to continue.

The historic data are actual consumption, while the forecast assumes average temperatures (Figure 2-2). The average 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 electricity use. Electricity consumption sharply increased in 1999 and 2000 during the technology boom, but rapidly diminished with the 2001 electricity crisis and following recession. In 2005 and 2006, electricity use returned to pre-energy crisis levels. Statewide electricity consumption is expected to grow at an average of 1.25 percent in the forecast period (2008–2018).

Figure 2-1: Number of Households by Region



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

Electricity consumption by the commercial and residential sectors is expected to increase (Figure 2-3). During the last 25 years, the commercial sector had the highest growth rate, followed by the residential sector. In the forecast period, the residential sector continues to grow at the historic 1.8 percent rate, while the commercial sector slows slightly to 1.4 percent annual growth. Electricity use in the industrial sector remains relatively flat, although the economic value of output is projected to continue to increase at 0.8 percent annually.

Overall, improvements in how efficiently California uses electricity have helped to offset growth, so that per capita use has grown very slowly. Energy efficiency standards and programs have held per person electricity use essentially constant over the last 30 years, fluctuating between 7,200 and 7,800 kilowatt hours per person, depending on economic and annual temperature conditions (Figure 2-4). Building and appliance standards have

offset rising consumption from the increase in the number of different types of electronic equipment in homes and business.

This forecast includes the projected effects of currently adopted building and appliance standards and the investor-owned utility energy efficiency programs implemented or approved through 2008. Because the forecast is developed using data that reflects the effect of many past years of energy efficiency programs, it also implicitly includes some effects that can be attributed to post-2008 programs, to the extent those programs have similar strategies and levels of effectiveness. The extent to which post-2008 targets contribute additional reductions in demand will depend on whether the new programs produce impacts beyond the *business-as-usual* effects accounted for in the forecast.

Economic conditions (shaded areas) directly impact electricity consumption. Since 1976, per capita use declined on average

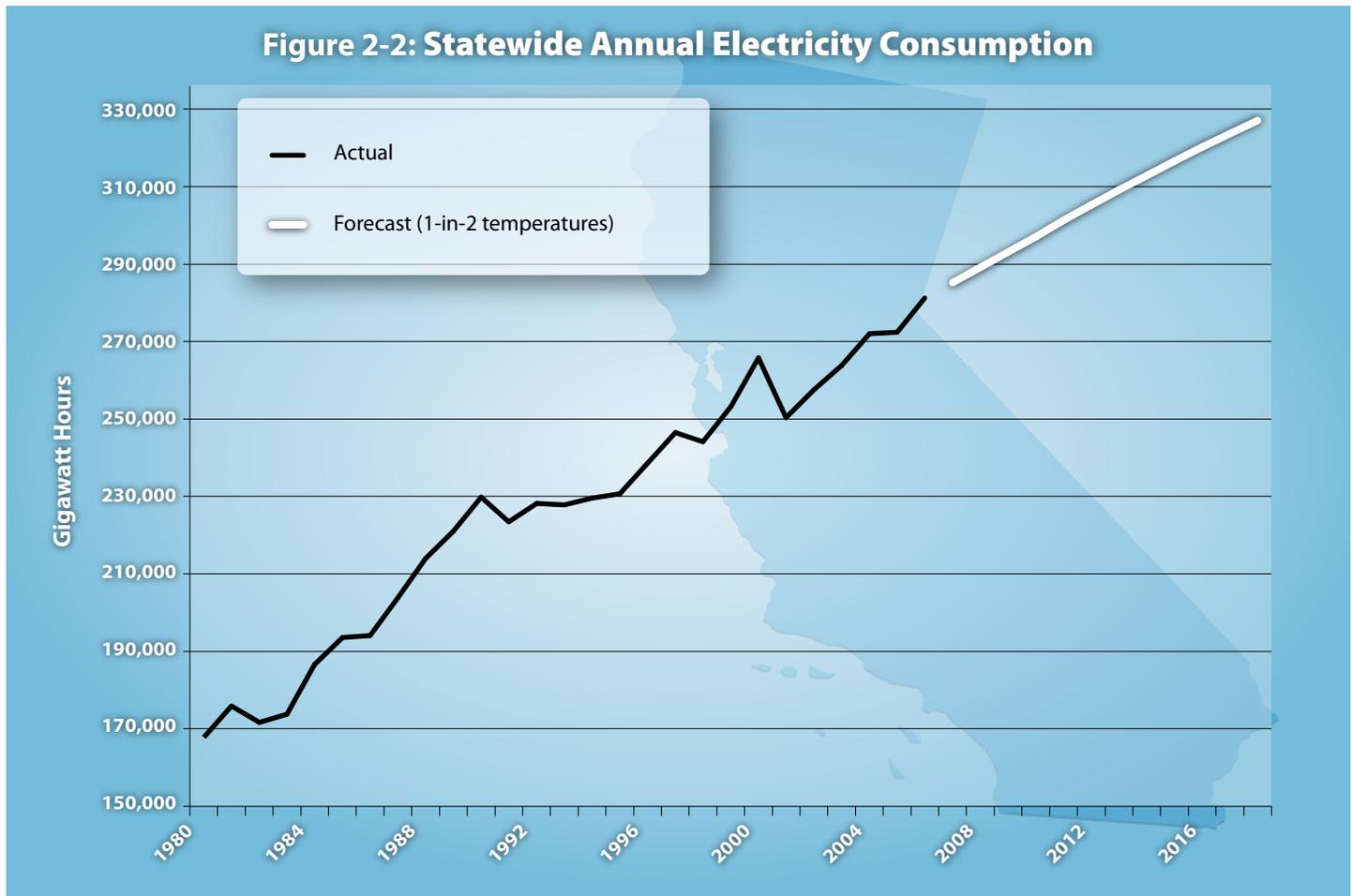
by 2 percent during recessions, while in non-recession years, use typically increased by .05 percent. In the forecast period, this trend of relatively constant use per capita is projected to continue at about 7,500 kilowatt hours per person.

Peak Demand on the Rise

Peak electricity demand per capita, the highest hourly demand in each year, is growing slightly, rather than staying fairly constant as with energy use per capita (Figure 2-5). Generally, peak demand is extremely volatile and highly sensitive to temperature conditions and reflects the amount of installed cooling equipment in a region. To account for the effect of temperature on peak 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 average peak demand forecast

assumes average annual maximum temperatures — those 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 for the 1-in-2 forecast was lower than actual demand in 2006.

Statewide annual peak demand is projected to grow, on average, 850 megawatts per year for the next 10 years, or 1.35 percent annually (Figure 2-6). Population growth in California’s drier, warmer areas increases peak demand 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 they result in little, if any, savings during the hottest hours when California peak demand occurs. The federal seasonal energy efficiency ratio performance number is based on outdoor temperatures that are far below the average annual



Source: California Energy Commission.

maximum temperatures experienced in California and on more humid conditions and, consequently, does not accurately reflect efficiency improvements in California’s hot, dry peak conditions. Therefore, while the electricity consumption forecast includes estimated energy savings from the 2005 standard’s change to seasonal energy efficiency ratio 13, no impacts from the 2005 standards are feasible to include in the peak demand forecast. While these higher efficiency air conditioners probably do save energy during many summer afternoon hours, their impact during the hottest peak hours is suspect, at best.

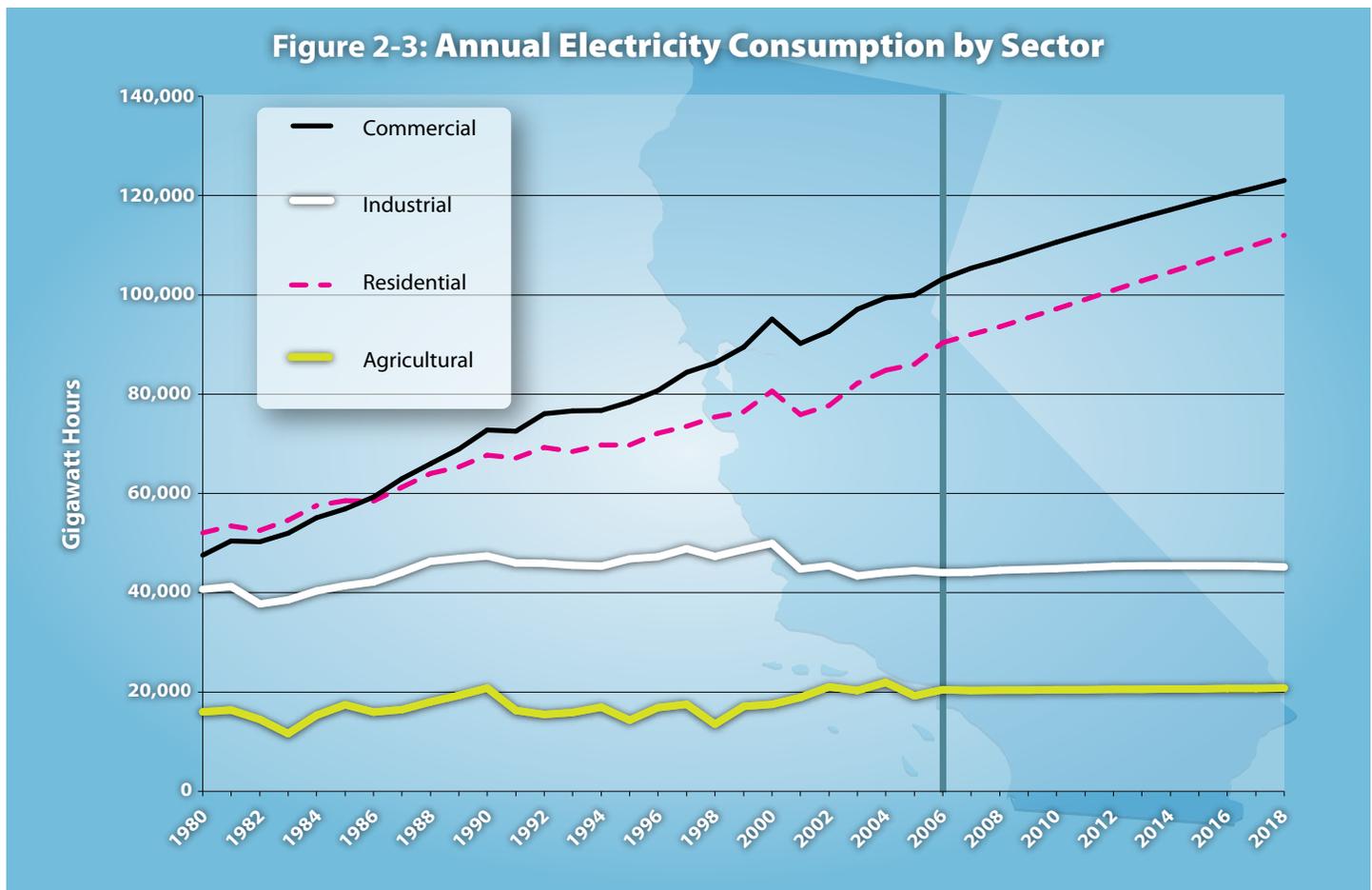
The growth in peak demand is somewhat offset by projected increases in the electricity provided by self generation, reflecting the effects of the California Solar Initiative, the New Solar Homes Partnership, and the Self-Generation Incentive Program. The peak demand forecast represents the net amount 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 megawatts by 2018, based on current costs and program performance. If the installed cost of photovoltaic systems declines significantly, either through reductions in component or installation costs or increases in federal/state tax credits, this projection could easily be 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 increases as temperature rises — to develop demand forecasts for varying degrees of hotter-than-average temperatures. In the 1-in-10 temperature scenario, which has a 10 percent chance of occurring in any year, demand is increased by 8 percent in any given year (Figure 2-6).

The actual and forecast load factor (using the 1-in-2 forecast) is also shown in Figure 2-6. The load distribution over the year is an

Figure 2-3: Annual Electricity Consumption by Sector



Source: California Energy Commission, *California Energy Demand 2008–2018*, CEC-200-2007-015-SF2.

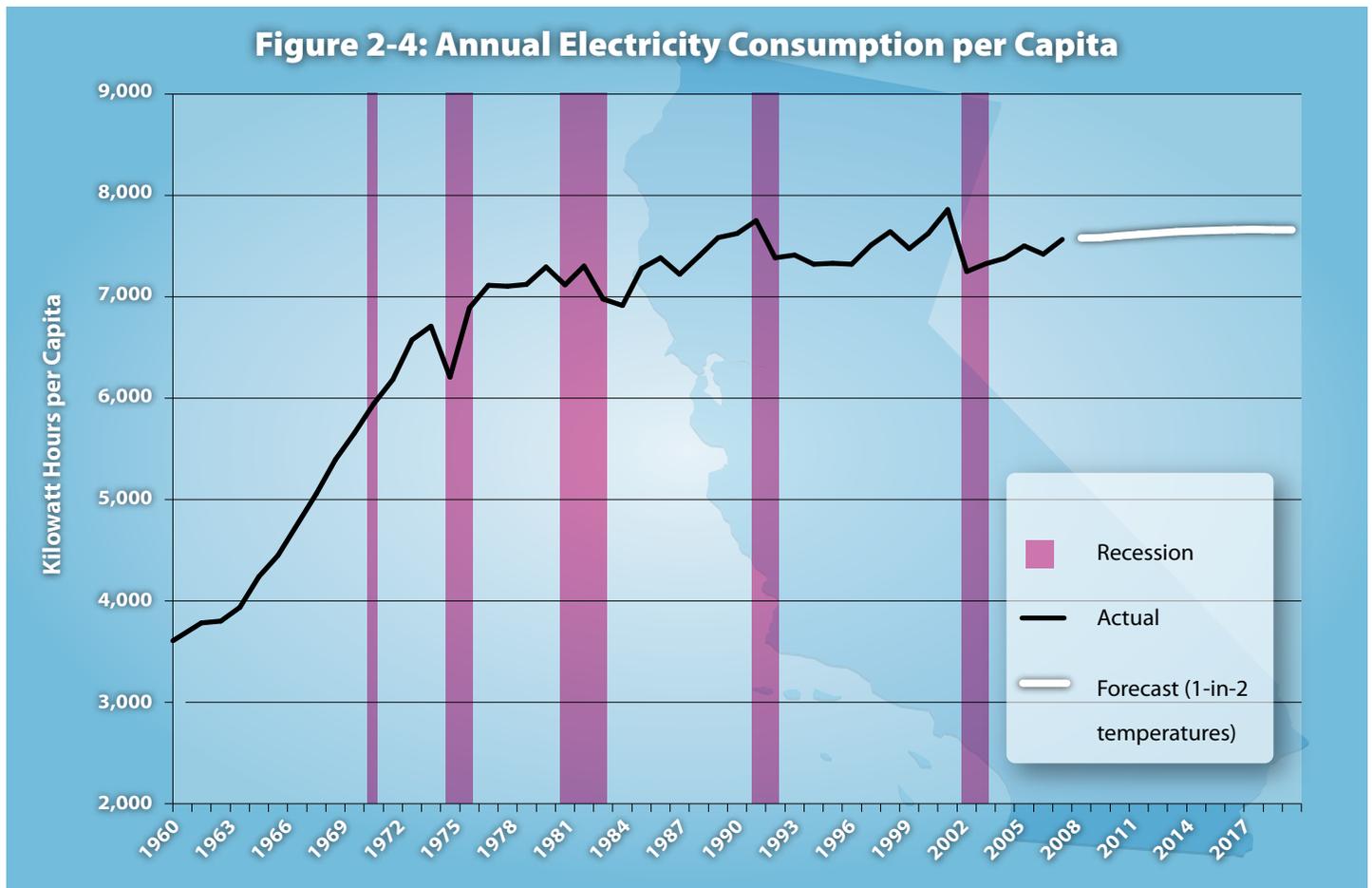
important characteristic of demand. System operators must plan for sufficient electricity supplies or capacity to meet peak demand; however, in off-peak hours only a fraction of that capacity will be used. The load factor, defined as average demand relative to peak demand, measures the extent that capacity is being used. A load factor of 100 percent means 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. Plant operators take advantage of some of these idle hours to perform essential maintenance, but in many of these hours, no maintenance is needed.

Low load factors can be costly to California’s electricity consumers. Load factors vary from year to year depending on weather. For example, 1998 was a cool year except for a brief hot spell, so average hourly demand was much less than in 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 electricity

crisis. In 2006, unusually hot weather simultaneously in Northern and Southern California produced a load factor of 52 percent.

While year-to-year temperature variations cause swings in the load factor, the decrease over time (historically and forecasted) reflects a number of continuing trends: more building occurring in warmer, inland areas in the state resulting in more homes and businesses with central air conditioning; more homes with cooling equipment even in mild climates; and higher 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 demand. Statewide demand in 2006 exceeded 55,000 megawatts for only 3 percent of the hours in that year (267 hours), compared to 1.5 percent (130 hours) in 2005 (Figure 2-7). The shift from 2005 to 2006 represents both warmer temperatures and load growth in 2006.

Figure 2-4: Annual Electricity Consumption per Capita



Source: California Energy Commission, *California Energy Demand 2008–2018*, CEC-200-2007-015-SF2.

Transmission planning studies, supply/demand assessments, and other analyses of the electricity system often require load projections for individual utilities and small geographic areas. To support these studies, staff develops forecasts for 16 climate zones in the state, taking into account the climate, energy use characteristics, and projected economic and demographic trends for each area. Peak demand for regional clusters is forecasted to increase in all cases (Figure 2-8). In the entire Central Valley and desert regions of the state, demand is projected to increase by 5,500 megawatts during the forecast period. Forty percent of this (2,200 megawatts) is in the Inland Empire area served primarily by Southern California Edison (SCE) and Riverside Public Utility. The remaining, 2,300 megawatts, is growth in the Central and Sacramento Valley areas, served by Pacific Gas and Electric (PG&E), Sacramento Municipal Utility District (SMUD), and other utilities. Projected electricity demand growth, while doubling, is noticeably less in the more developed coastal areas served by PG&E and SCE than it is in the valley/desert areas.

The long-term 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, for example, as shown for SCE (Figure 2-9).

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.

Resource Adequacy

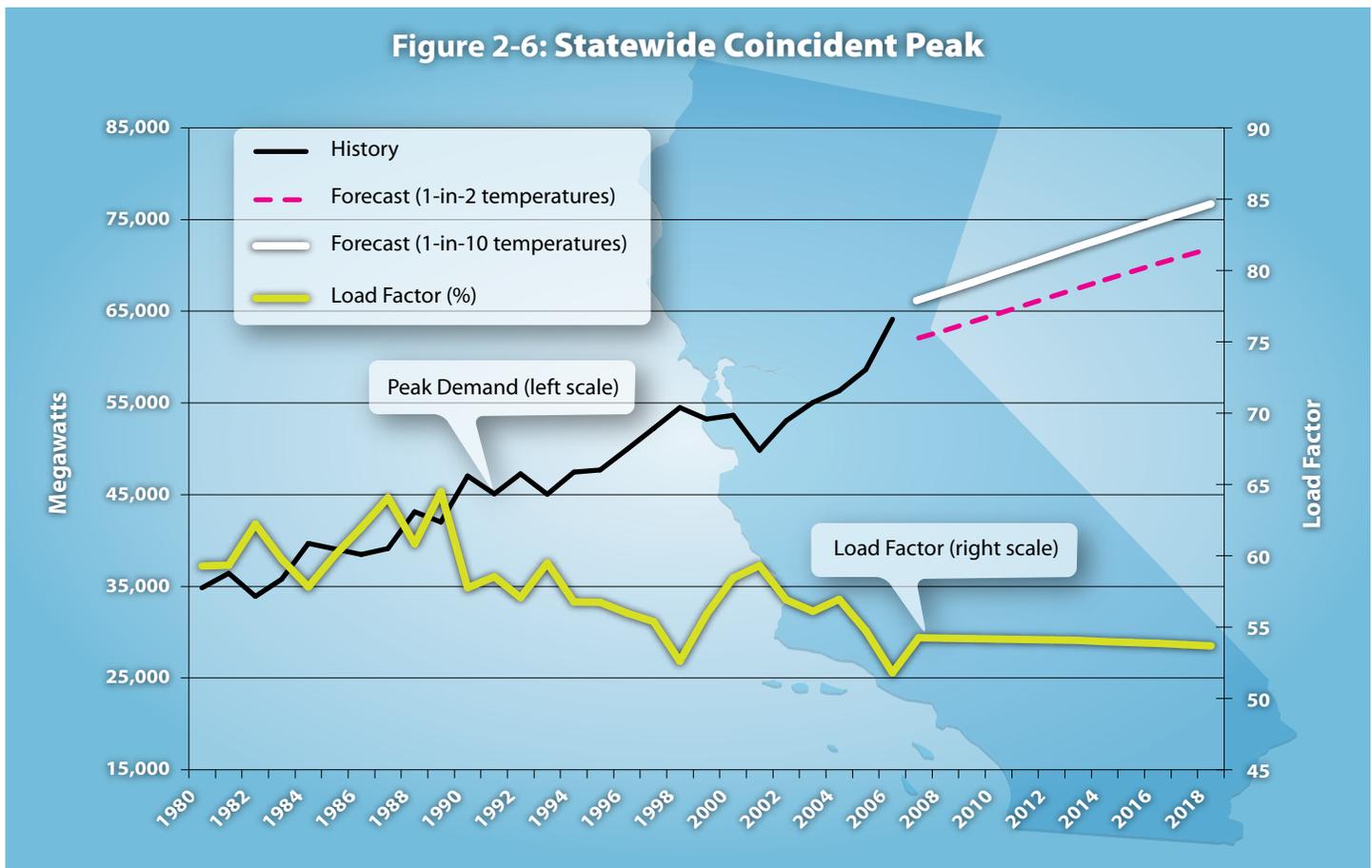
Reliable electricity service requires that the state must have enough electricity generation capacity to cover load and reserves during peak demand periods. In 2004, the California Public Utilities Commission (CPUC) established resource adequacy requirements (D.04-01-050) for load-serving entities under

Figure 2-5: Peak Demand per Capita



Source: California Energy Commission, *California Energy Demand 2008–2018*, CEC-200-2007-015-SF2.

Figure 2-6: Statewide Coincident Peak



Source: California Energy Commission, *California Energy Demand 2008–2018*, CEC-200-2007-015-SF2.

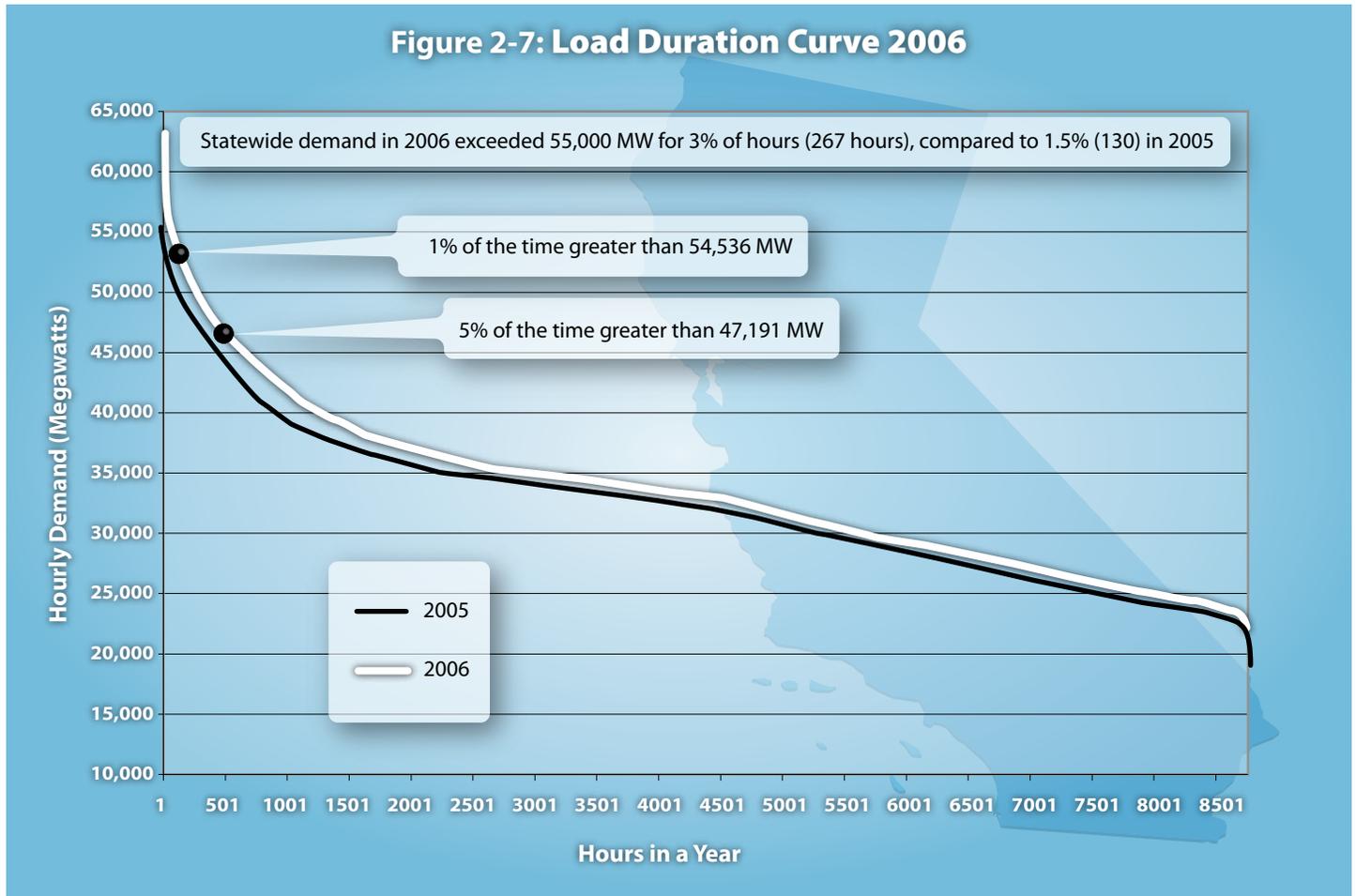
its jurisdiction, requiring that those entities own or contract with enough electricity generation to meet peak demand. In September 2005, AB 380 (Núñez, Chapter 367, Statutes of 2005) was enacted, resolving any disputes to the CPUC’s authority to impose such requirements on retail electricity service providers. In June 2006, the California Independent System Operator (California ISO) 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, such as for the Los Angeles Basin, and zonal procurement requirements, such as for Northern and Southern California. AB 380 requires that the state’s 54 publicly owned utilities, whether or not they are in the California ISO control area, must prudently plan for and procure adequate resources to meet their respective planning reserve margins. The publicly owned utilities are also required to provide the information necessary for the Energy Commission to evaluate and report their progress on resource adequacy.

The 18 public utilities outside the California ISO control area are not required by legislation or tariff requirements to buy, build, or contract for a specified amount of capacity (for example, an amount equal to 115 percent of their forecasted load during the summer peak in 2007).

Energy Commission staff has collected and reviewed load and resource information from the publicly owned utilities throughout the state. Staff’s assessment found that, in total, the utilities have resources sufficient to meet anticipated demands for the next several years. Even those public utilities that are not in the California ISO control area are generally adhering to self-imposed standards similar in rigor to those imposed by the California ISO.³⁵

35 California Energy Commission, *Progress Report on Resource Adequacy Among Publicly Owned Load-Serving Entities in California*, staff report, CEC-200-2007-016. August 2007. <www.energy.ca.gov/2007publications/CEC-200-2007-016/CEC-200-2007-016.PDF>.

Figure 2-7: Load Duration Curve 2006



Source: FERC From 714 data compiled by Energy Commission staff.

Scenario Assessments

Overview

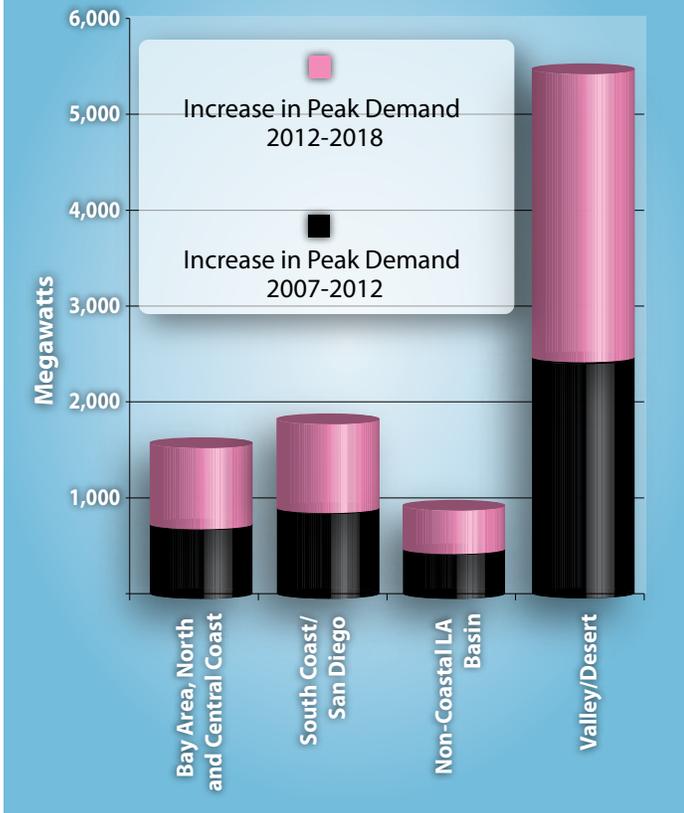
The Energy Commission undertook the Scenario Analyses Project to assess key policy strategies for the electricity system and, specifically, to better understand the actions necessary to achieve major reductions in greenhouse gases from electricity. Rather than focusing on the range of uncontrollable external forces affecting the energy industry, staff developed scenarios that focused on the broad policy options available to decision makers. These policy-driven analyses demonstrate the greenhouse gas emission consequences of the scenarios. They provide a context for assisting the efforts now underway by the California Air Resources Board (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 amounts of energy efficiency measures and renewable energy generation (both rooftop solar photovoltaic and supply-side generating technologies) in California and the Western Electricity Coordinating Council (WECC).^{36, 37} The interesting variables included the effect of resource plans that reduce greenhouse gas emissions compared to resource plans with more conventional resources. These analyses look only at carbon dioxide (CO₂) because this component of greenhouse gas

36 California Energy Commission, *Scenario Analyses of California's Electricity System*, CEC-200-2007-010-SF.

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

**Figure 2-8:
Regional Growth in Peak Demand**



Source: California Energy Commission, *California Energy Demand 2008–2018*, CEC-200-2007-015-SF2.

emissions comprises the overwhelming majority (98 percent) of total emissions from the electricity sector. In addition, the study investigated the impacts of a mix of resources to support load, system and production costs of different generation resources, fuel consumed in power generation, criteria pollutant emissions, and transmission additions required in each scenario. The staff effort did not attempt to devise the optimal amount of preferred resources, but, rather, explored how combinations of increases in amounts in California and the West affect greenhouse gas emissions, resource requirements, transmission requirements, and additional (or incremental) costs in those geographic areas.

The study used standard production cost models to simulate the results for a variety of scenarios composed of different levels of preferred resources — energy efficiency, rooftop solar photovoltaic, and supply-side renewable generating technologies — both for California and the balance of the Rest-of-WECC.

The simulations were conducted to 2020 to correspond most closely to the AB 32 target. 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 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 hydroelectric 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.

Study Design and Scenario Definitions

Staff’s study was designed to focus on 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, 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 incremental amounts 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 photovoltaic and supply-side renewable generating technologies, in California only, otherwise the assumptions of Case 1B.
- Case 4B — High levels of rooftop solar photovoltaic 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, Renewables 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, renewables, or photovoltaic that was developed in selected 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 high levels of amounts of preferred resources.

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



Source: California Energy Commission, California Energy Demand 2008–2018, CEC-200-2007-015-SF2.

The differences among the 10 California-based scenarios by their reliance on energy efficiency and renewables range from a low of Case 1 with about 32,000 gigawatt hours of renewables and zero efficiency to a high of Case 5E with more than 80,000 gigawatt hours of renewables and 60,000 gigawatt hours of energy efficiency (Figure 2-10).

Input Assumptions

Natural gas and coal fuel prices are a key input to any production cost modeling effort. Baseline projections used in the deterministic assessments and the alternative views used to investigate the consequences of higher or lower fuel prices were considered (Figures 2-11 and 2-12).³⁸

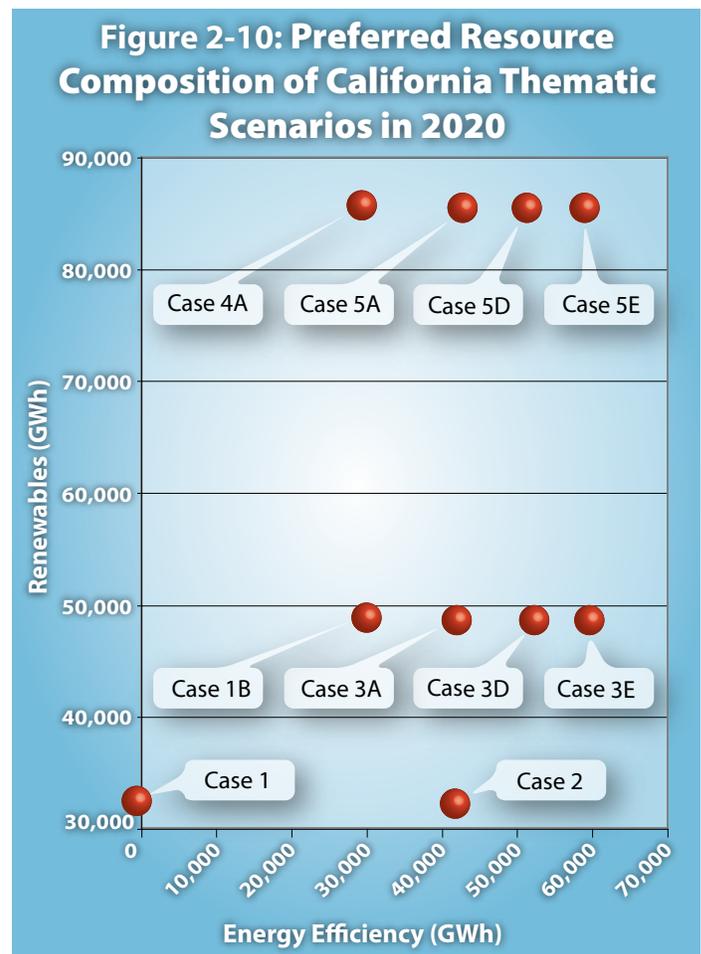
Cost of Generation

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 Model³⁹ uses capital, financing, and operational cost data to calculate levelized⁴⁰ costs of generation for various traditional and alternative electricity generating technologies. First introduced in the 2003 *Integrated Energy Policy Report (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, and of capacity factors for specific power plants (Figure 2-13).

38 California Energy Commission, *Scenario Analyses of California's Electricity System*, CEC-200-2007-010-SF. Global Energy Decisions, Inc. describes these alternative projections as encompassing 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.

39 California Energy Commission, *Comparative Costs of California Central Station Electricity Generation Technologies*, December 2007, CEC-200-2007-011-SF, 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.

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



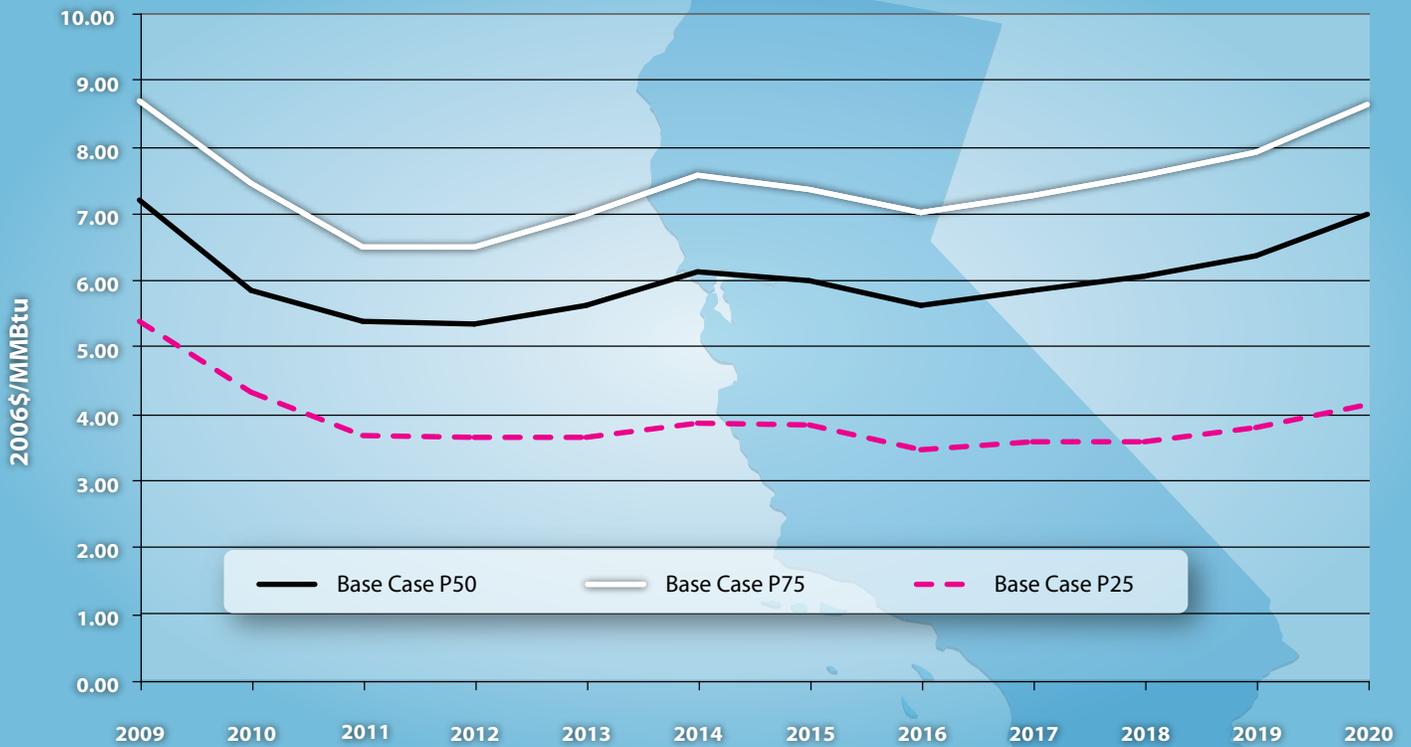
Source: California Energy Commission Scenario Project.

The principal weakness of the revised model remains its lack of information as to 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 regularly update changing technology costs over time.

Results of the Analyses

The results can be examined from multiple perspectives — generation by fuel type or technology, greenhouse gas emissions,

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



Source: Global Energy Decisions, Inc.

power plant fuel use, reliability, corresponding transmission additions, and cost. Staff evaluated the 14 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. In response to workshop comments, staff assessed the implications of a CO₂ cost adder on the dispatch of the fleet of plants in two of the scenarios to assess the level of dispatch cost increase needed to alter reliance on existing coal facilities.

Generation Mix

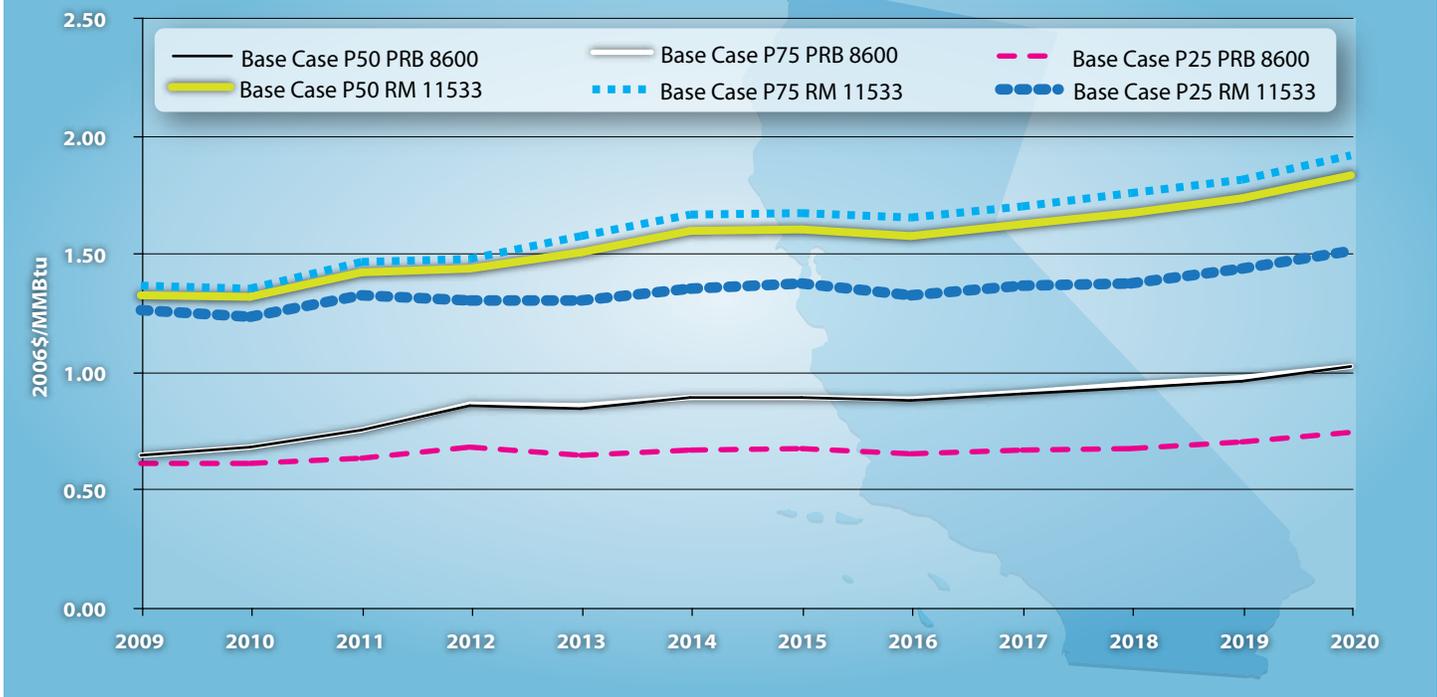
Each of the California generating resource outputs corresponds to each of the same thematic scenarios for 2020 (Figure 2-14).⁴¹

⁴¹ To simplify comparisons, incremental energy efficiency and rooftop solar photovoltaic 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.

The conventional resource scenario on the left of Figure 2-14 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 in-state greenhouse gas emissions and 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, natural gas-fired electricity generation is still the largest single source of the electricity consumed in California in 2020 (Figure 2-14). Hydroelectric, nuclear, and other fuel types or technologies are essentially unchanged across all scenarios.

An important result of the analysis is the wide difference in level of imports (top of each bar) into California across these scenarios. These imports are limited to short-term

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



Source: Global Energy Decisions, Inc.

market purchases that cannot necessarily be tracked to any specific generating plant.⁴² 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 greenhouse gas emissions.⁴³

Several notable results for Rest-of-WECC include large proportions of electricity from hydroelectric and coal generation when compared to California power plants (Figure 2-15). Contributions from hydroelectric and coal resources are almost unchanged across all of the scenarios, no matter how large the level of preferred resources. The addition of preferred resources displaces natural gas-fired electricity generation, just as in the

case within California. What is surprising, however, is that the change in natural gas-fired electricity generation is even larger in Rest-of-WECC than it is for California. This results from the higher operating costs of out-of-state natural gas-fired plants, making their output the first to be displaced as preferred resources are added. Although electricity generated in Rest-of-WECC and exported to California is a noticeable share of California’s electricity power sources, these “exports” are not important in the much larger Rest-of-WECC electrical system.

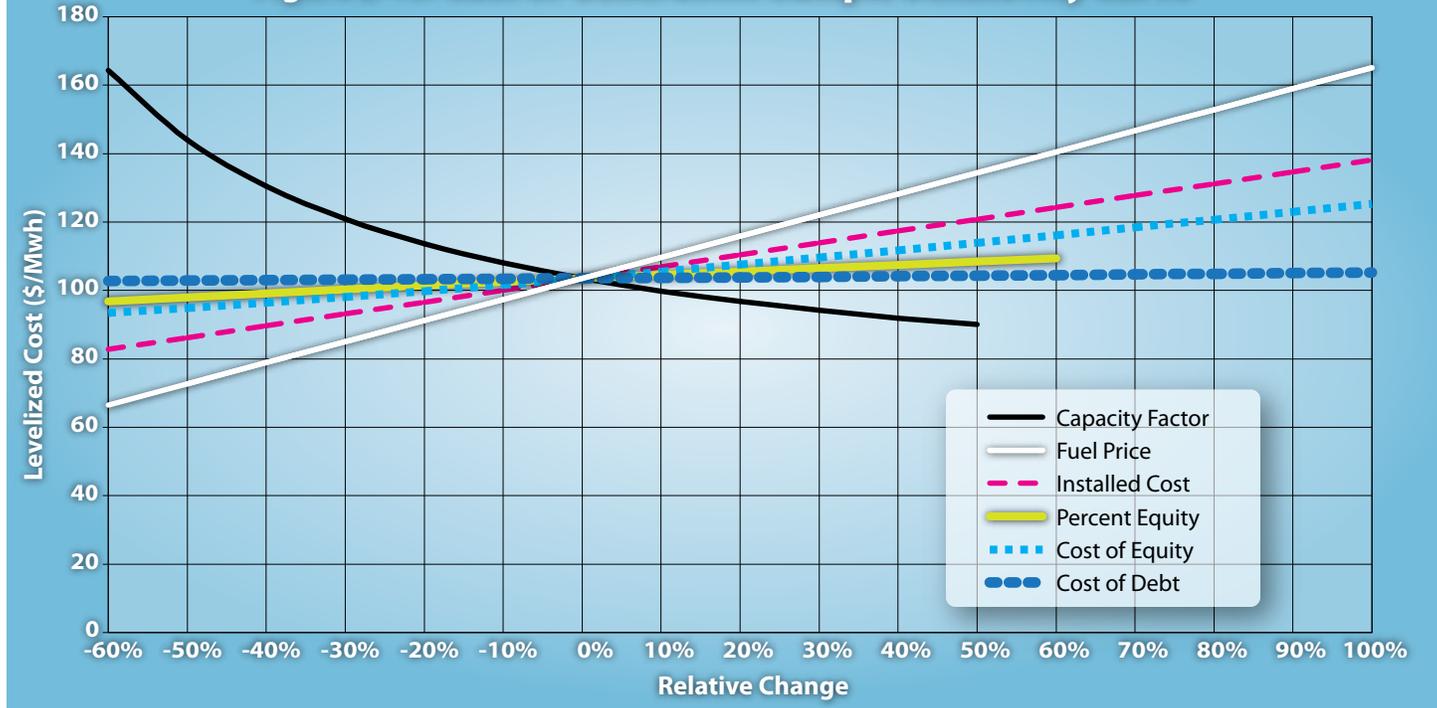
Greenhouse Gas Emissions

Each generating unit modeled was assigned an emission rate for CO₂, and the simulation results recorded CO₂ amounts based on the fuel burn of each unit. The total CO₂ emissions across the cases change as the energy generation changes. The California responsibility for CO₂ 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

⁴² 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.

⁴³ The physical system study design on which this analysis was conducted omits load-serving entity-specific transactions, thus making it impossible to determine whether the limitations on baseload coal generation required by SB 1368 (Perata, Chapter 598, Statutes of 2006) 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 2-13: Cost of Generation Sample Sensitivity Curve



Source: California Energy Commission.

(3) emissions from power plants located outside California that correspond to “spot purchases.” Similarly, CO₂ emissions from the Rest-of-WECC consist of 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.

Except for “spot purchases,” this portion of overall imports into California are allocated CO₂ emissions based on the average CO₂ profile of the annual average generation mix for Rest-of-WECC.

Changes in California CO₂ responsibility for 2020 in the scenarios are illustrated in Figure 2-16. A conventional resource mix in Case 1 has higher carbon emissions than Case 5E, the case with the largest amount of energy efficiency and renewables across the West. Even though the resource mix of Cases 5E and 5D are quite different regarding the amounts of natural gas consumed in California versus electricity imported into California, the level of CO₂ emissions are nearly the same. From a California responsibility perspective each of the pairs of cases—3A and 3B, 4A and 4B, and 5A and 5B—show slightly higher total emissions 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 CO₂ and other greenhouse gases remain un-priced attributes of electricity generation, the sources of California’s CO₂ emissions are substantially affected by the resource mix and cost differences between power plants in California and those in the Rest-of-WECC.

The change over time of California in-state power plant CO₂ production is largely based on the change in natural gas-fired electricity generation. Since coal and oil are negligible sources of generation in California, only natural gas really matters as a greenhouse gas source for power plants located in state. 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 these as “unspecified imports”) are markedly reduced in the various preferred scenarios. Greenhouse gas emissions from imports are reduced because imports are reduced, not because the emission characteristics of imports from Rest-of-WECC make any great change.

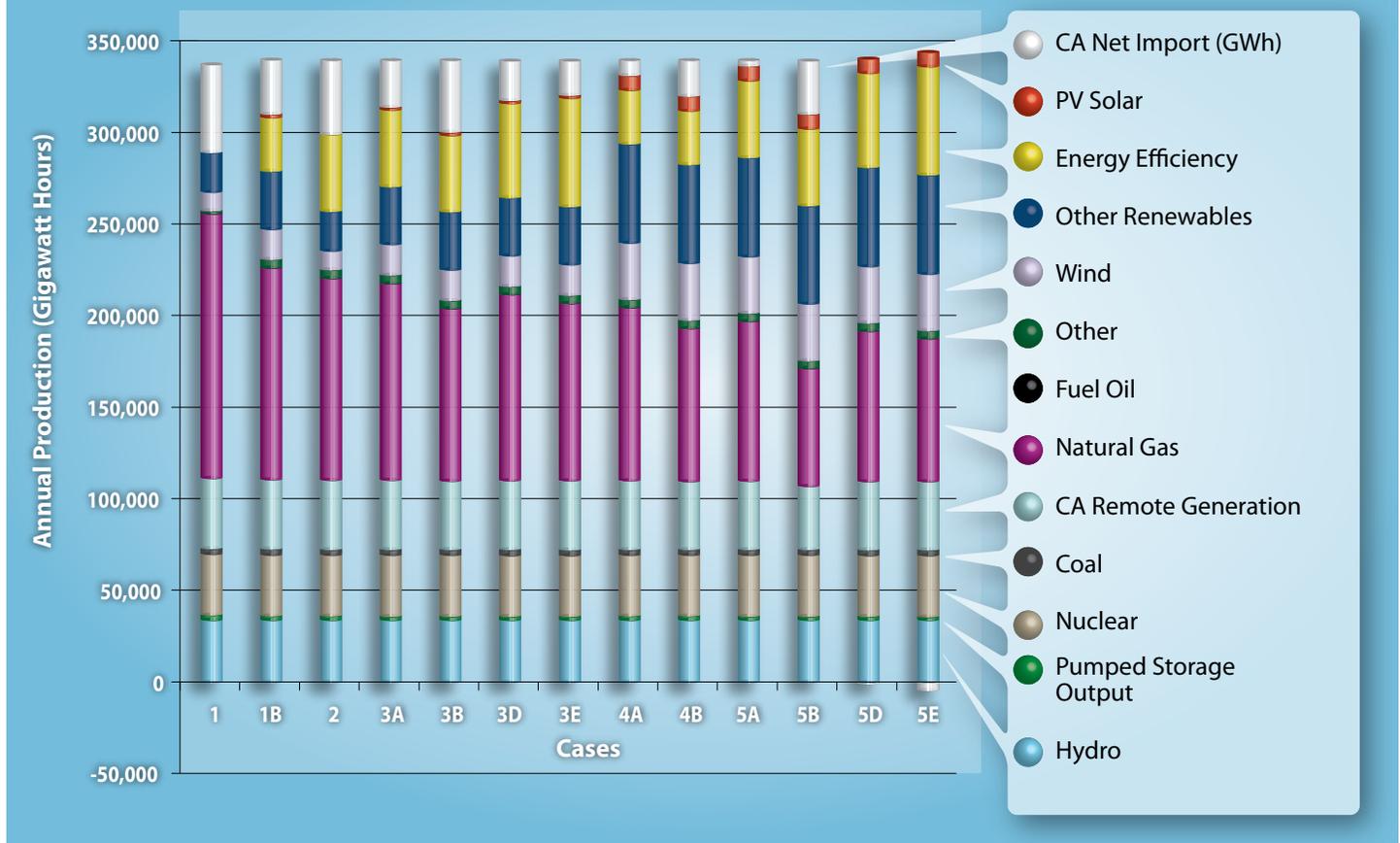
It is important to consider California's responsibility for greenhouse gas emissions through 2020 (Figure 2-17). In Case 1, Current Conditions, natural gas-fired generation is added to meet future load growth while renewables and energy efficiency are only added in nominal amounts. As a result, the CO₂ 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 CO₂ emissions are the lowest and noticeably less than in Case 5B (a high energy efficiency and high renewables throughout the West.) There was no attempt to create an additional level of energy efficiency beyond Case 5B for Rest-of-WECC, because no data source 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 unfold through time. While these strategies have been pursued, in part, for reasons other than greenhouse gas emission reduction, they clearly have a profound effect. In fact, the Case 1 to Case 1B differential has a much larger effect than the incremental effect of further pursuit of these strategies.

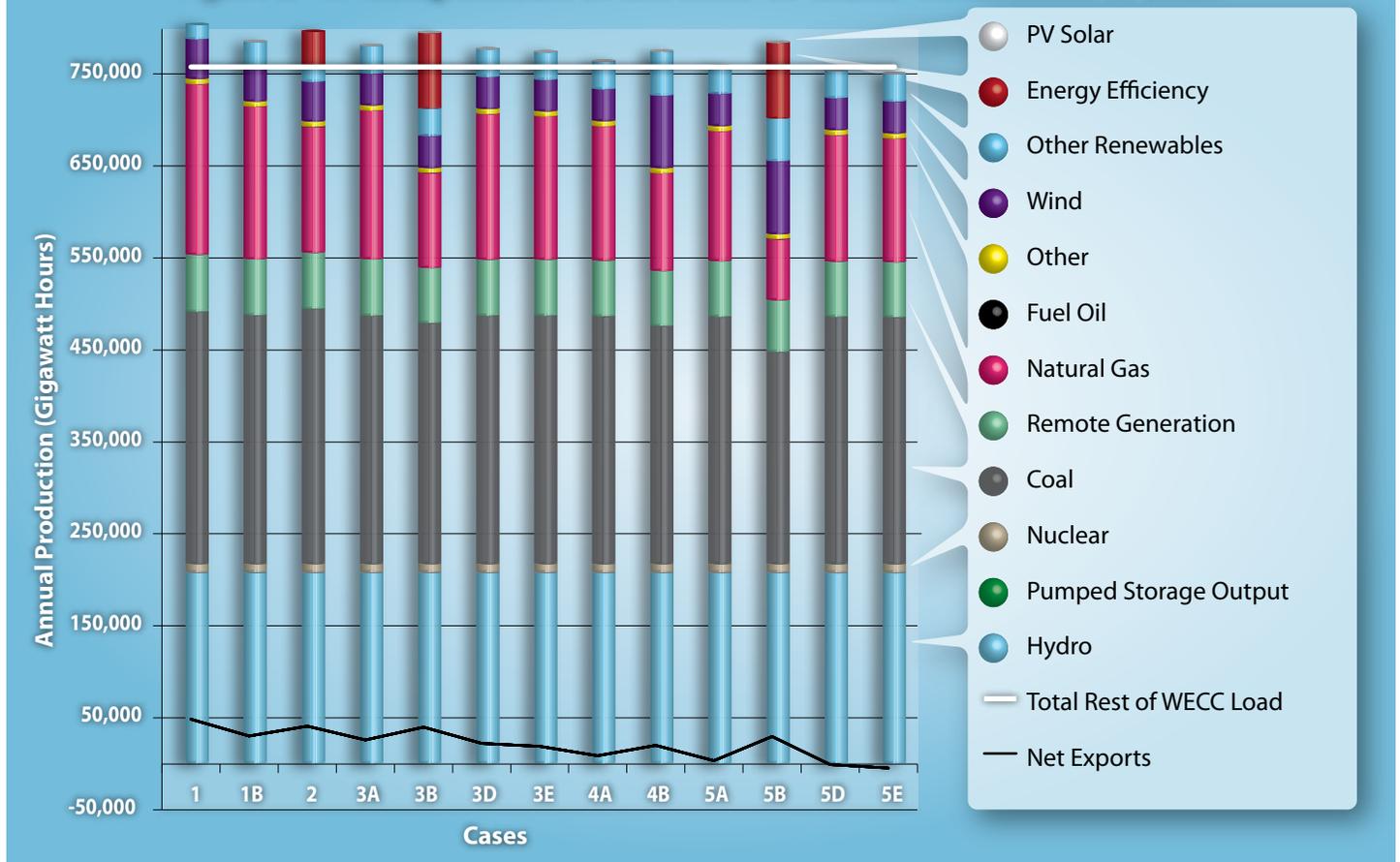
This figure also identifies how the electricity sector projections compare with an estimate of 1990 greenhouse gas emissions. The ARB has not finalized its inventory, and ARB uses certain conventions that do not match those of the Scenario Project, so minor adjustments to historic data have been made to assure consistency between the historic data and projected results. In making this comparison, staff does not assume 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.

Fig 2-14: Composition of California Resource Mix in Year 2020



Source: California Energy Commission Scenario Analyses Project.

Figure 2-15: Composition of the Rest-of-WECC Generation in 2020



Source: California Energy Commission Scenario Analyses Project.

It is clear that several strategies pursued individually can satisfy the range of 1990 values (estimates prepared by the 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 degree than other sectors.

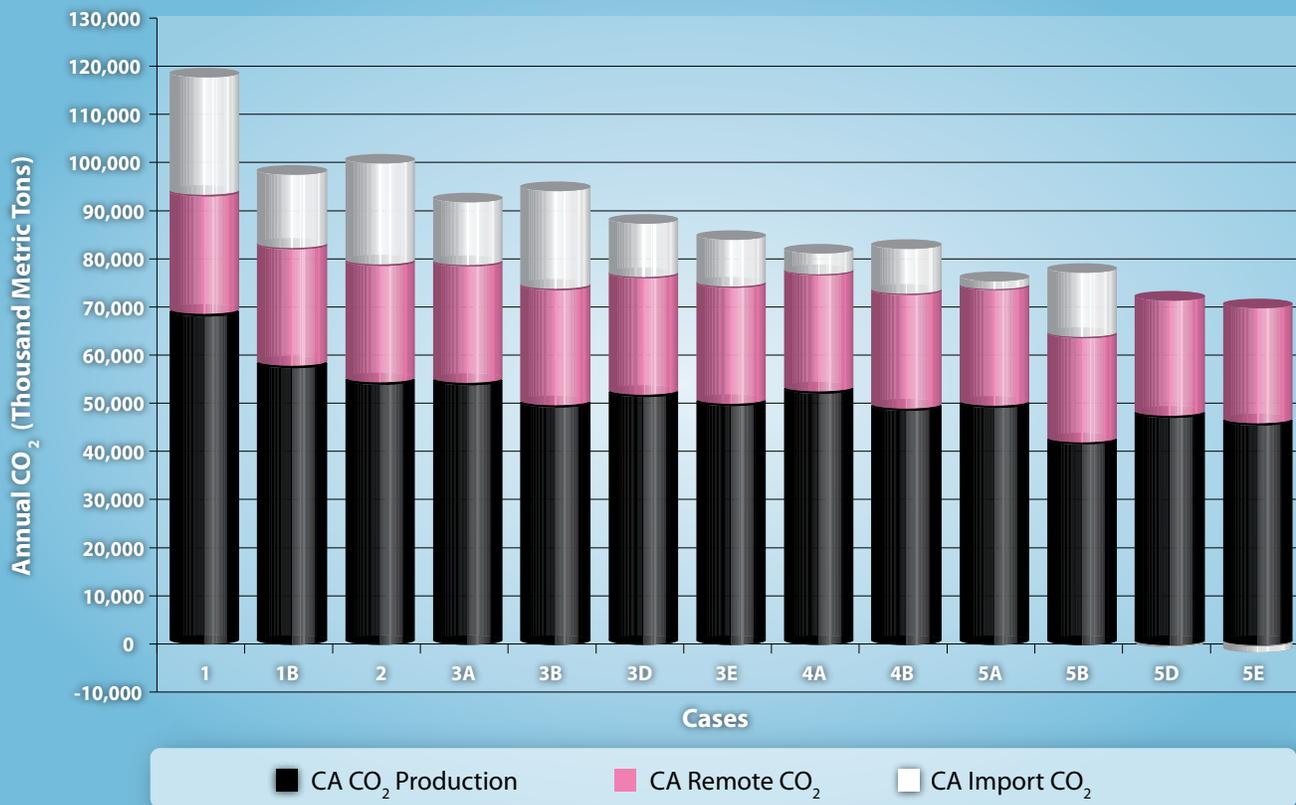
In addition, the volatility exhibited within the historic portion of Figure 2-17 makes clear the degree that hydroelectric variations can shift emissions from one year to the next. As noted in the staff analyses, any greenhouse gas compliance system has to recognize this volatility that is an inherent consequence of the generally beneficial use of hydroelectric generation in the Western electricity system.

Electricity Generation Fuel Use

Analyses were undertaken to look at the change in prospective natural gas demand as a power generation fuel in California and all the WECC (Figure 2-18). California and Rest-of-WECC natural gas use for electricity generation are comparable in volumes, even though it is proportionally 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.

The WECC-wide coal consumption for power generation was assessed, and 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 (Figure 2-19). Even in Case 5B, WECC-wide coal consumption only declines

Figure 2-16: Comparing California Carbon Dioxide Responsibility in Year 2020



Source: California Energy Commission Scenario Analyses Project.

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 million Btu 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 use, coal power generation prices are so much lower than natural gas prices that coal will continue to be dispatched regardless of resource additions promoted by policy makers.

Reliability

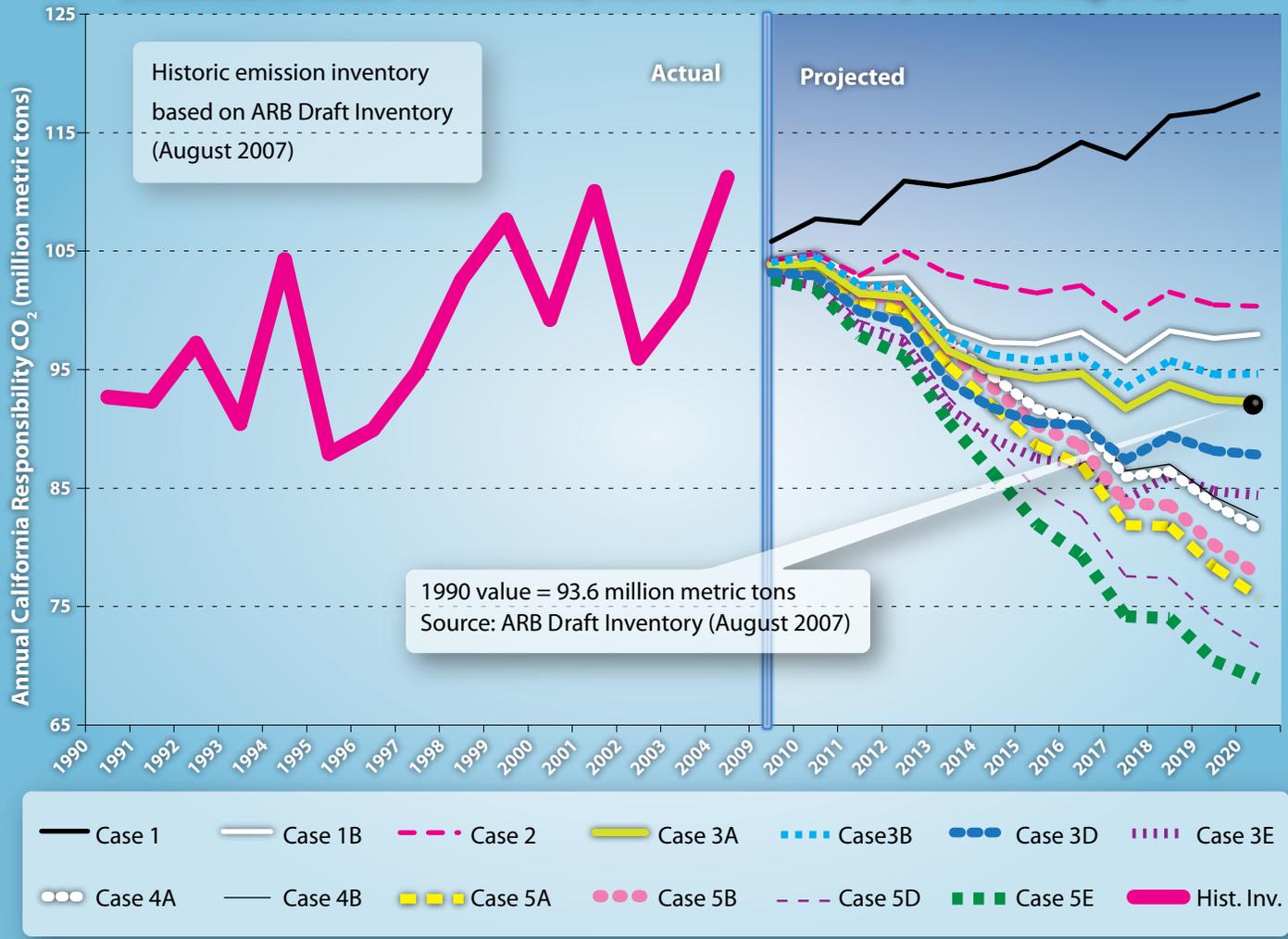
Because of the large amounts of non-dispatchable capacity added in several scenarios, reliability was built into the design

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 on high levels of renewables and high loads because of no increased reliance on energy efficiency), but found no expected un-served energy.⁴⁴ Further examination showed that actual resources exceeded planning reserve margin targets in

⁴⁴ Expected un-served energy measures the annual amount of electricity consumption that end users desired, but could not receive, through generation or transmission outages.

Figure 2-17: 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.

all years, since the dependable capacity of the resources added exceeded the capacity of the generic resources removed when the scenarios were constructed.⁴⁵ This result suggests that adding renewable resources as in Case 4A or Case 5A, even though they are not dispatchable, does not 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.⁴⁶

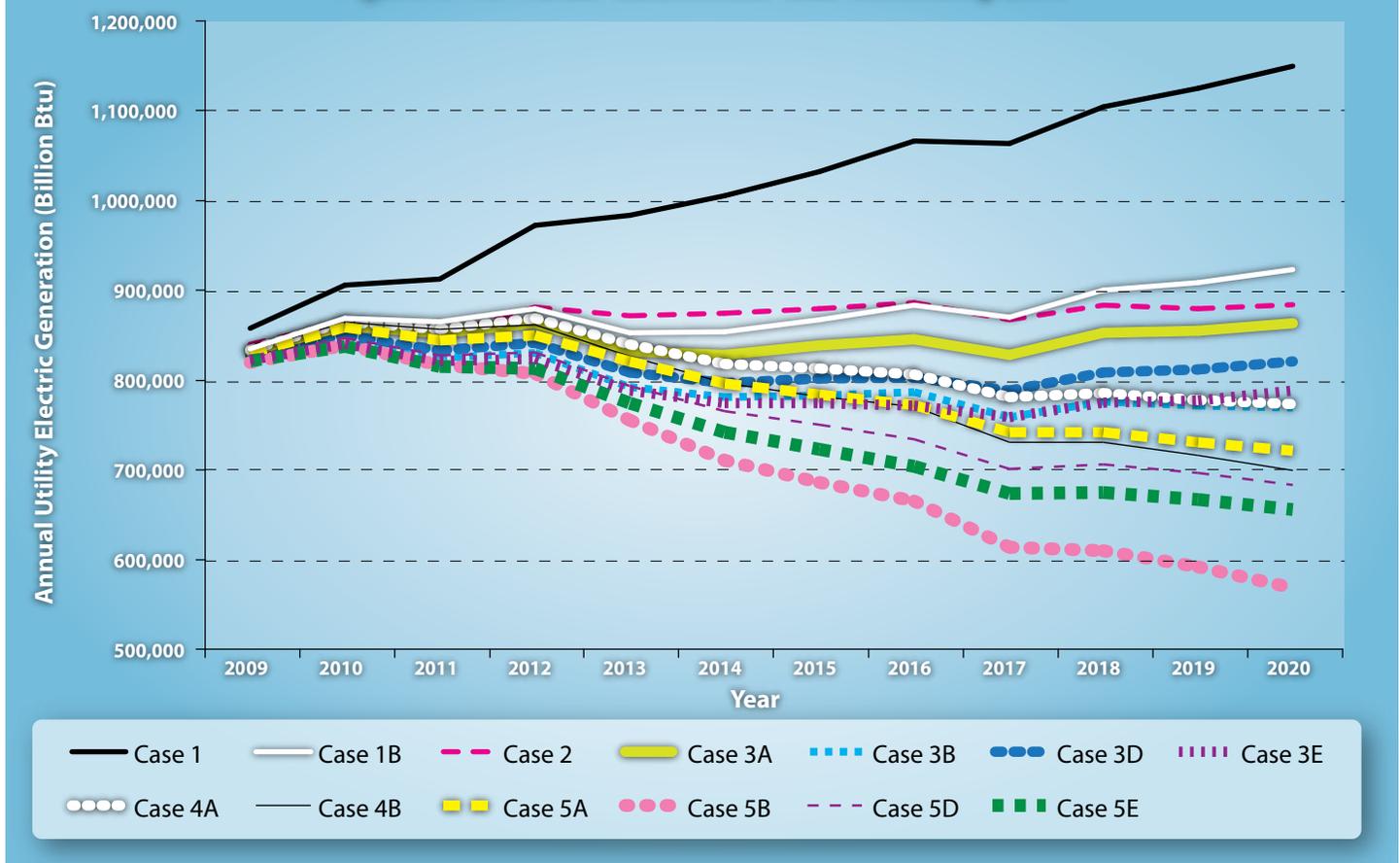
Utilities remain concerned about operational issues, especially those connected to retirement of aging power plants and replacement with renewables located at a distance from load centers, and whether the full set of transmission line additions needed to support this pattern of resource build out has been adequately assessed.⁴⁷ As further discussed in Chapter 4, the

⁴⁵ California Energy Commission, *Scenario Analyses of California’s Electricity System, Third Addendum*, Chapter 4 and Appendix D. CEC-200-2007-010-AD3.

⁴⁶ Op. cit., *Second Addendum*, Chapter 2 and Appendix A, CEC-200-2007-010-AD2.

⁴⁷ Southern California Edison, *Aging Plant Retirements*, IEPR Committee Workshop, August 16, 2007.

Figure 2-18: Total California Gas Consumption



Source: California Energy Commission Scenario Analyses Project.

Energy Commission supports more studies of the operational issues associated with renewables development. The Energy 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.

Transmission Additions

Load growth, merchant plant 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 2-1).

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 that case can be displaced by imports from New Mexico and Wyoming with the additional transmission upgrades.

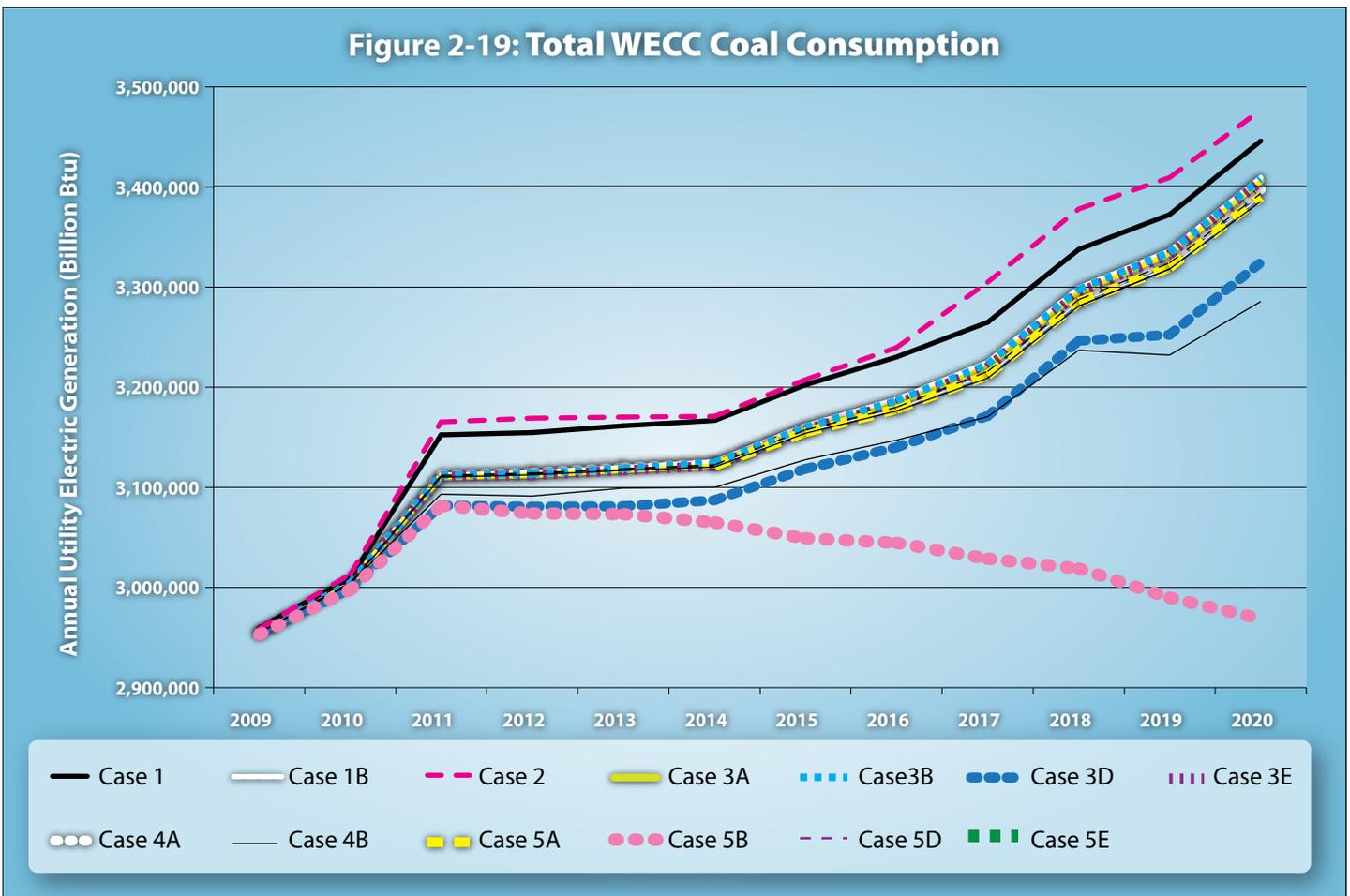
While the specific projects identified should not be considered for definitive planning studies, the variations on the chart reveal the strong interaction between generation development and transmission development. The Energy Commission is not the originator of this concept, but the 2003 *Integrated Energy Policy Report* has emphasized the need for increased attention for coordination among the entities responsible for transmission planning to make efforts

Table 2-1: 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	Tehachapi upgrades						
SCE	SCE			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

Source: California Energy Commission Scenario Analyses Project.

Figure 2-19: Total WECC Coal Consumption



Source: Global Energy Decisions, Inc.

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

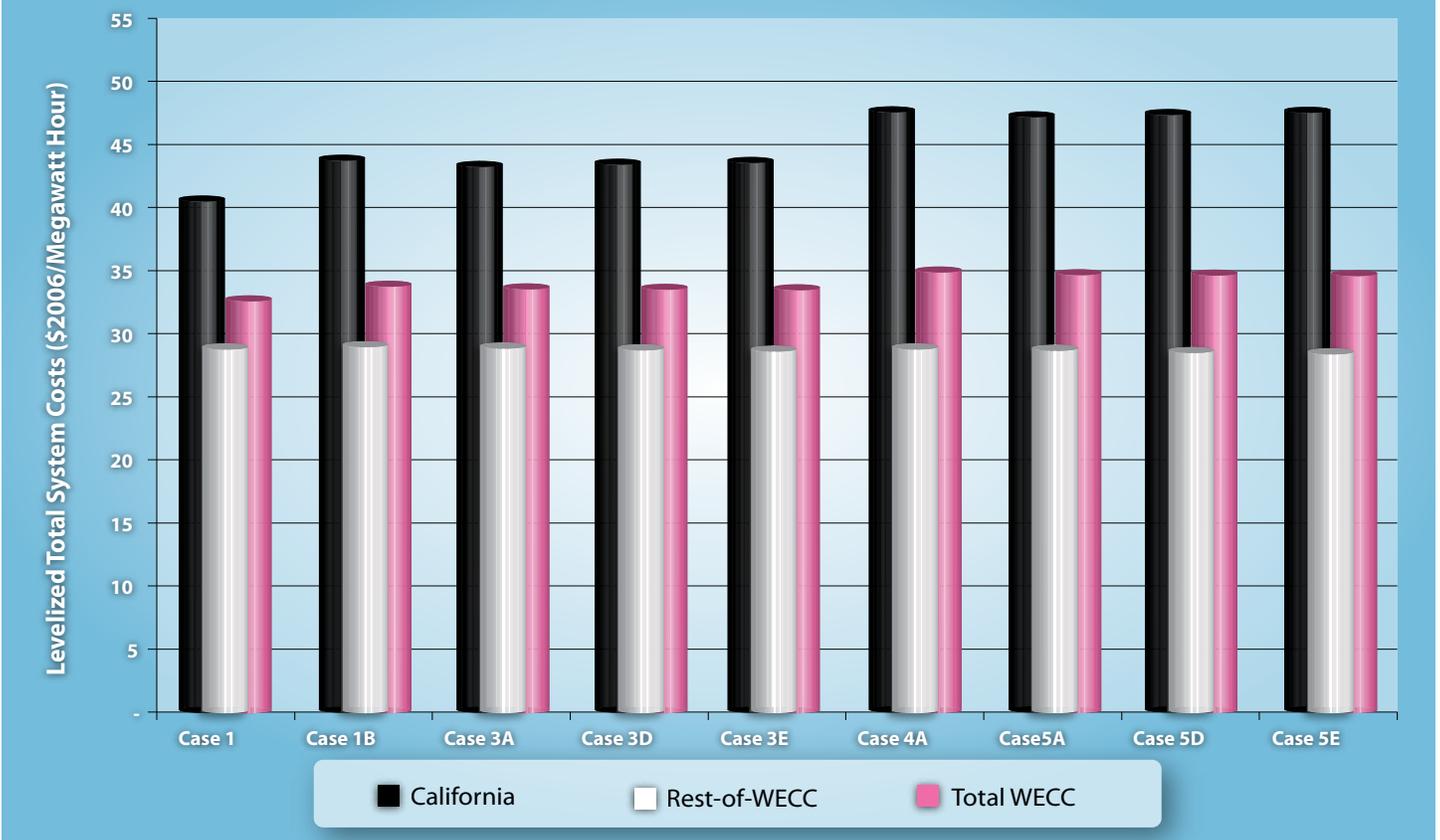
Achieving these greenhouse gas emission reduction benefits is not without cost in some areas. Figure 2-20 provides the results of the analysis on levelized system costs for the scenarios under the control of California policy makers. These results

assume that technology cost and performance stay constant through time, except for rooftop solar photovoltaic that is assumed to decrease by 50 percent.⁴⁸ 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 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

⁴⁸ 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.

Figure 2-20: Levelized System Costs



Source: California Energy Commission Scenario Analyses Project.

there is a noticeable increase in system costs per unit compared to what it would have been under current policies. This result stems in part from the higher costs assumed for the significant distributed rooftop photovoltaic included in these scenarios. Care must be taken when computing levelized cost and considering energy efficiency and end-user renewable resources because these activities reduce sales, thereby naturally raising levelized costs if only the remaining “purchased” electricity is considered. Figure 2-20 depicts energy efficiency and solar photovoltaic as resources, including their total energy contributions, which make the comparison more direct.⁴⁹ In addition, costs of these resources are partially covered by end-user contributions rather than entirely through general ratepayer cost recovery.

⁴⁹ California Energy Commission, *Scenario Analyses of California's Electricity System, Third Addendum*, Table 8, p. 26. CEC-200-2007-010-AD3.

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 hydroelectric generation — are sufficient to demonstrate that the results are sensitive to input assumptions.

A concise summary of the sensitivity of cost and greenhouse gas emissions relative to fuel price and hydroelectric generation was undertaken (Table 2-2). The hydroelectric 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 hydroelectric generation resulting from very dry or very wet precipitation patterns. A greenhouse gas emission reduction program must accommodate itself to the sort of swings in greenhouse gas emissions shown in California CO₂ column.

Initial Examination of Carbon Dioxide Cost Adder

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.

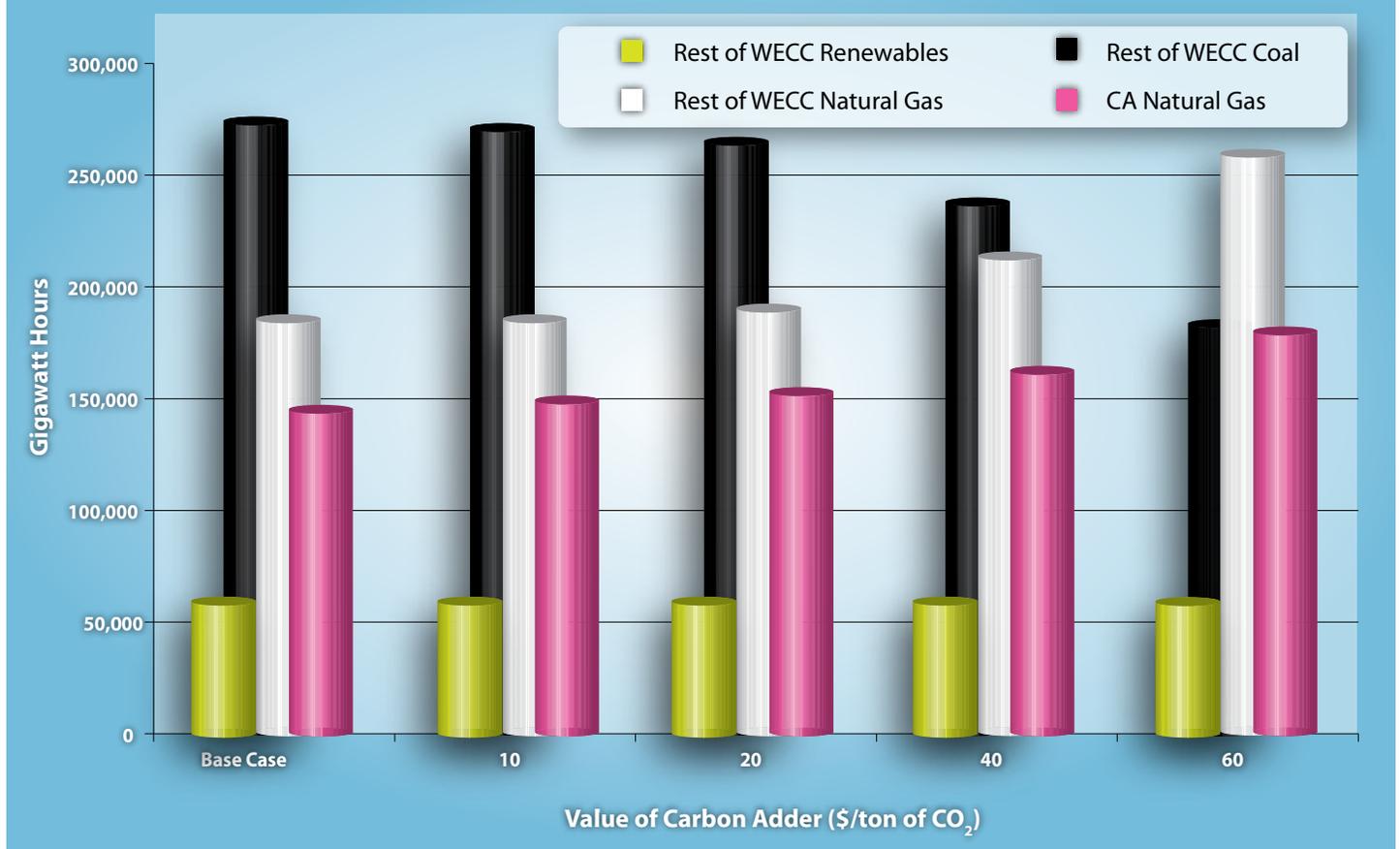
Figures 2-21 and 2-22 provide an overview of the degree to which resources are re-dispatched when a carbon dioxide cost adder of various levels affecting unit commitment and dispatch is imposed upon a given resource mix. Carbon dioxide cost adders from \$10 per metric ton to \$60 metric ton were explored, with only very slight responses when the carbon cost adder is at levels of \$10 and \$20 per metric ton. Both figures show that meaningful displacement of coal generated power begins when the adder reaches \$30 to \$40 per metric

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

Thematic Scenarios		Calif. System Costs (2006 Thousand Dollars)			Calif. CO ₂ Emissions (Thousand Metric Tons)		
		Low NG	Base	High NG	Low NG	Base	High NG
Case 1 - Current Conditions	High Hydro		16,164,681			62,742	
	Base	12,265,962	16,684,128	19,177,074	67,722	68,786	68,996
	Low Hydro		16,875,608			72,566	
Case 1B - Current Requirements	High Hydro		15,945,868			53,417	
	Base	13,004,270	16,354,098	18,224,842	57,259	57,992	57,940
	Low Hydro		16,507,640			61,199	
Case 3A - High EE in Calif. Only	High Hydro		15,299,757			50,022	
	Base	12,617,673	15,701,704	17,434,336	53,681	54,475	54,647
	Low Hydro		15,843,813			57,532	
Case 3B - High EE West-wide	High Hydro		15,077,660			45,091	
	Base	12,569,545	15,576,942	17,257,192	49,913	49,789	49,693
	Low Hydro		15,757,903			52,453	
Case 4A - High Renewables in Calif. Only	High Hydro		18,617,701			48,492	
	Base	16,452,327	18,935,010	20,318,987	51,935	52,702	52,938
	Low Hydro		19,039,752			55,276	
Case 4B - High Renewables West-wide	High Hydro		18,501,518			44,995	
	Base	16,443,014	18,904,156	20,272,379	48,824	49,158	49,245
	Low Hydro		19,055,587			51,566	
Case 5A - High EE and Renewables in Calif. Only	High Hydro		18,121,512			45,796	
	Base	16,184,232	18,407,604	19,636,497	49,045	49,760	49,937
	Low Hydro		18,491,545			52,262	
Case 5B - High EE and Renewables West-wide	High Hydro		17,799,534			38,502	
	Base	16,145,825	18,238,302	19,369,073	42,512	42,066	41,804
	Low Hydro		18,450,465			44,753	

Source: California Energy Commission Scenario Analyses Project.

Figure 2-21: Case 1 Annual Generation 2020



Source: Global Energy Decisions, Inc.

ton of CO₂.⁵⁰ 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-fueled plants in California are a principal means to displace generation from coal plants in Rest-of-WECC in this re-dispatch analysis. As natural gas plant use increases in California, this would increase both greenhouse gas and criteria pollutant emissions. Staff’s initial analysis of this issue for 2020 shows that even in Case 5B (high energy efficiency and high renewables throughout the West) California natural gas-fueled plants would supply more than half the entire increase in electricity generation displacing more expensive coal.

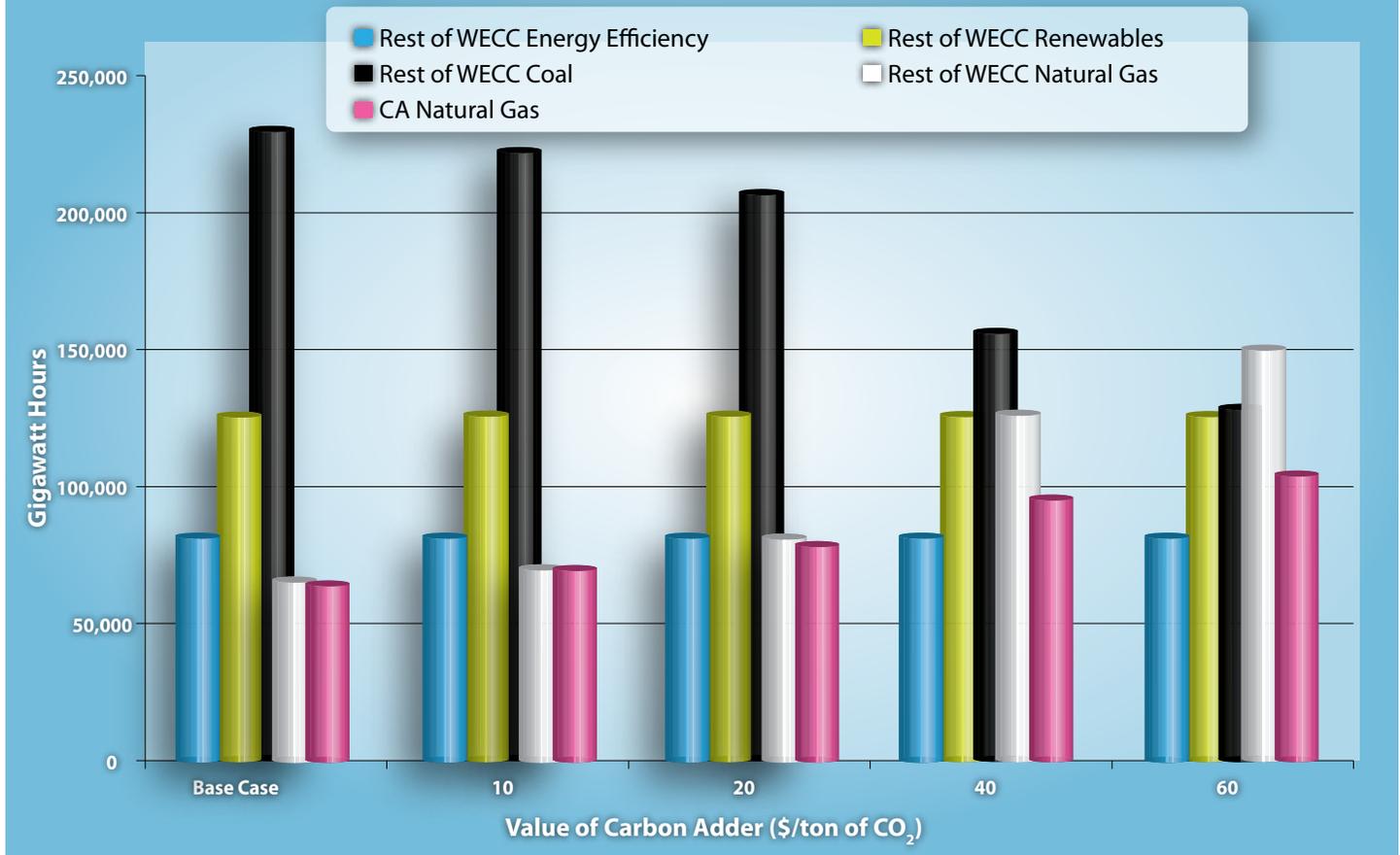
This initial result requires considerably more analysis, beyond the time frame of the 2007 IEPR, and it illustrates one of the themes flowing from the staff’s assessment — that is, California is unlikely to accomplish its electricity sector greenhouse gas emission reduction goals in isolation from Rest-of-WECC. The Energy Commission should communicate these initial results to the ARB and CPUC and undertake additional studies to better understand the implications of various prices attached to CO₂ emissions in the future.

Implications of the Results

Table 2-3 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-

50 Op. cit., Chapter 3. CEC-200-2007-010-AD3.

Figure 2-22: Case 5B Annual Generation 2020



Source: Global Energy Decisions, Inc.

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 2-3 also computes a simple statistic of effectiveness. It measures greenhouse gas emission reductions per thousand dollars of expenditure.

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 and 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 2-3 also illustrates the distinction between in-state power generation versus the broader view of California's responsibility for all generation that supports California loads.

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

	2020 System Cost Difference (2006 Thousand Dollars)	2020 CO ₂ Instate Emission Difference (Thousand Metric Tons)	2020 Reduction (\$ Per Metric Ton)	2020 CO ₂ California Responsibility Emission Difference (Thousand Metric Tons)	2020 Reduction (\$ Per Metric Ton)
Case 1B	-	-	NA	-	NA
Case 3A	(652,394)	(3,517)	(185.51)	(5,738)	(113.69)
Case 3D	(1,172,584)	(6,011)	(195.07)	(10,160)	(115.42)
Case 3E	(1,569,955)	(7,887)	(199.06)	(13,606)	(115.39)
Case 4A	2,580,912	(5,290)	487.91	(16,411)	157.27
Case 5A	2,053,506	(8,232)	249.46	(22,168)	92.63
Case 5D	1,554,921	(10,355)	150.16	(26,411)	58.87
Case 5E	1,164,144	(11,924)	97.63	(29,129)	39.96

Source: Global Energy Decisions, Inc.

The California Responsibility columns of Table 2-3 always show much lower dollar per ton of savings results than the in-state generation columns because the same expenditures necessary for the preferred measures affect both in-state and out-of-state generation. For example, the Case 4A result for renewables measures greenhouse gas savings just for in-state power plant greenhouse gas reductions costs more than \$480 per ton, while taking total power generation emission reductions into account reduces this cost to only \$150 per ton. Similar effects are shown for all of the cases in varying degrees, because the preferred strategies always have both in-state and out-of-state power generation greenhouse gas emission reductions.

The results have driven home the reality of California's interconnectedness with the rest of the West that is too easily forgotten in enthusiasm of greenhouse gas emission reduction strategies. It is critical in the near-term to solidify 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 as noted in the recent joint CPUC and Energy Commission decisions implementing AB 32. The decisions California makes affect other areas 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 placations developed at the Energy Commission. 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.

Findings of the Assessment

Although staff's study improves upon weaknesses of previous studies, the results suggest impacts rather than forecast them. 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 CO₂ emissions. The more intensive preferred resource scenarios would enable a higher contribution to AB 32's 2020 goals than 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.⁵¹
- Unless costs affecting power plant dispatch are revised or other dispatch priorities are otherwise affected, 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.⁵²
- 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 ton of CO₂.⁵³ The displaced coal generation would be replaced by higher generation from natural gas-fueled power plants, both in California and Rest-of-WECC.⁵⁴
- 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.⁵⁵

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 before industry restructuring, investor-owned electric utilities could construct, own, and operate new capacity to match their electricity generation

and reliability needs. Utility ownership of generation and transmission, combined with an authorized rate of return, limited utilities’ 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.⁵⁶

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.⁵⁷

51 California Energy Commission, *Scenario Analyses of California’s Electricity System*. CEC-200-2007-010-SF.

52 Ibid., p. 120.

53 Op. cit., *Third Addendum*, p. 30. CEC-200-2007-010-AD3.

54 Ibid., p. 29.

55 Op. cit., *Second Addendum*, p. 30. CEC-200-2007-010-AD2.

56 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.

57 Ibid., p. 21.

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 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 loosely 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 2-4 presents their estimates of the 95th percentile natural gas price from 2010 – 2016. In the near term (2010), investor-owned utility estimates of 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 2-4: 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; under current regulatory rules unexpectedly high prices do not unduly burden shareholders. The corrosive influence of "moral hazard," where decisions are made by entities that are financially insulated from 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 on 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 more than 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 report⁵⁸ 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 the cost and risk of an

efficient portfolio cannot be simultaneously lowered; costs can only be lowered with an increase in risk. Similarly, the risk of an efficient portfolio cannot be reduced 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, and it is not possible to say whether or not the portfolio is "efficient."

As part of its investigation, Energy Commission staff reviewed the long-term procurement plans filed by California investor-owned utilities — PG&E, SCE, and San Diego Gas & Electric (SDG&E) — at the CPUC on December 11, 2006, and later 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.⁵⁹ Although 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 (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.

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

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

Common Planning Assumptions and the Resource Planning Process

Based on the Energy Commission’s review, California’s investor-owned utilities use relatively primitive analytic methodologies for assembling their long-term procurement plans. Although characterized as “least cost, best fit” by the utilities, these plans fail to adequately address the interests of utility customers in reducing the long-term risk of continued volatility in the price of natural gas. The methodologies tend to focus on projected costs attributed to individual technologies and ignore portfolio effects. They apply inappropriately high discount rates to future fuel costs, thereby understating the impact upon consumers. The net result is a systematic undervaluing of non-fuel-intensive procurement alternatives, such as efficiency and renewables, and an increasing dependence on gas-fired generation.

State policy directives on loading order priorities have yet to effectively alter the analytic paradigm for procurement planning. Application of Modern Portfolio Theory and the Capital Asset Pricing Model, the underpinnings of financial analysis for the past several decades (and the basis for the 1990 Nobel Prize awarded to Harry M. Markowitz, Merton H. Miller, and William F. Sharpe), to electric utility procurement decisions should better align utility and customer interests. Accordingly, the Energy Commission intends to make the development of a common portfolio analytic methodology a core focus of the *2008 IEPR Update*, with the clear objective of influencing the long-term procurement plans filed by the investor-owned utilities with the CPUC in December, 2008.

Various state laws and CPUC decisions define the landscape of procurement choices available to the investor-owned utilities. Consistent with these multiple requirements, the 2008 IEPR Update process will:

- Invite the close collaboration of the CPUC staff with the Energy Commission staff in developing a schedule and structuring required investor-owned utility submittals that will prove most useful to the subsequent long-term procurement proceeding at the CPUC.

- Use common planning assumptions to the maximum extent practicable, particularly for key risk drivers such as the underlying probability distributions for natural gas price trends, greenhouse gas mitigation costs, technology characteristics, and so forth.
- Extend over a 20 to 30 year period of analysis, even though the investor-owned utilities’ procurement plans subsequently filed with the CPUC may be of shorter duration.
- Discount future fuel costs at the 3 percent social discount rate used by the Energy Commission in its standard-setting activities, unless the investor-owned utilities can demonstrate that these costs should be assigned to shareholders.
- Focus upon an “efficient frontier” of procurement portfolios from a consumer perspective utilizing a cost-based metric, with a sufficiently broad scope to incorporate environmental impacts.
- Engage multiple stakeholders in a transparent process of public workshops and hearings.

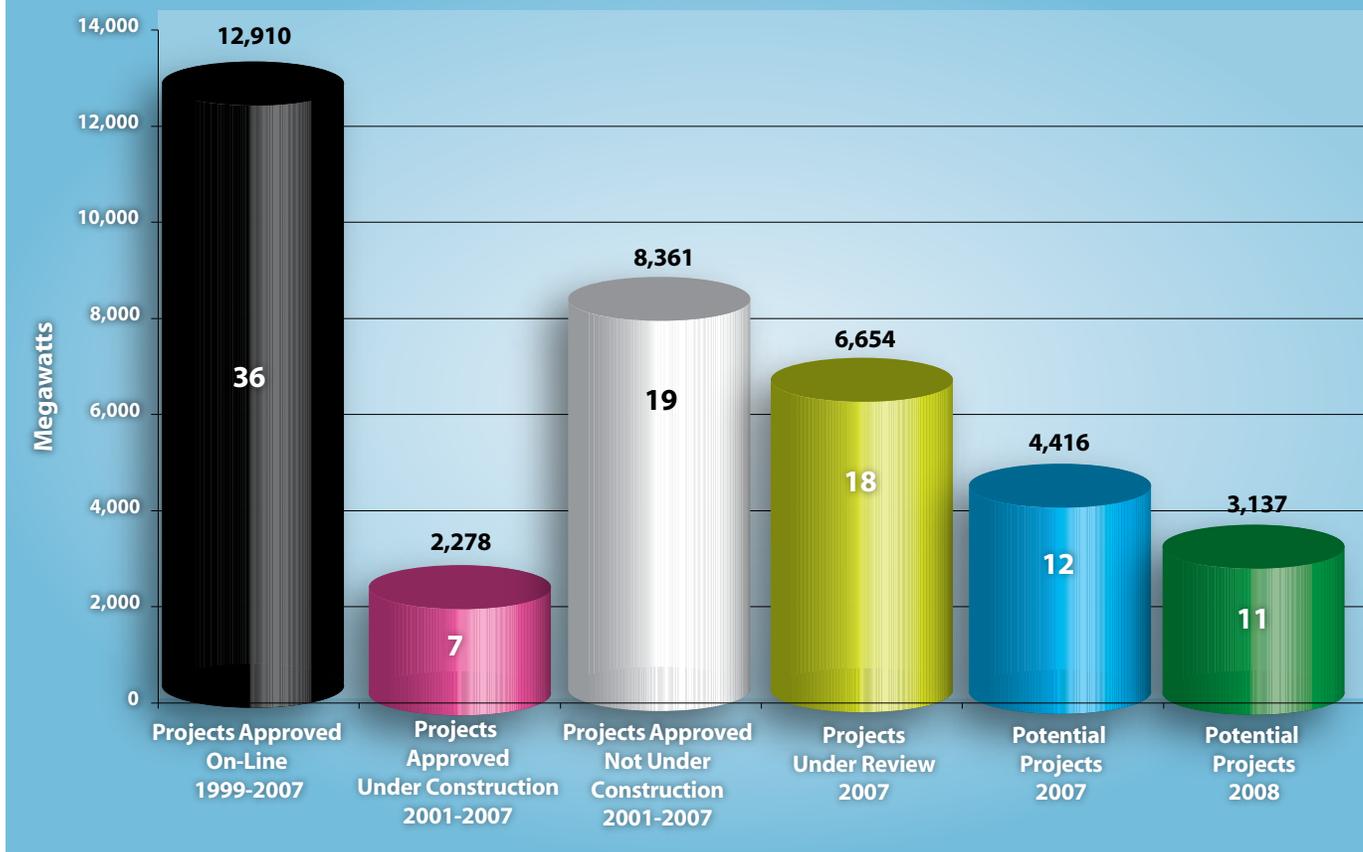
The Energy Commission envisions broadening this methodology and applying it to the larger publicly owned utilities in subsequent IEPR cycles. For purposes of the *2008 IEPR Update*, however, the emphasis will be on the investor-owned utilities and the California ISO control area.

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.⁶⁰ 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.

⁶⁰ California Gross System Power, 2006. The remaining 30 percent comes from renewables (11 percent) and large hydroelectric (19 percent).

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



Source: California Energy Commission.

Natural Gas

Since California’s electricity market was restructured in 1998,⁶¹ the Energy Commission has licensed 62 power plants totaling nearly 24,000 megawatts of new capacity (Figure 2-23). 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, only 36 plants — 12,910 megawatts — have come on line, with an additional 2,278 megawatts currently under construction. Although 18 plants, totaling 8,361 megawatts, have been approved, they have not moved forward with construction largely because they lack power purchase agreements necessary for their financing. Seven of these plants have actually been cancelled or had their permits

expire. 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 California’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.

61 Assembly Bill 1890 (Brulte), Chapter 854, Statutes of 1996.

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. As required by Senate Bill 1368 (Perata, Chapter 568, Statutes of 2006), the state has set a 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 1,100 pounds per megawatt hour similar to those of a modern natural gas combined cycle power plant.

The most likely way for coal plants to meet this standard is through the use of advanced coal technologies⁶² 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 available 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 December 2007, the Energy Commission adopted *Geologic Carbon Sequestration Strategies for California: The Assembly Bill 1925 Report to the California Legislature*.⁶³

The report concludes that, while technical challenges to CO₂ capture and sequestration remain, the primary barriers to progressing with initial projects are economic — with costs for CO₂ capture and compression, which are believed to make up 70 to 80 percent of total costs, estimated at \$50 to \$90 per

metric ton — and, more generally, statutory and regulatory.

The report also 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 CO₂ enhanced oil recovery projects in oil and gas fields than to simply isolate CO₂ for long-term storage purposes.

Two proposed new power plants in California — the 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 CO₂ capture with the prospect that the CO₂ could be sold for commercial purposes, including use in enhanced oil recovery.

Elsewhere in the United States, the federal 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 United States.⁶⁴ 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 as a promising future low CO₂ 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

62 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.

63 California Energy Commission, November 2007, CEC-500-2007-100-SF.

64 <www.netl.doe.gov/technologies/coalpower/futuregen/EIS/>.

to control their CO₂ 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. Emerging CO₂ markets' inability to establish a sufficiently high and sufficiently stable price for CO₂ 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 Newsletter*, Citigroup noted "... prophecies of a new wave of coal-fired generation have vaporized, while clean coal technologies such as integrated gasification combined cycle with CO₂ 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.⁶⁵

It is challenging to accurately assess the economics of CO₂ capture and sequestration because no policy exists to establish a price for CO₂ in the marketplace. Preliminary estimates for CO₂ capture and compression — by far the largest part of the entire cost of CO₂ capture and sequestration — are \$50 to \$100 per metric ton of CO₂ removed. This cost is sizeable given the \$8 per ton CO₂ adder established by the CPUC to be used by utilities for long-term planning and procurement. This does not include the cost of transporting CO₂ to the sequestration site. Other issues that could significantly increase costs include permitting, monitoring, acquiring property rights, and liability.

However, according to the Intergovernmental Panel on Climate Change, carbon prices could be about \$100 per ton by 2030 for the 445–490 parts per million CO₂ equivalent stabilization levels that the Intergovernmental

Panel on Climate Change has identified as needed to reduce global emissions to 50 to 85 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 electricity generation in the 2020 time frame. It does, however, remain an important national, and international, research and commercialization priority. 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

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 and because fuel represents a small portion of their costs, nuclear plants are also largely insulated from fuel price volatility.

The United States is currently experiencing 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 United States have received renewals to extend their operating licenses

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

66 The Intergovernmental Panel on Climate Change reports a 445–490 parts per million CO₂ equivalent as substantially reducing the expected magnitude, impact, and rate of climate change from business-as-usual scenarios by 2050 from 2000 emission levels and states that most individual studies for this category of reductions cluster around \$100 per ton CO₂ by 2030. Intergovernmental Panel on Climate Change, 2007, *Climate Change 2007: Mitigation*. Contribution of Working Group III to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change. Metz, B., O. R. Davidson, P. R. Bosch, R. Dave, and L. A. Meyer (eds). Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA. <www.ipcc.ch/pdf/assessment-report/ar4/wg3/ar4-wg3-chapter3.pdf>, p. 198, Table 3.5 and p. 206.

67 California Energy Commission, November 2007, CEC-500-2007-100-SF.

by 20 years, and some 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; uncertain construction timelines; regulatory risks associated with the use of once-through cooling; waste disposal; 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 on 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 United States effort to halt the proliferation of nuclear weapons.”

Although California consumers have paid more than \$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 United States nonproliferation efforts. While the federal government has proposed a major new reprocessing initiative (the Global Nuclear Energy Partnership, or GNEP), significant questions remain regarding reprocessing technologies available today and those that GNEP proposes.

For example, a recent National Academies panel concluded that the rationale for the GNEP program is unpersuasive, that the GNEP program should not go forward at its current pace, and that GNEP is relying upon technologies that are too early for commercial development (decades away) and too expensive (costing tens of billions of dollars or more). The panel further concluded that GNEP has had insufficient independent review, and there are major uncertainties about its ability to address U.S. waste disposal issues.

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, Finland’s AREVA nuclear plant continues to experience delays — most recently announcing that on-line operations may be postponed from 2009 to 2011 — and is believed 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 that 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.

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

69 Ibid.

70 “Atomic Renaissance,” *The Economist*, September 8-14, 2007, p. 71.

71 “AREVA-Siemens Consortium Announces Delay of Finnish Nuclear Reactor,” *Energy Business Review*, August 13, 2007. <www.energy-business-review.com/article_news.asp?guid=80B1249C-4590-4A5A-A624-AC9AD3901FA2>.

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. AB 1632's 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 economic, environmental, and regulatory obstacles involved in developing new nuclear power plants, the Energy Commission does not expect significant contributions from new nuclear plants toward the state's AB 32 goals by 2020.

Challenges Facing Southern California

As the state's demand for electricity increases, Southern California in particular continues to be vulnerable to supply shortages. Southern California utilities 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 to the point that in 2008, the Los Angeles Basin will be required to meet nearly half of its electrical load with local generating capacity.

Aging Power Plants

In 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 75 percent of the aging capacity identified in the study was located in the southern part of the state, including 16 plants totaling 2,400 megawatts owned by publicly owned utilities. Nevertheless, the issue of California's aging plants is still a statewide concern. 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.

Currently, only 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, SCE relies on these plants through 2016, and SDG&E's plan relies on 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. 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 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.⁷² Both SCE and the California ISO endorsed the assessment as a reasonable first step, but identified additional elements for 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 must address aging facilities owned by the investor-owned and publicly owned utilities and carefully consider issues surrounding once-through cooling and restrictions on emission credits in Southern California.

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.

Recognizing 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 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 the 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 and 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 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*, determining 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

The Surfrider Foundation filed a legal challenge in July 2007 against the San Diego Regional Water Control Board and the SWRCB for their 2006 renewal of the National Discharge Elimination System permit for the Encina power plant in San Diego.

In September 2007, the Coalition for a Sustainable Delta, representing local water districts and irrigators, announced plans to sue Mirant Delta LLC and the United States Army Corps of Engineers over alleged violations of the

72 California Energy Commission, *Scenario Analyses of California’s Electricity System, Second Addendum*, Appendix A. CEC-200-2007-010-AD2.

73 Tobias, Larry, California Independent System Operator, presentation, September 21, 2007. *Mitigation of Reliance on Old Thermal Generation Including Those Using Once-Through Cooling Systems*. <www.caiso.com/1c5e/1c5edff632c50.pdf>.

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

75 *Riverkeeper vs. U.S. Environmental Protection Agency (Riverkeeper II)*.

76 *Discharge Permits: EPA Suspends Cooling Water Rule in Response to Second Circuit Decision*, Environment Report (BNA), v. 38, No. 27 at 1481. July 6, 2007. <www.bna.com>.

Endangered Species Act due to the once-through cooling systems in the Pittsburg and Contra Costa power plants.

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.

The Energy Commission has worked closely with the Ocean Protection Council, the SWRCB, State Lands Commission, and other agencies involved with the once-through cooling issues to provide information on coastal power plant operations, resource adequacy, and local reliability issues, including:

- Assessments of impacts to marine and estuarine environments from once-through cooling based on staff analysis of six coastal power plant licensing applications
- Support from the Energy Commission's Public Interest Energy Research Program on ecosystem functions, species diversity, and measuring impacts from once-through cooling in different ecosystems
- Information from facility siting experience with inland and coastal plants to use air cooling
- Information on coastal plant operations, resources adequacy, and other energy issues associated with potential impacts to grid reliability from proposed regulatory changes on once-through cooling

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, 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.

In addition, existing facilities that currently use once-through cooling are likely to face significant legal challenges, particularly for permit renewals. Two-thirds of California's coastal power plants are located in the southern part of the state, which is already facing reliability challenges due to the number of

aging power plants coupled with a shortage of emission credits available for new plants in the South Coast Air Basin.

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."

However, the Nuclear Regulatory Commission ruled, in April 2007, that the decision to allow the Vermont Yankee nuclear facility to discharge warmer water into the Connecticut River is a state issue, not a federal issue, concluding that the Clean Water Act, "precludes [the Nuclear Regulatory Commission] from either second guessing the conclusions in NPDES permits or imposing [its] own effluent limitations – thermal or otherwise."⁷⁷

In addition, Nuclear Regulatory Commission officials testifying this summer at the Energy Commission's IEPR workshops on nuclear power indicated their intent to defer to SWRCB determinations.

New Air District Rule Limits Use of Emissions Credits

In the South Coast Air Basin, limitations on the supply of emission reduction credits constrain the ability to either license new power plants or repower existing ones.⁷⁸ 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.

⁷⁷ Nuclear Regulatory Commission Docket 50-271-LR, Memorandum and Order, April 11, 2007, in the matter of Entergy Nuclear Vermont Yankee, LLC & Entergy Nuclear Operation Inc., pp. 4–5.

⁷⁸ South Coast Air Quality Management District 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.

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 enough credits 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 megawatts 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-megawatt 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.

Grid Support/Local Capacity Requirements

Beginning in 2007, the California ISO identified the need for additional capacity in 2007 and 2008 in specific state geographic zones with constrained resources to meet local capacity requirements.⁷⁹ For 2007, the existing capacity needed to meet these requirements is 22,113 megawatts across 10 zones, many of which are coastal urban areas with older steam boiler facilities.⁸⁰

However, it is important to distinguish between capacity reserves and operational levels. On an energy production

basis, the coastal fleet contributed 22 percent of total 2006 in-state electricity sales. The two large nuclear plants account for 60 percent of that production; however, total electricity production from the coastal facilities has decreased by nearly half since 2001. In 2006, 11 of the 17 natural gas-fired power plants operated at or below a 15 percent capacity factor,⁸¹ reflecting that most older steam boiler units were not being used for the baseload generation as they were designed to do. In fact, four large plants that ran above 50 percent capacity factors in 2001 — Contra Costa, Pittsburg, Morro Bay, and Redondo Beach — all operated below 5 percent capacity factors in 2006.

For 2008, the existing capacity needed to meet local capacity requirements will increase to 22,899 megawatts. In addition, 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. Also, 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 06-07-029,⁸² 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 Southern California coastal areas require coordinated decisions and actions among all agencies to avoid reliability problems. Some current merchant electricity generators

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

80 California Independent System Operator, *2008 Local Capacity Technical Analysis: Report and Study Results*, April 3, 2007, table, p. 43. Specific plants to meet local capacity requirements are not named due to proprietary concerns.

81 Capacity factor means how much electricity a plant produces in a year relative to its potential production if it were to operate at full capacity for all 8,760 hours in a year.

82 California Public Utilities Commission, July 20, 2006. <www.cpuc.ca.gov/published/Final_decision/58268.htm>.

understandably question the *2005 IEPR* policy and want “market forces” alone to drive decisions on retirement or repowering.⁸³ 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 until early 2009.

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 must step up its efforts to evaluate the impacts of retiring, repowering, or replacing aging generation resources with resources compatible with the state’s air, water, and greenhouse gas goals, as well as the economic interests of its utility customers.

The Energy Commission recommends the following:

- The Energy Commission, the CPUC, the California ISO, and other interested agencies such as the Ocean Protection Council, State Water Resources Control Board and South Coast Air Quality Management District 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 investor-owned utilities 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 that plagued the 2003 and 2005 IEPR cycles. Although virtually all utility submissions to the Energy Commission call for real retail prices to fall, these forecasts do not consider the cost of infrastructure improvements and are based 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 *2007 Strategic Transmission Investment Plan*, adopted by the Energy Commission in November 2007 and prepared in support of the *2007 IEPR* proceeding, describes the state’s transmission challenges and provides recommendations to overcome them.⁸⁴ The report also makes recommendations regarding in-state transmission corridor planning and in-state transmission projects.

83 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.

84 California Energy Commission, *2007 Strategic Transmission Investment Plan*, November 2007. <www.energy.ca.gov/2007publications/CEC-700-2007-018/CEC-700-2007-018-CMF>.

Recommendations

To address issues identified as part of the Energy Commission's analyses of the electric sector and to better address costs and risks in the utility planning process, the Energy Commission makes the following recommendations:

- As an early part of the *2008 IEPR Update*, the Energy Commission will conduct a public process that includes CPUC staff, utilities, and other stakeholders to determine an effective method of better delineating the energy efficiency savings assumptions included in the Energy Commission staff demand forecast, both from historic as well as future standards and programs. The Energy Commission recognizes the value that such a methodology can provide in future state planning efforts related to both energy policy and greenhouse gas emissions reduction.
- The Energy Commission will use the 2009 IEPR cycle to extensively refine the input data used for developing technologies in the Cost of Generation Model and to establish a process to regularly update changing technology costs over time.
- The Energy Commission will include in the *2009 IEPR* a robust assessment of the effect of high levels of preferred resources on reducing natural gas prices.
- The Energy Commission will make the development of a common portfolio analytic methodology a core focus of the *2008 IEPR Update*, with the clear objective of influencing the long-term procurement plans filed by the investor-owned utilities with the CPUC in December 2008. This methodology should use common assumptions across utilities to the maximum extent practicable; extend over a 20- to 30-year period of analysis; discount future fuel costs as the same social discount rate used in standard-setting activities unless these costs are shown to be shareholder liabilities; and focus upon an "efficient frontier" from a consumer perspective utilizing a cost-based metric, with a sufficiently broad scope to incorporate environmental impacts.
- The Energy Commission will actively participate in the California ISO's study concerning aging power plants that use once-through cooling, with specific attention given to the challenges faced by the investor-owned and the publicly owned utilities in Southern California.
- As originally articulated in the *2005 IEPR*, the CPUC should require that investor-owned utilities procure enough capacity from long-term contracts to allow for the orderly retirement or repowering of aging plants by 2012.
- To ensure that California's interests are protected, the state should take an active role in the Yucca Mountain licensing proceeding and challenge the Department of Energy's inadequate response to potential impacts previously identified during the environmental impact statement and review process. The Energy Commission will continue to participate in Department of Energy and regional planning activities for nuclear waste shipments, as well as assess the reliability implications for California's operating nuclear plants from implementation of once-through cooling regulations.
- The Energy Commission will work with federal and state regulators, nuclear plant owners, and Institute of Nuclear Power Operators (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 should, as part of its long-term procurement plans, develop a contingency plan to replace generation from Palo Verde should it be shut down for an extended period.

Chapter 3

Meeting Energy Needs with Efficiency and Demand Response



*"Energy conservation is the foundation
of energy independence."*

Tom Allen, U.S. Representative, R-Maine

For the past 30 years, 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-1970s and has remained relatively flat — between 7,200 and 7,800 kilowatt hours per person — a success attributable in part to energy efficiency initiatives in the form of building efficiency and appliance efficiency standards and utility-sponsored incentive programs.⁸⁵

Energy efficiency and demand response programs are key strategies for addressing climate change and meeting the AB 32 goals for greenhouse gas 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 in reducing the costs of meeting peak demand during periods of high temperatures.

California continues to experience declining load factors.⁸⁶ 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 businesses 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 greenhouse gas 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.

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 must support expanded efforts in all programs. Scenario analyses have demonstrated that cost-effective efficiency programs can allow California to achieve at least a proportional reduction of carbon emissions from the electric sector. These analyses highlight the need to capture

85 *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.

86 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.

all cost-effective energy efficiency. The October 18, 2007, decision from the California Public Utilities Commission (CPUC) supports 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 updated regularly 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, the investor-owned utilities 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 publicly owned utilities have offered similar programs for their customers, although the significant differences in size among the publicly owned utilities affect their level of program development.

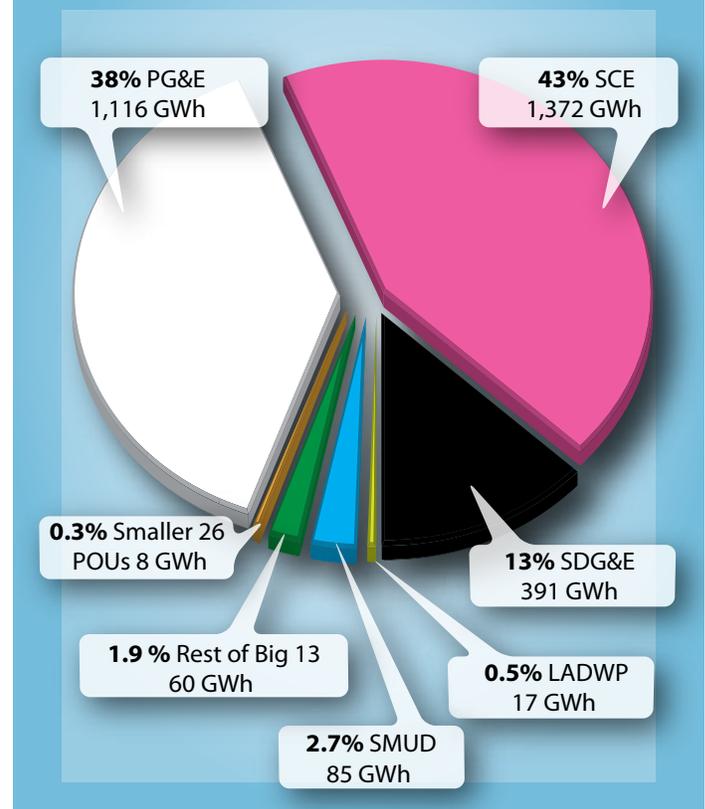
Each investor-owned utility and publicly owned utility customer pays a small public goods charge to support public programs for energy efficiency, low-income services, renewable energy, and public interest research and development. A natural gas surcharge provides similar support on the natural gas side. Since 2004, additional funding has been made available through the investor-owned utilities’ procurement proceedings to pursue energy efficiency beyond what is funded by the public goods charge. In the 2004–2005 energy efficiency program cycle, the investor-owned utilities had a budget of nearly a billion dollars and reported energy efficiency savings of 4,773 gigawatt hours, 948 megawatts, and 77 million therms.

Like the investor-owned utilities, the publicly owned utilities administer a variety of energy efficiency programs for their customers. During fiscal year 2005–2006, all

publicly owned utilities collectively spent more than \$54 million on energy efficiency and saved more than 170 gigawatt hours and 53 megawatts of peak electricity.

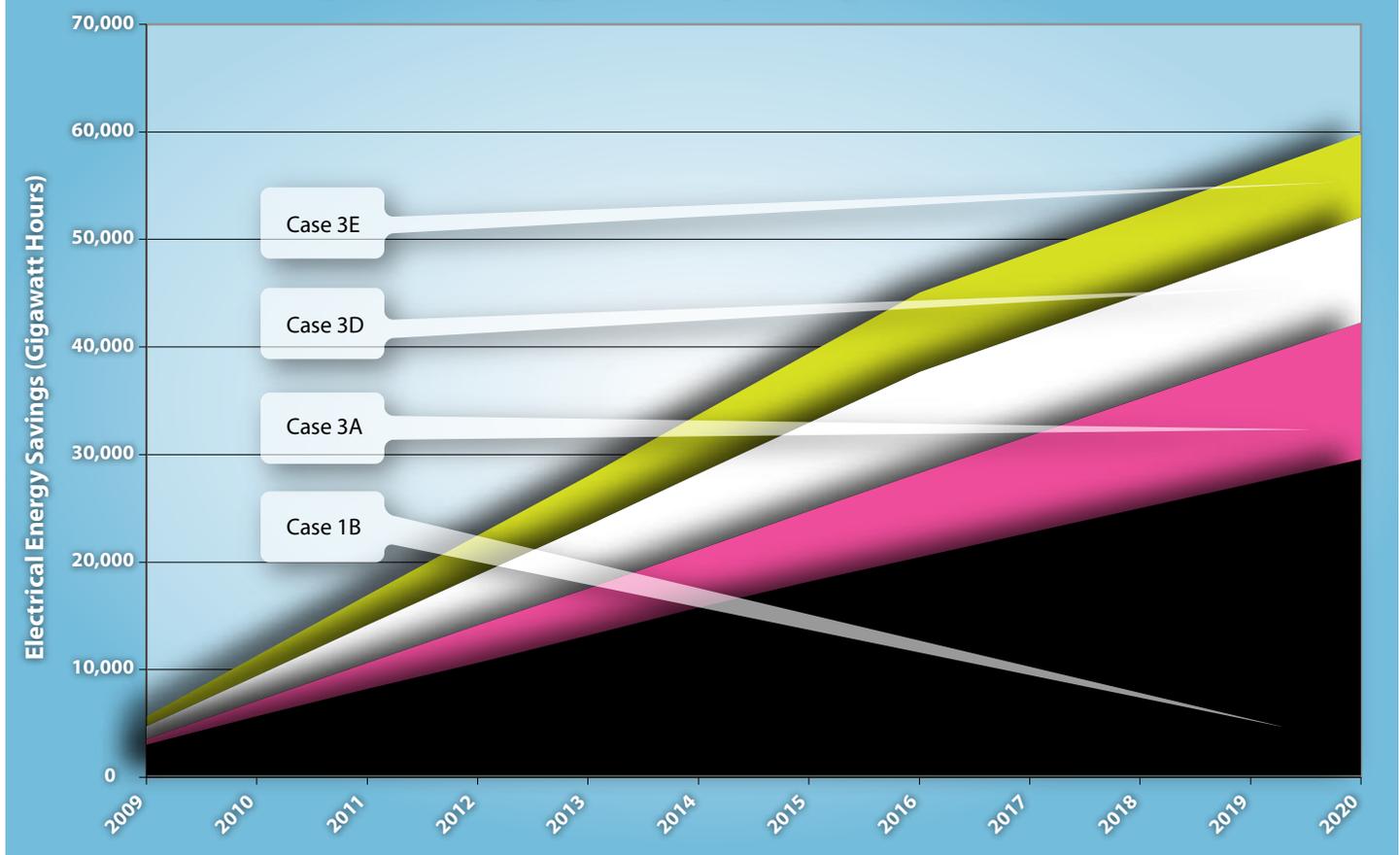
Figure 3-1 shows the electric energy savings reported for 2005 for both investor-owned utilities and publicly owned utilities. Combined, the investor-owned utilities’ programs command 95 percent of the savings. The two largest publicly owned utilities in the state, Sacramento Municipal Utility District (SMUD) and Los Angeles Department of Water and Power (LADWP), both of which have had programs as long as the investor-owned utilities, account for 3.2 percent of the statewide savings, but 60 percent of the publicly owned utility savings. SMUD expended \$22 million for energy efficiency — close to half the entire amount spent for all 39 of the publicly owned utilities that

Figure 3-1: Investor-Owned Utility and Publicly Owned Utility Share of Electric Energy Savings in 2005



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

Figure 3-2: Energy Efficiency through Time by Case



Source: Navigant Consulting, Inc.

supplied expenditure data. LADWP increased its expenditures to more than \$14 million in fiscal year 2006–2007, and is projected to spend \$80 million in fiscal year 2007–2008.

Using Efficiency to Reduce Greenhouse Gas Emission Levels

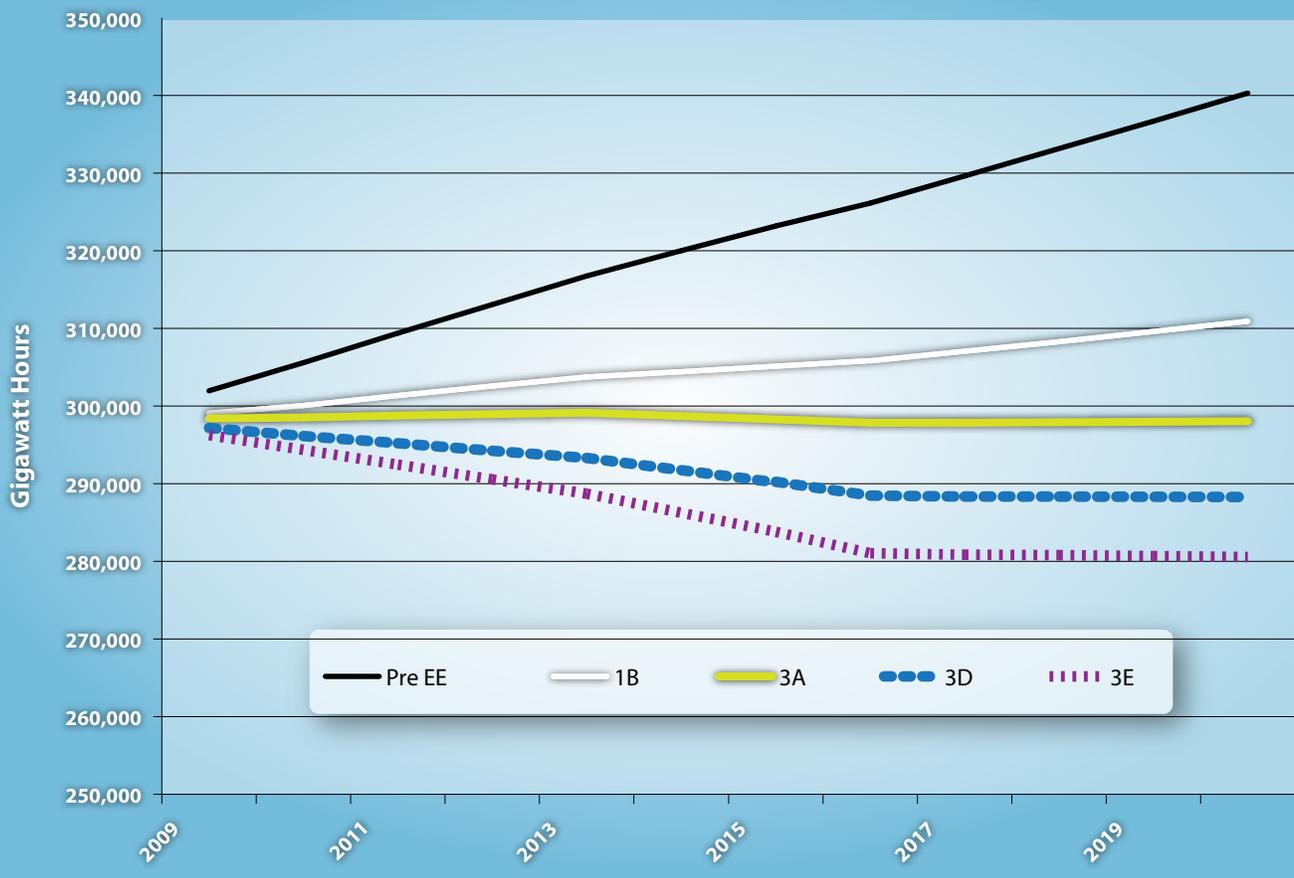
Drawing on the efficiency potential described in a 2006 study from Itron,⁸⁷ the Scenario Analyses Project examined the greenhouse gas implications of resource plans featuring high penetrations of energy efficiency measures and renewable

⁸⁷ Itron, Inc., et al., *California Energy Efficiency Potential Study*, submitted to Pacific Gas & Electric Company, May 24, 2006. Available from <www.calmac.org>. Commonly referred to as “the Itron Study,” this study projects electricity and natural gas efficiency potential through 2016 for the investor-owned utilities.

energy generation (both rooftop solar photovoltaic and supply-side generating technologies) in California and the Western states. A base case (Case 1) included the investor-owned utilities’ 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 (Figure 3-2). 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 investor-owned utility 2006 procurement plans. For the rest of the Western states, the current energy efficiency programs were assumed embedded in the load forecasts (that is, the forecasts reflect sales net of reductions from energy efficiency programs).

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



Source: Navigant Consulting, Inc.

- Aggressive development (Case 3A) – This case reflects aggressive expansion of energy efficiency programs beyond those of the investor-owned utilities. 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) – This case includes the entire economic emerging technology potential in California.

The culmination of savings in each of the cases would be 30,000 gigawatt hours in Case 1B, 42,000 gigawatt hours in Case 3A,

52,000 gigawatt hours in Case 3D, and 60,000 gigawatt hours in Case 3E.

California retail load becomes relatively flat from 2016 through 2020 after including the impacts of energy efficiency (Figure 3-3). 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.

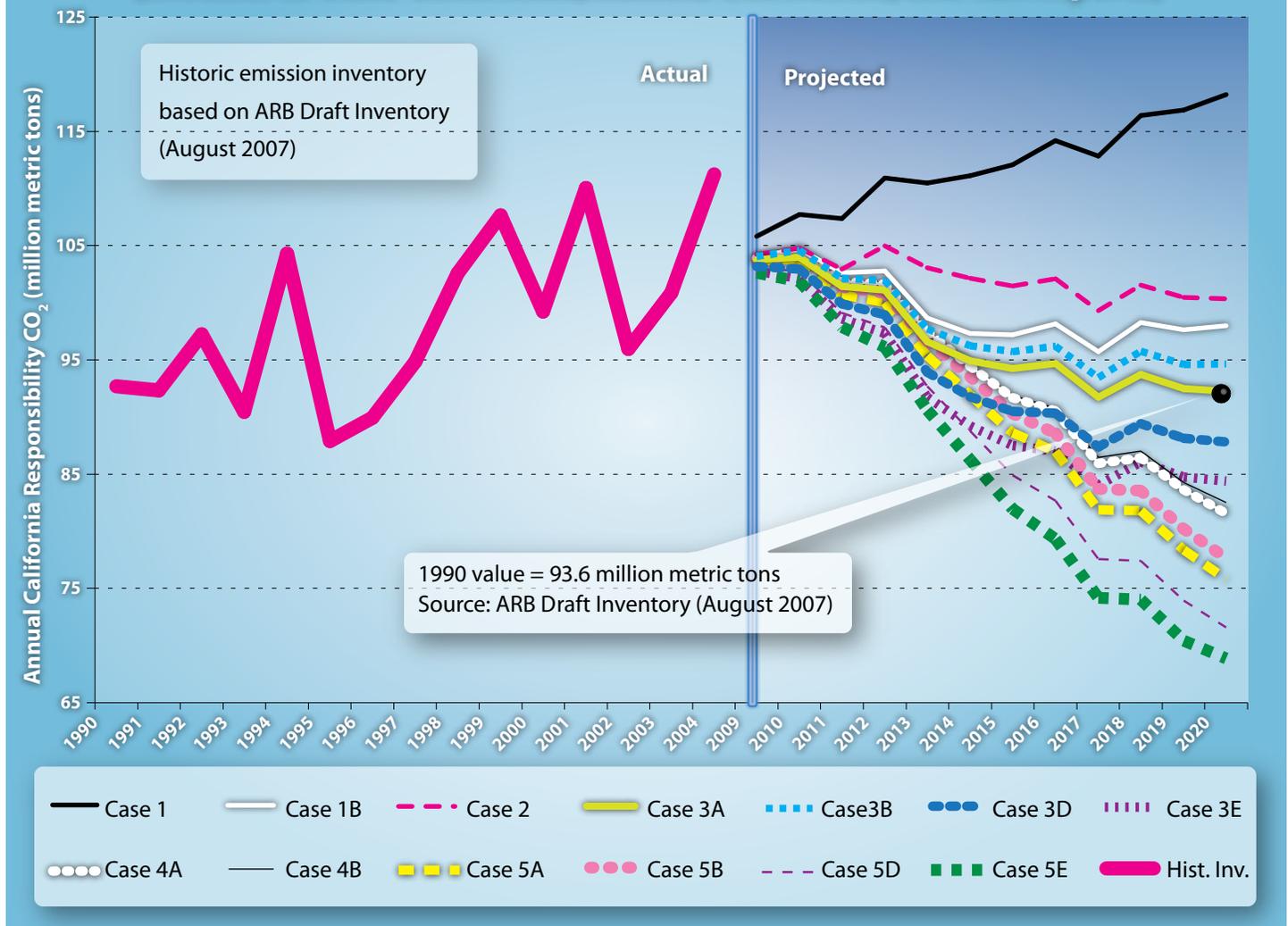
The fundamental question is what impact the high efficiency cases will have on California’s ability to reduce its overall greenhouse gas emissions to 1990 levels. Figure 3-4⁸⁸ shows the carbon emissions

88 For an explanation and discussion of Cases 4A and 4B, which represent high renewables only, see California Energy Commission, *Scenario Analyses of California’s Electricity System*, CEC 200-2007-010-SF.

from the power generated to serve load in California, also known as the California Carbon Responsibility, for all 13 scenarios modeled in the Scenario Analyses Project. This figure also identifies how these electricity sector projections compare with estimated 1990 electricity sector greenhouse gas emissions. Minor revisions to the draft emissions inventory issued by the ARB have been made to this figure to make historic values compatible with the projections. ARB has not indicated that reaching the 1990 level would be a goal for individual greenhouse gas emitting sectors rather than as an overall goal for all greenhouse gas emissions. 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 within 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 — in the highest contribution cases, by a significant margin. The scenario results indicate that a more than proportionate contribution toward the AB 32 goals from the electricity sector is feasible and may even be necessary if the multi-sector goal is to be achieved.

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



Source: California Energy Commission. Adapted from Figure 8, *Scenario Analyses of California's Electricity System, Third Addendum*, p. 16. CEC-200-2007-010-AD3.

Table 3-1: Predicted Greenhouse Gas Emissions for California in 2020
(Thousand Tons of Carbon Dioxide per Year)

Annual CO ₂ (000 metric tons)	Case 1B	Case 3A	Case 3D	Case 3E	Case 5A	Case 5D	Case 5E
Total California Responsibility	97,982	92,243	87,822	84,376	75,814	71,570	68,852

Source: California Energy Commission. Adapted from Table 4, *Scenario Analyses of California's Electricity System, Third Addendum*, p. 20. CEC-200-2007-010-AD3.

Cases 3A, 3D, and 3E reflect successively decreasing levels of emissions by 2020 (Table 3-1). In them, the cost per unit of greenhouse gas reduction from alternative levels of energy efficiency is relatively constant and negative (Table 3-2). The energy efficiency modeled is less costly than the generating resources it displaces, so not only does it provide a public good in emission reductions, it saves direct ratepayer expenditures.

The enhanced efficiency cases also depend on 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 Energy Commission and CPUC combined efforts gain all cost-effective energy efficiency.

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)	(5,738)	(113.69)
Case 3D	(1,172,584)	(10,160)	(115.42)
Case 3E	(1,569,955)	(13,606)	(115.39)

Source: Global Energy Decisions, Inc.

Achieving All Cost-Effective Energy Efficiency

Senate Bill 1037 (Kehoe, Chapter 366, Statutes of 2005) requires the 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 investor-owned utilities to ensure the use of cost-effective supply alternatives. SB 1037 also requires all publicly owned utilities, regardless of size, to report investments in energy efficiency programs annually to their customers and to the Energy Commission.

Under Assembly Bill 2021 (Levine, Chapter 734, Statutes of 2006), the Energy Commission, in consultation with the CPUC and the publicly owned utilities, must produce a statewide estimate of “all potentially achievable cost-effective electricity and natural gas efficiency savings and establish targets for statewide annual energy efficiency savings and demand reduction for the next 10-year period.”

Based on the *2006 Itron Study*, the remaining economic potential in 2016 for the investor-owned utilities and the publicly owned utilities is estimated to be 39,576 gigawatt hours, 6,597 megawatts, and 749 million therms, excluding the potential that might be available from emerging technologies. These values are indicated by a square on the next series of figures and are roughly equivalent to Scenario Case 3A. The emerging technologies represent an additional 12,000 gigawatt hours. In total, the savings targets proposed by the investor-owned utilities and publicly owned utilities for 2016 were 27,908 gigawatt hours, 5,880 megawatts, and 544 million therms.

With their current programs (extended through 2013), the investor-owned utilities would achieve savings equivalent to 71 percent of the identified electricity 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 publicly owned utilities intend to achieve 56 percent of their identified electricity economic potential by 2016. On a statewide basis, the investor-owned utilities and the publicly owned utilities, combined, are expecting to achieve 67 percent of their economic potential if they meet their proposed 10-year savings targets.

The Energy Commission has determined that a statewide efficiency target should be set at 100 percent of economic potential. The Energy Commission expects the state to achieve these targets through a combination of utility and non-utility programs coordinated at the state level by the Energy Commission and the CPUC. These efforts will include more expansive building standards; legislation or regulations requiring energy improvements at the time of a building's sale; local ordinances or codes affecting energy use; pursuit of emerging technologies; programs combining efficiency with renewables; new federal and state appliance standards; improved compliance mechanisms; and other programs that will result in long-term, sustainable savings.

The CPUC's October 18, 2007 decision concerning future savings goals from investor-owned utility programs orders a statewide energy efficiency strategic planning effort and greater statewide collaboration on energy efficiency and integration of program efforts and commits to working with the Energy Commission to achieve all cost-effective and feasible energy efficiency in the state. The decision expects that investor-owned utilities, in addition to their ongoing role as administrators of ratepayer-funded efficiency programs, would maximize the potential of their program efforts through collaboration with others planning and implementing programs to save energy. The publicly owned utilities should likewise maximize the potential of their program

efforts through collaboration with the Energy Commission and other energy efficiency planning and implementing entities.

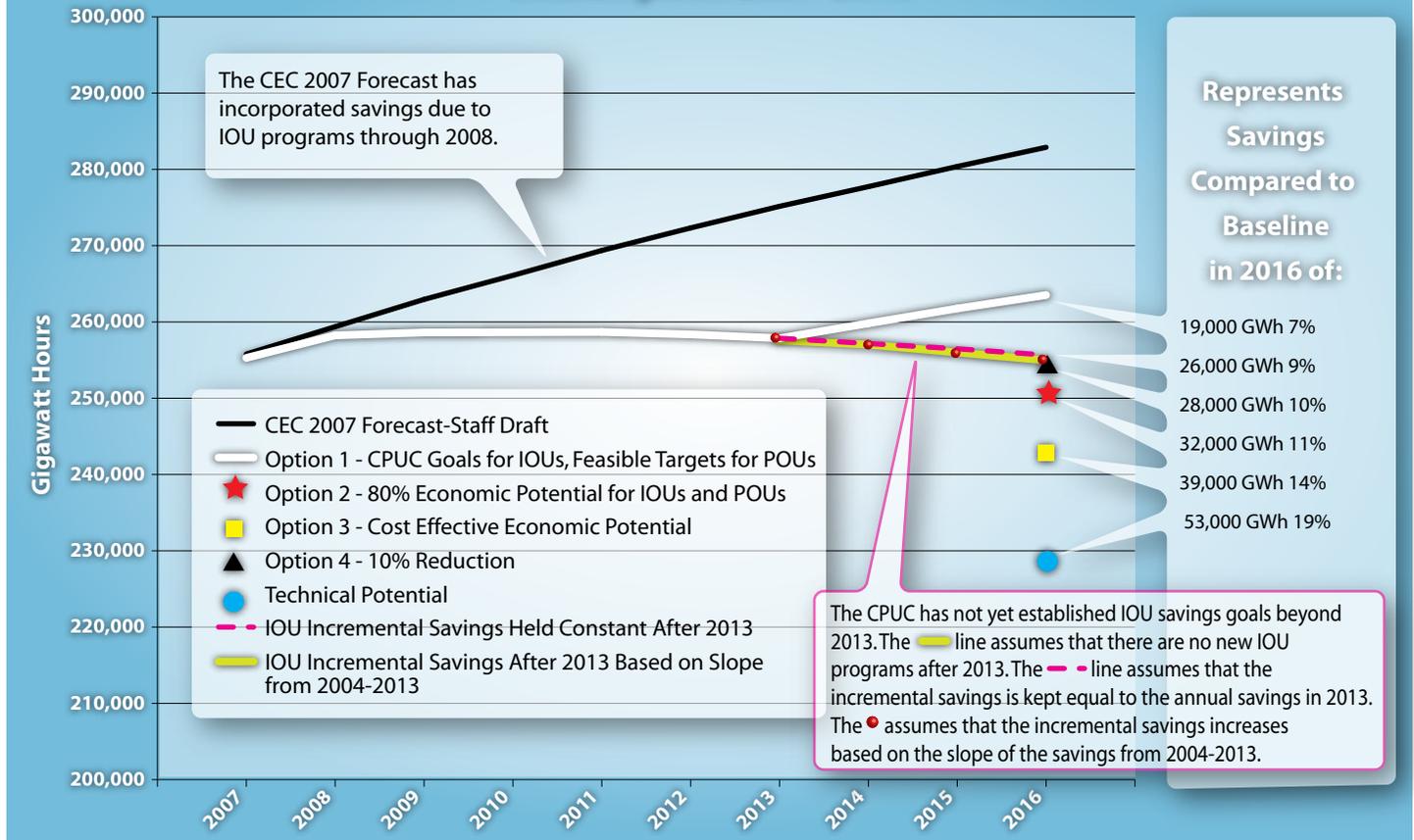
The CPUC's October 18, 2007 decision also advocates the use of utility efficiency program funds to support the Energy Commission's building standards efforts to achieve zero net energy residential buildings by 2020 and commercial buildings by 2030. The Energy Commission endorses these ambitious goals and will, with support from the CPUC and the utilities, strive to achieve them through successive cycles of the building and appliance standards in combination with other program efforts.

New market-based approaches, such as "white tags" or "white certificates," which are the equivalent of renewable energy credits, should also be considered. Each certificate would represent 1 megawatt hour 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.

Figure 3-5 illustrates the impact of four possible savings targets on reducing forecasted statewide investor-owned utility and publicly owned utility customer electricity consumption.

The top line shows the projected demand for electricity absent the effects of incremental investor-owned utility or publicly owned utility efficiency programs, for the period 2007–2016 for the publicly owned utilities and 2009–2016 for the investor-owned utilities. The dashed line shows the resulting statewide consumption if both the publicly owned utilities and investor-owned utilities are successful in meeting the energy savings targets proposed by the publicly owned utilities to the Energy Commission and adopted by the CPUC for the investor-owned utilities and extended at the incremental 2013 rate through 2016

Figure 3-5: Investor-Owned Utility and Publicly Owned Utility Electric Energy Consumption 2007-2016



Source: California Energy Commission. From *Achieving All Cost-Effective Energy Efficiency for California Utilities*. CEC-200-2007-019-SF.

(Option 1). The other lines and symbols on this graph show the potential impact of achieving the higher savings goal of the investor-owned utilities and publicly owned utilities obtaining 80 percent of their economic potential (Option 2), investor-owned utilities and publicly owned utilities 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 investor-owned utilities' proposed goals would achieve 95 percent of the economic potential, while the publicly owned utilities are projecting to achieve 62 percent.

Combined, the investor-owned utilities and publicly owned utilities would achieve 85 percent of the remaining economic potential for peak electricity demand savings

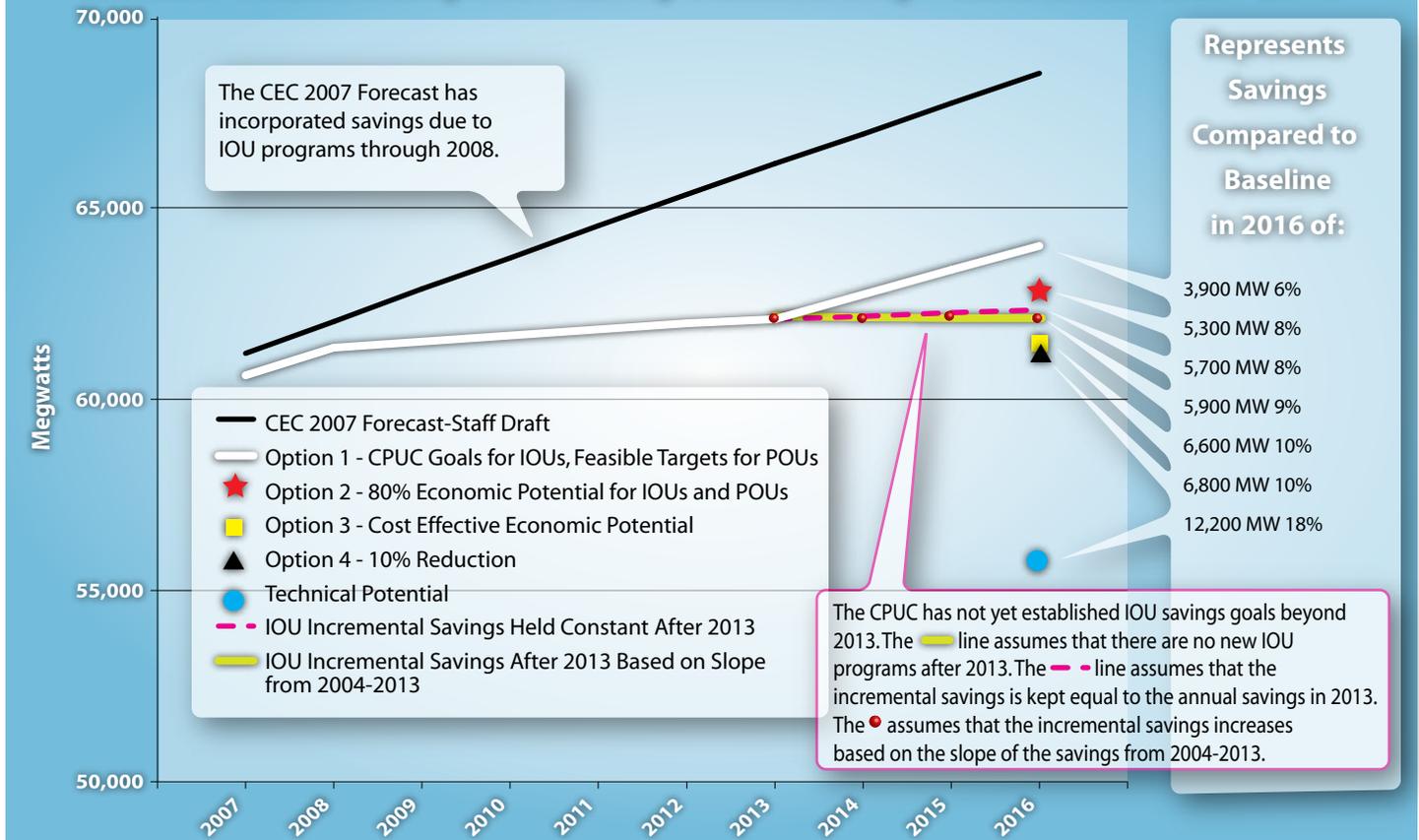
by 2016, excluding emerging technologies. This would reduce peak demand growth by 6 to 8 percent in 2016, depending on the investor-owned utility goals, or meet 70 percent of the expected growth over the next 10 years.

Natural gas efficiency targets proposed in Figure 3-7 capture a smaller percentage of the economic potential than the electricity efficiency targets. The investor-owned utilities would achieve 65 percent of the economic potential and the publicly owned utilities, 21 percent. Since the overwhelming portion of the natural gas consumption is represented by the investor-owned utilities, the combined percentage is also 65 percent of the economic potential.

For natural gas, proposed savings targets (predominantly investor-owned utilities) will reduce forecasted consumption by 2 to 4 percent in 2016 and capture 68 percent of the growth between 2007 and 2016.

Figure 3-6:

Investor-Owned Utility and Publicly Owned Utility Peak Demand 2007-2016



Source: California Energy Commission. From *Achieving All Cost-Effective Energy Efficiency for California Utilities*. CEC-200-2007-019-SF.

The publicly owned utilities 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 for these utilities. Thirteen of the 39 publicly owned utilities account for 93 percent of the consumption. Using a metric of savings to sales (consumption) ratio annualized 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. In some cases, the proposed annual increases in program budgets and expected savings exceed anything historically achieved by the investor-owned utilities. Given that other publicly owned utilities have experience with efficiency and know their customer base and local conditions well, and that they can learn from the experiences of the investor-owned utilities, the Energy Commission supports setting aggressive ramp ups.

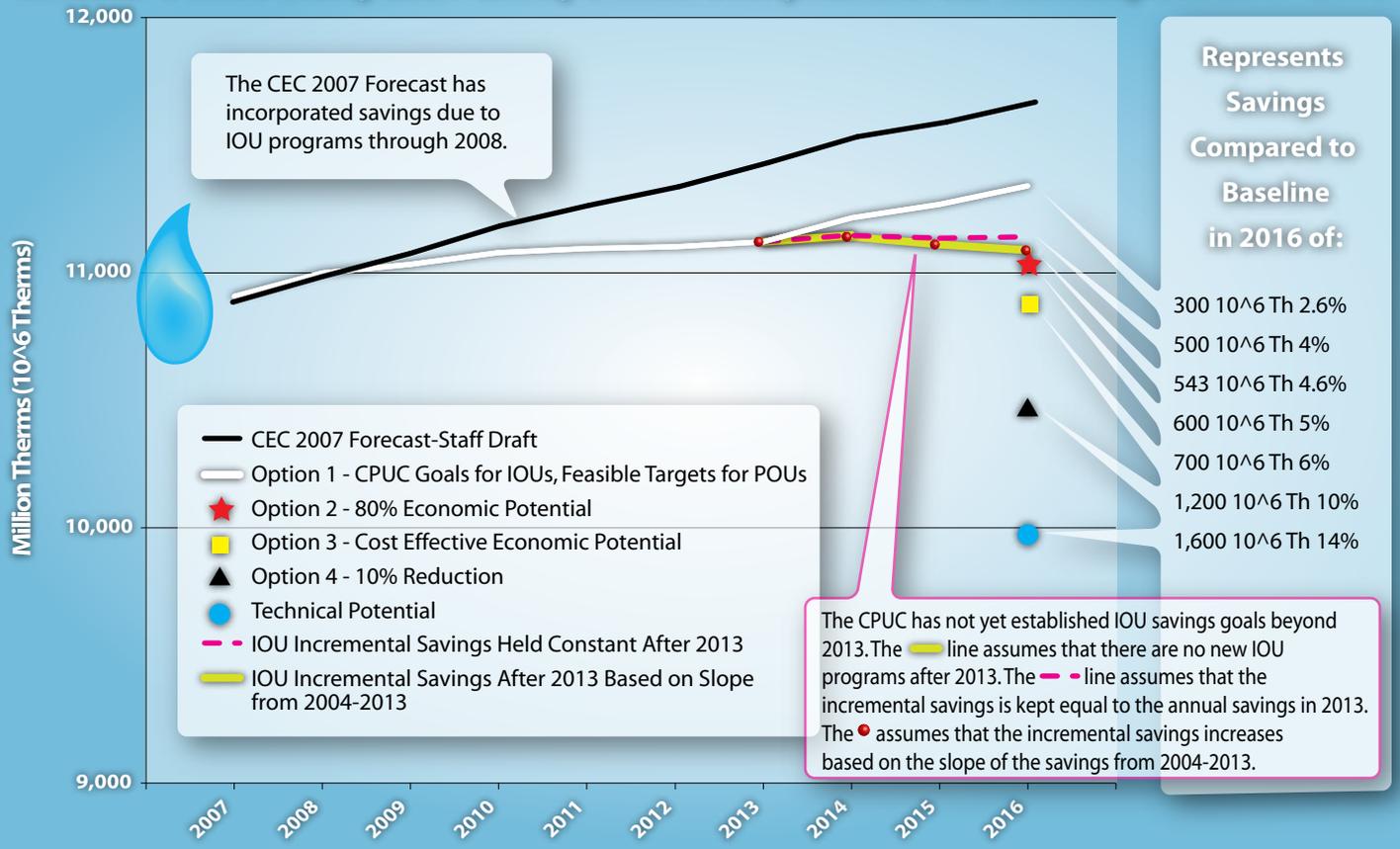
AB 2021 gives the Energy Commission authority to make recommendations for improvements in publicly owned utility efficiency program strategies or targets if necessary in the intervening years. The Energy Commission expects to provide recommendations as appropriate and also expects to specifically describe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

Energy Savings from Building Standards

The Energy Commission is in the process of developing the next version of building standards expected to be adopted in 2008. 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,

Figure 3-7:

Investor-Owned Utility and Publicly Owned Utility Natural Gas Consumption 2007-2016



Source: California Energy Commission. From *Achieving All Cost-Effective Energy Efficiency for California Utilities*. CEC-200-2007-019-SF.

New Solar Homes Partnership

At the direction of Governor Schwarzenegger, the California Solar Initiative was approved by the California Public Utilities Commission (CPUC) on January 12, 2006. The initiative creates a \$3.3 billion, 10-year program to put solar on a million roofs in the state. Under the initiative, the CPUC oversees a program to provide incentives for existing residential customers and all non-residential customers, while the Energy Commission manages a program to encourage solar in new home construction, the New Solar Homes Partnership.

The New Solar Homes Project is a 10-year, \$400 million program that targets single family, low-income, and multi-family housing. The program incorporates high

levels of energy efficiency and high-performing solar systems to help create a self-sustaining solar market in which home buyers demand energy-efficient solar homes.

By October 2007, the New Solar Homes Project had received applications for 1,287 building structures, primarily in Northern California, and has approved applications for 575 structures totaling about 1.2 megawatts of capacity. Housing developments represent most of the applications and include large developers like Lennar, Centex, Meritage, and Christopherson and smaller developers like Coastal View Construction, Pacific Century, KD Development, and Armstrong Construction.

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 photovoltaic incentive, the new home has to exceed the Title 24 building efficiency code by a minimum of 15 percent. This efficiency-first philosophy allows the photovoltaic system to cover more of the building's electric load. Builders are encouraged to exceed 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 have to consider vigorous efficiency coupled with technologies like solar photovoltaic systems. The Energy Commission recently initiated the investigative process required by Senate Bill 1 (Murray, Chapter 132, Statutes of 2006) to determine whether solar photovoltaic systems should be mandated in future building standards.

Several bills were introduced, but failed to pass, this legislative session to encourage or mandate green building practices in the residential, commercial, and state building sectors. Nevertheless, both the Department of Housing and Community Development (for residences) and the California Building Standards Commission (for all building sectors) continue to be 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 Energy Commission issued a booklet directed at homebuyers that provides information about home energy audits and rating programs, marketing this information through 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 significantly — residential lighting efficiency.

Title 24 Building Codes and Standards: Considering a “Zero Net Energy” Future

SB 1 requires the Energy Commission to examine whether solar photovoltaics should be mandated in future building standards. This study must identify all life cycle costs and benefits and demonstrate that solar photovoltaic systems are cost effective in order to include them in the Title 24 building standards. Periodic updates are required.

The California Public Utilities Commission, through its “Big Bold Energy Efficiency Strategies,” has adopted three programs designed to move all new residential and commercial construction to a zero net energy standard. The goal of this program is to reach zero net energy in residential construction by 2020 and in commercial construction by 2030.

Southern California Edison Chairman and Chief Executive Officer Alan J. Fohrer said that “significant additional progress will be made as a result of this new policy... Now the commission has made advancing customer energy efficiency the business of every department and employee of an investor-owned utility.” The Energy Commission applauds the CPUC’s significant advancement of energy efficiency programs. Together, success with these programs can result in changing the paradigm for energy growth in California

Improving the efficiency of electric lighting in California offers a cost-effective path to reducing energy use and greenhouse gas emissions. The greatest opportunity for saving lighting energy in California residences lies in addressing the continuing prevalence of incandescent lamps. This is already done, in part, by the building standards for new and renovated housing, but it affects only 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 to 17 lumens per watt. When compared with the 45 to 70 lumens per watt currently available in compact fluorescent lamps, incandescent lamps are clearly very inefficient.⁸⁹

The efficacy of incandescent lamps could be increased by 30 percent with technology presently available, such as halogen capsules with infrared coatings. These technologies, while cost-effective in most uses, are significantly more expensive than standard incandescents. Industry stakeholders suggest that, with additional technological improvements, incandescent efficiency could even exceed 40 lumens per watt. Meanwhile, emerging light-emitting diode (LED) sources currently achieve 40 lumens per watt, could achieve 60 lumens per watt in a few years, and could even reach 100 lumens per watt some time in the next decade.⁹⁰ These sources currently cost significantly more than today's common lighting alternatives, but also have significantly longer lifetimes.

In residential construction, the Energy Commission's 2005 Building Standards 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 percent, encouraging manufacturers to pursue improvements in efficiency. In the Climate Action Team's early action report, the Energy Commission has committed to updating its lighting standards by January 1, 2010, to address the challenge of further reducing greenhouse gas emissions.

This year, the Governor signed into law Assembly Bill 1109 (Huffman, Chapter 534, Statutes of 2007), which requires 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, in June 2007, the governor signed a bill (AB.178) banning lamps under 25 lumens per watt after 2012. Connecticut, Minnesota, New York, New Jersey, North Carolina, South Carolina, and Rhode Island have all introduced bills that in various ways restrict or ban the sale of incandescent lamps.

Federal Lighting Standards Proposals

The National Electrical Manufacturers Association has supported 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.

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 (the 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 act also includes a "second tier" of standards to be adopted by 2017 that would require general service lamps to achieve efficiencies of 50 lumens per watt by 2020.

The House of Representatives version of the energy bill (HR.3221) takes a similar approach. It requires minimum

89 Fernandes, Luis, *Efficiency Opportunities for Edison-Based Luminaires*, California Lighting Technology Center, September 12, 2007, p. 3.

90 Ibid.

The Water-Energy Nexus

In the 2005 *IEPR*, the Energy Commission explored the relationship between water and energy in California, finding that “significant untapped potential for energy savings exists in programs focused on water use efficiency.” Since 2005, there has been limited progress in expanding current utility energy efficiency programs to include water efficiency measures. In March of 2006, the CPUC committed to exploring inclusion of water efficiency measures in investor-owned utility programs, but has yet to implement the limited scope water-energy pilot projects planned to inform the 2009–2011 energy efficiency program cycle.

The Energy Commission reiterates the need to capture the energy savings benefits of water use efficiency, especially in light of climate change. Potential actions include:

- Standardizing and increasing the evaluation and monitoring of water efficiency programs to ensure the delivery of savings and benefits
- Implementing appropriate mandates, incentives, and funding to maximize the water efficiency potential of existing buildings and new construction
- Assessing the energy savings potential and associated greenhouse gas emission reductions from aggressive levels of water efficiency and recycling

- Identifying energy intensive water use by hydrologic region and alternatives for reducing energy intensity of water use in each region
- Fully incorporating water efficiency into the 2009–2011 energy efficiency program cycle
- Modifying CPUC or other state policies as necessary to allow for all energy savings associated with water efficiency or recycling to be included in any cost effectiveness analysis and developing accounting mechanisms as necessary to credit costs and savings appropriately

The Energy Commission is committed to using its Building and Appliance Efficiency Standards authority to save both water and energy. Most recently, Governor Schwarzenegger signed AB 662 (Ruskin, Chapter 531, Statutes of 2007) and AB 1560 (Huffman, Chapter 532, Statutes of 2007) expanding and reinforcing the Energy Commission’s authority to establish water conservation and efficiency standards for both buildings and appliances. The Energy Commission will define a Water-Energy Research Development and Demonstration Strategic Plan and Roadmap that explores ways to reduce the energy intensity of the water use cycle and better manage the energy demands of the water system. These actions will be done in coordination with other agencies’ efforts and those of the utilities to maximize the effectiveness of these efforts.

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 per watt after 2020, and it prohibits the sale of 100-watt incandescent lamps after January 1, 2012, unless their efficacy is at least 60 lumens per watt.

While both bills include preemption of state standards to improve general service lighting efficiency, HR.3221 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.

Table 3-3: Approved 2004–2013 CPUC Goals for Investor-Owned Utilities

	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*.

In fact, the lighting market is an international marketplace, with a variety of standards efforts addressing general service lighting.

The federal proposals would not provide sufficient savings to achieve California’s AB 1109 targets by 2018.⁹¹ Achieving the goals of that legislation will require increased use of the most efficient lighting options and a concerted effort to increase the efficiency of existing incandescent technologies. 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.

International Lighting Standards Proposals

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 to 22 lumens per watt, 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 intends to phase out inefficient lighting by 2012, using non-technology-specific national standards. These standards are 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 compact fluorescent lamps), 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 the National Electrical Manufacturers Association — has made public a proposal for Europe-wide regulation that, although divided into two stages of increasing stringency, is quite similar to federal legislation in the United States with slight differences in efficacy levels. Independently of European Union-wide activity, individual European countries have proposed or taken measures to curb the least efficient types of lamps.

Investor-Owned Utility 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 investor-owned utilities. The CPUC is currently considering whether to update these goals for 2009–2013 and how to extend them to 2020.

The goals are based on a 2002 perspective on technologies, utility program designs, and price levels and may therefore understate the amount of future potential available in 2007. The adopted cumulative 2013 goal for net savings captures 91 percent of the

91 Op cit., p. 36.

Figure 3-8: Investor-Owned Utility Electricity Goals Compared to Reported Savings (2004-2007)



Source: California Energy Commission. Based on investor-owned utility quarterly reports to the California Public Utilities Commission.

“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 range (dependent on funding) of achievable potential through utility incentive programs to be from 20 to 60 percent of the economic potential.⁹²

For the 2004–2005 program cycle, the investor-owned utilities planned energy efficiency savings of 4,600 gigawatt hours, 757 megawatts, and 42 million therms and a total expenditure of \$965 million, of which they spent approximately \$672 million. For the 2006–2008 efficiency program cycle, the investor-owned utilities budgeted a total of \$2 billion for three

years of efficiency programs for projected savings of 6,800 gigawatt hours in reduced annual electricity consumption, 1,000 megawatts in peak demand reduction, and 111 million therms of natural gas. As of July 2007, the investor-owned utilities 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 realized. In fact, electricity savings in 2005 increased by more than 68 percent on average over savings achieved in 2004. The year

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

Figure 3-9:
Investor-Owned Utility Peak Demand Goals Compared to Reported Savings (2004-2007)



Source: California Energy Commission. Based on investor-owned utility quarterly reports to the California Public Utilities Commission.

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 contributed to sharp drop off in 2006, but may have enhanced the credibility of claimed savings levels. Program savings in 2007 are through July. Figure 3-9 compares the investor-owned utilities' yearly peak demand savings goals to their yearly reported accomplishments. None of the investor-owned utilities 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 and 2005, Southern California Edison exceeded its goals by nearly 60 percent. The 2006–2008 program cycle exhibits a similar increased rate of savings in the second year.

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

In 2004–2005, at least half of reported gigawatt hour 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.

Lighting accounted for a slightly smaller share of demand savings than 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 (Figure 3-11). Commercial peak savings from lighting is nearly twice the size of residential savings.

Peak savings from HVAC programs average 22 percent of the 2004–2005 savings, but in the current program cycle, the 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 (Figure 3-12).

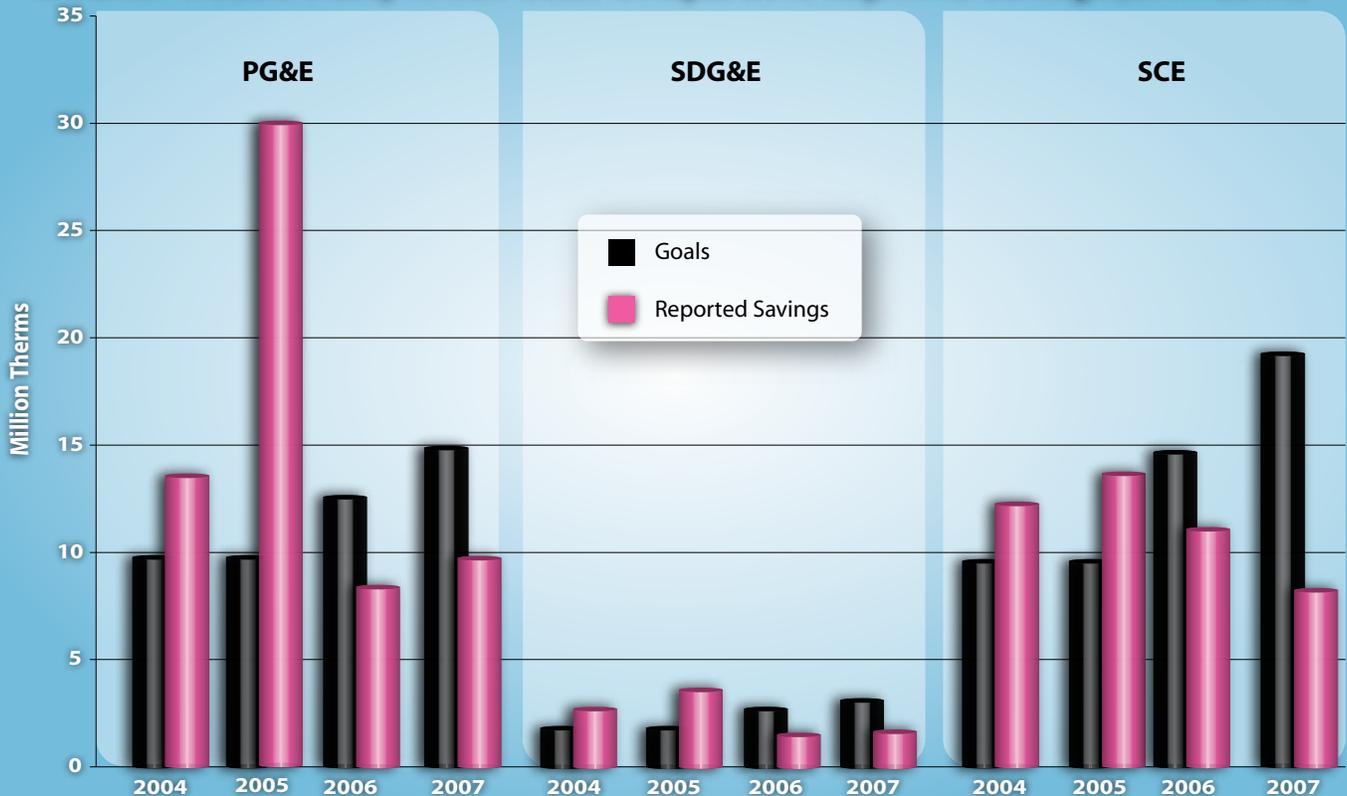
On September 20, 2007, in decision D.07-09-043, the CPUC adopted a risk/reward incentive mechanism for investor-owned utility energy efficiency programs. The system will require each utility to achieve at least 85 percent of the adopted energy and peak savings targets for the period 2007–2008 before 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, that 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.

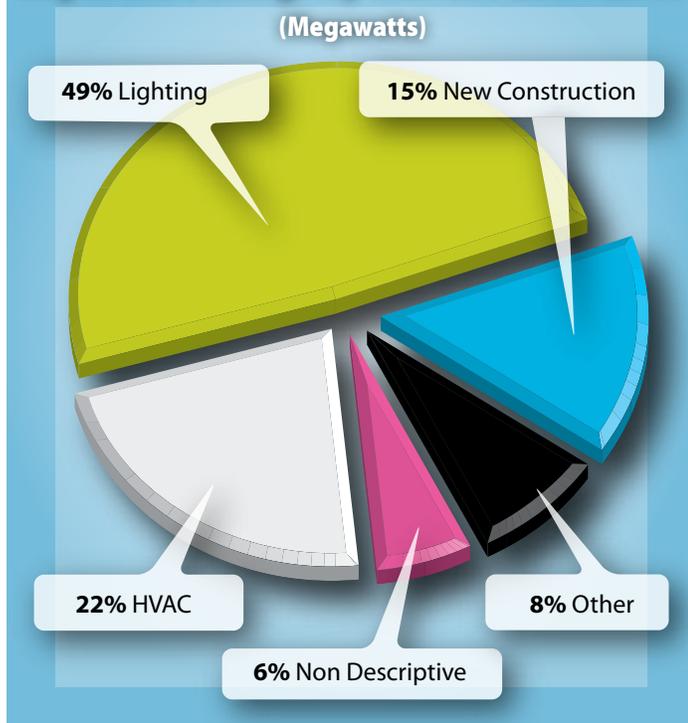
Utilities achieving below 65 percent of the goals would be subject to penalties (reductions in shareholder earnings) assessed at 5 cents per kilowatt hour, 45 cents per therm, and \$25 per kilowatt. No earnings or penalties apply to performance that falls between 65 and 85 percent of efficiency goal achievement. This system is similar to the previous incentive system in place from 1992 to 1998, but provides 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 \$450 million for each program cycle.

Figure 3-10: Investor-Owned Utility Therm Goals Compared to Reported Savings (2004-2007)



Source: California Energy Commission. Based on investor-owned utility quarterly reports to the California Public Utilities Commission.

Figure 3-11: Investor-Owned Utility Reported Savings by End Use 2004-2005
(Megawatts)



Source: California Energy Commission. Based on investor-owned utility quarterly reports to the California Public Utilities Commission.

Problems notwithstanding, evidence suggests that sufficient potential remains for utilities to achieve higher levels of savings. To do so, utilities, in collaboration with the CPUC and the Energy Commission, must adopt innovative program designs and structures, such as combining efficiency with renewable programs, greater interconnection with statewide standards, and consideration of white tags.

The CPUC decision of October 18, 2007, directs the investor-owned utilities 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.
- Heating, ventilation, and air conditioning will be reshaped to ensure optimal equipment performance.

Using Demand Response to Meet Electric System Peaks

Demand response can play a critical role as a resource in California’s electricity planning mix. Price-responsive demand response, coupled with advanced metering infrastructure,⁹³ 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 capacity costs. Despite its many advantages, price-responsive demand response is expected to reduce peak demand by only 2.2 percent in the summer of 2007, which is less than half the goal of 5 percent laid out in the *Electricity Action Plan II*.⁹⁴

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

Potential Savings from Demand Response

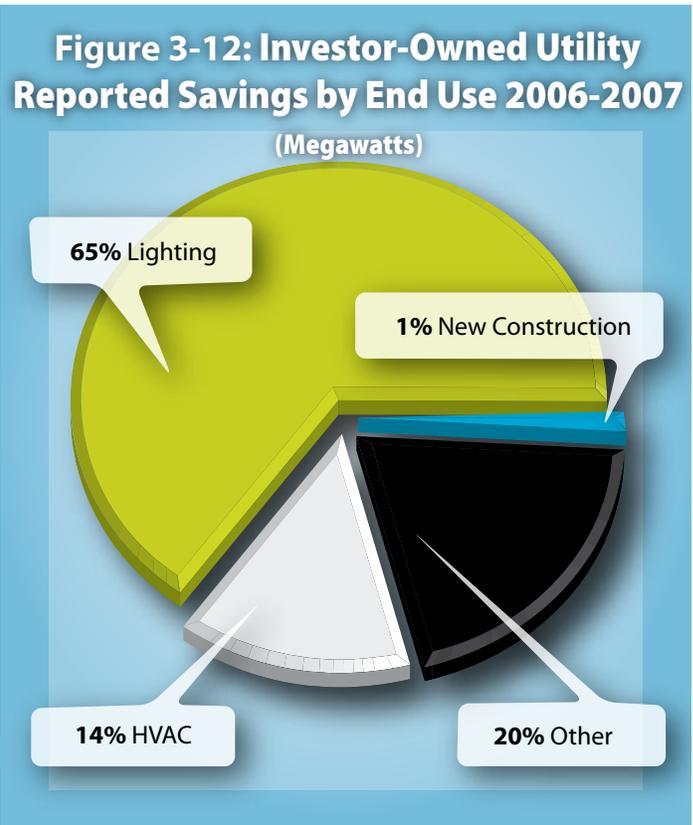
The potential reduction in peak demand that can be achieved through price-responsive demand response programs depends on the amount of coincident demand that is reduced per customer and on the number of participating customers. As with energy efficiency programs, it is normal practice to assess three levels of demand impacts: technical potential, economic potential, and market potential.⁹⁵

⁹³ Advanced metering infrastructure refers to the hardware and software that allow utilities to remotely collect energy usage and status data from customers; transmit and receive information from utility servers to customer sites and potentially to third parties; and bill customers for their usage based on time-differentiated prices.

⁹⁴ 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 5 percent target. This is elaborated upon in *The State of Demand Response in California*, by Ahmad Faruqui and Ryan Hledik, a draft consultant report prepared for the California Energy Commission, April 2007, CEC-200-2007-003-F. That document is hereafter referenced as *State of Demand Response*.

⁹⁵ 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 demand response and reliability-triggered demand response programs, see pp. 8–9 of California Energy Commission, *The State of Demand Response in California*, CEC-200-2007-003-F.

- “Technical potential” measures the outcome if all customers use the best available demand response 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 subset of the statewide pricing pilot. In the commercial and industrial classes, automated demand response 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.⁹⁶
- “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 demand response 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 peak usage by 27 percent, and those with the gateway system lowered peak usage by 43 percent. If 70 percent of the customers chose no enabling technology, 20 percent chose the smart thermostat, and 10 percent chose the gateway system, the result would yield a weighted average estimate of approximately 19 percent for the residential class. Corresponding values for the commercial and industrial classes are roughly 7 percent and 9 percent.
- “Market potential” (or “achievable potential”) measures what would happen if a cost-effective combination of



Source: California Energy Commission. Based on investor-owned utility quarterly reports to the California Public Utilities Commission.

technologies is adopted at some assumed level of penetration in the marketplace. 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, which is currently limited to customers above 200 kilowatts, but is likely to be deployed for all customers in the state during the next five years. Experience in other restructured states indicates that if the CPUC makes dynamic pricing the default rate, a larger fraction of customers would stay on it than they would if it were 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 it on a voluntary basis. In its initial analysis, the staff assumes that the actual number is likely to be somewhere

⁹⁶ 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 staff’s estimate of technical potential.

in the middle. This yields an estimate of approximately 5 percent. Obviously, programs that achieve greater customer participation will yield greater savings.

Achieving even a 5 percent peak demand reduction would yield several benefits for California. Three of the benefits can be quantified in a preliminary projection. The first and most significant benefit would be the reduction in necessary peaking generation capacity. This would be a long-run benefit, consisting of the sum of avoided capacity and energy costs. It could be readily estimated based on the capacity cost of a combustion turbine. The second benefit would be the avoided energy cost that is associated with the reduced peak load. Third would be the reduction in needed transmission and distribution capacity.

The aforementioned avoided capacity cost benefit is calculated by quantifying and valuing the amount of capacity that would be avoided by the 5 percent reduction in peak demand. A 5 percent reduction in California peak demand of approximately 61,008 megawatts amounts to 3,050 megawatts of avoided peak demand. The amount of peaking capacity necessary to meet this peak demand can be computed by allowing for a reserve margin of 15 percent and line losses of 8 percent. This amounts to 3,789 megawatts, or roughly the output of 50 combustion turbines.⁹⁷ A conservative value of the avoided cost of generation capacity is \$52 per kilowatt year.⁹⁸ Thus, the total value of avoided generation capacity costs would be roughly \$200 million per year.

Illustratively, the four combustion turbines installed by Southern California Edison (SCE) this summer were more expensive — the same methodology would value that capacity at \$101 per kilowatt year.⁹⁹ Using this as a benchmark, 3,100 megawatts of avoided

generation capacity would be worth \$380 million per year.

Using the relationship that was observed between annual generation capacity and energy benefits in a recent PJM Interconnection, LLC analysis of demand response, the annual value of avoided energy costs is estimated at around \$20 million.¹⁰⁰

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.

Using the SCE peakers as the capacity benchmark, the benefits would be \$470 million per year. Over a 20-year time horizon, the present value of demand response benefits could reach \$3 billion or \$5.5 billion measured against the SCE peakers.

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 customer acceptance issues. There are also analytical issues in this area, such as the need to modify existing cost-benefit methodologies for evaluating demand-side programs; to develop protocols for measuring demand response impacts; and to 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.

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 demand response program can just as easily be seen as a measure of the hidden subsidies, which in the

97 These turbines come in sizes generally ranging from 50 megawatts to 100 megawatts.

98 In R.02-06-001, the CPUC specified a value of \$85 per kilowatt 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 per kilowatt year is obtained.

99 The capital cost of the peakers is estimated at \$245 million for 180 megawatts of capacity. We assumed a 7.6 percent discount rate and a 20-year life of the peakers. See California Energy Commission, *Comparative Costs of California Central Station Electricity Generation Technologies*, CEC-200-2007-011-SF, for the source of the financial assumptions.

100 Newell, Sam and Frank Felder, *Quantifying Demand Response Benefits in PJM*, study report prepared for PJM Interconnection, LLC and the Mid-Atlantic Distributed Resources Initiative, January 29, 2007.

present time-insensitive rate structure provides the 5 percent of electricity demand that comes during peak load hours.

With well-designed rate designs in place, the focus must shift to overcoming the technological barriers to demand response. First is the need to install advanced metering infrastructure throughout the state. This is likely to happen over the next five years. To get the most from the advanced metering infrastructure 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.

Second, 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 must be adopted on a large scale for California to approach its potential for demand response.

Establishing Load Management Standards

Since the 1970s, the Energy Commission has had the authority to establish and enforce load management standards for the state. The standards 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. These adjustments in rate structure must be approved by the Public Utilities Commission in a proceeding to change rates or service and by publicly owned utilities for their service territories.
- 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 is a valuable policy tool for the state to bridge the gap between the current level of demand response 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 demand response objectives. At the same workshop, Southern California Edison, San Diego Gas & Electric Company, and Pacific Gas and Electric Company all indicated support for the Energy Commission's effort to invoke its load management authority.

This policy tool may be particularly effective in two areas. 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 that dynamic pricing tariffs create.

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 advanced metering infrastructure is rolled out to customers.¹⁰¹ Once advanced metering infrastructure has been fully deployed, dynamic pricing becomes feasible, but on an opt-in basis, it 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

¹⁰¹ As proposed by Pacific Gas & Electric.

system peak demand of around 3 percent, representing more than \$1 billion in financial benefits over the next 20 years.¹⁰²

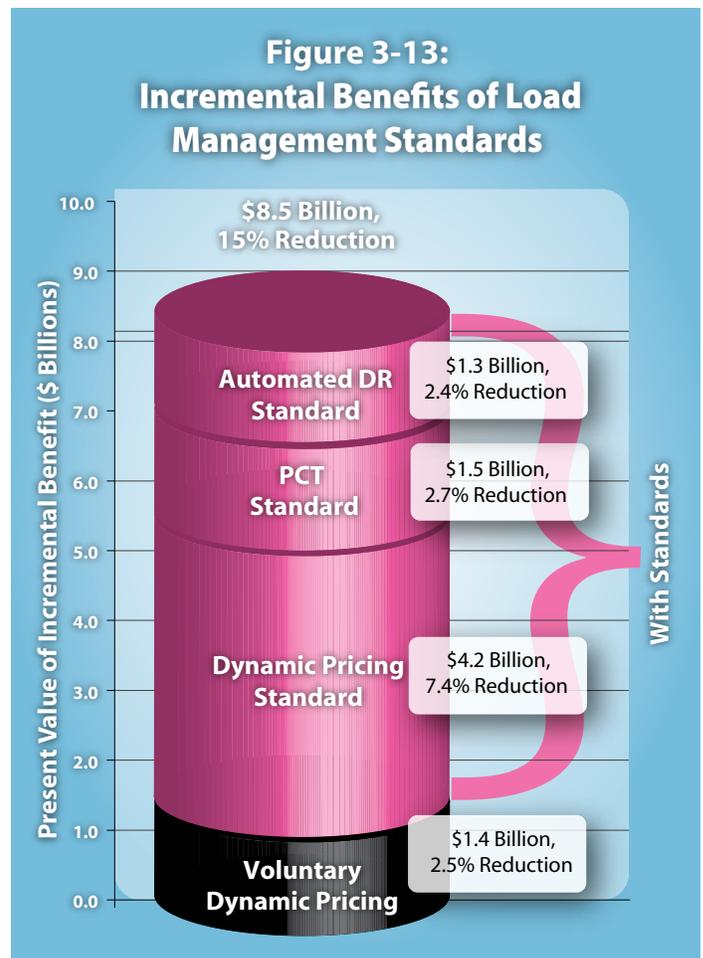
In a second case in which a dynamic pricing standard is adopted in California, requiring that some form of dynamic pricing be offered as the default rate, 80 percent of customers are likely to stay on dynamic pricing, with the other 20 percent opting back to the old rate. Assuming that these dynamic 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.

If on top of the default dynamic pricing standard, another standard were imposed that required the installation of programmable communicating thermostats in all residential dwellings, the potential benefits would rise even further. The standard could require that all residential customers be equipped with programmable communicating thermostats that can receive price signals from the utilities and/or the independent system operator (California 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.¹⁰³ The present value of the benefits would increase incrementally by around \$5 billion to \$10 billion.¹⁰⁴

Finally, an automated demand response standard could be included with the programmable communicating thermostat 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.



Source: California Energy Commission. *California's Next Generation of Load Management Standards*, p. 28. CEC-200-2007-007-F, September 2007.

102 For the methodology behind these computations, consult Faruqui, Ahmad and Ryan Hiedik, *California's Next Generation of Load Management Standards*, Chapter 2 (last section), September 2007, CEC-200-2007-007-F. Additionally, Monte Carlo simulations were performed to better understand the range of uncertainty around these estimates. For details, see Appendix A of the same document.

103 Note that this estimate assumes that these benefits will accrue over a 20-year period during which all residential customers have programmable communicating thermostats installed in their homes. There would be an initial period during which the programmable communicating thermostats would have to be rolled out to customers.

104 Some figures may not add up due to rounding.

Recommendations

- Adopt statewide energy efficiency targets for 2016 equal to 100 percent of economic potential, to be achieved by a combination of utility programs, state and local standards, and other programs.
- Enlist publicly owned utilities in a collaborative relationship to aggressively ramp up energy efficiency programs. Publicly owned utilities need to use their local conditions and customer knowledge to craft new program ideas. In doing so, sufficient incentives have to be provided.
- Pursue legislation that would require a cost-effective level of efficiency improvements at the time of sale of a building.
- Initiate a formal rulemaking process involving the CPUC and California ISO in 2008 to pursue the adoption of load management standards under the Energy Commission's existing authority.
- Enact appliance standards to improve the 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 and combine them with on-site generation so that newly constructed buildings are net zero energy by 2020 for residences and 2030 for commercial buildings.
- 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



*"I'd put my money on the sun and solar energy.
What a source of power! I hope we don't have to
wait 'til oil and coal run out before we tackle that."*

Thomas Edison

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. Preceding AB 32, Senate Bill 1078 (Sher, Chapter 516, Statutes of 2002) established a Renewables Portfolio Standard (RPS) program in 2002, 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. The *2003 Energy Action Plan* adopted by the Energy Commission and the California Public Utilities Commission (CPUC) accelerated that target date to 2010, and SB 107 codified the target. The *2004 Integrated Energy Policy Report (IEPR) Update* recommended expanding the target to 33 percent by 2020. The *2005 IEPR* and *2006 IEPR Update* reinforced that recommendation.

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 emissions. Renewables currently account for only 11 percent of electricity generation, a course that is not on track to meet RPS or AB 32 goals. Meeting the 33 percent goal in 2020 *is* feasible, but it will require significant changes in infrastructure and significant changes in program structure. Specifically, meeting the 33 percent goal will require:

- Investments in the state’s transmission infrastructure to adequately access renewable-rich resource areas, both in state and out of state
- The ability to integrate large quantities of intermittent resources
- Changes to the RPS program to address its current complexity, lack of transparency, and undervaluing of renewables

- Legislative authority to require renewable procurement beyond 20 percent by 2010

California must determine how to meet its renewables and greenhouse gas emission reduction goals while minimizing the costs and risks borne by ratepayers for electricity generation. The first section of this chapter explores those two key drivers of renewable resource development and discusses legislation that affects renewables development in California. The second section of the chapter discusses the feasibility of meeting the 33 percent renewables goal. That discussion responds to the Governor’s signing statement for AB 1585 (Blakeslee, Chapter 579, Statutes of 2005),¹⁰⁵ which 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
- Progress made by California’s public and private utilities and other entities that provide retail electricity in meeting the 20 percent by 2010 goal

Finally, the chapter offers recommendations for using and developing renewable resources to meet California’s energy needs.

¹⁰⁵ Assembly Bill 1585, 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. Because SB 107 did not pass until 2006, AB 1585 did not become law until that time. The Governor clarified in his signing statement that regardless of whether or not SB 107 passed, the Energy Commission must report on specific items related to the state’s 33 percent RPS goal.

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. 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)
- The Governor’s Market Advisory Committee’s view that renewable energy should not create offsets¹⁰⁶
- The 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.

106 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 www.climatechange.ca.gov/documents/2007-06-29_MAC_FINAL_REPORT.PDF pp. 61-62.

AB 32 requires the ARB to adopt a statewide greenhouse gas 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.”

AB 32 makes clear the intent of the Legislature to continue greenhouse gas 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 2050.¹⁰⁷ Led by California Environmental Protection Agency (Cal/EPA), the California Climate Action Team prepares reports to the Governor recommending strategies to achieve the state’s greenhouse gas 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-trade¹⁰⁸ system for greenhouse gas emissions because that simply reduces the demand for allowances from regulated sources and does not provide additional reductions in greenhouse gas emissions.¹⁰⁹

Furthermore, the report explains that a cap-and-trade system

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

108 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 (for example, per year). If a source finds it has more emission credits than emissions, it may sell the excess credits.

109 <www.climatechange.ca.gov/documents/2007-06-29_MAC_FINAL_REPORT.PDF>, accessed July 27, 2007.

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.”¹¹⁰

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 greenhouse gas emissions in California. To ensure the maximum contribution of this renewable energy target to greenhouse gas emission 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 greenhouse gas emissions is equivalent to the greenhouse gas emission reduction goal of 1990 levels by 2020. The ARB will also consider whether to establish a cap-and-trade system and 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 greenhouse gas-reducing alternatives to meet California’s growing energy demand.

The contribution of the 33 percent renewable goal to greenhouse gas 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 greenhouse gas 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, if one utility reduced its greenhouse gas emissions by adding renewable energy to meet the 33 percent by 2020 target, it would be able to sell its greenhouse gas allowances to another utility, producing no net greenhouse gas emissions reduction. To avoid this perverse effect, any expected greenhouse gas emissions reductions from achieving the state’s renewable energy goals should reduce the pool of available greenhouse gas allowances.

In addition, using renewable energy credits in a situation where they may actually result in no net greenhouse gas emissions reduction could affect the value of the renewable energy credits.¹¹¹ Although some states allow the greenhouse gas emissions attribute to be separated from renewable energy credits 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.

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 renewable energy credit.

¹¹¹ 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 Renewables Portfolio Standard Eligibility Guidebook, <www.energy.ca.gov/renewables/documents/index.html#rps>.

¹¹⁰ Ibid, p. 19.

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 renewable energy credit purchases, whether for state RPS compliance or for voluntary green power programs.”¹¹²

In a situation where renewable energy credits are used in such a way that they do not result in net greenhouse gas emissions reductions, the value of the renewable energy credit would depend on the supply of renewable energy credits, other low-greenhouse gas resources, and greenhouse gas 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 of the European Union, the excess supply of annual emissions allowances combined with the lack of carryover into Phase II of the European Union Emissions Trading System led the trading price to fall from 33 Euro to less than 1 Euro.¹¹³

In contrast, if renewable energy credits are taken off the top of the number of allowances, an increase in the use of renewable energy leads to a decrease in greenhouse gas emissions.¹¹⁴ In this case, the amount of greenhouse gas

emissions contained in a renewable energy credit would be a function of the electricity displaced by the generation of the renewable energy creating the renewable energy credit.

Taking 33 percent renewables by 2020 from the top of the quantity of allowances distributed under a cap-and-trade system reduces uncertainty and would create a price 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 41.5 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 beyond 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.¹¹⁵

112 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.

113 For reviews of the European Union Emissions Trading System see: <ec.europa.eu/environment/climat/emission/review_en.htm> and <www.openeurope.org.uk/research/etsp2.pdf>.

114 Although combustion of biomass releases carbon dioxide, 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., *The Value of the Benefits of U.S. Biomass Power*, Golden, Colorado: National Renewable Energy Laboratory, 1999. NREL/SR-570-27541. 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.

115 Bates White, LLC., *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-D.

Two important questions determine how California approaches 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 renewables 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 that 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.

The resulting market price referent,¹¹⁶ 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 renewables generation (other than biomass) are independent of fuel price volatility and depend primarily on capital investment during project development. Thus, renewables generation has value as a hedge against fuel price volatility. However, in the current investor-owned utility solicitation process for long-term RPS contracts, San Diego Gas & Electric (SDG&E) states that renewable energy developers tend to increase their bids if natural gas prices rise.¹¹⁷ Southern California Edison (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 investor-owned utilities to use a carbon adder¹¹⁸ for resource planning and bid evaluation of \$8 per ton of CO₂, escalating at 5 percent per year. However, other estimates of CO₂ emissions costs range from \$0 to \$58 per ton.¹¹⁹ A recent Synapse report estimates that in 2020, CO₂ emission costs will be \$10 to \$33 per ton,¹²⁰ indicating that the \$8 per ton figure may be too low. On October 4, 2007, the CPUC passed a resolution adding carbon adders to the 2007 market price referent, with values ranging from 0.271 to 0.972 cents per kilowatt hour (\$2.71 to \$9.72 per megawatt hour) depending on the contract length and contract start year.¹²¹ 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 is called a 'greenhouse gas adder'), of \$8 to \$25 per ton of CO₂, to be used in the evaluation of generation bids."

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

117 San Diego Gas and Electric 2007–2016 Long-Term Procurement Proceeding, Vol. 1, part 2, p. 211.

118 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.

119 California Energy Commission, *2006 Integrated Energy Policy Report Update*, p. 55. See footnotes for sources of various estimates.

120 Johnston, Lucy, Ezra Hausman, Anna Sommer, Bruce Biewald, Tim Woolf, David Schlissel, Amy Rocshelle, and David White, Synapse Energy Economics, Inc., *Climate Change and Power: Carbon Dioxide Emissions Costs and Electricity Resource Planning*, Synapse Energy Economics, Inc., June 8, 2006. Available at: <www.synapse-energy.com/Downloads/SynapsePaper.2006-06.0.Climate-Changeand-Power.A0009.pdf>.

121 California Public Utilities Commission Resolution E-4118, October 4, 2007. <www.cpuc.ca.gov/word_pdf/final_resolution/73594.pdf>.

The adopted values are based on approximately \$8 per ton in 2004, escalating at 5 percent per year through 2023. These values are considerably lower than market trading values for European Union Emissions Trading System credits for the year 2008. Since January 2006, European Union Emissions Trading System credits have been trading in the range of 15 to 26 Euros per metric ton and were valued at 21.55 Euros on October 31, 2007, or \$31.20 based on the October 31, 2007 exchange rate of \$1.4479 per Euro. The European Union Emissions Trading System credit has varied between about \$21 and \$38 per metric ton since January 2006. The CPUC intends to consider greenhouse gas adders for future years' RPS solicitations in 2008.

Legislation Affecting Renewables in California

State Legislation

Five recently enacted bills affect California's RPS program: Senate Bill 1036, which deleted the requirement for the Energy Commission to provide supplemental energy payments to cover above-market costs of renewables; Senate Bill 107, which made significant modifications in California's RPS program; Assembly Bill 1969, which requires IOUs to set a tariff to purchase renewable generation from small facilities operated by public water and wastewater agencies; Assembly Bill 1585, which requires the Energy Commission to evaluate the feasibility of the 33 percent by 2020 renewable goal; and Assembly Bill 809, which affects the RPS eligibility of small hydroelectric facilities.

- SB 1036 (Perata, Chapter 685, Statutes of 2007): SB 1036 switches the responsibility for administration of funds above market price referent 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.

- SB 107 (Simitian, Chapter 464, Statutes of 2006): 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 more fully into the RPS. Publicly owned utilities 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 investor-owned utilities, electric service providers, and community choice aggregators. A summary of the data submitted by the publicly owned utilities 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."¹²² Further, SB 107 continued the trend to relax deliverability requirements for renewable energy generated out of state. It allows electricity generated by an RPS-eligible¹²³ resource to be considered delivered "regardless of whether the electricity is generated at a different time from consumption by a California end-use customer."¹²⁴ 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 renewable energy credits for RPS compliance, the CPUC and Energy Commission must jointly determine that a renewable energy credit tracking system is operational and "can ensure that renewable energy credits shall not be double counted by any seller of electricity within the

¹²² Public Utilities Code Section 399.16(a)(3).

¹²³ For information on RPS eligibility, see the *Renewables Portfolio Standard Eligibility Guidebook*, <www.energy.ca.gov/renewables/documents/index.html#rps>.

¹²⁴ Public Resources Code Section 25741(a).

service territory of the Western Electricity Coordinating Council [WECC].¹²⁵ The Energy Commission and other WECC entities developed the Western Renewable Energy Generation Information System, which began operating in June 2007, to track renewable energy used for RPS programs in the WECC to prevent double counting. Also, a retail seller may purchase renewable energy credits from a publicly owned utility only if the Energy Commission has determined that the publicly owned utility is on track to meet its own RPS that is comparable to the standard applied to retail sellers.

- AB 1969 (Yee, Chapter 731, Statutes of 2006): 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 investor-owned utilities to set a tariff under which qualifying generation from public water and wastewater facilities up to 1.5 megawatts is purchased at the market price referent used for the RPS until a statewide cap of 250 megawatts is reached under the program. Furthermore, the CPUC instituted a parallel program for about 230 megawatts that is open to customers other than public water and wastewater agencies.¹²⁶
- AB 1585 (Blakeslee, Chapter 579, Statutes of 2005): 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 2005–2006 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.

- AB 809 (Blakeslee, Chapter 684, Statutes of 2007): AB 809 changes the definition of an “eligible renewable energy resource” to include conduit hydro of 30 megawatt or less under certain conditions and allows small hydro facilities with efficiency improvements that increase their capacity above 30 megawatt to retain their RPS eligibility, also under specific conditions.

Federal Proposed Legislation

As of October 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 cost of fuel price volatility on customers is ignored.¹²⁷ 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.

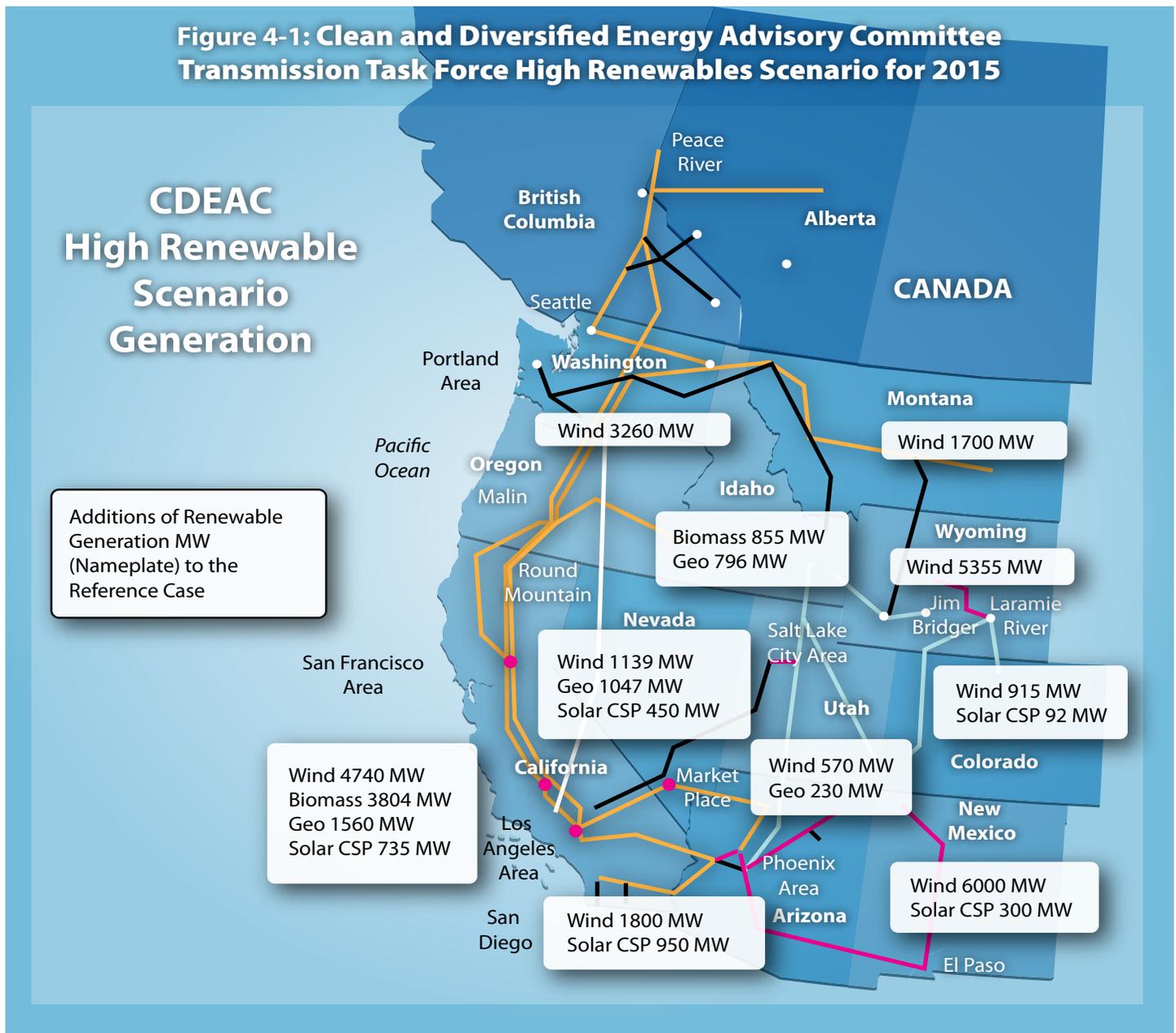
Also, a minimum standard would allow state and regional initiatives to take advantage of the diversity of resources across the states, allowing each state to decide how to meet electricity needs beyond the minimum standard. The Western states are rich in renewable resources, but the resource mix likely to be developed in the next 10 years varies widely from state to state.

125 Public Utilities Code Section 399.16(a) (1).

126 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, <www.cpuc.ca.gov/WORD_PDF/FINAL_DECISION/70660.PDF>, accessed August 6, 2007.

127 For a detailed discussion, see California Energy Commission, *A Mean-Variance Portfolio Optimization of California’s Generation Mix to 2020: Achieving California’s 33 Percent Renewables Portfolio Standard Goal*, draft consultant report, July 2007, p. 1. CEC-300-2007-009-D. <www.energy.ca.gov/2007_energypolicy/documents/index.html#071107>.

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



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

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 association’s goal of 30,000 megawatts of clean and diversified energy by 2015 (Figure 4-1).

The range of policies and requirements among the states in the West is readily accommodated in the Western Renewable Energy 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 study¹²⁸ 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

128 California Energy Commission, *Scenario Analyses of California’s Electricity System, Addendum 1*, pp. 4–5. CEC-200-2007-010-AD1. <www.energy.ca.gov/2007publications/CEC-200-2007-010/CEC-200-2007-010-AD1.PDF>.

renewable energy in California constant while adding high levels of renewable development in the West, similar to the Clean and Diversified Energy Advisory Committee scenario. 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 greenhouse gas-emitting resources into California. How to attribute greenhouse gas characteristics of power plants located out of state within the regulatory construct is one of the major unresolved challenges of greenhouse gas policy implementation.

However, out-of-state renewable generation may also help California realize its goals at lower cost to ratepayers.

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, subject to a cost limitation to be established by the CPUC on above-market costs of RPS contracts. To extend that authority to 33 percent will require additional legislation. Six topics identified in AB 1585¹²⁹ and related issues will affect the state's ability to achieve 33 percent renewable energy by 2020.

- 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

129 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 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." <www.governor.ca.gov/govsite/pdf/press_release_2005/AB_1585_signing.pdf>, accessed June 21, 2007.

- 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
- Federal Energy Regulatory Commission 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
- 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 megawatts 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 2013.¹³⁰ Segments capable of exporting 700 megawatts of wind from the area are scheduled for completion by the end of 2009.¹³¹

Los Angeles Department of Water and Power (LADWP) is expanding its transmission lines in the Tehachapi Wind Resource Area to accommodate at least 500 megawatts of wind and other renewables as part of a larger project that will add 1,150 megawatts of transfer capability for renewables and other transmission needs.¹³² The Energy Commission encourages LADWP to coordinate its plans with SCE to avoid duplicative transmission development.

130 Southern California Edison, *Fact Sheet: Tehachapi Renewable Transmission Project*, <www.sce.com/NR/rdonlyres/96270562-668A-49F8-BCD4-B96A9D8E3F9E/0/TRTPFSJuly07.pdf>, updated July 2007, accessed July 20, 2007.

131 Southern California Edison, 2006 Procurement Plan Volume 1B (Public Version), <www.pge.com/regulation/LongTermProcureOIR/Testimony/SCE/2006/LongTermProcureOIR_Test_SCE_20061211-02.pdf>, December 11, 2006, p. 95.

132 Department of Water and Power, City of Los Angeles, Renewable Transmission, presentation at April 17, 2007, IEPR workshop, Slide #5, accessed July 20, 2007, <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.

The Sunrise Powerlink transmission project would provide access to about 1,000 megawatts of renewable energy.¹³³ The project has been delayed by debate regarding the path the transmission line should take from Imperial County to San Diego County.¹³⁴ In response to public comments, alternative paths have been proposed. The Energy Commission 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, Imperial Irrigation District, Citizens Energy, and SDG&E, would provide access to more than 2,000 megawatts of new renewable energy resources in the Imperial Valley. The Energy Commission supports these projects for their contributions to achieving the state’s RPS goals. However, the Imperial Irrigation District has raised concerns that may delay completion of these projects.¹³⁵

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 need expansion to accommodate the full renewable energy development of that region. An Energy Commission report identifies potential renewable energy in Tehachapi by 2020 as about 8,000 megawatts of wind, with 4,500 megawatts included in a scenario achieving 33 percent by 2020.¹³⁶ Estimates for Imperial County total more than 3,700 megawatts of near-term potential for new renewables,

133 California Public Utilities Commission, San Diego Gas & Electric Company’s proposed Sunrise Powerlink Transmission Project, <www.cpuc.ca.gov/static/hottopics/1energy/a0512014.htm>, accessed July 20, 2007.

134 California Public Utilities Commission, San Diego Gas & Electric Company’s Sunrise Powerlink Project (Applications A.05-12-014 and A.06-08-010), <www.cpuc.ca.gov/environment/info/aspen/sunrise/sunrise.htm>, accessed July 20, 2007. See also Jones, J. Harry, “Public Can Weigh in on Sunrise Project,” San Diego Union Tribune, <www.signonsandiego.com/news/northcounty/20070126-999-1mi26sunrise.html>, accessed July 20, 2007.

135 Downey, Carrie A., November 9, 2007, Phase I Opening Brief of Imperial Irrigation District, in the matter of the application of San Diego Gas & Electric Company for a Certificate of Public Convenience and Necessity for the Sunrise Powerlink Transmission Project, Application No. 06-08-010, pp. 15–22.

136 <www.energy.ca.gov/pier/notices/2007-02-13_workshop/presentations/04_2007-02-13_DAVIS+DAHMAN+PATTEN.PDF>, p. 85.

Environmental Challenges to Siting Solar Plants in California

As a result of California's aggressive RPS targets, developers are proposing many large solar energy projects. These projects, located largely in the California desert on U.S. Bureau of Land Management (BLM) land, could have major biological impacts because of the amount of acreage involved. As of August 2007, the BLM has received applications for solar thermal and photovoltaic projects in California totaling 38,000 megawatts. Based on solar thermal applications received at the Energy Commission, the acreage needed for these projects could be as much as 308,000 acres, or 480 square miles. For comparison, 1,288 acres have been impacted by 12,376 megawatts of power plants (primarily natural-gas fired) currently operating or under construction that have been permitted by the Energy Commission since 1996.

Identifying enough habitats to mitigate the potential impacts of these projects will be a challenge depending on the species impacted. For example, when the Energy Commission licensed the Luz SEGS solar thermal projects in San Bernardino County in the 1980s and 1990s, it required five compensating acres for every one acre impacted because the projects affected high-quality protected species. The California desert has many specialized species, with two species of particular concern

being the desert tortoise and the Mojave ground squirrel. Both species have limited ranges which overlap with several areas under consideration in the Mojave Desert.

Because disturbed desert habitats recover very slowly, decommissioning and habitat restoration of solar project sites is of particular concern in these areas. When the Energy Commission licensed the Luz SEGS Unit 10 project in 1990, it required that \$100,000 be set aside for a decommissioning fund during the first year of commercial operation. After putting in foundation piers and fencing, the project owner went bankrupt. Because Unit 10 was never completed, decommissioning funds were not collected and the fencing and foundations remain on the one square mile project site, representing an ongoing loss of habitat.

The Energy Commission staff is working with the BLM, California Department of Fish and Game, U.S. Fish and Wildlife Service, counties, and project owners to address decommissioning of solar projects and restoration of disturbed project-site habitat. Since solar thermal projects 50 megawatts or larger located on BLM land will require approval from both the BLM and the Energy Commission, these agencies have entered into a Memorandum of Understanding that outlines roles and responsibilities in conducting a joint environmental review of these projects.

including about 1,000 megawatts of wind, about 2,400 megawatts of geothermal (1,900 megawatts more than existing), and large amounts of potential concentrating solar power.¹³⁷ RPS contracts have been signed for more than 800 megawatts of solar in Imperial County requiring new transmission.¹³⁸

137 Wind estimates are from <www.energy.ca.gov/2007publications/CEC-500-2007-014/CEC-500-2007-014.PDF>, p. 13. Geothermal estimate is from <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 <www.energy.ca.gov/2005publications/CEC-500-2005-072/CEC-500-2005-072-D.PDF>, p. 19.

138 California Energy Commission, Database of Investor-Owned Utilities' Contracts for Generation, Contracts Signed Towards Meeting the California Renewables Portfolio Standard Target, April 6, 2007. <www.energy.ca.gov/portfolio/contracts_database.html>, accessed July 20, 2007.

Federal Energy Regulatory Commission Support for Transmission

Since the *2006 IEPR Update*, the Federal Energy Regulatory Commission 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.¹³⁹ To implement this concept, the California ISO Board of Governors has approved making changes to its federal tariff, which was filed with Federal Energy Regulatory Commission on October 31, 2007.¹⁴⁰ The Energy Commission applauds the California ISO's action and 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.¹⁴¹ 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 generators 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 ad hoc contract-by-contract subsidy decisions. 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.

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 investor-owned utility rates. 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 must 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 Wisner 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."¹⁴²

In Europe, governments have developed mechanisms through which the costs of feed-in tariffs can be evenly redistributed.¹⁴³ In Germany, for example, regional transmission authorities evenly redistribute feed-in costs among national ratepayers. In the U.S., Letendre suggests that a similar redistributive role could be played by regional transmission authorities or independent system operators.¹⁴⁴

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

140 California Independent System Operator press release, *Greening the Grid Gets Green Light*, October 17, 2007. Also see <www.caiso.com/1816/1816d22953ec0.html>.

141 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.

142 Wisner, R., J. Hamrin, and M. Wingate, *Renewable Energy Policy Options for China: A Comparison of Renewables Portfolio Standards, Feed-In Tariffs, and Tendering Policies*. San Francisco, CA: Center for Resource Solutions, 2002. Prepared for the Center for Renewable Energy Development, Energy Research Institute, State Development Planning Commission.

143 Muñoz, M., V. Oschmann, and J. D. Tabara, (in press), *Harmonization of Renewable Electricity Feed-In Laws in the European Union*. Energy Policy.

144 As quoted in Wilson Rickerson and Robert C. Grace, *The Debate over Fixed Price Incentives for Renewable Electricity in Europe and the United States*, February 2007, <www.boell.org/docs/Rickerson_Grace_FINAL.pdf>, pp. 12–13.

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, grid access is guaranteed for generators responding to feed-in tariffs.¹⁴⁵ Germany's 2000 Erneuerbare-Energien-Gesetz (EEG) established a "countrywide compensation scheme . . . to help balance the costs [of renewable electricity] between the different electricity providers."¹⁴⁶ In 2004, the EEG was amended, and the equalization provided 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 who will also be able to monitor each other.)"¹⁴⁷ 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.¹⁴⁸ 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 an Energy Commission white paper on feed-in tariffs prepared in collaboration with the CPUC 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 qualifying facility 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.

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 greenhouse gas 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 (RETI). The RETI 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 impact. The RETI will identify top priority renewable energy zones and conceptual transmission plans for those zones and initiate the permitting processes for projects identified in RETI transmission plans.¹⁴⁹

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 for California, led by the Energy Commission and the Bureau of Land Management, with full participation from other state and

145 Ragwitz, M. and C. Huber, *Feed-In Systems in Germany and Spain: A Comparison*, Fraunhofer Institute: Systems and Innovation Research, 2004, source for Table 5.1, p. 54 in Mendonca, Miguel, *Feed-In Tariffs: Accelerating the Deployment of Renewable Energy*, World Future Council, London, 2007.

146 Mendonca, Miguel, *Feed-In Tariffs: Accelerating the Deployment of Renewable Energy*, World Future Council, London, 2007, p. 32.

147 Ibid., p. 35.

148 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), pp. 799–812. See also, Lewis, J. and R. Wiser, *Fostering a Renewable Energy Technology Industry: An International Comparison of Wind Industry Policy Support Mechanisms*, Lawrence Berkeley National Laboratory, Berkeley, California, 2005. <eetd.lbl.gov/ea/emp/reports/59116.pdf>.

149 California Renewable Energy Transmission Initiative Mission Statement, September 17, 2007, <www.energy.ca.gov/reti/MISSION_STATEMENT.PDF>.

local regulators. The programmatic environmental impact reports/ environmental impact statements 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.¹⁵⁰ 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.

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 September 2007, SCE alone had 28,000 megawatts of renewables in the queue.¹⁵¹ Most of the renewable energy projects in the current queue are fairly recent, although more than 700 megawatts of wind joined the queue before January 2004, including 300 megawatts of wind in Kern County that does not have an interconnection agreement.¹⁵²

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 RETI process rather than perform those studies on its own.¹⁵³ PG&E received CPUC approval for \$14 million in ratepayer money to study options for a major transmission line to bring up to 3,000 megawatts 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 a discussion of additional renewable generation-transmission studies underway.

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, and more than 90 percent of the associated energy) 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 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 greenhouse gas and renewable energy goals. As California moves to a carbon-constrained economy, there will likely be a higher value on environmental attributes of renewable energy without regard to location.

150 California ISO, FERC Electric Tariff, Third Replacement Volume No. II, Original Sheet No. 1005A, Effective March 1, 2006. <www.caiso.com/1bf0/1bf0e846437e0.pdf>, accessed July 20, 2007.

151 Presentation by Ron L. Litzinger, Southern California Edison, at the Third Annual California Power Markets Forum, October 29, 2007.

152 The latest update of the California ISO queue is available from www.caiso.com/docs/2002/06/11/2002061110300427214.html.

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

Renewable Energy Certificates and Deliverability

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 — so 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*, 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 renewable energy credits become eligible in the future, customers of the purchasing load-serving entity will likely forego any supply diversity or price stabilizing benefits from the purchase because the load-serving entity will still have to acquire a commensurate amount of conventional energy.

Provisions in SB 107 effectively allow "banking and shaping" of renewable energy by allowing renewable energy credits 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 renewable energy credits associated with energy produced from RPS-eligible resources to qualify toward RPS procurement requirements in the future, once certain conditions have been met. Tradable renewable energy credits may be allowed for RPS compliance after the CPUC and Energy Commission conclude that the Western Renewable Energy Generation Information System is operational, is capable of independently verifying delivery of renewable energy to a retail seller, and

can assure that renewable energy credits are not double counted by any seller within the WECC. Also, the CPUC may limit the amount of tradable renewable energy credits that a retail seller may procure to satisfy its RPS requirements. The CPUC is addressing renewable energy credits and other RPS implementation issues in its Rulemakings 06-05-027 and 06-02-012, and in subsequent RPS Rulemakings.¹⁵⁴

Allowing tradable renewable energy credits for RPS compliance, including out-of-state renewable energy credits, could help increase the development of renewable energy WECC-wide, reducing the greenhouse gas 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.

Existing coal and nuclear plants and some recently built gas-fired baseload plants cannot ramp up and down as rapidly as needed to meet the increased "peakiness" of 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

¹⁵⁴ California Energy Commission, *Renewables Portfolio Standard Eligibility Guidebook*, March 2007, <www.energy.ca.gov/2007publications/CEC-300-2007-006/CEC-300-2007-006-CMF.PDF>, p. 3.

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: Preliminary Results for the 2007 Integrated Energy Policy Report (Scenario Analyses Report)* focused on scenario analyses in California and throughout the WECC region, creating scenarios that integrated high renewables and high levels of energy efficiency.¹⁵⁵ Some scenarios in this report used a resource mix of about 30 percent renewable energy in California.
- The *Intermittency Analysis Project Report*¹⁵⁶ (IAP) analyzed renewable electricity scenarios for 2010 and 2020 and used a resource mix of 33 percent by 2020.

The *Scenario Analyses 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 Analyses 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 in-state renewables using a more fine-grained approach than the *Scenario Analyses 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 (Table 4-1).

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

	2020
Total Geothermal, MW	5,100
Total Biomass, MW	2,000
Total Concentrating Solar, MW (Intermittent)	3,100
Total Photovoltaic Solar, MW (Intermittent)	2,900
Total Wind, MW * (5,800 MW in Tehachapi Region) (Intermittent)	12,700
Total Renewable Capacity	25,800
Peak California Load, MW	80,742
Peak California ISO Load, MW	66,700
Intermittent Penetration in CA	23%
Intermittent Penetration in California ISO Service Territory	25%
Total Renewable Resource Penetration in California	32%

Source: California Energy Commission, Intermittency Analysis Project: Summary of Final Results, CEC-500-2007-081, Table 2-2, p. 18. www.energy.ca.gov/2007publications/CEC-500-2007-081/CEC-500-2007-081.PDF.

*Intermittent penetration percentage for California ISO control area assumes 90 percent of statewide intermittent resources are located in that region.

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,

155 California Energy Commission, *Scenario Analyses of California’s Electricity System*. CEC-200-2007-010-SF.

156 Porter, K. and Intermittency Analysis Project Team, *Intermittency Analysis Project: Summary of Final Results*, California Energy Commission, PIER Research Development & Demonstration Program, 2007. CEC-500-2007-081. <www.energy.ca.gov/2007publications/CEC-500-2007-081/CEC-500-2007-081.PDF>.

power quality, and transmission system operation.¹⁵⁷ The study also used emerging wind and solar technologies and performance in selecting resource types and locations.

In contrast to the *Scenario Analyses 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 Consulting. 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.

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 megawatts and megawatt hours the potential impact of the 2010 and 2020 renewable energy goals on statewide 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 megawatt hour and reported that emerging grid-friendly wind turbine technologies may reduce integration issues and costs.¹⁵⁸ Also, benefits of incorporating state-of-the-art wind energy forecasting techniques across the system were estimated at \$4.37 per megawatt hour.

The IAP did not focus specifically on estimating costs such as unit commitment or cost adders. The unit costs to manage

and procure the megawatts and megawatt hours 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 and other contributors reviewed several northwest utility studies of integration costs. The utility studies estimated costs from about \$3.20 to \$9.75 per megawatt hour 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.¹⁵⁹ 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 Northwest Power Planning Council 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 products¹⁶⁰

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 energy dispatch scenarios, and that transmission congestion

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

158 California Energy Commission, *Impact on Past, Present and Future Wind Turbine Technologies on California Grid*, BEW Engineering consultant report, CEC 500-2006-050, May 2006. As reported in Porter, K. and Intermittency Analysis Project Team, *Intermittency Analysis Project: Summary of Final Results*. California Energy Commission, PIER Research Development & Demonstration Program, CEC-500-2007-081, 2007. <www.energy.ca.gov/2007publications/CEC-500-2007-081/CEC-500-2007-081.PDF>, p. 3.

159 Northwest Power and Conservation Council, *Northwest Wind Integration Action Plan*, pre-publication version, March 2007 at <www.nwcouncil.org/energy/Wind/library/2007-1.pdf>, p. 8

160 Ibid.

patterns are more difficult to predict as the penetration of variable renewable energy resources increases.”¹⁶¹

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.¹⁶²

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 facility in rapidly growing Riverside County and the Iowa Hill facility being considered by the Sacramento Municipal Utility District may provide further assistance for “storing” renewable energy generated on windy nights.^{163, 164}

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 megawatts), such as automated demand response technologies, variable speed pumped hydro, and flywheel energy storage.¹⁶⁵ The IAP 33 percent by 2020 scenario also suggested a need for a significant amount of volt-amperes reactive compensation to maintain voltage stability.¹⁶⁶

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 investor-owned utilities. The CPUC directed PG&E, SDG&E, and SCE to develop 2006 long-term procurement plans to meet Energy Action Plan II targets of 20 percent renewable by 2010 and 33 percent by 2020.¹⁶⁷ The CPUC stated that it “will not approve plans that lack realistic and implementable provisions for meeting the EAP II targets.”¹⁶⁸

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 long-term procurement plan 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

161 Ibid.

162 Ibid, p. 3.

163 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, 2007. <www.energy.ca.gov/2007publications/CEC-500-2007-081/CEC-500-2007-081.PDF>, pp. 34–35.

164 Confluence Newsletter, Summer 2007, <hydrorelicensing.smud.org/IowaHill/News/Confluence%20News_Sumr07.pdf>. See also SMUD’s project description at <hydrorelicensing.smud.org/IowaHill/iowa/Iowa_PD.pdf>.

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. <www.energy.ca.gov/2007publications/CEC-500-2007-081/CEC-500-2007-081.PDF>, p. 5.

166 Ibid., p. 27.

167 <www.energy.ca.gov/energy_action_plan/2005-09-21_EAP2_FINAL.DOC>.

168 California Public Utilities Commission, Scoping Memo on the Long-Term Procurement Phase of Rulemaking R.06-02-013, <www.cpuc.ca.gov/EFILE/RULC/60186.htm>, p. 17.

2009 retail sales.¹⁶⁹ 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 retail sales in 2016, the end of the planning period covered by the 2006 long-term procurement plan.

Pacific Gas and Electric

PG&E's 2006 long-term procurement plan reports renewable energy in 2007 to be between 10,487 gigawatt hours and 10,498 gigawatt hours, 13.3 percent of the retail sales for 2006.¹⁷⁰ PG&E expects to have total retail sales between about 75,000 gigawatt hours and 85,000 gigawatt hours in 2010.¹⁷¹ 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 gigawatt hours to 17,000 gigawatt hours with a renewable resource mix between 980 and 1,000 megawatts in size. PG&E used 25 percent of 2015 retail sales, forecast to be about 19,000 to 23,000 gigawatt hours as a proxy for 33 percent by 2020, with between 2,800 megawatts and 5,000 megawatts of renewable resource capacity.¹⁷²

PG&E's plan anticipates achieving about 18 to 19 percent renewable deliveries in 2010 and 20 percent in 2011 or 2012, depending on the scenario. Three of four of the scenarios prepared by PG&E do not achieve 28 percent of renewables by 2016.¹⁷³

Assuming a 50 percent capacity factor to convert from energy (gigawatt hours) into capacity (megawatts), the Energy Commission estimated PG&E's scenarios are short of achieving 20 percent renewables by 2010 by between 823 gigawatt hours and 1,611 gigawatt hours (188 to 368 megawatts). Assuming 28

percent by 2016 is needed to be on track to achieve 33 percent by 2020, PG&E's scenarios are short by 4,548 gigawatt hours (1,038 megawatts) to 1,764 gigawatt hours (403 megawatts).¹⁷⁴

PG&E's long-term procurement plan 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.¹⁷⁵ PG&E assumes development of 2,400 megawatts of wind and 200 megawatts 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."¹⁷⁶

To address the need for transmission, PG&E describes short-term (1 to 5 years), medium-term (next 5 to 10 years), and long-term (next 10 to 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 and expand PG&E's ability to deliver new renewable power from remote locations.¹⁷⁷ PG&E also identifies three medium-term projects with its schedules, recognizing that the timing may change depending on the results of environmental and technical studies: (1) Midway-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.¹⁷⁸ 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

169 California Public Utilities Commission, October 19, 2006, Decision 06-10-050, in Rulemaking 06-05-027, *Opinion on Reporting and Compliance Methodology for Renewables Portfolio Standard Program*, <www.cpuc.ca.gov/WORD_PDF/FINAL_DECISION/61025.DOC>.

170 Pacific Gas and Electric Company, 2006 Long-Term Procurement Plan, Vol. 1, public version, Tables IVC-7 and IVC-8.

171 *Ibid.*, p. IV-31.

172 *Ibid.*

173 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.

174 *Ibid.*, pp. 19–20.

175 Pacific Gas and Electric Company, 2006 Long-Term Procurement Plan, Vol. 1, public version, p. V-49.

176 *Ibid.*, p. IV-34 for wind, p. IV-35 for geothermal.

177 *Ibid.*, p. V-50.

178 *Ibid.*, p. V-49.

capacity from British Columbia in its forecasts of pending additional research,¹⁷⁹ it estimates that almost 9,900 megawatts of renewable resources — wind, hydro (including “medium” hydro that is not eligible for the California RPS), biomass, and geothermal — could be developed in British Columbia.¹⁸⁰

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...”¹⁸¹

San Diego Gas & Electric

The Energy Commission’s analysis determined that SDG&E’s 2006 long-term procurement plan exceeds the 2010 RPS goal by approximately 334 gigawatt hours (76 megawatts) in 2010, but is short of a trajectory toward 33 percent in 2020 by approximately 880 gigawatt hours in 2016 (201 megawatts).¹⁸² SDG&E contests these findings and states that its plan is on a trajectory to meet the 33 percent target as discussed below.¹⁸³

SDG&E’s 2006 long-term procurement plan states that it has 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).¹⁸⁴

According to SDG&E, it plans to have 507 megawatts of renewable capacity in 2010 and 840 megawatts 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.¹⁸⁵ 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.¹⁸⁶

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 contracts 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, it 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 to 26 percent of 2010 retail sales to be delivered from renewable resources.¹⁸⁷

For 2016, SDG&E’s plan calls for 840 megawatts of renewable capacity.¹⁸⁸ 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

179 Ibid., pp. IV-33–34.

180 Ibid., p. IV-37.

181 Ibid., p. IV-27.

182 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 Company, p. 19.

183 San Diego Gas & Electric Company, Opening Brief, pp. 82–83.

184 San Diego Gas & Electric Company 2007-2016 Long-Term Procurement Plan, Vol. 1, part 2, pp. 190–191.

185 Ibid., Vol. 1, Part 1, p. 169.

186 San Diego Gas & Electric Company, December 11, 2006, 2007-2016 Long-term Procurement Plan, Volume 1, Public Version, <www.pge.com/regulation/LongTermProcureOIR/Testimony/SDGE/2006/LongTermProcureOIR_TestSDGE_20061211-01.pdf>, p. 168.

187 San Diego Gas & Electric Company, August 1, 2007, Opening Brief, CPUC Rulemaking 6-02-013, Order Instituting Rulemaking to Integrate Procurement Policies and Consider Long-Term Procurement Plans, <www.pge.com/regulation/LongTermProcureOIR/Pleadings/SDGE/2007/LongTermProcureOIR_SDGE_20070801-01.pdf>, pp. 83–84.

188 San Diego Gas & Electric Company, 2007–2016 Long-Term Procurement Plan, Vol. 1 part 1, p. 178.

renewable energy is likely to be “lumpy” and may be changed if the CPUC allows SDG&E to use unbundled renewable energy credits for the RPS, which SDG&E supports.¹⁸⁹

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 2020.¹⁹⁰ SDG&E, however, states that its plan actually shows reaching 29.4 percent renewable by 2016, consistent with reaching a 33 percent goal by 2020.¹⁹¹

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.”¹⁹² The Sunrise Powerlink would allow SDG&E to import an additional 1,000 megawatts from Imperial Valley to San Diego.¹⁹³ 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.¹⁹⁴

Southern California Edison

The Energy Commission’s analysis determined that SCE’s 2006 Long-Term Procurement Plan exceeds the 2010 RPS goal by approximately 765 gigawatt hours (175 megawatts) in 2010, but is short of a course toward 33 percent in 2020 by approximately 1,358 gigawatt hours in 2016 (310 megawatts). 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.¹⁹⁵

SCE’s 2006 Long-Term Procurement Plan meets the 20 percent by 2010 RPS goal, with about 15,000 gigawatt hours of renewable energy.¹⁹⁶ For 2006, SCE anticipated having 16.5 percent of its retail load met by output from eligible renewable resources.¹⁹⁷ In its long-term procurement plan, SCE states it may not be able to achieve 20 percent by 2010:

... 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 percent attrition rate assumed for the 33 percent scenario; delays in obtaining State or local transmission permits; missed milestones by project developers; and other unanticipated causes.¹⁹⁸

To meet the 20 percent by 2010 goal and 33 percent by 2020 goal, SCE assumes the following transmission will be built:¹⁹⁹

- Tehachapi (Phase 1) - 700 megawatts in 2010
- Tehachapi (Phase 2/3) - 1,700 megawatts in 2013
- Tehachapi (Phase 4) - 2,100 megawatts in 2015
- San Bernardino County - 2,000 megawatts every two years starting in 2015 up to 10,000 megawatts
- Salton Sea - 1,300 megawatts in 2017
- North of Lugo - 975 megawatts in 2020

SCE’s 2006 Long-Term Procurement Plan 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

189 Ibid., Vol. 1, part 2, pp. 191–192.

190 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.

191 Ibid., pp. 82–83.

192 San Diego Gas & Electric Company, 2007–2016 Long-Term Procurement Plan, Vol. 1, part 2, p. 192.

193 Ibid., p. 204.

194 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.

195 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.

196 Southern California Edison, 2006 Long-Term Procurement Plan, Volume 1B, public version, p. 78.

197 Ibid., p. 76.

198 Ibid., pp. 85–86.

199 Ibid., p. 77.

gigawatt hours in 2016, providing close to 33 percent of retail sales under the California Energy Commission load scenario, and about 30 percent of retail sales under the SCE load scenario.²⁰⁰

For comparison, SCE's 20 percent planning scenario shows about 20,000 gigawatt hours of renewable energy in 2016.²⁰¹

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.²⁰²

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.²⁰³ In this Required Plan, for resources procured beyond the 20 percent plan, SCE assumes renewables will be priced at 25 percent above the market price referent, arguing that "increasing demand by elevating the overall goal of the RPS program to 33 percent in a market already demonstrating resource shortages and consequently higher prices will likely lead to higher overall costs for the RPS program."²⁰⁴ To avoid the expense, SCE asked 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."²⁰⁵

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 investor-owned utilities are priced below the market price referent. Whether future costs remain below the market price referent 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 supplemental energy payment/market price referent 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).²⁰⁶ 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).²⁰⁷ The 2008 allowances have been trading at about 20 to 30 Euro per metric ton CO₂ in the European Union Emission Trading Scheme.²⁰⁸

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 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.²⁰⁹

200 Southern California Edison, 2006 Long-Term Procurement Plan, Vol. 1B, public version, pp. 85, 127.

201 Ibid., p. 78.

202 Ibid., p. 82.

203 Ibid., Vol. 1A, public version, p. 5, lines 18–27.

204 Ibid., Vol. 1B, public version, pp. 87–88.

205 Ibid., Vol. 1A, public version, p. 5.

206 California Energy Commission, *2006 Integrated Energy Policy Report Update*, November 2006, CEC-100-2006-001.

207 Deutsche Bank, July 25, 2007, *The European Union Wants to Cut Carbon Emissions by 20% by 2020, Deutsche Bank Significantly Upgrades Carbon Price Forecast*, <www.db.com/presse/en/content/press_releases_2007_3588.htm>.

208 5 July 2007, *EU Carbon Down, but Solid above 20 Euros*, <www.carbonpositive.net/viewarticle.aspx?articleID=98>. See also, <www.carbonpositive.net/viewarticle.aspx?articleID=137>.

209 Center for Resource Solutions, *Achieving a 33% Renewable Energy Target*. Prepared for the California Public Utilities Commission, November 2005. <www.cpuc.ca.gov/word_pdf/misc/051102_FinalDraftReport_RenewableEnergy.pdf>, pp. 99–101.

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 Analyses Report* show that a 2020 scenario with about 30 percent renewable energy may be achievable without a significant upward impact on rates.²¹⁰ 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 photovoltaic and total utility generation mix. The *Scenario Analyses Report* used total societal costs, including both rebates and photovoltaic purchase costs paid by homeowners and businesses. For that reason, and the fact that photovoltaic 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 become part of the rate base.

A second study, portfolio analysis,²¹¹ 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, potential cost of carbon regulation, generation costs in general, and upgrades to the transmission and distribution grids, among other factors. Major investments in 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.

Currently, 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 Analyses Project found a clear tradeoff between higher capital cost and lower production costs with generation portfolios weighted toward renewables. 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, countrywide turn away from high greenhouse gas 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.²¹² 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.

210 California Energy Commission, *Scenario Analysis of California’s Electricity System*. CEC-200-2007-010-SF.

211 Bates White, LLC, *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-D.pdf.

212 Ibid.

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.

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 expected value of net risk-adjusted 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 and less expensive and that substantially reduce CO₂ 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.

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
CO ₂ : 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 Photovoltaic	0%	8%	4%	0%	0%
Renewables Share	20%	41%	45%	64%	64%

Source: Bates White, LLC, *A Mean-Variance Portfolio Optimization of California's Generation Mix to 2020: Achieving California's 33 Percent RPS Goal*, draft consultant report, July 2007.

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.

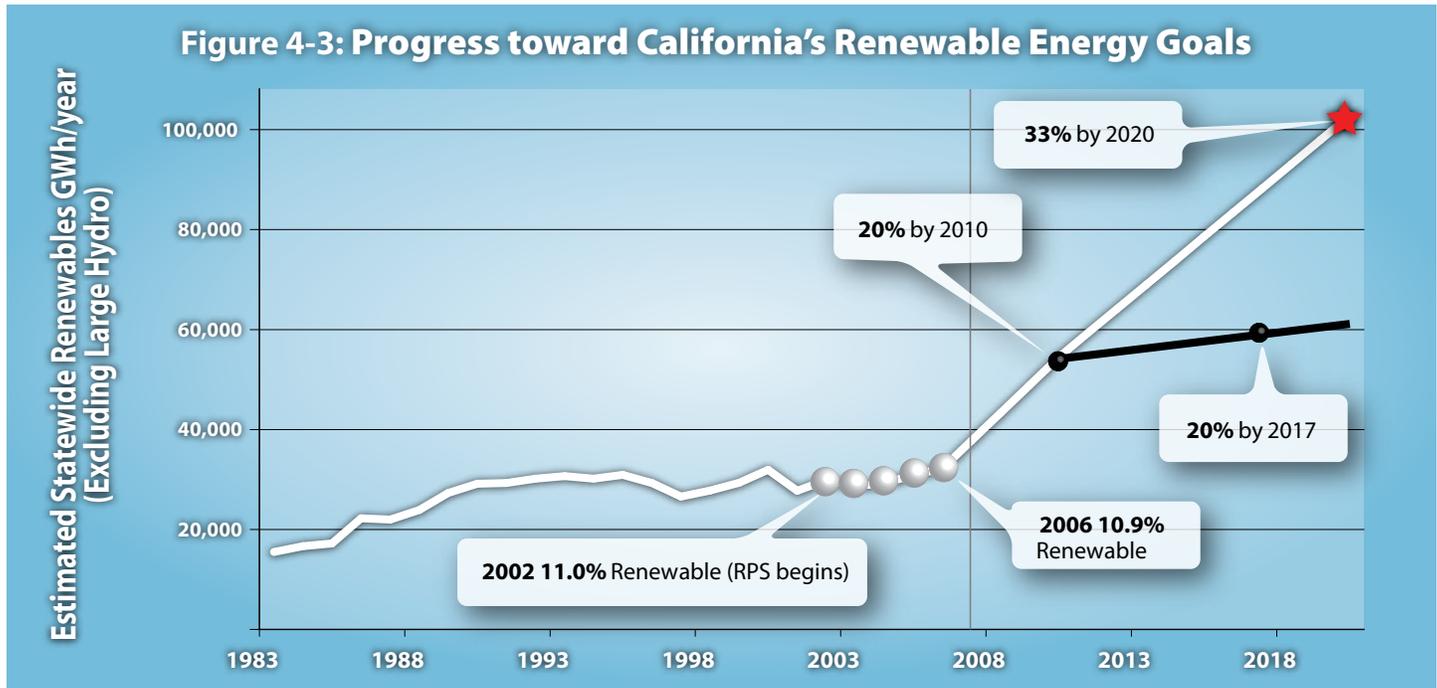
Given these caveats, the report's results in terms of costs and risks associated with various portfolios are illustrative. Further analysis is needed to apply the concepts of portfolio analysis to

models using more complete sets of inputs, such as those used in the *Scenario Analyses Report* and the Intermittency Analysis Project. 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 greenhouse gas goals while controlling ratepayer costs. Figure 4-2 shows the results from the preliminary portfolio analysis discussed in the report.²¹³ The vertical axis shows total portfolio electricity generation 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 and equivalent costs and results in significantly less CO₂ emissions than the business-as-usual case.²¹⁴

213 Adapted from Bates White, LLC, Figure 8, p. 28. <www.energy.ca.gov/2007publications/CEC-300-2007-009/CEC-300-2007-009-D.PDF>.

214 Ibid., pp. 25–30.



Source: California Energy Commission, Gross System Power 1998–2005.²¹⁵

In written comments on the portfolio analysis report, the investor-owned utilities 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, LLC 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.

215 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 generation across multiple years. Renewables 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. <energy.ca.gov/electricity/gross_system_power.html>.

216 San Diego Gas & Electric, comments, July 11, 2007 Integrated Energy Policy Report Committee Workshop on the Use of Portfolio Analysis in Electric Utility Resource Planning.

217 Pacific Gas and Electric Company, comments, July 11, 2007 Integrated Energy Policy Report Committee Workshop on the Use of Portfolio Analysis in Electric Utility Resource Planning.

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-varian portfolio analysis study indicate that further study is

218 Southern California Edison, 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.

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 Intermittency Analysis Project, 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.

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, insufficient progress has been made toward increasing the overall percentage of renewable energy deliveries in California's generation mix (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.

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 two to five 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 investor-owned utilities, publicly owned utilities, and electric service providers. Currently, mandatory RPS targets with consequences for noncompliance only apply to investor-owned

²²⁰ Ibid.

utilities and electric service providers, and rules for electric service providers are less clear than for investor-owned utilities and have been only recently developed. Publicly owned utilities 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."²²¹ Since the passage of SB 107, publicly owned utilities will not be allowed to sell renewable energy credits in the future to investor-owned utilities unless they are on track to meet RPS targets comparable to those of the investor-owned utilities.²²²

Progress Made by Investor-Owned Utilities

Although investor-owned utilities 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 investor owned utilities' long-term procurement plans and their expectations regarding future renewable deliveries, this section focuses on actual delivered energy (Table 4-3).

Comparing 2006 renewable generation (unverified data reported by the investor-owned utilities) with actual 2003 renewable generation shows that while overall investor-owned utility renewable deliveries have increased, particularly for SDG&E, overall procurement as a percent of retail sales has decreased by almost 1 percent. This means that renewable energy deliveries are not keeping up with load growth.²²³ To reach 20 percent in 2010, PG&E and SDG&E will have to increase renewable deliveries by approximately 2 and 5 percent per year, respectively.

²²¹ Public Utilities Code Section 387, paragraph (a).

²²² Public Utilities Code Section 399.13, paragraph (d), as amended by SB 107 (Simitian), Chapter 464, Statutes of 2006, <www.leginfo.ca.gov/pub/05-06/bill/sen/sb_0101-0150/sb_107_bill_20060926_chaptered.pdf>.

²²³ Use of 2003 for a comparison reflects the California Public Utility Commission's Decision 07-03-046 under Rulemaking 06-05-027 (the March 2007 Baseline Decision) that revises the methodology used to calculate the investor-owned utilities' initial baseline procurement amounts.

Table 4-3: Investor-Owned Utility Renewable Generation (2003–2006)

	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, *Renewables Portfolio Standard 2005 Procurement Verification Report*, CEC-300-2007-001-CMF, except 2003 RPS Renewable Generation, which is from *Renewables Portfolio Standard 2004 Procurement Verification Report*, CEC-300-2006-002-CMF. Data for 2006 submitted by investor-owned utilities in RPS Track Forms, to be verified in the forthcoming 2006 verification report.

Figure 4-4 shows the progress of the three large investor-owned utilities toward the short-term RPS target of 20 percent renewable generation by 2010. The dark bars show combined total retail sales for PG&E, SCE, and SDG&E, while the light bars show renewable generation. The line shows renewable generation as a percentage of retail sales.

The three major investor-owned utilities 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 investor-owned utilities 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.

Of the three major investor-owned utilities, SDG&E started with only 1 percent renewable generation and has made the most progress, but will have to increase much more rapidly to meet the goal (Figure 4-5). SCE continues to decline in renewable generation and will have 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.

The three major investor-owned utilities 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 investor-owned utilities 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 investor-owned utilities achieving about 25,000 gigawatt hours of renewable deliveries in 2010, provided contracts are not delayed.²²⁴ This is equivalent to about 14 percent of retail sales.

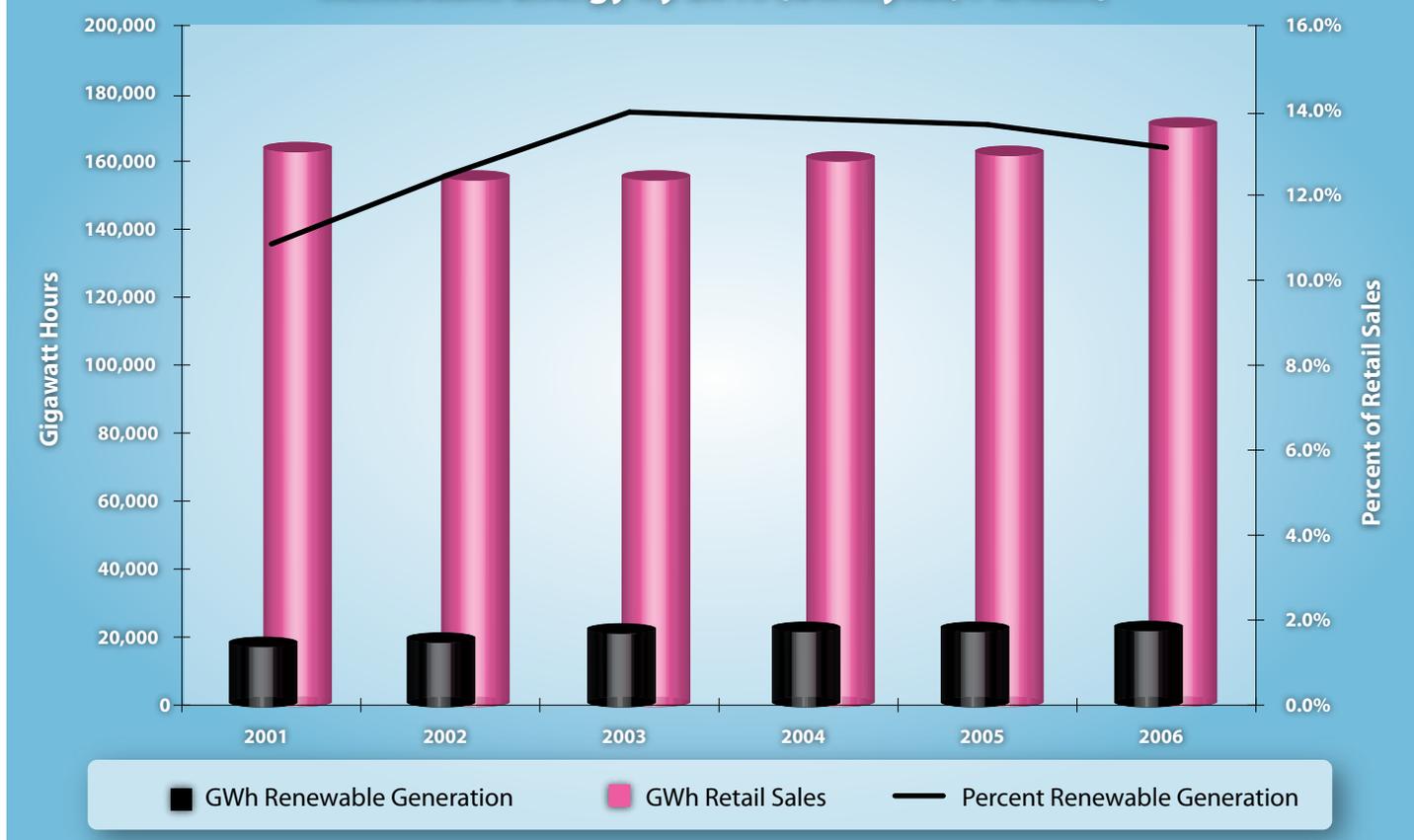
However, since June, the investor-owned utilities have requested CPUC approval for additional contracts that would deliver an additional 7,700 gigawatt hours by January 2011. These numbers are based on minimum quantities in the contracts in cases where there are options for additional build out. If all 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.

Investor-Owned Utility Contract Failure and Delay

The trend in failure and delay of investor-owned utility RPS contracts is not encouraging. As of March 2007, 50 percent of investor-owned utility RPS generation (gigawatt hours per year)

²²⁴ CPUC, *Progress of the California Renewables Portfolio Standard*, July 2007, at <www.cpuc.ca.gov/word_pdf/REPORT/69823.pdf>. Quantities are based on Figure 1, p. 5.

Figure 4-4: Progress of Large Investor-Owned Utilities toward 20 Percent Renewable Energy by 2010 (GWh/year, Percent)



Source: California Energy Commission.

under contract with new, repowered, or restarted facilities was canceled or delayed (Table 4-4). Since then, new contracts have been signed for large amounts of energy, bringing the failure rate to 27 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 October 2007, contract failure by this measure had increased slightly, to 35 percent.

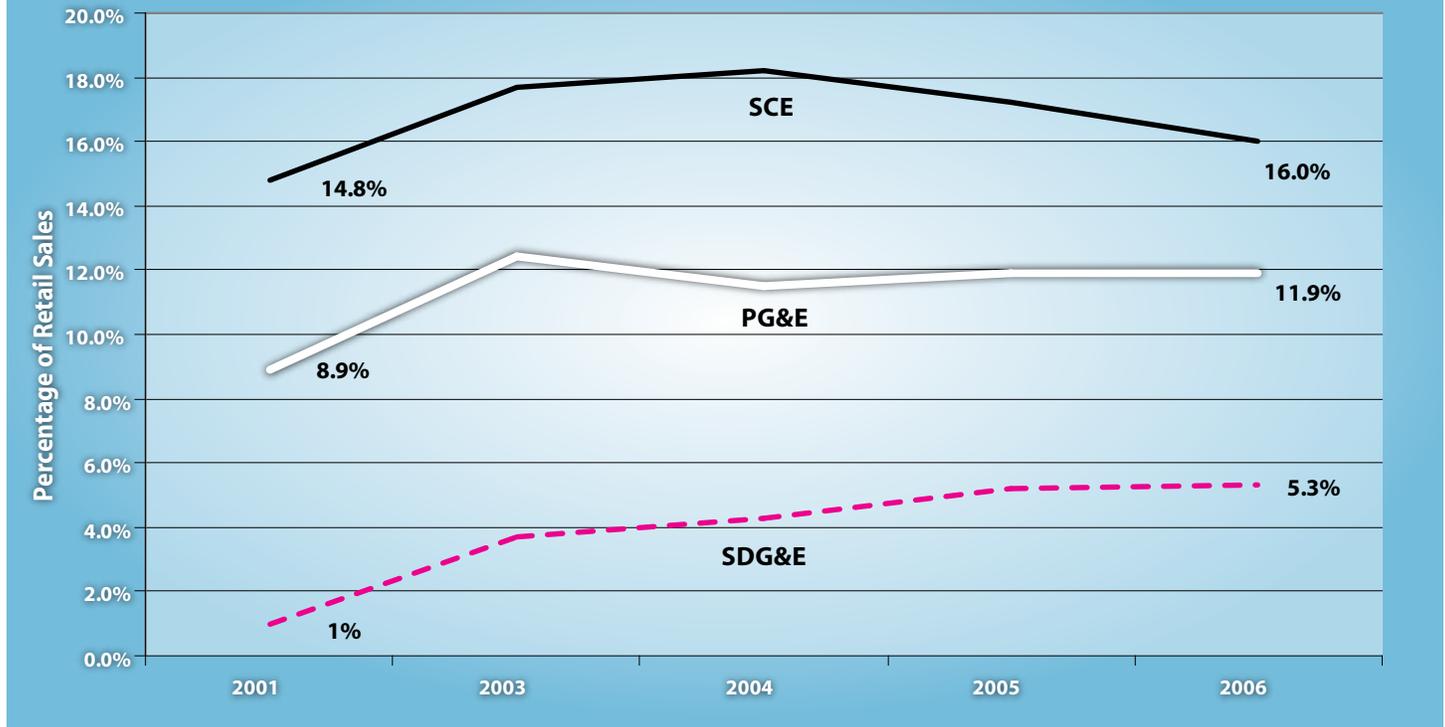
In terms of capacity, the March 2007 data show 1,410 megawatts of 2,283 megawatts, more than 60 percent of minimum capacity, were canceled or delayed. As of August 2007, 1,441 megawatts of 4,805 megawatts, about 30 percent of minimum capacity, were canceled or delayed.

Progress Made by Publicly Owned Utilities

Publicly owned utilities, 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 publicly owned utilities to meet their RPS requirements, including a summary of current publicly owned utility RPS targets, progress toward achieving those targets, and recent contracts and solicitations. Despite some improvements to encourage more regular reporting of publicly owned utility progress, the data that follow remain incomplete and somewhat uncertain in many respects.

Figure 4-5: Comparison of Investor-Owned Utility RPS Progress 2001–2006



Source: California Energy Commission 2004 and 2005 RPS verification reports and data submitted for 2006 RPS verification reports. Data for 2002 is from AB 1305 submittals and investor-owned utility reports to the CPUC.

Data Sources for Tracking Publicly Owned Utility RPS Activities

Publicly owned utilities 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 *publicly owned utility-qualifying* resources.²²⁵

Many publicly owned utilities, however, did not submit all required data for 2006. Thus, a variety of other data sources was 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

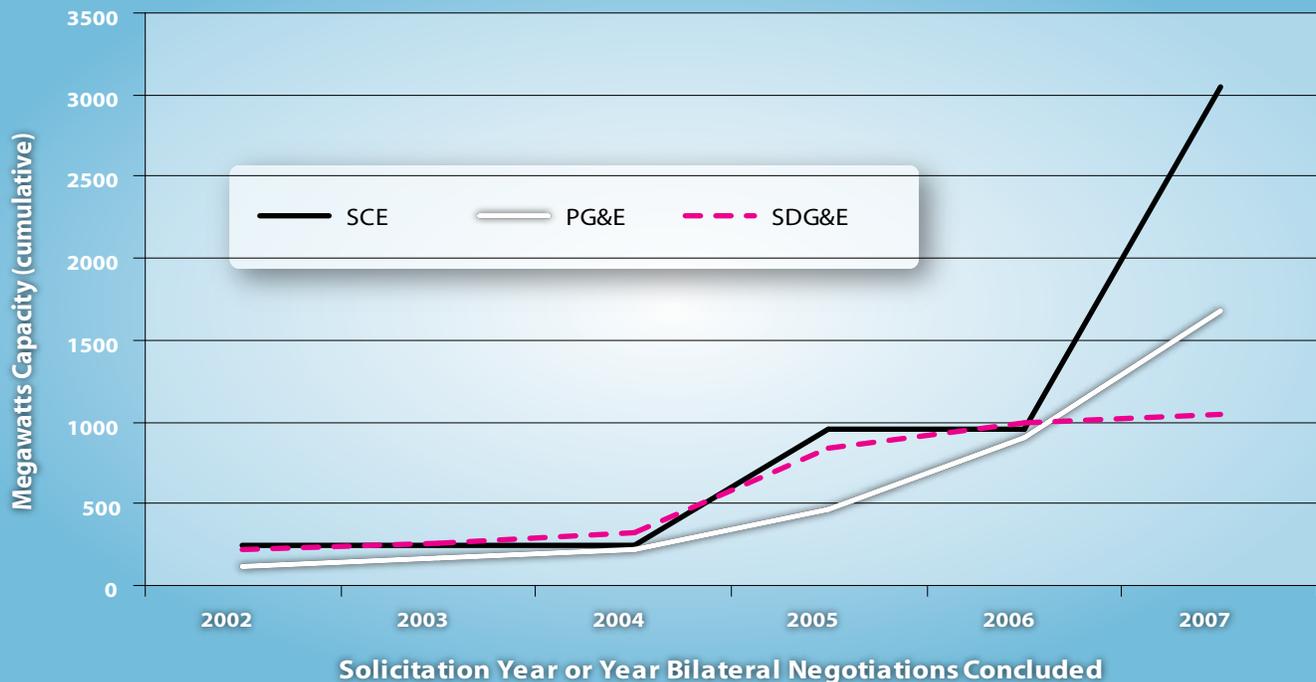
documents prepared by publicly owned utilities. Many of these data sources also provided information about recent publicly owned utility renewable energy contracts and solicitations.

Several comments are worth noting regarding how these data sources were used:

- The amount of energy supplied by Energy Commission-eligible resources considers only resource eligibility criteria (for example, no large hydro), but not deliverability-related eligibility criteria. That is, some renewable purchases indicated as Energy Commission-eligible represent resources that would not be eligible under the California RPS as applied to investor-owned utilities because of geographic location (out of state) and/or product type (for example, renewable energy credits).
- Prior reports have presented data on each publicly owned utility’s supply of Energy Commission-eligible and publicly owned utility-qualifying resources in

²²⁵ *Publicly owned utility-qualifying* resources include deliveries from renewable resources that are eligible under a publicly owned utility’s RPS target but that are not Energy Commission-eligible (for example, large hydro).

Figure 4-6: Cumulative Contracted Renewable Capacity 2002–2007



Source: California Energy Commission, Contract Database at <www.energy.ca.gov/portfolio/IOU_CONTRACT_DATABASE.XLS>.

2003.²²⁶ Staff re-calculated 2003 values based on data in the publicly owned utilities’ SB 1305 (Sher, Chapter 796, Statutes of 1997) 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 publicly owned utility’s retail load supplied by Energy Commission-eligible or publicly owned utility-qualifying resources, the percentages reported on the labels were adjusted to remove the renewable content associated with non-specific purchases.

Finally, staff notes that not all details presented here have been formally verified with publicly owned utilities, and feedback on the accuracy of the data presented here is welcomed.

Current Publicly Owned Utility RPS Targets

At least 29 of the state’s 47 publicly owned utilities, representing 98 percent of statewide publicly owned utility retail sales, have established some form of RPS commitment, although the details of their RPS policies vary considerably in terms of the target, time frame, and resource eligibility rules (Table 4-5). Some of these targets are equally or more aggressive than the RPS targets applied to the state’s investor-owned utilities (20 percent by 2010), while others are less so. At least 19 publicly owned utilities that have developed RPS targets allow some hydropower projects to qualify that are not otherwise eligible under the investor-owned utilities’ RPS requirements.

A number of the state’s larger publicly owned utilities have recently adopted more aggressive RPS policies. At least four — the Los Angeles Department of Water and Power, 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 investor-owned utilities. In addition, at least three publicly owned utilities have

226 KEMA, Inc., *Publicly Owned Electric Utilities and the California Renewables Portfolio Standard: A Summary of Data Collection Activities*, prepared for the California Energy Commission, November 2005, CEC-300-2005-023.

Table 4-4: New, Repower, Restart Facilities with Investor-Owned Utility 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, investor-owned utility RPS contract database (March and August 2007).

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 publicly owned utility, 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 publicly owned utilities’ RPS targets to those of the investor-owned utilities in terms of the incremental need for renewable energy. Relative to their eligible renewable energy deliveries in 2003, the state’s investor-owned utilities will — in aggregate — have to supply an additional 6 percent of retail sales with Energy Commission-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 2020.²²⁷ In comparison, the 20 publicly owned utilities for which data are available (representing 89 percent of statewide publicly owned utility load) will have to increase their supply of publicly owned utility-qualifying resources by 20.5 percent of retail sales (on an average, load-weighted basis) to meet their ultimate targets.²²⁸ The publicly

owned utility targets vary in target year and target percentage. Although large publicly owned utilities, including LADWP, Imperial Irrigation District, and Palo Alto, have set ultimate goals of 35, 30, and 33 percent by 2020 or earlier, respectively, most publicly owned utilities have not yet set 2020 goals comparable to those of the investor-owned utilities (Table 4-5).

Given publicly owned utilities’ widely varying compliance dates, however, it is also useful to compare the stringency of their goals relative to the investor-owned utilities’ compliance dates in terms of average annual procurement needs, starting from 2003 levels. To meet their 20 percent target by 2010, the state’s investor-owned utilities must 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 2020.²²⁹ In comparison, the 20 publicly owned utilities for which data are available (representing 89 percent of statewide publicly owned utility 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 publicly owned utilities began with lower levels

227 Ibid.

228 These 20 utilities consist of all those listed in Table 4-5 with available data on both RPS targets and publicly owned utility-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.

229 KEMA, Inc., *Publicly Owned Electric Utilities and the California Renewables Portfolio Standard: A Summary of Data Collection Activities*, prepared for California Energy Commission, November 2005, CEC-300-2005-023.

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 Time Frame
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
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
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: POU indicates publicly owned utility; 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.

of renewables, they must continue to add renewable resources at a much faster average rate than the investor-owned utilities in order to fulfill their proportional share of the overall state target.

Publicly Owned Utility Progress in Increasing Renewable Energy Deliveries

Since enactment of the state's RPS, progress by publicly owned utilities toward achieving their individual RPS goals has been uneven, but increases in renewable energy deliveries are apparent. Reasonably reliable data on deliveries by specific, Energy Commission-eligible resources in both 2003 and 2006 are available for 21 publicly owned utilities, representing 89 percent of total publicly owned utility retail sales. Among these utilities, deliveries of specific, Energy Commission-eligible resources increased by 3 percent of retail sales between these years on a load-weighted average basis.²³⁰

Among these 21 publicly owned utilities, deliveries of specific, Energy Commission-eligible resources declined from 2003 to 2006 for 7 utilities that represent 9 percent of total publicly owned utility retail sales. However, at least 14 publicly owned utilities, representing 80 percent of statewide publicly owned utility retail sales, saw an increase in deliveries from Energy Commission-eligible resources over this time frame equivalent to 3.5 percent increase per year. The following five utilities saw the largest percentage increases:

- Palo Alto increased its Energy Commission-eligible renewable percentage from 2.4 to 10.4 percent, primarily as a result of two new wind contracts (High Winds and Shiloh).
- Modesto increased its Energy Commission-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 Energy Commission-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 (East Bay Municipal Utility District) resources and by expanding its own wind project (Montezuma Hills).

- Anaheim increased its Energy Commission-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 Energy Commission-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 publicly owned utility, increased its Energy Commission-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 Energy Commission-eligible renewable deliveries between 2003 and 2006 among the 21 publicly owned utilities for which data exist can be compared to progress made by the three large investor-owned utilities 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 investor-owned utilities that will be used in the 2006 RPS verification report.²³¹

- 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 investor-owned utilities have decreased Energy

²³⁰ These 21 utilities consist of all those listed in Table 4-5 with available data on Energy Commission-eligible deliveries in both 2003 and 2006.

²³¹ Investor-owned utility 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 year's retail sales. California Energy Commission, *Renewables Portfolio Standard 2005 Procurement Verification Report*, August 2007, CEC-300-2007-001-CME, and *Renewables Portfolio Standard 2004 Procurement Verification Report*, February 2006, CEC-300-2006-002-CME.

Table 4-6: New Renewable Projects On Line (Publicly Owned Utilities)

Project	Technology	Capacity Under Contract to CA POU's (MW)	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.

Commission-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 publicly owned utilities for which data are available. Thus, clearly the publicly owned utilities were more successful than investor-owned utilities from 2003 to 2006 in increasing Energy Commission-eligible renewable energy deliveries.

Publicly Owned Utility Contracts and Solicitations

Since the beginning of 2003, publicly owned utilities have contracted for approximately 1,600 megawatts of renewable electricity capacity, 1,300 megawatts of which are from new resources that began, or are expected to begin, operation after passage of the state's RPS law in 2002. The 1,300 megawatts include approximately 900 megawatts of wind, 200 megawatts of geothermal, and 200 megawatts of biomass (including 100 megawatts of municipal solid waste to be developed by LADWP).

As of July 2007, more than 550 megawatts of the contracted new capacity was on line and delivering energy to the California publicly owned utilities, while only 324 megawatts of new, repowered, or re-started RPS capacity contracted by the investor-owned utilities were on line

as of early August.²³² New publicly owned utility wind projects make up almost all of this capacity, with the two largest projects located outside California (Table 4-6).

Approximately 700 megawatts of new renewables projects are under contract (or in development) but not yet on line. 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 megawatts), LADWP (185 megawatts), and Pasadena (5 megawatts)
- Four municipal solid waste projects, totaling 100 megawatts that LADWP has announced plans to develop
- A 25-megawatt landfill gas project in Brea under contract with Anaheim Public Utilities
- A 25-megawatt 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 publicly owned utilities are seeking additional renewable energy deliveries (Table 4-7). New

²³² See the Energy Commission database of renewable energy contracts signed by the investor-owned utilities under the state's RPS, at <www.energy.ca.gov/portfolio/contracts_database.html>.

Table 4-7: Renewable Solicitations Issued by Publicly Owned Utilities 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

Note: *Some of the Requests for Proposals do not explicitly identify Energy Commission-eligible as a requirement, but define eligible technologies to be largely consistent with Energy Commission rules. There are some modest exceptions. **Southern California Public Power Authority's (SCPPA) Requests for Proposals do not reference Energy Commission eligibility, but indicate "any certifiable renewable energy." Many of the solicitations provide greater delivery flexibility or even allow renewable energy credits.

Source: Press releases and solicitations issued by utilities, posted on utility websites.

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 publicly owned utilities' renewable deliveries in future years.

Assuming that all contracts come to fruition, the 1,300 megawatts of new renewable sources currently under contract to the publicly owned utilities are expected to meet 11 percent of 2003 publicly owned utility load. This compares to roughly 4,640 to 6,330 megawatts of new renewable energy contracts signed by the state's investor-owned utilities as of July 2007, equivalent to 10 to 13.5 percent of aggregate investor-owned utility load in 2003. In other words, while publicly owned utility progress in bringing new renewable energy projects on line has so far exceeded the progress made by the state's major investor-owned utilities, 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 electric service providers and California's small

and multi-jurisdictional utilities 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.
- Be 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 electric service providers also apply to small and multi-jurisdictional utilities. Following on the CPUC's decisions bringing all retail sellers into the RPS, the Energy Commission's RPS Guidebook requires electric service providers, community choice aggregates, and small and multi-jurisdictional utilities to report their RPS procurement for 2005 and 2006.

To date, 10 of 15 electric service providers have either provided required reports or provided a partial response to the Energy Commission. In addition, all but one of the five small and multi-jurisdictional utilities have responded. Therefore, the following discussion of electric service provider and small and multi-jurisdictional utility progress is based on incomplete, unverified data. This preliminary

data includes most of the total load served by electric service providers and small and multi-jurisdictional utilities.

The 2006 IEPR Update reported that electric service providers as a group served only about 0.25 percent of their retail sales from renewable sources immediately prior to 2006. In 2006, electric service providers as a group increased their renewable energy to 2 percent of retail sales. Of the six electric service providers 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 (Table 4-8). After a late start, electric service providers have a long way to go to meet the 2010 goals.

Two of California's five small and multi-jurisdictional utilities are large utilities that serve bordering states as well as California, while three small and multi-jurisdictional utilities are very small. Sierra Pacific Power, based in Nevada, reports procuring 31.8 gigawatt hours of renewable electricity in 2006 for its California load, or 5.9 percent of retail sales. PacificCorp reports 29.4 gigawatt hours 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.

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.

Additional Barriers to Renewable Energy Market Development

In addition to the issues already discussed, two more 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

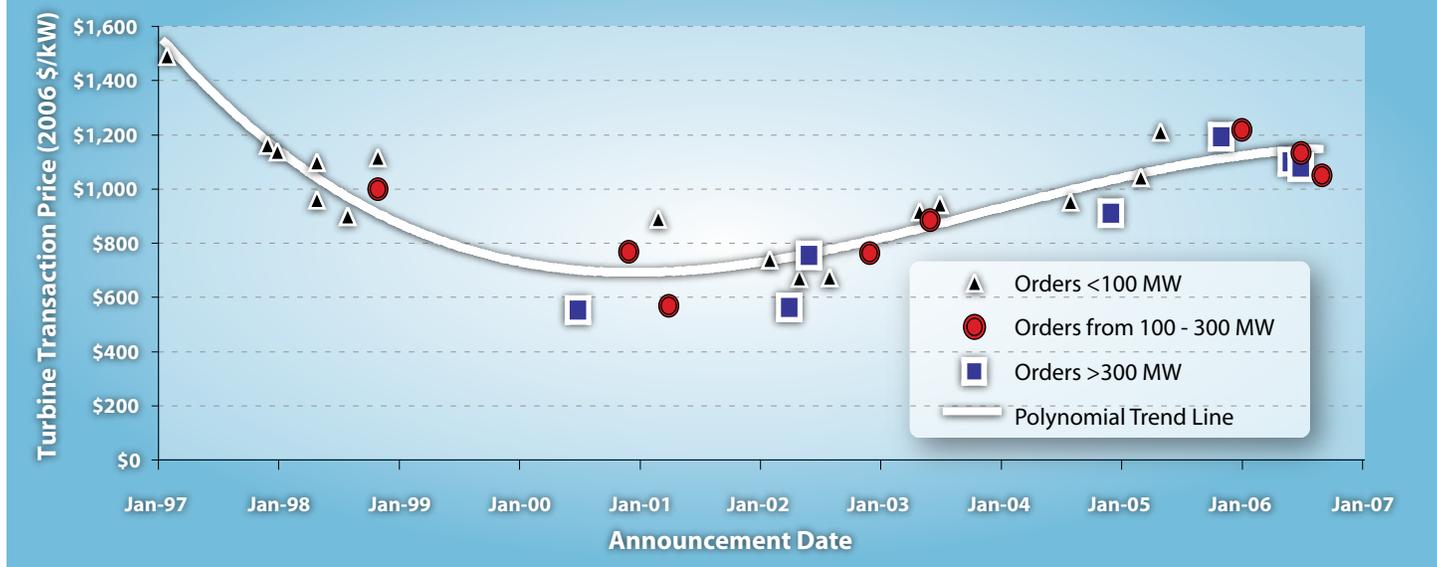
Global demand for wind turbines has increased dramatically in recent years, with annual installations growing from 6,800 megawatts in 2001 to more than 15,000 megawatts in 2006. With this rapid growth, demand for wind turbines has exceeded supply, and manufacturers of turbines and turbine components 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. Therefore, 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 per kilowatt between 2002 and 2006 (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 upscaling of turbine size (and hub height) and sophistication, and shortages in certain turbine components.

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

Figure 4-7: Wind Turbine Transaction Prices in the U.S. Market



Source:Wiser and Bolinger, 2007.

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 been seen with investor-owned utility 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 greenhouse gas 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 megawatts of California’s oldest existing wind projects with 1,000 megawatts of new wind turbines could result in more than 1,000 gigawatt hours per year of incremental wind power production, equivalent

to about 350 megawatts of new (that is, greenfield²³³) 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 indicated economic tradeoffs facing owners of existing wind turbines when deciding whether or not to repower. These tradeoffs 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 a 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

233 Previously undeveloped land.

234 KEMA, Inc., *Scoping-Level Study of the Economics of Wind-Project Repowering Decisions in California*, consultant report in preparation for the California Energy Commission.

costs (that is, marginally profitable existing projects) may find it economically advantageous to repower under reasonable assumptions about the amount of revenue (that is, from power and renewable energy credit 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 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 must 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, 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 gigawatt hours per year (roughly consistent with the KEMA estimate mentioned above), stating that this amount “is helpful, but not significant that it warrants special attention.”²³⁵ In its calculations, SCE assumed that the total amount of installed capacity would remain unchanged, but did not explain what prevented expansion of the megawatts 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.²³⁶

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.”²³⁷ “[T]he most profitable application ... would be Greenfield development, rather than brownfield²³⁸ development.”²³⁹ 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.

235 Southern California Edison Company, March 19, 2007, 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, p. 2. <www.energy.ca.gov/2007_energypolicy/documents/2007-03-13_workshop/comments/>, accessed June 29, 2007.

236 Ibid.

237 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.

238 Previously developed land.

239 Pacific Gas and Electric Company, March 19, 2007, post-workshop comments, op.cit., p. 7.

California Wind Energy Association’s (CalWEA) 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.²⁴⁰

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.”²⁴¹ 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 *Integrated Energy Policy Reports*, the RPS program structure needs greater transparency, less complexity, and full valuation of the system benefits of renewable energy. The areas most in need of change include the least-cost, best-fit evaluation and the use of natural gas prices to calculate the market price referent.

240 California Wind Energy Association, March 14, 2007, comments of the California Wind Energy Association on Wind Repowering, <www.energy.ca.gov/2007_energy_policy/documents/2007-03-13_workshop/comments/CALIFORNIA_WIND_ENERGY_ASSOCIATION_2007-03-14.PDF>, accessed June 29, 2007.

241 Ibid.

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 Intermittent Analysis Project, 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 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 request for proposals. 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.²⁴²

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

242 Southern California Edison, July 30, 2007, Written Description of RPS Bid Evaluation and Selection Process and Criteria (“LCBF Written Report”), CPUC Rulemaking 06-05-027, p. 3.

risk. 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.²⁴³

Natural Gas Prices and Market Price Referent

The risk to ratepayers of continued reliance on natural gas is not shared by the investor-owned utilities since fuel costs are 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 market price referent has now included a carbon adder in the market price referent.²⁴⁴ The CPUC expects to consider in more detail carbon adders for future market price referents.

The CPUC calculates market price referent values for a baseload proxy plant for use in RPS solicitations. The method of determining market price referent values generally involves evaluating (discounting) all project costs at the weighted average cost of capital. Finance-based approaches reflect cost and market risk.

Starting with the November 17, 2006 draft CPUC inputs to the market price referent, Bates White, LLC calculated market price referent values using finance-oriented valuation

principles, based on the Capital Asset Pricing Model.²⁴⁵ This approach relies on specific risk-adjusted discount rates for each project cost stream, as opposed to discounting all costs at the weighted average cost of capital as is done by the CPUC.

In this analysis, the Capital Asset Pricing Model-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 weighted average cost of capital-based market price referent values with Capital Asset Pricing Model-based market price referent values. Despite this assumption, the Capital Asset Pricing Model suggests higher market price referent values than those used by the CPUC.

Table 4-9: Weighted Average Cost of Capital-Based 2006 Market Price Referent Values (Nominal – dollars per kilowatt hour)

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.”

243 California Energy Commission, July 2007, *Portfolio Analysis and its Potential Application to Utility Long-Term Planning*, <www.energy.ca.gov/2007publications/CEC-200-2007-012/CEC-200-2007-012-SEP.pdf>, p. 11.

244 CPUC Resolution E-4118 rev. September 24, 2007.

245 Bates White, LLC’s analysis is based upon CPUC’s market price referent spreadsheet dated on November 17, 2006 (“2006 MPR Model_Draft Resolution E 4049_Distrib_11_17_06.xls”). Thus, the reported weighted average cost of capital-based market price referent values is 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 Market Price Referent Values (Nominal – dollars per kilowatt hour)

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, LLC, August 2007.

Table 4-11: Difference Between Weighted Average Cost of Capital and Capital Asset Pricing Model-Based 2006 Market Price Referent Values (Nominal – dollars per kilowatt hour)

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, LLC, August 2007.

33 Percent by 2020 Is Feasible with Changes in Program Structure

Using renewable resources to provide 33 percent of retail sales 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 at least in the following areas:

- Planning and permitting processes must be strengthened and streamlined through programmatic environmental impact reports/environmental impact statements for renewable energy generation in coordination with state and federal transmission corridor planning.
- The transmission grid and distribution system must 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 market price referent 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, related to use of supplemental energy payments now repealed by SB 1036, should be seen as a hallmark of the start-up phase of the RPS program. To scale the program toward reaching the 33 percent goal, California must move to a new system, such as the expanded use of feed-in tariffs.

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 market price referent from the table of market price referents that are in effect on the date the contract is signed. However, in each solicitation year’s table, the market price referents vary by start year. The decision requires that the actual market price referent tariff paid be equal to the market price referent for the start year during which the facility becomes commercially operational. Since market price referents 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 if the commercially operational date is delayed. Because for most solicitation years the market price referent 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 megawatts of additional “renewable resources from customers other than water and wastewater.”²⁴⁶

In May 2007, SCE started offering a set of standard contracts priced at the 2006 market price referent for biogas and biomass generators as large as 20 megawatts. The 2006 market price referent 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.²⁴⁷ The contracts are available until December 31, 2007, up to a maximum of 250 megawatts.

This offer was prompted by the Governor’s executive order S-06-06, issued in April 2006, which encouraged investor-owned utilities to increase sustainable use of biomass and other renewable resources.²⁴⁸

There are three standard contracts, divided by project size and location as follows:

- Less than 1 megawatt of generating capacity in SCE’s service territory
- One megawatt to 5 megawatts in the California ISO Control Area
- Greater than 5 megawatts to 20 megawatts under the operational control of the California ISO²⁴⁹

²⁴⁶ 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, <www.cpuc.ca.gov/WORD_PDF/FINAL_DECISION/70660.PDF>, accessed August 6, 2007. Attachment A, Item 11, and Conclusion of Law 25.

²⁴⁷ California Public Utilities Commission, June 22, 2007, AB 1969 Workshop Documents (Summary Matrix on Standard Terms and Conditions, Pacificorp Comments, and 250-Megawatt Allocation), Rulemaking 06-05-027, <www.cpuc.ca.gov/EFILE/PD/69606.htm>, accessed June 28, 2007.

²⁴⁸ 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.

²⁴⁹ Southern California Edison Biomass Standard Contracts – Protocol, pp. 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 Megawatt Allocation), Rulemaking 06-05-027, <www.cpuc.ca.gov/EFILE/PD/69606.htm>, accessed June 28, 2007.

Encouraging Solar Generation

Currently, Californians with a photovoltaic system that generates electricity in excess of their own consumption, provide it to the utilities for free. Recent experience with California’s electrical system underscores a real need for reliable, zero emission electricity especially at peak usage times within the state’s load centers. The Energy Commission believes that excess solar generation delivered to the grid should be compensated through a feed-in tariff. The price paid for each kilowatt hour delivered to the grid should be based on the RPS market price referent that includes a time-of-delivery adjustment. The Energy Commission and the California Public Utilities Commission should work together to establish an appropriate feed-in tariff for excess solar electricity.

SCE set the cutoff at 20 megawatts 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 market price referent, 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 cutoff could be for systems as large as 20 megawatts, 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.

Although the AB 1969 tariffs are not differentiated by technology type as are most feed-in tariffs, because they offer prices differentiated by time of delivery, they effectively result in different prices for different technologies due to differences in typical renewable generation profiles. For example, solar generation would be paid a higher average price per kilowatt hour because deliveries generally coincide with peak times of delivery. SCE’s tariff pays 3.28 times the base market price referent for deliveries during the summer peak time of delivery period. In contrast, unless wind generation was able to supply electricity during a significant part of peak and shoulder periods, with little energy delivered at night and on weekends, the average price paid for wind would be less than the base market price referent.

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 account for technology-specific market conditions. Rickerson and Grace²⁵⁰ 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.”

In many cases, feed-in tariffs in Europe and Canada are below California’s 2007 market price referents for selected technologies. Considering 19 European countries, Ontario, and pending feed-in tariff legislation in Michigan, feed-in tariffs for facilities with high quality wind resources range from \$0.062 to \$0.128 per kilowatt hour, with an average tariff of \$0.097 per kilowatt hour. In contrast, the 2007 market price referent ranges from \$0.09572 for 20 year contracts with facilities that begin commercial operations in 2008, to a levelized value of \$0.11954 per kilowatt hour if operations start in 2020. Feed-in tariffs range from \$0.045 to \$0.251 for solid biomass and from 0.036 to \$0.251 for biogas-fired generation. Six European countries have feed-in tariffs for geothermal generation below \$0.09 per kilowatt hour.²⁵¹

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.²⁵²

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.²⁵³

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.²⁵⁴ 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 request for offer 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 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

250 Wilson Rickerson and Robert C. Grace, February 2007, *The Debate over Fixed Price Incentives for Renewable Electricity in Europe and the United States*, <www.boell.org/docs/Rickerson_Grace_FINAL.pdf>, p. 7.

251 European feed-in tariff data is from Klein, A., A. Held, M. Ragwitz, G. Resch, and T. Faber, 2006, *Evaluation of Different Feed-In Tariff Design Options*, Best Practice paper for the International Feed-in Cooperation, available at <www.feed-in-cooperation.org/images/files/best_practice_paper_final.pdf>, and Mendonca, Miguel, *Feed-In Tariffs: Accelerating the Deployment of Renewable Energy*, World Future Council, London, 2007. Data for Ontario is from contract pricing as per OPA Renewable Energy Standard Offer Program Rules, version 2.0 at <www.powerauthority.on.ca/SOP/Storage/32/2804_RESOP_Program_Rules_Version_2.0.pdf>. For Michigan proposed legislation House Bill 5218, see <[www.legislature.mi.gov/\(S\(1jy314qsbq5nqqaohqvl0bva\)\)/mileg.aspx?page=getObject&objectName=2007-HB-5218](http://www.legislature.mi.gov/(S(1jy314qsbq5nqqaohqvl0bva))/mileg.aspx?page=getObject&objectName=2007-HB-5218)>. European and Canadian feed-in tariffs have been converted to dollars per kilowatt hour using the exchange rate of 1.1842 dollars per Euro as of January 1, 2006, to coincide with the same date used by Klein, et al. to convert European national currencies to Euros.

252 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. <www.bmu.de/files/pdfs/allgemein/application/pdf/erfahrungsbericht_eeg.pdf>, p. 4.

253 Commission of the European Communities, July 12, 2005, communication from the Commission: The support of electricity from renewable energy sources, Com(2005) 627 final, <ec.europa.eu/energy/res/biomass_action_plan/doc/2005_12_07_comm_biomass_electricity_en.pdf>

254 Presentation by Hans Cleijne at the May 21, 2007 Integrated Energy Policy Report Workshop, <www.energy.ca.gov/2007_energy_policy/documents/2007-05-21_workshop/presentations/Hans%20Cleijne-European%20feed-in%20tariffs%20without%20RPS.pdf>, slide 11.

the importance of peaking power to California. AES suggested a demonstration/transitional feed-in tariff for the 2008–2010 time frame before moving to large-scale use of feed-in tariffs.

PG&E's comments on the Energy Commission's October 15th and 16th IEPR hearings, supported the CPUC's decision to adopt 1.5 megawatts as the facility size under the AB 1969 tariffs, although the law had required a 1-megawatt cap with the larger size as an option. PG&E believes that "there may be a rationale for creating a feed-in tariff for units larger than 1.5 MW"²⁵⁵ and suggests that 20 megawatts may be too high and 5- or 10- megawatt facility size caps should be examined. Furthermore, "Although PG&E does not agree that a feed-in tariff for large generators will significantly affect renewable generation, PG&E agrees that . . . if feed in tariffs are to succeed, . . . the costs must be fairly distributed."²⁵⁶

In contrast, the Union of Concerned Scientists agrees that feed-in tariffs should be offered for RPS-eligible facilities less than 20 megawatts, but that "the MPR may not be the appropriate price for such a tariff."²⁵⁷ The Union of Concerned Scientists also recommends that the Energy Commission provide a white paper "analyzing the potential advantages and drawbacks of adopting feed-in tariffs" in California.²⁵⁸

The Natural Resources Defense Council recommended that "the IEPR include additional specific recommendations for how to . . . promote the use of biogas in California."²⁵⁹ In March 2007, the Energy Commission adopted revisions to the *Renewables Portfolios Standard Eligibility Guidebook* to

255 Pacific Gas and Electric, post-workshop comments, October 15–16, 2007, Integrated Energy Policy Report Committee hearings on the Committee draft *Integrated Energy Policy Report*, <www.energy.ca.gov/2007_energypolicy/documents/2007-10-15-hearing/committee_report_public_comments/Guliasi_Les_Pacific_Gas_and_Electric_2007-10-19_TN-42932.pdf>

256 Ibid.

257 Union of Concerned Scientists, post-workshop comments, October 15–16, 2007, Integrated Energy Policy Report Committee hearings on the Committee draft *Integrated Energy Policy Report*, <www.energy.ca.gov/2007_energypolicy/documents/2007-10-15_hearing/committee_report_public_comments/Chen_Cliff_Owen_Dai_The%20Union%20of%20Concerned%20Scientist_2007-10-19_TN-42941.pdf>.

258 Ibid.

259 Natural Resources Defense Council, post-workshop comments, October 15–16, 2007, Integrated Energy Policy Report Committee hearings on the Committee draft *Integrated Energy Policy Report*, <www.energy.ca.gov/2007_energypolicy/documents/2007-10-15_hearing/committee_report_public_comments/Natural_Resources_Defense_Council_2007-10-19_TN-42942.pdf>.

clarify how electricity generated from pipeline-quality biogas injected into the pipeline system can be eligible for the RPS.

In their comments on the committee draft *IEPR*, the three large investor-owned utilities recommended continued use of the current request for offers process for large renewable projects, arguing that the current solicitation process will result in lowest costs. However, the use of the market price referent, which has increased each year, may tend to set a floor price above the cost at which some renewable technologies can be profitably developed. The fact that several European countries that have rapidly and successfully increased wind generation have done so with feed-in tariffs below the market price referent indicates that wind generation, at least in Europe, may be less expensive than in California under the current market price referent solicitation process.²⁶⁰ Although a particular year's market price referent is not made public by the CPUC until after that year's solicitation is closed, the methodology is publicly available, and it is not difficult to estimate an upcoming market price referent.

In considering how to develop small- and large-scale feed-in tariffs, state agencies should design them to complement the state's plans to coordinate generation and transmission planning, through programmatic environmental impact reports/environmental impact statements, transmission corridor designation, and other measures discussed in the *2007 Strategic Transmission Investment Plan*.²⁶¹

To build the infrastructure needed to achieve the state's renewable energy goals, California utilities are building transmission lines to areas with large amounts of renewable energy potential. To make the most of this investment, the state needs to encourage development of renewable energy in these areas while safeguarding against the possible exercise of market power by renewable energy developers.

260 See Table 5.1, page 54 in Mendonca, Miguel, *Feed-In Tariffs: Accelerating the Deployment of Renewable Energy*, World Future Council, London, 2007. Developers and utility staff have speculated that the market price referent may set a price floor above the cost of profitably developing wind generation in California.

261 California Energy Commission, CEC-700-2007-018, November 2007.

Other Financing Assistance Options to Promote RPS Goals

As California's gateway to the capital markets, the State Treasurer's office should aggressively pursue all financial products that reduce the cost of capital for renewable energy projects in order to combat climate change. This office should work with Congress to help create a new renewable energy category for private activity bonds and help scale up the financing capability of clean renewable energy bonds. The State Treasurer should lead the way in expanding renewable energy development through both the California Pollution Control Financing Authority and the California Alternative Energy and Advanced Transportation Financing Authority.

FEDERAL ACTION:

Private Activity Bonds: Add new category for renewable energy projects. Municipal bonds provide tax-exempt financing for governmental and qualified purposes such as the construction of airports, hospitals, industrial development, certain waste and recycling activities, and 26 other designated public purposes. To extend this low cost of capital to renewable energy projects, the U.S. Internal Revenue Code should be amended to add a new category for renewable energy. This proposed legislation has no federal budget impact since each state is allocated a specified amount of bond financing authority each year based on population. In 2007, the State of California received a little over \$3 billion in bonding capacity for private activities, of which \$440 million was allocated by the state for solid waste and recycling projects.

Renewable Energy Bonds: Create special volume cap for renewable energy projects. Create special volume cap for tax-exempt bonds to finance renewable energy projects under the U.S. Internal Revenue Code. In addition to the Private Activity Bonds above, federal legislation created an additional \$ 15 billion special volume cap for tax-exempt bonds dedicated to highway and freight transfer facilities. Senators Salazar and Smith through S. 672 have similar legislation that would expand tax-exempt bond categories for renewable projects 40 megawatts or less. These projects would be exempt from the state volume caps for private activity bonds.

STATE ACTION:

California Alternative Energy and Advanced Transportation Financing Authority (CAEATFA): Issue tax-exempt bonds for renewable energy projects. If the federal tax code is amended to include a new category for renewable energy projects under private activity bond authority, then CAEATFA could issue tax-exempt bonds for renewable energy projects. CAEATFA finances facilities that use new energy sources and technologies and finances development of advanced transportation technologies. CAEATFA is also authorized to own all or part of a project and can lease the property back to the developer. This technique can be used to exempt projects from state sales taxes.

Clean Renewable Energy Bonds (CREBs): Package renewable energy projects through the California Pollution Control Financing Authority (CPCFA). CREBs are a new form of tax credit bond in which interest on the bonds is paid in the form of federal tax credits by the U.S. government. This allows borrowing at a zero percent interest rate. This would be an effective financing mechanism for renewable energy projects owned by municipal utilities or installed on government facilities. The total 2007 nationwide volume cap allocation was \$1.2 billion. Issuers must apply to the Internal Revenue Service for an allocation for each location. The IRS currently allocates the volume cap based on the "smallest to largest" criteria. For 2007, CREBs allocations ranged from \$23,000 to \$3.1 million. Larger CREBs allocations are anticipated in pending federal legislation, which also removes the "smallest to largest" allocation requirement.

LOCAL GOVERNMENT ACTION:

City of Berkeley: Finance solar installations through property taxes. The city is considering a plan to finance solar installations for property owners with low-interest revenue bonds backed by a 20-year property assessment. At current investor-owned utility tiered rates, the annual savings in utility bills is greater than the annual assessment for systems sized to save only the top tiers. The goal is to install solar on 25percent of the residences and reduce the city's greenhouse gas footprint by 2,000 tons per year.

A competitive request for offers does not protect the ratepayers against the risk of collusion by energy generators to ratchet up the price bid for RPS contracts in renewable resource zones with new infrastructure investment. Nor does it provide a transparent process for developers to easily know and anticipate what price they will receive for their energy. A technology-specific feed-in tariff can accomplish both of these goals and pay a price that reflects the value of the energy product provided by the renewable energy generator.

To fully examine the impacts of a renewable feed-in tariff in California, the Energy Commission, in collaboration with the CPUC, should develop a white paper investigating the use of feed-in tariffs, to be completed in 2008. In the white paper, the Energy Commission and CPUC should consider a range of mechanisms for determining the appropriate price to pay for renewable energy in designated renewable resource zones, including the following:

- The RPS market price referent including the recently approved greenhouse gas adder
- A technology-specific cost of generation plus a reasonable return on investment
- The median price awarded in the all-source long-term procurement competitive request for offers plus a premium
- The median price awarded to all RPS contracts through 2010

Outside the designated renewable resource zones, there is greater competition among renewable energy developers, producing a lower risk of market power collusion in competitive requests for offers. This might suggest less urgency for adoption of a feed-in tariff outside the areas of targeted new transmission infrastructure if the state were on track toward achieving its RPS and 33 percent by 2020 goals. Although the Committee would like to see all of the signed contracts for renewable energy come to fruition, the historical record to date indicates this is not likely to be the case. An expanded use of feed-in tariffs can stimulate the robust pace of renewable energy development needed to achieve 33 percent renewables by 2020.

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.²⁶²

Recommendations

To address the barriers to renewable development in the context of the state's greenhouse gas emission targets and the need to manage cost and risk to ratepayers for electricity, the Energy Commission makes the following recommendations:

- The Energy Commission should leverage its power plant licensing and transmission corridor designation authority, its environmental expertise, and its transmission planning and policy experience to help guide renewable resource development in California.
- The Energy Commission should establish a more cohesive statewide approach for renewable development that identifies preferred renewable generation and transmission projects in a "road map" for renewables.
- The CPUC should immediately implement a feed-in tariff, set initially at the market price referent, for all RPS-eligible renewables up to 20 megawatts in size.
- The Energy Commission should begin a collaborative process with the CPUC to develop feed-in tariffs for larger projects. Such tariffs should incorporate the value of a diverse mix of renewables as well as features of the most successful European feed-in tariffs.
- The CPUC should update how the market price referent is calculated to more fully reflect the risk of gas price volatility; the market costs of long-term, fixed-price power; and appropriate greenhouse gas adders.

²⁶² Rickerson, Wilson and Robert C. Grace, February 2007, *The Debate over Fixed Price Incentives for Renewable Electricity in Europe and the United States*, <www.boell.org/docs/Rickerson_Grace_FINAL.pdf>, p. 13.

- Greenhouse gas reductions from the RPS should be quantified and taken out of any allowance system for cap-and-trade purposes to avoid excess supply of tradable greenhouse gas emission reduction credits.
- Existing wind sites should be repowered and expanded to increase the efficient use of existing infrastructure and reduce environmental impacts.
- The Energy Commission and the CPUC should work together to establish an appropriate feed-in tariff for excess generation from customer-owned solar installations based upon the RPS market price referent and time-of-delivery adjustment.

Chapter 5



California's Electric Distribution System

"Never tell people how to do things. Tell them what to do and they will surprise you with their ingenuity."

George S. Patton

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 deliver 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 of these new resources.

Ideally, the 21st century distribution grid should allow grid operators to detect and respond to problems quickly by being able to 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 5 to 10 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.

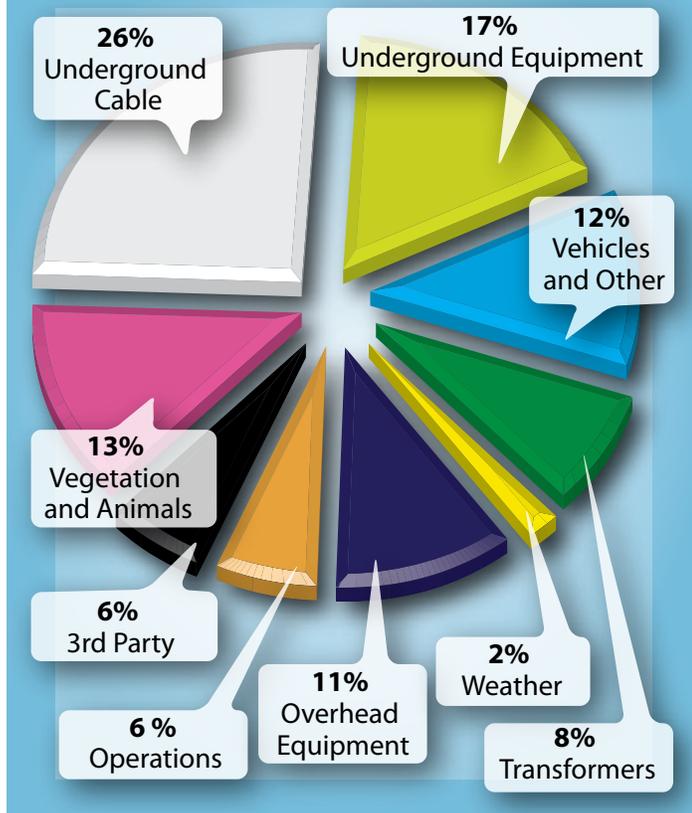
This chapter discusses the challenges facing California's distribution system along with the barriers to integrating distributed resources into that system.

Existing Distribution Infrastructure in California

Each utility service territory is physically distinct 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, Pacific Gas and 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.²⁶³

263 <www.pgecorp.com/corp_responsibility/reports/2006/company_overview.html>.

Figure 5-1: Distribution Failures

Source: California Energy Commission.

Serving 12 million people, Southern California Edison (SCE) provides electric service to central, coastal, and southern California, including larger urban population centers.²⁶⁴ San Diego Gas and Electric (SDG&E) is the smallest of the three large investor-owned utilities, 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.²⁶⁵ One of the biggest challenges each of these utilities face when planning for the future is unprecedented load growth in the hot inland areas of their service territories.

About 90 percent of all customer interruptions and outages — both within California and throughout the U.S. — are caused by distribution problems or “events” (Figure 5-1). In four days in early September of 2007, an unprecedented

645,000 SCE customers suffered distribution-caused outages. Some of these events 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.

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.

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 issues and challenges facing California’s electricity distribution system.²⁶⁶ 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.

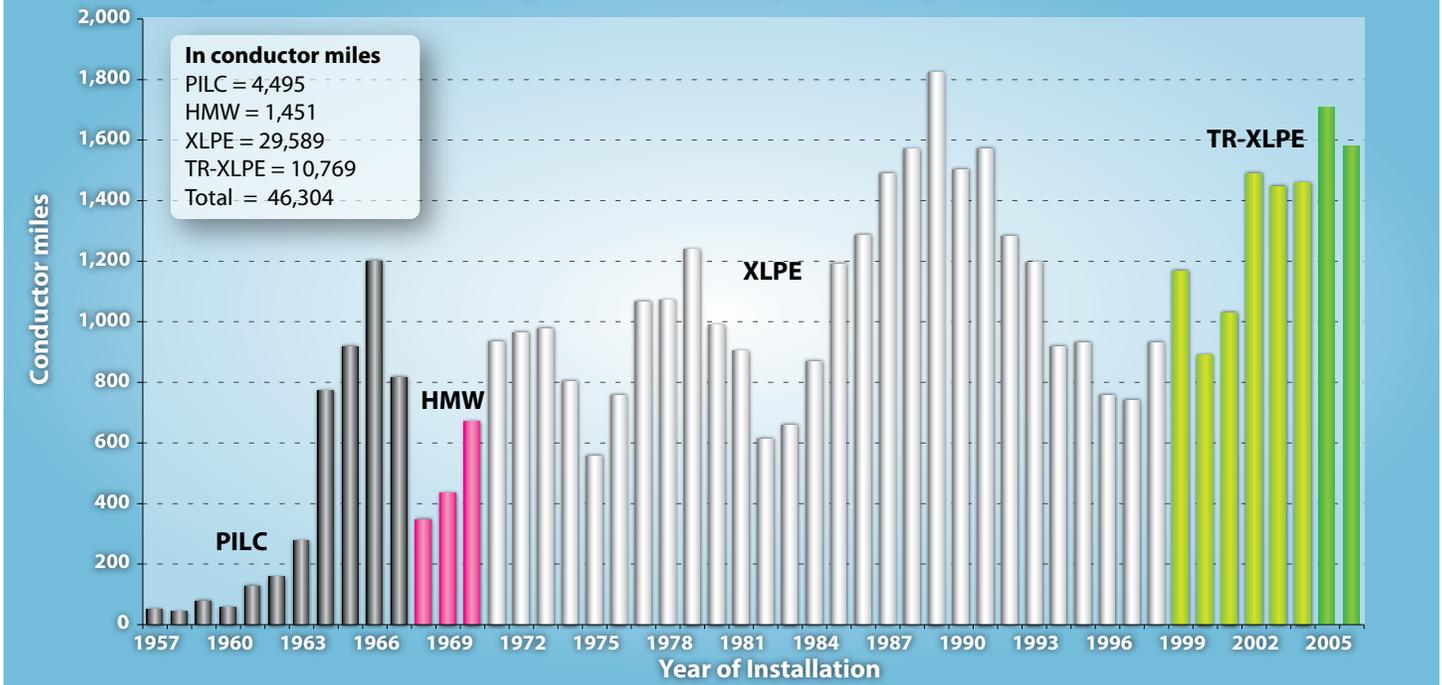
Throughout the 1970s and 1980s, SCE installed increasing amounts of underground cable, much of which is approaching the end of its design life (Figure 5-2). It will therefore have to be replaced in the near future to avoid failures. Depending on the amount and age of underground cable in their service territories,

264 <www.sce.com/AboutSCE/CompanyOverview/territorymap.htm>.

265 <www.sdge.com/aboutus>.

266 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



Note: 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.

Source: Southern California Edison.

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.

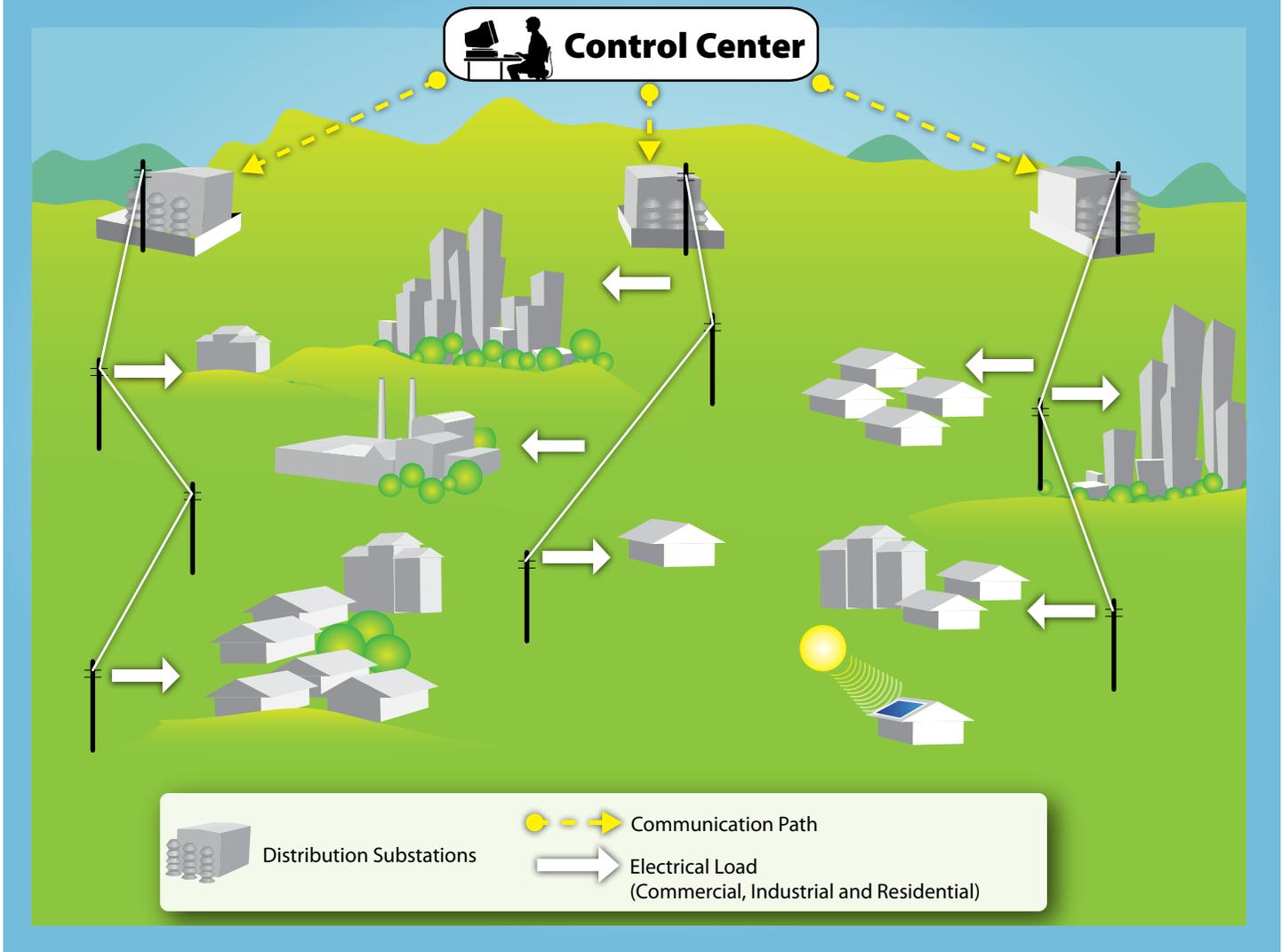
At the May 10 workshop, PG&E acknowledged that with 26,000 miles of underground cable and current replacement efforts at 70 miles per year, their efforts are equivalent to a 371-year replacement cycle.

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 it based on

age. At the workshop, PG&E indicated that its average cost to replace one foot of underground cable is \$120. By determining what cables actually have 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.

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 assure that power is reliably delivered from distant central station power plants. Public policy should 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.

Figure 5-3: Typical Distribution System



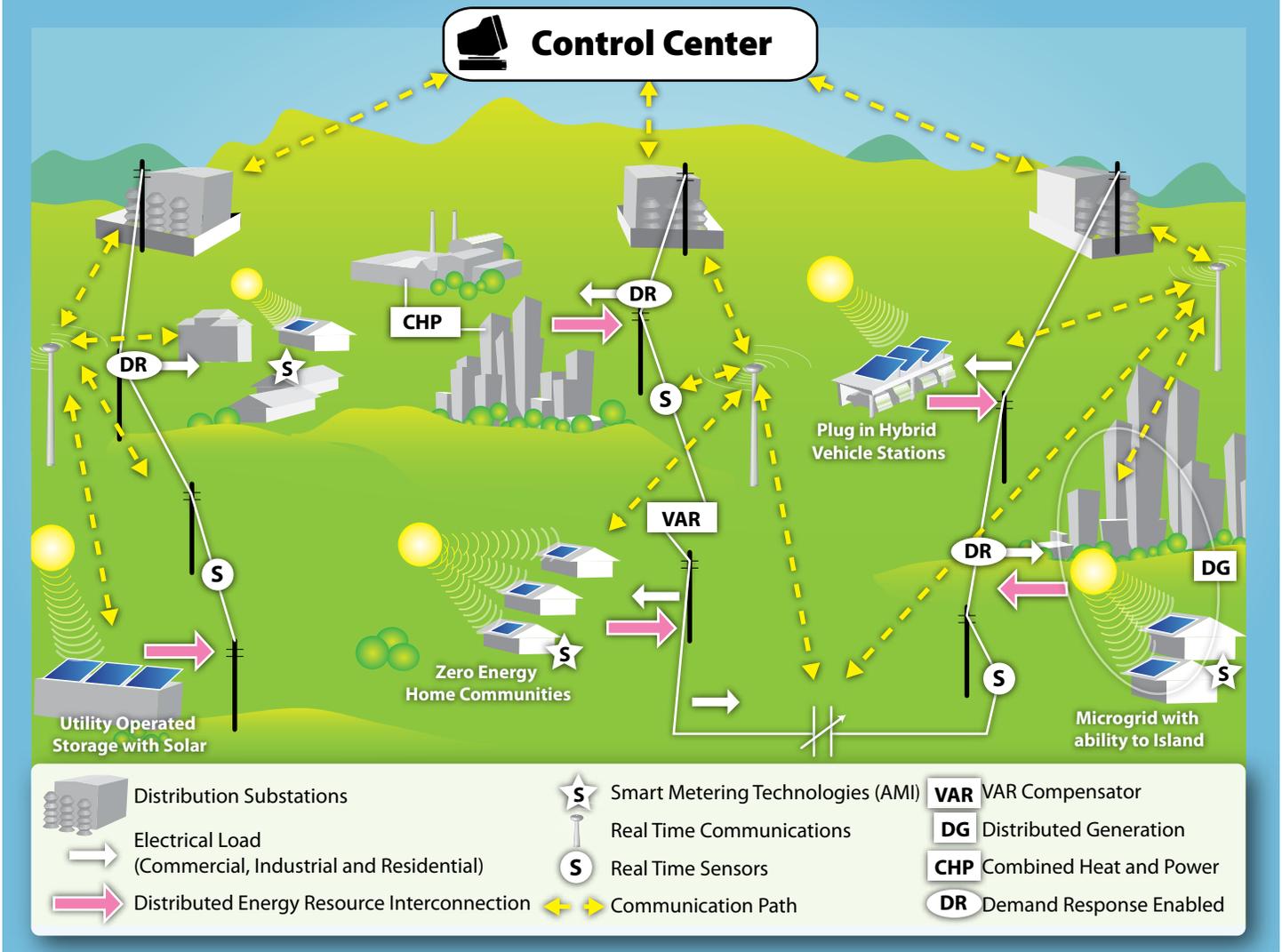
Source: California Energy Commission.

Another issue that SDG&E highlighted in the workshop 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

Figure 5-4: 21st Century Distribution System



Source: California Energy Commission.

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 remain for 20 to 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 the state must understand what it is investing in and whether these investments will result in a distribution system that will serve customers in the future. 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 generation²⁶⁷ resources such as solar, combined heat and power,²⁶⁸ 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 toward 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).

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, will give distribution grid operators the ability to detect and respond to problems quickly and safely. Being able to 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).

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.

- **Generation and Transmission 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.

²⁶⁷ Any small-scale electric generation that is located at or near the point of end use. It may be owned and operated by a customer, a utility, or a non-utility company.

²⁶⁸ Combined heat and power is the simultaneous production of electricity and heat from a single fuel source such as natural gas, biomass, biogas, coal, waste heat, or oil.

- **Integrated Distributed Energy Resources:** Integrating and leveraging resources, such as photovoltaics, combined heat and power, and energy storage, is a critical challenge for California 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 support 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 investor-owned utilities, a large out-of-state utility, Department of Energy, 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 that 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*,²⁶⁹ 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 Distribution Automation*,²⁷⁰ 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 Distribution Research Program 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),

²⁶⁹ 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.

²⁷⁰ California Energy Commission, *The Value of Distribution Automation*, PIER Final Project Report, Prepared by: Navigant Consulting, Inc., September 2007, CEC- 500-2007-103.

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 photovoltaic. By understanding how various ADA functions benefit stakeholders, Distribution Research Program managers can make strategic decisions to support research and development 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 and can operate in parallel

with the grid or in an intentional island mode. The Energy Commission's PIER Program and the Department of Energy 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 delivery 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 to develop a methodology using Optimal Technology's AEMPFASST 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. The Department of Energy 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 (for example, 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 and combined heat and power are valuable resource options for California. The Energy Commission has proposed policies to encourage development of distributed generation resources, including combined heat and power 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 distributed generation development.

Despite these efforts, significant issues facing distributed generation and combined heat and power 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 [distributed generation] stakeholders.²⁷¹

Both the 2003 and 2005 *Integrated Energy Policy Reports* recognized that focused policy direction would be needed for successful long-term deployment of distributed generation and combined heat and power. The 2003 *IEPR* recommended that California “Create a transparent electricity distribution system planning process that addresses the benefits of distributed generation.”²⁷² As part of the 2005 *IEPR* process, the Energy Commission assessed California’s combined heat and power market.²⁷³ In that assessment, potential project developers indicated the policy options most likely to increase the likelihood of a combined heat and power 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
- Allowing CHP owners to sell excess power to the grid²⁷⁴

Opening the wholesale market for combined heat and power projects was seen as the most important policy change for increasing the penetration of combined heat and power and for increasing societal benefits.²⁷⁵ By allowing large combined heat and power projects to find customers for their excess generation and to export power at wholesale prices, more than 2,400 megawatts of combined heat and power 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 encourage investor-owned utilities to support rather than oppose combined heat and power development.²⁷⁶ Developers felt that combined heat and power 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, and other states, the Energy Commission investigated the possibility of utility ownership of distributed generation facilities, particularly combined heat and power projects.²⁷⁷ The goal was to develop a pilot application testing alternative, “win-win” regulatory treatment of distributed generation projects. However, utilities showed no interest in owning non-renewable projects. This result is consistent with findings of a 2007 Department of Energy study²⁷⁸ that 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, distributed generation and combined heat and

271 California Energy Commission, *Distributed Generation Strategic Plan*, June 2002, CEC-700-02-002, p. 16.

272 California Energy Commission, *2003 Integrated Energy Policy Report*, December 2003, CEC-100-03-019, p. 16.

273 California Energy Commission, *An Assessment of California CHP Market and Policy Options for Increased Penetration*, 2005, CEC-500-2005-173.

274 *Ibid.*, p. XIII.

275 *Ibid.*, pp. 4–25.

276 *Ibid.*, pp. 3–21.

277 California Energy Commission contract number 500-02-014, WA #121.

278 U. S. Department of Energy, *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*, February 2007.

power in California continue to face major barriers to market entry in the context of traditional utility cost-of-service grid management.²⁷⁹ The 2005 *IEPR* reiterated that California must improve access to wholesale energy markets and streamline utility long-term contracting processes so that combined heat and power 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 distributed generation and combined heat and power.

In October 2007, Governor Schwarzenegger approved Assembly Bill 1613 (Blakeslee, Chapter 713, Statutes of 2007), which allows the CPUC to require utilities to purchase excess electricity from combined heat and power systems sized at 20 megawatts or less. This legislation represents a step toward opening the wholesale market for smaller combined heat and power projects and providing those operators with a market for their excess generation. However, because the bill does not compel the CPUC to impose this requirement on the utilities, nor does it provide a date certain by which such a requirement would take effect, it stops far short of providing small combined heat and power operators with the guaranteed access to wholesale markets recommended in the 2005 *IEPR*.

AB 1613 also requires the CPUC to establish a “pay-as-you-save” pilot program. This program is intended to enable customers to finance the upfront costs for purchasing and installing a small (less than 20-megawatt) combined heat and power system. Customers would repay those costs over time through on-bill financing at the difference between what they would have paid for electricity and the actual savings for a period of up to 10 years. This program will be available until the statewide cumulative capacity from combined heat and power systems participating in the program reaches 100 megawatts statewide. Since the availability of financing was not identified by stakeholders as a major barrier to combined heat and power development, it is not clear how significant this provision will prove to be.

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 distributed generation and cogeneration policy. The roadmap includes a 2020 distributed generation 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 distributed generation resources in their systems, but there is a continuing gulf between the perceptions of the investor-owned utilities and those of distributed generation advocates regarding the risks and value of distributed generation projects to those systems.

Investor-owned utilities continue to show little interest in accepting energy from customer-owned distributed generation projects or in developing utility-owned distributed generation or combined heat and power 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, large-scale combined heat and power systems continue to run under the terms of generation contracts signed during the early 1980s. As these contracts expire, as much as 2,000 megawatts could shut down by 2010.²⁸⁰

On September 20, 2007, in D.07-09-040, the CPUC adopted policies and pricing mechanisms applicable to the electric utilities’ purchase of energy and capacity from qualifying facilities. Steps remain to implement this decision. In fact, on October 25, 2007, the three investor-owned utilities, Toward Utility Rate Normalization, and the CPUC’s Division of Ratepayer Advocates filed an Application for Rehearing of the decision. However, this decision appears to be a major step toward ensuring that these combined heat and power resources continue to serve California’s electricity system.

279 California Energy Commission, *2005 Integrated Energy Policy Report*, November 21, 2005, CEC-100-2005-007-CMF, p. 76.

280 California Energy Commission, *2005 Integrated Energy Policy Report*, CEC-100-2005-007-CMF, p. 77.

The importance of keeping this distributed generation capacity in the system is elevated by the state's need to reduce greenhouse gas emissions as part of AB 32. Combined heat and power in particular offers low greenhouse gas 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 combined heat and power units appear to offer the greatest fuel efficiency of available distributed generation technologies. Because combined heat and power systems are located close to the load, transmission and distribution line losses are minimized, further reducing greenhouse gas impacts.

As regulations for AB 32 compliance are finalized, the benefits of distributed generation and combined heat and power for the electricity system will become more quantifiable. This will reinforce the need to make distributed generation and combined heat and power projects a higher priority in utility resource mixes for both investor-owned utilities and publicly owned utilities.

Distributed generation 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"²⁸¹ capacity that must operate, even if uneconomically, to preserve system reliability. This change lowers the costs of California ISO services and allows more than one year contracts.

Under the reliability must run contracts, plants had to be larger than 1 megawatt to participate. With the local utility now responsible for this reliability hedge, smaller plants, such as distributed generation 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 distributed generation 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 qualifying facilities for a five-year period through April 30, 2012.²⁸² 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 qualifying facilities currently under contract with PG&E."²⁸³

In April 2007, the CPUC released a proposed decision that would provide for contract terms as long as 10 years for distributed generation projects that fit as qualifying facilities. Subsequently, the CPUC approved D.07-09-040, setting the stage to 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 non-bypassable charges for departing load related to distributed generation and combined heat and power projects. Comments filed during the Energy Commission's distributed generation workshop noted the uncertainty generated by CPUC-proposed, unquantified departing load charges to be assessed on distributed generation projects.²⁸⁴ While the option for longer term contracts reduces uncertainty for project developers, this future non-bypassable 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.

281 A reliability must run contract is one entered into by the independent system operator with a generator which operates a generating unit giving the independent system operator the right to call on the generator to generate energy and/or provide ancillary services from the generating unit as and when this is required to ensure the reliability of the independent system operator-controlled grid.

282 California Public Utilities Commission, *Opinion on Future Policy and Pricing for Qualifying Facilities*, D.06-07-032, Administrative Law Judge Halligan, April 24, 2007, p. 4.

283 Ibid.

284 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.

This use of non-bypassable charges chills the market for distributed generation and combined heat and power 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:

- Develop state policy that articulates and supports modernizing California’s distribution system.
- Establish a transparent distribution planning process that is integrated with other resource procurement processes, assuring 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 combined heat and power, distributed generation, energy storage, advanced metering infrastructure, and plug-in hybrid electric vehicles — is developed during the same time frame.
- 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.
- Fund distribution research through the PIER program to develop and demonstrate technologies that will accelerate the transformation of the distribution grid into an intelligent and sustainable network.
- Develop policies and research to provide open data architecture supporting interoperability from transmission to generation, distribution, and customers and their meters and appliances.
- Develop a new rate design that encourages consumers and utilities to invest in promising technologies and participate in programs that provide value to them and the state (premium power quality and critical-peak and real-time pricing).
- Base a portion of each utility’s profit on criteria related to performance, achieving 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.

- Require 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.
- Recover 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.

Distributed generation, especially combined heat and power applications, provides significant system and efficiency benefits to California’s distribution system. The Energy Commission 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 distributed generation and combined heat and power 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 charges for distributed generation and combined heat and power, regardless of size or interconnection voltage and standby reservation charges for distributed generation.
- 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 distributed generation portfolio standard, including combined heat and power regardless of size or interconnection voltage, for electric utility procurement plans. Alternatively, the utilities could be required to treat distributed generation and combined heat and power, regardless of size or interconnection voltage, like efficiency programs.

- The CPUC should adopt revenue-neutral programs that would enable high efficiency combined heat and power to more easily export power to interconnected utilities. These programs should not lead to additional non-bypassable charges and could include:
 - Providing the option for 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
- The CPUC and the Energy Commission should continue to work collaboratively to develop a methodology to estimate distributed generation costs and benefits.
- The state should adopt greenhouse gas measures and regulations that fully reflect the benefits of combined heat and power with separate production of thermal and electric energy.

Chapter 6



Meeting Natural Gas Needs

“A nation behaves well if it treats the natural resources as assets which it must turn over to the next generation increased, and not impaired, in value.”

Theodore Roosevelt

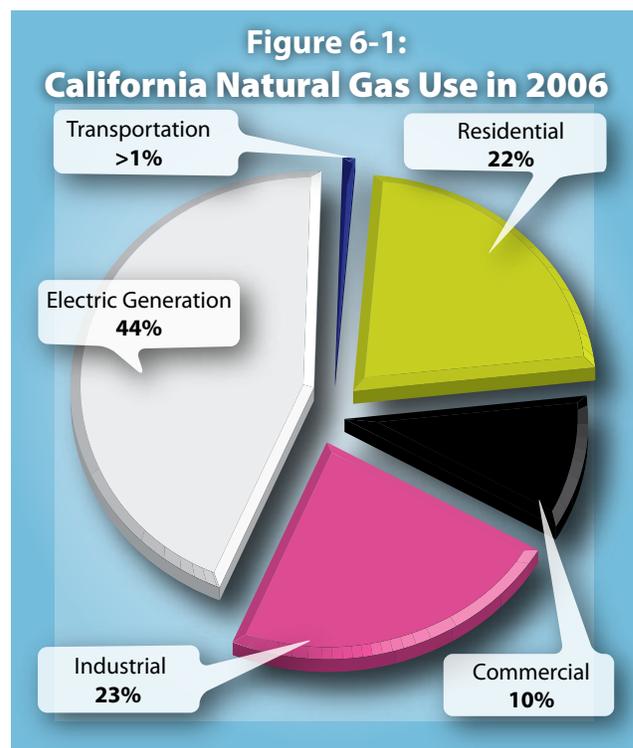
Almost 30 years ago, California’s serious air quality problems placed natural gas as the fuel of choice for electricity generation. In the late 1970s and early 1980s, for air quality and cost benefits, California moved away from petroleum to natural gas for generating electricity. Natural gas was cleaner burning, relatively cheap, and helped diversify the state’s 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.

Today, California faces a new challenge. Burning natural gas contributes to greenhouse gas emissions, and state law mandates that California’s greenhouse gas emissions be reduced to 1990 levels by 2020. This reduction must be balanced with the understanding that natural gas is the fossil fuel of choice and will likely play an even more important role in California’s energy future, despite policy makers’ emphasis on efficiency and renewables. As discussed in the description of the scenario analyses in Chapter 2, increased natural gas-fired generation in 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).

Natural gas is critical to California’s energy system, providing more than a third of the state’s total energy requirements. More

than 44 percent of the natural gas consumed in California is used to generate electricity. Natural gas is the primary fuel for residential cooking, space and water heating, and industrial processes (Figure 6-1).

In 2006, more than 85 percent of California’s natural gas supplies was from sources outside the state. This dependency poses an ongoing challenge in securing adequate and reliable supplies of



Source: Utility and pipeline filings to the California Energy Commission.

natural gas at reasonable prices. This occurs, in part, because natural gas well productivity in the United States is declining, and California is literally at the end of the interstate pipeline system, competing with growing North American demand.

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 from coal-based electricity generation to cleaner natural gas-fired generation to help reduce criteria pollutant emissions.

Over the past several years, in-state 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, it is 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 increasingly difficult to find and produce. 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 to 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 that country's domestic natural gas demand increases and field production declines. To fill this gap, the Energy Information Administration projects significant imports of natural gas from worldwide sources to increase over the next 20 years, shipped as liquefied natural gas by tanker, not pipeline, requiring additional infrastructure. By 2017, 15 percent of North American natural

gas supplies could be liquefied natural gas (Figure 6-2).

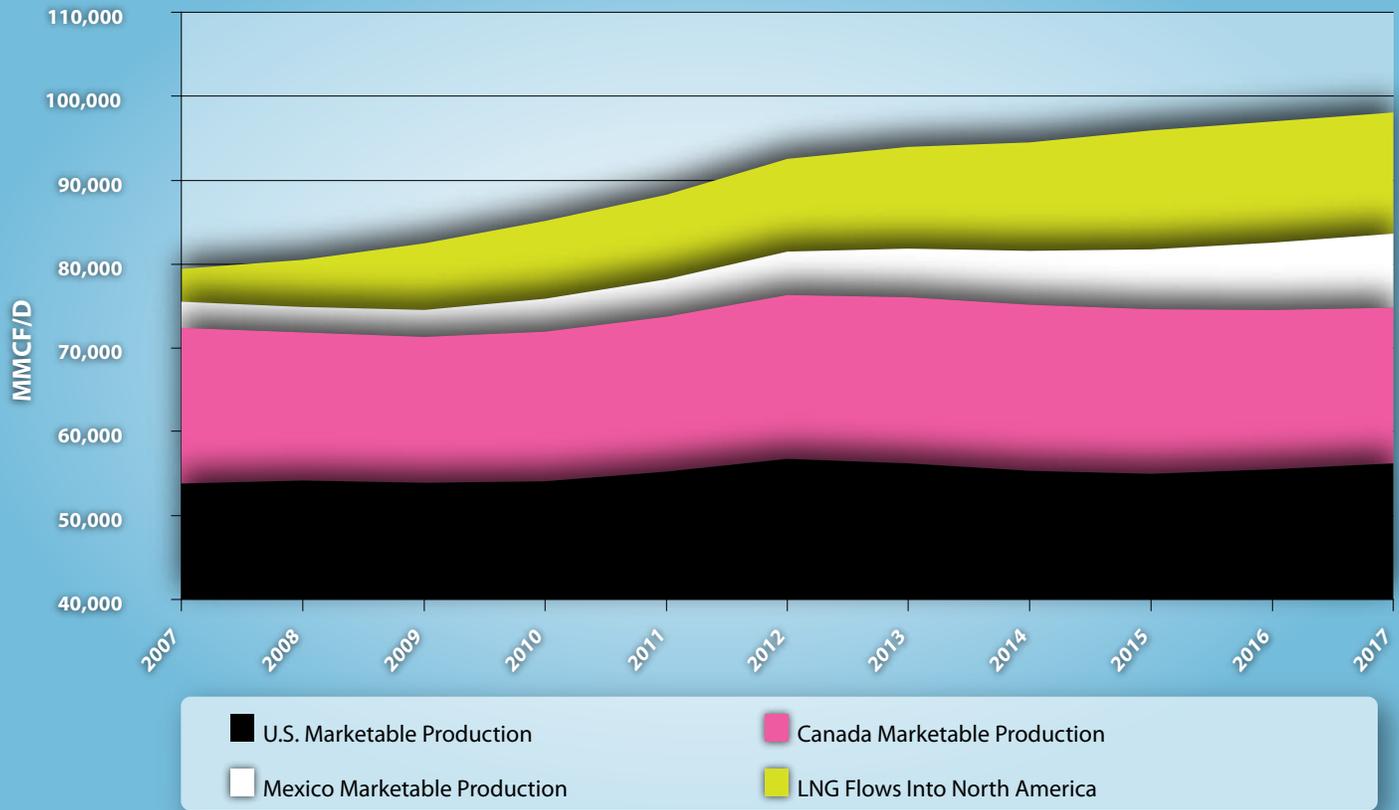
The state's energy efficiency programs and the use of renewable energy for electricity generation have helped keep California's growing natural gas demand in check even though its population continues to climb by a half million people each year.

California's overall natural gas demand is projected to grow at less than 1 percent per year, mostly for electricity generation. Lacking similar national efficiency and renewable standards, the comparable United States annual 2.1 percent growth rate for natural gas is higher than California's.

While California's average wholesale natural gas price is lower than in some regions of the United States, it has increased appreciably from \$3.20 per thousand cubic feet in 2002 to \$6.76 per thousand cubic feet in 2006. 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 more than 23,000 megawatts of natural gas-fired facilities with about 13,000 megawatts of that amount constructed and on line 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, using less natural gas for more electricity output. They also can ramp up and down more quickly to provide electricity to meet peak demand and system regulation requirements. 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

Figure 6-2: Origins of Natural Gas Supply for North America



Source: California Energy Commission.

nuclear and coal-fired plants until those technologies resolve their environmental problems of waste disposal and carbon sequestration. As discussed in Chapters 2 and 4, however, the high price volatility for natural gas and the ability of electric utilities to be financially insulated from fuel cost variability due to regulatory pass-through has made California’s increasing reliance on gas-fired electric generation problematic from a ratepayer perspective.

A Model Shift in Analysis

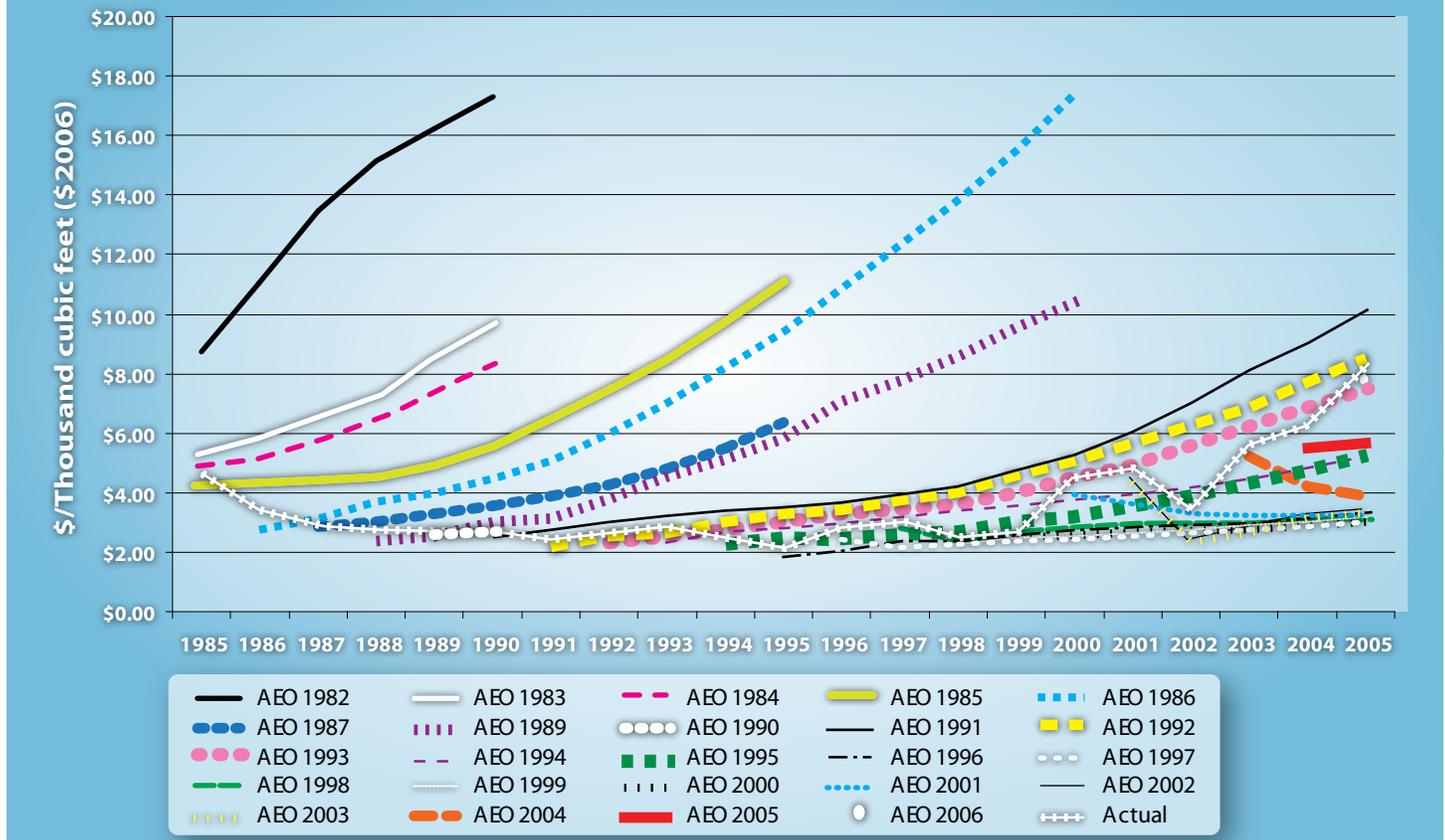
Mark Twain was correct when he said, “Prophesy is a good line of business, but it is full of risk.” Attempting to forecast California’s future natural gas demand, supplies, and prices is laden with uncertainties. Clearly, the natural gas price forecasts developed by Energy Information Administration 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 two of the biggest unknowns are how many liquefied natural gas 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?

Figure 6-3: Natural Gas Price Forecasts by Year Issued



Source: U.S. Department of Energy, Energy Information Administration, *Annual Energy Outlook Retrospective*, March 2007. DOE/EIA-0640(2006).

How can California determine increasing natural gas use if it 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 allow quantification of 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 it looks at the consequences of its 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 meet the state’s environmental goals. 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 encourages uses that meet the state’s environmental goals.

Rethinking Forecasting Methods

The California Energy Commission’s Scenario Analyses Project took the first step in moving toward exploring a carbon-constrained future by expanding how the state considers its

energy choices from a policy-driven perspective and which combination of resources will help reduce greenhouse gases. The Scenario Analyses Project examined the implications of using various amounts of energy efficiency, rooftop solar photovoltaic, and renewable electricity generating technologies to determine how these strategies would affect greenhouse gas emissions from the electricity sector. One of the variables evaluated in this assessment was the amount of natural gas used in electric power generation in each scenario. Staff studied these implications in a number of conventional and non-conventional scenario futures.

Scenario 1B, which reflects current efficiency and renewable policies, 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 Renewables Portfolio Standard (RPS) requirements, it does not notably reduce greenhouse gases.

The scenarios that combined high amounts of energy efficiency and renewables, in contrast, indicated slow declines in natural gas use for electricity generation. 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, 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. Five other western states and two Canadian provinces have signed a memorandum of understanding to pursue a major decrease in greenhouse gas 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 requiring 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 electricity as the "fuel of choice strategy" for all sectors including transportation, natural gas use will likely increase until displaced by renewables, coal with carbon sequestration, or nuclear generation.

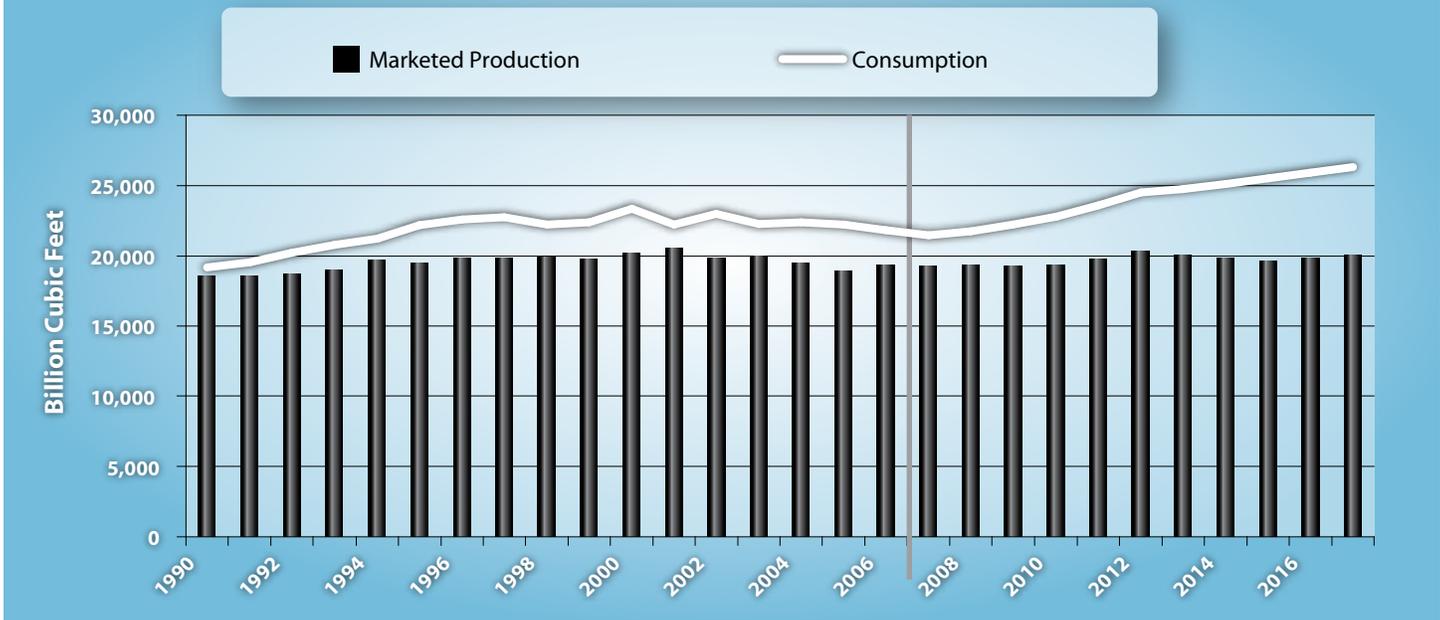
Natural Gas Supplies and Dependence on Imports

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, the 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 has become the fuel of choice for electricity generators to reduce criteria air pollutants, competition for natural gas has intensified with concerns about greenhouse gas emissions 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

Figure 6-4: United States Production and Consumption 1990–2017



Source: Energy Information Administration.

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.

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 current levels of about 18 billion cubic feet per day to only about 19 billion cubic feet per day by 2012, remaining flat afterward. 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.

Although higher natural gas prices have spurred more drilling, production has not increased, and drilling prices are higher (Figure 6-5). If declines in productivity per new average well continue at the 4 percent per year rate experienced from 2000 to 2006, 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, California can achieve only slight increases in production over the next several years. And despite earlier optimism, natural gas resources previously slated for delivery from Arctic Canada (Mackenzie Delta) and Alaska's North Slope into the North American gas market are not likely to be available until at least 2020.

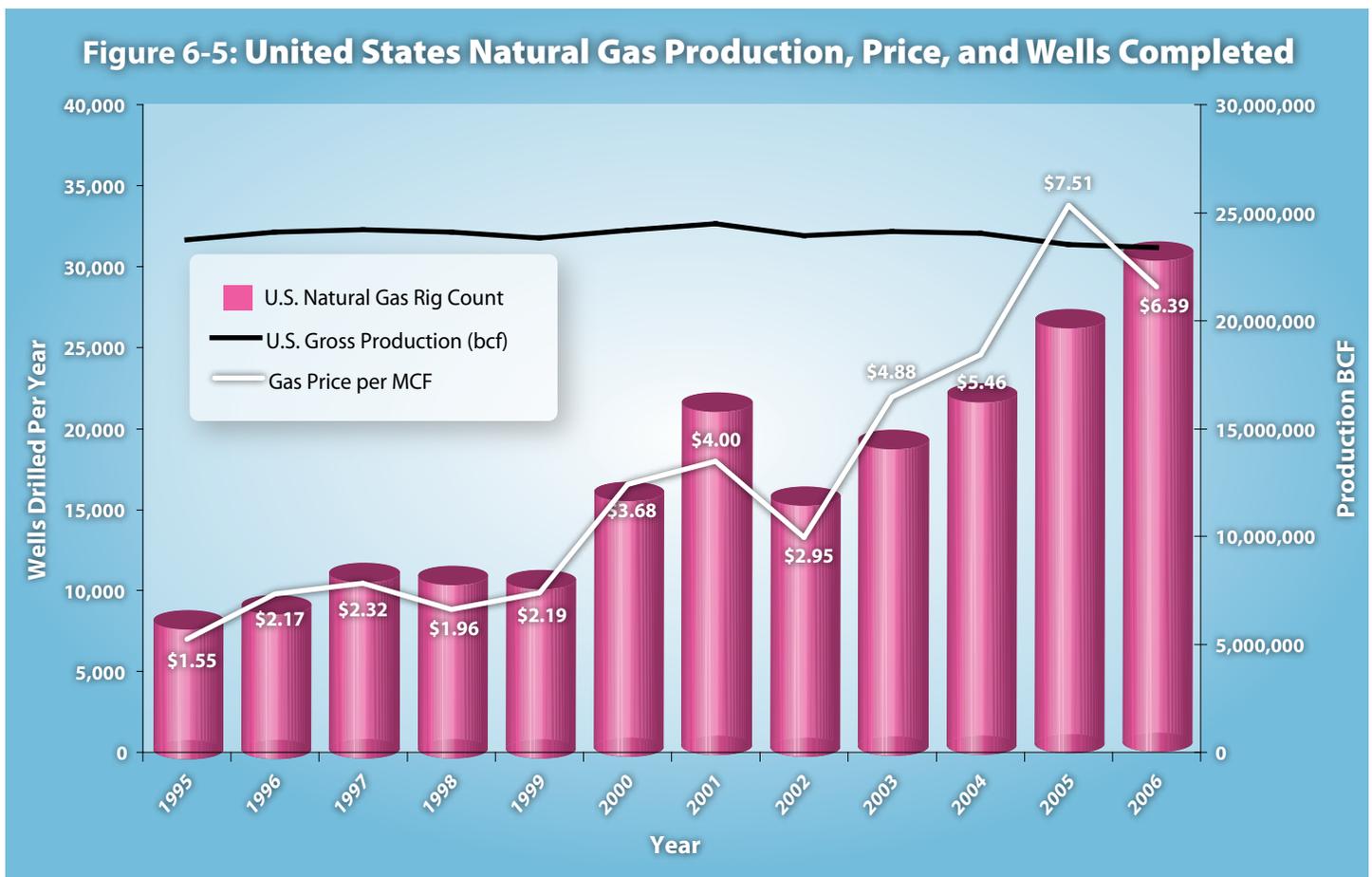
Supply Uncertainty

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 8 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.

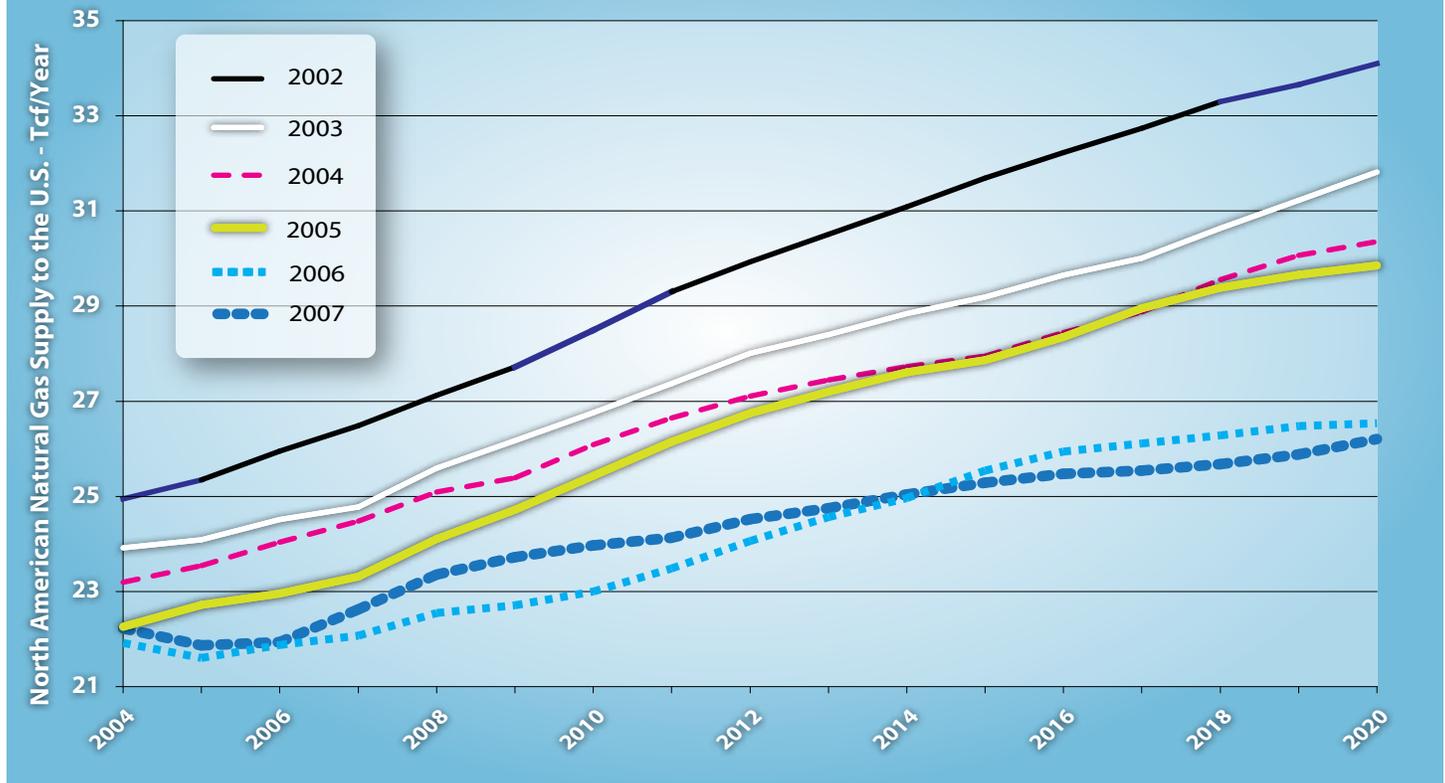
Over time, the forecasts started incorporating the industry's inability to produce additional North American natural gas, despite ever increasing drilling. Given the challenges in producing North American natural gas, staff expects more downward adjustments in future forecasts. Pacific Gas and Electric Company (PG&E) has publicly commented that it believes 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,



Source: California Energy Commission.

Figure 6-6: Department of Energy Natural Gas Supply Forecasts in North America (2004–2020)



Source: Energy Information Administration, U.S. Department of Energy.

east Texas, and 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, and shale gas, or in very deep water, all of 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 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 liquefied natural gas.

Alternative Natural Gas Sources

Liquefied Natural Gas – 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. Liquefied natural gas is one potential supply of natural gas.²⁸⁵

Liquefied natural gas 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 Semptra’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 liquefied natural gas will require infrastructure improvements including a re-gasification terminal.

Imports of liquefied natural gas to the United States are expected to increase almost 13 percent annually by 2017 to 11.3 billion cubic feet per day or about 20 percent of United States supplies,

²⁸⁵ Liquefied natural gas is natural gas that has been chilled, reducing it to a liquid form and 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.

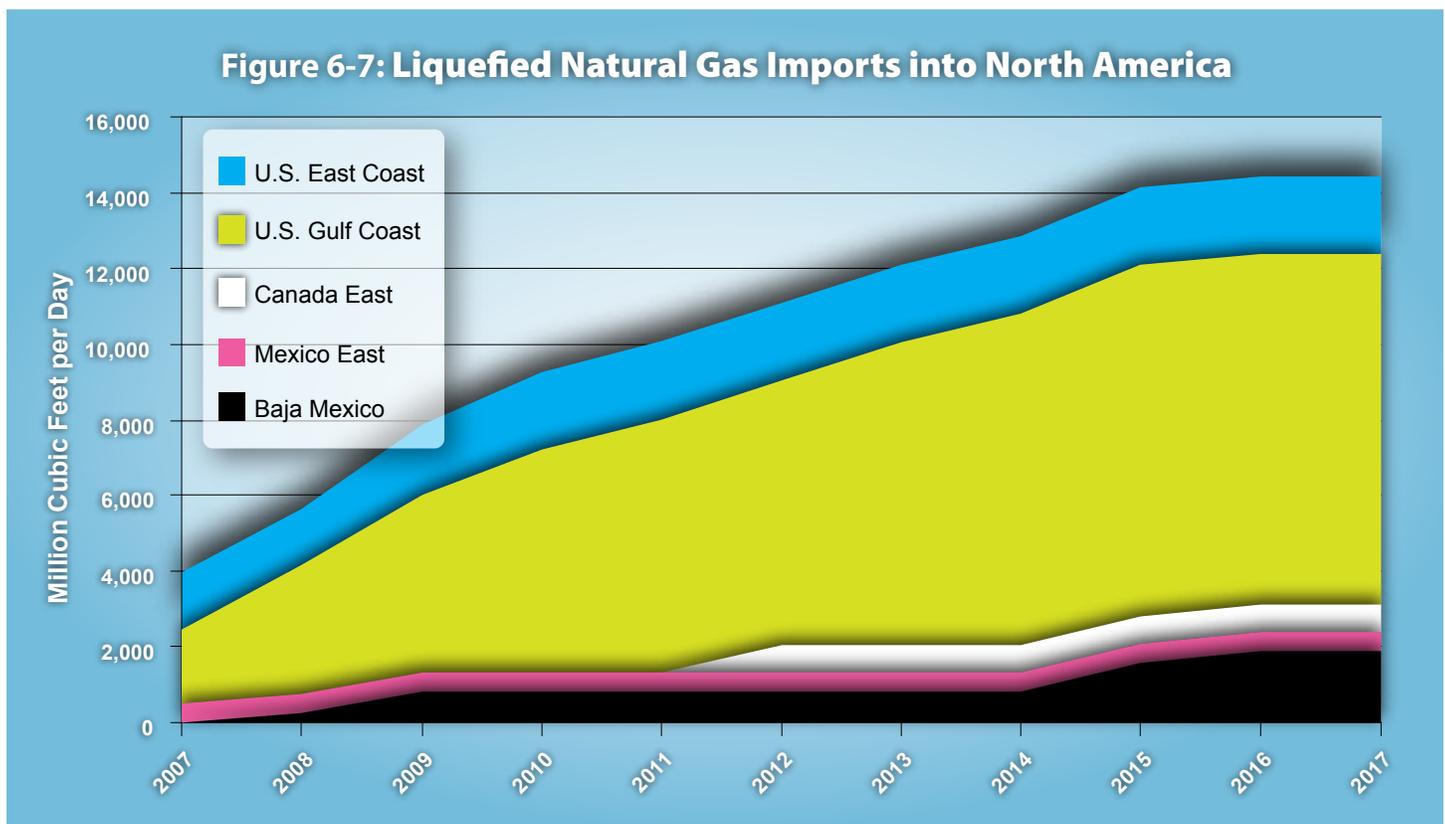
according to Energy Commission staff. Staff included only facilities that fall into the following three categories: currently operating (with any scheduled expansion), currently under construction, and currently permitted (high probability of construction).

Although much of these supplies will be shipped into the United States Gulf Coast region, they 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 (IEPRs), the Energy Commission found the construction of liquefied natural gas 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 IEPRs 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. In 2007, that conclusion remains inescapable.

Twelve applications to build liquefied natural gas re-gasification facilities are in various stages of review on the West Coast including four in California, four in Oregon, three in British Columbia, and one in Mexico. California has already engaged in the liquefied natural gas debate by participating in direct discussions with the Federal Energy Regulatory Commission, which manages the environmental review process for onshore liquefied natural gas facilities, and the Coast Guard, which is responsible for the offshore review. In addition, the Energy Commission coordinates the activities of the Liquefied Natural Gas Interagency Working Group, composed of the federal, state, and local agencies responsible for overseeing the licensing of liquefied natural gas facilities in California. It is the mission of the Energy Commission, and the Liquefied Natural Gas Working group, to help ensure that any liquefied natural gas 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.

Currently, staff analysis anticipates receiving about 500 million cubic feet a day of natural gas from the almost completed Costa



Source: California Energy Commission.

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 San Diego Gas & Electric Company (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.

Currently, 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 of 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 liquefied natural gas facility may be built on the West Coast instead. Market conditions and environmental review of the proposed sites will determine the outcome.

While there is no assurance that West Coast liquefied natural gas projects will lower natural gas prices to California, staff’s modeling shows that liquefied natural gas delivered to the United States is cheaper, on a cost basis, than the high cost elements of newer North American production and would tend to keep prices lower than they would be if no liquefied natural gas came to North America. Additional supplies, no matter where they come from, are expected to 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.²⁸⁶ 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 overcome 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 its natural gas supplies are produced in state. Just

Promoting Biogas

The Energy Commission believes that California should promote the use of pipeline-quality biogas from dairies and landfills. Pipeline-quality biogas injected into California’s natural gas pipeline system should be compensated for through a feed-in tariff mechanism paid by the gas utilities. The Energy Commission and Public Utilities Commission should work together to establish an appropriate price per therm to be paid for pipeline-quality biogas along the lines of the market price referent used in the Renewables Portfolio Standard program.

²⁸⁶ The Bioenergy Interagency Working Group, *Bioenergy Action Plan for California*, July 13, 2006.

Figure 6-8: Western North American Pipelines and Supply Basins



Source: California Energy Commission.

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 more than 2 trillion cubic feet of natural gas annually (Figure 6-8). Since the 2001 electricity crisis, delivery capacity to California had expanded about 18 percent by 2006, climbing to about 9.2 billion cubic feet per day and ensuring

that California 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 make it difficult to satisfy all demand requirements by pipeline capacity. In these cases the state's storage facilities supply additional natural gas. As noted earlier, there will be two pipelines bringing natural gas from a liquefied natural gas facility in Costa Azul, Baja Mexico into Southern California.

If the Costa Azul liquefied natural gas 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, most likely one of 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 two and three 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.

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 liquefied natural gas. 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.”²⁸⁷

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, natural gas-fueled vehicles, and other technologies such as plug-in hybrids in transportation may also play a larger role in future demand.

In fact, natural gas, like petroleum, has become a global commodity, and California competes not just with the Midwest and East Coast for access to less abundant natural gas supplies, but also with Western Europe and Asia Pacific consumers in a world market for natural gas — at prices that are likely to continue increasing.

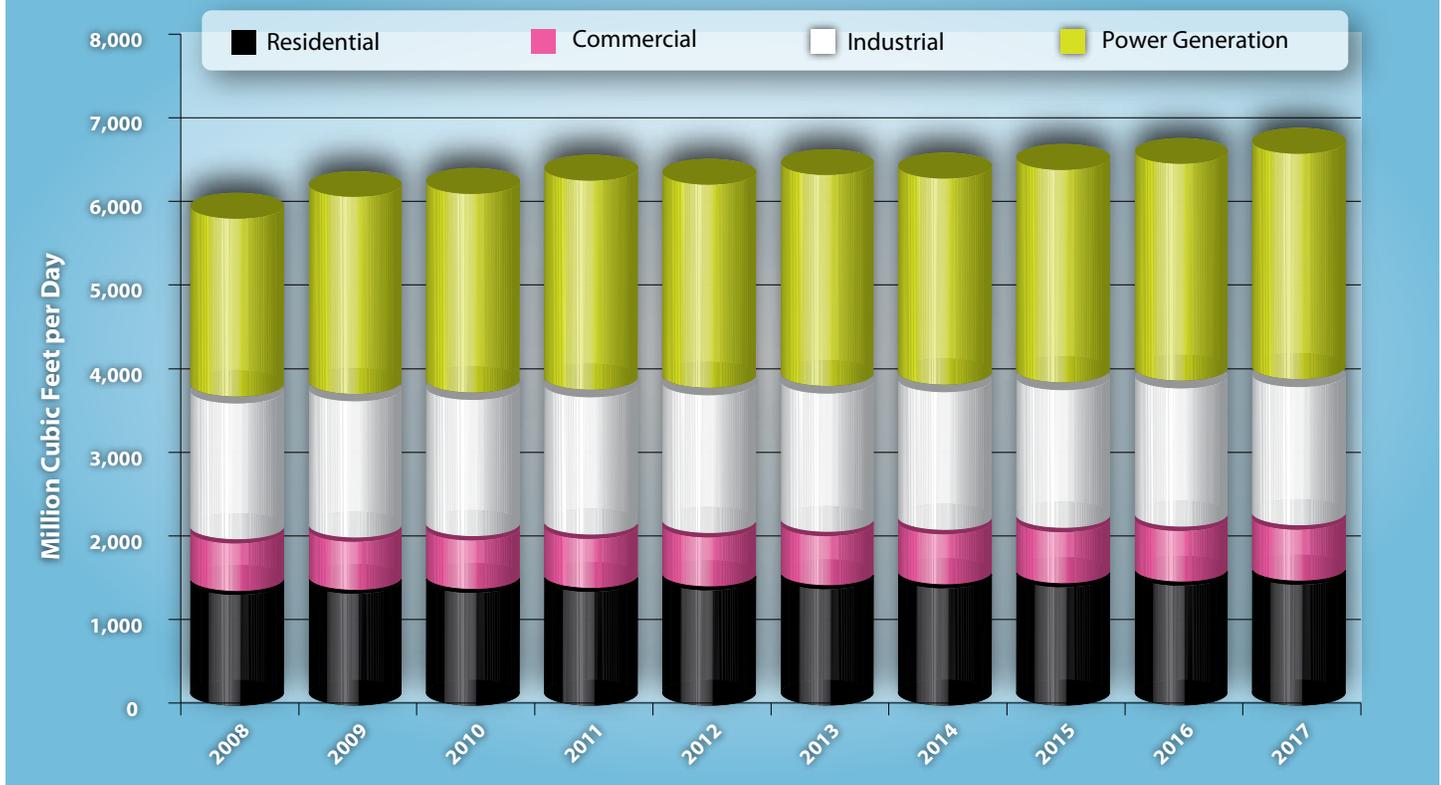
California Depends on Natural Gas

California’s demand growth for natural gas in residential, industrial, and commercial sectors has remained slow, with each sector expected to grow less than 1 percent each year in the next decade (Figure 6-9).

Peak electricity demand is expected to grow at about 1.35 percent each year through 2017, and will be the sector with the largest natural gas increase 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. This forecasted increase in natural gas consumption does not take into consideration any impacts implementing the State Alternative Fuels Plan (AB 1007, Pavley, Chapter 371, Statutes of 2005) would have on the transportation sector. If natural gas

287 Pacific Gas and 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.

consumption occurs at the rate that the State Alternative Fuels Plan suggests, natural gas consumption for transportation could increase from 37.2 million cubic feet per day in 2006 to as much as 87.5 million cubic feet per day in 2017 (conservative case), 154.2 million cubic feet per day (moderate case), or 239.1 million cubic feet per day (aggressive case). These increases could occur if all barriers to natural gas as a transportation fuel are overcome and no competition develops from other alternative fuels.

California no longer has the luxury to view natural gas from a “California demand only” perspective but must examine how the demands from its competitors are changing — the western states and Canada, as well as the eastern United States.

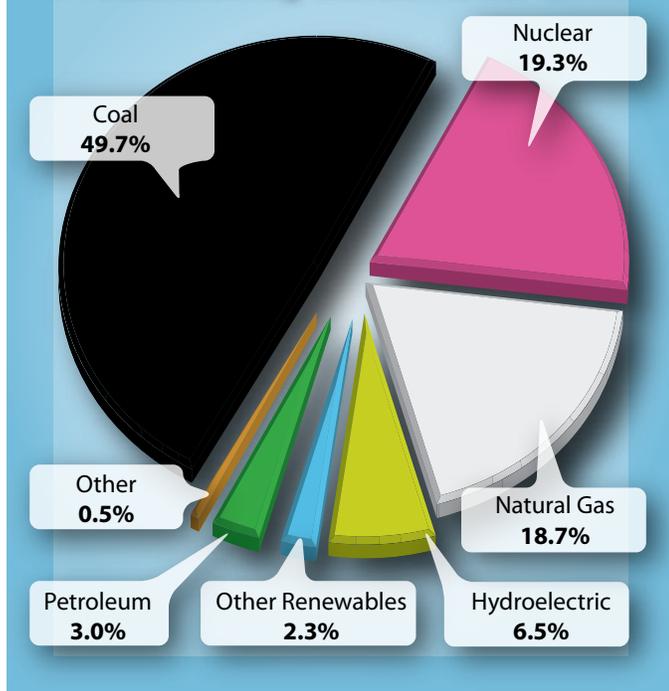
Currently, the United States, Canada, and Mexico consume about 74.5 billion cubic feet of natural gas each day. This demand is expected to increase 2.3 percent each year, reaching more than 89 billion cubic feet per day by 2017. Although the United States is the dominant consumer of natural gas, at 83 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’s 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 States’ 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 continue. Electric power generation in North America is projected to be 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.

Figure 6-10: United States Electricity Production by Resource for 2005



Source: U.S. Energy Information Administration, Form EIA-880, *Annual Electric Generator Report*.

If the eastern United States and Canada adopt more aggressive strategies to reduce greenhouse gas, demand may 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.

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. 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 is too high. Decisions made 25 years ago by the rest of the country about the fuel for its electricity generation system did not affect California. Today, these decisions do. And California has helped push those choices toward natural gas, with SB 1368 (Perata, Chapter 598, Statutes of 2006), 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.

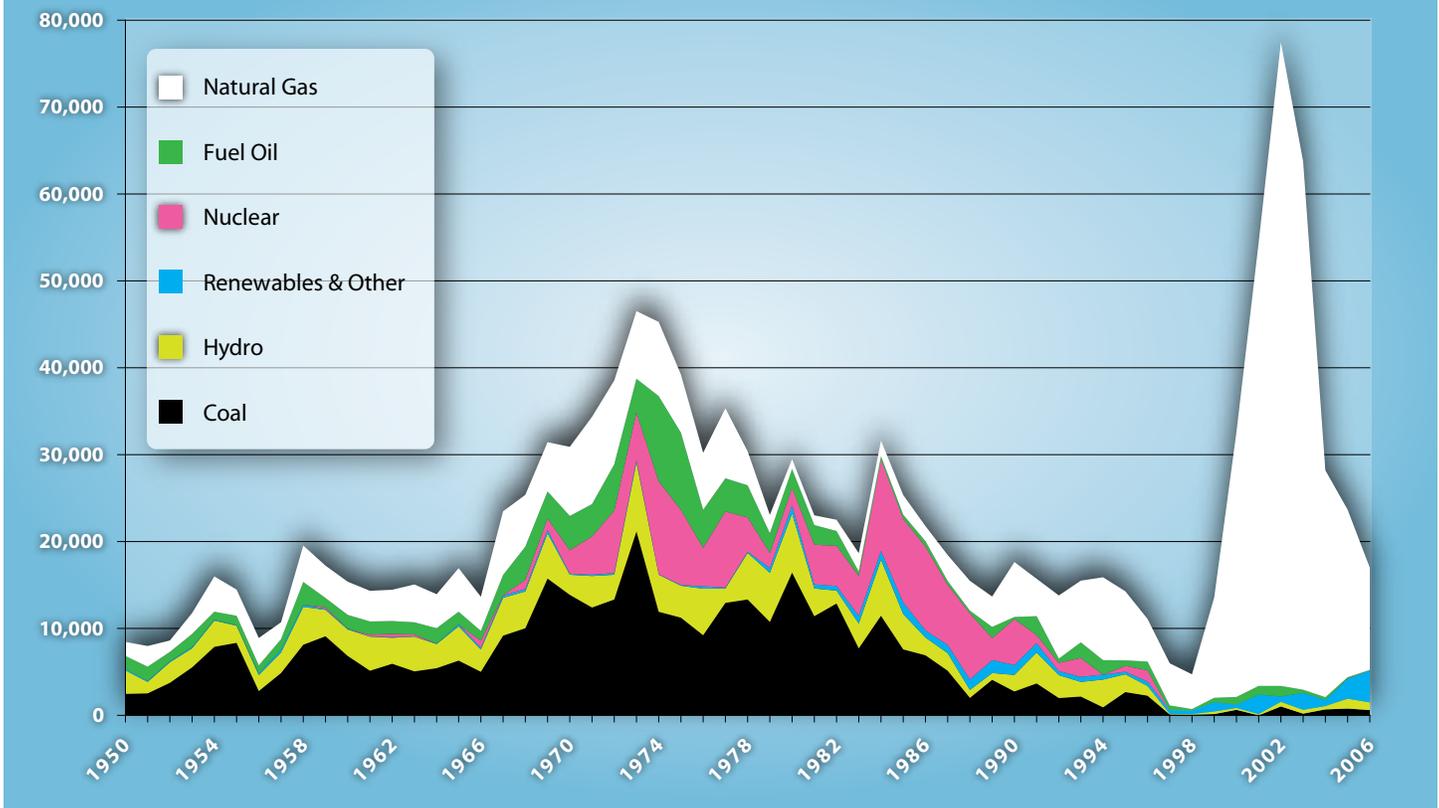
Although demand throughout the world impacts California, there is a more immediate impact from natural gas demand in the western United States and western Canada. Expected natural gas demand in the western states and Canadian provinces has a direct influence on gas prices and the ability for California to secure its necessary supplies. By 2017, the western United States and western Canada will be consuming more than 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.

Currently, Alberta oil sands are consuming approximately 6 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 \$90 per barrel, every effort is being made to produce as much as possible. More oil production means more natural gas from the western

Figure 6-11: North American Electricity Capacity Additions Since 1950 in Megawatts



Source: 2007 Energy Information Administration Data.

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.

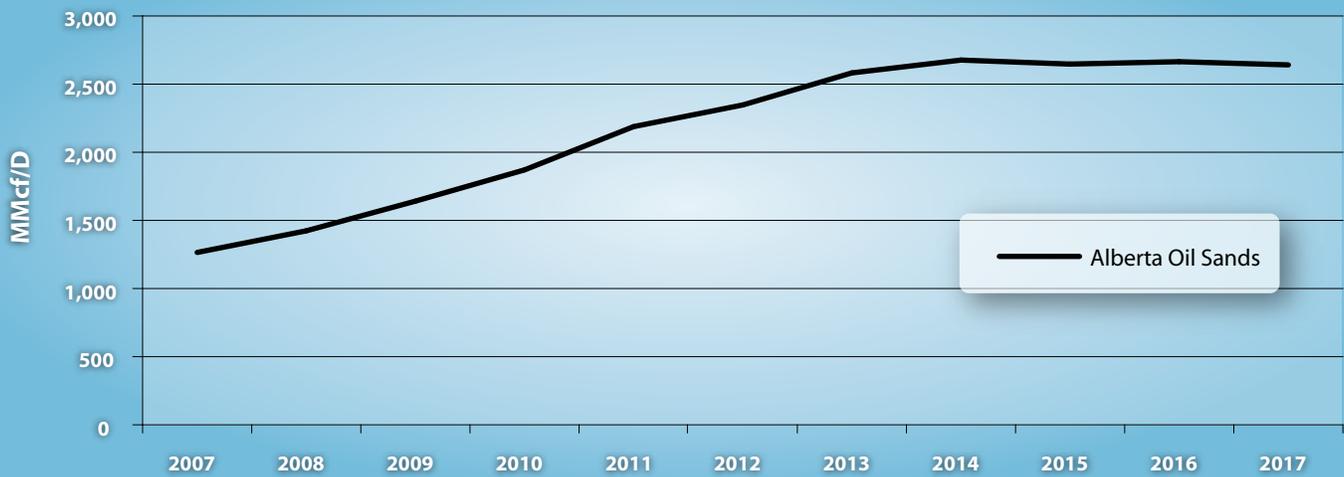
This increase in natural gas demand in western and eastern Canada impacts the amount of natural gas Canada will have available to export to the United States. The United States will have to either seek additional liquefied natural gas imports or prices will have to increase enough to encourage more unconventional North American production.

Demand Impacts Natural Gas Prices

Natural gas prices ebb and flow with demand and supply — and demand for natural gas is increasing faster than supply 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 liquefied natural gas imports, proposed carbon controls to reduce greenhouse gas emissions, and a growing population have combined to push national prices higher. Natural gas is not immune to wide price swings, but it seems unlikely that 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

Figure 6-12: Alberta Oil Sand Production Increases Natural Gas Demand



Source: California Energy Commission, 2006 Natural Gas Staff Assessment.

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 relatively 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.

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 American 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 Committee²⁸⁸ 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

288 Global Insight, 2006, *The Impacts of Natural Gas Prices on the California Economy*.

\$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.

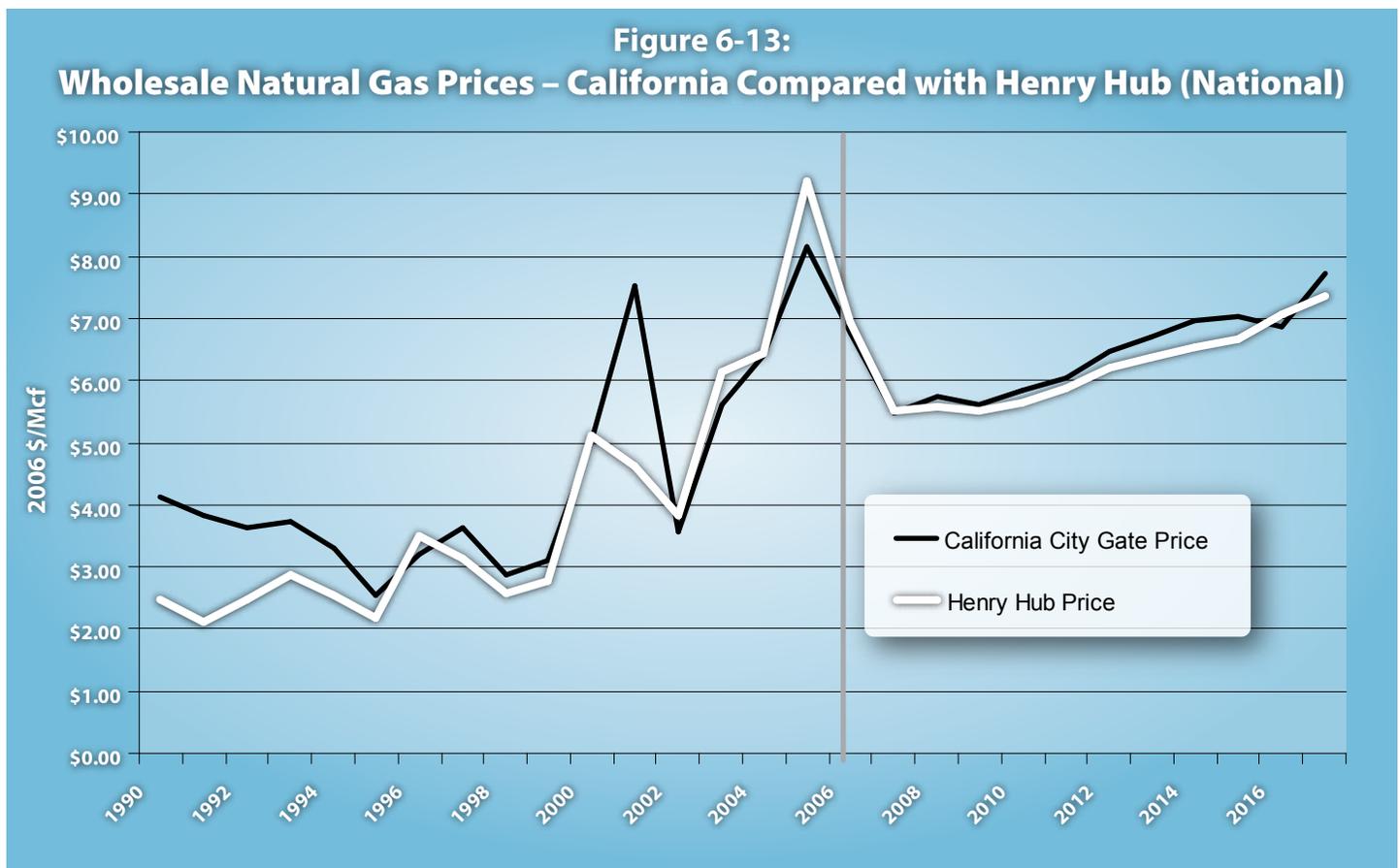
California’s electricity generators are estimated to pay between \$5.10 and \$8.60 per thousand cubic feet through 2017, and prices vary based on whether or not the generator is served by a natural gas utility or takes its fuel supplies directly from another source, such as an interstate pipeline or 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?

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 more than 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



Source: California Energy Commission.

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.

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 liquefied natural gas.

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

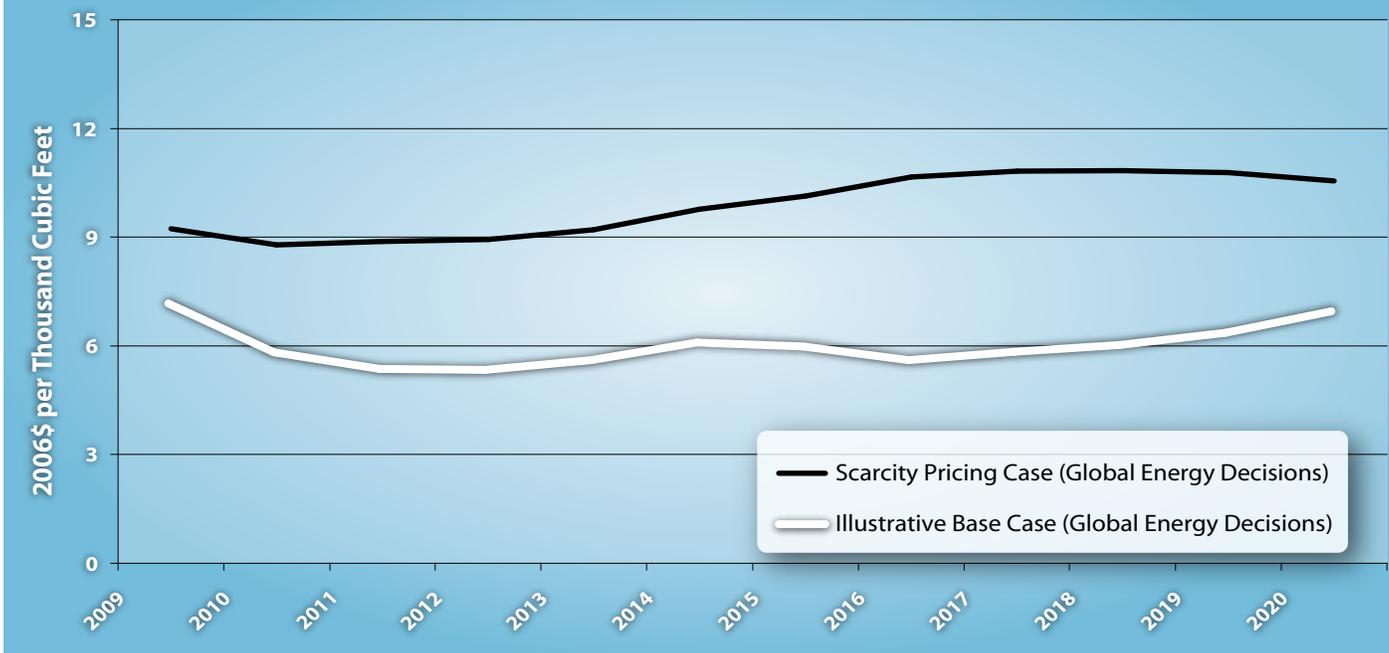
that makes them less fuel- and cost-efficient than newer, cleaner plants. They waste two-thirds of the natural gas they use to make electricity — they are only 33 percent efficient. The state has about 16,000 megawatts of aging natural gas-fired electricity generating capacity; many of these units are 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 hours, 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 one-half times the increased efficiency, reducing the amount of natural gas consumed by 50 percent. These facilities can be particularly efficient when a heat recovery steam generator used to power a conventional steam turbine in a combined cycle configuration captures waste heat from the gas turbine. Other designs are run in a cogeneration configuration: the exhaust heat is used for space or water heating or drives an absorption chiller for cooling or refrigeration. This type of cogeneration configuration can be more than 90 percent efficient.

Combined heat and power facilities must provide a larger role in meeting California's electricity supply needs. The *2003 and 2005 IEPRs* 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 power plants.

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

Figure 6-14: Illustrative Scarcity Price Compared to Illustrative Base Case



Source: California Energy Commission based on Global Energy Decisions information.

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 Renewables 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 helping to meet the AB 32 goals. The state also has a goal of achieving 33 percent renewables by 2020. However, 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 conventional fuels. Staff’s analysis looked at two scenarios from the Scenario Analyses Project: Case 1B using just enough efficiency and renewables to meet the energy efficiency and 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 more than 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.²⁸⁹

Natural Gas as a Complementary Strategy to Meet Greenhouse Gas Emission Reductions

As its population continues to grow, California manages to keep natural gas demand for residential, commercial, and industrial customers to less than 1 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 natural gas in the 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 natural gas demand — a total of almost 7 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 analyses calculated that if a \$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, it also has a responsibility to provide a reliable and affordable fuel source for home and business use.

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.
- 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. Pipeline-quality biogas injected into California's natural gas pipeline system should be compensated through a feed-in tariff mechanism paid by the gas utilities. The Energy Commission and Public Utilities Commission should work together to establish an appropriate price per therm to be paid for pipeline-quality biogas along the lines of the market price referent used in the RPS program.
- The Energy Commission and CPUC should adopt a

²⁸⁹ Altos and Global Energy natural gas demand, California Energy Commission, *Scenario Analyses of California's Electricity System, Second Addendum*. CEC-200-2007-010-AD2-SF.

“loading order” for natural gas resources, similar to the one in place for the electric sector. This will encourage utilities to seek out low-carbon fuels before conventional sources of natural gas, with the first priority being all cost-effective natural gas efficiency and solar resources, followed by renewable fuels like biomethane.

- 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, it 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

“Embrace the future and recognize the growing demand for a wide range of fuels or ignore reality and slowly — but surely — be left behind.”

Mike Bowlin, Chairman and CEO of ARCO (now BP)

Perhaps no other population in the world has embraced the automobile as passionately — nor is any other state defined as much by the car — as California.

Cars give Californians the individual freedom and autonomy its citizens crave. 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 (CO₂) and other greenhouse gases in California come from burning transportation fuels, mainly gasoline and diesel in cars and trucks. California must change its relationship with automobiles and the way it views transportation — at a personal, as well as a state policy, level.

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. The consequences are clear: major investments in petroleum refinery and delivery infrastructure expansions, more dependency on foreign energy supplies, and decreased environmental and public health quality.

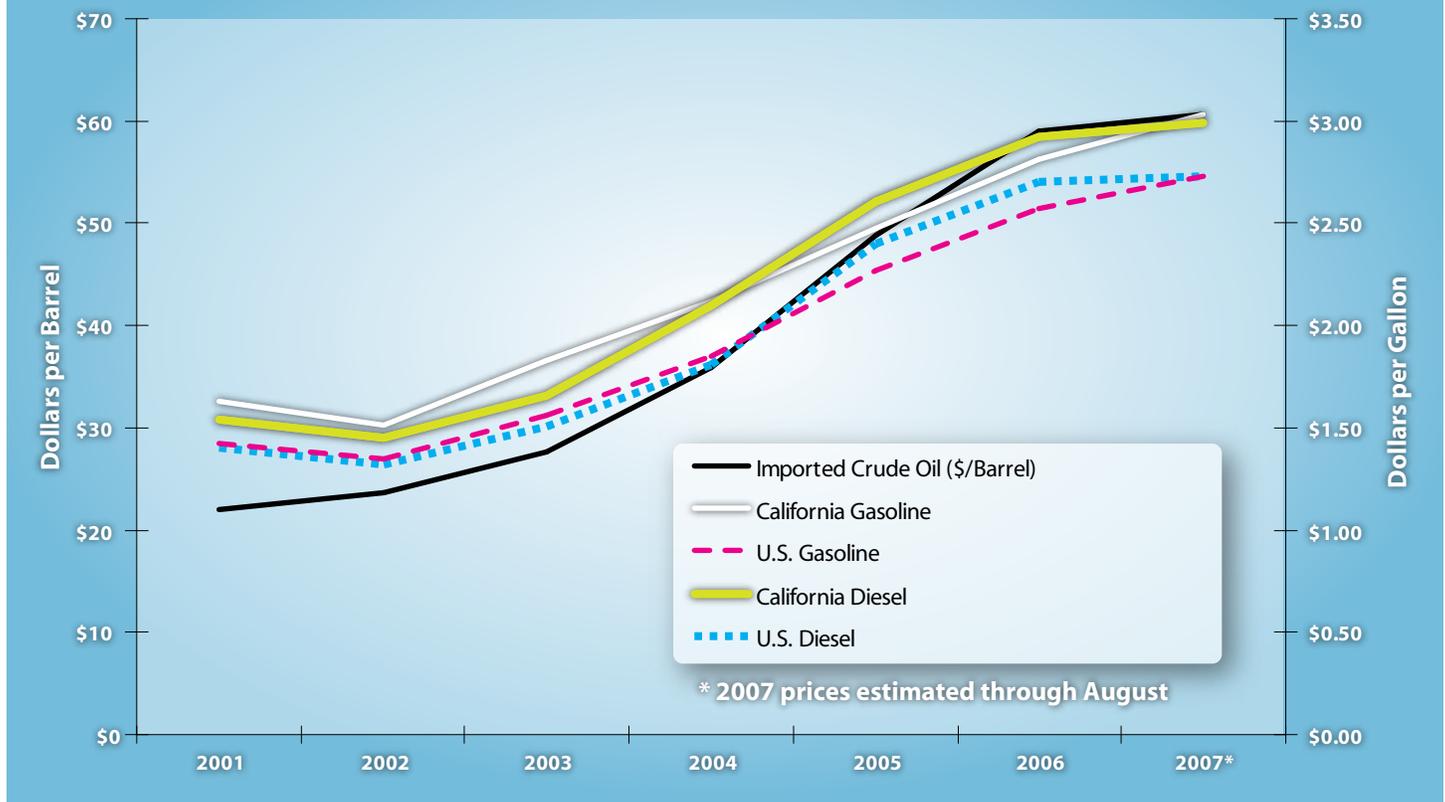
California's energy policy — the loading order — identifies energy efficiency, renewables, and new infrastructure improvements as the state's priorities in meeting growing energy demand. These strategies also apply to transportation.

Improved efficiency of transportation energy use, in large part through vehicle standards, is the most effective and sustainable strategy for reducing the state's 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.

More than 40 percent of all energy used in the state moves people and goods, and most transportation fuel demand is met by petroleum. The state's nearly 26 million registered vehicles consume about 380 million barrels of gasoline (16 billion gallons) and almost 100 million barrels of diesel (4 billion gallons) each year. California is the third largest consumer of gasoline in the world, behind the entire United States and China.

Due to high oil prices and in-state refinery maintenance and breakdowns, California's gasoline prices reached a record high of \$3.46 per gallon during May 2007 (Figure 7-1). Consumers are unable to change their driving habits quickly; therefore, when transportation fuel prices increase over a short period of time, consumers are left with less disposable income. In addition to the impact of high transportation fuel prices, increases in crude oil prices drive up the average cost of production of goods and services. This negatively affects the state's economy and gross state product.

Figure 7-1: Gasoline, Diesel, and Crude Oil Prices



Source: California Energy Commission.

Significant petroleum price increases, 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 (Figure 7-2). Skyrocketing demand in China and other developing nations, along with current global conflicts, particularly in Nigeria and the Middle East, are exacerbating the situation. Other factors such as weather and geopolitical events also affect crude oil and transportation fuel prices.

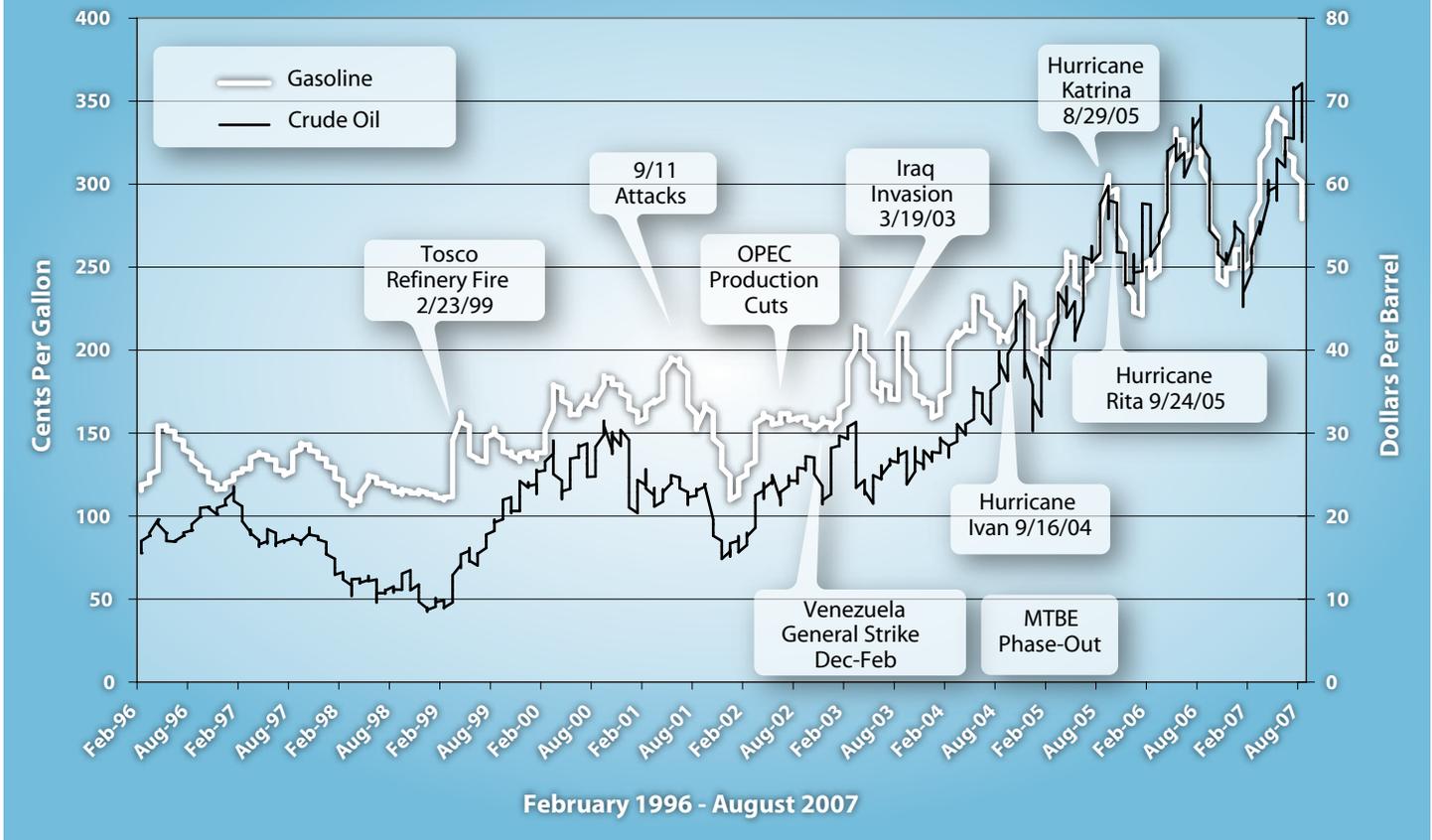
By October 2007, crude oil prices had exceeded \$90 per barrel. The price of crude oil, regardless of its origin, is affected by the worldwide price for benchmark crude oils, and these price trends emphasize the importance of reducing California’s growing dependence on foreign oil sources.

Twenty-five years ago, California received 94 percent of its crude oil supplies from in-state production and imports from Alaska; foreign sources contributed the remainder (Figure 7-3). By 2006, the situation had changed, with foreign imports making up 45 percent of crude oil processed by California refineries. Additionally, due to the limited refining capacity in California, the state must import 10 percent of its refined blending components and finished gasoline and diesel to meet the growing demand.

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. This adds further challenges.

Unplanned outages at in-state refineries or pipeline facilities quickly tighten gasoline and diesel supplies, creating price spikes. California is not connected by pipeline to other domestic refining centers, and in-state refiners cannot readily

Figure 7-2: California Gasoline and World Crude Oil Prices



Source: California Energy Commission.

procure gasoline, diesel, and other blending components when outages occur. Relying on imports of petroleum and finished product coming into the constrained import infrastructure creates a market conducive to extreme price volatility. This contributes to higher and more prolonged price spikes, as has been experienced in recent years.

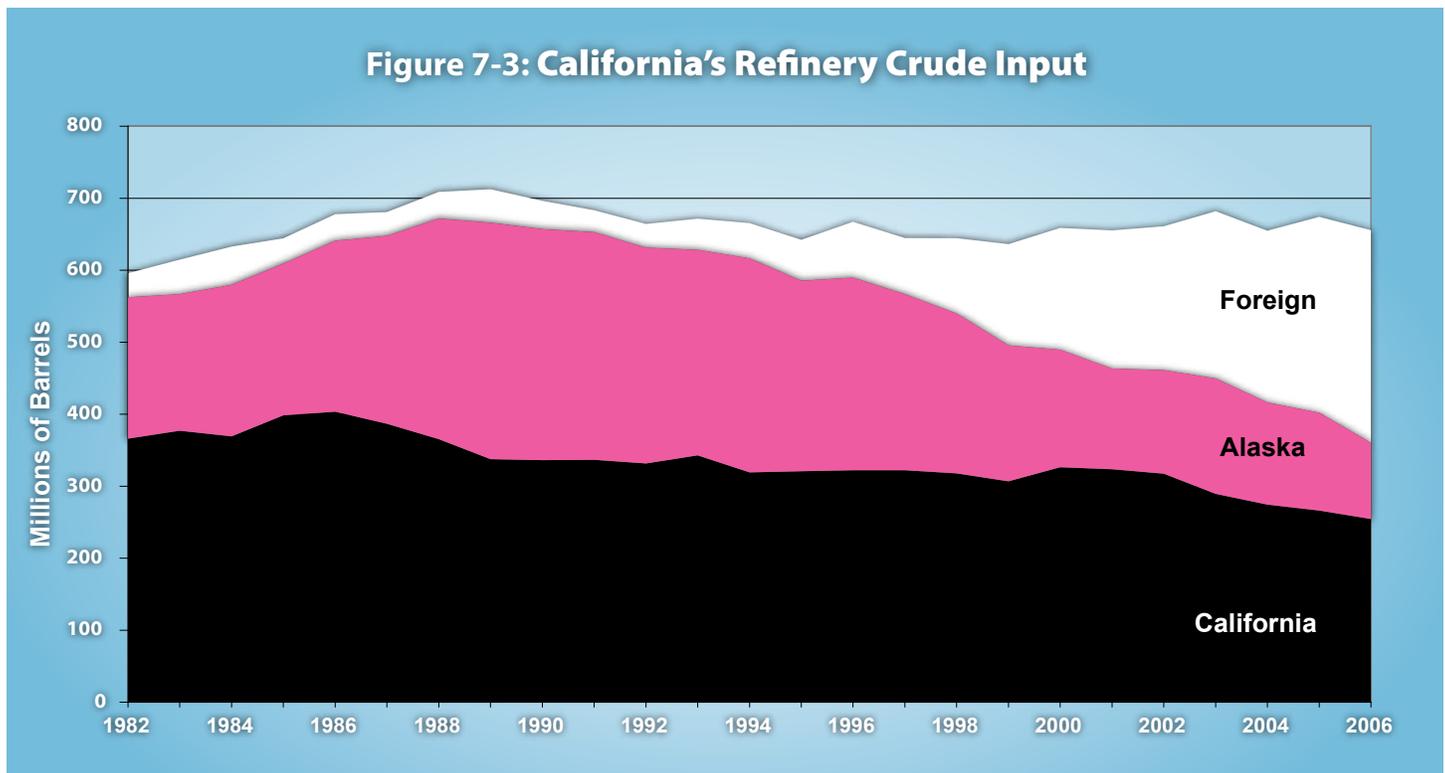
Transportation Fuel Demand Trends

In the past 20 years, California’s population has increased at an annual average rate of 1.7 percent, 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.²⁹⁰ Nevertheless, California’s population is estimated to exceed 44 million by 2020. Even if not climbing at historically high rates, the total growth will be considerable and result in substantial increases in transportation fuel demand for the state. The policies that result from the state’s AB 1007 plan (Pavley, Chapter 371, Statutes of 2005), discussed later in this chapter, from the programs that will be funded by AB 118 (Núñez, Chapter 750, Statutes of 2007), and from California’s overall AB 32 protocols will have a major impact on what fuels are used in the state to meet this rising transportation fuel demand.

²⁹⁰ Based on population projection series from the Department of Finance July 2007 report, *Population Projections by Race/Ethnicity for California and Its Counties 2000–2050* (population growth rate of .26 percent for the 2005–2030 time frame) and demographic data obtained from the California Energy Commission Demand Analysis Office.

Figure 7-3: California's Refinery Crude Input



Source: California Energy Commission.

Besides population growth, California's transportation fuel demand is affected by many other factors, including economic growth, fuel prices, and consumer behavior. 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 affects 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).²⁹¹ California's gasoline use steadily increases at an average annual rate of 0.76 to 1.63 percent through 2012. From 2012 to 2020, gasoline demand grows 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. These projections reflect extrapolation from current conditions and market behavior, and will likely differ significantly as the policies put in place in response to AB 1007 and AB 118 are implemented.²⁹²

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 in 2005 to between 638 and 702 million barrels in 2020.

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

²⁹¹ California Energy Commission, *Transportation Energy Forecasts for the 2007 Integrated Energy Policy Report*, September 2007, CEC-600-2007-009-SF.

²⁹² Ibid.

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 California 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 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 more than 60 percent of Arizona’s, as neither of these landlocked states has any refineries. California refineries also provide between 25 and 35 percent of Oregon’s fuels delivered via marine tankers. These states have joined with California in collaborative arrangements to address greenhouse gases in the region. If the other states develop policies similar to those California is considering under AB 1007 and AB 32, their demand for petroleum products will likely differ from these projections.

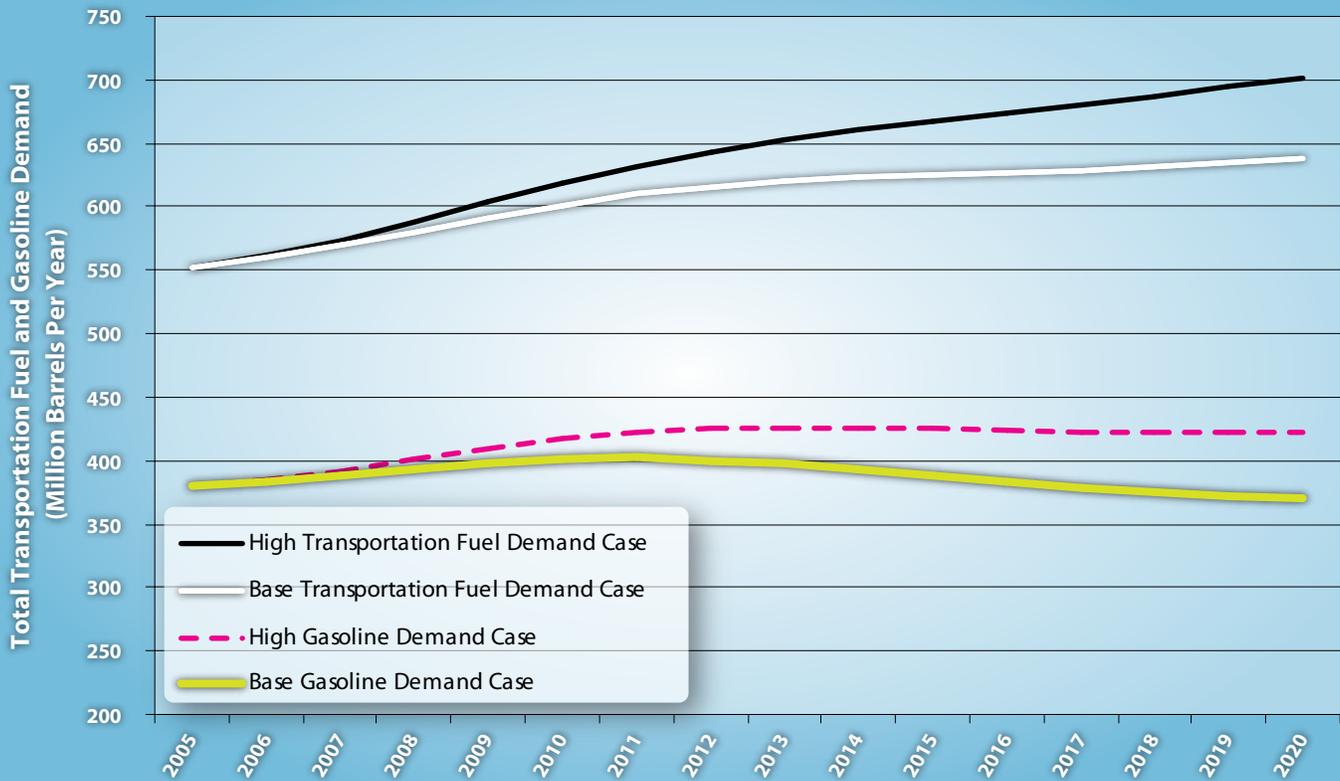
Exports to Nevada and Arizona rely on pipelines that are linked to distribution terminals located in Reno, Las Vegas, and Phoenix. This network of interstate pipelines is owned and operated by the Kinder Morgan Pipeline Company. Demand for transportation fuels in each of these states is increasing rapidly. 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

Figure 7-4: Projected California Gasoline Prices



Source: California Energy Commission, *Transportation Energy Forecasts for the 2007 Integrated Energy Policy Report*, September 2007, CEC-600-2007-009SF.

Figure 7-5: Transportation Fuel Demand



Source: California Energy Commission.

increase at a rate of 2.4 to 2.6 percent per year from 2006. These additional pipeline exports will either have to be produced by California refineries or have to be imported through Southern California’s increasingly constrained petroleum infrastructure.

California Ethanol Demand

Currently, ethanol is blended into the gasoline pool to about 6 percent. 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.²⁹³ Energy Commission staff believes the majority of California’s gasoline market will contain 10 percent ethanol (E-10) by

2012. As such, ethanol demand in the state under the Base Case gasoline demand scenario is expected to increase from almost 23 million barrels in 2006 to approximately 40 million barrels in 2012, a 10 percent average annual rate of growth.²⁹⁴ The 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.

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

²⁹⁴ In the high gasoline demand and limited in-state ethanol production scenario, total imports of ethanol could grow to 36 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, total ethanol imports could decline to 21 million barrels by 2020.

²⁹³ <www.energy.ca.gov/low_carbon_fuel_standard/>.

financing are also pursued to completion, annual in-state conventional ethanol 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. These emerging fuels, such as ethanol and biodiesel, can potentially displace a significant volume 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 two major areas of concern — the constrained petroleum infrastructure and options to reduce petroleum dependency (alternative fuels and emission and vehicle standards) — that reduce its greenhouse gas 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 (2005 IEPR)* noted that although some necessary improvements have been 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 it is to meet its rising fuel demand.

Little has improved since the *2005 IEPR*; in fact, the outlook for improvements to 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 exceeding 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, the magnitude and timing of marine terminal expansion activity, and the actual demand that occurs. Several conclusions from the *2005 IEPR* 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 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 that accommodate the increased number of vessels carrying cargoes of crude oil, gasoline, diesel, and jet fuel must also expand. Without an adequate import infrastructure, supplies of transportation fuels will not be sufficient 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.

Vessels unable to unload cargoes despite an immediate need for the product not only impact the tankers' owners, with delay costs of \$30,000 to \$100,000 per day, but also consumers, with increased retail fuel costs. For example, a 10-cent-per-gallon increase in gasoline, diesel, and jet fuel prices can mean more than \$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 experience significant marine vessel traffic.

Over the past 15 years, approximately 6 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, or refusal to renew existing marine terminal operating leases, erodes the ability to meet California's transportation fuel demand. Constrained storage capacity also limits increased imports of alternative fuels, in particular the 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 and recreational development and by port representatives for expansion of cargo container handling facilities.

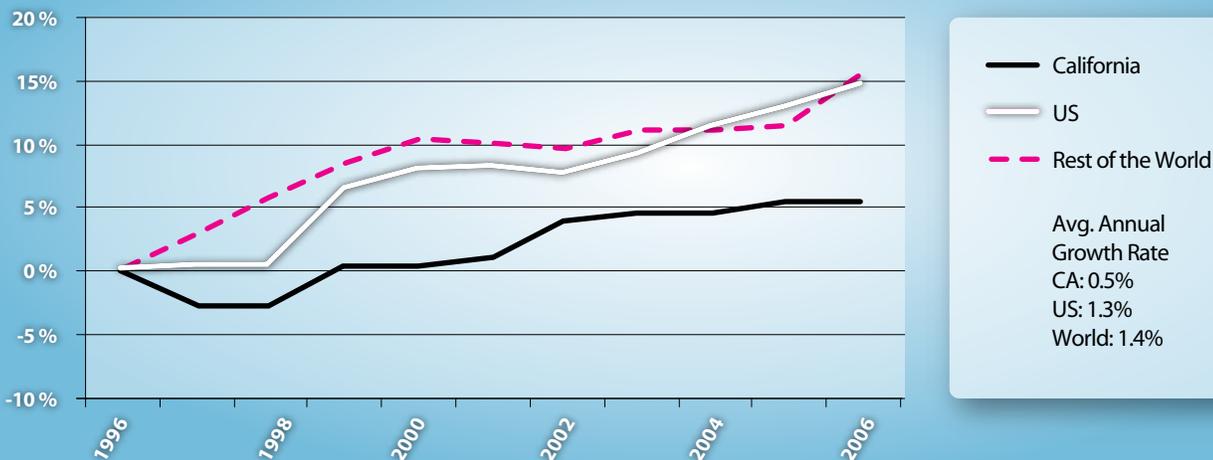
Dredging and Maintenance Standards

Unlike facilities in the Los Angeles Basin, San Francisco Bay marine petroleum terminals face significant limitations caused by the relatively shallow depths of their shipping channels. The draft, or depth, at which a vessel sits in the water, particularly modern, very large crude carriers, 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 limit the allowable time 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 fuel 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

Figure 7-6:
Refinery Capacity Growth for U.S., California, and the World



Source: California Energy Commission; Media Briefing Presentation on Energy Commission Spring 2006 Price Spike Report to the Governor, CEC-999-2006-015.

Lands Commission in 2004. MOTEMS are a comprehensive standard for the design, construction, maintenance, inspection, and repair of petroleum marine terminals. The primary purpose of these standards is to prevent crude oil and petroleum product spills. Since the average age of most of these marine terminals is more than 50 years, their design and configurations have not been updated to accommodate the growth in vessel size or structures. Applying the MOTEMS 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 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 of oil terminals in order 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 their capacity to process crude oil. In 2005, California refineries processed 674 million barrels (1.8 million barrels 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 7-6). Based on forecasted increases in future transportation fuel consumption in California and neighboring states, demand is growing 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 almost 1 percent per year through 2020. The rate of refinery growth in the Pacific Northwest (Washington state), as well as potential future projects to increase the capability to produce California fuels will increase in importance since this region is a modest source of California transportation fuels. It is

therefore likely that future *IEPR* work will expand to incorporate a larger regional outlook for refinery growth and individual state demand projections, compared to the three-state analysis (California, Arizona, and Nevada) conducted for *2007 IEPR*.

Even this small, expected refinery growth requires more tankers than are presently available 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 increased levels of crude oil imports and storage capacity. Imports of crude oil into California are expected to rise at an annual average rate between 1.7 and 2.7 percent per year through 2020.

Additional storage tank capacity necessary to meet California's product storage requirements by 2020 ranges from 5.4 million to 13.1 million barrels, and the additional crude oil storage capacity needed ranges from 5 to 17 million barrels. California must prepare for this range of additional storage capacity even as it develops and implements its alternative fuels plans under AB 1007. Additional infrastructure will be necessary to meet California's transportation requirements, even with alternative fuels meeting a greater percentage of those requirements.

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. This facility is a critical element of the assumption of adequate capacity through 2015. Without an expansion of the existing crude oil import capability for the San Pedro harbor, refiners will eventually be forced to reduce production of transportation fuels as they run out of options to import additional crude oil. It is estimated that this spare crude oil import capacity could be used up as soon as 3 to 5 years from today. Further delay of the release of the draft environmental impact report for the Pier 400 project by the Port of Los Angeles could extend the ultimate completion date long enough to 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 will range from 167 to 291 per year, depending on assumptions about state oil production and refinery capacity additions. 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.

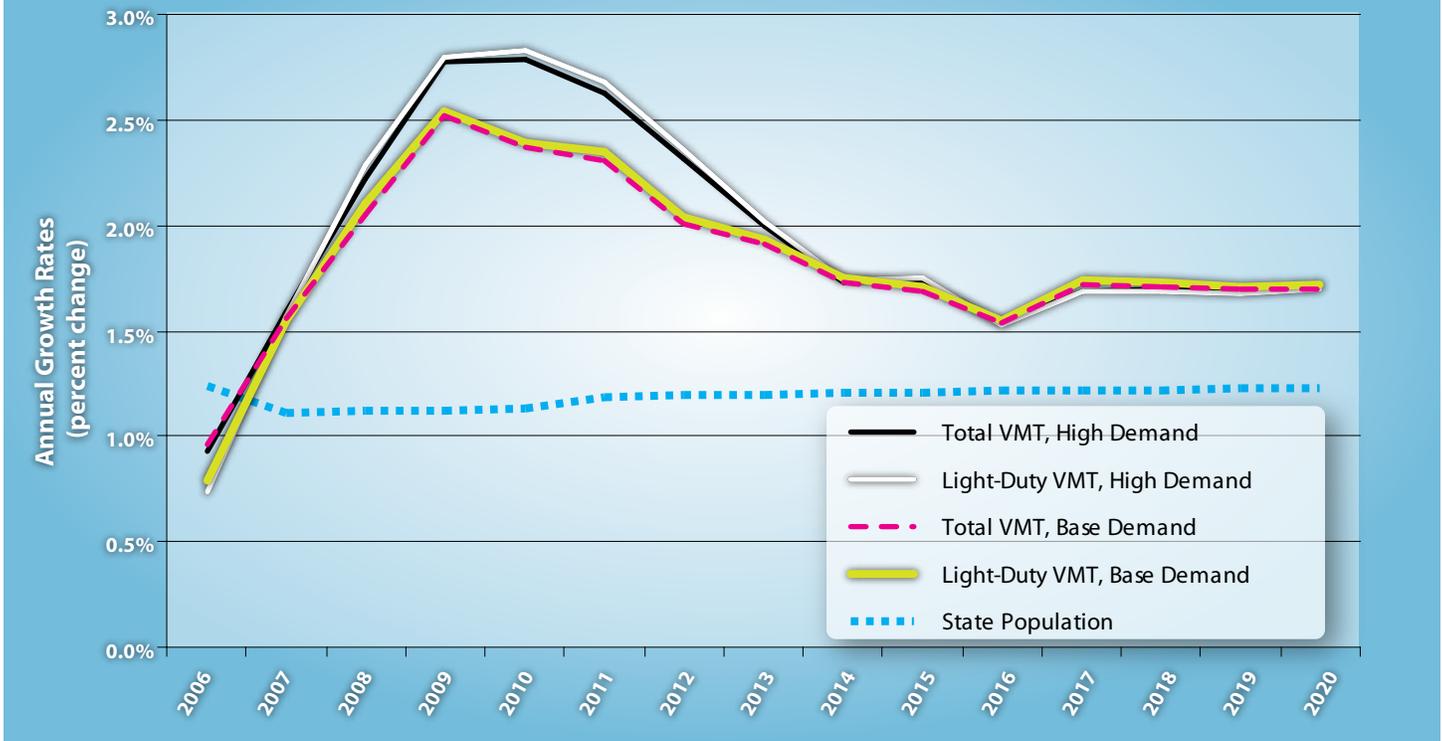
The proportion of criteria pollutants by various marine vessels from petroleum tanker emissions are marginally less than emissions from container ships per port visit. Overall, emissions from marine tankers in 2001 represented between 1.2 and 8.2 percent of air pollution from all sources in the Port of Los Angeles, depending on type of pollutant.

Providing Transportation Options with Efficiency and Alternative Fuels

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 7-7 shows the narrow range of future travel demand expected under differing 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 are extensive and poorly served by public transit. Reducing public access to work, recreation, and other travel cannot be achieved without disruption and economic loss. Moreover, population growth translates directly into increases in aggregate travel demand. Future land use decisions will impact this relationship, as described in Chapter 8.

Consumers must have a broader set of choices if they are to simultaneously reduce the environmental, social, and economic costs of transportation energy use while maintaining their mobility. Although conventional petroleum fuels will be the

Figure 7-7: A Population on the Move



Source: California Energy Commission.

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.

Government mandates, policy directives, incentives, and increased concerns over the negative environmental and economic consequences of global climate changes all indicate that there will be an increase in 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 must 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 it meets its 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 its growing population, this should be viewed as a strategy to allow time for the market and consumer behavior to adjust 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.

High-Speed Rail

With California's relentless population growth, demand for air travel will also increase — particularly between the northern and southern portions of the state. California's airports, however, are reaching their capacity to provide service, and proposals to expand San Francisco and Los Angeles airports have met with strong opposition from environmentalists and local communities.

Aviation accounts for about 10 percent of greenhouse gas emissions from transportation in the U.S., or about 2.7 percent of total national greenhouse gas emissions. Because international treaties prevent California from regulating aviation fuels, those fuels are not covered by the state's low carbon fuel standard.

At some point, California will have to provide an alternate means of travel between northern and southern California, one that also reduces greenhouse gas emissions. A potential option is a high-speed rail system, similar to those currently in use in Europe and Asia. The Center for Clean Air Policy estimates that high-speed rail in California could displace 1.3 million metric tons per year of CO₂ from airplane emissions.

The California High-Speed Rail Authority was created in 1996 to build a high-speed train network to transport passengers between the state's major metropolitan areas. The full system will cost more than \$33 billion to build and will take 8 to 11 years to develop and begin operation of an initial segment of the train.

Currently, a \$10 billion bond measure to help pay for high-speed rail is slated for the November 2008 ballot. However, political leaders have suggested delaying the measure (which has been delayed twice before) to 2010 or 2012.

Corporate Average Fuel Economy Standards

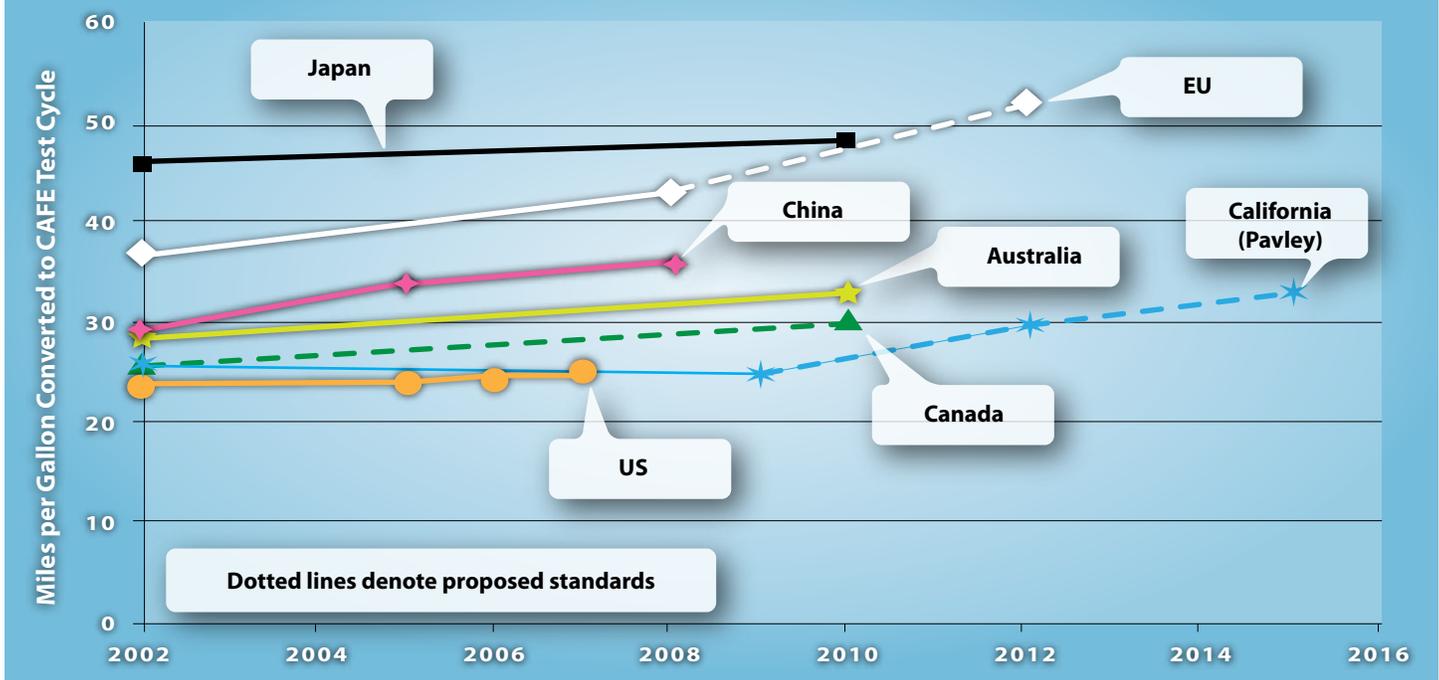
The average, on-road fuel economy of cars and light-duty trucks in California increased from 12.6 miles per gallon (mpg) in 1970 to 20.7 in 1985 as a result of federal standards. These standards have not substantively changed in the last 22 years. Fleet averaged, on-road fuel economy has deteriorated steadily as consumers purchased more light trucks, especially sports utility vehicles (SUVs), which meet a lower mile-per-gallon corporate average fuel economy (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 two 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 2003, NHTSA adopted new, "reformed" light truck CAFE requirements 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 the standard to 21.0 mpg in 2005, 21.6 mpg in 2006, and 22.2 mpg 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.

Figure 7-8: Comparison of Fuel Economy of Passenger Vehicles



Source: Pew Center on Global Climate Change, *Comparison of Passenger Vehicle Fuel Economy and Greenhouse Gas Emission Standards Around the World*, December 2004.

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 the fuel efficiency standard for cars to 35 mpg by 2020. By November 2007, no action had been taken by the House of Representatives, and the fate of any legislation to modify corporate average fuel economy 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 lose market share to other companies. By integrating "fuel economy discipline" through more demanding CAFE requirements, 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.²⁹⁵ 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 standards than California and United States (Figure 7-8).

²⁹⁵ McManus, Walter S., Ph.D., director, Automotive Analysis Division, University of Michigan Transportation Research Institute, Ann Arbor, Michigan, *The Impact of Attribute-Based Corporate Average Fuel Economy (CAFE) Standards: Preliminary Findings*, July 2007, UMTRI-2007-31, p. 5.

A study by the Union of Concerned Scientists²⁹⁶ 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 decrease the demand for oil in the U.S. by close to 2.5 million barrels of oil per day.

Since more than 39 percent of California’s greenhouse gases 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 U.S. market to improve from a 2005 base of 23.7 mpg to 32 to 35 mpg.²⁹⁷ The modest improvements seen to 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 single most significant and cost-effective petroleum reduction strategy resulting from this joint study, which was based upon technologies either already on, or about to enter, the market.

Fuel Substitution Options — Assembly Bill 1007 Alternative Fuels Plan

Governor Schwarzenegger, in his response to the 2003 *Integrated Energy Policy Report*, called upon the Energy Commission to craft a workable long-term plan to increase the use of alternative fuels. Recent legislation, AB 1007, directs the Energy Commission, in partnership with the 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 the use of alternative fuels in 2012, 2017, and 2022.
- Recommend policies, such as standards, financial incentives, and research and development programs, to stimulate the development of alternative fuel supply, new vehicles and technologies, and fueling stations.

The Energy Commission initiated a process involving more than 50 multiple one-on-one meetings with key stakeholders and six public workshops conducted over the past year. The Plan, developed in partnership with the ARB, was adopted by the Energy Commission on October 31, 2007.

The Plan presents actions California must take to increase the use of alternative fuels and make alternative fuels a significant option to meet the state’s transportation energy needs in an environmentally sound and sustainable way. Sustainability requires the state to meet its future transportation energy needs with a growing viable supply of alternative fuels and to ensure that in accessing biofuels as alternative fuels, food access and energy crop needs are balanced, biodiversity is protected, and water demands and use of agricultural chemicals do not harm the environment.

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

²⁹⁶ <www.ucsusa.org/clean_vehicles/fuel_economy/35-mpg-by-2020-benefits.html>.

²⁹⁷ Ibid., Table ES-2.

longer term vision for the year 2050, increased use of alternative fuels, 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)²⁹⁸
- Greenhouse gas reduction: Assembly Bill 1493, 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
- State air quality goal: on-going reductions in criteria pollutants and toxic air contaminants

The Plan concludes that existing programs and regulations alone cannot achieve the state's multiple policy goals; the state needs a portfolio of alternative, low-carbon fuels to meet the multiple goals of petroleum use and greenhouse gas emission reduction and biofuels production and use. The Plan recommends multiple strategies which combine private capital investment, financial incentives, and technology advancement approaches.

Achieving the state's petroleum use reduction, climate change air quality, 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 and state incentives will be needed to complement mandates, standards, and regulations, and they must be coordinated, sustained, and consistent over the 20- to 30-year period. More importantly, substantial capital investment by the private sector must be properly directed toward advanced

technology and infrastructure. With these strategies, the Plan identifies the potential for steady and substantial growth in the use of many alternative fuels, the mix of which will change and evolve over the near term (2007–2015), mid term (2016–2030,) and long term (2031–2050).

Full Fuel Cycle Evaluation

Figure 7-9 shows the greenhouse gas and petroleum reduction performance of new light-duty vehicles on a well-to-wheels basis for selected alternative non-petroleum fuels as a function of feedstock, compared to Phase 3 Reformulated Gasoline. The figure clearly shows the greenhouse gas emissions are dependent on feedstock origins and production pathways.

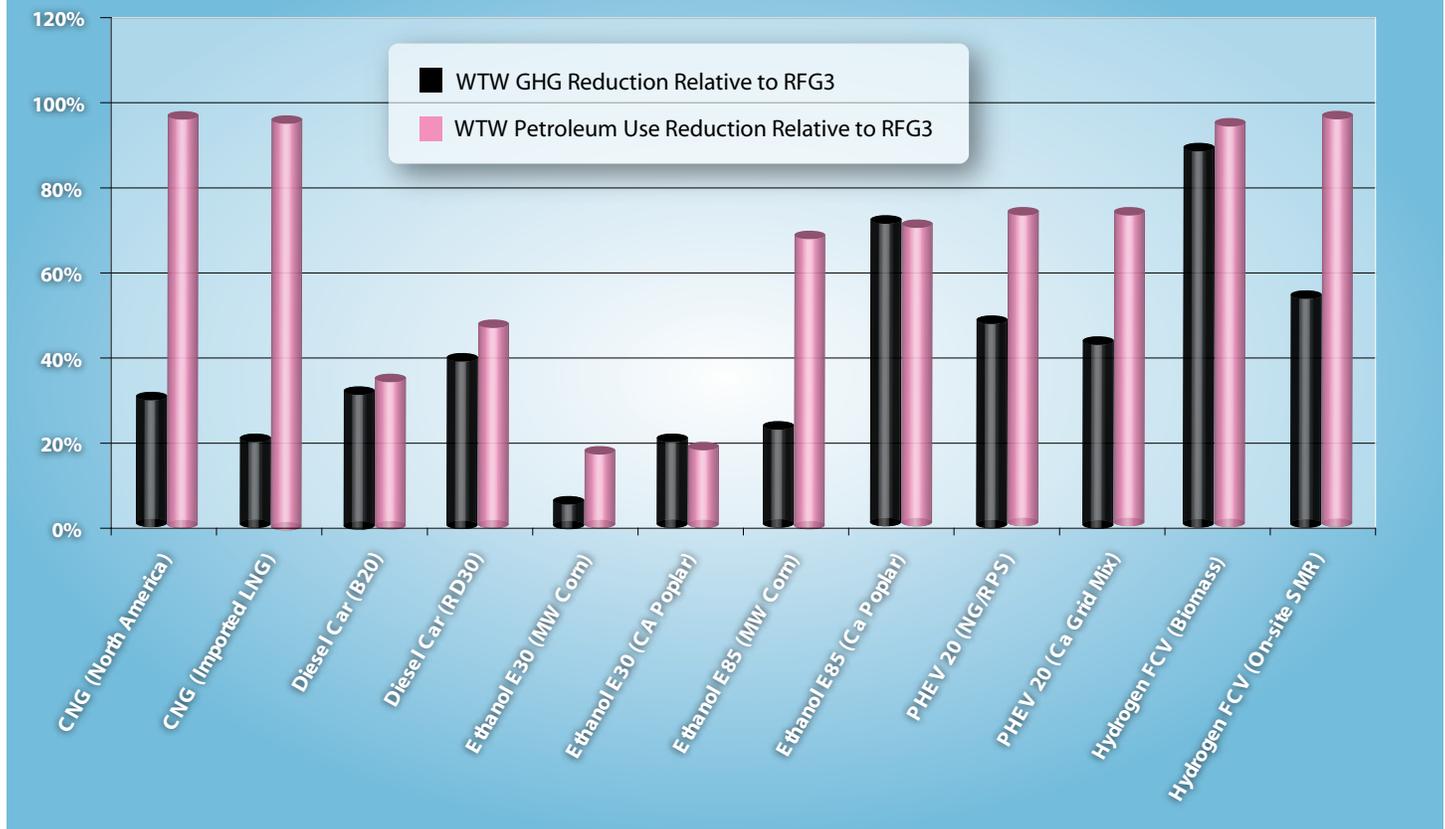
Results of the Plan's full fuel cycle well-to-wheels analysis demonstrate that alternative fuels can provide substantial greenhouse gas reduction benefits when used in mid-size passenger cars and urban buses. Depending on the fuel pathway chosen, fuels such as ethanol, natural gas, liquefied propane gas, electricity, and hydrogen have decided advantages over conventional gasoline and diesel fuels. Most of the alternative fuels have a 10 percent or better carbon intensity, when compared to petroleum fuels. The Energy Commission plans to update the full fuel cycle analysis in future IEPR cycles to address sustainability issues and land use conversion impacts of biofuels.

Alternative Fuels Goals

Goals for each fuel were developed using a scenario approach without expressing a policy preference for any single fuel or technology. Each scenario has a Business-As-Usual, 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

298 California Energy Commission, *Reducing California's Petroleum Dependence*, August 2003, CEC-600-03-005.

Figure 7-9: Vehicle Greenhouse Gas and Petroleum Reduction Performance



Source: California Energy Commission, Full Fuel Cycle Assessment: Well to Wheels Energy Inputs, Emissions and Water Impacts: State Plan to Increase the Use of Non-Petroleum Transportation Fuels, AB 1007 (Pavley) Alternative Transportation Fuels Plan Proceeding, Revised, August 2007, CEC-600-2007-004-REV.

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

Biofuels, produced from the state’s agricultural, forestry, and urban waste residues, should be pursued in the short term because of the resulting petroleum use 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 CO₂ 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 have to be better quantified.

Key Findings and Conclusions

The Plan recommends a five-part strategy to achieve the state’s petroleum reduction, biofuels, and greenhouse gas reduction goals.

A multi-part strategy will maximize the use of alternative fuels: relying on increased alternative fuels use; blending biofuels; advancing fuels and vehicle technologies; improving vehicle fuel efficiency; and implementing measures to reduce vehicle miles traveled.

The Plan established targets on a gallon of gasoline equivalent basis for alternative fuels use in the on-road and off-road sectors (excluding air, rail, and marine), including but not limited to, electricity, natural gas, propane, hydrogen, ethanol, renewable diesel, and biodiesel of 9 percent by 2012, 11 percent by 2017, and 26 percent by 2022.

Table 7-1: Alternative Fuels Use Goals			
Alternative Fuels Case	Milestone Year		
	2012	2017	2022
AB 1007 Goals (Moderate Case)	9%	11%	26%

Source: California Energy Commission, *State Alternative Fuels Plan*, October 2007, CEC-600-2007-011-CTF.

These strategies can help achieve the 2050 future vision outlined in the Plan and support the Governor’s goal of reducing statewide greenhouse gas to 80 percent below 1990 levels by 2050.

The combination of regulations or standards, financial incentives, and technology advancements are needed to achieve the state’s multiple policy goals.

The Low Carbon Fuel Standard will achieve 30 percent of the transportation sector’s proportional share of the greenhouse gas reductions; provide a durable framework for the production and use of alternative fuels; and stimulate technology innovation.

Private investment and state and federal incentive funding are needed to offset the cost difference between gasoline or diesel and alternative fuel use; share the cost of installing fueling stations; and fund the development and demonstration of clean and advanced transportation technologies to the extent that market competition and market mechanisms cannot fulfill this need.

Assembly Bill 118 (Núñez, Chapter 750, Statutes of 2007) provides a source of state incentive funding to stimulate production and use of alternative fuels in California.

Recommendations

To continue to meet California’s growing transportation fuels needs while also complying with the directives of AB 32, 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.

- 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.
- Monitor the impact on infrastructure development 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.
- Press for a firm federal funding mechanism to maintain an adequate depth for tanker traffic in the Pinole Shoal in San Francisco Bay.
- Update and reissue every two years the State Alternative Fuels Plan, as part of the Energy Commission’s biennial *Integrated Energy Policy Report*, to include specific recommendations; state agency, and private sector responsibilities; and timetables necessary to increase the use of alternative fuels in California.
- Work collaboratively with Air Resources Board, key stakeholders, and other relevant agencies to regularly update the full fuel cycle analysis in an open and transparent manner.
- Continue to refine the underlying economic analysis, assessment of alternative fuels’ current status, and market potential for alternative fuels.
- Improve its analytical ability to better quantify the agricultural land conversion and water consumption effects of biofuels production.
- Develop and recommend sustainability standards to guide the future development of alternative fuels in California, in partnership with the Air Resources Board.
- Move quickly to implement AB 118, beginning with forming the advisory body as directed in the legislation.
- Develop a strategic investment plan for alternative fuel and vehicle incentives, as required by AB 118 to be updated annually.

Chapter 8

Mitigating Energy Needs with Smart Growth



*"The oldest task in human history: to live
on a piece of land without spoiling it."*

Aldo Leopold, Ecologist (1887–1948)

The neighborhoods Californians live in and the cars they 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 several 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 and large cities like Los Angeles. More expensive housing and less land available for development have pushed suburbs even farther from city centers, with potential homeowners employing the “drive ‘til you qualify” mortgage option in the hope of finding affordable housing.

This 60-year legacy of suburban growth and increased auto use and an inexpensive and reliable fuel supply have increased the miles Californians drive to work, to the grocery store, to soccer games, and to social events. The resulting vehicle miles traveled account for 27 percent of California’s greenhouse gas emissions and are increasing at a rate markedly faster than the population.

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 2000.²⁹⁹ Residential energy use (electricity and natural gas) accounts for 14 percent of California’s greenhouse gas emissions.³⁰⁰ 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 better than 20 percent more primary energy than those of multi-family housing and 9 percent more than those of single-family attached housing.³⁰¹

California’s efforts to reduce greenhouse gas emissions lead the nation. Programs to replace petroleum with cleaner alternative fuels, reduce greenhouse gases from new cars sold in the state, and reduce the amount of carbon in the state’s fuels are some of the leading edge policies the state is implementing to reduce the impact of transportation on California’s climate.

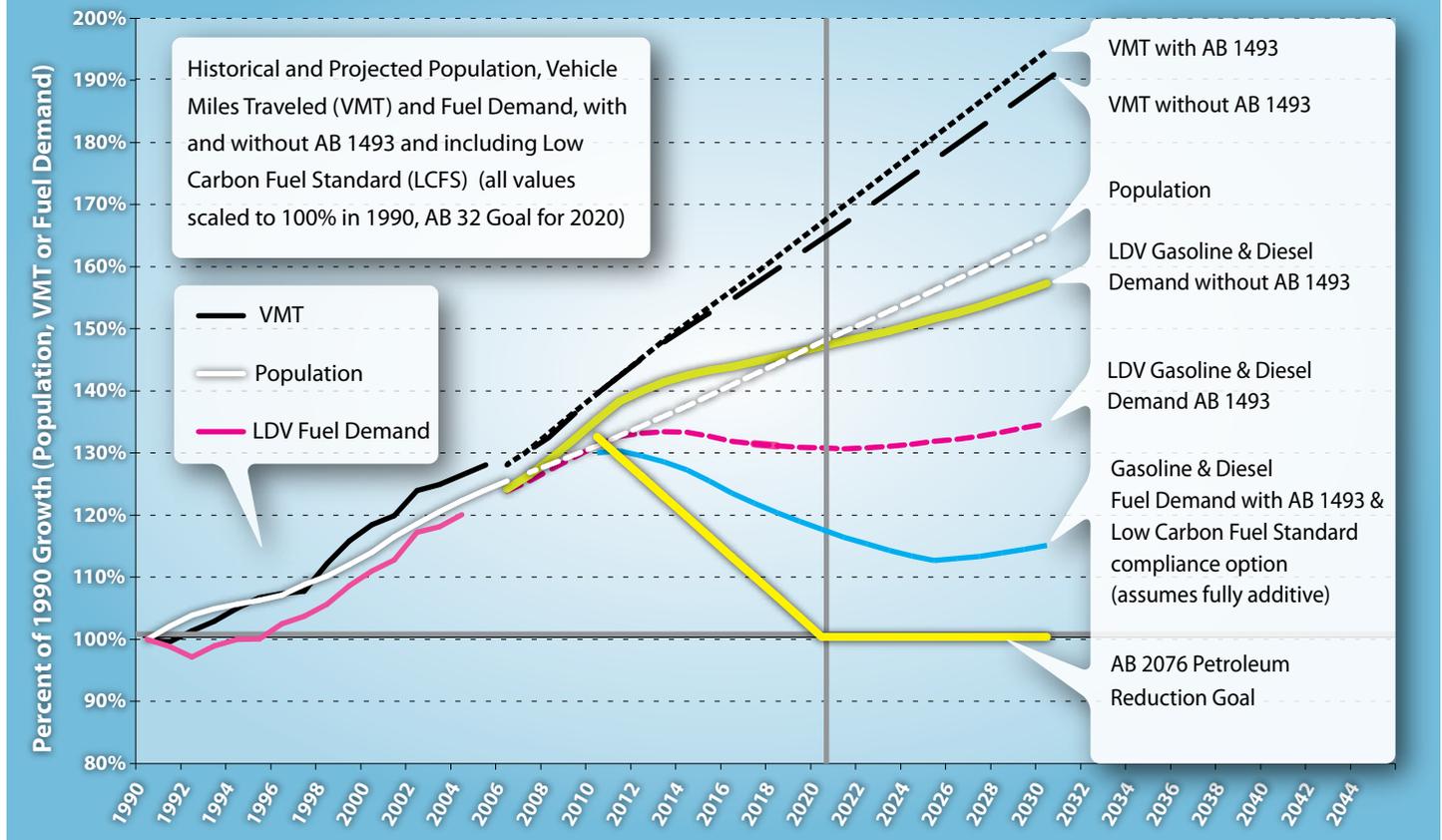
But even these programs, added together, are not enough to meet AB 32 goals due to the significant expected increase in vehicle miles traveled, which is impacted by community design choices. Given the long-term nature of neighborhoods, there are also likely

299 National Association of Homebuilders, *America’s Housing 1900-2000, A Century of Progress*, <www.nahb.org/assets/doc/files/v5-51-3200312545PM.pdf>.

300 www.climatechange.ca.gov/policies/1990s_in_depth/page5.html.

301 Rong, Fang, 2006, *Impact of Urban Sprawl on U.S. Residential Energy Use*, University of Maryland, <https://drum.umd.edu/dspace/handle/1903/3848>.

**Figure 8-1:
Historical and Projected Population, Vehicle Miles Traveled, and Fuel Demand (2007)**



Source: California Energy Commission.

significant indirect energy savings from improved infrastructure design attributes, such as narrower streets, more efficient street lighting, enhanced tree shading, reduced imperviousness of pavement, and maintenance of natural drainage courses that should be considered. A new land use dynamic is needed. Planning that results in a larger proportion of more compact and energy- and resource-efficient homes close to transit, work, and services — smart growth — must be a state priority.

Impact of Land Use on Energy Consumption, Production, and Distribution

Urban growth patterns have caused California’s vehicle miles traveled to increase at a rate of more than 3 percent a year between 1975 and 2004, markedly faster than the population growth rate

over the same period. These vehicle miles traveled created 130.9 million metric tons of CO₂ in 2004. The Energy Commission estimates that vehicle miles traveled will continue to grow at nearly 2 percent annually into the foreseeable future. A continuing increase in vehicle miles traveled 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 (Pavley, Chapter 200, Statutes of 2002), which requires the Air Resources Board to adopt regulations to reduce the emissions of greenhouse gases by motor vehicles, and the Low Carbon Fuel Standard.³⁰²

The degree to which transportation greenhouse gas emissions must be reduced is uncertain given the status of several approaches to reduce these emissions. However, it is apparent that reduced growth of vehicle miles traveled will be required to meet

302 <www.energy.ca.gov/low_carbon_fuel_standard/>.

greenhouse gas reductions goals. It is imperative that land use planning and infrastructure investments place a high priority on reducing the growth of vehicle miles traveled. Meeting Executive Order S-3-05's long-term goal, which requires a reduction of greenhouse gas emissions by 2050 to 80 percent below 1990 emissions levels, would certainly require nearly carbon-free transportation and strong actions to reduce vehicle miles traveled.

Figure 8-1 shows California's growth in vehicle miles traveled. Gasoline and on-road diesel consumption are indexed to the 1990 value, the year that is the AB 32 greenhouse gas emission target required to be met by 2020. Figure 8-1 can also be used to view the historical growth in transportation fuel use (and associated greenhouse gas emissions) relative to vehicle miles traveled 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 and vehicle miles traveled projected by Energy Commission staff for the *2005 Integrated Energy Policy Report*. Transportation fuel use is plotted both with and without the effect of AB 1493, and one line shows the result with AB 1493 and with the Low Carbon Fuel Standard, assuming it is entirely added to reductions obtained by implementing AB 1493.³⁰³

Since greenhouse gas emissions from gasoline are such a large portion of total state greenhouse gas 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 more than 1990 consumption, if AB 1493 is not approved by the courts, and about 31 percent more if it is upheld and implemented on the schedule adopted by the California Air Resources Board (ARB).

Figure 8-1 also shows the effect of the Low Carbon Fuel

303 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.

Standard, 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.³⁰⁴ The Low Carbon Fuel Standard technical report shows annually decreasing carbon intensity,³⁰⁵ but the effects of the Low Carbon Fuel Standard are projected only to 2020. The additive effect of these strategies reduces future transportation fuel consumption to the point that by 2025, it is only about 15 percent above 1990 consumption. This indicates that even with AB 1493 and the Low Carbon Fuel Standard, significant further efforts (roughly equivalent to the projected magnitude of AB 1493 or the Low Carbon Fuel Standard) 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 vehicle miles traveled, influencing the distance that people travel and the mode of travel they choose.

A 2002 U.S. Environmental Protection Agency study³⁰⁶ 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 sprawl characteristics mentioned above had significantly less average vehicle ownership, daily vehicle miles

304 The Air Resource Board's Zero Emissions Vehicle Program is designed to evolve the California passenger car fleet to vehicles with no direct emissions. <www.arb.ca.gov/msprog/zevprog/zevreview/zev_review_staffreport.pdf>.

305 Table 2-2 of the Low Carbon Fuel Standard technical report.

306 Ewing, R., R. Pendall, and D. Chen, *Measuring Sprawl and Its Impact*, Smart Growth America/ U.S. Environmental Protection Agency, Washington D.C., 2002.

traveled 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 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 vehicle miles traveled. A doubling of neighborhood density can be expected to result in approximately a 5 percent reduction in both vehicle trips and vehicle miles traveled 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 cities³⁰⁷ — seemed to produce substantially lower vehicle miles traveled than dense mixed-use developments in the exurbs.³⁰⁸ Trip frequencies seem to depend mostly on socioeconomic and demographic factors, but overall vehicle miles traveled 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 [vehicle miles traveled] by about 15 percent per capita over 30 years at an average metropolitan growth rate.”³⁰⁹

The length and number of work trips seem to be growing because of an imbalance between the availability and affordability of housing with the number and earning power of jobs. In the San Francisco Bay Area, average commuting vehicle miles grew by 23 percent between 1980 and 1990 as rising housing prices forced more and more people to move further out and commute into San Francisco. If jobs were brought into balance

with housing, “(all) things being equal, every 10 percent increase in the number of jobs in the same occupational category within four miles of one’s residence (would be) associated with a 3.29 percent decrease in daily work-tour VMT.”³¹⁰

A balance of jobs and housing may reduce daily work vehicle miles traveled, which is important in managing congestion, but work trips account for a small and shrinking percentage of total travel. According to the National Household Travel Survey 2001 Highlights Report, 45 percent of daily trips were made for family and personal reasons, such as shopping and running errands; 27 percent were made for social and recreational purposes; and 15 percent were made for commuting to work.³¹¹ “Nonwork is the major reason for travel even in peak travel periods. It may also be linked to the rapidly increasing numbers of commercial vehicles in service.”³¹²

Non-work vehicle miles traveled is a large portion of travel, which may not respond to traditional methods of reducing vehicle miles traveled in the same way.

Transit-oriented developments, for example, may be more successful if they are designed to facilitate non-auto errand trips as well as transit commutes. The relationships between possible explanations and travel behavior are complex, and researchers are just beginning to try to understand them.

Unintended Tax Consequences

Land use patterns, and the vehicle miles traveled 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.

307 A city’s downtown and adjacent neighborhoods.

308 Prosperous rural communities beyond the suburbs that become commuter towns for an urban area.

309 Professor and director, National Center on Smart Growth, University of Maryland, College Park, Maryland.

310 Cervero, Robert and Michael Duncan, “Which Reduces Vehicle Travel More: Jobs-Housing Balance or Retail-Housing Mixing?” *Journal of the American Planning Association*, Autumn 2006, Vol. 72, No. 4, p. 482.

311 U.S. Department of Transportation and Bureau of Transportation Statistics, 2003, NTHS 2001 Highlights Report, BTS03-05, Washington, D.C.

312 Nelson, Dick and John Niles, January 9–13, 2000, *Observations on the Causes of Nonwork Travel Growth*, Transportation Research Board 79th Annual Meeting, Washington, D.C., Paper No. 00-1242, p. 2.

Proposition 13 significantly cut local tax revenue 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.

Residential Energy Supply and Use Offer Additional Opportunities

To ensure a reliable and secure source of electricity and reduce residential greenhouse gas 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 and more efficient streetlights are some measures that would produce significant energy savings at the individual building and community levels. 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 re-use 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 standards. In addition, the Great Park will incorporate advanced metering infrastructure, solar photovoltaics, district heating and cooling, distributed generation, transportation strategies, lighting technology, waste to energy, and grid islanding.³¹³

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. 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

313 Irvine Great Park Energy Subteam Update, November 2006.

California Water Plan, and storm water plans) and the state's purse strings can be used as levers to affect land use patterns.

Local Government Plans Must Address Energy and Greenhouse Gas Emissions Reductions

The state has limited authority in direct land use planning; rather, it conducts activities that influence land use decisions indirectly. 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 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 more than half of the state's jurisdictions have general plans more than 10 years old.³¹⁴

Currently, there is no state guidance for how local governments should assess, report, avoid, or mitigate greenhouse gas emissions resulting from their land use decisions.

The passage of SB 97 (Dutton, Chapter 185, 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 greenhouse gas emissions or the effects of greenhouse gas emissions. This will lead to local governments performing analysis of, and offering mitigation efforts for, the potential greenhouse gas emissions impacts of growth within their jurisdictions and will require them to address greenhouse gas considerations in their general plan and other planning efforts.

Issues such as housing, transportation and congestion, economic development, air pollution, and greenhouse gas reduction 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 instead allow low density, sprawling development in the jurisdiction, the region could still suffer from the negative impacts (congestion, greenhouse gas emissions, and so forth) of the development.

Regional Blueprint Planning Efforts Show Promise

California's Regional Blueprint Planning Program³¹⁵ 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 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 and in business, academia, development, construction, and environmental organizations to foster consensus on a vision and preferred land use pattern in a given region. The regional blueprint planning grants are

314 Roberts, T., remarks presented at Land Use and Energy Workshop, California Energy Commission, September 22, 2006.

315 <calblueprint.dot.ca.gov>.

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 2% New Housing	41% New Jobs 38% New Housing	36% more new jobs near transit 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 CO ₂ 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: Sacramento Area Council of Governments, Blueprint Program, 2005.

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 vehicle miles traveled. 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 vehicle miles traveled by 12.3 miles per household per day, and produce 15 percent less CO₂ and particulate matter per capita, as compared to the business-as-usual case Base Case 2050 (see Table 8-1). However, even though vehicle miles traveled decline compared to the business-as-usual Base Case 2050, Sacramento total regional vehicle miles traveled per day grow from 43 million in 2000 to 53 million in 2050 because the number of households more than doubles during that time frame.

The completed Blueprints are in early stages of implementation and will need technical, financial, and regulatory assistance to achieve maximum results. Smaller metropolitan planning organizations, with less staff and modeling capability, could benefit from mentoring assistance from the larger metropolitan planning organizations that have been able to move faster and generally further with their Blueprint programs. The state can replicate best practices completed in some Blueprint programs

to help other regions to form a value added data collaborative. These collaboratives could pull city and county geographic information system data into one place where the members of the collaborative could cost-effectively update, coalesce, and amend the data into one fully accessible, integrated database needed for quality Blueprint planning. Aggregated data increases the capacity of regional transportation planning, air quality planning, and local general planning to coordinate for improved energy and greenhouse gas efficiency. Each of the metropolitan planning organizations is unique, with its own approach to travel modeling, vehicle miles traveled analysis, and greenhouse gas emission quantification. Third party review of the range of methods for the purpose of producing a set of research, data development, and modeling improvements to advance all metropolitan planning organization programs to a single, standardized level of excellence is needed as soon as possible. Model improvements will lend better accuracy to vehicle miles traveled quantification and enhance the state, regional, and local ability to deploy resources to reduce energy use and greenhouse gas emissions.

Blueprint practitioners have requested state support to better assess new challenges presented by the land use demands of energy crops and the effect they have on long-term food production, water demand, and land use patterns affecting vehicle miles traveled and greenhouse gases. Interagency support and funding is needed to develop a knowledge base

and integrate it into land use planning programs for fully informed decision making with energy, environmental, economic, and social tradeoffs clearly defined.

The state must provide assistance to build the many levels of strong leadership necessary to shape land use practices and to guide the development of methods to measure and track the effects of land use on the state's energy and climate goals. A state growth plan, prepared in conjunction with regional and local interests, is essential. 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 compile the data and programs into 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. The statewide plan should be updated every 10 years, adding maturing regional and local data and plans, to keep the state plan current.

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 it 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 only has the authority to 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.

The state can use the disbursement of transportation and housing funds to motivate collaborative planning at a regional level in an attempt to significantly reduce a community's greenhouse gas emissions. A common methodology for reporting and measuring greenhouse gas 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 greenhouse gas 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 84³¹⁶ will determine the extent to which bond monies contribute to less energy-intensive land use and reduce vehicle miles traveled. 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 greenhouse gas 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-

316 Proposition 1B, Highway Safety Traffic Reduction, Air Quality and Port Security Bond Act of 2006; Proposition 1C, Housing and Emergency Shelter Trust Fund Act of 2006; Proposition 1D, Kindergarten-University Public Education Facilities Bond Act of 2006; Proposition 84, Water Quality, Safety and Supply, Floor Control, Natural Resources Protection, Park Improvements.

smart growth areas must pay the full cost of utility line extensions. Some of the programs are already showing reductions in vehicle miles traveled: Portland residents decreased their daily per capita vehicle miles traveled by 4 percent between 1996 and 2005, while the nation and California both increased daily per capita vehicle miles traveled 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 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 and municipal utilities must play an even greater role in planning and development programs and projects. Investor-owned utilities 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 greenhouse gas emissions are in the early stages of exploration. Further research and development is necessary to explain and quantify the effect land use has on energy systems. Research is needed to develop and update existing modeling and decision-support tools to improve the integration of energy considerations into future planning and development efforts. For example, differences in land development patterns result in differences in trip mode choice, number, and length. Mechanisms to account for the "Five Ds" — density, diversity, design, destination, accessibility, and distance to transit — have been developed and successfully used to improve the ability of travel models to assess how vehicle miles traveled are affected

by land use patterns. Many local governments and regional agencies, however, find that access to information and a lack of funding prevent them from improving their models to develop and implement climate-friendly and energy-efficient plans and programs. Other metropolitan planning organizations have used internal funding and grants to successfully integrate land use and transportation planning, embedding the Five Ds sensitivity into their travel models to better assess smart growth options. Best practice data, modeling, and public education methods found in some California metropolitan planning organizations should be packaged and shared with all such organizations.

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 greenhouse gas reduction planning efforts of local governments. A number of currently funded projects support this charge. In the next year, more than \$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 and methodologies are critical to these initiatives.

Transportation research also is underway through PIER funding, with research designed to reduce petroleum consumption and greenhouse gas emissions through increased vehicle efficiency and lower carbon fuels. Creation of new, and validation of existing, 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 vehicle miles traveled must be explored.

Recommendations

- The state should collect required regional plans and adopt a statewide growth management plan to align state planning, financing, infrastructure,

and regulatory land use policies and programs.

- 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 its AB 32 scoping plan. ARB 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 Air Resources Board should require local jurisdictions to adopt plans to reduce their greenhouse gas emissions.
- The Climate Action Team’s Land Use Subgroup should convene a proceeding to develop recommendations for measuring and reducing vehicle miles traveled.
- The state should mandate 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 state 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 and the local air quality management district.
 - Require local governments to adopt the portion of the regional plan and greenhouse gas emission reduction target that impacts their jurisdiction into their general plans. The plans should clearly identify areas where growth and development should and should not occur.
 - Require municipal planning organizations and/or council of governments and air quality management districts 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 integrate 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’, municipal planning organizations’/ council of governments’ and air quality management districts’ adoption of them — shall be updated on a 10-year schedule.
- State infrastructure financing should encourage development that is consistent with the state’s greenhouse gas emission and energy consumption goals.
 - The state should require 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 state should require that all state infrastructure planning, financing, and compliance programs only allow resources — financial, technical, or otherwise — to be spent for development of projects in complete consistency with regional blueprints.
 - The state should require 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 Regional Planning Grant Program and Blueprint Learning Network to assist regional agencies and local governments in developing improved regional land use plans. The grant program should include energy consumption and greenhouse gas emission reduction as primary outcomes of the blueprints developed within the program.
 - The state should work with the Blueprint Learning Network to develop new analytical capacity needed to better inform the long-term planning decisions presented by increased demand for energy crop land allocations and the integrated environmental, energy, economic, and social tradeoffs that will be presented to both rural and urban regional and local governments.
 - The state should work with the Blueprint Learning Network to explore best practices and develop a set of recommendations to improve and standardize the level of accuracy of vehicle miles traveled and greenhouse gas quantification produced by each municipal planning organization and to develop a standardized methodology for applying this information in climate change and energy action plans, blueprint planning, and local planning.
 - When growth management legislation is passed, the Blueprint Regional Planning Grant Program and the Blueprint Learning Network should be modified to support development of the regional growth management plans as specified in the legislation.
 - The state 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 state government, to update its Energy Aware Planning Guide to provide guidance for regional and local governments attempting to adopt local growth management, energy, and climate action plans.
- Once the Sustainable Communities program is established, the Energy Commission should coordinate with the California Department of Transportation's existing research efforts to 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 state 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 policies 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 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.

Appendix
A



Participants in the
2007 Integrated Energy
Policy Report Process

Individuals from many government and private entities either attended public workshops and/or made comments to the proceeding. In an extra effort of interagency cooperation and collaboration, Commissioner John Bohn of the California Public Utilities Commission contributed to many of the workshops and provided valuable input to this proceeding. The Committee thanks Commissioner Bohn and these many other individuals for their participation in the 2007 IEPR process.

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Constellation Generation Group

- John Tormey
- Joe C. Turnage, Ph.D.

Constellation NewEnergy, Inc

- Andrew B. Brown

Council on Foreign Relations

- Charles Ferguson, Ph.D.

Cultural Economist

- Ronald R. Cooke

Cummins Power Generation

- Eric R. Wong

CURRENT Group LLP

- Jim Birnbaum
- Rosemary McMahill

Ecosystem Solar Electric Corporation

- Nick Panchev

Edison Mission Group/Carson Hydrogen Power, LLC

- Lawrence J. Kostrzewa

Electric Power Research Institute

- Richard Rhudy
- Bob Woehl

Ellison, Schneider and Harris

- Douglas Kerner

ENCO Utility Services

- Jack Stermer

Energy & Environmental Economics, Inc.

- Snuller Price
- C. K. Woo

Energy Investors Fund

- John E. Buehler, Jr.

EnerNOC, Inc.

- Carmen Baskette

Environmental Health Coalition

- Laura Hunter

enXco Development

- Greg Blue

Exergy Consulting

- Beverly Alexander

Florida Power & Light Energy

- John Seymour
- Diane Fellman

Flynn Resources Consultants

- Ed Chang

Fresno Nuclear Energy Group, LLC

- John Hutson
- Tom McClean

FTI Consulting

- Tom Lumsden

Fuel Cell Energy, Inc.

- William Karambelas

CALIFORNIA ENERGY COMMISSION

FutureGen Alliance, Inc.

- Michael Mudd

Future Ports

- Elizabeth Warren

Gas Technology Institute

- John Kelly

George Mason University

- Allison Macfarlane, Ph.D.

Global Energy Decisions

- J. Richard Lauckhart

Golden State Water Co. (for Bear Valley Electric Service)

- David X. Kolk

Goldman Sachs

- Curtis Kebler

GPI

- Greg Morris

Green Party of San Diego County

- Lupita Jimenez

Green Power Institute

- Gregory Morris

Harding Consulting

- Jim Harding

Hydro Company, Inc. (dba Nevada Hydro Co., Inc.)

- Rexford J. Wait

ICE Energy, Inc.

- Donald C. Liddell

Independent Energy Producers

- Steven Kelly

Institute for Local Government

- Steve Sanders

Insulation Contractors Association

- Robert Burt

INTERTIE, LLC

- Richard Mrlik

Kern River Gas Transmission

- Brent Arnold

Kinder Morgan

- Donald C. Liddell

League of Women Voters of California

- Janis Hirohama
- Jane Turnbull

Levy Associates

- Roger Levy

Local Power

- Robert Freehling

London Economics International, LLC

- Serkhan Bahceci
- Steven Ostrover

Long Beach Citizens for Utility Reform & Californians for Renewable Energy

- Bry Myown
- Regina Taylor

M.Cubed

- Richard McCann

Marsh Alternative Risk Solutions

- Partho Ghosh

Massachusetts Institute of Technology Laboratory for Energy and the Environment

- Howard Herzog
- James Katzer
- Mort Webster

Metropolitan Water District of Southern California

- Sydney B. Bennion
- Ernest Hahn
- Jon C. Lambeck
- Dianna Mahmud

MightyComm

- Tom Fulks

Milbank, Tweed, Hadley & McCoy

- Kevin McSpadden

Mirant California

- Kerry Hettevik

National Academies

- Kevin Crowley

The National Center for Smart Growth, University of Maryland

- Reid Ewing

Natural Resources Defense Council

- Audrey Chang
- Thomas B. Cochran, Ph.D.
- Ronnie Cohen
- Amanda Eaken
- Lara Ettenson
- David Goldstein
- Kristin Grenfell
- George Peridas
- Victoria Rome
- Devra Wang
- Eric Wanless

Navigant Consulting, Inc.

- Sean Biggs
- Lisa Frantzis
- Ryan Katofsky
- Jay Paidipati
- Forrest Small

Neste Oil Holding (U.S.A.), Inc.

- Henrik Erämetsä
- Neville Fernandez
- Doug Newman

North American Energy Credit and Clearing Corporation

- John Flory

North American Young Generation in Nuclear

- Ken Schrader
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Nuclear Energy Institute

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Oak Creek Energy Systems

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O'Connor Consulting Services

- Tod O'Connor

Ocean Power Delivery

- Des McGinnes

Ocean Power Technologies

- George Taylor

Pacific Gas & Electric Company

- Mike Alexander
- Antonio Alvarez
- Darren Bouton
- Lloyd Cluff
- Robert Cowden
- Kevin Dasso
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- Hugh Meriam
- Jill Scotcher
- Kathy Treleven
- Fong Wan
- Christopher J. Warner

PacifiCorp

- Jeremy Weinstein

PilotPower Group, Inc.

- Thomas R. Darton

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Policy Communications

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Power and Water Resources Pooling Authority

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- Frank von Hippel, Ph.D.

Public Policy Institute of California

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RCM Biothane

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Robertson – Bryan, Inc. (for Delano-Earlimart Irrigation District & Eastside Power Authority)

- Stuart Robertson
- Dale R. Brogan

Ron Hofmann Consulting

- Ron Hofmann

Rumla, Inc.

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San Diego Association of Governments

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San Diego Gas & Electric Company

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- Jim Avery
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- Teresa Farrelly
- Dave Geier
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- William L. Reed
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Sempra Energy Solutions, LLC

- Greg Bass

Sempra Energy Utilities (Southern California Gas Company)

- Bernie Orozco
- Wendy Keliani

Sempra Global Enterprises

- Alvin S. Pac

Sempra LNG

- Dale Kelly-Cochrane

SFA Pacific, Inc

- Dale Simbeck

Sierra Club

- Gene Frick
- Jim Metropulos
- Tom Politeo

Solar Millennium

- Rainer Aringhoff

Southern California Edison Company

- Gary Allen
- Manuel Alvarez
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- Frank J. Cooley
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***Southwest Consortium for Environmental
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- D. Rick Van Schoik

Starwood Energy Group

- Steve Zaminski

Stillwater Associates

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Stoel Rives, LLP

- Jerry R. Fish

Strategen Consulting, LLC

- Douglas C. Liddell

Strategic Energy, LLC

- Carl Boyd

Summit Blue Consulting

- Dan Violette

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- Dwight Stevenson

The Utility Reform Network

- Cynthia Mitchell

TransCanada Corporation

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- Ken Tate

Transmission Agency of Northern California

- James Beck
- James Feider

Turlock Irrigation District

- Howard Shapiro
- Robert E. Jones

Union of Concerned Scientists

- Cliff Chen
- David Lochbaum
- Dai Owen

Utility Savings & Refund, LLC

- Charles Toca

US Renewables Group

- Thomas King

Valerio

- Steve Faichney

Valley Electric Association

- Terry Stagg

VRB Power Systems, Inc.

- Douglas C. Liddell

Wal-Mart Stores, Inc.

- Donald C. Liddell

Waste Management, Inc.

- Chuck White

Wavebob

- Andrew Parish

Wave Energy

- Mirko Previsic

Western Electricity Coordinating Council

- Steve Cauchois

Western Power Trading Forum

- Gary B. Ackerman

Western States Petroleum Association

- Gina Grey
- Joe Sparano

Wind-Works

- Paul Gipe

Woodside Natural Gas

- Colin Coe
- Dane McQueen

Private Individuals

- Rochelle Becker
- Jack Biesek
- F. Brandt
- Norman Burgess
- Tom Campbell
- Joan Carter
- Paula Daillak
- William Denneen
- Constance Dunbar
- Scott L. Fielder
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- Bonnie Raitt
- Jane Carney Schulze
- Chip Sharpe
- Mark Skinner
- S. Swift
- Carl E. Walter



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Energy
Commission

Arnold Schwarzenegger
Governor