CALIFORNIA ENERGY COMMISSION

2009 INTEGRATED ENERGY POLICY REPORT

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ARNOLD SCHWARZENEGGER
GOVERNOR

We dedicate the 2009 Integrated Energy Policy Report to

DR. ARTHUR ROSENFELD

Energy Commissioner
April 2000 – January 2010

A living legend who is widely recognized for his dedication to the cause of energy efficiency and whose leadership in scientific research, technology development, and public policy innovation leaves a lasting and profound legacy.

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PREFACE

The 2009 Integrated Energy Policy Report was prepared in response to Senate Bill 1389 (Bowen, Chapter 568, Statutes of 2002), which requires that the California Energy Commission prepare a biennial integrated energy policy report that contains an integrated assessment of major energy trends and issues facing the state's electricity, natural gas, and transportation fuel sectors and provides policy recommendations to conserve resources; protect the environment; ensure reliable, secure, and diverse energy supplies; enhance the state's economy; and protect public health and safety (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 2009 Integrated Energy Policy Report Committee. As in previous Integrated Energy Policy Report proceedings, the Committee recognizes that close coordination with federal, state, and local agencies is essential to adequately identify and address critical energy infrastructure needs and related environmental challenges. In addition, input from state and local agencies is critical to develop the information and analyses that these agencies need to carry out their energy-related duties. This *2009 Integrated Energy Policy Report* reflects the input of a wide variety of stakeholders and federal, state, and local agencies that participated in the Integrated Energy Policy Report proceeding. The information gained from workshops and stakeholders along with Energy Commission staff analysis was used to develop the recommendations in this report. The Committee would like to thank participants for their thoughtful contributions of time and expertise to the process.

The *2009 Integrated Energy Policy Report* proposes policy and program direction to address the many challenges facing California's energy future that are discussed throughout the body of the report. Specific recommendations are presented in Chapter 4, but the Energy Commission believes that certain policies and programs have priority and even urgency if California is going to address its diverse set of energy goals. The Executive Summary therefore identifies those actions and policies that the Energy Commission considers to be of highest importance.

EXECUTIVE SUMMARY

As California pursues its goal to address climate change by reducing greenhouse gas emissions, the driving force for the state's energy policies continues to be maintaining a reliable, efficient, and affordable energy system that minimizes the environmental impacts of energy production and use. Although the economic downturn has reduced energy demand in the short-term, demand is expected to grow over time as the economy recovers. It is essential that the state's energy sectors be flexible enough to respond to future fluctuations in the economy and that the state continue to develop and adopt the "green" technologies that are critical for long-term reliability and economic growth.

Assembly Bill 32 (Núñez, Chapter 488, Statutes of 2006), the Global Warming Solutions Act of 2006, established the goal of reducing greenhouse gas emissions to 1990 levels by 2020, and serves as the comprehensive framework for addressing climate change. However, many of the policies in place prior to passage of AB 32 are also valued for their role in meeting the state's climate change goals. One of these policies is the loading order for electricity resources, which calls for meeting new electricity needs first with energy efficiency and demand response; second, with new generation from renewable energy and distributed generation resources; and third, with clean fossil-fueled generation and transmission infrastructure improvements. A second important policy in place prior to the passage of AB 32 is the Renewables Portfolio Standard, established in 2002, which currently requires retail sellers of electricity to procure 20 percent of their retail sales from renewable resources by 2010.

More recently, Governor Schwarzenegger issued Executive Orders in 2008 and 2009 that established the Renewable Energy Action Team to develop a plan for renewable development in sensitive desert habitat, accelerated the Renewables Portfolio Standard requirement to 33 percent by 2020, and directed the Air Resources Board to adopt regulations by July 31, 2010, to meet that requirement.

While reducing greenhouse gas emissions is of paramount concern, it is not the only environmental issue facing California's electricity sector. The State Water Resources Control Board has issued a draft policy to phase out the use of once-through cooling in the state's 19 coastal power plants to reduce impacts on marine life from the pumping process and the discharge of heated water. Another issue is the lack of emission credits in the South Coast Air Quality Management District that makes it difficult to obtain the necessary permits to build reliable replacement power before aging, less-efficient power plants can be retired or repowered.

The transportation and building sectors are primary contributors to greenhouse gas emissions in California. Governor Schwarzenegger's Executive Order S-01-07 established a low carbon fuel standard for transportation fuels sold in California that will reduce the carbon intensity of California's passenger vehicle fuels by at least 10 percent by 2020. In addition, the Alternative and Renewable Fuel and Vehicle Technology Program created by AB 118 (Núñez, Chapter 750, Statutes of 2007) is working to develop and deploy alternative and renewable fuels and advanced transportation technologies to help meet the state's climate change policies. Further, the federal government in June 2009, granted California's request for a waiver that allows California to enact stricter air pollution standards for motor vehicles than those of the federal government. The standards (AB 1493, Pavley, Chapter 200, Statutes of 2002) are expected to reduce greenhouse gas emissions from California passenger vehicles by about 22 percent in 2012, and about 30 percent in 2016, while improving fuel efficiency and reducing motorists' costs.

This Executive Summary focuses on the policy recommendations that the Energy Commission believes should be the state's top priorities for meeting the goal of providing reliable, efficient, and cost-effective energy supplies for its citizens. Additional recommendations for specific actions needed in the various energy sectors are provided in Chapter 4.

Electricity

Supply and Demand

Figure E-1 shows California's electricity generation supply mix in 2008. In-state generating facilities accounted for about 68 percent of total generation, with the remaining electricity coming from out-of-state imports.

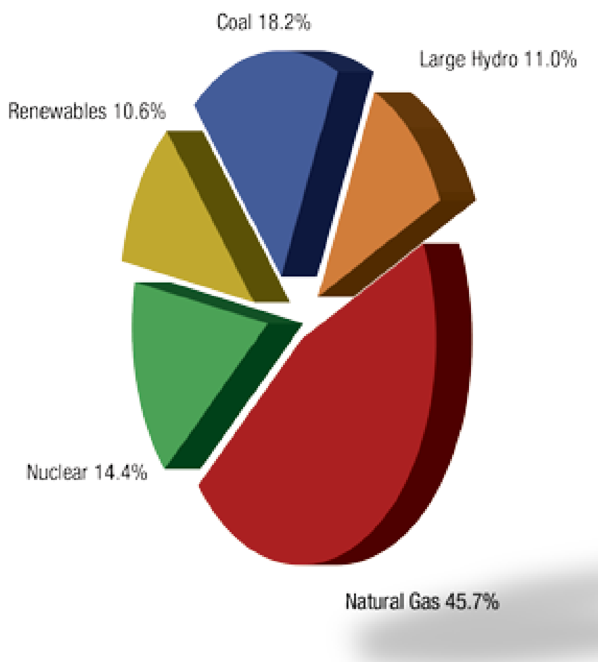
Since deregulation in 1998, the Energy Commission has licensed more than 60 power plants: 44 projects representing 15,220 megawatts are on-line, 6 projects totaling 1,578 megawatts are under construction, and 12 projects totaling 6,415 megawatts are on hold but available for construction. In addition, the Energy Commission has a historic high level of more than 30 proposed projects under review, totaling more than 12,000 megawatts, many of which are large-scale solar thermal power plants that present new and challenging environmental impacts that must be considered.

On the demand side, Californians consumed 285,574 gigawatt hours of electricity in 2008, primarily in the commercial, residential, and industrial sectors (Figure E-2). The Energy Commission staff forecast of future electricity demand shows that consumption will grow by 1.2 percent per year from

2010–2018, with peak demand growing an average of 1.3 percent annually over the same period. The current forecast is markedly lower than the forecast in the *2007 Integrated Energy Policy Report*, primarily because of lower expected economic growth in both the near and long term as well as increased expectations of savings from energy efficiency.

Because of economic uncertainties surrounding the current recession and the timing of potential recovery, the Integrated Energy Policy Report (IEPR) Committee directed staff to look in its forecast at alternative scenarios of economic and demographic growth and their impacts on electricity demand. Staff analyzed both optimistic and pessimistic scenarios and found only small differences in projected electricity demand. Annual growth rates from 2010–2020 for electricity consumption and peak demand would increase from 1.2 percent and 1.3 percent, respectively, to 1.3 percent and 1.4 percent in the optimistic case and fall to 1.1 percent each under the pessimistic scenario.

FIGURE E-1: CALIFORNIA'S GENERATION MIX 2008



Source: California Energy Commission

Energy Efficiency and Demand Response

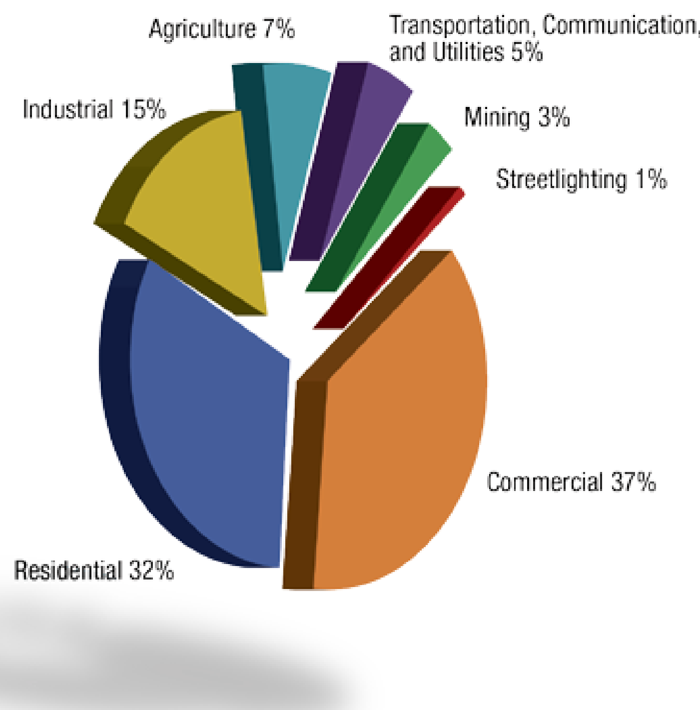
Energy efficiency is a zero-emission strategy to reduce greenhouse gas emissions in the electricity sector. Energy efficiency and conservation programs also reduce energy costs, which makes businesses more competitive and allows consumers to save money. In addition, energy efficiency reduces the cost of meeting peak demand during periods of high temperatures and high prices. By reducing the demand for electricity, energy efficiency programs also play a major role in increasing reliability of the electricity system by reducing stress on existing power plants and the transmission system and reducing the demand for new power plants and transmission infrastructure.

Because of the state's energy efficiency standards and efficiency and conservation programs, California's energy use per person has remained stable for more than 30 years while the national average has steadily increased. However, stabilizing per capita electricity use will not be enough to meet the carbon reduction goals of AB 32. To meet those goals, the state must increase its efforts to achieve all cost-effective energy efficiency. Many of these efforts will be carried out by the investor-owned utilities and the publicly owned utilities, both of which are governed by legislative and regulatory mandates to identify and develop energy efficiency potential and to set annual savings goals. The Energy Commission then uses these goals as the basis for developing its statewide energy efficiency goals.

Strategies to achieve all cost-effective energy efficiency and greenhouse gas emissions reduction goals include promoting the development of zero net energy buildings, increased building and appliance standards, and better enforcement of those standards.

A zero net energy building merges highly energy-efficient building construction, state-of-the-art appliances and lighting systems, and high performance windows to reduce a building's load and peak requirements and can include on-site solar water heating and renewable energy, such as solar photovoltaic, to meet remaining energy needs. The result is a grid-connected building that draws energy from, and feeds surplus energy to, the grid. Making zero net energy buildings a reality by 2020 for residences and 2030 for commercial buildings will require ongoing collaboration among the Energy Commission, the California Public Utilities Commission, and the Air Resources Board; coordination with local governments that have the authority over land use development and planning; and collaboration with the building industry.

FIGURE E-2: ELECTRICITY CONSUMPTION BY SECTOR 2008



Source: California Energy Commission

California's building and appliance standards provide a significant share of energy savings from reduced energy demand. The 2008 Building Efficiency Standards will take effect on January 1, 2010, and will require, on average, a 15 percent increase in energy efficiency savings compared with the 2005 Building Efficiency Standards. The 2009 Appliance Efficiency Regulations became effective statewide on August 9, 2009, and, as required by AB 1109 (Huffman, Chapter 534, Statutes of 2007), set new efficiency standards for general purpose lighting of a phased 50 percent increase in efficiency for residential general service lighting by 2018. The first phase takes effect January 1, 2010.

Another issue associated with energy efficiency is how to incorporate the expected energy savings from meeting the state's long-term energy efficiency goals into the Energy Commission's electricity and natural gas demand forecast. Not all of the specific efforts and programs to achieve those goals are in place, since utility programs and efforts are only approved by the California Public Utilities Commission in three-year cycles. However, it is important to understand the impacts of these expected incremental savings as part of the Energy Commission's demand forecasting efforts.

Recommendations

■ The Energy Commission will adopt and enforce building and appliance standards that put California on the path to zero net energy residential buildings by 2020 and zero net energy commercial buildings by 2030.

■ The Energy Commission and the California Public Utilities Commission should work together to develop and implement audit, labeling, and retrofit programs for existing buildings that achieve all cost-effective energy efficiency measures, maximize the benefit of existing utility programs, and expand the use of municipal and utility on-bill financing opportunities.

■ The Energy Commission will use the 2009 adopted forecast as a starting point to estimate the incremental impacts from future efficiency programs and standards that are reasonably expected to occur, but for which program designs and funding are not yet committed. Staff is planning to use and possibly modify Itron's forecasting model, SESAT, for this new purpose, with Itron providing training for the model in early 2010. The Energy Commission, in cooperation with the California Public Utilities Commission, the investor-owned utilities, and the publicly owned utilities, will devote sufficient resources to develop in-house capability to differentiate these future energy efficiency savings from energy efficiency savings that are already accounted for in the demand forecast.

Renewable Energy

Renewable energy is the first supply-side resource in the loading order and a key strategy for achieving greenhouse gas emission reductions from the electricity sector. Increasing the amount of renewable energy in California's electricity mix also reduces the risks and costs associated with potentially high and volatile natural gas prices while also reducing the state's dependence on imported natural gas used to generate electricity. Renewable resources also provide other benefits such as economic development and new employment opportunities – benefits that have become increasingly important given the current recession.

Challenges with increasing the amount of renewable resources in California's electricity mix are plentiful. They include the difficulty of integrating large amounts of renewable energy into the electricity system; uncertainty on the timeline for meeting Renewables Portfolio Standard goals; environmental concerns with the development of renewable facilities and associated transmission; difficulty in securing project financing; delays and duplication in siting processes; time and expense of new transmission development; the cost of renewable energy in a fluctuating energy market; and maintaining the state's existing baseline of renewable facilities.

The Renewables Portfolio Standard requires retail sellers (defined as investor-owned utilities, electric service providers, and community choice aggregators) to increase renewable energy as a percentage of their retail sales to 20 percent by 2010. State law also requires publicly owned utilities to implement the standard but gives them flexibility in developing specific targets and timelines. In November 2008, Governor Schwarzenegger raised California's renewable energy goals to 33 percent by 2020 in his Executive Order S-14-08, and in September 2009, Executive Order S-21-09 directed the Air Resources Board to develop regulations by July 31, 2010, for a 33 percent Renewable Energy Standard.

In July 2009, the California Public Utilities Commission reported that the three investor-owned utilities were supplying approximately 13 percent of their aggregated total sales from eligible renewable resources as of 2008, far below the 20 percent required by 2010. Publicly owned utilities are showing some progress in renewable energy procurement with expectations for the 15 largest publicly owned utilities of 12.4 percent of Renewables Portfolio Standard-eligible renewable retail sales by 2011, but this progress still falls far short of the renewable target.

Not all renewable generators provide the operating characteristics that the system needs to maintain local area reliability, and integrating certain renewable technologies can make it more difficult to operate the system reliably. While geothermal and biomass resources can provide baseload power, resources like wind, hydro, and solar are intermittent and not always available to meet system needs during peak hours. Intermittent resources can also drop off or pick up suddenly, requiring quick action by system operators to compensate for the sudden changes. Significant energy storage will be required to integrate future levels of renewables, thus allowing better matching of renewable generation with electricity needs. These technologies can also reduce the number of natural gas-fired power plants that would otherwise be needed to provide the characteristics the system needs to operate reliably. However, many storage technologies are still in the research and development stage, are relatively expensive, and need further refinement and demonstration.

Governor Schwarzenegger's Executive Order S-06-06 further requires the state to meet 20 percent of the Renewables Portfolio Standard with biopower. However, new biomass facilities continue to face barriers to development. There is significant potential for renewable generation fueled by biomethane from the state's dairies, but the high cost of emissions controls interferes with dairies' ability to obtain air permits. New solid fuel biomass facilities also face challenges in obtaining air permits, as well as the added challenge in the South Coast Air Quality Management District of obtaining permits to emit particulate matter. Existing biomass facilities, which provide a significant portion of the state's baseload renewable capacity, also face challenges from the expiration at the end of 2011 of the Renewable Energy Program, which provides production incentives that enable them to keep operating.

While renewable energy provides obvious environmental benefits by reducing greenhouse gas emissions and criteria pollutants associated with electricity generation, the infrastructure required to add large amounts of renewable resources can have negative environmental effects. Efforts like the Renewable Energy Transmission Initiative are working to facilitate the early identification and resolution or to avoid land use and environmental constraints to promote timely development of California's renewable generation resources and associated transmission lines. Also, Governor Schwarzenegger's Executive Order S-14-08 establishes a process to conserve natural resources while expediting the permitting of renewable energy power plants and transmission lines. The Executive Order established the Renewable Energy Action Team, comprised of the Energy Commission, the California Department of Fish and Game, the federal Bureau of Land Management, and the U.S. Fish and Wildlife Service, to identify and establish areas for potential renewable energy development and conservation in the Colorado and Mojave deserts to help reduce the time and uncertainty associated with licensing new renewable projects on both state and federal lands. As part of implementing the Executive Order, the agencies are developing the Desert Renewable Energy Conservation Plan, a road map for renewable energy project development that will advance state and federal conservation goals while facilitating the timely permitting of renewable energy projects in desert regions of the state.

Recommendations

■ The Energy Commission, the Air Resources Board, the California Public Utilities Commission, and the California Independent System Operator must continue to work together to implement a 33 percent renewable electricity policy that applies to all load-serving entities and retail providers.

■ To reduce regulatory uncertainty for market participants and ensure a long-term and stable renewable energy policy framework for California, the state should pursue legislation to codify the 33 percent renewable target that was identified in Governor Schwarzenegger's Executive Orders S-14-08 and S-21-09.

■ The Energy Commission will work with the California Public Utilities Commission, the California Independent System Operator, the federal Bureau of Land Management, the California Department of Fish and Game, and other agencies to implement specific measures to accelerate permitting of new renewable generation and the transmission facilities needed to serve that generation. These measures include the elimination of duplication, shortened permitting timelines, and planning processes such as the Renewable Energy Transmission Initiative and the Desert Renewable Energy Conservation Plan that balance clean energy development and conservation.

■ To meet the Governor's target of 20 percent of the state's renewable energy goals from biomass resources that was identified in Executive Order S-06-06, the Energy Commission will facilitate and coordinate programs with other state and local agencies to address barriers to the expansion of biopower, including regulatory hurdles and project financing. The Energy Commission will also encourage additional research and development to reduce costs for biomass conversion, biopower technologies, and environmental controls.

■ The Energy Commission will conduct further analysis to identify solutions to integrate increasing levels of energy efficiency, smart grid infrastructure, and renewable energy while avoiding infrequent conditions of surplus generation, or overgeneration, in which more electricity is being generated than there is load to consume it. Potential solutions include better coordination of the timing of resource additions and the mix of resources added to meet customer needs efficiently and maintain system reliability, as well as additional research, development, and demonstration of existing and emerging storage technologies. In addition, there will be efforts to determine what new, more flexible, and efficient natural gas technologies best fit into an electricity grid in transition. The Energy Commission will complete an initial study of the surplus generation issue to identify specific resource and data needs as part of the *2010 Integrated Energy Policy Report Update*, with an in-depth analysis forthcoming in the *2011 Integrated Energy Policy Report*.

Distributed Generation and Combined Heat and Power

Distributed generation resources are grid-connected or stand-alone electrical generation or storage systems connected to the distribution level of the transmission and distribution grid and located at or very near the location where the energy is used. The benefits of distributed generation go far beyond electricity generation. Because the generation is located near the location where it is needed, distributed generation reduces the need to build new transmission and distribution infrastructure and also reduces losses at peak delivery times. Customers can use distributed generation technologies to meet peak needs or to provide energy independence and protect against outages and brownouts.

California is promoting distributed generation technologies through several programs that support distributed generation on the customer side of the meter, such as the California Solar Initiative, which includes the New Solar Homes Partnership, the California Public Utilities Commission's Self-Generation Incentive Program, and the Energy Commission's Emerging Renewable Program. Large-scale distributed generation such as combined heat and power, also referred to as cogeneration, is an efficient and cost-effective form of distributed generation. The *Climate Change Scoping Plan* has a target of adding 4,000 megawatts of combined heat and power capacity to displace 30,000 gigawatt hours of demand, thus reducing greenhouse gas emissions by 6.7 million metric tons of carbon by 2020.

Despite consistent emphasis in past *Integrated Energy Policy Reports* on the need to address barriers to the development of combined heat and power facilities, insufficient progress has been made. In an effort to push forward, the Energy Commission developed a new study of market potential for combined heat and power facilities that includes facilities smaller than 20 megawatts in size that do not typically have excess power to export to the grid. The study examined market penetration over the next 20 years for a base case (status quo) and four alternative cases that included various stimulus and incentive measures. The base case showed about 3,000 megawatts of combined heat and power market penetration, including both generation capacity and avoided electric air conditioning. (The study included alternative incentive scenarios, one of which made available an additional 497 megawatts of combined heat and power for addition to the base case in the event of the passage of SB 412 [Kehoe, Chapter 182, Statutes of 2009]. The bill became law in October.) Implementation of all of the stimulus efforts and incentives used in the alternative cases would more than double market penetration over the next 20 years to about 6,500 megawatts, exceeding the Air Resources Board's 4,000 megawatt target for capacity additions.

Recommendation

■ The Energy Commission will work with the Air Resources Board in the development of combined heat and power to meet the state goals for emission reductions from this technology. Actions include mandates to remove market barriers to the development of combined heat and power facilities and the provision of analytical support on efficiency requirements and other technical specifications so that combined heat and power is more widely viewed and adopted as an energy efficiency measure.

Nuclear Power Plants

As part of the *2008 Integrated Energy Policy Report Update*, the Energy Commission developed *An Assessment of California's Nuclear Power Plants: AB 1632 Report*, as directed by AB 1632 (Blakeslee, Chapter 722, Statutes of 2006). The report addressed seismic and plant aging vulnerabilities of California's in-state nuclear plants – Pacific Gas and Electric Company's Diablo Canyon Power Plant and Southern California Edison's San Onofre Nuclear Generating Station – including reliability concerns as well as concerns over safety culture, plant performance, and management issues at San Onofre. The *AB 1632 Report* also recommended additional studies that Pacific Gas and Electric Company and Southern California Edison should undertake as part of their license renewal feasibility studies for the California Public Utilities Commission and directed the utilities to provide a status report on their efforts toward implementing the recommendations in the *AB 1632 Report* in the *2009 Integrated Energy Policy Report*.

Major policy decisions that will be made in the next several years will shape the next three decades of nuclear energy policy in California. An overarching issue with the state's nuclear facilities is plant license renewal. The Nuclear Regulatory Commission operating licenses for San Onofre Units 2 and 3 are set to expire in 2022, and for Diablo Canyon Units 1 and 2, in 2024 and 2025, respectively. Pacific Gas and Electric announced on November 24, 2009, its intention to file a license renewal application for Diablo Canyon, and Southern California Edison plans to file for license renewal for San Onofre in late 2012.

The Nuclear Regulatory Commission license renewal application process determines whether a plant meets its renewal criteria, but not whether the plant should continue to operate. The Nuclear Regulatory Commission specifically states that it "has no role in the energy planning decisions of State regulators and utility officials as to whether a particular nuclear power plant should continue to operate." It is left to state regulatory agencies to determine whether it is in the best interest of ratepayers and cost effective to continue operation of their state's nuclear plants.

Although the California Public Utilities Commission does not approve or disapprove license applications filed with the Nuclear Regulatory Commission, both Pacific Gas and Electric and Southern California Edison must obtain the California Public Utilities Commission's approval to pursue license renewal before receiving California ratepayer funding to cover the costs of the Nuclear Regulatory Commission license renewal process. The utilities' submission of license renewal feasibility assessments to the California Public Utilities Commission initiates the California Public Utilities Commission's license renewal review proceedings. The California Public Utilities Commission proceedings will not only consider energy planning issues and whether continued operation of the nuclear power plants is in the ratepayers' best interest, but will also consider matters of state jurisdiction such as the economic, reliability, and environmental implications of relicensing.

The California Public Utilities Commission's General Rate Case Decision 07-03-044 required Pacific Gas and Electric to incorporate the Energy Commission's AB 1632 assessment findings and recommendations in its license renewal feasibility study and to submit the study to the California Public

Utilities Commission no later than June 30, 2011, along with an application on whether to pursue license renewal for Diablo Canyon. Letters on June 25, 2009, from the president of the California Public Utilities Commission to Pacific Gas and Electric and Southern California Edison reiterated the requirement for each utility to complete the *AB 1632 Report's* recommended studies, including the seismic/tsunami hazard and vulnerability studies, and report on the findings and the implications of the studies for the long-term seismic vulnerability and reliability of the plants. These studies are necessary to allow the California Public Utilities Commission to properly undertake its obligations to ensure plant and grid reliability in the event that either Diablo Canyon or San Onofre has a prolonged or permanent outage and for the California Public Utilities Commission to reach a decision on whether the utilities should pursue license renewal. However, the utilities' reports to date indicate they are not on schedule to complete these activities in time for California Public Utilities Commission consideration. In addition, both utilities have indicated objections to providing some of the studies and/or requirements indicated by the *AB 1632 Report* and the California Public Utilities Commission General Rate Case Decision.

The Energy Commission believes that the comprehensiveness, completeness, and timeliness with which both utilities provide the studies identified in the *AB 1632 Report* will be a critical part of the California Public Utilities Commission and Nuclear Regulatory Commission reviews of the utilities' license renewal applications.

Recommendation

- Pacific Gas and Electric Company and Southern California Edison should complete all of the studies recommended in the *AB 1632 Report*, should make their findings available for consideration by the Energy Commission, and should make their findings available to the California Public Utilities Commission and the U.S. Nuclear Regulatory Commission during their reviews of the utilities' license renewal applications.

Transmission and Distribution

The state's transmission and distribution system is another critical component of the electricity sector for serving California's growing population and integrating renewable energy. The *2009 Strategic Transmission Investment Plan* describes the immediate actions that California must take to plan, permit, construct, operate, and maintain a cost-effective, reliable electric transmission system that is capable of responding to important policy challenges such as achieving significant greenhouse gas reduction and Renewables Portfolio Standard goals. The plan makes a number of recommendations intended to make the critical link between transmission planning and permitting so that needed projects are planned for, have corridors set aside as necessary, and are permitted in a timely and effective manner that maximizes existing infrastructure and rights-of-way, minimizes land use and environmental impacts, and considers technological advances.

Recommendations

The Energy Commission supports the many recommendations made in the *2009 Strategic Transmission Investment Plan* including those identified below.

- The Energy Commission staff will work with the recently formed California Transmission Planning Group and the California Independent System Operator in a concerted effort to establish a 10-year statewide transmission planning process that uses the Energy

Commission's Strategic Plan proceeding to vet the California Transmission Planning Group plan described in Chapter 4 of the *2009 Strategic Transmission Investment Plan*, with emphasis on broad stakeholder participation.

- The Energy Commission staff will work with the California Independent System Operator, the California Public Utilities Commission, investor-owned utilities, and publicly owned utilities to develop a coordinated statewide transmission plan using consistent statewide policy and planning assumptions.

Coordinated Electricity System Planning

California has numerous agencies that are involved in electricity planning. While there is some degree of coordination among various agencies and processes, the state needs to find better ways to coordinate and streamline the collective responsibilities of those agencies to achieve the state's greenhouse gas emission reduction, environmental protection, and reliability goals while reducing duplicative or contradictory processes. California needs to better coordinate its electricity policy, planning, and procurement efforts to eliminate duplication and to ensure that planners and policy makers understand the interactions and conflicts that may exist among state energy policy goals.

Recommendation

- The Energy Commission will work with the California Public Utilities Commission and California Independent System Operator, along with other agencies and interested stakeholders, to develop a common vision for the electricity system to guide infrastructure planning and development. Such coordinated plans can be used to guide each agency's own infrastructure approval and licensing responsibilities and thus maximize coordinated action to achieve state energy policy goals.

Addressing Procurement in the Hybrid Market

At the October 14, 2009, Integrated Energy Policy Report Committee Hearing on the draft *IEPR*, the IEPR Committee solicited comments from parties on how the state should address the current hybrid electric procurement market (a market split between utility-owned generation and contracted third party generation) and improve the investor-owned utility procurement process for electric generation. These issues are critical to state energy policy but did not receive sufficient analysis throughout the 2009 IEPR process. The Independent Energy Producers Association submitted comments expressing support for an examination of the hybrid market structure to determine if it is functioning properly and achieving its original goal of providing a level playing field for utility-owned and independent power generation. In addition, the Western Power Trading Forum submitted comments expressing concerns that utility domination of infrastructure investment is potentially detrimental to competitive wholesale and retail markets and therefore potentially detrimental to technological innovation. The Forum asserts that the existing hybrid market structure requires ratepayers to bear the financial and operational risks associated with new investment and ignores the market's capabilities to actively manage and hedge those risks, and it believes that improving competition at the wholesale and retail levels would create downward pressure on prices.

Recommendation

- The Energy Commission believes these issues deserve a fuller vetting, including an assessment of alternative market models that would better serve the goal of reduced cost to customers. The Energy Commission will invite the California Public Utilities Commission to participate in a more complete evaluation of the existing hybrid market structure as part of the *2010 Integrated Energy Policy Report Update* to identify possible market enhancements and changes to utility procurement practices that would facilitate the reemergence of merchant investment.

Natural Gas

Natural gas is the cleanest of the fossil fuels used in the state and will continue to be a significant energy source for the foreseeable future. Maintaining a reliable natural gas delivery and storage infrastructure is therefore important to support the receipt and delivery of adequate supply to California's millions of natural gas consumers and keep prices low for the residential, commercial, industrial, and electric generation sectors. An expanding California natural gas infrastructure also will allow for the efficient delivery to California of increasing domestic shale gas production and liquefied natural gas imports.

Recent technological advancements in exploration, drilling, and hydraulic fracturing have transformed shale formations from marginal natural gas producers to substantial and expanding contributors to the natural gas portfolio. Recoverable shale reserve estimates range as high as 842 trillion cubic feet, a 37-year supply at today's consumption rates. While natural gas production from shale formations has significantly increased domestic production, there is ongoing investigation of potential environmental concerns related to shale gas development, including carbon emissions and possible groundwater contamination.

As recently as two years ago, domestic natural gas production and imports to California were on the decline, and liquefied natural gas was seen as a source to better serve the natural gas needs of California. The recent development of natural gas shale formations has contributed to increased domestic production of natural gas, and liquefied natural gas does not seem to be a priority fuel for California at this time. If private investors are willing to invest in liquefied natural gas facilities without committing taxpayer or ratepayer funds, however, liquefied natural gas should be considered a viable option. The Energy Commission does not oppose development of liquefied natural gas facilities as long as liquefied natural gas development is consistent with the state's interests in balancing environmental protection, public safety, and local community concerns to ensure protection of the state's population and coastal environment.

While there is widespread agreement that the physical market factors of supply and demand are primary contributors to natural gas prices and volatility, there also is growing interest and concern about the influence financial market factors, particularly commodity speculation, have on natural gas prices and volatility. The growth in speculative commodity trading from nontraditional participants, such as pension funds, university endowments, hedge funds, and index portfolios, has changed the futures market. Unlike traditional participants like utilities and refiners who used the market to hedge against volatile energy costs, these new participants use the market as an opportunity for profit. Significant disagreement exists about the influence speculative trading has on the natural gas market, prices, and volatility.

Finally, past efforts to forecast natural gas prices have been highly inaccurate compared to actual prices, even when price volatility was largely dominated by traditional, physical market factors. Additionally, as the United States continues moving toward a carbon-constrained existence, future greenhouse gas policies will further complicate these efforts, likely rendering future natural gas price forecasts even less accurate and more uncertain. The uncertainty associated with predicting major input variables and the resulting natural gas price forecasts bring into question the value of producing date-specific, single-point natural gas price forecasts.

Recommendations

- California should work closely with western states to ensure development of a natural gas transmission and storage system that has sufficient capacity and alternative supply routes to overcome any disruption in the system, such as weather-related line freezes and pipeline breaks. The state should support construction of sufficient pipeline capacity to California to ensure adequate supply at a reasonable price.

- The Energy Commission will continue to monitor the potential environmental impacts associated with shale gas extraction, including carbon footprint, volume of water use and risk of groundwater contamination, air pollution, and potential chemical leakage. Specifically, the Energy Commission staff will coordinate and exchange information with energy agencies in states with shale gas development, such as New York, Texas, and other midcontinent states, and will report new findings in the *Integrated Energy Policy Report* and other Energy Commission forums.

Fuels and Transportation

State and federal policies encourage the development and use of renewable and alternative fuels to reduce California's dependence on petroleum imports, promote sustainability, and cut greenhouse gas emissions. Governor Schwarzenegger's Executive Order S-06-06 established clear targets for increased use and in-state production of biofuels. California and the federal government also have policies to improve vehicle efficiencies and to reduce vehicle miles traveled in efforts to achieve 2050 greenhouse gas reduction targets of 80 percent below 1990 levels as directed in the Governor's Executive Order S-3-05. Until new vehicle technologies and fuels are commercialized, petroleum will continue to be the primary fuel source for California's vehicles, and the state must enhance and expand the existing petroleum infrastructure, particularly at in-state marine ports, while at the same time working to develop an alternative fuel infrastructure.

The fuels and transportation energy sector is responsible for producing the greatest volume of greenhouse gas emissions – nearly 40 percent of California's total. AB 32 does not directly address greenhouse gas emissions reduction in the transportation sector. Instead, reductions are addressed through California's Low Carbon Fuel Standard, AB 1493 (Pavley, Chapter 200, Statutes of 2002), AB 1007 (Pavley, Chapter 371, Statutes of 2005), and AB 118, the Alternative and Renewable Fuel and Vehicle Technology Program. The policies and standards resulting from these mandates will ultimately change vehicle and fuel technologies in California and accelerate the market for low carbon fuels well beyond the current level of demand.

The current recession has had a significant impact on the state's transportation sector. California's average daily gasoline sales for the first four months of 2009 were 2.1 percent lower than the same period in 2008, continuing a reduction in demand observed since 2004. Daily diesel fuel sales for the first three months of 2009 were 7.7 percent lower than the same period in 2008, continuing a declining trend since 2007. Job growth and industrial production – drivers of air travel – are also declining, causing the aviation sector to experience a drop in air traffic. Recent demand trends for jet fuel, which saw an 8.9 percent decline in 2008, are similar to diesel fuel and reflect the impact of the economic downturn and higher fuel prices.

The initial years in the Energy Commission's transportation fuel demand forecast show a recovery from the recession. Because the economic and demographic projections used in these forecasts indicate a return to economic and population growth, fuel demand in the light-, medium- and heavy-duty vehicles and aviation sectors tends to resume historical growth patterns. However, the mix of fuel types is projected to change significantly as the state transitions from gasoline and diesel to alternative and renewable fuels.

California needs sufficient fuel infrastructure to ensure reliable supplies of transportation fuels for its citizens. Reliance on foreign oil imports increasingly puts the state's fuel supply at risk, not only because of security and reliability concerns, but also because the marine ports are not expanding to meet expected growth in demand. Alternative and renewable fuels could face the same constraints at the ports should the state begin to rely on imports of those fuels to meet state and federal renewable fuel standards. In fact, renewable and alternative fuels face even more serious infrastructure issues, as much of the infrastructure that will soon be needed is not even in place. Both petroleum and renewable fuels face infrastructure challenges from the wholesale and distribution level all the way through to the end user.

Recommendations

■ With the advent of new California programs such as the Alternative and Renewable Fuel and Vehicle Technology Program (a comprehensive investment program to stimulate the development and deployment of low-carbon fuels and advanced vehicle technologies), the Low Carbon Fuel Standard, and a federal waiver allowing California to set its own carbon dioxide motor vehicle emission standards, California is well positioned to develop a system of sustainable, clean, alternative transportation fuels. The state should continue on its present course of action by providing responsible agencies with the time and funding to implement these programs.

■ The Energy Commission will collaborate with partner agencies and stakeholders to develop policy changes to address regulatory hurdles and price uncertainty for alternative fuels, particularly biofuels, in California.

■ To maintain energy security, state and local agencies need to ensure that there is adequate infrastructure for the delivery of transportation fuels. The state should modernize and upgrade the existing infrastructure to accommodate alternative and renewable fuels and vehicle technologies as they are developed and to address petroleum infrastructure needs to preserve past investments and to expand throughput capacity in the state.

■ The Energy Commission believes that transportation energy efficiency should be pursued through increased federal vehicle fuel economy standards and more sustainable land use practices in conjunction with local governments.

Land Use and Planning

Although land use decisions are made on the local level, they often have statewide implications by directly influencing consumer transportation choices, energy consumption, and greenhouse gas emissions. The *2006 Integrated Energy Policy Report Update* stated that the single largest opportunity to help California meet its statewide energy and climate change goals resides with smart growth – development that revitalizes central cities and older suburbs, supports and enhances public transit, promotes walking and bicycling, and preserves open spaces and agricultural lands. The *2007 Integrated Energy Policy Report* further noted that to reduce greenhouse gas emissions, California must begin reversing the current 2 percent annual growth rate of vehicle miles traveled.

The Energy Commission is one of several state agencies helping local and regional governments make sustainable land use decisions. The California Department of Transportation coordinates local and state planning through its Regional Blueprint Planning Program. Senate Bill 375 (Steinberg, Chapter 728, Statutes of 2008) requires the Air Resources Board to set regional emissions goals by working with metropolitan planning organizations. Senate Bill 732 (Steinberg, Chapter 729, Statutes of 2008), recognizing the need for state agencies to work more closely together on this issue, created the Strategic Growth Council, a cabinet level committee composed of agency secretaries from Business, Transportation and Housing; California Health and Human Services; the California Environmental Protection Agency; and the California Natural Resources Agency, along with the director of the Governor's Office of Planning and Research.

These state agencies need to coordinate more closely to help local governments achieve the benefits of sustainable land use planning. Before adopting new state policies, state government must improve its outreach to local governments to better understand the problems they face. This includes taking into account and addressing the fiscal realities local governments confront in difficult economic times.

Recommendations

- To reduce energy use and support the transportation greenhouse gas emission reduction goals of SB 375, state agencies in collaboration with the Strategic Growth Council and local and regional governments will continue to conduct research, develop analytical tools, assemble easy-to-use data, and provide assistance to local and regional government officials to help them make informed decisions about energy opportunities and undertake sustainable land use practices, while recognizing the different needs of rural and urban regions.

The Potential of Carbon Capture and Sequestration

California will need innovative strategies to address greenhouse gas emissions associated with energy production and use. One such strategy is carbon capture and storage, also known as carbon capture and sequestration. The *2007 IEPR* focused on geologic sequestration strategies for the long-term management of carbon dioxide, but there have been encouraging technology advancements and investments since then. Technology developers and policy makers who are examining carbon capture and sequestration applications have expanded from an initial focus on coal and petroleum coke to natural gas and refinery gas, the predominant fossil fuels used in California power plants and industrial facilities.

Recommendation

■ The Energy Commission recommends that, as a mechanism for achieving state energy and environmental objectives, it continue to support and conduct carbon capture and sequestration research to demonstrate technology performance and facilitate interagency coordination to develop the technical data and analytical capabilities necessary for establishing a legal and regulatory framework for this technology in California.

Achieving Energy Goals

California needs reliable, affordable, and clean supplies of energy to serve its citizens and maintain a strong economy. The state's electricity, natural gas, and transportation sectors must continuously respond to changes in supply and demand, new policies and technologies and their associated challenges, and increasing environmental regulation. California must bolster its current energy foundation with an aggressive and wide-ranging agenda that will continue to reduce energy demand, promote development of renewable energy resources, ensure development of cleaner fossil resources, give consumers more energy choices, and build the necessary infrastructure to protect the state from future supply disruptions and high prices.

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CHAPTER 1
CALIFORNIA'S ENERGY POLICIES

In 2006, the Legislature passed and Governor Schwarzenegger signed Assembly Bill 32 (Núñez, Chapter 488, Statutes of 2006), the Global Warming Solutions Act of 2006, which established the goal of reducing greenhouse gas (GHG) emissions to 1990 levels by 2020. AB 32 was the first law of its kind to address climate change by implementing regulatory market mechanisms to achieve real and measurable GHG reduction targets. AB 32 is the driving force for California's energy policy and programs, and the state must integrate many existing policies and legislation into a symbiotic whole under AB 32's broad umbrella.

At the same time, it is important to recognize that AB 32 is one of many policies that guide energy development, production, and use in California. Many policies and programs in existence prior to passage of AB 32 helped the state make steady progress toward more responsible stewardship of the planet and its resources. These are discussed later in the chapter and include the goal of achieving all cost-effective energy efficiency, the Renewables Portfolio Standard, the California Solar Initiative, the power plant Emission Performance Standard, and regulations to reduce GHG emissions from motor vehicles. While many of the energy policies in place are complementary, there can also be overlap or conflict among those policies because they are often designed to address different problems.

In addition to the challenge of integrating new and existing policies, laws, and regulations, there are challenges in coordinating the various agencies that implement those policies.

The Energy Commission, the California Public Utilities Commission, California Independent System Operator, the California Air Resources Board, California Environmental Protection Agency, and the State Water Resources Control Board all have very specific missions, jurisdictions, and expertise. Working collaboratively is a challenging and ongoing goal, as agencies strive to integrate policies to establish priorities and transform broadly framed objectives into concrete, efficient, and coordinated programs and actions.

This chapter provides background on and a brief status of current policies and programs that affect California's three major energy sectors – electricity, transportation, and natural gas – as well as those that affect land use and planning. The purpose is to provide decision makers with the context for the more detailed discussions in subsequent chapters of the various policy efforts underway and the challenges associated with meeting California's energy policy goals. The description of the energy policy landscape may also help decision makers see how policies overlap or complement each other, as well as where gaps may exist that require additional action to ensure a clean, efficient, and affordable energy future for California.

AB 32 Framework

Assembly Bill 32 legislation charged the California Air Resources Board (ARB) with developing regulations and developing market mechanisms to ultimately reduce California's GHG emissions by 25 percent by 2020. The ARB's *Climate Change Scoping Plan* report, approved on December 12, 2008, outlines the main strategies for meeting that goal. The *Climate Change Scoping Plan* contains a range of GHG-reduction actions including direct regulations, alternative compliance mechanisms, monetary and nonmonetary incentives, voluntary actions, market-based mechanisms such as a cap-and-trade system, and an AB 32 cost of implementation fee regulation to fund the program. The ARB and other state agencies must adopt these reduction measures by the start of 2011. The ARB has already adopted a number of "early action" measures required by the *Climate Change Scoping Plan*, such as the Low Carbon Fuel Standard, and is now working on the plan's other measures.[1]

In April 2009, the California Environmental Protection Agency (Cal/EPA) released the *Draft 2009 Climate Action Team Biennial Report to the Governor and Legislature* that describes the impacts of climate change on public health, infrastructure, natural resources, and the economy. In addition, the report describes research efforts to date.[2] The Energy Commission is a key agency for implementing energy-related actions in the ARB's *Climate Change Scoping Plan* and the *Climate Action Team Biennial Report*.

Electricity

California's loading order provides an overall framework for meeting the state's growing electricity needs while achieving the GHG emissions reduction goals mandated by AB 32. The loading order was originally adopted in the *2003 Energy Action Plan I*, a collaborative effort by the Energy Commission, the California Public Utilities Commission (CPUC), and

1 California Air Resources Board, *Climate Change Scoping Plan*, December 2008, available at: [http://www.arb.ca.gov/cc/scopingplan/scopingplan.htm].

2 *Climate Action Team Biennial Report to the Governor and Legislature*, March 2009, available at: [http://www.energy.ca.gov/2009publications/CAT-1000-2009-003/CAT-1000-2009-003-D.PDF].

the California Power Authority (now defunct). The loading order calls for California's electricity needs to be met first with increased energy efficiency and demand response; second, with new generation from renewable energy and distributed generation resources; and third, with clean fossil-fueled generation and infrastructure improvements. The policies and programs affecting the electricity sector are presented below in the same general sequence as the loading order.

Energy Efficiency and Demand Response

Energy efficiency and demand response measures are the first resources in the loading order because they can contribute to meeting climate change goals with little or no impact on the environment and with measurable benefits (for example, cost savings) to the consumer. Since the 1970s, the Energy Commission has set efficiency standards for buildings and appliances to reduce energy demand and increase savings from energy efficiency.

The following mandates and plans in the area of energy efficiency and demand response will contribute toward reducing energy demand and meeting the AB 32 goals:

Assembly Bill 2021 (Levine, Chapter 734, Statutes of 2006): This bill requires the Energy Commission, in consultation with the CPUC and publicly owned utilities, to develop a statewide estimate 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.

Assembly Bill 758 (Skinner, Chapter 470, Statutes of 2009): This bill requires the Energy Commission to establish a regulatory proceeding by March 1, 2010, to develop a comprehensive program to achieve greater energy savings in existing residential and nonresidential buildings.

CPUC Long Term Energy Efficiency Strategic Plan: In September 2008, the CPUC adopted California's first strategic plan for energy efficiency that provides a road map to achieve maximum energy savings across all sectors in California. The plan includes four specific programmatic goals, known as the "Big Bold Energy Efficiency Strategies": 1) all new residential construction in California will be zero net energy by 2020; 2) all new commercial construction in California will be zero net energy by 2030;[3] 3) heating, ventilation, and air conditioning will be transformed to ensure that its energy performance is optimal for California's climate; and 4) all eligible low-income customers will be given the opportunity to participate in the low-income energy efficiency program by 2020.

ARB's *Climate Change Scoping Plan*: The plan outlines emission reductions in the electricity sector from maximizing building and appliance standards, implementing additional conservation and efficiency programs, increasing combined heat and power (CHP), and more utility programs. The plan also calls for similar strategies in the natural gas sector such as increased installations of solar water heating systems throughout the state.

Strategies and Progress

AB 2021 is a key legislative strategy for the utilities to expand their energy efficiency programs. Under AB 2021, the Energy Com-

3 A zero net energy building combines building energy efficiency design features and clean on-site or near-site distributed generation of sufficient quantity on an annual basis to offset any residual purchases of electricity or natural gas from utility suppliers.

mission is required to develop statewide estimates of energy efficiency potential and goals for California's private and public utilities. The Energy Commission reports on utility progress in meeting these goals as part of its biennial *Integrated Energy Policy Report* (*IEPR*).

The 2008 progress report, *Achieving Cost-Effective Energy Efficiency for California: Second Annual AB 2021 Progress Report*,[4] found that during the CPUC's 2006–2008 efficiency program cycle, the investor-owned utilities (IOUs) exceeded their three-year energy efficiency goals. During this period, the IOUs achieved more than 200 percent of their electric energy savings goal and 150 percent of their natural gas savings goal. However, these savings have not yet been verified, and measurement and verification studies completed for the 2004–2005 efficiency programs indicate that verified program savings could be less than those reported. The progress report also found that efficiency savings recorded by publicly owned utilities increased substantially from 2007 to 2008, reaching 66 percent of AB 2021 adopted goals in 2008.

There are various efforts underway to increase energy efficiency savings in California. The Energy Commission's Public Interest Energy Research (PIER) program helps improve energy efficiency technologies and strategies, with $180 million devoted to efficiency-related efforts from 1997–2007.[5] The PIER program funds research, development, and demonstration (RD&D) in the following efficiency program areas: buildings end-use energy efficiency, industrial/agriculture/water end-use efficiency, demand response, and distributed energy resources system integration.[6] With the passage of the Energy Independence and Security Act (EISA) of 2007 (Title XIII), the evolution of the nation's smart grid provides new potential to achieve higher penetration of energy efficiency and demand response technologies and capabilities. The PIER program is actively funding new research in the smart grid area to better define how to take advantage of all the capabilities the smart grid will offer California in the future.

In the area of demand response and load management, the Energy Commission's *2007 IEPR* recommended initiating a formal rulemaking process involving the CPUC and California Independent System Operator (California ISO) to pursue the adoption of load management standards under the Energy Commission's existing authority. The Energy Commission opened an informational proceeding and rulemaking on load management standards in January 2008. In November 2008, the Energy Commission's Efficiency Committee published a draft analysis that focused on advanced metering, time variant rate design, and demand response enabling technologies. The Efficiency Committee and staff held workshops and discussions with stakeholders from December 2008 through March 2009. Since that time, the National Institute of Standards and Technology has taken up the issue of demand response communication standards for possible federal action. In addition, most California utilities have aggressively expanded their advanced metering infrastructure rollouts and the U.S. Department of Energy has directed smart grid American Recovery and Reinvestment Act of 2009 (ARRA)

4 California Energy Commission, *Achieving Cost-Effective Energy Efficiency for California: Second Annual AB 2021 Progress Report*, December 2008, CEC-200-2008-007, [http://www.energy.ca.gov/2008publications/CEC-200-2008-007/CEC-200-2008-007.PDF].

5 California Energy Commission, *PIER Annual Report*, March 2009, CEC-500-2009-064-CMF, available at: [http://www.energy.ca.gov/2009publications/CEC-500-2009-064/CEC-500-2009-064-CMF.PDF].

6 California Energy Commission, Public Interest Energy Research program, available at: [http://www.energy.ca.gov/research/index.html].

funding toward demand response issues like advanced metering infrastructure.[7] In light of these significant developments, Energy Commission staff is currently working with the Efficiency Committee to evaluate the necessity of a formal regulation to achieve state demand response and load management policy goals.

Another effort to support energy efficiency and conservation is the Energy Efficiency and Conservation Block Grant Program, which is funded by the ARRA, created by the EISA of 2007. As part of the increasing national focus on the importance of energy efficiency, ARRA is providing $351.5 million in funding to California. Of that amount, $302 million will go directly from the U.S. Department of Energy (DOE) to large incorporated cities and counties in California, and $49.6 million will be made available through the Energy Commission to 265 small incorporated cities and 44 small counties not eligible for direct grants from the DOE.

The Energy Commission adopted the Energy Efficiency and Conservation Block Grant *Block Grant Guidelines* on October 7, 2009, which describe the eligibility and procedural requirements for applying for program funds, and released the grant solicitation and application package on October 8. The Energy Commission held a series of application development clinics throughout California to assist eligible small cities and counties with their applications. Applications are due on January 12, 2010. Overall, this program is a crucial strategy for assisting small cities and counties in implementing projects and programs that reduce total energy use and fossil fuel emissions and improve energy efficiency in building and other appropriate sectors.

ARRA is also providing $226 million in funding to the Energy Commission for the State Energy Program. Earlier in the year, the Energy Commission held a series of informational workshops throughout the state to inform stakeholders of the funding guidelines and application process. The Energy Commission adopted the *State Energy Program Guidelines* on September 30, 2009, which describe implementation and administration of specific program areas funded by the State Energy Program. As of November 2009, the Energy Commission had allocated $25 million to the Department of General Services' Energy Efficient State Property Revolving Loan Program, $25 million to the Energy Conservation Assistance Act 1% Low Interest Loans, and $20 million to the Green Jobs Workforce Training Program. In addition, the Energy Commission is in the process of making $95 million available for energy projects focused on residential and commercial building retrofits for energy efficiency measures and installing on-site photovoltaic systems. Under this program, local jurisdictions, nonprofits, or private organizations can create partnerships and apply for program funding under a competitive solicitation process for three different areas: the California Comprehensive Residential Building Retrofit Program, the Municipal and Commercial Building Targeted Measure Retrofit Program, and the Municipal Financing Program for programs related to AB 811 (Levine, Chapter 159, Statutes of 2008), which authorizes all cities and counties in California to designate areas where willing property owners can enter into contractual assessments to finance installation of distributed renewable generation, as well as energy efficiency improvements.

Overall, this program is an important strategy for making buildings and industrial facilities more energy efficient and will help finance such projects.

7 See [http://www.recovery.gov/Pages/home.aspx].

Renewable Energy

Second in the state's loading order is to meet new electricity needs with renewable energy resources. With the passage of AB 1890 (Brulte, Chapter 854, Statutes of 1996), the Legislature established a public goods charge to support renewable energy development. Since then, the state has implemented other policies to expand renewable energy production goals in California. Some of these policies were implemented prior to passage of AB 32, but they all play a critical role in meeting the state's GHG emissions reduction goals:

Senate Bill 1078 (Sher, Chapter 516, Statutes of 2002): Established California's Renewables Portfolio Standard (RPS) requiring retail sellers of electricity (IOUs, community choice aggregators, and electric service providers) to procure 20 percent of retail sales from renewable energy by 2017. The publicly owned utilities are encouraged, but not required, to meet the same goal. The bill delegated specific roles to the Energy Commission and CPUC.

***Energy Action Plans I* (2003) and *II* (2005):** The first *Energy Action Plan* recommended accelerating the RPS deadline to 20 percent by 2010, and the second recommended an accelerated goal of 33 percent renewables by 2020.

Senate Bill 107 (Simitian, Chapter 464, Statutes of 2006): Required the IOUs to meet the "20 percent by 2010" goal as recommended in the *Energy Action Plan I*. The bill expanded the RPS reporting requirements of the publicly owned utilities to the Energy Commission and expanded RPS eligibility of out-of-state renewable resources.

Executive Order S-06-06 (2006): Established a biomass target of 20 percent within the established RPS goals for 2010 and 2020.

Executive Order S-14-08 (2008): Established accelerated RPS targets (33 percent by 2020) as recommended in the *Energy Action Plan II*. The order also called for the formation of the Renewable Energy Action Team, comprised of the Energy Commission, Department of Fish and Game, Bureau of Land Management, and U.S. Fish and Wildlife Service. Through the team, the Energy Commission and the Department of Fish and Game are to prepare a plan for renewable development in sensitive desert habitat.

Executive Order S-21-09 (2009): Directs the ARB to work with the CPUC, the California ISO, and the Energy Commission to adopt regulations increasing California's RPS to 33 percent by 2020. The ARB must adopt these regulations by July 31, 2010.

Strategies and Progress

The state has implemented several key strategies and programs to increase renewable energy generation consistent with these policies. These include the Energy Commission's Renewable Energy Program, the RPS program jointly administered by the Energy Commission and the CPUC, the Renewable Energy Transmission Initiative, the Desert Renewable Energy Conservation Plan, feed-in tariffs for renewable generators, the Bioenergy Action Plan, and multiple RD&D activities.

The Energy Commission's Renewable Energy Program has, since 1998, encouraged investments in renewable energy by providing rebates and electricity production incentives for new and existing renewable facilities and emerging renewable technologies. The program has supported more than 5,000 megawatts (MW) of existing and new renewable generating capacity with approximately $2 billion in funding over the life of the program. Funding collection for the program is set to expire January 1, 2012.

Under SB 1078, the Energy Commission and the CPUC jointly implement the RPS for all but the publicly owned electric utilities, who implement their own RPS programs. The Energy Commission is responsible for certifying eligible facilities as "RPS eligible" and has certified 600 facilities since 2002. The Energy Commission is also responsible for tracking and verifying RPS procurement and was instrumental in the development of the Western Renewable Energy Generation Information System as the official accounting system for tracking renewable energy credits (also known as RECs) in the Western Interconnection region.[8] The CPUC's responsibilities include approving IOU procurement plans and RPS-eligible contracts for IOUs, ensuring compliance, and setting benchmark pricing for investor-owned utility RPS contracts. The CPUC also oversees RPS programs for electric service providers and small and multi-jurisdictional utilities. As of November 2009, the CPUC had approved 129 RPS contracts totaling 10,271 MW, with an additional 30 contracts for 4,605 MW under review. About 900 MW of these approved contracts are online and delivering energy to the grid.[9]

The Energy Commission and CPUC are responsible for tracking and verifying utilities' progress toward RPS goals. In July 2009, the CPUC reported that the three IOUs were supplying approximately 13 percent of their aggregated total sales from eligible renewable resources as of 2008. The Energy Commission has not yet verified RPS procurement for 2008. Publicly owned utilities are showing progress in renewable energy procurement,

8 For more information, see [http://www.wregis.org/].

9 California Public Utilities Commission, *Renewables Portfolio Standard Quarterly* Report, November 2009, available at: [http://www.cpuc.ca.gov/NR/rdonlyres/52BFA25E-0D2E-48C0-950C-9C82BFEEF54C/0/FourthQuarter2009RPSLegislativeReportFINAL.pdf].

with expectations for the 15 largest publicly owned utilities of 12.4 percent of RPS-eligible renewable retail sales by 2011. In addition, the Los Angeles Department of Water and Power recently set goals to divest entirely from coal-powered generation and increase its renewable energy portfolio to 40 percent by 2020.

Meeting RPS goals depends in large part on building new transmission lines to access remote renewable resources. To help address land use and environmental concerns, the state launched the Renewable Energy Transmission Initiative (RETI) in 2007, to identify areas where renewable energy could be developed economically and with minimal environmental impacts and the transmission projects needed to access those areas. RETI is a stakeholder collaborative supervised by a coordinating committee made up of the Energy Commission, the CPUC, the California ISO, and publicly owned utilities. RETI and other transmission-related issues are discussed in more detail in Chapters 2 and 3.

Another strategy to address environmental barriers is Governor Schwarzenegger's Executive Order S-14-08, which directs state agencies to work with federal agencies to prepare a Desert Renewable Energy Conservation Plan (DRECP) for the Mojave and Colorado deserts of California. The science-driven DRECP is intended to become the state road map for renewable energy project development that will advance state and federal conservation goals while facilitating the timely permitting of renewable energy projects in these desert regions.

The DRECP efforts will be informed by multiple environmental and land use planning activities including the Bureau of Land Management's Solar Programmatic Environmental Impact Statement (Solar PEIS) and RETI activities, such as the competitive renewable energy zones, and associated transmission line segments to access the zones in the Colorado and Mojave Desert regions. The DRECP will cover a range of activities related to the development of renewable energy projects and associated transmission needs, as well as habitat conservation and mitigation strategies in the plan's study area.

An additional strategy to help the state meet its RPS targets is the use of feed-in tariffs – fixed, long-term prices for energy. Countries such as Spain and Germany have implemented successful feed-in tariff programs, but this concept has been slow to gain momentum in California. The state made some progress when the CPUC adopted a feed-in tariff (Decision 07-07-027) in February 2008, for renewable energy systems at publicly owned water and wastewater treatment facilities. In the same decision, the CPUC expanded the feed-in tariff approach to any renewable system with a capacity of up to 1.5 MW in the Southern California Edison (SCE) and Pacific Gas and Electric (PG&E) service areas.

Governor Schwarzenegger's Executive Order S-06-06 is part of a strategy to develop an integrated and comprehensive state policy on the use of biomass for electricity generation. In response, the Bioenergy Interagency Working Group[10] developed the *Bioenergy Action Plan for California* in 2006, which identified 63 action items for various state agencies to advance the use of bioenergy in California.[11]

The Executive Order required the Energy Commission to provide a progress report in

10 The Working Group is led by Commissioner James Boyd of the California Energy Commission and includes the California Air Resources Board, California Environmental Protection Agency, California Public Utilities Commission, California Resources Agency, Department of Food and Agriculture, Department of Forestry and Fire Protection, Department of General Services, Integrated Waste Management Board, and the State Water Resources Control Board.

11 Bioenergy Interagency Working Group, *Bioenergy Action Plan for California*, July 2006, CEC-600-2006-010, available at: [http://www.energy.ca.gov/bioenergy_action_plan/index.html].

the biennial *IEPR* on the 63 action items. To date, the Energy Commission has found that most of the items have been implemented or are ongoing. For those that have not been put into action, many are no longer relevant, have been overtaken by other events, or have not been funded. In 2008, California met the goal of generating 20 percent of its renewable electricity from biomass sources. However, biomass capacity in the state has decreased since 2002, from 6,192 MW to 5,724 MW.[12] This decrease resulted from the expiration of standard offer contracts from the 1990s, while very few contracts have been signed for new electricity generation fueled by biomass and biogas. The existing fleet of biomass generators depends on financial support from the Energy Commission's Renewable Energy Program, funding for which expires in 2011. These findings are provided in the Energy Commission's *2009 Draft Bioenergy Progress to Plan* report, with anticipated publication in January 2010.

Overall, RD&D continues to be another important strategy for expanding renewable energy development in California. From 1976–2007, the Energy Commission's PIER program has dedicated $131 million to renewable energy research. In addition, the PIER Transmission Research Program is focused on specifically addressing the issues associated with renewable integration into the California transmission system, while research in other areas such as demand response, energy storage, and smart grid technologies will help with renewable integration.

Finally, one other strategy for meeting the RPS is the California ISO's Integration of Renewable Resources Program, which involves working with the Energy Commission and other agencies to identify issues and solutions for the integration of large amounts of renewable resources into the California ISO Control Area.[13] The California ISO completed studies on 20 percent RPS by 2010 in July 2009, and is working on the 33 percent RPS by 2020 scenarios, which it expects to complete by December 2009.

Distributed Generation

Increased use of distributed generation is another strategy for meeting the state's GHG reduction goals. Distributed energy systems are complementary to the traditional electric power system and include small-scale power generation technologies (for example, CHP, photovoltaic, small wind turbines) located close to where the energy is being used. Distributed generation has many advantages, including increased grid reliability, energy price stability, and reduced emissions, especially in industrial applications. California is leading the nation in implementing policies to encourage distributed generation development. The following policies were enacted to encourage the use of distributed generation systems as a way of meeting the state's climate change goals while increasing reliability:

Assembly Bill 1969 (Yee, Chapter 731, Statutes of 2006): This bill authorized feed-in tariffs for small renewable generators of less than 1 MW at public water and wastewater treatment facilities. In July 2007, the CPUC (D. 07-07-027) implemented AB 1969, expanded the feed-in tariffs to 1.5 MW, and included nonwater customers in the PG&E and SCE territories. The power sold to the utilities under feed-in tariffs can be applied toward the state's RPS targets. Senate Bill

12 Presentation by Daryl Metz at the August 10, 2009, IEPR Staff Workshop on RD&D of Advanced Generation Technologies, "California Generation Portfolio," California Energy Commission.

13 California Independent System Operator, see [http://www.caiso.com/1c51/1c51c7946a480.html].

380 (Kehoe, Chapter 544, Statutes of 2008) codified CPUC's expanded feed-in tariff to include all RPS-eligible generators 1.5 MW and below. The program cap was also expanded from 250 MW to 500 MW. As of August 2009, 14.5 MW of contracted capacity had resulted from the tariff.

Assembly Bill 1613 (Blakeslee, Chapter 713, Statutes of 2007): Also known as the Waste Heat and Carbon Emissions Reduction Act, this bill was designed to encourage the development of new CHP systems in California with a generating capacity of up to 20 MW, resulting in more efficient use of natural gas and reduced GHG emissions. The bill requires the CPUC and the Energy Commission to establish policies and procedures for the purchase of electricity from eligible CHP systems.

ARB's Climate Change Scoping Plan: The ARB set a target of 4,000 MW of CHP that would displace 30,000 gigawatt hours of demand from other power generation resources with the overall goal of reducing carbon dioxide (CO_2) by 6.7 million metric tons.

Senate Bill 1 (Murray, Chapter 132, Statutes of 2006): This bill enacted the Governor's Million Solar Roofs program with the overall goal of installing 3,000 MW of solar photovoltaic (PV) systems.

Senate Bill 32 (McLeod, Chapter 328, Statutes of 2009): This bill requires each local publicly owned electric utility with 75,000 or more retail customers to offer a feed-in tariff for eligible renewable energy facilities up to 3 MW in size until the utility meets its proportionate share of a total statewide cumulative cap of 750 MW. The feed-in tariff price is to reflect the value of every kilowatt hour of electricity generated based on the time of delivery. The price may be adjusted based on other attributes of renewable generation. SB 32 also requires IOUs to expand their current feed-in tariffs for eligible renewable energy facilities from 1.5 MW to 3 MW until the utility meets its proportionate share of a total statewide cumulative cap of 750 MW. Prior to this bill, the statewide cap was 500 MW. The feed-in tariff shall provide performance guarantees for any generator greater that 1 MW.

Strategies and Progress

Increasing CHP is a key strategy for displacing conventional power sources. To help track the state's CHP goals, the ARB will report on the GHG emissions reductions resulting from the increase of electricity generated from CHP. Also, in January 2010, the Energy Commission is scheduled to adopt guidelines to establish the technical criteria for CHP system eligibility for programs developed by IOUs and publicly owned utilities.

To implement SB 1, the state officially launched Go Solar California in 2007, to bring customer awareness to the CPUC's California Solar Initiative and the Energy Commission's New Solar Homes Partnership, and solar incentive programs offered by publicly owned utilities beginning 2008. The California Solar Initiative offers rebates to existing homes and nonresidential energy customers installing solar systems in IOU service territories, with 226 MW of new solar systems installed as of June 2009.

The New Solar Homes Partnership offers incentives for home builders to construct solar homes in IOU service territories. The goals of the program are to achieve 400 MW of installed solar capacity by the end of 2016, create a self-sustaining solar market without the need for government incentives, and foster sufficient market penetration in the new residential market so that 50 percent or more of new housing built by 2016 and thereafter will include solar systems. However, with the recent extreme downturn in new home construction, program activity has been slow and is likely to remain so until the economy recovers.

Solar incentive programs offered by the publicly owned utilities must abide by the minimum guidelines adopted by the Energy Commission in December 2008. These solar incentive programs have their own processes and requirements and are expected to achieve 700 MW of installed solar capacity by the end of 2016.

Another customer-side strategy is the Self-Generation Incentive Program, which is implemented by the CPUC through the IOUs and provides rebates for customers who install wind turbines and fuel cells. The program originally included microturbines, small gas turbines, wind turbines, solar photovoltaics, fuel cells, and internal combustion engines, but as of January 1, 2008, eligibility was limited to fuel cells and wind energy technologies. However, SB 412 (Kehoe, Chapter 182, Statutes of 2009), signed in October 2009, expands program eligibility to include "distributed energy resources that the [CPUC], in consultation with the State Air Resources Board, determines will achieve reductions of greenhouse gas emissions." As of December 2008, the IOUs have paid more than $600 million in rebates for more than 1,200 projects totaling more than 337 MW of generating capacity. The Energy Commission administers a similar program, the Emerging Renewables Program, which continues to be limited to small wind turbines and fuel cells that use renewable fuels.

Net metering is another strategy to help increase customer-side distributed generation technologies, particularly PV. Customers who install an on-site renewable energy system can apply for net metering, which is a special billing arrangement with the utility. The customer's electric meter tracks electricity generated by the renewable system versus electricity consumed, with the customer paying only for the net amount taken from the grid over a 12-month period. As of October 2009, the CPUC reports that more than 90 percent of the 509 MW of grid-connected solar in IOU territories are net metered.[14] In addition, in October 2009, PG&E committed to increase the amount of net metering for rooftop solar in its territory from 2.5 percent to 3.5 percent to ensure that investment in solar continues to grow.[15]

Natural Gas and Nuclear Power Plants

Despite long-term efforts to promote preferred resources like energy efficiency, demand response, distributed generation, and renewable energy, California still relies on natural gas and nuclear power plants for about 60 percent of its electricity. Since deregulation in 1998, the Energy Commission has reviewed and licensed 66 electric generation projects, totaling 25,744 MW. Forty-seven of these licensed facilities, totaling more than 15,000 MW of natural gas-fired capacity, have been built and are on-line.

The following are key policies affecting natural gas and nuclear power plants:

State Water Resources Control Board's Once-Through Cooling Resolution (2006): The State Water Resources Control Board (SWRCB) passed a resolution to reduce marine impacts from once-through cooling (OTC) systems used by 21 coastal power plants in

14 California Public Utilities Commission, *California Solar Initiative Staff Progress Report*, October 2009, Table 7, [http://www.cpuc.ca.gov/NR/rdonlyres/4B614602-0E76-4533-A03A-BC01B6A89831/0/ProgrReportOct09Final_3_withcover.pdf].

15 Office of the Governor, October 26, 2009, press release, "Governor Schwarzenegger Secures Commitment to Continue Net Metering for Solar," [http://gov.ca.gov/press-release/13731/].

California, including natural gas and nuclear plants. This began as a coordinated process between several government agencies to phase out the use of OTC.

Assembly Bill 1632 (Blakeslee, Chapter 722, Statutes of 2006): This legislation directed the Energy Commission to assess the vulnerability of California's largest baseload plants, PG&E's Diablo Canyon Nuclear Power Plant (Diablo Canyon) and SCE's San Onofre Nuclear Generating Station (SONGS), to an extended shutdown due to a major seismic event or aging. AB 1632 also called for an examination of potential impacts from the accumulation of nuclear waste at both locations and an exploration of other key issues such as plant relicensing and worker safety.

Senate Bill 1368 (Perata, Chapter 598, Statutes of 2006): This bill limited long-term investments in baseload generation by the state's utilities to power plants that meet an emissions performance standard jointly established by the Energy Commission and the CPUC.

***2005* and *2007 IEPR* Policy on Aging Power Plants:** In both reports, the Energy Commission recommended that the CPUC require IOUs to procure enough capacity from long-term contracts to allow for the orderly retirement or repowering of aging plants by 2012. In the *2007 IEPR*, the Energy Commission recommended that California's utilities adopt all cost-effective energy efficiency measures for natural gas, including replacement of aging power plants with new efficient power plants. In addition, the *2007 IEPR* recommended the Energy Commission, the CPUC, the California ISO, and other interested agencies work together to complete studies on the impacts of retiring, repowering, and replacing aging power plants, particularly in Southern California.

ARB's *Climate Change Scoping Plan*: The *Climate Change Scoping Plan* calls for industrial facilities, such as power plants, to implement cost-effective GHG emissions reduction strategies. Specifically, the *Climate Change Scoping Plan* requires a reduction in GHG emissions from fugitive emissions (for example, from leaks in plant equipment like valves, seals, and so on) from oil and gas extraction and gas transmission.

Assembly Bill 1318 (Perez, Chapter 285, Statutes of 2009): Under existing law, air pollution control districts or air quality management district governing boards are required to establish emission reduction credit systems that are to be used to offset certain future increases in the emission of air contaminants. These must be banked prior to use to offset future increases in emissions. This bill exempts certain actions on emission credits undertaken by the South Coast Air Quality Management District (SCAQMD) to be exempt from the California Environmental Quality Act (CEQA).

Senate Bill 827 (Wright, Chapter 206, Statutes of 2009): This bill authorizes SCAQMD to issue permits under specific circumstances notwithstanding the court decision on CEQA.

Strategies and Progress

The federal government's Clean Water Act, enacted in 1972, is the primary law governing water pollution in the United States. The act implemented a permit system for regulating point sources of pollution (for example, industrial facilities) to be overseen by the U.S. Environmental Protection Agency (U.S. EPA) or states with approved permitting programs, such as California. Section 316(b) of the Clean Water Act addresses the adverse environmental impacts caused by cooling water intake structures from power plants and other industrial sources. This section requires that the location, design, construction, and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impacts.

In April 2006, the SWRCB issued a resolution to reduce OTC impacts from existing power plants to comply with the Clean Water Act. The SWRCB issued a preliminary proposal to phase out OTC and provided it for review to the Energy Commission, California ISO, and the CPUC. The SWRCB received pertinent feedback from the energy agencies about the ability to maintain reliability while complying with OTC policy. The SWRCB issued a second proposed retirement schedule, but the energy agencies still had concerns that the proposed schedule would impact electricity reliability. In June 2008, the SWRCB formed the Interagency Working Group to foster communication among seven government agencies. The three energy agencies – the Energy Commission, CPUC, and the California ISO – were encouraged by the SWRCB to propose alternatives to its compliance schedule.

The energy agencies submitted a final strategy in May 2009, that calls for replacing existing OTC facilities with some combination of repowered technologies onsite, new generation located in other areas, and/or upgrades to the transmission system. The SWRCB accepted the proposal and included references to it in its draft OTC policy on June 30, 2009.[16] The OTC concerns relating to grid reliability, with emphasis on Southern California, are discussed in more detail in Chapter 3.

In addition to marine impacts from OTC, the primary concerns regarding the state's nuclear plants relate to the potential for extended outages at the plants from seismic events or plant aging and the absence of a repository for disposal of the high-level radioactive waste produced at the plants. In addition, the plants pose a small risk of potentially severe impacts from acts of terrorism or accidents.

The Energy Commission's report, *An Assessment of California's Nuclear Power Plants: AB 1632 Report,*[17] adopted as part of the *2008 IEPR Update*, recommended that PG&E and SCE update studies on the seismic hazard at their nuclear plants, investigate plant seismic safety compliance with current codes and standards, describe plant repair plans and time frames in the event of an earthquake, provide evidence of strong safety cultures (especially at SONGS), and report findings from these studies as part of their license renewal feasibility studies for the CPUC and in future *IEPRs*.

The strategies just described are meant to minimize reliability, economic, and environmental risks associated with California's operating power plants. SB 1368, on the other hand, applies to all new power generation. In 2007, the Energy Commission adopted regulations for publicly owned utilities to meet the Emissions Performance Standard as required by SB 1368. The regulations require a baseload standard for generation of 1,100 pounds of CO_2 per MW hour and establish a public review process to ensure compliance with the Emissions Performance Standard.

16 Jaske, Michael R. (California Energy Commission), Peters, Dennis C. (California Independent System Operator), and Strauss, Robert L. (California Public Utilities Commission), *Implementation of Once-Through Cooling Mitigation Through Energy Infrastructure Planning and Procurement*, California Energy Commission, July 2009, CEC-200-2009-013-SD, available at: [http://www.energy.ca.gov/2009publications/CEC-200-2009-013/CEC-200-2009-013-SD.PDF].

17 Available at: [http://www.energy.ca.gov/2008publications/CEC-100-2008-009/CEC-100-2008-009-CMF.PDF]. The report was based on a report prepared by MRW & Associates for the California Energy Commission, *AB 1632 Assessment of California's Operating Nuclear Plants*, October 2008, CEC-100-2008-005-F, available at: [http://www.energy.ca.gov/2008publications/CEC-100-2008-005/CEC-100-2008-005-F.PDF].

Transmission and Distribution

The state's transmission and distribution system is another critical component of the electricity sector for serving California's growing population and integrating renewable energy. The state has implemented several key legislative mandates addressing transmission planning and permitting, and recent passage of legislation requiring a "smart grid" deployment plan reflects the growing importance of these technologies in improving efficiency, reliability, and cost-effectiveness of the state's electrical system.

Senate Bill 1565 (Bowen, Chapter 692, Statutes of 2004): In 2004, the Legislature addressed the need for an official state role in transmission planning with the passage of this bill. Senate Bill 1565 directed the Energy Commission to develop a *Strategic Transmission Investment Plan* which identifies and recommends actions to stimulate transmission investments to ensure reliability, relieve congestion, and meet future growth in load and generation, including renewable resources, energy efficiency, and other demand reduction measures. The *Strategic Transmission Investment Plan* is a companion document to the *Integrated Energy Policy Report* and is adopted by the Energy Commission along with that report.

Senate Bill 1059 (Escutia, Chapter 638, Statutes of 2006): This bill required the Energy Commission to designate transmission corridor zones on state and private lands available for future high-voltage electricity transmission projects, consistent with the state's electricity needs identified in the *Integrated Energy Policy Reports* and *Strategic Transmission Investment Plans*.

Senate Bill 17 (Padilla, Chapter 327, Statutes of 2009): This bill requires the CPUC (in consultation with the Energy Commission, the California ISO, and other key stakeholders) to determine the requirements for a smart grid deployment plan consistent with the policies set forth in the bill and federal law by July 1, 2010. The bill requires the smart grid to improve overall efficiency, reliability, and cost-effectiveness of electrical system operations, planning, and maintenance. Each electrical corporation must develop and submit a smart grid deployment plan to the CPUC for approval by July 1, 2011.

Strategies and Progress

The Energy Commission has prepared and published two strategic plans in response to SB 1565. The first was released in 2005 and the other in 2007. Both reports provided an overview of the significant transmission planning and system issues hindering development of a more robust high-voltage grid and identified actions necessary to improve California's transmission system.

The *2009 Strategic Transmission Investment Plan*, prepared in support of the *2009 IEPR*, describes the immediate actions that California must take to plan, permit, construct, operate, and maintain a cost-effective, reliable electric transmission system that is capable of responding to important policy challenges such as achieving significant GHG reduction and RPS goals. The *2009 IEPR* provides the report's top priority recommendations in Chapter 4.

In 2004, the PIER program established the Transmission Research Program to specifically address the research and development needs of California's transmission system. The program considers new and emerging technologies that can increase the capabilities of existing transmission lines and provide better understanding of system management issues associated with the penetration of high amounts of renewable generation and integrating new high-speed data collection technologies like synchrophasors.[18] Research continues in areas specifically addressing the issues associated with renewable integration into the California transmission system.

California Climate Change Policies: The policies directing the state to meet climate change goals, such as the RPS and the ARB's *Climate Change Scoping Plan*, intend to reduce the state's dependence on fossil fuels – such as natural gas – and replace them with cleaner fuel resources.

Natural Gas

California's dependence on natural gas as a fuel for electricity generation and for heating and process industries requires the state to have reliable and cost-effective sources of supply and sufficient infrastructure to deliver that supply. During the 2009 IEPR proceedings, the IEPR Committee focused on natural gas issues relating to price volatility, supply, and infrastructure needs. Aside from GHG emission reduction policies, other guiding policies regarding natural gas relate to forecasting, supply stability, and reliability. The following policies and regulations provide direction on natural gas programs and development:

California Public Resources Code: The code directs the Energy Commission to conduct assessments and forecasts of all aspects of energy industry supply, production, transportation, delivery and distribution, demand, and prices at least every two years and to identify impending or potential problems or uncertainties in the electricity and natural gas markets, as well as potential options and solutions and recommendations.

18 Synchrophasors can collect and report critical electrical measurements approximately 30 times per second, providing information about grid conditions to system operators so they can make time-sensitive decisions. As more renewable resources are integrated into the grid, operators need this kind of technology to respond to unpredicted changes in output that are characteristic of some renewable technologies.

Strategies and Progress

California relies on natural gas for more than 45 percent of its total system power needs.[19] Eighty-seven percent of natural gas supplies are imported via pipelines from the Southwest, the Rocky Mountains, and Canada. This reliance on out-of-state natural gas leaves California vulnerable to supply disruptions and price volatility. Since 2000, the United States has experienced four major price spikes that affected residential, commercial, and industrial consumers, as well as power generators and gas producers. During the 2000–2001 energy crisis, natural gas cost California $19.4 billion, more than double the price paid for similar amounts in the years just before the crisis.

This issue has been addressed by new expansions of interstate pipelines, improvements in utilities' receiving ability, and the enhancement by utilities and independent storage owners of their storage operations to meet future high demand conditions. These efforts have given California's utilities the flexibility to choose supply sources in their day-to-day operations and have forced natural gas production areas to compete for a share of the state's natural gas market. However, California is still part of an international natural gas market that includes Canada, the United States, and Mexico. A disruption in one

19 California Energy Commission, Energy Almanac, available at: [http://energyalmanac.ca.gov/electricity/total_system_power.html].

area ripples through the rest of the market.

As domestic production of conventional natural gas has declined, shale-deposited natural gas within the United States and Canada could provide California with a more stable supply of natural gas in the future. In the last 20 years, technological innovations have eliminated the barriers that prevented the production of this resource. It is possible that this new supply could flow eastward and allow more natural gas from the Rockies and the Southwest to be sent to California. However, further analysis is needed on environmental concerns related to groundwater impacts and the carbon footprint from drilling, as well as market uncertainties based on investments and the infancy of shale development.

Importing liquefied natural gas (LNG) is another strategy that could offset declining domestic production of natural gas. In the *2007 IEPR*, staff projected that as much as 20 percent of North American natural gas requirements might be met with LNG by 2017. However, development of new terminals appears to be slowing, and imports of LNG to the United States have been lower than projected. There is a new sense that the United States may not need to rely on LNG to make up previously projected supply deficits.

The *2007 IEPR* recommended that California should promote the use of pipeline-quality biogas from dairies and landfills as a strategy to diversify supplies of natural gas. At the 2009 IEPR Scoping Workshop in June 2008, the Natural Resources Defense Council recommended that the *2009 IEPR* pursue policies that encourage the replacement of natural gas with renewable resources. The Energy Commission examined this issue and found that there are still significant barriers hindering the in-state development of this resource, including AB 4037 (Hayden, Chapter 932, Statutes of 1988), which discourages injection of biogas into natural gas pipelines by penalizing landfill gas and pipeline operators if vinyl chloride is found in the pipeline. This has resulted in pipeline operators purchasing from out-of-state sources that are not restricted under the law.

Fuels and Transportation

California has taken a clear policy stance of decreasing reliance on petroleum fuels by increasing the mix of alternative and renewable fuels and improving fuel efficiency. Petroleum will continue to be the primary fuel source for California's vehicles, at least in the near term, so it must be factored into all policy decisions regarding infrastructure and transportation supply and demand. As California relies increasingly on crude oil imports, the state is looking at ways to enhance and expand the existing petroleum infrastructure, particularly at in-state marine ports. California has adopted the following policies affecting the transportation sector.

Assembly Bill 1493 (Pavley, Chapter 200, Statutes of 2002): The bill required the ARB to develop and adopt, no later than January 1, 2005, regulations to achieve the maximum feasible and cost-effective reduction of GHG emissions from motor vehicles.

***2003 Integrated Energy Policy Report*:** The Energy Commission showed that it is feasible to significantly reduce the state's dependence on petroleum by increasing vehicle efficiency and the use of alternative fuels and recommended that the state increase the use of nonpetroleum fuels to 20 percent of on-road fuel consumption by 2020, and 30 percent by 2030, based on identified strategies that are achievable and cost-beneficial.[20]

***2005 Integrated Energy Policy Report*:** The Energy Commission examined petroleum reduction options and recommended that the state develop flexible overarching strategies that simultaneously reduce petroleum fuel use, increase fuel diversity and security, and reduce air pollution and GHG emissions and that it implement a public goods charge to establish a secure, long-term source of funding for a broad transportation program.[21]

Executive Order S-3-05 (2005): The executive order established statewide GHG emission reduction targets that preceded the enactment of AB 32: by 2010, reduce emissions to 2000 levels; by 2020, reduce emissions to 1990 levels; and by 2050, reduce emissions to 80 percent below 1990 levels.

Assembly Bill 1007 (Pavley, Chapter 371, Statutes of 2005): This bill required the Energy Commission to prepare, jointly with the ARB, a plan to increase the production and use of alternative and renewable fuels in California based on a full fuel-cycle assessment of the environmental and health impacts of each fuel option. The *State Alternative Fuels Plan* was adopted by the two agencies in December 2007. The plan highlights the need for state government incentive investments of more than $100 million per year for 15 years and recommends that the state adopt alternative and renewable fuel use goals of 9 percent by 2012, 11 percent by 2017, and 26 percent by 2022.

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20 California Energy Commission, *2003 Integrated Energy Policy Report*, available at: [http://www.energy.ca.gov/reports/100-03-019F.PDF].

21 California Energy Commission, *2005 Integrated Energy Policy Report*, CEC-100-2005-007-CMF, available at: [http://www.energy.ca.gov/2005publications/CEC-100-2005-007/CEC-100-2005-007-CMF.PDF].

***Bioenergy Action Plan* (2006):** The Energy Commission adopted this plan with the intent to maximize the contributions of bioenergy toward achieving the state's petroleum reduction, climate change, renewable energy, and environmental goals. The plan recommends a production target of a minimum of 20 percent of biofuels produced in California by 2010, 40 percent by 2020, and 75 percent by 2050.[22]

Executive Order S-06-06 (2006): This order set targets for the production of biofuels based on the recommendations of the *Bioenergy Action Plan* and charged the Energy Commission, along with other commissions and departments, to identify and secure funding for RD&D projects to advance the use of biofuels for transportation.

Executive Order S-01-07 (2007): Governor Schwarzenegger's order established a Low Carbon Fuel Standard (LCFS) for transportation fuels sold in California. By 2020, the standard will reduce the carbon intensity of California's passenger vehicle fuels by at least 10 percent. The Executive Order directs the secretary for the Cal/EPA to coordinate the actions of the Energy Commission, the ARB, the University of California, and other agencies to assess the "life-cycle carbon intensity" of transportation fuels. ARB completed its review of the LCFS protocols and adopted them as an early action in October 2007. The ARB, through its rulemaking, adopted the new standard in April 2009.

Assembly Bill 118 (Núñez, Chapter 750, Statutes of 2007): This bill created the Alternative and Renewable Fuel and Vehicle Technology Program. The statute, subsequently amended by AB 109 (Núñez, Chapter 313, Statutes of 2008), authorizes the Energy Commission to develop and deploy alternative and renewable fuels and advanced transportation technologies to help attain the state's climate change policies. The Energy Commission has an annual program budget of approximately $100 million and is required to adopt and update annually an investment plan that determines the funding priorities.

The Energy Independence and Security Act of 2007: This federal legislation requires ever-increasing levels of renewable fuels – a Renewable Fuel Standard (RFS) – to replace petroleum. Primarily focused on ethanol, the law establishes the national goal of using 36 billion gallons of renewable fuel per year by 2022. An updated version of the standard, called RFS2, is scheduled to take effect January 1, 2010.[23]

Senate Bill 375 (Steinberg, Chapter 728, Statutes of 2008): This bill requires the ARB to develop, in consultation with metropolitan planning organizations, passenger vehicle GHG emission reduction targets for 2020 and 2035 by September 30, 2010. Through the SB 375 process, regions will work to integrate development patterns, the transportation network, and other transportation measures and policies in a way that achieves GHG emission reductions while meeting regional planning objectives.

22 California Energy Commission, *Bioenergy Action Plan*, July 2006, CEC-600-2006-010, available at: [http://www.energy.ca.gov/bioenergy_action_plan/index.html].

23 United States Senate Committee on Energy and Natural Resources, summary and related documents available at: [http://energy.senate.gov/public/index.cfm?FuseAction=IssueItems.Detail&IssueItem_ID=f10ca3dd-fabd-4900-aa9d-c19de47df2da&Month=12&Year=2007].

Strategies and Progress

Under AB 1493's authority, the ARB approved regulations to reduce GHGs from passenger vehicles in September 2004, with the regulations to take effect in 2009. However, in March 2008, the U.S. EPA denied the ARB's first waiver request to implement GHG standards. The denial was based on a finding that California's request did not show it was needed to meet "compelling and extraordinary conditions" as required under the federal Clean Air Act.

The regulations became the subject of automaker lawsuits, and their implementation was stalled by the U.S. EPA's denial. In May 2009, parties on both sides entered an agreement to resolve these issues. The U.S. EPA granted ARB's waiver on June 30, 2009, and the ARB held a hearing on September 24, 2009, on proposed amendments to the regulations. It is expected that the Pavley regulations will reduce GHG emissions from California passenger vehicles by about 22 percent in 2012 and about 30 percent in 2016, while improving fuel efficiency and reducing motorists' costs.

On April 22, 2009, the Energy Commission adopted its first Investment Plan for the Alternative and Renewable Fuels and Vehicle Technology Program.[24] The Investment Plan contains specific recommendations for expending the $176 million appropriated for the first two years of the program (fiscal years 2008–09 and 2009–10). The Investment Plan allocates $46 million for electric drive vehicles, $40 million for hydrogen fueling stations, $12 million for generation I biofuels (or ethanol), $6 million for generation II biofuels (or renewable diesel and biodiesel), $43 million for natural gas development including biomethane production plants, $2 million for propane medium-duty vehicles (such as school buses), and $27 million for workforce training, sustainability studies, standards and certification, and public education.

Another $83.45 million from ARRA federal stimulus funds will be added to this effort, as well as training and workforce development needs in the transportation sector. Leveraging these federal dollars for projects consistent with the AB 118 funding goals will spur innovation and competition in the development of alternative fuels, technologies, advanced vehicles, and alternative fuel infrastructure, leading to an eventual reduction in petroleum fuel usage.

In response to the federal ARRA of 2009, staff released a solicitation on April 22, 2009, titled *American Recovery and Reinvestment Act of 2009 Cost Share: Alternative and Renewable Fuel and Vehicle Technology Program* to offer cost share funding opportunities using AB 118 funds. Projects resulting from this solicitation include the development of 55 ethanol (E85) stations, more than 3,100 electric charging stations, 5 public access LNG stations, and the purchase of 442 LNG medium-duty trucks and 123 medium-duty hybrid electric trucks.

In addition to the ARRA cost share solicitation, the Energy Commission has entered into interagency agreements with state entities that specialize in workforce training. These agreements support the transportation component of the California Clean Energy Workforce Training Program, a collaborative effort among the Energy Commission, the Employment Development Department, and the California Workforce Investment Board.

The paramount matter is the Energy Commission's progress in achieving the goals and objectives set forth in the *State Alternative Fuels Plan*. According to the Energy Informa-

24 California Energy Commission, *Investment Plan for the Alternative and Renewable Fuel and Vehicle Technology Program*, commission report, April 2009, CEC-600-2009-008-CMF, available at: [http://www.energy.ca.gov/2009publications/CEC-600-2009-008/CEC-600-2009-008-CMF.PDF].

tion Administration (EIA), California's overall alternative fuel usage increased to 109,114 gasoline gallon equivalent (GGE) in 2007 from just over 70,000 GGE in 2003. The number of alternative fuel vehicles in use also increased. The largest alternative fuel categories in use are compressed natural gas, liquefied petroleum gas, and LNG followed by E85. Federal, state, and local government agencies are the predominant consumers of alternative fuels. As the trend away from petroleum-fueled vehicles grows, the reduction in GHG emissions will become more apparent. Since 2000, the growth in hybrid vehicles alone in California has contributed to a reduction in GHG emissions of about 60 million metric tons.

As for the in-state biofuels production goals, the state is not on track to meet the 2010 target. The biofuels industry – in California as well as the rest of the country – entered a period of severe decline in 2009, a victim of tight credit, a glut of production capacity, dwindling demand, and low oil prices. Many business models for producing biofuel were based on oil being priced above $80 a barrel; with oil prices falling well below that benchmark, producing ethanol became uneconomical. Plants producing ethanol from corn shut down across the country as corn prices spiked even as ethanol prices dropped, and many companies sought bankruptcy protection.

Companies making biodiesel from vegetable oil or animal fat suffered similar fates. Delayed federal rules on changing fuel mixes added to uncertainty for the biofuel industry. While congressional mandates allowing biodiesel blending and requiring the use of second-generation biofuels are slated to take effect in 2010, the U.S. EPA postponed issuing regulations needed to implement the requirements.

By the fall of 2009, two-thirds of United States biodiesel production capacity sat idle, according to the National Biodiesel Board.[25] In September 2009, 98 percent of California's ethanol production capacity was reported to be closed down.

The Energy Commission's PIER transportation subject area is focusing RD&D funding on vehicle technologies, transportation systems, and alternative fuels to help reduce petroleum consumption and GHG emissions while assisting economic development within California. In 2009, PIER transportation subject area solicitations invested over $5.8 million in advanced heavy duty natural gas engine development and advanced biofuels development. The PIER-funded vehicle technology and alternative fuel research can be deployed through the Alternative and Renewable Fuels and Vehicle Technology Program.

PIER transportation also offers small grants that address transportation concept feasibility research. Research guidance is provided by PIER transportation's three focus areas and road maps. Successful projects can receive additional funding from the PIER program to further develop proven concepts. The Energy Commission conducted the first two transportation small grant solicitations and received a total of 45 proposals. Proposal concepts include research addressing vehicle efficiency improvements, batteries, electric vehicles, and sustainable communities modeling.

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25 *Wall Street Journal*, August 27, 2009, available at: [http://online.wsj.com/article/SB125133578177462487.html?mod=googlenews_wsj].

Land Use and Planning

Land use planning is a local issue, under the jurisdiction of local governments. Decisions about land use, however, directly affect energy use and the consequent production of GHG emissions in the state. In addition, local government building departments are responsible for enforcing the mandatory energy efficiency standards for buildings.

Since the 1950s, California's land use patterns have emphasized suburban development of large residential tracts located far from city centers and places of work or business. This land use planning has resulted in many citizens purchasing more affordable housing in the suburbs and commuting long distances to the workplace. With transportation being a major contributor – approximately 40 percent – to GHG emissions in this state, smart land use planning and growth are increasingly important strategies to combat declining air quality and the loss of open space and wildlife habitat and to improve the quality of life for California's residents. Nearly 26 million vehicles, most of which are powered by fossil fuels, along with a high rate of vehicle miles traveled, contribute significantly to California's GHG emissions and climate change issues. Projections show that the state cannot reduce GHG emissions to 80 percent of 1990 levels by 2050 unless vehicle miles traveled are reduced by at least 17 percent.[26]

Reducing vehicle miles traveled in a meaningful way requires replacing the existing suburban development model with one that encourages denser, more compact cities that offer better mass transit options and amenities that encourage walking or biking. Indeed, "smart growth" – applying development principles that make prudent use of resources and create low-impact communities demonstrating enlightened design and layout – was identified in the *2006 IEPR Update* as the single largest opportunity to help California meet its statewide energy and climate change goals.

Housing, transportation planning, and local GHG reductions all require local and regional approaches. But smart growth became an increasingly important issue after the California Office of the Attorney General ruled that local jurisdictions must consider GHG emissions when submitting CEQA documents for planning projects.

To encourage and facilitate smart growth, state agencies – including the Energy Commission – are offering assistance to local governments. California has enacted new policies that emphasize smart growth plans at the local level and incorporate energy, transportation, climate change, and housing needs. The following policies provide direction on local government assistance:

Senate Bill 375 (Steinberg, Chapter 728, Statutes of 2008): This bill established mechanisms for the development of regional targets for passenger vehicle GHG reductions.

Senate Bill 732 (Steinberg, Chapter 729, Statutes of 2008): This bill established a five-member council to help state agencies allocate Strategic Growth Plan funds to promote efficiency and sustainability and support the Governor's economic and environmental goals.

Strategies and Progress

Senate Bill 375 requires metropolitan planning organizations to incorporate a Sustainable Community Strategy as an element of their Regional Transportation Plans. The strategy will be effectively a blueprint-like

26 California Energy Commission, *State Alternative Fuels Plan*, December 2007, CEC-600-2007-011-CMF, p. 75, available at: [http://www.energy.ca.gov/ab1007/index.html].

set of planning assumptions that shape the land use component of the Regional Transportation Plans. The goal is to promote development density near urban cores and transit centers. Senate Bill 375 creates incentives for local governments and developers by providing relief from certain CEQA requirements for development projects consistent with regional plans that achieve the targets.

Funding is a key part of assisting local government agencies with their Regional Transportation Plans. Since 2005, the California Department of Transportation (Caltrans) has coordinated local and state planning through its California Regional Blueprint Planning Program, a voluntary, competitive grant program encouraging metropolitan planning organizations and councils of government to conduct comprehensive scenario planning. The goal of the program is for regional leaders, local governments, and stakeholders to reach consensus on a preferred growth scenario – or "blueprint" – for a 20-year planning horizon (through 2025). Caltrans has awarded a total of $20 million in federal Regional Transportation Plan funds since initiating the program in 2005. In 2009 alone, Caltrans granted $5 million to nine metropolitan planning organizations and nine rural regional transportation planning agencies.[27]

To support the goals of SB 375, the Energy Commission is conducting research to help determine the most effective ways to reduce fuel consumption and emissions through integrated land use and transportation planning. Working with the University of California, Berkeley Global Metropolitan Center, PIER expects to quantify the impacts that smart growth can bring in reducing the effects of global climate change. PIER-funded research includes a project titled Assess New Transportation and Urban Development Patterns in a Climate-Constrained Future that will analyze how various policy options would mitigate transportation GHG emissions given California's expected population growth.

Through new legislation and adopted policies, California has become a leader in the worldwide search for solutions to the growing problem of climate change. Many of the state's energy policies highlighted in the *2009 IEPR* are being used as templates by other governments as they strive to protect consumers, the economy, and the environment.

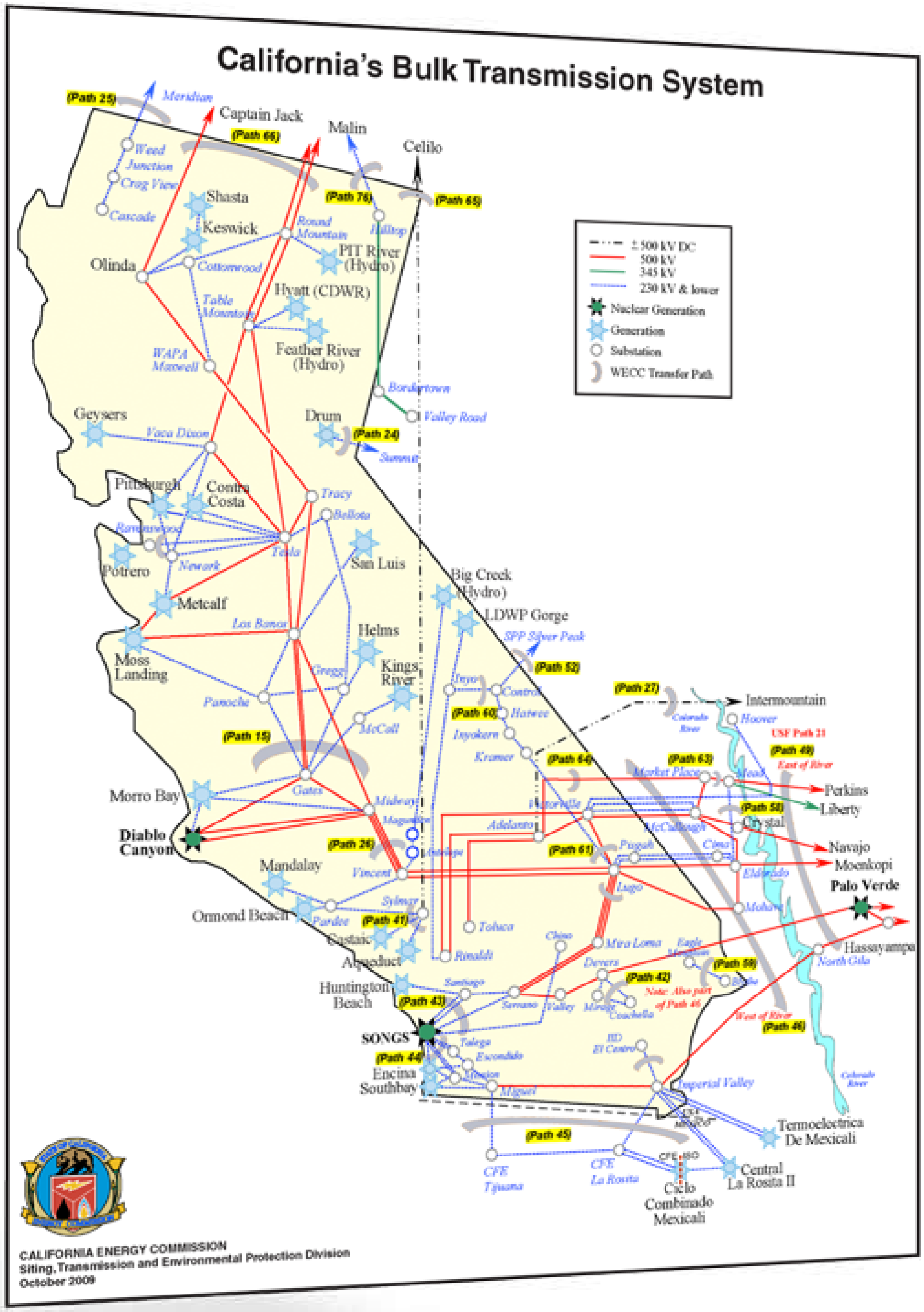
27 California Department of Transportation, California Regional Blueprint Planning Program, see [http://www.dot.ca.gov/hq/tpp/offices/orip/blueprint/index.html].

CHAPTER 2
ENERGY AND CALIFORNIA'S CITIZENS

California's energy policies have tangible and direct effects on energy consumers – individuals, businesses, industries, and government. The state's citizens have three basic priorities when it comes to energy: it must be reliable and affordable and have minimal environmental impacts. These priorities apply equally to each of the state's three major energy sectors: electricity, transportation, and natural gas. Each sector is covered in a separate section that describes supply and demand trends along with the environmental, reliability, and economic issues facing that sector. The electricity sector is further broken down based on the loading order elements of energy efficiency, renewable energy, distributed generation, conventional resources, and transmission infrastructure.

However, important overlaps exist between each sector. Natural gas remains the predominant fuel for electricity generation, so circumstances that affect natural gas supplies and prices will also affect the electricity system. Changes in natural gas supplies and prices can also affect the transportation sector as the state moves toward increased use of alternative transportation fuels like compressed natural gas. Similarly, increased electrification of the transportation system will affect electricity demand, which could increase the need for energy efficiency as well as the amount of renewable energy needed to meet the state's renewable energy goals. Increased use of renewable energy could affect demand for natural gas and, therefore, natural gas prices and the need for new natural gas infrastructure.

FIGURE 1: BULK TRANSMISSION SYSTEM IN CALIFORNIA



Source: California Energy Commission, 2009.

While this chapter characterizes various issues in each sector as relating primarily either to reliability, the environment, or the economy, there are no distinct lines among these categories and, in fact, most issues affect all three to some extent.

Electricity

California's electricity system is a giant machine with many interrelated moving parts in constant need of maintenance and upgrades. This system of electricity generators, delivery facilities, and energy consumers must constantly adapt so that the amount of electricity generated instantly and continuously matches the amount of energy consumed. This section provides an overview of the three main components of the electricity system: transmission and distribution, supply, and demand. It then discusses the environmental, reliability, and economic issues associated with the various resources in the state's loading order that was described in Chapter 1.

California's electricity needs are satisfied by a variety of load-serving entities, including investor-owned utilities (IOUs), publicly owned utilities, electric service providers, and community choice aggregators. In the October 14, 2009, hearing on the draft *2009 Integrated Energy Policy Report (IEPR)*, several parties noted the need for equitable treatment of publicly owned and investor-owned utilities in all energy policy areas but particularly in energy efficiency evaluation, measurement, and verification as well as in meeting the state's renewable energy goals. The Energy Commission agrees that equal treatment is important given that energy policy goals are statewide goals and should therefore apply to all load-serving entities, but also recognizes that a "one size fits all" approach may be problematic given the unique needs and circumstances of some utilities.

Electricity Transmission and Distribution

The backbone of California's electricity system is the state's network of electric transmission and distribution lines that brings power to California consumers from generators both in and out of state. Following California's deregulation of the electricity system in 1998, the three major investor-owned utilities (Pacific Gas and Electric Company, Southern California Edison, and San Diego Gas & Electric Company) and several publicly owned utilities transferred operation of their transmission systems to the California Independent System Operator (California ISO).[28] These utilities continue to operate their own distribution systems, but rely on the California ISO to operate the overall transmission network. Several publicly owned utilities, including Sacramento Municipal Utility District (SMUD), the Los Angeles Department of Water and Power (LADWP), and the Imperial Irrigation District, still control and operate both their transmission and distribution systems, although the systems are connected to the California ISO-controlled grid.

Figure 1 shows the bulk transmission system now in place in California. Key features are the extensive interconnections to the north and southeast that allow imported electricity to flow into California. Through these lines California is connected to the overall Western Interconnection covering most of western North America, from British Columbia and Alberta to the north, Baja Mexico to the south, and Colorado to the east.

28 The California Independent System Operator is a Federal Energy Regulatory Commission-regulated nonprofit corporation tasked with ensuring competitive and nondiscriminatory access to the California transmission system and is responsible for managing the flow of electric power for the majority of California.

Because California's transmission and distribution system is an intrinsic component of the high-voltage Western Interconnection, the state needs to be both a participant and a partner in various regional and federal planning and permitting initiatives that will alter the way transmission planning and permitting occur in the future. Most of these initiatives encourage centralized transmission and distribution planning at the regional level, supplemented by federal incentives and regulation. Developers of new transmission are also focusing on the western United States by proposing over 30 enhancements and new projects that could increase the transfer capacity in various sub-regions and across the interconnection to bring renewable energy resources to market.

Electricity Supply

Power plants comprise the second component of California's electricity system. To match supply with demand, electricity systems rely on a portfolio of power plants that use different fuels and have different operating characteristics. California relies on generating resources that include large hydroelectric, natural gas, nuclear, cogeneration, and renewables (Figure 2). This mix can vary year-to-year, seasonally, daily, and even hourly.

To provide reliable energy, California's system operators must constantly balance supply and demand in real time. The availability of generating resources depends on the lead-time involved, with some generators needing a full day to start up and others needing only minutes. Other generators operate as "spinning reserves," generating less than their capacity but able to ramp up their generation relatively quickly to meet increased demand for electricity. Some resources, like nuclear, coal, geothermal, biomass, and cogeneration, usually run at or near full capacity when operating because of technical constraints, economics, or contracts. Other resources, like hydroelectric, wind, and solar, operate when conditions allow.

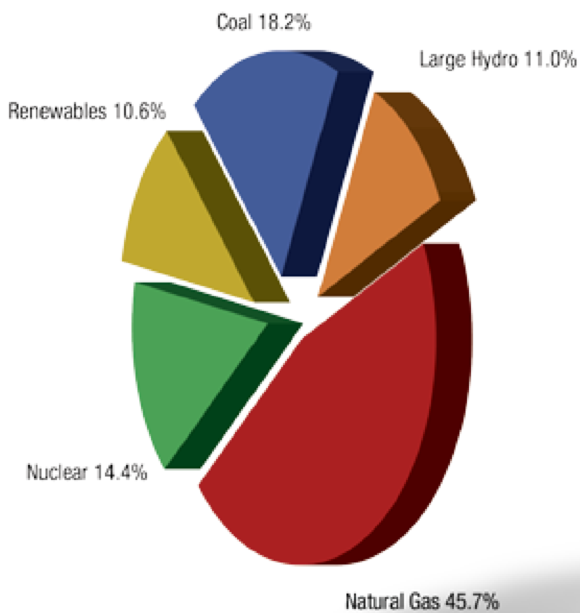
Table 1 shows the entire generation mix that served Californians in 2008. The in-state values listed are a reasonably accurate snapshot of the entire California power mix for the year. The breakdown of power imported from the Northwest and Southwest is an estimate based on specific claims by energy service providers (retailers) and the general resource mix of those regions since there are no publicly available data-tracking mechanisms for the generation sources of imported power. The California Air Resources Board (ARB) is charged with addressing this issue in its implementation of AB 32, (Núñez, Chapter 488, Statutes of 2006) including regulations for first jurisdictional deliverers to report on specified imports.[29]

The resource mix for imports is based on the Energy Commission's *2008 Net System Power Report*.[30] The report represents the amount of electricity used by California customers for which no retailers claimed a specific source of generation. In recent years, as California retailers have increasingly identified larger shares of their generation as coming from specific sources, the net system power has changed in two very important ways: it now represents a smaller share of total generation serving California (due to growing retailer claims on specific sources of generation), and it is characterized by a higher percentage

29 First deliverer, or first seller, is the entity with ownership/title that first delivers power at a California point of delivery. For in-state production, the first seller is the generator; for imports, the first seller is the importer.

30 California Energy Commission, *2008 Net System Power Report*, July 2009, CEC-200-2009-010-CMF, available at: [http://www.energy.ca.gov/2009publications/CEC-200-2009-010/CEC-200-2009-010-CMF.PDF].

FIGURE 2: CALIFORNIA'S GENERATION MIX 2008



Source: California Energy Commission

of unclaimed coal and natural gas generation sources. Therefore, the total system power shown in Table 1 is used as an indicator of the sources of generation serving California end users until the ARB begins collecting data from all first deliverers of power into California under AB 32.

The Energy Commission is responsible for licensing in-state thermal power plants 50 megawatts (MW) and larger. Since deregulation in 1998, the Energy Commission has licensed more than 60 power plants: 44 projects representing 15,220 MW are on-line, 6 projects totaling 1,578 MW are under construction, and 12 projects totaling 6,415 MW are on hold but "available" for construction. In addition, the Energy Commission has 30 proposed projects under review (both conventional and renewable) totaling more than 12,000 MW, which significantly exceeds historic workloads and is presenting challenges given existing staff resources.

Natural Gas-Fired Generation

Natural gas plants (both in-state and out-of-state plants) provide about 46 percent of California's electricity needs. More than 15,000 MW of natural gas power plant capacity has come on-line since 1998. There are also 18 proposed natural gas-fired plants that are currently under review in the Energy Commission's power plant licensing process.

Of California's electricity sources, natural gas-fired plants tend to be the most flexible, allowing for peaking, cycling, and some baseload duty. Natural gas-fired generation typically is used to compensate for varying hydroelectric availability and likely will be needed to help integrate higher amounts of renewable generation to meet the state's Renewables Portfolio Standard goals. Emissions from natural gas generation account for a large portion of in-state greenhouse gas (GHG) emissions from the electricity sector, so

TABLE 1: 2008 TOTAL SYSTEM GENERATION (GIGAWATT-HOURS)

FUEL TYPE	IN-STATE	NORTHWEST IMPORTS	SOUTHWEST IMPORTS	TOTAL ENERGY SYSTEM
Coal	3,977	8,581	43,271	55,829
Large Hydro	21,040	9,334	3,359	33,733
Natural Gas	122,216	2,939	15,060	140,215
Nuclear	32,482	747	11,039	44,268
Renewables	28,804	2,344	1,384	32,532
Biomass	5,720	654	3	6,377
Geothermal	12,907	0	755	13,662
Small Hydro	3,729	674	13	4,415
Solar	724	0	22	746
Wind	5,724	1,016	591	7,331
Total	**208,519**	**23,945**	**74,113**	**306,577**

Source: Energy Information Agency, Energy Commission Quarterly Fuels and Energy Report Database, and Senate Bill 1305 Reporting Requirements it is essential for the Energy Commission to consider GHG impacts of natural gas plants in its power plant licensing process. However, because of the essential physical services provided by natural gas plants, California cannot simply retire all of its natural gas plants to meet its GHG emissions goals.

Hydroelectric Resources

Large hydroelectric power (larger than 30 MW in capacity) is a major source of California's electricity. In 2008, large hydroelectric plants produced 33,733 gigawatt hours (GWhs) or 11 percent of total system power. California has nearly 400 hydro plants, most of which are located in the eastern mountain ranges, with total dependable capacity of about 14,000 MW. The state also imports hydro-generated electricity from the Pacific Northwest. While hydroelectric power offers the potential for low-cost baseload electricity, it is also subject to large annual fluctuations because of changes in rainfall and snowpack. For example, from 1995–1998, hydroelectric resources accounted for as much as 28 percent of California generation but only provided 13 percent of total state generation in 2001.[31]

With current climate change concerns, there will be an increasing need to evaluate the possible impacts on California's hydropower resources. A recent draft paper by the California Climate Change Center looked at potential climate change effects on two hydroelectric facilities in California: the Upper American River Project, operated by SMUD in Northern California, and the Big Creek system, operated by Southern California Edison in Southern California.[32] The paper concluded that these facilities could experience a reduction in both energy generation and associated revenues as a result of climate change. However, the results of the analysis also showed that the two hydroelectric facilities should still be able to supply peak power during the spring and early summer days in both Northern and Southern California, although meeting increased power demand in late summer could be difficult if the occurrence of heat waves increases.

Nuclear Generation

Generation from nuclear power plants represented 44,268 GWhs of California's total system power in 2008. California relies on three nuclear power plants for about 14 percent of the state's overall electricity supply:

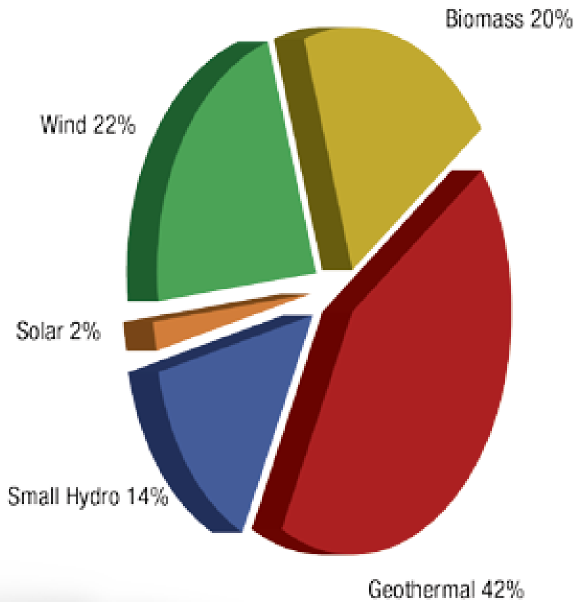
- Diablo Canyon Power Plant: Pacific Gas and Electric (PG&E) owns and operates Diablo Canyon, which has a total generating capacity of 2,220 MW in two units. The Diablo Canyon facility is located near San Luis Obispo, along the coast between San Francisco and Los Angeles.

- San Onofre Nuclear Generating Station (SONGS): Southern California Edison (SCE), San Diego Gas & Electric (SDG&E), and the City of Riverside are co-owners of the San Onofre Nuclear Generating Station, which is operated by SCE. The two operating units have a total capacity of 2,254 MW. The San Onofre Nuclear Generating Station is located near the boundary between SCE's and SDG&E's service territories near San Clemente, north of San Diego, in southern California.

31 MRW & Associates, *Framework for Evaluating Greenhouse Gas Implications of Natural Gas-Fired Power Plants in California*, consultant report, May 2009, CEC-700-2009-009, available at: [http://www.energy.ca.gov/2009publications/CEC-700-2009-009/CEC-700-2009-009.PDF].

32 California Climate Change Center, *Climate Change Impacts on the Operation of Two High-Elevation Hydropower Systems in California*, draft paper, March 2009, CEC-500-2009-019-D, available at: [http://www.energy.ca.gov/2009publications/CEC-500-2009-019/CEC-500-2009-019-D.PDF].

FIGURE 3: CALIFORNIA RENEWABLE ENERGY GENERATION BY TECHNOLOGY, 2008



Source: California Energy Commission

- Palo Verde Nuclear Generating Station: Palo Verde is co-owned by Arizona Public Service Corporation, SCE, and five other utilities. Arizona Public Service Corporation operates the plant. Palo Verde's three units have an overall capacity of 3,810 MW. Palo Verde is located near Phoenix in Wintersburg, Arizona. California utilities own 27 percent of the plant.

California's nuclear plants have been operating for roughly 20 years and are licensed to continue operating through 2022 (SONGS) and 2024 and 2025 (Diablo Canyon Units 1 and 2, respectively). They provide benefits to California in the form of resource diversity, low operating costs, relatively low GHG emissions, and enhanced grid reliability. However, they also pose risks associated with nuclear waste storage, transport, and disposal, as well as potentially severe effects from accidents, acts of nature like earthquakes or tsunamis, or terrorism.

California has a moratorium on building new nuclear power plants until a means for the permanent disposal or reprocessing of spent nuclear fuel has been demonstrated and approved in the United States. In 1978, the Energy Commission found that neither of these conditions had been met. In 2005, the Energy Commission reaffirmed these findings and also found that reprocessing remains substantially more expensive than waste storage and disposal and has substantially adverse implications for nuclear nonproliferation efforts.

Renewable Resources

California has a wide array of renewable resources, including biomass, geothermal, hydroelectric, solar, and wind. In 2008, renewable energy represented about 10.6 percent of California's total system power, supplying 32,532 GWhs. The breakdown of renewable energy by resource type is shown in Figure 3.

Much of California's renewable development arose from the federal Public Utility Regulatory Policies Act of 1978 (PURPA), which required utilities to purchase power from nonutility generators, including renewable generators, at the utilities' full avoided cost. PURPA was implemented in California through the use of "standard offer" contracts between utilities and nonutility generators. As a result of these contracts, about 5,000 MW of renewable capacity was added to California's electricity system between 1985 and 1990.

California currently has roughly 7,400 MW of utility-scale renewable generating capacity, ranging in size from a few hundred kilowatts to large projects in the hundreds of megawatts.[33] The Energy Commission and the Bureau of Land Management (BLM) are currently reviewing applications for power plant certification for about 6,000 MW of new solar capacity.[34] In addition, the amount of grid-connected distributed photovoltaic systems continues to grow, with about 440 MW installed as of 2008.[35]

Combined Heat and Power

A subset of California's natural gas-fired and renewable plants uses combined heat and power (CHP), also known as cogeneration. These plants provide approximately 9,000 MW to California's electricity supply portfolio. About half of existing CHP is in the industrial sector, primarily food processing and oil refining, and about one-third is in enhanced oil recovery. The remaining CHP is in the commercial, mining, and agricultural sectors. CHP facilities can use a variety of fuel types, from natural gas to renewable sources like biomass or biogas.

CHP plants provide significant benefits because they generate both mechanical energy (electricity) and thermal energy (heat). Since the thermal energy can be recovered and used for heating or cooling in industry or buildings, these systems are more efficient than those that generate electricity alone, and they therefore reduce GHG emissions associated with electricity generation. Given the GHG reduction benefits from these facilities, the ARB *Climate Change Scoping Plan* has set a target of 4,000 MW of additional installed CHP capacity by 2020 to displace 30,000 GWhs of demand from other, less efficient generation sources. Because of the significant additional amount of CHP envisioned for the system, these resources must be carefully considered when looking at system integration issues.

Resource Adequacy

An important aspect of electricity supply is having adequate reserves to ensure reliable electricity service. The California Public Utilities Commission (CPUC), in consultation with the California ISO, has developed resource adequacy standards for IOUs and electric service providers to ensure that the state has enough electricity generating capacity to meet demand and required reserves during peak demand periods.

Publicly owned load-serving entities in the California ISO control area must also meet basic requirements related to resource adequacy and reporting.[36] In 2008, publicly owned utilities represented 22.6 percent of California

33 California Energy Commission, California Power Plant Database, see [http://energyalmanac.ca.gov/electricity/index.html].

34 California Energy Commission, Siting, Transmission, and Environmental Protection Division, see [http://www.energy.ca.gov/siting/solar/index.html].

35 California Energy Commission, Energy Almanac, available at: [http://energyalmanac.ca.gov/renewables/solar/pv.html].

36 There are 18 publicly owned load-serving entities outside the California Independent System Operator control area that are not subject to formal requirements.

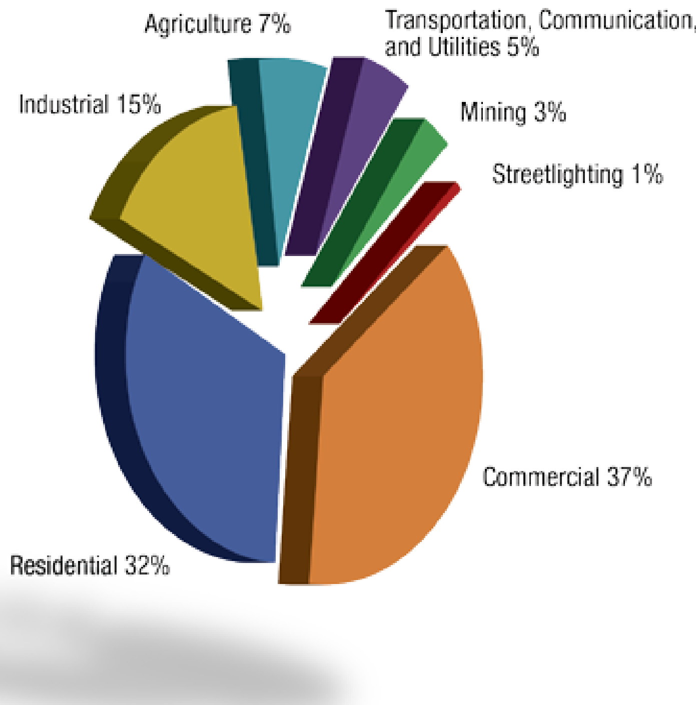
peak loads and 23.7 percent of energy needs. The largest 15 publicly owned utilities account for 94 percent of publicly owned utility peak load and 95 percent of energy requirements.

AB 380 (Núñez, Chapter 367, Statutes of 2005) requires the Energy Commission to report to the Legislature as part of the *IEPR* on the progress of the state's 54 publicly owned load-serving entities in planning for and procuring adequate resources to meet the needs of their end-use customers.

Fifty publicly owned utilities provided resource adequacy or resource plan filings to the Energy Commission in 2009. Based on those filings, the Energy Commission has found the publicly owned utilities to be resource adequate for both the year ahead and the long term. This finding is important for assuring that the publicly owned utilities will be able to provide reliable service to their customers during normal and peak conditions.

The publicly owned utilities also reported an increase in renewable contracts and a decline in the use of coal resources as contracts with coal-fired power plants expire over time. This shift in resource types will contribute to statewide goals for reduced GHG emissions.

FIGURE 4: ELECTRICITY CONSUMPTION BY SECTOR 2008 (GIGAWATT-HOURS)



Source: California Energy Commission

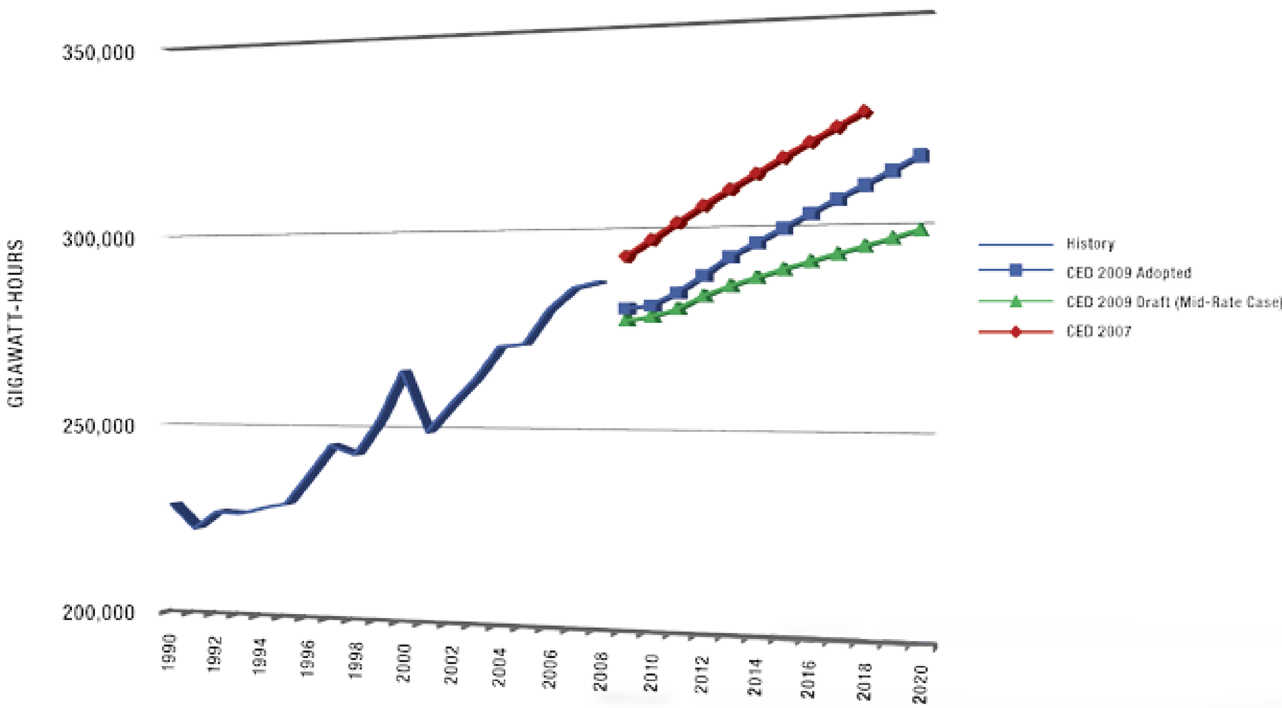
Electricity Demand

Californians consumed 286,771 GWhs of electricity in 2008, primarily in the commercial, residential, and industrial sectors (Figure 4).[37]

Demand for electricity varies over time with daily, weekly, and seasonal cycles and can fluctuate constantly even within a given hour. Demand is generally lower at night and on weekends and holidays, with the maximum demand generally occurring during the afternoon on a hot summer weekday. This

37 The difference between electricity consumption and total system power shown in Table 1 is due to line losses.

FIGURE 5: STATEWIDE ELECTRICITY CONSUMPTION



Source: California Energy Commission, *California Energy Demand 2010–2020 Adopted Forecast*, December 2009, CEC-200-2009-012-CMF.

maximum point is known as the "peak" and is an important factor in electricity and transmission planning since generation and transmission must be built out to capacity that can meet peak demand when needed.

Electricity Demand Forecast

In each two-year IEPR cycle, the Energy Commission forecasts electricity consumption over a 10-year period as well as expected peak demand during the same period. Once adopted by the Energy Commission, the forecast is used in various venues, including the CPUC procurement process, transmission planning studies, and the California ISO's grid studies.

Forecasts of expected growth in electricity demand over time are an important tool for determining future electricity generation and transmission needs. Timely and accurate planning can ensure that California's citizens will have secure and reliable energy resources during normal and peak conditions. In addition, forecasts help the state plan for times of emergency (for example, a natural disaster), which is important for maintaining the health and safety of the general public.

Figure 5 compares three forecasts of statewide electricity demand: the *2007 IEPR* forecast (California Energy Demand [CED] 2007), the draft demand forecast prepared by staff in the spring of 2009 (CED 2009 Draft Mid-Rate Case), and the Energy Commission's adopted demand forecast (CED 2009 Adopted) that reflects the IEPR Committee's direction in response to issues and concerns raised in the IEPR workshop on the draft demand forecast. The CED 2009 forecast report was adopted by the Energy Commission on December 2, 2009.

Electricity consumption is projected to grow at a rate of 1.2 percent per year from 2010–2018, with peak demand growing at an average annual rate of 1.3 percent over the same period. Although the CED 2009 adopted forecast projects electricity consumption to be higher than the earlier CED 2009 Draft (Mid-Rate Case), it is still markedly below the CED 2007 forecast. By 2018, electricity consumption is forecast to be down by more than 5 percent and peak demand by around 3.5 percent compared to CED 2007. Two factors explain most of the difference: lower expected economic growth, not only in the near term but also in the longer term, and increased energy efficiency impacts compared to what was included in the CED 2007 forecast. These changes reflect the increased emphasis on energy efficiency and increased level of efficiency expenditures now considered committed and therefore included in the forecast, as well as improved use of recent historic data that was not available for the CED 2007 forecast.

In the 2009 IEPR cycle, staff focused on two primary topics related to the demand forecast. The first was the uncertainty of the economic and demographic projections used in the forecast given the current economic recession, which appears to be affecting California more than the rest of the nation. Second was quantifying the effect of energy efficiency programs in the demand forecast itself, particularly the expected impacts of uncommitted energy efficiency programs – those programs that have not yet been approved or funded. In addition, parties continue to express concern about the uncertainty regarding the amount of committed energy efficiency included in the forecast. The Energy Commission is attempting to resolve this uncertainty by distinguishing between committed and uncommitted energy efficiency programs. Committed program impacts are included within the demand forecast, while uncommitted program impacts are counted as a potential supply resource.

New legislation (Senate Bill 695, Kehoe, Chapter 337, Statutes of 2009) allows the expansion of direct access service to individual retail nonresidential end-use customers, with a maximum level of annual kilowatt-hours supplied by electric service providers and the phase-in period to be determined by the CPUC. Since many more of California's customers will have this option available, the Energy Commission will incorporate direct access in future *IEPR* forecasts. In addition, since passage of SB 695 will likely affect the CPUC's 2010 Long-Term Procurement Plan (LTTP) process, Energy Commission staff plans to prepare a supplemental analysis that disaggregates the *2009 IEPR* planning area demand forecasts into bundled and direct access segments in early 2010.

The Effect of Economic Uncertainties on the Demand Forecast

For the CED 2009 forecast, the IEPR Committee directed staff to investigate alternative scenarios of economic and demographic growth into the future and to quantify the impacts that a reasonable range of assumptions could have on electricity demand. Despite uncertainty about economic impacts from the current recession and when and how California will recover, the alternative scenarios result in a surprisingly narrow band of electricity and peak demand.

Staff examined the impacts of two alternative economic scenarios for California electricity demand: an *optimistic* case provided by IHS Global Insight and an Economy.com *pessimistic* case. Figure 6 shows the projected impacts of the optimistic and pessimistic scenarios on statewide consumption, and Figure 7 shows impacts on peak demand.

FIGURE 6: PROJECTED STATEWIDE ELECTRICITY CONSUMPTION, CALIFORNIA ENERGY DEMAND 2009 ADOPTED AND ALTERNATIVE ECONOMIC SCENARIOS

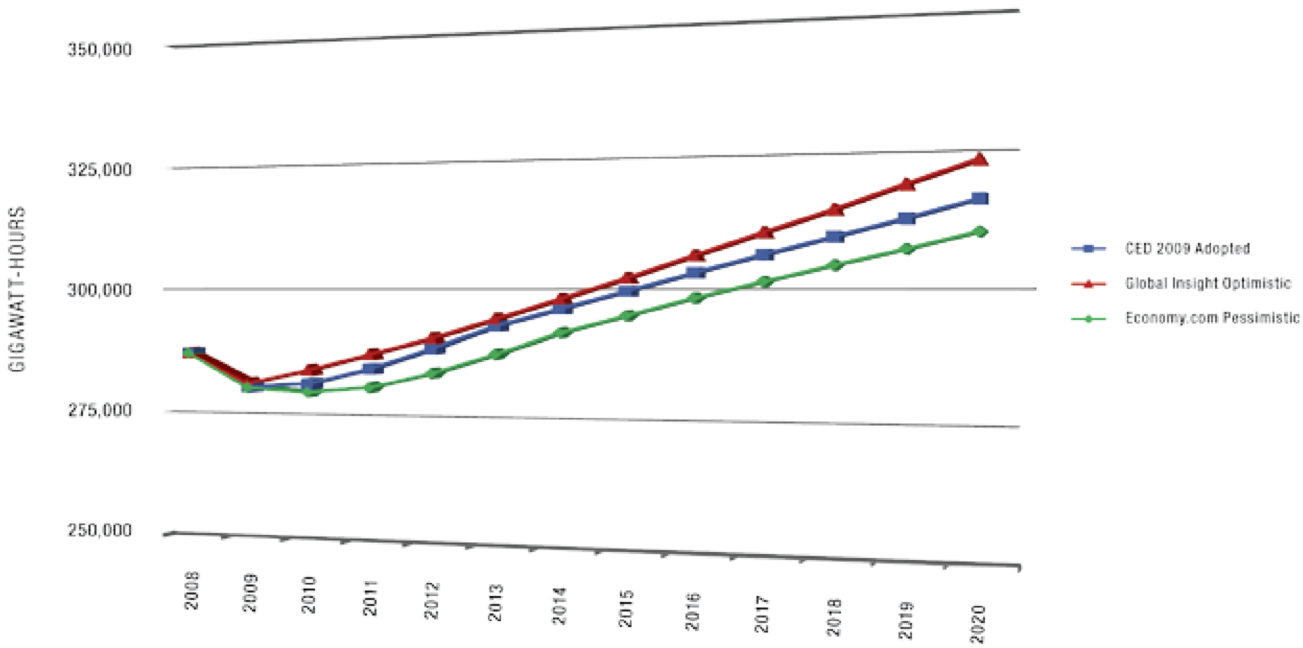
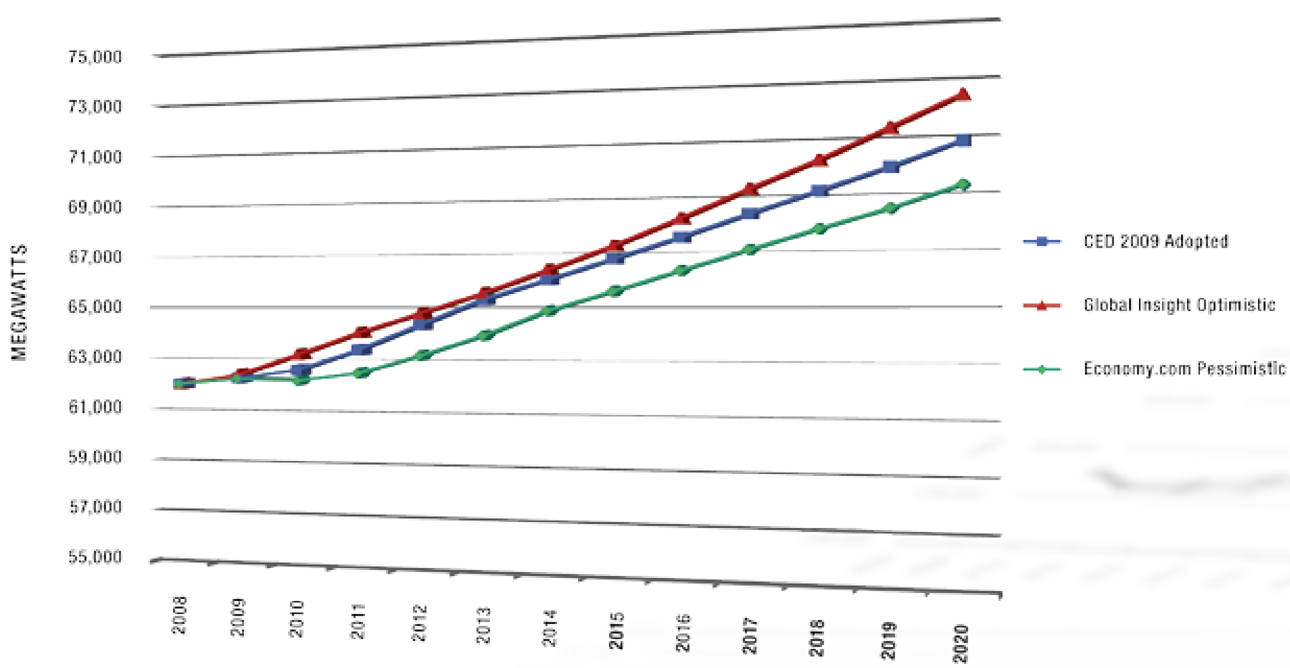


FIGURE 7: PROJECTED STATEWIDE PEAK DEMAND, CALIFORNIA ENERGY DEMAND 2009 ADOPTED AND ALTERNATIVE ECONOMIC SCENARIOS



Source for figures: California Energy Commission, *California Energy Demand 2010–2020 Adopted Forecast*, December 2009, CEC-200-2009-012-CMF.

Electricity consumption is projected to be 2.3 percent higher in the optimistic economic case than in the CED 2009 forecast by 2020, and 1.9 percent lower in the pessimistic scenario. The peak demand forecast increases by 2.3 percent under the optimistic scenario by 2020 and falls by 2.2 percent in the pessimistic case. The percentage of peak reduction is higher than that of consumption in the pessimistic case because the relative decrease in consumption is projected to be higher for the residential and commercial sectors than for the industrial, which has a higher load factor. Annual growth rates from 2010–2020 for electricity consumption and peak demand increase from 1.2 percent and 1.3 percent, respectively, to 1.3 percent and 1.4 percent in the optimistic case and fall to 1.1 percent each under the pessimistic scenario.

Energy Efficiency

The first element in the state's loading order for meeting electricity needs is energy efficiency. Energy efficiency and demand response strategies are essential to reducing the GHG emissions associated with electricity generation. The ARB's *Climate Change Scoping Plan* calls for energy efficiency measures that would reduce electricity demand by 32,000 GWhs relative to "business as usual" projections for 2020. The ARB expects energy efficiency to reduce CO_2 emissions by 19.5 million metric tons by 2020.

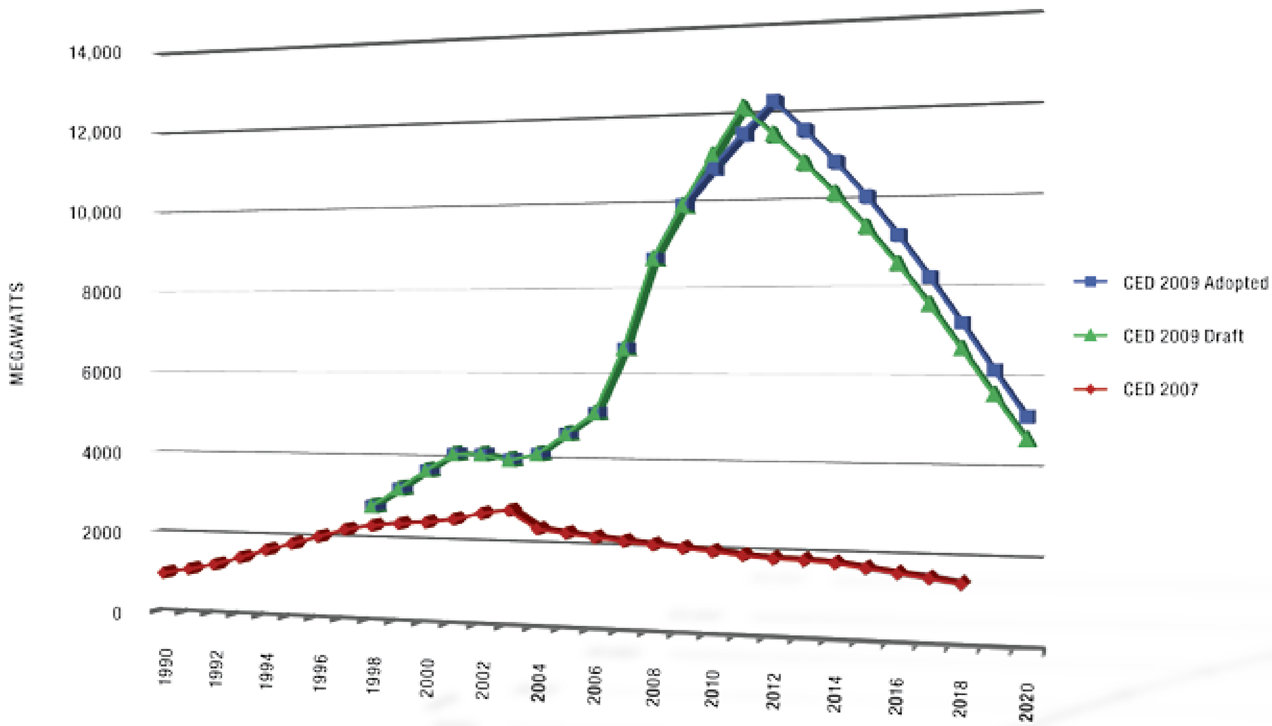
Every day, California citizens and businesses make millions of energy-related decisions as they go about their daily activities without realizing how those decisions affect energy use and energy demand. While some consumers may perceive energy conservation or efficiency as cutting back on activities or doing without creature comforts, conservation and efficiency are actually about using energy resources in a smarter and more effective way so those resources will go farther and have fewer negative consequences on the environment. Well-designed energy efficiency and conservation programs can reduce energy dependence, make businesses more competitive, and allow consumers to save money and live more comfortably. Energy efficiency programs can also play a major role in increasing reliability of the electricity system and reducing the cost of meeting peak demand during periods of high temperatures and high prices.

Energy efficiency measures, including building and appliance efficiency standards and utility-sponsored incentive programs, reduce overall electricity demand and therefore the overall need for new power plants. Reduced electricity demand can also help system operators in several ways. First, it increases system reliability because less demand means less strain on the electricity system since less energy has to be generated and delivered. Second, because California's renewable energy goals are based on a percentage of retail sales of electricity, reducing overall electricity demand means fewer retail sales and, therefore, less renewable energy that must be generated. This means fewer renewable plants will need to be built, which will reduce the operational and reliability issues associated with those avoided plants.

Energy Efficiency and the Demand Forecast

The importance of energy efficiency in reducing GHG emissions is influencing both near-term program funding and the future treatment in the demand forecast of efficiency resulting from programs. This influence is reflected in near-term energy efficiency program proposals made by IOUs to the CPUC in the current proceeding to determine funding and program designs for 2010–2012. As a result of historic high levels of funding for the 2010–2012 program designs in CPUC Decision (D.) 09-09-047, the amount of energy efficiency considered committed and there-

FIGURE 8: COMPARISON OF COMMITTED UTILITY PROGRAM CONSUMPTION IMPACTS FOR INVESTOR-OWNED UTILITIES



Source: California Energy Commission, *California Energy Demand 2010–2020 Adopted Forecast*, December 2009, CEC-200-2009-012-CMF.

fore included in the Energy Commission's baseline demand forecast is substantially higher than in the *2007 IEPR*, resulting in lower expected energy demand.

While progress has been made to delineate energy efficiency program impacts as presented in the Energy Commission's adopted demand forecast, numerous uncertainties remain. The energy efficiency attributions noted below are preliminary, based on the best available information and analysis to date, and will require further analysis to more clearly and completely understand the interactions among codes and standards, naturally occurring savings, and utility programs.

Figure 8 shows the change in IOU energy efficiency program impacts between the *2007 IEPR* and the staff's draft and Energy Commission-adopted forecast assumptions in this *2009 IEPR* for the three IOUs. The adopted forecast incorporates the recent shift in the CPUC efficiency program cycle from 2009–2011 to 2010–2012. A similar pattern of increased utility program impacts is included in the adopted demand forecast for the larger publicly owned utilities (SMUD and LADWP).

The steep drop off shown in 2013 and beyond reflects the short lifetime of some energy efficiency program measures, uncertainties about whether impacts from utility programs continue beyond the life of the measures installed, and reconciling these programmatic questions with the traditional price elasticity response when electricity rates are assumed to increase steadily into the future. There is also great uncertainty about the nature of the consumer response to subsidized efficiency programs and whether savings from various measures translate into actual changes in consumer demand for electricity. For example, the financial benefits of increased efficiency may induce some consumers to "take back" some of the efficiency gains by increasing their energy use. It is also unclear whether consumers will voluntarily pay for a replacement measure when the subsidized measure wears out, although staff's analysis assumes that they will not in most cases.

For some measures, by the time an efficiency measure that was installed through a utility program subsidy wears out, the market likely will be transformed as a result of new efficiency options, such as the virtual disappearance of single-pane windows from home improvement stores. For other measures, replacement is governed by mandatory efficiency standards. An example is staff's assumption that AB 1109 (Huffman, Chapter 534, Statutes of 2007) combined with federal lighting standards will result in the replacement of lighting measures with efficient devices and accompanying standards that essentially eliminate inefficient bulb technologies.

The Energy Commission staff demand forecasting models have been developed in a way that is especially appropriate for including efficiency standards, whether for appliances or for whole buildings. Including floor space or the vintage of housing and equipment for a given addition of floor space or housing in the models allows the requirements of standards to affect the limited proportion of the population subject to the standards in any year. Following the effective implementation date, standards gradually affect an increasingly larger proportion of the total floor space or housing stock. Each cycle of increasingly tightened standards can be readily evaluated to determine the additional energy savings contributed from each vintage of standards, assuming that new housing stock or new appliance purchases would have been subject to the previous standards.

However, the emphasis of many utility programs – encouraging retrofitting of existing floor space or equipment with more efficient devices – does not focus exclusively on newly built floor space or housing units, but upon the entire stock of floor space or housing units, which is not as readily addressed by this modeling approach. Moreover, consumers voluntarily participate in utility programs, presumably based on some combination of perceived financial benefits and altruism (wanting to "improve the environment"). In recognition of the uneven ability of its models to treat utility programs, Energy Commission staff are adapting the forecasting models to better incorporate such retrofit actions, but only limited progress was made in the timeline of the 2009 IEPR proceeding.

As an interim step, staff worked with the CPUC Energy Division and utilities to obtain more complete evaluation, measurement, and verification data for IOU program savings. Since the CPUC Energy Division itself has made more progress in estimating firm savings from programs than in the past, these new data sometimes portray IOU programs in a different light than do previously available self-reported, first-year savings data that have not been adjusted based on in-depth measurement studies. However, these detailed evaluation, measurement, and verification data *ex post* results are only available for recent years, which required staff to make assumptions about the performance of programs and measures funded in earlier years. Further effort to develop a consensus about historic measure performance is needed. With commitment to this effort and improvements in access to measure-level data for multiple program years, further progress can be made following the 2009 IEPR cycle.

As described in the *2008 IEPR Update*, the Energy Commission has chosen to continue to distinguish between the impacts of energy efficiency programs considered committed and those which, although part of long-term goals, are classified as uncommitted because program designs are not complete and funding has not been authorized.[38] Thus, the baseline or reference demand forecast only includes committed impacts. These committed impacts can be from existing standards as they affect a growing proportion of the stock of buildings and/or appliances, or from utility programs for the period of time during which specific program designs have been approved or program funding has been authorized.

Beyond these impacts there are efficiency goals that have been set by the CPUC, the Energy Commission, and the ARB for which no specific program designs have been approved or actual program funding levels authorized. The CPUC, in D.08-07-047, established long-term energy savings goals encompassing the three electricity IOUs, currently adopted state and federal appliance standards, and state building codes resulting in zero net energy residential and commercial construction in 2020 and 2030.[39] The Energy Commission in the *2007 IEPR* established the goal of achieving 100 percent of cost-effective energy efficiency savings. Following input from the Energy Commission and CPUC, the ARB also established 2020 energy efficiency goals in its *Climate Change Scoping Plan.*

Part of the foundation for determining incremental uncommitted energy efficiency impacts – those impacts that are in addition to impacts already included in the baseline forecast – is improving the base demand forecasting models and analyses of committed energy efficiency programs. The Energy Commission staff demand forecast model is being modified to more explicitly incorporate the impacts of energy efficiency measures. Tracking the penetration of energy efficiency measures will provide more accuracy about what efficiency is included within the baseline forecast, thus improving the ability to determine the incremental impacts of higher levels of penetration of these measures.

The effort to directly capture savings from utility efficiency programs in the Energy Commission's demand forecasting models for all IOU programs is too extensive for the resources and timeline available for the *2009 IEPR*, so the focus in this cycle has been on the most important of the program-induced measures: residential and commercial lighting and heating, ventilation, and air conditioning. Energy Commission staff and the consulting firm Itron are collaborating to refine an existing energy efficiency projection capability to build off the level of energy efficiency measures in the baseline forecast to determine truly incremental impacts from further penetration of those or other high value measures. The Itron model SESAT, which was used for the CPUC's 2008 Goals Study,[40] is the starting point for this effort.

Itron adapted the existing SESAT model as part of its contractual support to the CPUC for the 2008 Goals Study. A model like SESAT can be configured to directly incorporate the nonprogrammatic assumptions of the baseline demand forecast or use alternative assumptions. Some assumptions, such as household growth in the residential sector, are easy to match, while others such as saturations for

38 The "taxonomy" paper developed initially by Itron and now being refined through the Demand Forecast Energy Efficiency Quantification Project Working Group process contains provisional definitions of these terms.

39 California Public Utilities Commission, Decision 08-07-047, available at: [http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/85995.htm].

40 Ibid.

residential sector end uses are not.[41] For example, the 2008 Goals Study implementation of SESAT did not allow saturations of end uses to change through time. In contrast, the Energy Commission's demand forecast allows for such changes.

In developing incremental energy efficiency impacts relative to the Energy Commission's baseline demand forecast, all nonprogrammatic assumptions should be the same. However, to achieve this level of consistency requires substantial work to revamp the SESAT dataset used in the 2008 Goals Study, and this would likely mean that the sum of the committed energy efficiency in the baseline demand forecast and the incremental uncommitted energy efficiency quantified using SESAT would no longer exactly match the aggregate impacts adopted by the CPUC in the 2008 Goal Study decision. The degree of benchmarking the incremental analyses necessary to assure consistency has diminishing returns at some point.

Early in the 2009 IEPR development process, the CPUC's Energy Division requested that the Energy Commission develop a demand forecast as well as projections of incremental uncommitted energy efficiency for use in the forthcoming 2010 LTPP proceeding. The Energy Division requested that the Energy Commission evaluate previously established scenarios from the 2008 Goal Study as adopted in CPUC D. 08-07-047, including high, medium, and low cases. The IEPR Committee decided not to investigate other possible specifications of uncommitted energy efficiency, such as the levels included within the ARB *Climate Change Scoping Plan*, and to defer that analysis to other proceedings.[42]

Developing this incremental energy efficiency projection method and applying it to existing energy efficiency policies creates fresh estimates of the incremental impact of these policies relative to the baseline demand forecast. This effort is principally intended to reduce the uncertainty about overlap between the Energy Commission's demand forecast and other independently developed estimates of uncommitted energy efficiency. The *2009 IEPR* and the CPUC's 2010 LTPP rulemaking are the arenas where the merits of these various estimates will play out.

The client for this initial product was the CPUC 2010 LTPP proceeding, with a focus on establishing the procurement authority for IOUs after accounting for preferred resource additions. It was not intended to establish a new policy for high levels of energy efficiency. The IEPR Committee, therefore, allowed staff to implement the project on a schedule that satisfies the timing of the CPUC rather than *2009 IEPR* itself. Thus, at this writing the project is underway and scheduled to be completed in late January 2010. Once the draft results are completed, the IEPR Committee will conduct a workshop to receive public comments on the work. After comments are incorporated, the Committee will review and sanction the results for delivery to the CPUC.

41 Saturation refers to the amount of diffusion or distribution of a product or measure within a market.

42 An obvious home for such an effort is the triennial Assembly Bill 2021 energy efficiency goal-setting report required for submission to the Legislature in 2010. Since this report requires that goals be established for both investor-owned and public utilities, and the California Public Utilities Commission itself intends to undertake another goal study in 2010, it is appropriate to defer examination of these more aggressive goals to allow staff's projection capabilities to be improved further.

The incremental efficiency efforts for the *2009 IEPR* focused on evaluating electricity efficiency and conservation. Staff did not update natural gas efficiency impacts from those estimated in the *2007 IEPR* forecast. Future forecasts, however, will expand the efficiency analysis to fully account for embedded natural gas efficiency.

Energy Efficiency and the Environment

California is a national leader in promoting energy efficiency. Due in part to a decades-long focus on energy efficiency, California has the lowest per capita electricity use in the United States, with energy use per person having remained stable for more than 30 years while the national average has steadily increased. However, stabilizing per capita electricity use will not be enough to meet the carbon reduction goals set in the ARB's *Climate Change Scoping Plan*. Very aggressive efforts will be needed in coming years to meet and exceed prior energy efficiency and demand response program goals.

With the focus on reducing GHG emissions in the electricity sector, energy efficiency takes center stage as a zero-emissions strategy. One of the primary strategies to reduce GHG emissions through energy efficiency is the concept of zero net energy buildings. In the *2007 IEPR*, the Energy Commission recommended increasing the efficiency standards for buildings so that, when combined with on-site generation, newly constructed buildings could be zero net energy by 2020 for residences and by 2030 for commercial buildings. As mentioned in Chapter 1, the CPUC's Big Bold Energy Efficiency Strategies that were adopted as part of its *Long-Term Energy Efficiency Strategic Plan* include these goals as well. A zero net energy building merges highly energy-efficient building construction and state-of-the-art appliances and lighting systems to reduce a building's load and peak requirements and includes on-site renewable energy such as solar PV to meet remaining energy needs. The result is a grid-connected building that draws energy from and feeds surplus energy to the grid. The goal is for the building to use zero net energy over the year. The ARB recommends that energy efficiency measures in these buildings provide as much as 70 percent savings relative to existing buildings, with on-site renewable generation to meet the remaining load.[43] The CPUC's *2007 Long-Term Energy Efficiency Strategic Plan* contains a detailed implementation plan for zero net energy buildings with goals, strategies, timelines, and recommendations.

In addition to the concept of zero net energy, the CPUC's plan presents the importance of zero net peak energy use, meaning that the building does not require extra energy during peak energy use times, and zero net carbon, meaning that the building generates more zero-carbon energy on site than it uses from the grid in an average year. The ARB's *Climate Change Scoping Plan* also promotes zero-carbon footprint new homes, zero net energy homes, and green building standards.

Making zero net energy buildings a reality by 2020 for residences and 2030 for commercial buildings will require ongoing collaboration among the Energy Commission, the CPUC, and the ARB, as well as coordination with local governments that have the authority over land use development and planning. It will also require coordination among local, state, and industry players to promote and incentivize the installation of all cost-effective

43 California Air Resources Board, *Climate Change Scoping Plan*, December 2008, p.42, available at: [http://www.arb.ca.gov/cc/scopingplan/document/adopted_scoping_plan.pdf].

California Business on the Cutting Edge of Energy Efficiency Research

Adura Technologies is a San Francisco-based wireless lighting controls company founded in 2005 to commercialize research conducted at the University of California, Berkeley's Center for the Built Environment. The original idea for wireless lighting controls was developed at UC Berkeley with the help of a PIER research grant. The resulting study indicated potential energy savings from 65 to 70 percent for lighting, and Adura Technologies was formed to commercialize the technology. Since then, Adura has partnered with PIER's Lighting California's Future research program to integrate motion and daylight sensing technology into its system.

Adura's wireless lighting controls have enormous energy efficiency implications for the commercial building sector. Besides avoiding the costs of re-wiring existing buildings, these lighting systems can reduce energy demand and associated $CO2$ emissions. There may be additional potential benefits as wireless building control systems expand to other market segments and operating functions like heating, daylight shading, and demand response programs.

Adura is considered one of the most exciting clean tech/energy efficiency companies in Silicon Valley. Following its inception, Adura has built on its role as a manufacturing partner and has raised more than $7.5 million in venture capital funds. Adura won a Flex Your Power Award (2005), the Clean Tech Open (2006), and a UC/CSU/CCC Sustainability Award (2008). Adura's wireless lighting control system was named one of Buildings Magazine's Top 100 products for 2009. Adura currently employs 30 Californians and is directly involved in educating electricians and electrical contractors on lighting control strategies and technologies through its involvement in the California Advanced Lighting Controls Training Program.

energy efficiency measures; expand the scope of and accelerate certification of highly efficient appliances; push for the incorporation of the cost of carbon in cost-effectiveness tests for new codes and standards and utility programs; encourage and expand green building programs; and promote and incentivize on-site renewable energy generation.

The Energy Commission has adopted several key strategies for achieving the goal of zero net energy homes by 2020 and commercial buildings by 2030. One such effort, aimed at reducing "plug load" energy in buildings, includes broadening the range of appliances covered by the Title 20 Appliance Efficiency Standards to include consumer electronics and other appliances as they emerge on the consumer market. Other efforts include building standards for water efficiency; education about existing standards and increased enforcement; the adoption of voluntary "reach" building codes and standards that save energy above and beyond already mandated savings; and implementation of those reach standards through green building standards. Another effort is the Home Energy Rating System (HERS) Phase II program, effective September 1, 2009, which adopted a home energy rating scale that starts at zero consistent with the long-term goal of achieving zero net energy new homes by 2020.

Meeting the goal of zero net energy buildings will require increases in the Title 24 Building Efficiency Standards during each upgrade cycle. Because home electronics and other equipment and devices plugged into electrical outlets represent higher loads than those currently assumed in the standards, plug loads must be tested, modeled, and updated in building energy budgets and accounted for in Title 24 compliance software calculations. The scope of building efficiency standards will also need to be expanded to include process loads such as data centers, laboratories, and refrigeration systems. Continued research and development is also needed on building science technologies like energy use modeling, energy use data collection, and in-home energy use monitors.

The Buildings End-Use Energy Efficiency program area within the Energy Commission's Public Interest Energy Research (PIER) program focuses on lowering building energy use in both new and existing buildings in residential and commercial applications. By developing lower first-cost options for energy efficient products and helping to lower operating costs for energy-consuming systems, the PIER program helps increase the adoption of energy efficiency measures in California. Other research and development efforts within PIER that can help the state reach its goal of zero net energy buildings include those in agriculture, food processing, demand response, water-related energy consumption, demand shifting, metering and sub-metering, tariff analysis, urban planning, sustainable communities, codes and standards, water heating, data processing, building energy use benchmarking, motors, and process heating, among others. PIER's research and development also supports private sector research efforts and helps move technologies and tools into the market.

The goal of zero net energy buildings requires not just energy efficiency but also on-site renewable energy generation. For new residential construction, the Energy Commission's New Solar Homes Partnership provides incentives to install solar energy systems on new homes that meet specific energy efficiency requirements. For existing homes, new and existing commercial buildings, and industrial, government, and nonprofit buildings in the service territories of the IOUs, the CPUC's California Solar Initiative includes minimum energy efficiency requirements for newly constructed buildings; the CPUC is currently exploring whether energy efficiency requirements for existing residential and commercial buildings should be increased.

The *2008 IEPR Update* identified the need for active policies to deploy cost-effective and zero carbon renewable energy space heating and cooling technologies, which could contribute to the state's zero net energy goals. The potential value of renewable heating and cooling technologies could be very high, since California residential and commercial cooling accounts for approximately 30 percent of electric system peak load.[44] As recommended in the *2008 IEPR Update*, the Energy Commission's PIER program needs to develop a targeted program to address technical and infrastructure barriers to emerging renewable heating and cooling technologies.

Green building standards are another tool to help achieve the goal of zero net energy buildings, as well as to reduce GHG emissions that impact the environment. The California Building Standards Commission adopted Green Building Standards for newly constructed residential and commercial buildings in July 2008, which are the first statewide green building codes in the nation. The Green Building Standards contain both voluntary and mandatory green building measures, and sections of the standards are intended to become mandatory in the next code cycle. The code standardizes practices for reducing water use and electricity consumption and examines other aspects of typical construction practices. The Energy Commission advised the Building Standards Commission in the design of the voluntary levels, or tiers, of energy efficiency that are more stringent than the statewide Title 24 Building Energy Standards and will continue to expand its efforts to incorporate reach standards into the Green Building Standards.

44 See [http://enduse.lbl.gov/info/LBNL-47992.pdf].

Energy Efficiency and Reliability

By reducing demand, energy efficiency increases the reliability of the electricity system because it reduces stress on existing power plants and transmission and distribution infrastructure. Efficiency also reduces the demand for new power plants, which can help reduce the state's dependence on natural gas. Further, less demand for electricity will help soften potential reliability impacts on the electricity system from the retirement of the state's fleet of aging power plants and plants that use once-through cooling. Finally, less overall demand for electricity could mean less renewable energy will be needed to meet California's Renewables Portfolio Standard, which can indirectly buffer the impacts of integrating large amounts of renewables into the system.

California has pursued its energy demand reduction goals through two primary avenues: utility-sponsored programs to reduce end-user consumption, and codes and standards designed to lower the energy use of buildings and appliances. By 2004, these efforts had cumulatively saved more than 40,000 GWhs of electricity and 12,000 MW of peak electricity, equivalent to twenty-four 500-MW power plants. More than half of the statewide savings has come from the building and appliance standards, with the balance resulting from programs implemented by the state's IOUs and publicly owned utilities.

Appliance Efficiency Standards

The first appliance efficiency regulations were adopted in California in 1976. The Energy Commission sets minimum efficiency thresholds that apply to appliances using a significant amount of energy, are based on feasible and attainable efficiencies, and are cost effective to consumers based on a reasonable use pattern over the design life of the appliance.

The 2009 Appliance Efficiency Regulations became effective statewide on August 9, 2009. These regulations set new efficiency standards for general purpose lighting as required by AB 1109 (Huffman, Chapter 534, Statutes of 2007) as a first step in achieving a 50 percent increase in efficiency for residential general service lighting by 2018. AB 1109 also set aggressive savings requirements for lighting for commercial buildings and outdoor lighting over the same time period.

The Energy Commission continues to press the federal government for an exemption to exceed federal standards for residential clothes washers, which will result in substantial savings of both energy and water. The Energy Commission will also continue to pursue aggressive and expansive appliance standards for other appliances and equipment, including but not limited to consumer electronics, lighting, water-using equipment and irrigation controls, and refrigeration systems.

Efficiency Standards for New Buildings

The Energy Commission established the nation's first energy efficiency standards for residential and nonresidential buildings in 1978. The standards apply to newly constructed residential and nonresidential buildings, as well as additions and alterations to existing buildings, and are updated over time to reflect new energy efficiency technologies and methods. The Energy Commission adopted the 2008 Building Efficiency Standards in April 2008. The new standards will take effect on January 1, 2010, and will require, on average, 15 percent increased energy savings for newly constructed residential buildings compared with the 2005 Building Efficiency Standards. The updated standards make many energy efficiency improvements for newly constructed nonresidential buildings and additions and for alterations to both residential and nonresidential buildings. Two examples of updates are increased requirements for cool roof products to help reduce air conditioning use in areas of the state with high summer peak load and requirements for higher performing windows.

The standards also focus on the problem of construction defects in the installation of energy efficiency features that can lead to reduced energy savings from those features. To address these construction defects, standards since 1998 have required that features prone to poor installation be verified by a third-party HERS rater using Energy Commission-specified diagnostic testing and field verification protocols. In showing compliance with the energy budget, field-verified measures are given higher credit because they require on-site inspections and/or on-site testing. The emphasis on field-verified measures helps educate the building industry and homeowners about the importance of high quality workmanship and quality assurance to achieve higher performing buildings and lower energy bills. With each new update, the standards expand the emphasis on field verification and diagnostic testing.

The Energy Commission is also developing "reach standards" – a voluntary standard exceeding existing standards – for the Title 24 Building Efficiency Standards. As part of the public process of developing building standards every three years, the Energy Commission will develop two levels of incremental improvements in building performance: a lower level that represents mandatory standards and a higher level that is voluntary. In each subsequent standards cycle, the higher level from the previous cycle is considered for setting the new mandatory standards, and a new reach standard is developed.

Adopting voluntary reach standards has many benefits. It allows proactive cities, counties, green building standards, incentive programs, and others to adopt the voluntary standards in their jurisdictions, which many cities and counties have already done. The reach standards also are adopted as the eligibility criteria for solar incentive programs, such as the California Solar Initiative and New Solar Homes Partnership programs, and as

Building Regulations Ordinance Uses Sustainable Design and Construction

The city of Los Altos developed a Green Building Regulations Ordinance, effective July 2008, to conserve natural resources through sustainable design and construction practices. The ordinance requires all newly constructed residential and nonresidential buildings to be 15 percent more energy efficient than what is required by the 2005 Title 24 Building Standards. Much of the motivation and effort that went into developing and adopting the local standards was supplied by a staff member of the city's Building Division, who is a Certified Energy Plans Examiner, Certified HERS rater, and instructor at a local community college teaching the Building Energy Efficiency Standards and who also provides periodic training to city of Los Altos staff on enforcement requirements. The ordinance affects newly constructed residential, commercial, and multifamily buildings in the city of Los Altos.

levels for qualifying for higher public goods charge incentives through utility new construction programs.

Cities or counties can choose to adopt local energy standards that are more stringent than the statewide Title 24 Building Energy Efficiency Standards and can enforce the standards on a voluntary or mandatory basis. Voluntary standards motivate the building community by offering incentives such as fast track permitting or reduced permit fees. Most mandatory local standards are intended as key climate change mitigation initiatives and to reduce electricity demand, especially during peak periods on hot summer afternoons. Recently local energy standards have been adopted as part of local comprehensive "green" ordinances and include requirements related to land use, water use, recycling, indoor air quality, and GHG reduction goals as well as energy efficiency requirements.

Many local governments have also adopted stringent local standards to address local building patterns or issues and local air, water, land use, or resource constraints or to comply with state legislation or Executive Orders. The Energy Commission must approve mandatory local standards that exceed statewide standards. Cities or counties adopting such standards are recognized as early adopters and include large and small cities and counties located in high density urban areas as well as lower density suburban regions. The Energy Commission commends the following cities and counties that have adopted energy ordinances requiring more stringent energy requirements than those set by California's 2005 Building Energy Efficiency Standards: Culver City, La Quinta, Los Altos, Los Altos Hills, Marin County, Mill Valley, Palo Alto, Palm Desert, Rohnert Park, City and County of San Francisco, San Mateo County, Santa Barbara, Santa Monica, and Santa Rosa. The Energy Commission is pleased that many of these governments are preparing to update their ordinances to be more energy efficient than the new 2008 standards, which go into effect January 1, 2010.

Compliance with and enforcement of the building standards are major challenges. Newly constructed residential buildings have been estimated to be as much as 30 percent out of compliance with the 2005 Title 24 Building Efficiency Standards,[45] which could represent up to 180 GWhs per year[46] of lost energy savings and therefore lost opportunities for GHG emission reductions. The 536 local building departments in the state are responsible for enforcing standards by issuing permits and conducting on-site inspections during construction. With the economic downturn and reduced budgets, however, many cities have downsized their building department staff in order to maintain other vital staff such as police or fire crews. Other factors that affect compliance with and enforcement of building standards include the complexity of the building standards, the effects of changes in architectural style, and the need for performance standards to provide choice in energy-using features and equipment. The Energy Commission has actively sought sufficient staff resources to maintain a presence in the field to encourage improvements in compliance and enforcement and is working with the California Building Officials and California utilities to provide tools and information that will simplify standards enforcement and provide expanded training for the industry and building officials.

Building standards also apply to additions to and remodels of existing buildings, which provide a critical opportunity to improve energy efficiency levels. Permits are required for any alteration that permanently changes the

45 Quantec, LLC (merged with The Cadmus Group, Inc. in 2008), see [http://www.cadmusgroup.com].

46 BII & ConSol, July 2009, see [http://www.consolenergy.com/].

energy use of a building, including installation and change-out of heating, ventilation, and air conditioning (HVAC) equipment. Unfortunately, many installers fail to obtain the proper permits for HVAC change-outs. This not only places homeowners at risk by bypassing the health and safety protections associated with permits, but it also reduces revenues that fund enforcement activities of local governments. In addition, without permits, building departments are unaware of the HVAC change-outs and therefore do not review and inspect the systems to ensure compliance with building codes and standards. Failure to obtain permits also has negative effects on the entire HVAC industry because installers who avoid the cost associated with permits and complying with licensure laws and building codes may charge less than contractors who follow the law, which represents unfair competition.

The HVAC industry estimates that 30 to 50 percent of central air conditioning systems are not being installed properly. The CPUC's *Long-Term Energy Efficiency Strategic Plan* reported that fewer than 10 percent of installed HVAC systems obtain permits, while the HVAC industry recently quoted a figure of less than 5 percent. This represents a major problem that makes it impossible for building departments to verify compliance and represents a huge lost opportunity for energy efficiency savings.

To address challenges with compliance and enforcement, the Energy Commission develops and provides comprehensive and audience-specific education and outreach information on the standards to improve local enforcement and building industry compliance. In addition to its Energy Standards Hotline, the Energy Commission is launching a California Building Standards Online Learning Center to assist building department personnel in understanding and complying with the standards. The Energy Commission's Compliance and Enforcement Unit also investigates complaints and provides assistance to enforcement agencies, the public, and other energy professionals to increase compliance with the building standards. As part of this effort, staff works with various building departments throughout the state and also conducts regional outreach through International Code Council chapters to increase communication and cooperation between building departments. In addition, there is certification and ongoing management of HERS providers who train, manage, and certify HERS raters and are responsible for field verifications of performance-based energy efficiency measures in the building standards.

To increase compliance with the building standards, the Energy Commission also is working with the Contractors State License Board to take action in investigating and disciplining unlawful activity by licensed and unlicensed contractors in relation to the standards. In addition to the board, the Energy Commission is working with the HVAC industry and California building officials to focus on the problems with failure to obtain permits for change-outs. Further, to help property owners understand the benefits of proper permitting and code compliance, the Energy Commission has developed educational time-of-sale consumer information.

California has agreed to achieve a 90 percent compliance rate with state building energy codes within eight years, by 2017, in exchange for stimulus funds. To meet this aggressive goal, the Energy Commission needs to develop a method to determine the level of compliance, enforcement, and quality of installations throughout the industry and use this information as a benchmark against which to determine 90 percent compliance. Strategies can include auditing and scoring the 536 building departments in the state and providing them with education and tools to increase their compliance rate, with follow-up audits after some period of time to evaluate improvements.

Efficiency in Existing Residential and Commercial Buildings

Existing residential buildings present a significant challenge to meeting the state's energy efficiency goals. Over half of the single-family homes in California were built before building standards went into effect, and retrofitting these homes could provide significant savings. At the same time, utility rebate programs have not done enough to capture cost-effective energy savings in existing buildings. To address the existing building sector, the state must move beyond programs that target single-measure rebates, such as replacing incandescent bulbs with compact fluorescent bulbs, and instead design comprehensive programs that include building energy use performance labeling or benchmarking; comprehensive deep retrofit programs; marketing, outreach, and education efforts presented in layperson terms; and creative funding mechanisms that help building owners with the necessary capital to cover the cost of the retrofits with an affordable cash flow over the life of the measures to allow the energy savings to pay for the investment.

Point-of-sale and/or point-of-remodel legislation should be introduced to trigger retrofits at times of financial transactions or major construction projects. Innovative incentives, such as refunds for HERS Phase II inspections when a predetermined amount of expenditure will go into retrofits, or a cap on the maximum amount of expenditure required (2.5 percent of sale price or 10 percent of estimated remodel costs) will safeguard against slowing a sale or dissuading homeowners from selling their homes or making improvements. This strategy will also require HERS providers to develop training programs so that enough HERS raters will be available statewide.

In addition, legislation, utility incentives, or local ordinances should consider triggers such as point-of-sale or point-of-remodel to require HVAC equipment tune-up by qualified HVAC service technicians, similar to a Department of Motor Vehicle smog check requirement. Most homeowners do not know the benefits of HVAC maintenance and its positive impact on HVAC performance and do not adequately maintain their HVAC systems.

Innovative financing options need to be explored and developed that offer competitive rates to finance whole-house energy retrofits. Recently emerging municipal financing, energy utility on-bill financing, waste collection on-bill financing, and water utility on-bill financing pilots around the country should be monitored and explored as possible mechanisms to allow payback out of energy savings and keep the debt with the property.

Existing commercial buildings also offer significant potential for efficiency improvements. Building energy performance rating can set the stage for retro-commissioning and other energy efficiency improvements. Assembly Bill 1103 (Saldaña, Chapter 533, Statutes of 2007) requires disclosure of nonresidential building energy performance ratings at the time of lease, lending, or sale. The Energy Commission has opened an Order Instituting a Rulemaking to develop regulations for implementing AB 1103 that are expected to be adopted in early 2010. This historic building energy performance rating disclosure law provides an important opportunity to provide energy use data for commercial buildings at the time that purchase, lease, and financing decisions are being made, which will allow decision makers to value energy efficiency as a building property asset. Building energy performance ratings will ultimately add value to commercial buildings in the form of increased resale value and increased marketability.

One issue associated with implementing AB 1103 is that the national Energy Star Portfolio Manager rating system specified in the law will not provide a 1 to 100 rating for the majority of nonresidential buildings in California. Therefore, to fully implement this new energy performance disclosure law, the Energy Commission has developed a California Commercial Building Energy Performance Rating System. A California-specific rating can be disclosed to meet the intent of this law when a national rating is not available. The California-specific rating may also be disclosed voluntarily by building owners who are disclosing the national rating.

Another challenge is that the AB 1103 energy performance disclosure requirements apply only to entire buildings, not the individual spaces within those buildings. Many nonresidential buildings have tenant-leased spaces that are separately metered and have individual utility accounts. Future legislation should therefore address ways to obtain and disclose meaningful building performance ratings for tenant-leased spaces.

The European Union's 2003 Energy Performance of Buildings Directive (EPBD) should be looked to as a model for commercial building energy performance rating methods. The EPBD established two types of performance ratings: operational ratings and asset ratings. Operational ratings, like the Energy Star Portfolio Manager, can track the energy performance of buildings over time and compare energy use to comparable buildings. Asset ratings, in contrast, judge the efficiency of only the permanent building energy systems that should be valued as part of a commercial property assessment. This asset rating system is analogous to the HERS for residential buildings. California should participate in and leverage the work begun at the national level to develop an asset rating system for commercial buildings.

Efficiency in the Industrial Sector

The state's building efficiency standards do not apply to industrial plants or their manufacturing processes. Consequently, no regulatory mechanism is in place to ensure energy efficiency implementation in the industrial sector. However, with approximately 50,000 industrial plants and related businesses, California's industrial sector consumes 15 percent of the state's total electricity and 50 percent of its natural gas, making it essential to address energy usage in this sector.

The Energy Commission's objective is to increase operating efficiency in the industrial sector to allow plants to reduce their energy costs and lower their GHG emissions while remaining competitive. Since 2004, the Commission's Industrial Energy Efficiency Program has conducted industrial best practices training workshops in partnership with the United States Department of Energy (DOE), utilities, and industry. Initial survey results on the effectiveness of the training indicate that energy efficiency measures are being implemented by 60 percent of the plants.

The Energy Commission also conducts no-cost technical energy audits at industrial plants using DOE's Energy Savings Assessment protocol, software tools, engineering calculations, and specialized measurement equipment. These assessments have resulted in estimated savings of 22 million therms of natural gas, 41,000 kilowatt hours of electricity, and 147,000 tons of carbon dioxide per year.[47] In addition to the energy savings, the assessments represent energy cost savings to industrial plants of $19 million per year. The Energy Commission expects to conduct approximately 10 assessments per year through 2012, with the goal of cumulative energy savings by 2012 of 50,000 MWhs per year of electricity and 40 million therms per year of natural gas.

An example of the potential for savings in the industrial sector is a food processing plant in central California that uses steam for

47 Presentation of Donald Kazama, California Energy Commission, Association of Energy Engineers' West Coast Energy Management Congress, Long Beach, California, June 11, 2009.

dried fruit processing and compressed air for production machinery operations. The plant underwent an on-site technical audit of its steam and compressed air system. For a total project cost of $150,000, energy efficiency improvements at the plant are saving $46,000 per year in electricity costs, $23,000 per year in natural gas costs, and $2,000 per year in reduced water consumption. Total costs savings per year exceeded $70,000, for a total project simple payback in 2.1 years.

Efficiency from Publicly Owned Utility Programs

Because publicly owned utilities represent about 22 percent of statewide electricity consumption, their contribution to meeting the state's energy efficiency goals is very important. AB 2021 (Levine, Chapter 734, Statutes of 2006) requires the Energy Commission to estimate statewide energy efficiency potential and establish targets for energy efficiency savings and demand reduction for California's investor and publicly owned utilities every three years, with the goal of reducing energy consumption by 10 percent over the next 10 years. The Energy Commission adopted the initial targets in 2007. In addition, the Energy Commission evaluates and reports on the annual progress of 39 publicly owned utilities' energy efficiency program investments and savings to the Legislature as part of the *IEPR*.[48]

From 2007 to 2008, publicly owned utility expenditures in energy efficiency programs increased 65 percent and totaled $104 million. Annual efficiency savings increased by nearly 58 percent for energy and nearly 46 percent for peak hours compared to 2007. However, combined savings accomplishments of these utilities reached only 66 percent of the 2008 adopted target for energy savings. While the trend of increasing savings is encouraging, publicly owned utilities should continue to explore all opportunities for increased efficiency savings to meet the targets adopted by the Energy Commission and contribute to meeting the statewide goal of achieving 100 percent cost-effective energy efficiency.

In 2008, the publicly owned utilities reported on the results of their program measurement and verification activities for the first time. While the results are preliminary at this time, publicly owned utility-verified savings appear to be consistent with reported program savings for 2008.

Publicly owned utilities face several challenges in increasing their efficiency savings. The current economic recession is affecting customers' willingness to participate in efficiency programs. Another issue is that many of the smaller publicly owned utilities serve a relatively small customer base so their programs can reach saturation rather quickly. In addition, the smaller utilities typically have fewer staff and capital resources than the larger utilities, making it difficult to administer efficiency programs. Even the larger publicly owned utilities are facing challenges from a retiring workforce and bringing new staff up to speed quickly.

For the small utilities, success appears to be in large part due to careful consideration of their customers' needs when designing their efficiency programs. That knowledge, coupled with a commitment to personalized customer outreach and educational efforts, has helped some utilities succeed despite challenges. The state's publicly owned utilities are also working cooperatively through their representative associations, the Northern California Power Agency, the Southern California Public Power Authority, and the

48 For details on publicly owned utility progress, see California Energy Commission, *Achieving Cost-Effective Energy Efficiency for California: Second Annual AB 2021 Progress Report*, June 2009, CEC-200-2009-008-SD, available at: [http://www.energy.ca.gov/2009publications/CEC-200-2009-008/CEC-200-2009-008-SD.PDF].

Publicly Owned Utility Success Stories

Lodi Electric, with a customer base of less than 30,000, reported an increase in energy efficiency savings from 383,317 kilowatt hours in 2007 to 3,090,527 kilowatt hours in 2008. This quantum leap in savings was the result of a large commercial lighting program. Lodi Electric's efficiency program used Energy Star appliance rebates and energy audits as well as targeting specific customers with the "Keep-Your-Cool" refrigerator door gasket replacement program, which provided significant savings for the customer with minimal upfront costs. This program was originally developed by Silicon Valley Power and shared with members of the Northern California Public Power Authority. Another well-designed program is the HVAC system performance test, which ensures that the customer's whole HVAC system is functioning efficiently before a rebate for new equipment is issued to maximize energy savings.

Truckee-Donner Public Utilities District, with a customer base of 13,000, reported an increase in energy efficiency savings from 603,611 kilowatt-hours in 2007 to 4,455,607 kilowatt-hours in 2008, mainly due to an increase in residential lighting savings. To maintain and increase customer participation during these difficult economic times, Truckee-Donner is focusing on direct installation and giveaway programs. For example, their LED holiday lighting exchange program has proven to be very popular. Customers exchange old incandescent holiday lighting for high efficiency LED holiday lights that are more than 80 percent more efficient. Like Lodi, Truckee-Donner has also had success with a direct install "Keep-Your-Cool" refrigerator door gasket replacement program.

California Municipal Utilities Association, to learn from one another's experiences.

Publicly owned utilities need to continue to use their unique customer knowledge to focus attention on new customer segments, expand measures that are low- or no-cost options, and market new incentive tools. The publicly owned utilities are encouraged to apply integrated resource planning to compare demand-side resources with supply-side resources using cost-effectiveness metrics. This approach, along with the willingness to fund energy efficiency from procurement sources, will increase future energy savings sufficiently to reach adopted targets. Efforts to complete measurement and verification studies should continue. These studies provide an opportunity to improve program delivery and cost-effectiveness and to show that energy savings have been realized, and they should be funded accordingly.

Energy Efficiency and the Economy

In the *2007 IEPR*, the Energy Commission recommended that the state adopt targets for the next 10-year period equal to 100 percent of total cost-effective energy efficiency savings to be achieved by a combination of state and local standards, utility programs, and other strategies. The targets were to be met through a combination of collaborative efforts by utilities, legislative mandates, and regulatory standards. In addition, the CPUC's *California Long-Term Energy Efficiency Strategic Plan* recommends maximum implementation of cost-effective energy efficiency.

The Energy Commission's 2007 Scenario Analyses Project found that regardless of the level of energy efficiency, the cost is negative. "[S]ociety is better off with…higher levels [of energy efficiency] than without…even without a carbon cost adder being included. Energy efficiency is less costly than the generating resources it displaces."[49] The combined economic potential to save energy in 2016 for California's three large IOUs is estimated to be 40,700 GWhs of electricity, higher than the ARB's demand reduction goal of 32,000 GWhs, and 6,800 MW of peak electrical demand. This does not include potential savings from emerging technologies.[50]

When determining the cost-effectiveness of energy efficiency measures, the Energy Commission believes there is a need to accurately value carbon savings embedded in energy efficiency. The definition of cost-effective energy efficiency should include a value for carbon dioxide (CO_2) and GHG emission reductions, consistent with the Title 24 Building Efficiency Standards. Utilities should also include an externality value for CO_2 and GHG emission reductions in the evaluation of their energy efficiency program impacts.

In addition, the Energy Commission recommends creating a task force comprised of state, local, utility, and industry stakeholders to work collaboratively to clarify definitions, set out strategies, identify potential hurdles and potential solutions, and set schedules and milestones to reaching the goal of 100 percent cost effective energy efficiency by 2016. The task force should develop a statewide strategic plan to serve as a road map of actions needed to achieve all cost-effective energy efficiency potential in California.

With the downturn in the national economy, energy costs represent a larger share of consumers' budgets, including low-income

49 California Energy Commission, *2007 Integrated Energy Policy Report*, December 2007, CEC-100-2007-008-CMF, available at: [http://www.energy.ca.gov/2007publications/CEC-100-2007-008/CEC-100-2007-008-CMF.PDF].

50 Itron, *California Energy Efficiency Potential Study*, May 24, 2006, pp. ES-8 – ES10, [http://www.itron.com/pages/news_articles_individual.asp?nID=itr_008890.xml].

customers whose numbers are increasing as a result of the financial crisis. One of the goals of the CPUC's *Long-Term Energy Efficiency Strategic Plan* is for all low-income homes to be energy efficient by 2020.[51] The CPUC issued a decision in November 2008, approving the Low-Income Energy Efficiency (LIEE) 2009–2011 program budgets for the four major IOUs.[52] The goal is for all eligible customers in the low-income sector, estimated at 4 million households, to have the opportunity to participate in the LIEE program. As part of achieving this goal, the CPUC is requiring the IOUs during 2009, to develop an integrated marketing, education, and outreach program for all energy efficiency programs, including LIEE. IOUs are also required to target their outreach to LIEE customers who are high energy users, have high energy burden, and/or have high energy insecurity, while also addressing low-income customers with lower energy use. The Energy Commission applauds the CPUC's significant contribution to meeting the state's energy efficiency goals, particularly with regard to the significant impact the CPUC is making in the low-income sector, recently swollen by the downturn in the economy.

Funding for IOU efficiency programs continues to be a high priority for the state. On September 24, 2009, the CPUC approved the 2010–2012 utility energy efficiency portfolios for $3.1 billion dollars of ratepayer-supported energy efficiency programs for 2010–2012 to be administered by the IOUs. The three-year program is estimated to avoid the construction of three 500-megawatt power plants, save almost 7,000 gigawatt hours of electricity and 150 million metric therms of natural gas, and avoid 3 million tons of GHG emissions. The program launches the nation's largest home retrofit program, which targets 20 percent savings for as many as 130,000 homes during 2010–2012. It also provides $175 million to launch California's Big Bold Energy Efficiency Strategies for zero net energy homes and commercial buildings, including design assistance, incentives for above-code construction, and research and demonstration of new technologies and materials.

The portfolios also include phasing down subsidies for basic compact fluorescent lamps while shifting the emphasis to advanced lighting programs, as well as requiring benchmarking for commercial buildings in California that receive energy efficiency funding. In addition, more than $260 million in funding will be provided for 64 cities, counties, and regional agencies for local efforts targeting public sector building retrofits and leading-edge energy efficiency opportunities. Performance metrics will be required to measure the progress of each program toward market transformation and achievement of the short-, medium-, and long-term goals and strategies set forth in the CPUC's *Long-Term Energy Efficiency Strategic Plan*.

Achieving the state's goal of all cost-effective energy efficiency will be challenging and will require continued and accelerated collaborative efforts between state and local agencies along with meaningful input from utilities and industry stakeholders. In particular, state energy agencies must work closely with local and regional governments to provide assistance in meeting the challenges of adopting and implementing energy efficiency programs to reduce GHG emissions. Toward that end, the Energy Commission is updating its 1993 *Energy Aware Planning Guide* with as-

51 California Public Utilities Commission, *California Long-Term Energy Efficiency Strategic Plan*, September 2008, available at: [http://www.californiaenergyefficiency.com/docs/EEStrategicPlan.pdf].

52 Decision 08-03-011 was approved 5-0 by the California Public Utilities Commission on November 6, 2008. The decision approved budgets for the energy-related low income programs totaling approximately $3.6 billion for the four major investor-owned utilities: Pacific Gas and Electric Company, San Diego Gas & Electric, Southern California Gas, and Southern California Edison.

Center Develops Statewide Demand Response Technologies

The Demand Response Research Center was launched in 2004 by the Energy Commission with the objective of researching and developing a broad knowledge of demand response technologies, capabilities and opportunities. The center has been working toward developing many important technologies and technical capabilities necessary for a successful statewide demand response, including communication techniques and devices like two-way communicating utility devices in homes, commercial buildings and industrial plants. These communicating devices can be pre-programmed to react when the system sends signals that prices or demand are high and can then turn off noncritical appliances (like washing machines, dishwashers, or unnecessary lights) or processes (like the defrost cycle of the refrigerator or preselected commercial or industrial processes) until the "event" is over and the price of energy or stress on the utility system goes down. Research efforts at the center also include development of open demand response communication standards (OpenADR) between the utility and on-site communicating devices and meters; methods to analyze behaviors and perceptions related to energy use as well as the most effective kinds of pricing signals (automatic control with optional override versus a reminder phone call); structures for time-varying pricing; and methods to set appropriate demand response program baselines and goals. The center has also field tested different kinds of communicating devices and has researched the potential for demand response to transition between sectors, such as from commercial to industrial facilities. OpenADR has been identified as one of 16 potential national standards to support national smart grid development. Next steps include research studies of small commercial customer behavior and the potential impact of residential time-of-use rates.

sistance from the Local Government Commission and other parties, with a target release of early 2010. The guide will provide regional and local governments with a solid reference of energy-conserving/GHG-reducing planning ideas, policy language, program implementation options, environmental and economic effects, examples of programs in operation, and contact information.

The Energy Commission also provides monetary support to local governments through the Energy Conservation Assistance Account Program, a low-interest loan program established in 1979 for public nonprofit schools and hospitals, public care institutions, and local governments. In coordination with the Energy Partnership Program, the program provides a wide range of assistance, from identifying energy saving opportunities in planned facilities to audits and feasibility studies for improvements in existing facilities. The Energy Commission has successfully implemented this revenue bond program and continues to pursue revenue bonds as necessary to continue program operations. Since July 1, 2006, the program has provided technical assistance to 149 projects and awarded 31 low-interest energy efficiency loans. For example, the Sacramento City Unified School District requested technical assistance to evaluate potential efficiency improvements in several of its high schools. Lighting retrofits, controls, and LED exit signs were recommended at each of the schools, leading to reduced energy use and average savings of approximately $53,000 per year. The program is expected to be augmented with American Recovery and Reinvestment Act of 2009 (ARRA) funds.

The Energy Efficiency and Conservation Block Grant Program, created by the Energy Independence and Security Act of 2007, will provide $3.2 billion in ARRA funding to cities and counties throughout the United States. Of that funding, $302 million will go directly to large incorporated cities and counties in California, with another $49.6 million allocated through grants to 265 small incorporated cities and 44 small counties that are not eligible for direct grants from the DOE. The Energy Commission will distribute the funding to help cities and counties implement cost-effective projects and programs to reduce total energy use, reduce fossil fuel emissions, and improve energy efficiency in the building, transportation, and other appropriate sectors.

Demand Response

Demand response efforts seek to slow the rising cost of electricity and improve the reliability of the electricity grid by improving the efficiency of the generation, distribution, and consumption of electricity. Demand response measures provide incentives and tools that encourage and enable customers to periodically reduce their consumption in response to system conditions. The demand for electricity varies with the time of day and the season of the year. Most California consumers demand more electricity during the day than at night, and more in summer than winter, due to the increased use of air conditioning and other consumer electronic products during those times. The maximum peak load is projected to grow at a rate of 1.3 percent per year, faster than the overall growth in electricity demand.

Increases in peak demand create inefficiencies within the electricity system. System operators must manage generation output in real time to match demand as it rises and falls to prevent excessive voltage and frequency changes that could interrupt or damage electrical devices. As demand goes up during peak hours, power companies generally dispatch power plants in decreasing order of efficiency; therefore as the load goes up, the overall efficiency of producing electricity goes down. As efficiency goes down, the cost to provide that power and the GHG emissions of that power go up. When demand falls, the opposite occurs.

Not only are peaking units generally less efficient, but because they operate only a few hundred hours per year, operators must pay for the unit's ownership and operating costs over a much shorter period. This results in much higher costs when compared with facilities that can spread their fixed costs over more hours of operation. Peaking units are necessary, however, to ensure that adequate power is available during peak times or to meet unexpectedly high load requirements.

Giving consumers information on the real cost of electricity as it is being used is an important demand response measure. Although the cost of providing electricity to consumers changes depending on the current load on the system, electricity rates have historically only been based on the total amount of energy consumed monthly rather than on when that electricity is actually used. These rates provide no signal of actual energy costs, nor do they provide incentives for consumers to reduce their electricity loads during the few critical hours each year when high demand strains the capacity of the system, system stability is at risk, and electricity is the most costly to generate.

The CPUC has recommended policy to move all ratepayers to some form of time-variant pricing along with Advanced Metering Infrastructure – advanced two-way communicating meters – and the Energy Commission has supported this policy. However, Senate Bill 695 (Kehoe, Chapter 337, Statutes of 2009) delays implementation of default time-variant pricing for residential customers until 2013. In its current load management standards proceeding, the Energy Commission proposed adopting a requirement that all utilities in the state adopt some form of time-variant pricing for customers that have advanced meters. To guarantee achieving the potential system cost savings of such a pricing system, the Energy Commission, CPUC, and utilities need to develop plans for default time-variant pricing that can be implemented when the legislated restrictions expire. The interim should be used to upgrade and update billing systems, develop effective and fair revenue-neutral dynamic rate designs, and use interval data as it becomes available to analyze customer impacts and develop customer education efforts to maximize demand response while minimizing and mitigating customer costs.

In the state's *Energy Action Plans*, both the Energy Commission and the CPUC have supported time variant pricing. The CPUC rulemaking (R.07-01-041) to evaluate the utilities' demand response programs sought to establish protocols for estimating load impacts, cost-effectiveness, and modifications to support the California ISO's efforts to incorporate these programs into market designs. A decision (D.08-04-050) regarding load impact estimations was issued in April 2008.[53] The Energy Commission joined in instituting the CPUC rulemaking (R.02-06-001) "to develop demand response as a resource to enhance electricity system reliability, reduce power purchase and individual consumer costs, and protect the environment." The rulemaking focused on developing dynamic rates and demand response programs for large customers and conducting research to evaluate the potential costs and benefits of building an advanced metering infrastructure to serve all IOU customers.

Research by the Demand Response Research Center indicates that with proper application, the new Open Automated Demand Response (OpenADR) standard has the potential to substantially increase the amount of demand response capabilities that exist for grid operators in the future. As California

53 California Public Utilities Commission, available at: [http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/81972.htm].

implements the new smart grid, increased demand response capabilities can offset the need for increasing the number of conventional generating power plants in the future. A key element of OpenADR is the ability of customers to pre-select and automate their desired demand response actions (such as lowering air conditioning or lighting), and these actions will occur automatically when called upon unless overridden by the customer. Automated demand response actions can be signaled by an energy price or other signal indicating the grid is stressed and a pre-approved/coordinated load reduction is desired. Research indicates that customers readily accept this automated process, and in the years of field testing customer comfort complaints have been negligible. In some cases, commercial businesses that have participated in pilots or programs have not only fully accepted the efforts but have also used their participation as a sign to their customers of their environmental stewardship and willingness to help California make the transition to a more efficient and lower GHG emitting future.

Renewable Energy

The second resource in the loading order to meet new electricity needs is renewable energy, which will also help achieve a significant portion of the ARB's target for GHG emission reductions from the electricity sector. Increasing the amount of renewable energy in California's electricity mix reduces the risks and costs associated with potentially high and volatile natural gas prices while also reducing the state's dependence on imported natural gas used to generate electricity. Renewable resources provide other benefits such as economic development and new employment opportunities, benefits that are becoming increasingly important given the current recession.

California's Renewables Portfolio Standard (RPS), established in 2002, is an essential tool to help the state reduce its GHG emissions. The RPS requires retail sellers (defined as IOUs, electric service providers, and community choice aggregators) to increase renewable energy as a percentage of retail sales to 20 percent by 2010. State law also requires publicly owned utilities to implement an RPS but gives them flexibility in developing specific targets and timelines. In November 2008, Governor Schwarzenegger's Executive Order S-14-08 raised California's renewable energy goal to 33 percent by 2020, and in September 2009, his Executive Order S-21-09 directed the ARB to work with the CPUC, the California ISO, and the Energy Commission to adopt regulations by July 31, 2010, to implement that higher goal.

The 33 percent RPS target is expected to provide 15.2 percent of the total GHG reductions needed to meet the AB 32 goal of achieving 1990 emissions levels by 2020.[54] However, despite efforts to expand renewable generation, recent utility RPS procurement forecasts for 2010 and 2020 indicate that substantial challenges remain. As of November 2009, the CPUC had approved 129 RPS contracts totaling 10,271 MW; of that approved capacity, a little less than 10 percent – 917 MW – has come on-line and is delivering energy to the grid. An additional 30 contracts for 4,605 MW are under review.[55] While the IOUs have made progress adding renewable contracts to their portfolios, they do not expect to meet

54 California Air Resources Board, *Climate Change Scoping Plan*, 2008, Appendix G, Table G-I-2, p. G-I-7, available at: [http://www.arb.ca.gov/cc/scopingplan/document/appendices_volume2.pdf].

55 California Public Utilities Commission, *Renewables Portfolio Standard Quarterly Report*, November 2009, available at: [http://www.cpuc.ca.gov/NR/rdonlyres/52BFA25E-0D2E-48C0-950C-9C82BFEEF54C/0/FourthQuarter2009RPSLegislativeReportFINAL.pdf].

the 2010 target and will be significantly below the 33 percent target in 2020 unless they add renewable resources at a much faster pace.

Recent estimates of the amount of renewable energy needed by 2020 to meet the 33 percent target range from 45,000 GWhs to almost 75,000 GWhs. This wide range reflects different assumptions about energy efficiency achievements, expected electricity demand and retail sales in 2020, and the amount of energy that will be provided by combined heat and power (CHP), rooftop solar, and existing renewable facilities. Estimates of existing renewables vary from 27,000 GWhs to 37,000 GWhs, depending on the vintage of the estimate, the amount of out-of-state renewable generation attributed to publicly owned utilities, and the amount of unclaimed renewables (renewable generation not claimed as eligible for the RPS) included in the estimate. Energy Commission staff estimate that if the ARB *Climate Change Scoping Plan* goals are achieved for energy efficiency, CHP, and roof-top solar, the state will still need 45,000 GWhs of additional renewable energy to meet the RPS goals in 2020.

The main issues associated with meeting the state's renewable goals include the need for adequate transmission to access renewable resources, challenges to integrating high levels of renewable energy into the existing electricity system, potential difficulties in meeting higher RPS targets given progress to date on reaching the 20 percent by 2010 goal, and environmental concerns associated with building new renewable plants and the transmission to bring the energy from those plants to the state's load centers.

Renewable Energy and the Environment

Renewable energy provides obvious environmental benefits by reducing air and water pollution associated with electricity generation. However, renewables can also face challenges due to environmental concerns with specific technologies or where plants are located. This section discusses some of those issues, including eligibility requirements for the state's RPS and their impact on municipal solid waste plants and deliveries of renewable energy from outside California, environmental impacts of renewable generation and transmission infrastructure, and the potential effects of climate change on that infrastructure.

Expanding Renewables Portfolio Standard Eligibility

Given the Governor's expanded goal of 33 percent renewables by 2020, the Scoping Order for the *2009 IEPR* identified the need to review eligibility criteria for the RPS. As part of its responsibilities under the RPS, the Energy Commission sets eligibility criteria and certifies facilities as RPS eligible. The Energy Commission currently defines eligible renewable resources by fuel source rather than by specific technologies, but state law related to the RPS law contains specific technology requirements that must be considered when determining RPS eligibility.

An example is the use of municipal solid waste (MSW) to produce energy. Although the Energy Commission defines MSW as an RPS-eligible fuel, current law narrowly defines which MSW conversion technologies are allowed. To date, no MSW gasification facility has met these stringent requirements, particularly the requirement that the MSW conversion occur without the use of air or oxygen except ambient air to maintain temperature control.[56] While the Energy Commission is

56 April 21, 2009, IEPR workshop comments by Phoenix Energy: "There is no way you can do this without the presence of oxygen. Limited oxygen, yes, but if you follow the definition to the letter of the law, it can't be done." Transcript p. 74, see [http://www.energy.ca.gov/2009_energypolicy/documents/2009-04-21_workshop/2009-04-21_TRANSCRIPT.PDF].

not aware of any gasification technologies that meet the current requirements, staff will continue to evaluate each RPS certification application to determine whether the MSW conversion technology meets the requirements for RPS eligibility. Because the law requires proposed MSW facilities to obtain air permits, it may be difficult for such facilities, even if they meet RPS eligibility requirements, to be built in areas of the state such as the South Coast Air Quality Management District (SCAQMD) that are in nonattainment for federal air quality standards.

Most Western Electricity Coordinating Council (WECC) states do not explicitly allow MSW to be used for RPS compliance. California's RPS allows MSW that has undergone gasification or been converted to biodiesel to be used for RPS compliance, but combustion of solid unconverted MSW is not eligible (with the limited exception of facilities located in Stanislaus County and operational before September 26, 1996). Similarly, Arizona allows only gasified MSW to be used for RPS compliance and does not specifically permit combustion of solid MSW. Nevada is the only WECC state to explicitly allow unlimited or unrestricted combustion of solid MSW (as well as gasified MSW) to be used for RPS compliance. All other WECC states do not identify MSW in any form as eligible for RPS compliance.

As the space available for landfills becomes more limited in California, renewable energy developers have expressed interest in MSW gasification and are seeking clarification of rules for RPS eligibility of MSW conversion. In a 2006 report, the California Biomass Collaborative estimates that "biomass in the landfill disposal stream (23.1 million tons plus 2.6 million tons of green ADC [alternative daily cover]) could support about 1,750 MWe of electricity generation with another 900 MWe coming from the plastics and textiles

Agency Plan Recommends Climate Change Adaptation Strategies

In August 2009, California's Natural Resources Agency released a comprehensive plan to guide adaptation to climate change, becoming the first state to develop such a strategy. Adaptation generally refers to adjustments in natural or human systems to actual or expected climate changes to minimize harm or take advantage of opportunities.

The 2009 California Climate Adaptation Strategy Discussion Draft summarizes the latest science on how climate change could affect the state and recommends adaptation strategies for the electricity sector.

The Natural Resources Agency's plan recommends encouraging renewable energy development in the least-sensitive environmental areas of the state to maintain natural habitats and healthy forests that will further buffer the environmental impacts of climate change.

components."[57] Given the state's aggressive renewable energy targets and the need for additional renewable energy to meet those targets, the Energy Commission suggests that it work with the California Integrated Waste Management Board to review emerging conversion technologies that use MSW to produce a clean burning fuel that most closely meets the intent of current RPS eligibility requirements as well as environmental considerations and, if appropriate, suggest modifications to applicable state statutes to allow such technologies to be RPS eligible.

Another eligibility issue is the delivery of renewable generation from out-of-state generators. Generation from a renewable power plant located outside California is eligible for the state's RPS if the facility began operation after January 1, 2005, can demonstrate delivery of energy into California, and does not cause or contribute to any violation of a California environmental quality standard or requirement within California.[58] As of September 2009, the Energy Commission has certified only 24 out-of-state renewable facilities as eligible for the RPS, compared to more than 576 eligible in-state facilities.

57 California Energy Commission, *Biomass in Solid Waste in California: Utilization and Policy Alternatives, PIER Collaborative Report*, April 2006, Contract 500-01-016, p. 2, available at: [http://biomass.ucdavis.edu/materials/reports%20and%20publications/2006/MSW_Biomass_White_Paper_2006.pdf].

58 If an out-of-state facility commenced commercial operations before January 1, 2005, it may still be eligible if it meets one of the following criteria: a) The electricity is from incremental generation resulting from project expansion or repowering of the facility on or after January 1, 2005, or b) the facility is part of a retail seller's existing baseline procurement portfolio as identified by the California Public Utilities Commission or part of a publicly owned utility's baseline as determined by Public Utilities Code section 387.

The delivery requirement for out-of-state renewable facilities is flexible, allowing delivery to occur "regardless of whether the electricity is generated at a different time from consumption by a California end-use customer."[59] This approach can allow out-of-state renewables to be "firmed" or "shaped" to address issues like intermittency, inadequate transmission, or scheduling barriers. Firming and shaping can also provide greater value to the electricity system by converting off-peak renewable generation to on-peak energy delivery. Allowing out-of-state renewables to be firmed and shaped rather than immediately scheduled for delivery may also increase the availability of lower cost renewable resources. Firming and shaping allows renewable electricity counted for California's RPS to be consumed outside California, provided that an equal amount of electricity is delivered to California within the same calendar year. Some parties have argued that counting large amounts of out-of-state renewables for California's RPS could reduce in-state air quality or job creation benefits. On the other hand, as discussed in the *2009 Strategic Transmission Investment Plan*, if California decides to build most of its own renewable energy resources to meet its RPS goals, many miles of land will be needed for new transmission lines to access those resources, which could face challenges associated with public opposition due to land use and environmental concerns.

As shown in Table 2, other states in the WECC area with RPS programs have their own delivery requirements. Arizona has the most restrictive electricity delivery policy, requiring that all electricity generated by the renewable resource being used for compliance with a utility's RPS target be physically delivered to that utility's service territory. Most other WECC states with an RPS program allow some

59 Public Resources Code § 25741(a).

TABLE 2: RPS DELIVERY AND LOCATION REQUIREMENTS IN OTHER WESTERN STATES

State	Unbundled RECs Allowed	Delivery Requirements	Facility Location Requirement
Arizona	No	Delivered to the utility sytem	No requirement, but 1.5 multiplier for in-state solar installed before 2006 and for in-state renewables with components manufactured in-state and installed before 2006.
California	No	For out-of-state facilities, matching quantity of energy delivered to in-state zone or node. Facilities must have come on-line after January 1, 2005, if not included in the baseline procurement portfolio of a California IOU or publicly owned utility.	Must be interconnected to the Western Electricity Coordinating Council area (WECC)
Colorado	Yes	None	No requirement, but 1.25 multiplier for in-state generation.
Montana	Yes	Delivered to state if not located in-state. Out-of-state renewables must have commenced commercial operation after January 1, 2005.	None
Nevada	Yes	Delivered to the state	None
New Mexico	Yes	Delivered to the state, unless waived by the New Mexico Public Services Commission based on a determination "that there is an active regional market for trading renewable energy and renewable energy certificates in any region in which the [utility] is located."	None
Oregon	Yes subject to caps	**Unbundled RECs:** None **Bundled RECs:** Delivered to the transmission system of the utility, to Bonneville Power Administration, or to a designated point for subsequent delivery to the utility.	**Unbundled RECs:** WECC **Bundled RECs:** U.S. portion of WECC
Washington	Yes	Delivered to state only if not located in Pacific Northwest. If generator is located outside of the Pacific Northwest, the electricity must be delivered to the state "on a real-time basis without shaping, storage, or integration services."	**Unbundled RECs:** Pacific Northwest

Source: KEMA, Inc.

use of unbundled renewable energy credits (RECs)[60] for RPS compliance. However, their use is often constrained by electricity delivery requirements, location requirements, or explicit caps. As a result, some of these states' policies are arguably more restrictive than California's in terms of geographic scope.

Delivery requirements are only one of many RPS design issues that affect how difficult it may be to meet the targets. Simply comparing delivery requirements across states, although important, does not give a complete picture of compliance flexibility.

Limiting access to out-of-state renewable resources could create geographic inequities between California's utilities because there are more in-state renewable resources located in the southern regions of the state, and transmission from south to north is limited. These inequities could be addressed by the use of tradable RECs. The CPUC issued a proposed draft decision authorizing tradable RECs for RPS compliance in December 2008, and issued a revised version in March 2009. If adopted, the revised proposed decision would "allow transfer of RPS credits without regard to constrained transmission pathways."[61]

Although tradable RECs do not necessarily maintain the local benefits of in-state generation, including environmental benefits, they could help California's RPS by avoiding transmission congestion barriers and their associated costs. The use of tradable RECs would add renewable energy to the grid on a regional, WECC-wide basis and could therefore place downward pressure on costs for electricity.

Environmental Impacts of Renewable Infrastructure

While Californians are generally supportive of renewable energy and its environmental benefits, many citizens are concerned about proposed renewable energy projects and associated transmission lines because of potential environmental impacts. For example, proposed solar plants located in the California desert may affect sensitive species habitat or cultural resources or require large amounts of water.

Initiatives are already underway to facilitate the early identification and resolution of land use and environmental constraints to promote timely development of California's renewable generation resources and associated transmission lines. The Renewable Energy Transmission Initiative (RETI) collaborative process, discussed in more detail in the transmission section later in this chapter, has identified and ranked renewable resource development areas and associated transmission lines to deliver renewable power to load centers. The *RETI Phase 2A Report* is one of the data sources for ranking the transmission projects to interconnect renewables that are in the state's best interests.

To help address potential impacts of new renewable power plants and related transmission lines, the Energy Commission and California Department of Fish and Game are implementing Governor Schwarzenegger's Executive Order S-14-08, which established a process to conserve natural resources while expediting the permitting of renewable energy power plants and transmission lines. The Executive Order's primary objectives are to identify and establish areas for potential renewable energy development and conservation areas in the Colorado and Mojave deserts to reduce the

60 As defined in California, a renewable energy credit is a certificate of proof, issued through the accounting system established by the California Energy Commission, that one unit of electricity was generated and delivered by an eligible renewable resource. Unbundled renewable energy credits are those credits that are sold separately from the underlying electricity.

61 California Public Utilities Commission, Draft Proposed Decision Authorizing Use of Renewable Energy Credits for Compliance with the California Renewables Portfolio Standard, ALJ Simon, March 2009, p. 14, available at: [http://docs.cpuc.ca.gov/efile/PD/99016.pdf].

time and uncertainty associated with licensing new renewable projects on both state and federal lands. Federal participation was secured in November 2008, when the two state agencies signed a Memorandum of Understanding with the Bureau of Land Management (BLM) and U.S. Fish and Wildlife Service to create the Renewable Energy Action Team (REAT).

The REAT is developing the Desert Renewable Energy Conservation Plan (DRECP) and a best management practices and developer guidance manual. The REAT meets regularly to discuss renewable energy project permitting issues and to assist developers who are preparing applications to the different agencies. Federal participation was further supported by the Secretary of the Interior's March 2009 Secretarial Order 3285 directing all Department of the Interior agencies and departments (which include the BLM and U.S. Fish and Wildlife Service) to encourage the timely and responsible development of renewable energy, while protecting and enhancing the nation's water, wildlife, and other natural resources.

The DRECP will develop a conservation strategy that will use California's unique Natural Community Conservation Plan process and may develop a federal Habitat Conservation Plan process and/or amend existing resource management plans accordingly. The DRECP will also coordinate with existing desert conservation plans within the Mojave and Colorado deserts (for example, the West Mojave Plan), renewable energy development project plans, the BLM's Solar Programmatic Environmental Impact Statement (Solar PEIS), and Renewable Energy Transmission Initiative (RETI) planning to form an integrated framework for balancing natural resource conservation and renewable energy development within the Mojave and Colorado deserts.

On October 12, 2009, Governor Schwarzenegger and Secretary of the Interior Ken Salazar signed another Memorandum of Understanding (MOU) directing California agencies and U. S. Department of the Interior agencies to take the necessary actions to further the implementation of the Governor's Executive Order S-14-08 and the Secretary's Order 3285 in a cooperative, collaborative, and timely manner. To this end, state and federal agencies have accelerated processing of projects seeking ARRA funds that meet the milestones published pursuant to the MOU so that renewable energy projects that have been permitted[62] can meet the December 2010 start-of-construction date. The state and federal agencies also are coordinating closely to review in a timely manner other renewable energy projects that are not seeking ARRA funds.

Work on the renewable energy permitting elements of Executive Order S-14-08 is split into six tasks including: 1) developing the DRECP Planning Agreement; 2) publishing a best management practices manual for the development of renewable energy projects by December 2009; 3) developing and gathering public stakeholder and independent scientific input; 4) developing the draft DRECP Conservation Strategy by December 2009; 5) developing the draft DRECP by December 2010; and 6) completing the final draft DRECP environmental review and approval by June 2012.

Another environmental issue associated with renewable infrastructure is potential air quality concerns with new biomass facilities in California. With the Governor's direction in Executive Order S-06-06 to meet 20 percent of the RPS with biopower, it will be important to address these concerns. There is significant potential for renewable electricity generation fueled by biomethane from the state's dairies, but the high cost of emissions controls can interfere with dairies' ability to

62 California Energy Commission, Renewable Energy Action Team, available at: [http://www.energy.ca.gov/33by2020/documents/2009-10-15_Milestones_REAT.PDF].

obtain air permits. California is the largest dairy state in the nation, with more than 1.7 million cows on about 1,800 farms. These cows produce 65 billion pounds of manure per year that could produce biogas that can be burned to produce electricity.

In 2006, the Energy Commission approved grants for five new dairy digester projects in the San Joaquin air basin with generators to meet the dairies' electricity needs and, with approved power purchase agreements, to sell excess electricity to local utilities. However, because the air basin is an extreme nonattainment area, the San Joaquin Air Quality Management District imposed strict nitrogen oxide (NOx) requirements on these generators that required the use of advanced emission control systems. Because of low milk prices, the dairies were unable to meet the increased costs of installing emissions controls and could not agree to the conditions of the permit. Although discussions between the air district, the dairymen, the California Environmental Protection Agency, the ARB, local air districts, and other stakeholders resulted in conditional agreement on permits, these may have been the last ones issued for dairies with generators.[63]

New solid fuel biomass facilities also face challenges in obtaining NOx permits, as well as the added challenge in the SCAQMD of obtaining permits to emit particulate matter (PM). For example, a 25-MW solid-fuel biomass project would need permits for about 90 tons per day of PM-10 emission offsets or emission reduction credits.[64] At a cost of approximately $350,000 per pound per day (or $31.5 million), this requirement could make new biomass projects in the southern part of the state nonviable from a financial perspective.

Climate Change Effects on Renewable Infrastructure

Changes in the environment can also affect renewable energy.[65] Renewable energy depends on natural resources like water, biomass, wind, and the sun, so it can be particularly sensitive to climate variability. The U.S. Climate Change Science Program has identified impacts of climate change on the country's renewable energy resources, including changes in availability of water, biomass, and incoming solar radiation as well as significant changes in established wind patterns and potential effects on geothermal resources.[66] Climate change impacts that affect aspects of conventional energy facilities, such as power plant cooling and water availability, would also apply to certain renewable technologies such as biomass, geothermal, and solar thermal.

In California, only small hydroelectric facilities, those 30 MW or less in size, are eligible for the RPS. Small hydroelectric facili-

63 April 10, 2009, letter from the Western United Dairymen to Governor Arnold Schwarzenegger, available at: [http://www.energy.ca.gov/2009_energypolicy/documents/2009-04-21_workshop/comments/Letter_from_Western_United_Dairymen_to_the_Governor_04-10-09_TN-51189.pdf].

64 California Air Resources Board, facility details for Burney Mountain Power, available at: [http://www.arb.ca.gov/app/emsinv/facinfo/facdet.php?co_=45&ab_=SV&facid_=42&dis_=SHA&dbyr=2007&dd=].

65 California Energy Commission, *Potential Impacts of Climate Change on California's Energy Infrastructure and Identification of Adaptation Measures*, January 2009, CEC-150-2009-001, available at: [http://www.energy.ca.gov/2009publications/CEC-150-2009-001/CEC-150-2009-001.PDF].

66 United States Climate Change Science Program, *Effects of Climate Change on Energy Production and Use in the United States*, February 2008, a report by the U.S. Climate Change Science Program and the subcommittee on Global Change Research, available at: [http://www.climatescience.gov/Library/sap/sap4-5/final-report/sap4-5-final-all.pdf].

ties provide about 1.5 percent of California's power but about 13.5 percent of total renewable generation,[67] so potential impacts on precipitation levels and the timing and rate of snowmelt could affect the amount of electricity provided by small hydro facilities and ultimately their contribution to the state's renewable goals.

While large hydroelectric resources are not RPS eligible, they are a large source of carbon-free electricity in California. In 2008, 11 percent of California's electricity was produced from large hydroelectric power plants, presently the state's largest source of renewable energy. The state's hydroelectricity production relies on predictable water reserves. With changes in snow elevations, snowpack, and snowmelt, less water may be available for hydroelectric generation when it is needed most during the summer. When repeated dry years lead to a drought, reservoir levels can be too low for hydroelectric power generation.

Biomass generation sources include the wastes and byproducts from forestry and agriculture. If climate change results in drier conditions or variations in crop yield, it could affect the type and amount of biomass feedstocks available to existing and future biomass facilities. However, higher daily and seasonal temperatures can also affect insect pest and disease life cycles as winters become milder, which could increase forest mortality, potentially making more biomass fuel available following disease outbreaks but reducing long-term supplies.

California has aggressive policies targeting rooftop photovoltaic systems, which depend both on the amount of incoming solar radiation and changes in temperature. Analysis of systems outside California have shown that a 2 percent decrease in solar radiation resulted in a 6 percent decrease in the electricity output of solar cells.[68]

Wind generation will most likely be affected regionally by climate change rather than uniformly throughout California. Analysis conducted by Breslow and Sailor suggests that average wind speeds in the United States will decrease by 1.0 to 3.2 percent in the next 50 years and will eventually decrease 1.4 to 4.5 percent over the next 100 years.[69] Meanwhile, geothermal resources could be affected by decreased efficiency due to the increased ambient temperature at which heat is discharged. According to a recent assessment by the U.S. Climate Change Science Program, "For a typical air-cooled binary cycle geothermal plant with a 330°F resource, power output will decrease about 1% for each 1°F rise in air temperature."[70]

Clearly, more research is needed on the effects of climate change on renewable and low and noncarbon resources, including: effects on biomass supplies and the influence that this would have on the optimal siting of a biomass facility; the California-specific impacts of climate change on photovoltaic technologies; and the location and scale of changes in California's wind patterns, especially in areas targeted for extensive wind energy development. In addition, the *2009 California Climate*

67 California Energy Commission, 2008 Total System Power, see [http://energyalmanac.ca.gov/electricity/total_system_power.html].

68 Fidje, A. and T. Martinsen, *2006: Effects of Climate Change on the Utilization of Solar Cells in the Nordic Region*. Extended abstract for European Conference on Impacts of Climate Change on Renewable Energy Sources. Reykjavik, Iceland, June 5–9, 2006.

69 Breslow, P. and J. Sailor, *Vulnerability of Wind Power Resources to Climate Change in the Continental United States*, Tulane University, April 2001.

70 Bull, S. R., D. E. Bilello, J. Ekmann, M. J. Sale, and D. K. Schmalzer, *Effects of Climate Change on Energy Production and Use in the United States*, February 2008, a report by the U.S. Climate Change Science Program and the subcommittee on Global Change Research. Washington, D.C.

Adaptation Strategy Discussion Draft[71] recommends using the Energy Commission's PIER regional climate modeling and related study efforts to assess the potential impacts of climate change on energy infrastructure from sea-level rise, precipitation, and temperature changes and other impacts.

Renewable Energy and Reliability

There are several ways renewable resources can affect energy reliability. Renewable resources help reduce the state's dependence on natural gas, making the state less vulnerable to natural gas supply disruptions. By reducing the amount of natural gas needed in the electricity sector, renewables could also free up more natural gas for use in industrial processes or residential cooking and heating. In addition, diversifying the state's electricity portfolio reduces customer risk in much the same way that diversifying an investment portfolio reduces financial risk.

However, not all renewables provide the operating characteristics that the system needs to maintain local area reliability, and integrating certain renewable technologies can make it more difficult to operate the system reliably. Necessary operating characteristics include providing baseload power that can meet demand around the clock and throughout the year, peaking power that meets demand during hot summer months, ramping ability in response to changing demand, and voltage support.

Challenges associated with integrating renewables into the system are covered in more detail in Chapter 3. Simply put, California's system operators must constantly balance changing supply and demand to provide reliable electricity and to ensure that the electric grid remains stable. While geothermal and biomass facilities can provide baseload power, intermittent resources like wind, hydro, and solar operate when nature allows and are therefore not always available to meet system needs during peak hours. Intermittent resources can also drop off or pick up suddenly, requiring system operators to compensate quickly for sudden changes. For example, photovoltaic arrays are very sensitive to cloud cover, which can cause generation to drop substantially in less than a minute and jump back to full generation a few minutes later.[72]

Natural gas plants tend to provide the flexibility the system needs for peaking, cycling, and some baseload operation. Because of the engineering realities of how the system operates, natural gas plants can support the integration of renewable resources by providing the operational characteristics the system needs to operate reliably. The challenge will be to identify where and what types of natural gas plants will best allow integration of renewables into the system to meet renewable goals while maintaining reliability. Other solutions such as energy storage and hybrid renewable plants are also possible and could be preferable in the longer term as more aggressive climate mitigation targets are addressed.

Another issue with integrating large amounts of renewables into the system is the potential for overgeneration, particularly in the spring when there is a need to spill

71 California Natural Resources Agency, *2009 California Climate Adaptation Strategy Discussion Draft*, August 2009, available at: [http://www.energy.ca.gov/2009publications/CNRA-1000-2009-027/CNRA-1000-2009-027-D.PDF].

72 Curtright, Aimee E. and Jay Apt., *Applications: The Character of Power Output from Utility-Scale Photovoltaic Systems,* Progress in Photovoltaics: Research and Applications, 2008, 16: 241–247, see [http://www.clubs.psu.edu/up/math/presentations/Curtright-Apt-08.pdf]. See also, Dan Rastler, EPRI, presentation at the April 2, 2009, IEPR workshop, available at: [http://www.energy.ca.gov/2009_energypolicy/documents/2009-04-02_workshop/presentations/0_3%20EPRI%20-%20Energy%20Storage%20Overview%20-%20Dan%20Rastler.pdf].

water stored in dams to make room for snow melt. Overgeneration occurs when generation exceeds demand despite the actions by the system operator to reduce generation. Overgeneration can lead to circumstances where market prices for electricity actually become negative as the system operator, in order to maintain system operations, must literally pay adjacent balancing authorities to take the excess energy.

One strategy to improve reliability by addressing the variability of renewable resources and overgeneration concerns is the use of utility scale and distributed energy storage, which is discussed in more detail in Chapter 3. Energy storage provides the ability to make best use of renewable generation facilities by addressing potential mismatches between generation and load while also addressing other issues like ramping rates and power quality. Large utility-scale energy storage technologies like pumped hydroelectric storage, compressed air energy storage, or large multi-megawatt battery storage systems can store renewable energy generated off-peak for later use during peak periods or to provide firming. Pumped hydroelectric storage uses water pumped from a lower elevation reservoir to a higher elevation using low-cost off-peak electric power (including renewable energy) to run the pumps. The water is then allowed to return and generate electricity during times when the renewable generation needs firming or to match the renewable load to the needs of the utility electrical system. Compressed air energy storage uses a compressor to pressurize a storage reservoir using off-peak energy and then releases the air through a turbine during on-peak hours to produce energy. Large compressed air energy storage systems use underground caverns such as depleted natural gas mines to store the air and can provide energy storage for long periods of time. Battery energy storage technology has improved over time to the point where there are several emerging battery technologies that can provide utility-scale energy storage.

Another tool to help increase reliability by reducing the impacts of renewable variability on the system is to improve the ability to forecast expected generation from intermittent resources. Progress has been made in reducing forecasting error in hour-ahead and day-ahead generation from wind facilities, but additional work is needed to improve forecasting capability for solar facilities.

Renewable Energy and the Economy

As economic concerns continue to dominate the daily news, the United States' new administration is shifting energy policy strategies to embrace a new clean energy economy, making development of renewable energy resources part of the nation's economic recovery plan.

At the same time, California's citizens continue to face the risk of potential sustained high natural gas prices. In 2008, 45.7 percent of the state's electricity came from natural gas-fired generation, up from 36.5 percent in 2002. Because the electricity generation sector is the state's largest consumer of natural gas, price increases and volatility can have major effects on electricity prices and on the operating costs of existing and new natural gas plants that are needed to meet California's increasing electricity demand. Diversifying the electricity system by adding renewables helps to reduce these effects.

California has already invested billions of dollars to promote renewable energy. Senate Bill 1 (Murray, Chapter 132, Statutes of 2006) enacted a \$3.35 billion set of solar incentive programs to achieve 3,000 MW of solar energy systems by 2016. The programs are administered by the Energy Commission (\$400 million), CPUC (about \$2.1 billion), and publicly owned utilities (\$784 million). The CPUC is responsible for providing incentives to the nonresidential and existing residential markets in IOU service areas. The Energy Commission's New Solar Homes Partnership program offers incentives to encourage solar installations, with high levels of energy efficiency, in the residential new construction market for IOU service areas. Publicly owned utilities are responsible for solar incentive programs in their service areas.

The Energy Commission's Renewable Energy Program that was established in 1998 represents an additional $2.1 billion to support the continued operation of existing renewable facilities and the development of new renewable generating facilities and emerging renewable technologies.[73] The consumer education component of the Renewable Energy Program also funded the development of the Western Renewable Electricity Generation Information System, which tracks renewable generation in the Western Electricity Coordinating Council area to ensure that generation is counted only once for purposes of California's RPS.

Although the Renewable Energy Program was established prior to passage of the state's RPS, it is an important tool to help the state achieve its RPS and GHG emission reduction goals. The program has supported 4,500 MW of existing facilities and has helped develop nearly 500 MW of new large-scale generating capacity as well as about 130 MW from new customer-scale facilities. The program is also ensuring that California can reliably track and verify renewable generation claimed to meet the RPS. However, authorization to collect funds for the program is slated to end January 1, 2012. Because of the importance of the Renewable Energy Program in helping to support the state's renewable energy goals, the Energy Commission recommends that the Legislature extend the collection of public goods charge funding for the program through 2020.

New renewable power plants that are being proposed and developed in California to meet the state's RPS also represent a significant investment in renewable energy. As of August 2009, nine solar thermal projects were under review by the Energy Commission and the BLM totaling more than 4,500 MW of new renewable capacity. An additional 19 solar thermal projects totaling 5,600 to 5,900 MW have been announced but have not yet applied to the Energy Commission for certification.[74] These projects represent billions of dollars of capital investments, as well as significant job and tax benefits from the construction and continued operation of the projects themselves.

Integrating renewable resources into the electricity system has potential economic consequences – primarily, increased potential costs. To the extent that natural gas remains a low-cost fuel, gas-fired generation can help the electricity system absorb the costs of transitioning to a higher level of renewable energy in the electricity system. But determining the actual costs of increased levels of renewables is difficult. Cost studies to date have widely varying assumptions, uncertainties, and approaches. However, study results are influenced by some common factors:

- Estimates of future natural gas prices
- Estimates of the cost of generation for gas-fired and renewable generating technolo-

73 Funding for the New Solar Homes Program under the Renewable Energy Program is included in the total for the California Solar Initiative. See [http://www.energy.ca.gov/renewables/quarterly_updates/2009-1Q_FIANACIAL_SUMMARY.PDF] for a description of Renewable Energy Program funding expenditures as of March 2009.

74 "Announced" refers to projects that have been publicly announced in the news media, have power purchase agreements pending with or approved by the California Public Utilities Commission, or have made official declarations of intent. See [http://www.energy.ca.gov/siting/solar/index.html] for a complete list of projects.

gies, including the potential cost of GHG allowances for gas-fired generation, costs for siting and permitting, and the cost of capital to finance new renewable projects

- Availability of tax credits and other incentives for renewable generation

In June 2009, the Energy Division of the CPUC issued the preliminary results of a study on the impacts of the 33 percent by 2020 renewable target that examined four different potential scenarios and identified the costs and tradeoffs of each approach.[75] The study suggests that achieving 33 percent renewable energy could increase costs by about 10 percent compared to an all gas scenario and about 7 percent compared to simply maintaining 20 percent renewables through 2020. The study also indicated that the state needs to build four major new transmission lines at a cost of $4 billion for the 20 percent reference case, which holds renewable energy at 20 percent of retail sales through 2020. To meet a 33 percent by 2020 RPS target, the study indicates a need for seven additional transmission lines at a cost of $12 billion but assumes that the ARB's *Climate Change Scoping Plan* goals for energy efficiency, combined heat and power, and rooftop solar are not met.

Because the cost of generation is one of the important variables in studies evaluating the costs of moving to increased levels of renewables, the Energy Commission has continued to update its Cost of Generation Model to provide a consistent set of assumptions. The Cost of Generation Model was introduced in the *2003 IEPR* and has been revised in each IEPR cycle to improve the model's accuracy, flexibility, and transparency. The goal of the model is to have a single set of current cost estimates that can be used in energy program studies at the Energy Commission and elsewhere.

The Energy Commission's 2009 *Comparative Cost of California Central Station Electricity Generation Technologies Report* updated the estimates of levelized costs that were prepared for the *2007 IEPR.* Levelized, or annualized, costs are equal to the net present value of current and future annual costs, which allows technologies with different annual costs to be compared with each other. The current version of the model has been improved to capture long-term changes in technology costs over time. It also now includes ranges of costs for each technology, recognizing that the range of cost for a technology can be more significant than differences in average costs between technologies. Single-point estimates do not reflect actual market dynamics or the wide array of component costs, operational factors, or unpredictable future tax benefits.

For the *2009 IEPR*, the Energy Commission staff updated the levelized cost estimates for plants that could be developed by IOUs and publicly owned utilities, as well as merchant plants financed by private investors that sell electricity to the competitive wholesale power market. The update also included long-term changes in cost variables that determine levelized cost, the most significant of which is instant cost. Instant cost, sometimes referred to as overnight cost, is the initial capital expenditure.

Based on initial capital expenditure, wind and solar technologies show a significant cost decline. Solar photovoltaic technology has shown dramatic cost changes since 2007, and is expected to show the most improvement of

75 Gillette, Anne and Jaclyn Marks, California Public Utilities Commission, *33% Renewable Portfolio Standard Implementation Analysis Preliminary Results*, June 2009, available at: [http://www.cpuc.ca.gov/NR/rdonlyres/1865C207-FEB5-43CF-99EB-A212B78467F6/0/33PercentRPSImplementationAnalysisInterimReport.pdf].

all the technologies evaluated in the model, bringing its capital cost within range of that of natural gas-fired combined cycle units.[76]

In general, IOU plants are less expensive than merchant facilities because of lower financing costs. However, the model indicates that merchant plants for some of the renewable technologies, such as the solar units, become less expensive because of the effect of cash-flow financing and tax benefits.

As part of the cost analysis, the Energy Commission compared its cost assumptions for renewable technologies with those used in the RETI process and in the CPUC's evaluation of the cost of RPS implementation. The Energy Commission's cost assumptions were generally consistent with the RETI assumptions with the exception of the cost of single-axis PV, which was lower. Relative to the CPUC's cost assumptions, the Energy Commission's results were higher for solar thermal power plants and lower for wind.

Evaluation of the generation costs for renewable technologies is ongoing, and it is difficult at this point to draw concrete conclusions from the analyses to date. However, in looking at the inputs for determining the cost of renewable generation technologies, there is a clear need for future studies to consider – either qualitatively or quantitatively – macroeconomic and externality factors associated with renewable generation that may influence costs. Factors that should be considered include:

- CO_2 abatement costs, including carbon capture and storage
- Environmental sensitivity and land-use constraints
- Permitting risk
- Transmission limitations and equity issues related to who bears the cost of new transmission
- System integration costs and system diversity benefits
- Availability of financing and tax credits
- Macro-economic benefits (jobs creation, security, fuel diversity, etc.)
- Natural gas price and wholesale price effects from increased penetration of renewables
- Costs of energy storage technologies

Because costs can change dramatically more often than the biennial IEPR cycle, there is a need for ongoing cost analysis efforts integrated across utility, community, and building-scale applications of renewable energy technologies. Also, because levelized energy costs value each kilowatt hour (kWh) delivered to the grid equally regardless of the time it is delivered and its impact on the remainder of the system, more comprehensive cost analysis should be complemented by value analysis that supports planning for least cost overall electric system operation.

Recognizing that renewables often are more costly than conventional energy sources, the RPS law prior to 2008 set aside a fixed amount of public goods charge funding to

76 For detailed tables showing individual technology costs, see California Energy Commission, *2009 Comparative Cost of California Central Station Electricity Generation Technologies Report*, August 2009, CEC-200-2009-017SD, pp. 16–19, available at: [http://www.energy.ca.gov/2009publications/CEC-200-2009-017/CEC-200-2009-017-SD.PDF].

offset potentially higher costs to the IOUs of procuring renewable energy. In 2008, legislative action transferred administration of these funds from the Energy Commission to the CPUC, refunded $462 million in unused funds to the IOUs, and eliminated the collection of that portion of the public goods charge. There is now a "cost limitation" for each utility that is equal to the actual amount of funding collected for this purpose from 2002–2007 plus the projected amount that would have been collected from 2008–2011.

Under the RPS law, once the cost limitation is reached, the CPUC cannot require IOUs to purchase any additional renewable energy that is more expensive than the benchmark "market price referent" price set by the CPUC. IOUs can, however, voluntarily procure renewable energy priced above the market price referent, and the CPUC is allowed to approve recovery of the above-market costs of those contracts through rates. As of May 2009, PG&E and SDG&E had reached their cost limitations ($381.9 million and $69 million, respectively), and as of September 2009, SCE appears to have reached its cost limitation as well.[77]

With the cost limitation reached by the three IOUs, the state needs another approach to maintain downward pressure on the costs of renewables. Some recent studies suggest that well-designed feed-in tariffs – fixed, long-term prices for renewable energy – can help with the development of renewable resources at lower costs than other policies.[78] Feed-in tariffs can be based on a generator's cost of generation plus a reasonable profit, on the value that generator provides to the system (such as delivering during peak periods), or on a hybrid of the two. A cost-based approach can be most easily tailored to put downward pressure on costs, but a hybrid approach may be necessary because utilities and states may not have the legal authority to set wholesale electricity prices based on the cost of generation.[79] If a combined approach is used, care is needed to maintain transparency, certainty, and a clear link to the cost of generation for feed-in tariffs to stimulate development of renewable energy.

In setting feed-in tariffs, there are two important considerations. First, to keep downward pressure on costs, feed-in tariffs should not be "one-size-fits-all," but instead should be based on the size and type of renewable resource. For example, the cost of generating energy from a 100-MW wind farm is much less than the cost of generating energy from

77 California Public Utilities Commission Resolution E-4253, September 24, 2009, page 2, [http://docs.cpuc.ca.gov/word_pdf/AGENDA_RESOLUTION/107332.pdf].

78 Studies include: Summit Blue Consulting and Rocky Mountain Institute, 2007, *An Analysis of Potential Ratepayer Impact of Alternatives for Transitioning the New Jersey Solar Market from Rebates to Market-Based Incentives*, final report, Boulder, CO, Summit Blue Consulting, prepared for the New Jersey Board of Public Utilities, Office of Clean Energy; de Jager, David and Max Rathmann, Ecofys International, BV, *Policy Instrument Design to Reduce Financing Costs in Renewable Energy Technology Projects*, October 2008, PECSNL062979, International Energy Agency Implementing Agreement on Renewable Energy Technology Deployment, available at: [http://www.iea-retd.org/files/RETD_PID0810_Main.pdf]; Ragwitz et al., OPTRES, *Assessment and Optimization of Renewable Energy Support Schemes in the European Electricity Market*, final report, February 2007, European Commission, available at: [http://www.optres.fhg.de/OPTRES_FINAL_REPORT.pdf]; and Cory, Karlynn, Toby Couture, and Claire Kreycik, NREL, *Feed-In Tariff Policy: Design, Implementation, and RPS Policy Interactions*, March 2009, p. 9, available at: [http://www.nrel.gov/docs/fy09osti/45549.pdf].

79 For more information, see California Public Utilities Commission Rulemaking (R.) 08-08-009.

Feed-In Tariffs and Transmission

Transmission remains one of the major barriers to meeting California's renewable energy goals, and while feed-in tariffs alone are not a solution, they could be structured to coordinate the development of renewable projects and the transmission lines needed to access those projects.

Several countries, including Germany, Spain, and France, have created feed-in tariffs to target specific locations and technologies. Under Germany's feed-in tariff, for example, developers receive higher incentives for developing off-shore wind in deeper waters and further from shore. China is also beginning to use a geographic approach to feed-in tariff development that uses competitive bidding to set feed-in tariffs for specific areas.

In California, utility solicitations for RPS energy do not coincide with the permitting or construction of transmission expansions or extensions required to access renewable resources. This can result in facilities being selected that will depend on transmission expansion that may not be actively pursued in a reasonable time frame. Tying feed-in tariffs to areas where transmission lines are permitted and construction funding is committed could help bring renewable generation on-line as soon as a new transmission line is commissioned, allowing the transmission and generation facilities to be developed in parallel.

a 2-MW field of photovoltaic panels. Differentiating feed-in tariffs by type and size can ensure a good mix of new renewable energy projects and avoid paying too much for some technologies and too little for others. Setting a different feed-in tariff for each type of renewable energy technology can also stimulate competition among equipment manufacturers to bring costs down and maximize profit margins for project developers.[80] This approach is being used in Germany, where feed-in tariffs are stimulating development in a broad range of renewable energy types and project sizes.

Second, once a contract is signed, the original price should be set for the life of the contract to provide revenue certainty that is needed for projects to get financing. To encourage faster renewable development, lower tariffs could be offered for projects that come on-line in later years, with the rate of decline for each feed-in tariff revisited at specified intervals to ensure it is consistent with market conditions. For example, solid-fuel biomass facilities can invest in more efficient equipment to reduce their costs, but they have little control over the costs of collecting and transporting fuel to their facilities. If the cost of biomass fuel or transport rises significantly, the feed-in tariff may need to be revised to reflect market realities. On the other hand, if feed-in tariffs prove too successful at bringing renewable energy on-line faster than what is needed to meet the state's renewable goals, a cap could be used to contain costs. However, a capped feed-in tariff raises some doubts for developers about whether they will obtain a feed-in tariff contract. It can also create un-

80 Grace, R., W. Rickerson, K. Corfee, K. Porter, and H. Cleijne, KEMA, *California Feed-In Tariff Design and Policy Options*, final consultant report, prepared for the California Energy Commission, CEC-300-2008-009F, pp. 24–25, available at: [http://www.energy.ca.gov/2008publications/CEC-300-2008-009/CEC-300-2008-009-F.PDF].

certainty for manufacturers regarding long-term market growth unless the cap is set as a long-term target.

The renewable energy data used in the Energy Commission's staff Cost of Generation Model could provide a good starting point for developing either cost-based or hybrid feed-in tariffs in California. A review of feed-in tariff rate-setting processes in Europe and the United States suggests that using cost-of-generation data to calculate feed-in tariff levels would require decisions on the following key criteria:

- The level of return on equity and/or debt consistent with the risk profile of the specific technologies.
- The ownership structure, if tariffs will be differentiated by owner type.
- The degree of leverage (debt versus equity).
- How costs are allocated for transmission, distribution, and interconnection.
- How to address the range of costs for each technology to balance costs to ratepayers against stimulating investment.
- How complex the rate-setting model will be and the optimal level of stakeholder involvement.

Over the past several years, the Energy Commission has explored the potential benefits of a feed-in tariff in California as a way to accelerate renewable energy generation and increase the likelihood of meeting California's RPS goals. The *2007 IEPR* recommended setting feed-in tariffs initially at the CPUC's market price referent for all RPS-eligible renewables up to 20 MW while continuing to explore feed-in tariffs for larger projects. The *2008 IEPR Update* reiterated this recommendation, adding that feed-in tariffs for larger projects should include must-take provisions as well as cost-based technology-specific prices that generally decline over time and are not linked to the market price referent.

Feed-in tariffs for smaller projects make sense as an interim step toward broader development of feed-in tariffs because smaller projects can interconnect to the grid at the distribution level and typically do not require new transmission investment.[81] Also, smaller projects often do not require as extensive an environmental review or as lengthy a permitting process as larger projects. Analysis in the RETI process has suggested that there is technical potential for as much as 27,500 MW of wholesale distributed PV projects up to 20 MW in size near substations.[82]

Opinions regarding the effects of feed-in tariffs vary. Some parties are concerned that feed-in tariffs would be too costly and would increase electricity rates for utility customers. Others argue that providing clear up-front feed-in tariff guidelines would reduce the time and expense of obtaining a long-term contract by allowing pre-approval of projects that meet those guidelines.[83] Feed-in tariffs could also reduce financing costs by providing increased

81 KEMA, *California Feed-In Tariff Design and Policy Options*, May 2009, CEC-300-2008-009-F, available at: [http://www.energy.ca.gov/publications/displayOneReport.php?pubNum=CEC-300-2008-009-F].

82 California Energy Commission, *RETI Phase 1B*, January 2009, available at: [http://www.energy.ca.gov/2008publications/RETI-1000-2008-003/RETI-1000-2008-003-F.PDF].

83 RightCycle and FIT Coalition, written comments for May 28, 2009, IEPR workshop, available at: [http://www.energy.ca.gov/2009_energypolicy/documents/2009-05-28_workshop/comments/RightCycle_and_the_FIT_Coalition_Comments_TN_51944.pdf].

certainty for investors.[84] And as with all strategies to reduce the impacts of climate change, determining the cost-effectiveness of feed-in tariffs to incentivize renewable energy must factor in the potential health and environmental costs of not meeting the state's GHG emission reduction goals.

Feed-in tariffs have already proven to be cost-effective in some European countries. In Germany, for example, the cost of the feed-in tariff for power customers in 2007 was quite small: only about 3 percent of the price of power for residential customers.[85] The National Renewable Energy Laboratory states that the European experience with feed-in tariffs shows that "renewable energy development and financing can happen more quickly and often more cost-effectively than under competitive solicitations."[86]

Within the U.S., the Gainesville Regional Utilities in Gainesville, Florida, has identified feed-in tariffs for solar PV as its least-risk and most cost-effective method for securing renewables, noting the low risk and guaranteed rate of return as favorable to investors and the minimal effect on its customer rates, which are about average for Florida.[87]

In California, IOUs have offered a feed-in tariff since 2008 for projects up to 1.5 MW based on the market price referent.[88] As of August 2009, this feed-in tariff has resulted in only 14.5 MW of contracted capacity, suggesting that the market price referent does not provide enough revenue to stimulate development of small-scale renewable projects. The CPUC is considering expanding its feed-in tariffs to renewable projects as large as 10 or 20 MW.[89]

On March 27, 2009, the CPUC administrative law judge (ALJ) in Rulemaking 08-08-009 filed an Energy Division staff proposal for comment. The staff proposal addresses the design and contract terms for an expanded feed-in tariff program with eligibility for projects up to 10 MW in size. It also proposes terms and conditions to include in a standard feed-in tariff contract for projects between 1.5 MW and 10 MW in size. The staff proposal does not consider pricing for an expanded program, but assumes that prices will continue at the current market price referent level.

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84 de Jager, David and Max Rathmann, Ecofys International, BV, *Policy Instrument Design to Reduce Financing Costs in Renewable Energy Technology Projects*, October 2008, PECSNL062979, International Energy Agency Implementing Agreement on Renewable Energy Technology Deployment, available at: [http://www.iea-retd.org/files/RETD_PID0810_Main.pdf].

85 Fell, Hans-Josef, member of the German Bundestag, March 2009, *Feed-In Tariff for Renewable Energy: An Effective Stimulus Package without New Public Borrowing*, p. 21, available at: [http://www.boell.org/docs/EEG%20Papier%20engl_fin_m%C3%A4rz09.pdf].

86 Cory, Karlynn, Toby Couture, and Claire Kreycik, NREL, *Feed-In Tariff Policy: Design, Implementation, and RPS Policy Interactions*, March 2009, p. 9, available at: [http://www.nrel.gov/docs/fy09osti/45549.pdf], references listed on pp. 14–17.

87 Comments by John Crider, Gainesville Regional Utilities, May 28, 2009, IEPR workshop, transcript pp. 119–120, available at: [http://www.energy.ca.gov/2009_energypolicy/documents/2009-05-28_workshop/2009-05-28_TRANSCRIPT.PDF].

88 California Public Utilities Commission, *Summary of Feed-In Tariffs*, available at: [http://www.cpuc.ca.gov/PUC/energy/Renewables/feedintariffssum.htm]. See also, California Public Utilities Commission Energy Division, Resolution E-4137, February 2008, [http://docs.cpuc.ca.gov/PUBLISHED/AGENDA_RESOLUTION/78711.htm].

89 See CPUC R.08-08-009, *Administrative Law Judge's Ruling on Additional Commission Consideration of a Feed-In Tariff*, see http://docs.cpuc.ca.gov/efile/RULINGS/99105.pdf and "Administrative Law Judge's Ruling Regarding Briefs on Jurisdiction in the Setting of Prices for a Feed-in Tariff," available at: [http://docs.cpuc.ca.gov/efile/RULINGS/101672.pdf].

On August 27, 2009, the ALJ filed an additional staff proposal for comment. The additional proposal addresses a pricing mechanism for system-side distributed generation, which Energy Division staff asserts is consistent with the program goals, guiding principles, and the feed-in tariff proposal filed on March 27, 2009. The staff pricing proposal focuses on system-side renewable distributed generation, defined as small projects (from 1 to 20 MW) that export all of the project's electricity to the utility and connect to the distribution grid. Neither of these proposals takes into account potential legal issues raised by parties in legal briefs filed in June and July 2009 on the question of federal and state jurisdiction in setting the price paid to a wholesale generator by a utility under a feed-in tariff.

California's two largest publicly owned utilities are also developing feed-in tariffs. The LADWP is developing a feed-in tariff for solar on rooftops of public organizations that are not eligible for tax credits, such as the Los Angeles Unified School District, Los Angeles Community College District, the University of California, and California State University.[90] SMUD is also moving forward with a feed-in tariff beginning in January 2010 that is aimed at systems up to 5 MW connected to SMUD's local distribution system, with a systemwide cap of 100 MW.[91] The feed-in tariff applies to both renewable and fossil-fuel generation technologies.

90 Comments by Los Angeles Department of Water and Power at May 28, 2009, IEPR workshop, transcript p. 170.

91 Sacramento Municipal Utility District news release, July 17, 2009, available at: [http://www.smud.org/en/news/Documents/09archive/07-17-09_smud_feed-in-tariff.pdf].

Distributed Generation and Combined Heat and Power

The next element in California's loading order for meeting new electricity needs is distributed generation and CHP. As stated in the *2005 Energy Action Plan*, "After cost-effective efficiency and demand response, we rely on renewable sources of power and distributed generation, such as combined heat and power applications."[92]

Distributed generation resources are grid-connected or stand-alone electrical generation or storage systems, connected to the distribution level of the transmission and distribution grid, and located at or very near the location where the energy is used. The benefits of distributed generation go far beyond electricity generation. Because the generation is located near the point where it is needed, distributed generation reduces the need to build new transmission and distribution infrastructure and also reduces losses at peak delivery times. Customers can use distributed generation technologies to meet peak needs or to provide energy independence and protect against outages and brownouts.

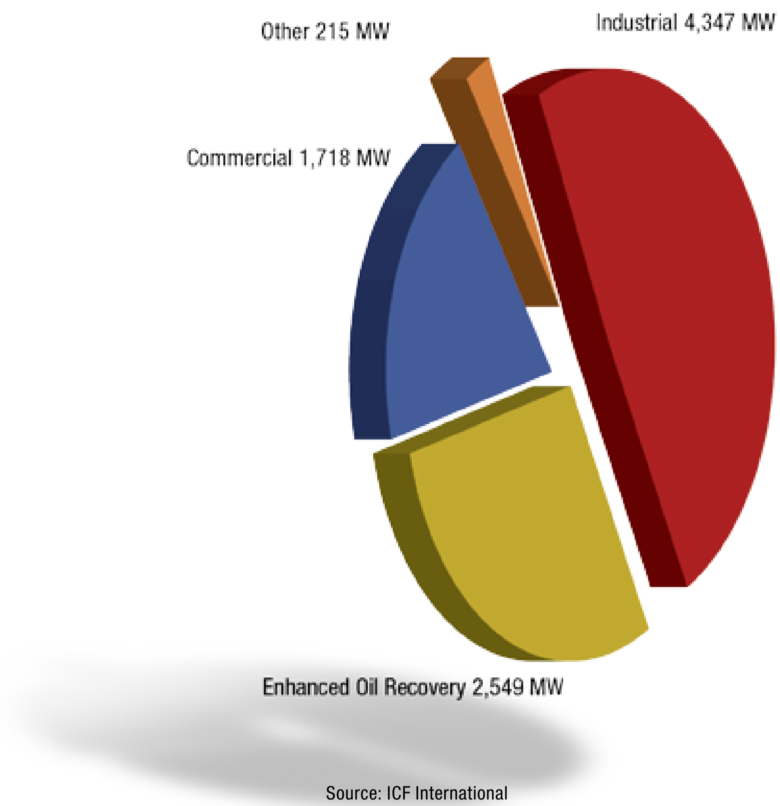
California is promoting distributed generation technologies through such programs as the California Solar Initiative, the Self-Generation Incentive Program, the New Solar Homes Partnership program, and the Emerging Renewables Program, all of which support distributed generation on the customer side of the meter. On the utility side of the meter, efforts to support distributed generation include the feed-in tariff for small renewable generators (discussed in the earlier section on renewable energy resources) and the feed-in

92 California Energy Commission and California Public Utilities Commission, *Energy Action Plan II*, September 21, 2005, [http://www.energy.ca.gov/energy_action_plan/2005-09-21_EAP2_FINAL.PDF].

tariff for small, new, highly efficient CHP to be implemented under AB 1613 (Blakeslee, Chapter 713, Statutes of 2007). The CPUC opened a rulemaking in June 2008 to implement the requirements of AB 1613, including establishing the policies and procedures for purchasing electricity from new CHP systems, and the Energy Commission is in the process of developing guidelines establishing technical eligibility criteria for programs to be developed by the CPUC and publicly owned utilities. Assembly Bill 1613 requires that the guidelines be adopted by January 1, 2010.

CHP, also referred to as cogeneration, is the most efficient and cost-effective form of distributed generation, providing benefits to California citizens in the form of reduced energy costs, more efficient fuel use, fewer environmental impacts, improved reliability and power quality, locations near load centers, and support of utility transmission and distribution systems. In this sense, CHP can be considered a viable end-use efficiency strategy for California businesses. Widespread development of efficient CHP systems will help avoid the need for new power plants or expansion of existing plants.

FIGURE 9: EXISTING COMBINED HEAT AND POWER IN CALIFORNIA



Source: ICF International

Existing Combined Heat and Power in California

California is one of the most prolific states in the country in terms of the amount of CHP in the state's energy mix. California has almost 1,200 sites representing nearly 9,000 MW of installed CHP capacity (see Figure 9).

The industrial sector represents about half of existing CHP, the bulk of which is in food processing and refining. The remainder of the industrial sector is from process industries like chemicals, metals, paper, and wood products. About one-third of existing CHP is in enhanced oil recovery because of the large steam load to produce heavy oil. The third largest group of CHP installations is in the commercial sector, which includes universities, hospitals, prisons, utility generation, water treatment, and other commercial applications. The remaining CHP is in the mining and agricultural sectors.

Existing CHP installations in California can also be characterized in terms of facility size, primary fuel, and technology (prime mover). Large installations make up most of the existing capacity, with systems smaller than 5 MW representing only 5.5 percent. Systems larger than 100 MW represent almost 40 percent of the total existing capacity. The market saturation of CHP in large facilities is much higher than for smaller sites; much of the remaining technical market potential for CHP is for smaller systems.

The dominant fuel used for CHP is natural gas, representing 84 percent of the total installed capacity. Renewable fuel makes up 4.5 percent of the total capacity, mostly in the wood products, paper, and food processing industries and in wastewater treatment facilities.

Because of the concentration of large-scale systems in the existing CHP population, the most common prime movers are gas turbines. In the very large sizes, these are often in a combined cycle configuration. In intermediate sizes, simple cycle gas turbines are used. Renewable fuels or waste fuels are used in boilers driving steam turbines in the wood, paper, food, and petrochemical industries. Most of the small systems are driven by gas-fired reciprocating engines; while total capacity is small (5 percent), the reciprocating engine technology represents the greatest number of CHP sites (62 percent).

Within existing CHP, there are approximately 6,000 MW of CHP capacity under qualifying facility contracts under which all or a portion of the output is sold to the utilities. The continued existence and viability of this power is a major issue; the *2007 IEPR* noted that as much as 2,000 MW of CHP capacity could shut down by 2010 as contracts expire.

Combined Heat and Power and the Environment

In December 2008, the ARB adopted its *Climate Change Scoping Plan* with a target of 4,000 MW of CHP to displace 30,000 GWhs of demand and reduce GHG emissions by 6.7 million metric tons of CO_2 by 2020. A CHP facility produces electricity and utilizes the excess heat, thus increasing efficiencies and reducing GHG emissions.

For CHP to meet ARB's goals, a new generation of highly efficient CHP facilities must be encouraged and supported. Critical to achieving these efficiencies and meeting these targets will be the legislatively mandated minimum efficiency standard of 60 percent to guide development and operation of these facilities over time. AB 1613 is intended to encourage the development of new CHP systems in California with a generating capacity of not more than 20 MW. Assembly Bill 1613 directs the Energy Commission to adopt guidelines by January 1, 2010, establishing technical criteria for eligibility of CHP systems for programs to be developed by the CPUC and publicly owned utilities. When these guidelines are adopted, they will set an efficiency standard for CHP facility development and assure that facilities are designed and operated in a way that reduces GHG emissions and will create a new benchmark for CHP efficiencies in California. As CHP technology continues to develop, efficiencies more than 70 percent can be expected to become standard and cost effective.

Another environmental benefit of CHP that is often overlooked has to do with water use. In California, central-station thermal, water-cooled power generators use enormous amounts of water for cooling. The National Renewable Energy Laboratory estimates that almost half a gallon of water is evaporated at central station thermoelectric plants for every kWh of electricity consumed at the point of use.[93] CHP generally does not use condensers or cooling towers, therefore, its water consumption is much lower.

CHP that uses renewable fuels provides additional environmental benefits to California. There is potential for doubling the renewable CHP at the state's wastewater treatment plants. Sludge from waste treatment plants can be fed into an anaerobic digester to create biogas (methane), which is then burned in a CHP system. The wastewater treatment plants can also co-digest other biodegradable waste streams, such as the dairy and food processing industry and restaurant waste. Many waste treatment plants are exploring co-digestion to increase their biogas production and to take advantage of underused digester capacity. California's dairy and food processing industries are exploring co-digestion to solve the problem of waste disposal. Using these wastes for electricity generation also addresses the adverse impact of the GHG emissions from untreated wastes, as well as the GHG impacts from transporting wastes for disposal elsewhere. A recent report by the Energy Commission staff identified a market potential of 450 MW of CHP capacity from co-digesting sludge and other biodegradable waste.[94] There are, however, some economic and regulatory barriers, including streamlining the permitting process and providing some financing options that municipally owned waste treatment plants require.

An assessment of statewide CHP technical and market potential, discussed in more detail below, suggests that the largest untapped market for CHP is in the commercial and institutional sectors (20 MW and less).[95] Unlike industrial sector CHP, these smaller systems will use distributed generation applications that will be located at or near existing customer's thermal loads. Because a CHP unit must be in close proximity to the facility where the waste heat will be utilized, new green space will not be needed to develop this new generation, meaning fewer environmental impacts. Additionally, most small CHP and distributed generation are interconnected to the distribution system. Developing generation closer to load centers instead of in remote areas miles where it will be consumed would help reduce the need to build new transmission infrastructure and thereby avoid the associated environmental impacts.

Combined Heat and Power Technical Potential

The technical potential of CHP is an estimation of market size constrained only by technological limits – the ability of CHP technologies to fit customer energy needs. CHP technical potential is calculated in terms of CHP electrical capacity that could be installed at existing and new facilities based on the estimated electric and thermal needs of the site. The technical market potential does not include screening for economic rate of return, or other factors such as ability to retrofit, an owner's interest in using CHP, availability of capital or natural gas, and variations in energy consumption within customer application/size class. Identifying the technical market potential is a preliminary step in assessing actual economic market size and ultimate market penetration.

93 National Renewable Energy Laboratory, *Consumptive Water Use for U.S. Power Production*, December 2003, NREL/TP-550-33905, available at: [http://www.nrel.gov/docs/fy04osti/33905.pdf].

94 California Energy Commission, *Combined Heat & Power Potential at California's Wastewater Treatment Plants*, final staff paper, September 2009, CEC-200-2009-014-SF, available at: [http://www.energy.ca.gov/2009publications/CEC-200-2009-014/CEC-200-2009-014-SF.PDF].

95 *Combined Heat and Power Market Assessment*, draft consultant report, October 2009, CEC-500-2009-094-D, available at: [http://www.energy.ca.gov/2009publications/CEC-500-2009-094/CEC-500-2009-094-D.PDF].

TABLE 3: TOTAL COMBINED HEAT AND POWER TECHNICAL POTENTIAL (MW) IN 2009 BY MARKET SECTOR

MARKET TYPE	FACILITY SIZE				
	50–500 kW	500 kW–1 MW	1–5 MW	> 20 MW	TOTAL
Industrial Onsite	966	501	1,403	245	4,157
Commercial Traditional	297	133	124	0.0	568
Commercial Heating & Cooling	2,862	760	1,668	604	6,802
Export Existing	71	110	261	3,530	4,544
Total	**4,197**	**1,504**	**3,456**	**4,379**	**16,071**

Source: ICF International

CHP is best applied at facilities that have significant and concurrent electric and thermal demands. In the industrial sector, CHP thermal output has traditionally been in the form of steam used for process heating and for space heating. For commercial and institutional users, thermal output has traditionally been steam or hot water for space heating and potable hot water heating, and more recently for providing space cooling through the use of absorption chillers.

Two different types of CHP markets were included in the evaluation of technical potential for this assessment. The first is the traditional CHP market where the electrical output meets all or a portion of the baseload needs for a facility and the thermal energy is used to provide steam or hot water. In this market, industrial facilities often have "excess" thermal load compared to their on-site electric load (meaning the CHP system will generate more power than can be used on-site if sized to match the thermal load). In the commercial sector, CHP systems almost always have excess electric load compared to their thermal load, so these facilities will use all power generated on site. In California, interest in the combined cooling, heating, and power market could potentially open up the benefits of CHP to facilities that do not have the year-round heating or hot water loads to support a traditional CHP system. A typical system would provide the annual hot water load, a portion of the space heating load in the winter months, and a portion of the cooling load during the summer months.

The previous two categories are based on the assumption that all of the thermal and electric energy is used on-site. Within large industrial process facilities, there is typically an excess of steam demand that could support CHP with significant quantities of electricity export to the wholesale power system. The export potential was quantified and evaluated as a separate market.

Table 3 shows the total technical potential for CHP in existing facilities in California for 2009. There is more potential in commercial facilities than in industrial facilities, which is

TABLE 4: TOTAL COMBINED HEAT AND POWER TECHNICAL POTENTIAL GROWTH (MW) BETWEEN 2009 AND 2029 BY MARKET SECTOR

MARKET TYPE	FACILITY SIZE				
	50–500 kW	500 kW–1 MW	1–5 MW	>20 MW	TOTAL
Industrial Onsite	132	62	154	64	438
Commercial Traditional	47	15	19	4	85
Commercial Heating & Cooling	622	190	416	181	1,526
Export New Facilities	22	16	39	45	294
Total	**823**	**283**	**628**	**294**	**2,346**

Source: ICF International

a switch from the traditional characterization of CHP target markets. There is also a heavy concentration of potential in the small size ranges, indicating that many large facilities already have CHP systems for their on-site needs, leaving the remaining large size system potential in the export market.

The utility with the largest amount of CHP technical potential is PG&E, with SCE a close second. Since PG&E also has the largest amount of existing CHP installations, the remaining CHP potential indicates that SCE has more room for growth in CHP capacity as a percentage of current CHP installations. The LADWP also has a significant amount of remaining potential given the small size of its service area.

While the 2009 technical potential estimate is based on the facility data in the potential CHP site list, the 2029 estimate includes economic growth projections for target applications between 2009 and 2029 (Table 4). To estimate the development of new facilities and growth in existing facilities between the present and 2029, economic projections for growth by target market applications in California were used.[96] Due to recent economic factors, the outlook on growth rates for several industries are not as strong as they once were, leading to a lower amount of new technical potential additions in the forecast period.

Clearly, California contains significant technical potential for growth in CHP installations. Considering the market for both existing and new commercial and industrial facilities, there is a total technical market potential that

96 These growth projections were derived from data in the Annual Energy Outlook 2009 stimulus case developed by the U.S. Department of Energy's Energy Information Administration. The growth rates were used in this analysis as an estimate of the growth in new facilities or capacity additions at existing facilities. In cases where an economic sector is declining, it was assumed that no new facilities would be added to the technical potential for combined heat and power.

is more than 18,000 MW by 2029. The most significant regions for growth are in PG&E and SCE service territory; however the other utilities in California also have significant room for growth.

Combined Heat and Power Market Potential

To determine the outlook for CHP market penetration in California, several factors were considered in the analysis:

- The relationship of delivered natural gas and electricity prices, or spark spread.
- The cost and performance of the CHP equipment suitable for use at a given facility.
- The electric and thermal load characteristics of commercial, industrial, and institutional facilities in the state.
- Incentive payments to the CHP user that reflect societal or utility benefits of CHP.
- Customer decisions about the economic value that will trigger investment in CHP or the willingness to consider CHP.

All of these factors are accounted for in the forecasts of CHP market penetration between 2009 and 2029. A base case to reflect current market conditions and policies was developed first, followed by four alternative cases that include CHP stimulus measures including restoration of the Self-Generation Incentive Program, implementation of payments to CHP operators for CO_2 emissions reductions compared to separately purchased fuel and power, addition of an effective economic mechanism for the export power from facilities larger than 20 MW, and an "all-in" case that includes all of these measures combined.

Base Case Results

In the 20-year forecast period, the base case market penetration of CHP generating capacity equals 2,731 MW with an additional 267 MW of avoided electric capacity for air conditioning supplied by CHP for a total market impact of 2,998 MW. (With the passage of SB 412 [Kehoe, Chapter 182, Statutes of 2009], an additional 497 MW of combined heat and power was made available for addition to the base case, in accordance with an alternative incentive scenario analyzed for this assessment.)

Figure 10 shows the generating capacity market penetration by CHP system size. In the base case, the largest share of the market penetration will be in sizes below 5 MW. This distributed generation CHP market makes up 65 percent of the total market penetration. The 5- to 20-MW size category makes up 25 percent of the market. Without a mechanism (such as a Qualifying Facility contract) for export of power in the greater than 20-MW size category, these large systems will make up only 10 percent of the new market penetration expected over the next 20 years.

Incentive Cases

The assessment of CHP potential included different incentive scenarios and an all-in incentive case. Following are brief descriptions of the assumptions used for the incentive cases analyzed for this assessment.

CO_2 Payments Case. CHP is a more efficient use of energy than purchasing boiler fuel and electricity separately. The CHP operator does not gain any special benefit from this fact, only from the reduction in operating costs at the site. Benefits of CHP that contribute to State or federal policy goals such as increased efficiency or CO_2 emissions reduction are external to the decisions to build and operate CHP. Providing CHP operators with a payment for reducing overall CO_2 emissions would internalize this benefit into the CHP deployment decision and stimulate the CHP market based on the social value of emissions reduction that is provided. An average value of $50/ton of CO_2 emissions reduction is provided for all CHP electric output and also for avoided electricity generation due to CHP supplied air conditioning as well.

Restore the Self-Generation Incentive Program Eligibility. Senate Bill 412 expands program eligibility to include "distributed energy resources that the [CPUC], in consultation with the State Air Resources Board, determines will achieve reductions of greenhouse gas emissions." This includes CHP facilities that meet specified emissions and efficiency standards. The CPUC will be required to implement the Self-Generation Incentive Program using its own discretion about program details. For this analysis, conducted before SB 412's passage, it was assumed that all payments would be restored as they existed before they were suspended in 2007 and that the current phased expansion of benefits for projects up to 5 MW would be included as well.

Basic Large Export Case. When the AB 1613 feed-in tariffs for new CHP are finalized they will apply only to systems 20 MW or less. In the base case, no mechanism for exporting power from larger facilities (greater than 20 MW) was assumed. In this first of two expanded export scenarios, export of power from large facilities is assumed to be at a contract price reflecting the cost of power generation from a combined cycle power plant using the plant cost and performance assumptions defined in an Energy Commission staff report.[97]

97 California Energy Commission, *Comparative Costs of Central Station Electricity Generation*, draft staff report, August 2009, CEC-200-2009-017-SD, available at: [http://www.energy.ca.gov/2009publications/CEC-200-2009-017/CEC-200-2009-017-SD.PDF].

Strong Stimulus Large Export Case. A second contract price track for large export CHP projects was also evaluated that included an aggressive contract price.

All Incentives Case. The all-in case represents a combination of restoration of the Self-Generation Incentive Program, addition of CO_2 emissions reduction payments of $50/ton, and encouragement of large export projects with the aggressive contract pricing mechanism and accompanying CO_2 payments. The large export market contributes 2,714 MW to this case.

Incentive Case Results

Figure 11 shows the cumulative CHP market penetration for the incentive cases. The figure includes both CHP generation and avoided air conditioning. The range of market penetration from the base case to the all-in case is from 3,000 to 6,500 MW. The case results can be summarized as follows:

- CO_2 payments increase market penetration by 244 MW.
- The restoration of the Self-Generation Incentive Program for the next 10 years increases market penetration by 497 MW.
- Expanding export contracting to facilities larger than 20 MW with a basic contracting mechanism increases market penetration by 1,441 MW. All of this increase in export market penetration is for facilities larger than 20 MW.
- In the all-in case, which includes all measures plus a more aggressive large export contract price, the market increases by 3,521 MW, with 79 percent of this increase in the export market.

FIGURE 10: BASE CASE CUMULATIVE COMBINED HEAT AND POWER MARKET PENETRATION BY SIZE CATEGORY

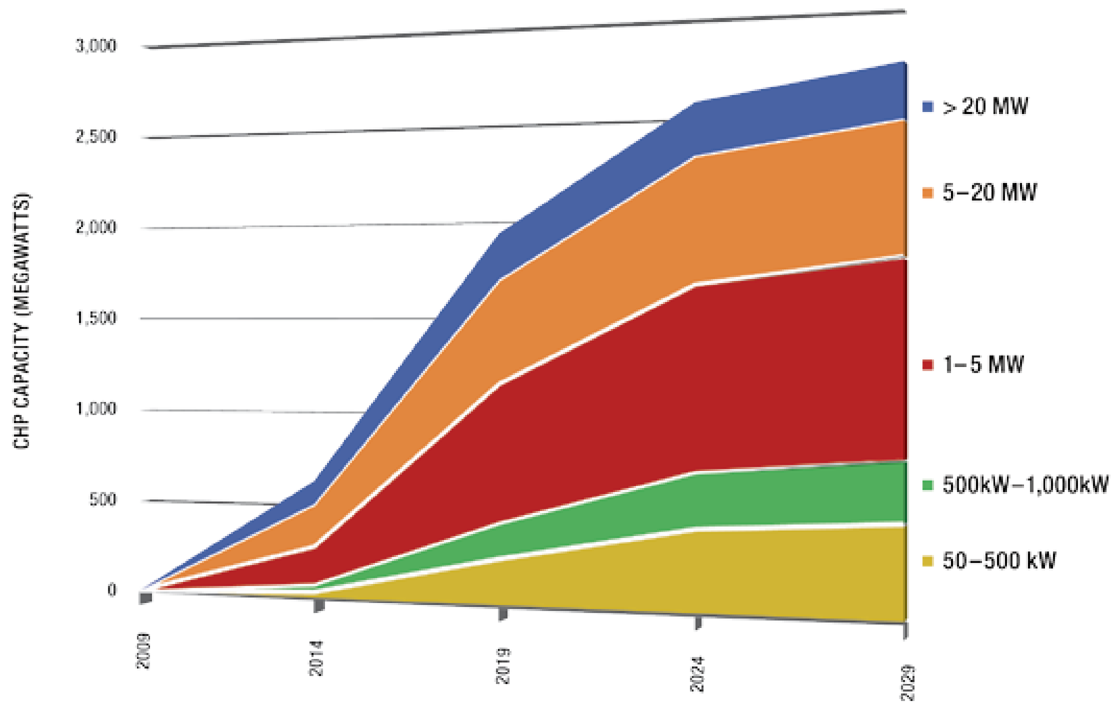
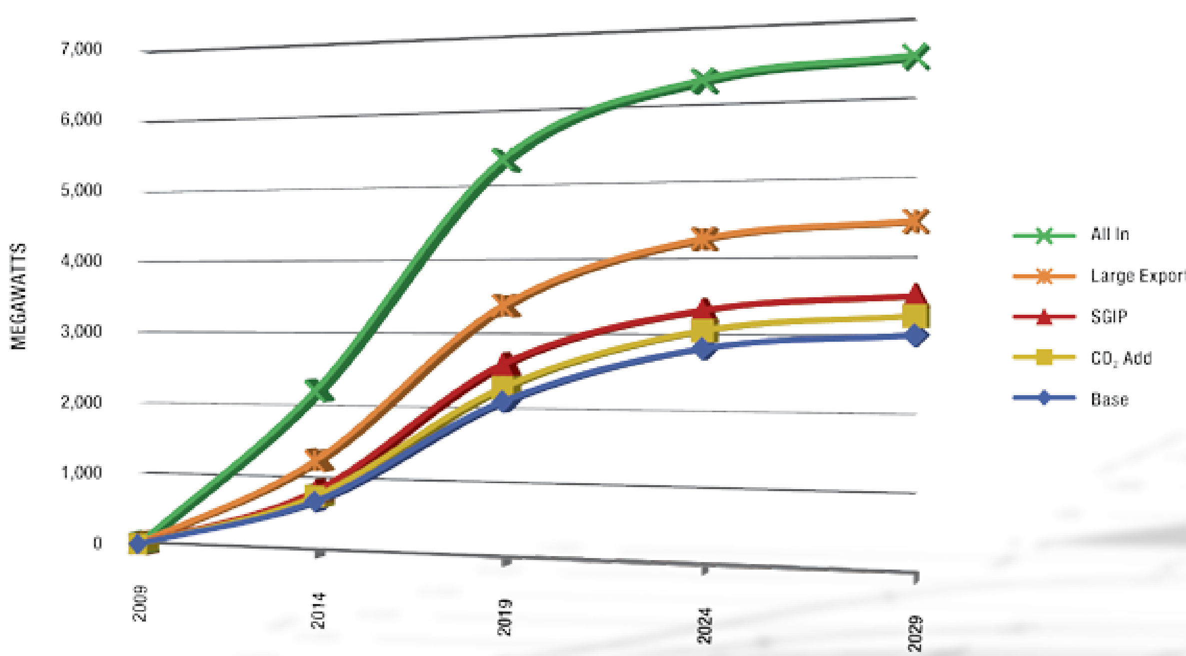
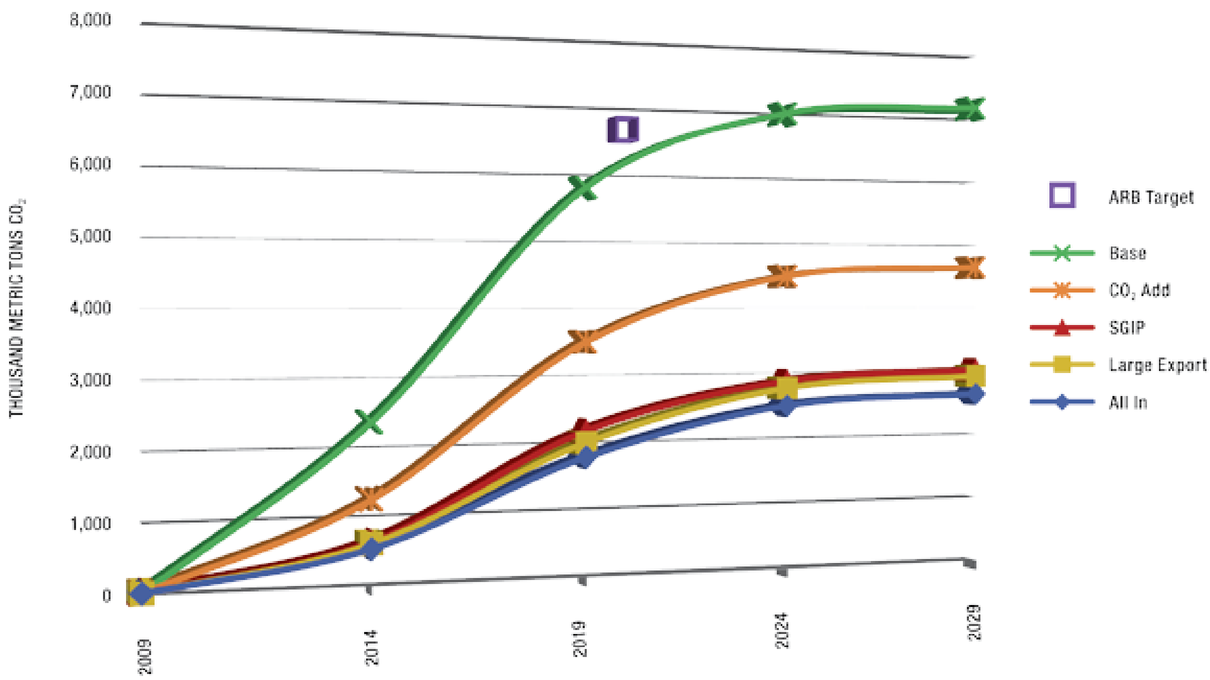


FIGURE 11: INCENTIVE CASES CUMULATIVE MARKET PENETRATION RESULTS



Source for figures: ICF CHP Market Model

FIGURE 12: GREENHOUSE GAS EMISSIONS SAVINGS BY SCENARIO USING AIR RESOURCES BOARD AVOIDED CENTRAL STATION EMISSIONS ESTIMATE



Source: ICF CHP Market Model

TABLE 5: COMPARISON OF STUDY RESULTS GREENHOUSE GAS SAVINGS TO AIR RESOURCES BOARD GOALS

SCENARIO	CAPACITY MW	OUTPUT GWh/YEAR	AVERAGE LOAD FACTOR	AVOIDED CO_2 MMT/YEAR	CO_2 SAVINGS RATE lb/MWh
ARB 2020 Goal	4,000	30,000	85.6%	6.70	492
Base Case 2020	2,240	14,486	73.8%	1.93	294
Base Case 2029	2,998	18,296	69.6%	2.67	322
All In Case 2020	5,532	39,545	81.6%	6.05	337
All In Case 2029	6,549	45,779	80.2%	7.20	347

Source: ARB and ICF International

GHG Emissions Savings

Emissions reductions by scenario were calculated and are shown in Figure 12. Annual GHG savings by the end of the forecast time horizon (2029) range from 2.7 million metric tons carbon dioxide equivalent (CO_2e) emissions to 7.0 million metric tons in the all-in case. The graph also shows the ARB target for CHP of 6.7 million metric tons reduction by 2020.

Table 5 compares the study results with the ARB target of GHG emissions savings from CHP by 2020. In the base case, market penetration by CHP is projected to be 56 percent of the ARB target estimate for additional CHP capacity market penetration, and power generation and avoided air conditioning from CHP is less than half of the ARB estimate. In the all-in case, 2020 market penetration and generation both exceed the ARB targets, and the expected GHG savings reach 90 percent of the target 2020 GHG emissions reduction.

Because both the ARB estimates and this study are based on the ARB assumption for avoided GHG emissions, the differences to the CO_2 savings rates shown in the table – 492 lb/MWh for ARB and 294–347 lb/MWh for this study – are primarily due to changes in the operating profile and performance assumptions for CHP. The differences are as follows:

- ARB assumes an 85 percent load factor for CHP, while the calculated value for the all-in case is 80.2 percent.

- ARB assumes an overall CHP efficiency of 77 percent, while the calculated value for the all-in case is 67.8 percent.

Combined Heat and Power and Reliability

As businesses, government facilities, hospitals, and data centers increasingly depend on sophisticated technologies and computers and information systems to run their operations, it is critical to provide protection from both short and extended power outages resulting from grid failures, natural disaster, terrorist attacks, or other disruptions. Hospitals and data centers in particular are vulnerable should power be interrupted. Reliable power is essential to keep cooling and ventilations system operating, high-tech diagnostic systems working, and electronic patient information available. Encouraging and supporting the development of CHP at hospitals throughout California will assure these essential services continue to operate reliably, even if there is a major disruption of regional power.

Traditionally, on-site diesel generators are used to protect facilities from utility power outages. However, recent events suggest that these generators may not be reliable and able to operate during both short and extended outages. During the August 2003 Northeast blackout, about half of New York City's 58 hospitals experienced failures of their backup diesel generators. Even though periodic testing is required, infrequent use of conventional diesel backup generators increases the potential for failure when they are needed most.

In addition, if there is a prolonged outage, fuel supplies for diesel generators may also be a problem. After Hurricane Katrina, diesel fuel for backup generators could not be resupplied for many reasons including blocked or destroyed roads and contaminated fuel supplies. Because CHP systems operate continuously (or for extended periods every day) and because they operate (typically) on natural gas, CHP systems eliminate many of these issues. During and after Hurricane Katrina, natural gas lines remained pressurized. As a result, natural gas was the only fuel available for several weeks afterwards.[98]

98 Gillette, Stephen F., *CHP Case Studies – Saving Money and Increasing Security*, available at: [http://www.chpcenternw.org/NwChpDocs/Microturbines_Capstone_overview_cases.pdf].

Encouraging and supporting the development of CHP at hospitals and other facilities or institutions that support essential health and safety functions for the state can provide a range of benefits beyond assured reliability. Benefits for hospitals include cost savings, improved patient service, and improved reliability and power quality to ensure expensive and sensitive electronics and equipment are not damaged when voltage fluctuates. From the state's perspective, encouraging the installation of CHP in hospitals and other essential facilities will assure that if electric supplies are interrupted for hours, days, or weeks, as was the case when Hurricane Katrina devastated New Orleans, California citizens will be able to find a "safe haven" at hospitals and other similar institutions in the state that are equipped with CHP systems. A secondary benefit of increased use of CHP at hospitals throughout the state is the retirement of old diesel backup generators and the reduction of emissions associated with their operation.

Combined Heat and Power and the Economy

A facility with constant thermal load, constant electrical load, and hence a uniform "power-to-heat ratio" (or electrical load-to-thermal load ratio), is an ideal CHP prospect. However, many of the remaining CHP prospects have fluctuating loads and variable load profiles. For these facilities, electricity export loosens the operating constraints. A thermally matched CHP system will compete economically and environmentally with the separate production of electricity at a central station plant and the production of steam or heat on site. However, the following barriers limit the economic competitiveness:

- Uncertainty about the differential between the cost of buying electric power from the grid and the cost of natural gas.
- A required payback period of as little as two years and usually no longer than five years. The new assessment of CHP potential indicates that these facts imply a very high risk perception on the part of potential CHP project developers.
- The ability of a CHP system owner to offset only about 80 percent of the electrical retail rate because of standby and demand charges. Tariffs in other states provide higher offsets.
- Current tariffs not fully accounting for the system and societal benefits that CHP provides.
- Additional technical economic and technical design challenges faced by facilities with fluctuating loads.

The variation in CHP market penetration forecasts under various economic assumptions illustrates the effects of those factors on the attractiveness of CHP. An export tariff would mitigate some of the barriers, depending on the tariff's simplicity, a term of at least 10 years, and prices that reflect capacity, energy, environmental values, and locational values. Restoration of the Self-Generation Incentive Program that provides up-front incentive payments to offset some of the capital costs of the CHP system and a CO_2 emission reduction payment for CHP electric output are examples of economic incentives that can on their own or in combination promote CHP in California markets.

Natural Gas Power Plants

Natural gas plays a significant role in providing power to California citizens. In 2008, 46.5 percent of California's electricity came from natural gas. Citizens, community activists, and environmental groups have environmental and safety concerns with building new natural gas plants, but at the same time, Californians want reliable and affordable electricity for their homes and businesses. A balance between these competing objectives can be difficult to achieve, as almost every energy technology has costs and benefits.

Natural Gas Plants and the Environment

Natural gas has become California's fuel of choice for most new power plants because it is cleaner than other fossil fuels. Yet, emissions from natural gas generation account for (on average) 78 percent of the in-state electric GHG emissions.[99] However, natural gas power plants can also play a key role in meeting the state's climate change goals and RPS targets. The Energy Commission's *Framework for Evaluating Greenhouse Gas Implications of Natural Gas-Fired Power Plants in California* report identifies specific roles and expectations for gas-fired generation to support the integration of renewables under the policy mandates to reduce GHG emissions from the electricity sector. The report found that a natural gas plant providing support to integrate renewable energy under a 33 percent RPS will yield a GHG emission benefit if the addition raises the overall efficiency of the electric system, or if the new plant serves increased demand for electricity more efficiently than the existing power plant fleet. The analysis found that although a single natural gas-fired power plant produces GHG emissions, under certain circumstances the addition of a gas-fired plant may yield a systemwide GHG emission benefit.[100]

Marine impacts from once-through cooling (OTC) power plants are another major environmental concern with the state's natural gas and nuclear power plants. As part of an interagency working group, the Energy Commission, CPUC, and California ISO have been working with the State Water Resources Control Board (SWRCB) to outline a proposal to maintain electric grid reliability while reducing OTC in California's 21 coastal power plants. These plants together pump up to 17 billion gallons of ocean, bay, or estuary water each day.[101] The pumping process impinges on fish, invertebrates, and crustaceans, and destroys billions of fish eggs and larvae, and the heated discharge water also harms marine organisms by increasing the water temperature. The draft has issued a compliance schedule for retiring, refitting, or repowering OTC plants to comply with the federal water policy.

It is crucial that the state develop new generating capacity to replace OTC power plants that may retire in the near future. Plants most likely to retire are located in and around the Southern California area, which has some of the worst air quality in the nation. Replacement power sources will have to meet stringent local air quality requirements; however, emission offsets are in short supply

99 MRW & Associates, *Framework for Evaluating Greenhouse Gas Implications of Natural Gas-Fired Power Plants in California*, consultant report, May 2009, CEC-700-2009-009, available at: [http://www.energy.ca.gov/2009publications/CEC-700-2009-009/CEC-700-2009-009.PDF].

100 Ibid.

101 State Water Resources Control Board, *Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling*, March 2008, available at: [http://www.energy.ca.gov/2008publications/SWRCB-1000-2008-001/SWRCB-1000-2008-001.PDF].

in the SCAQMD, constraining the Energy Commission's ability to license new power plants in Southern California. Chapter 3 describes the system integration challenges associated with potential retirement of OTC plants as well as difficulties in providing replacement power due to limits on emission reduction credits.

On October 8, 2008, the Energy Commission adopted an Order Instituting Informational proceeding to solicit comments on how to satisfy its responsibilities under the California Environmental Quality Act (CEQA) related to GHG impacts of proposed new power plants. The Energy Commission's Siting Committee released its *Committee Guidance on Fulfilling California Environmental Quality Act Responsibilities for Greenhouse Gas Impacts in Power Plant Siting Applications* in May 2009, which outlined the power plant siting process during the interim period before the AB 32 regulations take effect. The Siting Committee recommended that the Energy Commission analyze each project according to basic CEQA precepts for determining 1) whether the project has a significant adverse cumulative effect, 2) if so, whether feasible mitigation can be required for the project, and 3) if not, whether the project has overriding benefits that justify licensing the project. The Siting Committee also recommended that the Energy Commission revisit this approach once the ARB's AB 32 regulations are in effect.

As California moves toward reducing GHG emissions associated with electricity generation, it will need innovative strategies to address emissions from fossil power plants that may be required to support system operation or integration of renewable resources. One such strategy is CO_2 capture and storage, also known carbon capture and sequestration (CCS). As part of the *2007 IEPR*, the Energy Commission and the California Department of Conservation developed a report focused on geologic sequestration strategies for the long-term management of carbon dioxide, entitled, *Geologic Carbon Sequestration Strategies for California: Report to the Legislature.*[102]

There have been encouraging technology advancements and investments since publication of the *2007 IEPR*, and technology developers and policy makers examining CCS applications have expanded their view from an initial focus on coal and petroleum coke to natural gas and refinery gas, the predominant fossil fuels used in California power plants and industrial facilities.

In terms of technology improvement, new and improved solvents are being commercially offered or tested that reduce the energy requirements of post-combustion closed loop absorber-stripper CO_2 capture systems. Such improvements are important because the cost of CO_2 capture is usually the most expensive element of CCS, particularly the energy cost associated with steam heating in the stripper reboiler. In addition, the expanding number of commercial developers working on multiple competing processes is indicative of a robust market that is more likely to achieve the necessary technology scale-up sooner and produce future cost-saving advancements. Nonetheless, CCS projects are large capital endeavors and multi-year testing of full-scale, integrated CO_2 capture, compression, pipeline transportation, and geologic injection systems is necessary before widespread commercial application can be expected.

In the last two years, oxy-combustion CO_2 capture components and systems have been tested at ten times the size of previous pilot units, including California's Clean Energy Systems' rocket engine–derived gas generator. Pre-combustion CO_2 capture systems are now

102 California Energy Commission and Department of Conservation, *Geologic Carbon Sequestration Strategies for California: Report to the Legislature*, February 2008, CEC-500-2007-100-CMF, available at: [http://www.energy.ca.gov/2007publications/CEC-500-2007-100/CEC-500-2007-100-CMF.PDF].

being proposed in commercial power plants based on solid fuel gasification, such as the Hydrogen Energy California project in Kern County (a joint venture of BP and Rio Tinto).

The U.S. Department of Energy (DOE) recently solicited proposals for large-scale industrial CCS projects at facilities fueled chiefly by noncoal energy; it is poised to award more than $1.3 billion in project co-funding authorized by the ARRA of 2009. Further, DOE has added funds to its cooperative agreement with the Energy Commission for the West Coast Regional Carbon Sequestration Partnership (WESTCARB; a public-private research collaborative involving more than 80 organizations) to work with PG&E to conduct an engineering-economic evaluation of CCS at natural gas combined cycle plants in California. WESTCARB also continues to work with the California Geological Survey and industry partners to characterize California deep saline formations suitable for commercial-scale CO_2 storage; two CO_2 storage field tests in the Central Valley are planned.

Although the cost of applying CCS to natural gas power plants or oil refinery furnaces is relatively high using proven technologies (about $75 per metric ton of CO_2 avoided),[103] the prospect of energy-saving technology improvements and the sale of captured CO_2 to oilfield operators for oil recovery has increased the likelihood that CCS can be economically competitive and, as a consequence, the interest of state agencies working on AB 32 compliance. Positive public comment was also cited as a contributing factor to increased discussion of CCS and support for near-term technology development in the ARB's *Climate Change Scoping Plan*. This momentum appears to be continuing, with an interagency group formed in August 2009 to develop recommendations on CCS-related policy issues.

103 Ibid.

Addressing policy questions in tandem with technology development and demonstration is particularly important for CCS because institutional barriers have been as much of an impediment as high cost. In many cases, the necessary regulatory and statutory frameworks are unclear or do not yet exist.[104] At the federal level, the U.S. Environmental Protection Agency in 2008 proposed new rules for wells used to inject CO_2 for long-term geologic storage.[105] These rules are expected to become final by early 2011, and further federal rules may be forthcoming restricting emissions of CO_2 as an air pollutant. However, many of the legal and regulatory issues needing resolution are within the domain of state rather than federal law.

In particular, legal clarity is needed on ownership of subsurface "pore space" where CO_2 is stored, the ability to independently transfer pore space rights and the dominance of such rights relative to surface and mineral rights, procedures by which access rights to multiple adjoining pore space "parcels" may be secured for CO_2 storage zones spanning multiple estates, and potential long-term liabilities for stored CO_2. More than 30 states are currently wrestling with these issues, with several states having passed laws that suggest approaches for consideration by the California Legislature.

Regulatory issues needing clarity include procedures by which operations permitted for CO_2-enhanced oil recovery become long-term CO_2 storage projects as well; CEQA responsibility and siting jurisdiction for power plant projects with CO_2 capture, pipeline transportation, and off-site geologic CO_2 storage (similar jurisdictional questions may arise for

104 Ibid.

105 See [http://www.epa.gov/safewater/uic/wells_sequestration.html#regdevelopment].

other industrial project types); responsibility for monitoring, reporting, and remediation (if necessary) when custody of captured CO_2 is transferred from a regulated industrial source to a subsurface storage site operator; and rules for offshore (sub-seabed) CO_2 storage projects. Most of these issues require legislative solutions, although AB 32 rulemaking may provide some guidance. In the case of oilfield CO_2 injection wells, U.S. Environmental Protection Agency (EPA) has requested public input on treatment of their conversion to geologic sequestration wells, as part of the new "Class VI" rulemaking for dedicated geologic sequestration wells (under the underground injection control [UIC] program for groundwater protection). California must decide whether to seek primacy for administration of the UIC program for Class VI geologic sequestration wells, as it does for UIC Class II oil and natural gas exploration and production wells.

Resolution of legal and regulatory uncertainties will be crucial to helping spur CCS investment and further project development, but economic challenges will remain so long as the value of CO_2 emission allowances remains low. Cap-and-trade proposals with "safety valves" and other measures to limit the rate at which allowance prices rise to their expected long-term value could hamper private investment in CCS without some form of policy incentives. Given the expense and lead-time of the full-scale demonstrations needed to establish CCS technology viability, and the social benefit of associated "learning by doing" cost reductions, California should continue state investment in CCS R&D and demonstrations in tandem with investment by DOE and private industry. Public-private partnerships for CCS demonstration are expected to prove vital to realizing future dividends in terms of more cost-effective commercial application and an overall reduction in the cost of meeting the state's long-term GHG reduction goals.

Natural Gas Plants and Reliability

As the California's population continues to grow, the state will have to ensure that enough new power plants are built to meet the increase in energy demand. At the same time, state policy goals to increase the use of preferred resources, like renewables, along with policies to reduce the use of OTC and to retire aging power plants, will affect system reliability. The impacts of various state policies on reliability are discussed in more detail in Chapter 3.

The Energy Commission's, *Framework for Evaluating Greenhouse Gas Implications of Natural Gas-Fired Power Plants in California* found that as California's integrated electricity system evolves to meet GHG emissions reduction targets, the operational characteristics associated with increasing renewable generation will increase the need for flexible generation to maintain grid reliability. The report asserts that natural gas-fired power plants are generally well-suited for this role and that California cannot simply replace all natural-gas fired power plants with renewable energy without endangering the safety and reliability of the electric system. The report acknowledges that California will need to modernize its natural gas generating fleet to reduce environmental impacts, however. Overall, the report found that the future of natural gas plants will likely fill five auxiliary roles: 1) intermittent generation support, 2) local capacity requirements, 3) grid operations support, 4) extreme load and system emergencies support, and 5) general energy support. The question remains as to the quantity, type, and location of natural gas-fired generation to fill remaining electricity needs once preferred resource targets are achieved.

Given the role of natural gas power plants for electricity reliability and integrating renewable energy, efforts to mitigate OTC include a compliance schedule that maintains electric grid reliability and stability while reducing OTC in California's existing coastal power plants. It is likely that plant operators will choose retirement in the face of costly retrofits or repowering. If replacement resources are not built, this could greatly impact electricity reliability for the citizens of California. The compliance schedule focuses only on natural gas plants using OTC, as nuclear plants will require special studies.

Replacement of OTC plants is complicated by the current emission credit limitations in the South Coast Air Basin, as discussed earlier in this section. These limitations are causing delay in environmental improvements that accompany investments in new and updated infrastructure. Fortunately, because SWRCB has agreed to delay its original compliance schedule, in part due to these air credit issues, these delays are not jeopardizing the long-term reliability of the region's electricity supplies. These issues related to emissions credits in the South Coast Air Basin are discussed further in Chapter 3.

Nuclear Power Plants

Major policy decisions that will be made in the coming years will shape the next three decades of nuclear energy policy in California. Nuclear plant owners and state officials will face decisions about plant license renewal and OTC at the same time that the federal government is reassessing its approach to nuclear waste disposal. In addition, California is addressing critical environmental issues associated with the electricity sector. The costs and benefits of nuclear power are being reexamined in California and nationwide because of major shifts in policies to limit GHG emissions and encourage new nonfossil-fueled electric generation sources.

Nuclear power plants play a significant role in California's energy mix, providing about 14 percent of the state's total electricity in 2008 from two operating in-state facilities, PG&E's Diablo Canyon Power Plant (Diablo Canyon) and SCE's San Onofre Nuclear Generating Station (SONGS), and from the Palo Verde Nuclear Generating Station in Arizona. As part of the *2008 IEPR Update*, the Energy Commission developed *An Assessment of California's Nuclear Power Plants: AB 1632 Report,*[106] which addressed seismic and plant aging vulnerabilities of California's in-state nuclear plants, including reliability concerns. In addition, the report identified a number of other issues important for the state's nuclear policy and electricity planning. These include:

- Continuing Nuclear Regulatory Commission (NRC) concerns over safety culture, plant performance, and management issues at SONGS.
- The evolving federal policy on long-term waste disposal.
- Costs and benefits of nuclear power compared to other resources.
- Potential conversion from once-through cooling to closed-cycle wet cooling.

An overarching issue with the state's nuclear facilities is plant license renewal. The NRC operating licenses for California's nuclear plants are set to expire in 2022 (SONGS Units 2 and 3) and 2024 and 2025 (Diablo Canyon Units 1 and 2, respectively).[107] It is unknown whether the NRC will approve applications by PG&E and SCE for 20-year license renewals,

106 California Energy Commission, *An Assessment of California's Nuclear Power Plants: AB 1632 Report*, October 2008, CEC-100-2008-009-CMF, available at: [http://www.energy.ca.gov/2008publications/CEC-100-2008-009/CEC-100-2008-009-CMF.PDF].

107 Nuclear Regulatory Commission, Facility Information Finder, see [http://www.nrc.gov/info-finder.html].

Reactor Vessel Integrity

The NRC recently revised its regulations to provide licensees with a new alternative for assessing the probability of a crack forming through the wall of a reactor pressure vessel. If such a crack occurred, it could damage the reactor core and, in rare cases, release radioactive materials into the environment. The probability of crack formation relates directly to the extent of reactor pressure vessel embrittlement, which determines the ability of metals that make up the reactor pressure vessel to withstand stress without cracking.

The old regulations required licensees to demonstrate that reactor pressure vessel embrittlement would not exceed a screening limit corresponding to a one-in-200,000-year probability of through-wall crack formation. While NRC's recently adopted regulations expand this requirement to a one-in-a-million-year probability, they also allow for the use of a less-conservative method for assessing the probability. With the old methodology, Diablo Canyon Unit 1 and nine other reactors would have exceeded the screening limit during a 20-year license extension and would not be eligible for license renewal unless they could reduce the embrittlement rate or demonstrate that operating the reactor would not pose an undue public risk. In contrast, the new method results in a much lower calculated embrittlement for most reactors, and is no longer expected to limit any U.S. reactor from obtaining a 20-year license renewal (NUREG-1806, p. xxii and Appendix D).

but the NRC has yet to deny a single application and has issued license renewals for 54 of the nation's 104 nuclear power reactors. SCE plans to file a SONGS license renewal application in late 2012. PG&E announced on November 24, 2009 its intention to file the Diablo Canyon application.

The NRC license renewal application process determines whether a plant meets the NRC renewal criteria, not whether it should continue to operate. The NRC states, "Although a licensee must have a renewed license to operate a plant beyond the term of the existing operating license, the possession of that license is just one of a number of conditions that must be met for the licensee to continue plant operation during the term of the renewed license. State regulatory agencies and the owners of the plant would ultimately decide whether the plant will continue to operate based on factors such as need for power or other matters within the State's jurisdiction or the purview of the owners … the NRC has no role in the energy planning decisions of State regulators and utility officials as to whether a particular nuclear power plant should continue to operate."[108]

The NRC license renewal proceeding focuses on plant aging issues, such as metal fatigue or the degradation of plant components, as well as environmental impacts related to an additional 20 years of plant operation. The NRC has consistently excluded from its proceedings issues raised by states and public interest groups that are not directly related to plant aging or to deficiencies in the environmental impact assessment. For example, during the license renewal proceeding for the Indian Point Power Plant in New York, the NRC dismissed from the proceeding most of the State of New York's contentions, including those regarding seismic vulnerability, plant vulnerability to terrorist attack, and the inadequacy of emergency evacuation plans for the plant.

Although the CPUC does not approve or disapprove license applications filed with the NRC, both utilities must obtain CPUC approval to pursue license renewal before receiving California ratepayer funding to cover the costs of the NRC license renewal process.[109] The CPUC proceedings will determine whether it is in the best interest of ratepayers for the nuclear plants to continue operating for an additional 20 years. The proceedings will address issues that are important for electricity planning but are not included in the NRC's license renewal application review.

The purpose of the CPUC license renewal review is to consider matters within the state's jurisdiction, including the economic, reliability, and environmental implications of relicensing.[110] For example, the CPUC will consider the cost-effectiveness of license renewal compared with and replacement power options.

To initiate the CPUC license renewal review, PG&E and SCE are required to submit license renewal feasibility assessments to the CPUC. For example, the CPUC required PG&E to submit an application by June 30, 2011, on whether renewing Diablo Canyon's operating licenses is cost-effective and in the best interest of PG&E's ratepayers.[111] In letters to SCE

108 Nuclear Regulatory Commission, Generic Environmental Impact Statement, NUREG-1437, Vol I, see [http://www.nrc.gov/reading-rm/doc-collections/nuregs/staff/sr1437/v1/part01.html#_1_12].

109 California Public Utilities Commission, D.07-03-044 in proceeding A.05-12-002, March 15, 2007.

110 The State Water Resources Control Board and the California Coastal Commission would also have the opportunity to review impacts to California from license renewal within the context of their permitting authority and proceedings.

111 Pacific Gas and Electric is required to submit its application by June 30, 2011. Southern California Edison has not been given a deadline. CPUC decision D.07-03-044.

and PG&E in June 2009, the CPUC emphasized that the utilities must address in their feasibility assessments all the issues raised in the *AB 1632 Report*.[112] The CPUC specifically directed the utilities to undertake the following activities:

- Report on the findings from updated seismic and tsunami hazard studies and assess the long-term seismic vulnerability and reliability of the plants.

- Summarize the implications for Diablo Canyon and SONGS of lessons learned from the response of the Kashiwazaki-Kariwa nuclear plant to the 2007 earthquake.

- Reassess whether access roads surrounding the plants are adequate for emergency response and evacuation following a major seismic event.

- Study the local economic impact of shutting down the plants as compared to alternative uses for the plant sites.

- Report on plans and costs for storing and disposing of low-level waste and spent fuel through 20-year license extensions and plant decommissioning.

- Quantify the reliability, economic, and environmental impacts of replacement power options.

- Report on efforts to improve the safety culture at SONGS and on the NRC's evaluation of these efforts and the plant's overall performance (SCE only).

112 Letter from CPUC to Alan Fohrer, CEO of Southern California Edison, June 25, 2009; Letter from CPUC to Peter Darbee, CEO of Pacific Gas and Electric, June 25, 2009.

The comprehensiveness, completeness, and timeliness of these activities will be critical to the CPUC's ability to assess whether or not the utilities should apply to the NRC for license renewals. However, the utilities' reports to date indicate they are not on schedule to complete these activities in time for CPUC consideration. In addition, PG&E has objected to providing the seismic studies to the CPUC as part of a license renewal review.

In October 2008, PG&E commented to the Energy Commission on the draft *AB 1632 Report* that it does not interpret the requirement to submit a license renewal feasibility study to the CPUC as including seismic safety, which it considers to be "outside the scope of license renewal," or those issues "that are not within the CPUC's jurisdiction."[113] PG&E also articulated its belief that the plan for the Energy Commission and the CPUC to review the costs and benefits of license renewal and to assess whether or not the utilities should pursue license renewal "improperly infringes upon the sole jurisdiction of the NRC to determine whether or not nuclear license should be extended."[114] PG&E reiterated this point in a letter to the CPUC, specifying that it would provide the information requested in the *AB 1632 Report*, subject to the CPUC's jurisdiction. In its letter to PG&E, the CPUC indicated that the requested information is all subject to CPUC jurisdiction since it informs procurement planning.[115]

113 Pacific Gas and Electric Company comments on California Energy Commission final Commission report, *An Assessment of California's Nuclear Power Plants: AB 1632 Report*, October 2008, p. 1, available at: [http://www.energy.ca.gov/2008publications/CEC-100-2008-009/CEC-100-2008-009-CMF.PDF].

114 Pacific Gas and Electric Company, October 22, 2008, p. 4.

115 Letter from California Public Utilities Commission to Peter Darbee (Pacific Gas and Electric Company), June 25, 2009.

PG&E continues to object to a CPUC review of Diablo Canyon seismic studies as part of a license renewal review, and its current schedule would in fact not allow time for this review.[116] PG&E is required to submit its license renewal feasibility assessment to the CPUC by June 30, 2011,[117] but does not expect to complete updates to the seismic hazard model and the seismic vulnerability assessment until 2012 and 2013, respectively.[118] Furthermore, PG&E said that it will require ratepayer funding to undertake the 3-D seismic mapping surveys recommended in AB 1632 and that it may use the CPUC license renewal review proceeding as an opportunity to request this funding. If this occurs, the results of these studies will likely not be available for CPUC consideration during this proceeding.

A similar issue arises with SCE. The utility plans to submit an application to the CPUC in late 2010 to pursue an NRC license renewal application and to address issues from the *AB 1632 Report* and the CPUC.[119] However, SCE anticipates also using this application to request funding to complete AB 1632-recommended studies. Furthermore, SCE anticipates filing its CPUC application in the third quarter of 2010, but does not anticipate completing many of its studies until the end of 2010. As a result, SCE acknowledges that the application likely will not include results from all of the AB 1632 studies.[120] However, SCE believes it will be able to provide sufficient information for the CPUC to reach an informed decision, with some studies included in its application and others provided as they are completed.[121]

Nuclear Plants and the Environment

While nuclear power generates lower GHG emissions than power fueled by natural gas and other fossil fuels, it is not expected to contribute significantly to the state's near-term GHG emissions goals given the significant financial risk and expense of building a new nuclear power plant, the regulatory hurdles associated with licensing a new plant, and the environmental issues associated with this technology. These issues include nuclear waste disposal, leakage of radioactively contaminated water, and OTC impacts on aquatic environments, as well as potential severe consequences from acts of terrorism, nature (earthquakes, tsunamis), or accidents. In addition, the nuclear power life cycle or "cradle-to-grave" impacts result in GHG emissions from uranium mining and enrichment; plant construction; decommissioning; and waste storage, transport, and disposal.

Even more so than with natural gas plants, citizens tend to be vocal about potential negative impacts of nuclear facilities operating near

116 Written comments by Pacific Gas and Electric Company on the *2009 Draft IEPR*, October 29, 2009, pp. 16–18, see [http://www.energy.ca.gov/2009_energypolicy/documents/2009-10-14_workshop/comments/PGE_Comments_on_the_2009%20IEPR_Draft%20Committee_Report_2009-10-29_TN-53877.pdf].

117 California Public Utilities Commission decision D.07-03-044.

118 Pacific Gas and Electric data request responses F.01 and F.03.

119 Letter from Alan Fohrer (Southern California Edison) to CPUC, August 4, 2009.

120 Southern California Edison data request response L.01.

121 Written comments by Southern California Edison on the *2009 Draft IEPR*, October 30, 2009, p. 15, [http://www.energy.ca.gov/2009_energypolicy/documents/2009-10-14_workshop/comments/Southern_California_Edison_TN-53916.PDF].

their communities. Concerns include the disposal of radioactive waste, plant safety, and the use of ocean water for power plant cooling.

Nuclear Waste Issues

After decades of federal efforts to establish a permanent geologic repository for spent nuclear fuel and high-level waste at Yucca Mountain, Nevada, development of the Yucca Mountain Repository Program will be suspended in 2010. The program has long been challenged by scientific and technical uncertainty about its suitability for isolating the wastes from the environment and has faced staunch political and legal opposition.[122]

The federal energy and water appropriations bill for fiscal year 2010, signed into law in October 2009, eliminated all funding for development of Yucca Mountain, including further land acquisition, transportation development, and site engineering.[123] This budget cut, initiated by the President's budget proposal, demonstrates the Obama Administration's belief that the Yucca Mountain repository is not a workable solution to the problem of nuclear waste disposal.[124] This represents a major shift in U.S. nuclear waste policy.[125]

Halting development of Yucca Mountain means that the federal government has no clear policy in place for the long-term disposal of nuclear waste. Possible options include long-term dry cask storage at reactor sites or at a few centralized storage facilities, and/or the development of commercial reprocessing.

The federal appropriations bill sets aside $5 million to establish a Blue-Ribbon Commission of experts to investigate such alternative solutions and make recommendations to the Administration. It is not clear how the Commission will be chosen.[126]

The uncertainty surrounding U.S. nuclear waste disposal policy means that nuclear reactor operators, including PG&E and SCE, can no longer count on transferring spent fuel to a federal nuclear waste repository in the near or medium-term future. As a result, the utilities must continue to store spent nuclear fuel at the reactor sites. For California, this means that the 6,700 assemblies of spent fuel (2,600 metric tons of uranium) currently being stored at operating and decommissioned nuclear

122 For an overview of the scientific concerns with Yucca Mountain, see the interview with Dr. Allison Macfarlane in David Talbot's "Life after Yucca Mountain," *Technology Review*, MIT, July/August 2009. For a longer discussion of the scientific and technical concerns and the legal and political challenges surrounding Yucca Mountain, see California Energy Commission's *Nuclear Power in California: 2007 Status Report*, October 2007, CEC-100-2007-005-F.

123 Terminations, Reductions, and Savings: Budget of the U.S. Government, Fiscal Year 2010, Office of Management and Budget, available at: [http://www.whitehouse.gov/omb/budget/fy2010/assets/trs.pdf], p.68, and Energy and Water Development and Related Agencies Appropriations Act, 2010, signed as Public Law 111-85 on October 28, 2009.

124 Appendix: Budget of the U.S. Government, Fiscal Year 2010. Office of Management and Budget, p. 432, available at: [http://www.whitehouse.gov/omb/budget/fy2010/assets/appendix.pdf].

125 Although funding to continue development of Yucca Mountain may be eliminated, the federal government is still legally obligated to develop a permanent nuclear waste depository at Yucca Mountain pursuant to a 1987 amendment to the Nuclear Waste Policy Act that explicitly targets Yucca Mountain as the exclusive site for a nuclear waste repository. Congress would have to pass an amendment to the Nuclear Waste Policy Act before an alternate site could be developed as a permanent repository.

126 H.R. 3183 and S. 1436.

plants in-state will remain at these sites for the foreseeable future.[127]

PG&E and SCE have built intermediate-term waste storage facilities at their plants, known as independent spent fuel storage installations (ISFSIs). The ISFSIs at Diablo Canyon and SONGS are currently licensed for 20 years, but they may be eligible for multiple license extensions.[128] The NRC allows spent fuel to be stored at reactor sites in above-ground storage for 100 years and is considering extending that limit by 20 years. PG&E and SCE report enough storage space at their respective nuclear plant sites for all spent fuel generated through the plants' current licenses.

The utilities have not reported plans to pursue the Energy Commission recommendation to modify their spent fuel pools' racking to a less dense orientation.[129] However, the density of the spent fuel pools should decrease as the utilities move assemblies into dry cask storage. Thus far, PG&E has transferred 96 spent fuel assemblies to the Diablo Canyon ISFSI, and SCE has transferred 827 spent fuel assemblies to the SONGS ISFSI.

With the federal nuclear waste program in limbo, at-reactor storage continues to be the de-facto federal spent fuel storage policy. If Yucca Mountain is permanently abandoned, a federal permanent geologic repository or centralized dry cask storage facility likely will not be available for decades. Consequently, even if the plants' operating licenses are not renewed, it is likely that spent fuel will remain at the reactor sites for an extended period. As discussed in the *AB 1632 Report*, on-site ISFSIs would not necessarily restrict the decommissioning of the rest of the site and its conversion to other uses.

In addition to spent fuel, the nuclear plants generate low-level radioactive waste that must be disposed of at special facilities. In the past, the utilities shipped their low-level waste to several disposal facilities, but there is currently just one facility that will accept low-level waste from California reactors, and it accepts only the least radioactive grade of waste. As a result, PG&E and SCE are also storing more highly radioactive classes of low-level waste at the reactor sites. Each plant generates around 150 cubic feet per year of this waste from regular operations.[130]

Once-Through Cooling

As discussed in the section on natural gas power plants, the SWRCB released a draft policy in June 2009 on the use of coastal waters for power plant cooling.[131] The SWRCB and the California EPA have found that SONGS' cooling system is responsible for about one-third of all OTC-related impingement mortality and entrainment losses along the California coast.[132] The proposed policy calls for coastal power plants to cut water intake by 95 percent to reduce the harmful impacts on marine life. To meet these requirements, the nuclear plants would need retrofitting for closed-

127 Utility responses to California Energy Commission data requests, 2007 and 2009.

128 San Luis Obispo Mothers for Peace is challenging Diablo Canyon's Independent Spent Fuel Storage Installation license before the Ninth Circuit Court of the U.S. Court of Appeals.

129 Pacific Gas and Electric and Southern California Edison data request responses, C.15.

130 Utility responses to California Energy Commission data requests, 2009.

131 See [http://www.swrcb.ca.gov/water_issues/programs/npdes/cwa316.shtml].

132 State Water Resources Control Board and California Environmental Protection Agency, *Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling: Draft Substitute Environmental Document,* July 2009, p. 47, available at: [http://www.swrcb.ca.gov/water_issues /programs/npdes/docs/cwa316/draft_sed.pdf].

cycle wet, dry cooling towers, or other cooling means. Previous studies have found that for California's nuclear plants, these options would be very expensive and possibly infeasible from an engineering perspective.[133] The Energy commission expects to review and comment on the studies required in the draft OTC policy regarding compliance implications and compliance alternatives for the two nuclear facilities.

If the SWRCB's policy is approved, the agency will direct PG&E and SCE to commission independent studies to assess the costs of alternative options for SONGS and Diablo Canyon to meet the requirements of the SWRCB's policy. These studies would be completed within three years of the effective date of the policy. The Energy Commission believes that these studies should also be included in the cost-benefit assessment of the plants' license renewal feasibility studies.

Climate Change Impacts

One final environmental issue is the potential impact of climate change on the nuclear facilities. The Energy Commission staff report, *Potential Impacts of Climate Change on California's Energy Infrastructure and Identification of Adaptation Measures*, discussed potential impacts of climate change on power plant infrastructure. Power plants located along the coast could be impacted by coastal erosion, sea level rise, and storm conditions. For example, Diablo Canyon pumps cooling water through an intake pipe that takes the full brunt of northern swells from Pacific storms. To avoid shutting down or tripping the units, the facility has had to curtail power twice per storm season (on average) because of debris buildup on the intake screens. The shutdowns can last anywhere from 18 hours to several days.

Nuclear Plants and Reliability

An issue of critical importance to the state for reliability planning is the possibility of a nuclear plant shutdown or even an extended outage, such as the multi-year outage at the Kashiwazaki-Kariwa plant in Japan following a major earthquake. The *AB 1632 Report* found that, given the current transmission system, a prolonged shutdown of SONGS could result in serious grid reliability shortfalls, whereas a prolonged shutdown of Diablo Canyon would generally not pose reliability concerns.[134] However, the *AB 1632 Report* also found that further reliability assessments are needed to fully understand the reliability implications of extended outages at the nuclear plants.

In a supporting document appended to the SWRCB's draft ocean cooling policy, the Energy Commission, CPUC, and California ISO noted the difficulties faced by regulators in evaluating the electric system reliability impacts of shutting down either SONGS or Diablo Canyon. Further studies are needed to understand what new generators, transmission lines, and/or demand response initiatives would be needed to prepare for the eventual shutdowns of the nuclear plants or to plan for possible extended outages while maintaining grid stability and local reliability. The need for and cost of these alternate resources should be considered in the cost-benefit assessment of the plants' license renewal feasibility studies and should also be considered in the context of CPUC and California ISO reliability planning. Given the long time frame required for permitting and building new generation and transmission resources, these studies should be completed soon.

133 California Energy Commission, *An Assessment of California's Nuclear Power Plants: AB 1632 Report*, pp. 297–300, available at: [http://www.energy.ca.gov/2008publications/CEC-100-2008-009/CEC-100-2008-009-CMF.PDF].

134 Ibid., pp. 23–24.

Seismic Issues

Diablo Canyon and SONGS are located along California's seismically active coastline. The plants were designed to withstand large earthquakes without release of radiation or major damage; however, scientific understanding of the coastal fault zones has improved over the decades since the plants were designed, with a new fault discovered offshore of Diablo Canyon just last year. Plant components that do not serve a safety function were designed for less stringent seismic standards than the core of the nuclear plants. A large earthquake could cause enough damage to these components to necessitate extended plant shutdowns – five of the seven reactors at the Kashiwazaki-Kariwa plant in Japan remain shut down more than two years after being damaged by an earthquake.[135]

An extended plant shutdown would have economic, environmental, and reliability implications for ratepayers.[136] The CPUC will therefore consider the risk of an extended outage as part of its license renewal cost-benefit assessment. To support this assessment, the *AB 1632 Report* recommended that utilities update the nuclear plants' seismic assessments, including assessments of the earthquake and tsunami hazards at the plants, the vulnerability of nonsafety related parts of the plants, and the time needed to repair the plants following an earthquake. It is crucial that the utilities complete these studies and submit them as part of the CPUC's license renewal review.

In July 2009, the utilities reported to the Energy Commission that they intend to complete these assessments. However, both utilities reported plans to use a probabilistic approach to their seismic hazard assessments rather than the deterministic approach recommended by the *AB 1632 Report*, and SCE did not commit to using some of the advanced mapping and survey techniques that were recommended.[137] Furthermore, SCE's tight schedule for completing the studies raises questions about how comprehensive its seismic assessment will be. As described above, the utilities do not intend to complete all the studies in time for submittal to the CPUC with their license renewal feasibility studies.

PG&E has begun to update the Diablo Canyon seismic hazard and vulnerability assessments and expects these assessments to be completed in 2013.[138] PG&E is using a number of advanced techniques to identify and better characterize fault zones near Diablo Canyon, including multi-beam bathymetry, high-resolution marine magnetics, and aeromagnetic surveys, and is purchasing industry seismic data in the vicinity of the plant.[139] PG&E is also sponsoring research on numerical simulations of near fault ground motions to improve ground motion models.[140] In addition, PG&E is planning to request ratepayer funding to undertake the three-dimensional geophysical seismic reflection mapping surveys recommended in the *AB 1632 Report*.[141] PG&E will not include the United

135 World Nuclear Association, Nuclear Power Plants and Earthquakes, available at: [http://www.world-nuclear.org/info/inf18.html].

136 World Nuclear Association. Findings show the shutdown of the 8,000-MW Kashiwazaki-Kariwa plant cost the plant owner an estimated $5.6 billion in inspections, repairs, and replacement power during the first eight months of outage.

137 Pacific Gas and Electric data request response F.09; Southern California Edison data request response F.01.

138 Pacific Gas and Electric expects to complete the tsunami assessment by December 2009, the seismic reliability studies on nonsafety related plant components by April 2010, the seismic hazard assessment in early 2011, and the seismic vulnerability assessment in 2013. The data request responses F.03, F.09, F.12, F.13.

139 Pacific Gas and Electric data request response F.07.

140 Pacific Gas and Electric data request response F.02.

141 Pacific Gas and Electric data request response L.02.

States Geological Survey National Hazard Mapping Project models in its studies because the models do not include detailed information pertinent to the Diablo Canyon area. Instead, PG&E believes that information developed in its own studies will inform the USGS databases.[142]

PG&E has already completed initial assessments of two specific seismic hazards in the area of Diablo Canyon, concluding that seismic activity that could be generated by the newly discovered Shoreline Fault is within the design margins of Diablo Canyon. The NRC's preliminary assessment concurs with this conclusion.[143] PG&E is conducting additional geophysical studies and will provide a final report in December 2010.[144] PG&E has similarly concluded that new estimates of the near fault ground motions from large strike-slip earthquakes, including directivity and maximum component effects, reveal a lower hazard than previously thought and therefore do not represent an increased hazard to Diablo Canyon.[145]

Research indicates that SONGS could experience larger and more frequent earthquakes than was anticipated in the original plant design and that additional research is needed to characterize the seismic hazard at the site. The *AB 1632 Report* recommended that SCE develop an active seismic research program for SONGS, similar to PG&E's Long-Term Seismic Program, to assess whether the plant has sufficient design margins to avoid major power disruptions.

As of July 2009, SCE had not begun its updates to the SONGS seismic hazard and vulnerability assessments. Yet, the utility states that it expects to complete these by the end of 2010.[146] The studies are to include seismic source characterization, review of GPS data, probabilistic seismic hazard analysis modeling, review of earthquake recurrence relationships, ground motion updates for current attenuation relationships, review of new tsunami data from the University of Southern California and the National Oceanic and Atmospheric Administration, and an assessment of the reliability implications of the plant's non-safety related components.[147]

It is not clear whether SCE can complete all of these studies in a comprehensive manner by the end of 2010. Indeed, the utility has not committed to using three-dimensional geophysical seismic reflection mapping and other advanced techniques as part of these studies or to installing a permanent GPS array. Instead, SCE committed only to evaluating the costs and benefits of these techniques,[148] an evaluation the Energy Commission has determined should be conducted by state agencies, not the utilities.[149] It remains to be clarified whether SCE plans to collect any new data on the seismic hazards in the SONGS region or whether it is planning simply to review currently available data.SCE established a Seismic Advisory Board to guide and review

142 Pacific Gas and Electric data request response F.10.

143 Nuclear Regulatory Commission. "Preliminary Deterministic Analysis of Seismic Hazard at Diablo Canyon Nuclear Power Plant from Newly Identified 'Shoreline Fault'." Research Information Letter 09-001. April 8, 2009.

144 Pacific Gas and Electric data request responses F.01, F.06.

145 Pacific Gas and Electric data request response F.02.

146 Southern California Edison data request responses F.01, F.13-F.15.

147 Southern California Edison data request responses F.01, F.12.

148 Southern California Edison data request responses F.07, F.11.

149 California Energy Commission, *An Assessment of California's Nuclear Power Plants: AB 1632 Report*, p. 9, available at: [http://www.energy.ca.gov/2008publications/CEC-100-2008-009/CEC-100-2008-009-CMF.PDF]

the SONGS seismic studies.[150] SCE plans for the board to periodically review the seismic hazard at SONGS and to determine the need for new research and investigations into the plant's seismic setting. As currently structured, the board includes geologists from PG&E and private consultants in geology, seismology, and structural engineering who are familiar with the SONGS plant from previous work for SCE.[151] It includes just one expert not previously employed by SCE or currently employed by PG&E. This is unfortunate since a more independent advisory board would likely contribute to stronger studies.

Nuclear Plant Safety Culture

The state is concerned with a number of other issues that may affect the decision on whether the utilities should pursue plant relicensing. These include the reliability implications of lapses in the safety culture at SONGS and plans for emergency evacuations from both plants.

In 2007, the NRC identified a number of concerns about the safety culture at SONGS, particularly with respect to human performance and problem identification and resolution. Since then, SCE's management put a new leadership team in place at SONGS and instituted a series of safety reforms and monitoring programs.[152] For example, SCE implemented safety improvement plans and conducted extensive evaluations to identify the root causes of safety lapses. The utility also instituted weekly monitoring of core performance indicators, established weekly site-wide meetings on human performance and safety issues, set up a system for employees to voice their concerns regarding safety issues, and conducted a safety culture assessment.

The NRC recently concluded that these improvements were not adequate in addressing the overall safety culture at SONGS. The NRC was particularly concerned that it had identified problems in the areas of human performance and problem identification and resolution over the course of four consecutive assessments, including its most recent assessment in September 2009.[153] During the September 2009 assessment, the NRC also identified an additional safety-related issue of "failing to use conservative assumptions" in decision-making.[154]

As a result of these safety culture failures, the NRC intends to maintain the additional oversight that it initially imposed over SONGS in December 2008. At that time, the NRC discovered that a battery used to power a backup generator at the plant had been inoperable since 2004. Although the NRC ranked this as a finding of low to moderate safety significance, the agency noted that the persistence of the problem for four years pointed to inadequate maintenance procedures for the plant overall. The NRC also expressed dissatisfaction that SONGS' self-evaluations had not identified seven other problems at the plant.[155]

In light of these performance lapses, Senator Barbara Boxer and California State Senator Christine Kehoe wrote to the NRC expressing concern about SCE's fall 2009 steam generator replacement project. The NRC responded

150 Southern California Edison data request response F.05, September 18, 2009.

151 Ibid.

152 Southern California Edison data request response, M.09.

153 Nuclear Regulatory Commission, Mid-cycle Performance Review and Inspection Plan – San Onofre Nuclear Generating Station, September 1, 2009, p. 1, available at: [http://www.nrc.gov/NRR/OVERSIGHT/ASSESS/LETTERS/sano_2009q2.pdf].

154 Ibid, p. 2.

155 Nuclear Regulatory Commission, Office of Public Affairs, "NRC to Provide Additional Oversight to San Onofre Nuclear Generating Station," December 22, 2008.

by expressing confidence in SCE's ability to complete the project safely without any additional restrictions or NRC oversight. This is consistent with the NRC's position that, while SONGS' progress in improving safety culture has been inadequate, the plant continues to be operated in a safe manner.[156]

The Institute for Nuclear Power Operations (INPO), a peer oversight agency, may also be dissatisfied with SONGS' rate of improvement. After a January 2009 inspection, INPO reviewers reportedly concluded that the site had made inadequate progress in all of the areas identified as needing special focus six months earlier, and ranked SONGS in the bottom quartile of U.S. commercial nuclear plants.[157]

Lack of progress may also be evident in reduced plant performance. SONGS's 2008 capacity factor was just 81 percent,[158] significantly lower than the 92 percent industry average.[159] This relatively low level of availability was partially the result of Unit 3's refueling outage extending 66 days,[160] 28 days longer than the industry average.[161]

Improvements to the safety culture and plant performance at SONGS will be reflected in improved ratings by the NRC and INPO and by shorter outages and higher capacity factors. If sufficient improvements are not demonstrated in the coming years, the implications of sustained safety culture lapses and the possible impact on reliability of the plants will need to be considered as part of the state's license renewal assessment for the plant.

Another issue is emergency evacuation planning. The *AB 1632 Report* recommended that the utilities reassess the adequacy of plant roads for allowing access for emergency response teams and for allowing local communities and workers to evacuate. The report recommended that this reassessment be conducted as part of license renewal studies to ensure that plant assets would be protected in an emergency. PG&E has commissioned a study, to be completed in early 2010, on evacuation time estimates for Diablo Canyon.[162] SCE reassesses its evacuation time studies annually.[163]

Nuclear Plants and the Economy

Nuclear power plants face a number of economic barriers, including high capital costs and long construction lead times. While nuclear plants are relatively cheap to run, construction costs are high. These costs are also highly uncertain since few nuclear plants have been constructed in the U.S. since the 1980s.[164]

156 Nuclear Regulatory Commission, Mid-cycle Performance Review and Inspection Plan – San Onofre Nuclear Generating Station, September 1, 2009, p. 1.

157 See [http://www.voiceofsandiego.org/articles/2009/02/26/science/963songs022509.txt].

158 Southern California Edison, *2008 Financial and Statistical Report*, p. 24, available at: [http://www.edison.com/files/2008_Financial&StatisticalRpt.pdf].

159 U.S. Energy Information Administration. U.S. Nuclear Statistics, see [http://www.eia.doe.gov/cneaf/nuclear/page/operation/statoperation.html].

160 Southern California Edison, *2008 Financial and Statistical Report*, p. 24, available at: [http://www.edison.com/files/2008_Financial&StatisticalRpt.pdf].

161 Nuclear Energy Institute, U.S. Nuclear Refueling Outage Days, available at: [http://www.nei.org/resourcesandstats/documentlibrary/reliableandaffordableenergy/graphicsandcharts/refuelingoutagedays/].

162 Pacific Gas and Electric data request response M.06.

163 Written comments by Southern California Edison on the *2009 Draft IEPR*, October 30, 2009, p. 19, [http://www.energy.ca.gov/2009_energypolicy/documents/2009-10-14_workshop/comments/Southern_California_Edison_TN-53916.PDF].

164 U.S. Nuclear Regulatory Commission. 2009-2010 Information Digest, p. 36, available at: [http://www.nrc.gov/reading-rm/doc-collections/nuregs/staff/sr1350/v21/sr1350v21.pdf].

During the late 1990s and early part of this decade, vendor estimates for new nuclear plants were on the order of $1,000–$1,500 per kW. However, these general estimates were not tied to particular projects. In recent years as some companies have begun to seriously evaluate options for new nuclear generation, vendor bids have been much higher, on the order of $4,000–$6,000 per kW.[165] For a typical 2,200 MW nuclear plant, this amounts to $9-$13 billion in capital costs. Recently, several utilities reported even higher cost estimates of $14 billion ($6,300 per kW) for proposed plants,[166] and Moody's Investors Service estimated that costs for a new plant could potentially reach $7,000–$7,500 per kW.[167]

Until one or more new nuclear plants are constructed in the U.S., these estimates will remain preliminary, making construction of a new nuclear plant a risky endeavor. The risk of capital cost increases is compounded by the long length of time that it takes to get approval for and then construct a new nuclear plant, which raises the risk of cost increases due to regulatory delays, inflation, and increases to financing costs. As a result, Moody's cautioned that they "view new nuclear generation plans as a 'bet the farm' endeavor for most companies" and warned that companies that pursue new nuclear generation may face credit rating downgrades if they do not mitigate this risk.

165 KEMA, *Renewable Energy Cost of Generation Update*, PIER Interim Project Report, August 2009, CEC-500-2009-084, Appendix A.

166 Florida Power & Light's Turkey Point plant, Georgia Power and Georgia Public Service Company's Vogtle plant, and Duke Energy's Lee Nuclear Station, see [http://progress-energy.com/aboutus/news/article.asp?id=20482]; [http://southerncompany.mediaroom.com/index.php?s=43&item=353]; [http://www.bizjournals.com/charlotte/stories/2008/11/03/daily19.html].

167 Moody's Corporate Finance, "New Nuclear Generating Capacity: Potential Credit Implications for U.S. Investor Owned Utilities," May 2008, pp. 1 and 15.

Other cost issues relating to nuclear power plants include security (to protect sites from terrorism and theft); plant decommissioning; and nuclear waste storage, transport, and disposal. The federal Nuclear Waste Policy Act of 1982 made the federal government responsible for the permanent disposal of spent nuclear fuel and high-level waste. Since 1982, nuclear plant owners have been required to pay 0.1 cents per kWh of power generated from their plants into a Nuclear Waste Fund to finance federal efforts to build a permanent nuclear waste repository. In return for these payments, the DOE committed to opening a repository by January 31, 1998.

As of September 2008, the Nuclear Waste Fund contained $31.4 billion, with $1.4 billion from California. However, more than 11 years after the deadline, a repository has yet to be constructed. As a result, PG&E, SCE, and many other utilities have sued the DOE for breach of contract. PG&E claimed damages of $90.6 million through 2004 for costs at Diablo Canyon ($36.8 million) and Humboldt Bay ($53.8 million).[168] In October 2006, the U.S. Court of Federal Claims awarded PG&E $42.8 million. PG&E won an appeal on the award amount, and the lawsuit has been remanded to the U.S. Court of Federal Claims for a recalculation of damages. The DOE has conceded that PG&E is entitled to $75 million, but continues to contest $15.6 million of additional costs that are mostly related to on-site storage of Greater than Class C waste at Humboldt Bay. PG&E plans to file an additional claim to cover ISFSI-related costs incurred from 2005–2009.[169]

168 Pacific Gas and Electric's initial damage claim was for $92.1 million. Pacific Gas and Electric recalculated its claim based on the appellate court's decision.

169 Pacific Gas and Electric data request response D.09.

SCE claimed $150 million in damages through 2005. In addition to ISFSI licensing, construction, and operating costs, SCE is seeking additional compensation for payments made to General Electric for storage of Unit 1 spent fuel and investments in the proposed Private Fuel Storage facility in Utah.[170] A trial was conducted in late April 2009, and a decision is expected in late 2009 or early 2010.[171]

If a federal repository is established, spent fuel will need to be packaged for transport, aging, and disposal. Dry cask storage, an interim storage solution, could prove costly to utilities in the long-term, especially if they need to pay to transfer their fuel from their dry casks into federally approved transport, aging, and disposal casks. The nuclear plants will also need to dispose of a substantial quantity of low-level radioactive waste when they are decommissioned, and the cost to transport and dispose of this waste is expected to be hundreds of millions of dollars or more.

Transmission

Senate Bill 1565 (Bowen, Chapter 692, Statutes of 2004) requires the Energy Commission to adopt a strategic plan for the state's electric transmission grid as part of the IEPR proceeding. In further recognition of the importance of the state's role in transmission planning, Senate Bill 1059 (Escutia, Chapter 638, Statutes of 2006) creates a link between transmission planning and permitting by authorizing the Energy Commission to designate transmission corridor zones (transmission corridors) on nonfederal lands that will be available in

170 MRW & Associates, Inc. *AB 1632 Assessment of California's Operating Nuclear Plants: Final Report,* prepared for the California Energy Commission, October 2008, pp. 220–221.

171 Southern California Edison data request response D.09.

the future to facilitate the timely permitting of high-voltage transmission projects.

The *2008 IEPR Update* noted that the primary barrier to increased development of renewable generation continues to be the lack of transmission to access these resources, particularly those generating resources located (or proposed) in remote areas of the state. In particular, that report identified two major transmission-related barriers to achieving the state's renewables goals. First, there is a need for mechanisms to remove barriers to joint transmission projects between publicly owned utilities and IOUs. This issue is described below in the section on transmission and the economy. Second, with regard to transmission siting, the state must continue to actively address environmental, land use, and local public opposition issues by working closely with stakeholders during the planning process. This issue is described below in the section on transmission and the environment.

The *2009 Strategic Transmission Investment Plan*, prepared in support of the *2009 IEPR*, describes the immediate actions that California must take to plan, permit, construct, operate, and maintain a cost-effective, reliable electric transmission system that is capable of responding to important policy challenges such as achieving significant GHG reduction and RPS goals. This section briefly summarizes some of the major issues covered in the plan.[172]

172 For additional detail, see California Energy Commission, *2009 Strategic Transmission Investment Plan*, Final Commission Report, December 2009, CEC-700-2009-011-CMF, available at: [http://www.energy.ca.gov/2009publications/CEC-700-2009-011/CEC-700-2009-011-CMF.PDF].

Transmission and the Environment

In the *2007 Strategic Transmission Investment Plan,* the Energy Commission identified the importance of early consideration of nonwires alternatives in statewide transmission planning processes. Essentially, nonwires alternatives are the preferred resources identified in the state's loading order and include energy efficiency, demand reduction measures (demand response and load management), and the use of small-scale and customer-level distributed generation resources and/or clean fossil-fired central station generation located within the load service area. Cost-effective energy efficiency is the resource of first choice for meeting California's energy needs; at the same time it is imperative that California reach its 33 percent RPS goals and expand distributed generation applications, particularly rooftop solar PV and CHP. Nonwires alternatives are increasingly identified as viable alternatives to new conventional generation and transmission facilities required to connect new generation to demand centers. The CPUC currently performs a project-specific, nonwires alternative analysis as part of its environmental review process for permitting transmission projects, initiated with the filing of a Certificate of Public Convenience and Necessity (CPCN).

As noted in the *2008 IEPR Update*, integrating land use and environmental concerns into transmission planning processes can be a challenge. Efforts are already underway to aid in the early identification and resolution or to avoid land use and environmental constraints to promote timely development of California's renewable generation resources and associated transmission lines. The RETI has proven to be a successful model for bringing together renewable transmission and generation stakeholders to link transmission planning and transmission permitting. This will ensure that needed projects are planned for, have corridors set aside as necessary, and are permitted in a timely and effective manner that minimizes environmental impacts, makes the best use of existing infrastructure and rights-of-way, and takes advantage of technological advances.

In August 2009, RETI released its *Phase 2A Report*, which presents a conceptual transmission expansion plan to increase the capacity of the state's transmission grid to deliver renewable generation to load centers. It also forms the basis for the development of a draft method for identifying which of the RETI line segments should be considered for corridor designation by the Energy Commission. Next steps include a possible update of the *Phase 2A Report* to address developments in the tax code that affect the economic rankings of competitive renewable energy zones. Stakeholders are also considering participation in the California ISO Annual Transmission Plan proceeding and the electric utilities' California Transmission Planning Group (CTPG).[173] Beyond this, the stakeholders are evaluating the benefits of conducting Phase 2B work to prioritize the transmission infrastructure identified in the conceptual transmission plan, address in greater detail out-of-state renewable resources and revise the transmission infrastructure accordingly, and develop an interim interconnection plan to exploit initial renewable generation opportunities that can rely on temporary fixes to the existing grid to be brought on-line.

Another important effort to integrate land use concerns with transmission planning is the Energy Commission's transmission corridor designation process established under SB 1059. The transmission corridor designation process will help promote improved public involvement in transmission planning processes so that public concerns can be heard and addressed. In addition, early outreach by utilities to local governments and land use agencies will help with early identification of land use and environmental conflicts, which are typically the major impediments to securing any transmission permit. The corridor designation process can also provide better education to the public and local government agencies about why new transmission infrastructure is needed and how it will help the state meet its environmental goals.

Transmission and Reliability

To ensure a reliable network, regulators' challenge is to identify the best mix of transmission projects. Policy decisions like the retirement of aging power plants or OTC plants may require transmission solutions to maintain system reliability in the southern part of the state. Success in meeting RPS and GHG reduction goals depends in large part on the ability to interconnect substantial amounts of new generation from renewable resources. Occasional local opposition to power plants in load centers necessitates remote generation that may prompt the need for increased transmission.

In the *2009 Strategic Transmission Investment Plan*, the IEPR and Siting Committees note that the highest priority is to continue

173 The California Transmission Planning Group includes the California Independent System Operator, the California Municipal Utilities Association, the Imperial Irrigation District, the Los Angeles Department of Water and Power, Pacific Gas and Electric Company, Southern California Edison Company, San Diego Gas & Electric Company, and the Transmission Agency of Northern California.

to support the projects identified in previous strategic plans. The Energy Commission found that these projects met the criteria for strategic transmission resources because they provided statewide benefits. As currently planned, these projects would significantly increase the transmission network's ability to reliably connect renewable generation to California load centers. These projects include:

- Imperial Irrigation District Upgrades
- SCE Tehachapi Upgrades (Segment 1 – Antelope-Pardee; Segment 2 – Antelope-Vincent; Segment 3 – Antelope-Tehachapi; and Segments 4-11 – Tehachapi Renewable Transmission Project)
- SCE Devers – Palo Verde 2 (the entire California-Arizona interconnection, as well as the California-only variation)
- LADWP Tehachapi Upgrade (Barren Ridge Renewable Transmission Project)
- PG&E Central California Clean Energy Transmission Project (C3ETP)
- SDG&E Sunrise Powerlink Transmission Project
- Lake Elsinore Advanced Pumped Storage Project – Transmission Portion
- Green Path North Coordinated Projects
- SCE El Dorado to Ivanpah Transmission Project (new project not in previous strategic plans)

The *2009 Strategic Transmission Investment Plan* provides a complete description of these projects and their current status.

The second priority should be transmission segments identified in the RETI process as "foundation" and "delivery" segments that limit environmental impacts by using or expanding existing transmission segments. Together with the first priority projects listed above, these segments would provide a strong system to move and deliver electricity throughout California. RETI has not performed the thorough planning studies that are required to move these projects forward toward permitting approvals. The detailed analysis of these projects should be conducted through RETI or the newly formed CTPG, described in more detail in the section on transmission and the economy.

Six conceptual transmission projects meet these two priority criteria. They are the "no regrets" RETI lines that could be built within an existing transmission corridor or by expanding an existing corridor. Two additional projects (Gregg – Alpha Four and Tracy – Alpha Four) do not meet these criteria but are needed to complete a link to Northern California load centers; without these two lines, the renewable energy would reach Fresno but not load centers in the Bay Area.[174]

The third priority should be to continue the analysis of the RETI renewable foundation and renewable collector lines that require new corridors and begin the planning work for the priority renewable areas outside Tehachapi, the Imperial Valley, and eastern Riverside County. Public outreach and corridor identification for

174 The eight-second priority conceptual transmission projects include five Renewable Energy Transmission Initiative (RETI) renewable foundation lines (Kramer – Lugo 500 kV, Lugo – Victorville #2 500 kV, Devers – Mira Loma #1 and #2 500 kV, Gregg – Alpha Four 500 kV, and Tracy – Alpha Four 500 kV 1 & 2) and three RETI Renewable Delivery lines (Devers – Valley #3 500 kV, Tesla – Newark 230 kV, and Tracy – Livermore 230 kV).

the RETI "no regrets" lines that require new corridors should continue with local RETI forums, and the transmission planning should be developed through the CTPG. Which areas or competitive energy renewable zones (CREZs) should be given priority should be revisited because there are several factors that will affect the viability of the areas. The proposed national monument in the Mojave Desert area could reduce the size of several of the CREZs. The Solar PEIS currently being developed by the BLM will likely identify preferred solar development areas while removing other areas from development. The California ISO is completing its first clustered interconnection studies based on the new Generator Interconnection Process. While these studies will only identify transmission needs for a small part of the generation potential of many of the CREZs, the new studies will identify some of the transmission upgrades that are required to connect proposed generators to the existing transmission grid, and the extent of these required upgrades could affect the development of renewable areas. All of these studies will help identify preferred renewable generation areas for California and will help prioritize the planning and permitting of future transmission needs.

Transmission and the Economy

Joint transmission projects between IOUs and publicly owned utilities promote economic efficiency by eliminating potentially redundant facilities, thereby reducing ratepayer expenses and environmental impacts. With respect to the issue of overcoming obstacles to joint transmission projects, the *2008 IEPR Update* recommended that the Energy Commission use the *2009 IEPR* and *2009 Strategic Transmission Investment Plan* processes as forums to identify and evaluate regulatory or policy changes that would reduce both legal and market obstacles to joint project development. Toward that end, two joint IEPR/Siting Committee workshops were held in support of the *2009 Strategic Transmission Investment Plan* that vetted the issue of coordinated statewide transmission planning to meet California's RPS goals. In the *2009 Strategic Transmission Investment Plan*, the Energy Commission recognizes the formation of the CTPG and the significant progress the CTPG appears to be making toward establishing a coordinated statewide utility transmission planning process that could lead to joint IOU/publicly owned utility projects.

As described by the comments received under this proceeding by the CTPG,[175] the purpose of the CTPG is to find the best transmission solutions for meeting California's environmental, reliability, economic, and other policy objectives. Under the CTPG, IOUs, publicly owned utilities, and the California ISO are planning to work together to avoid transmission duplication, optimize use of existing rights-of-way, reduce environmental impacts, and lower costs for consumers. The CTPG is intended, along with existing efforts, to fulfill the CTPG members' obligations and requirements under Order No. 890 issued by the Federal Energy Regulatory Commission (FERC). Order No. 890 requirements include nine transmission planning principles that address many of the issues central to an open and inclusive planning process, including 1) coordination with customers and neighboring transmission providers; 2) open meetings available to all parties; 3) transparency in methodology, criteria, and processes; 4) opportunities to use customer data and methodological input; 5) the obligation to meet specific service requests of transmission customers on a comparable basis;

175 Post-Workshop Comments of Joint Parties Comments on Transmission Planning Information and Policy Actions, May 29, 2009, available at: [http://www.energy.ca.gov/2009_energypolicy/documents/2009-05-04_workshop/comments/Joint_Parties_Post-Workshop_Comments_052909_TN-51751.pdf].

6) a clear dispute resolution process; 7) regional coordination; 8) study of economic effect of congestion and integration of new resources; and 9) a process for allocating costs of new projects.

The Energy Commission supports the plans of the IOUs, publicly owned utilities, and the California ISO to work together to avoid transmission duplication, optimize use of existing rights-of-way, reduce environmental impacts, lower costs for consumers, and develop a process for cost allocation for joint projects. If CTPG's consolidated utility approach is successful, this collaboration could result in the development of joint transmission projects necessary for implementing a true statewide planning process that reflects broad stakeholder interests.[176]

Another high-priority economic issue for transmission is the broader cost allocation issue for interstate transmission projects. The *2007 Strategic Transmission Investment Plan* described the results of a PIER-funded study that examined cost allocation and cost recovery procedures in other regions of the country for insights that could apply to a California-western region context. The study also identified a number of basic principles for developing cost allocation procedures that could guide western planners.

Currently, there is a high degree of interest at the federal level in moving toward interconnection-wide transmission planning and federal intervention in planning, permitting, and cost allocation. Congress is considering legislation that would establish new FERC authority for transmission siting and cost allocation. This issue is of concern to California because if FERC mandates a cost allocation method, California could be required to pay for projects not consistent with the California RETI effort, California RPS goals, and carbon reduction policies.

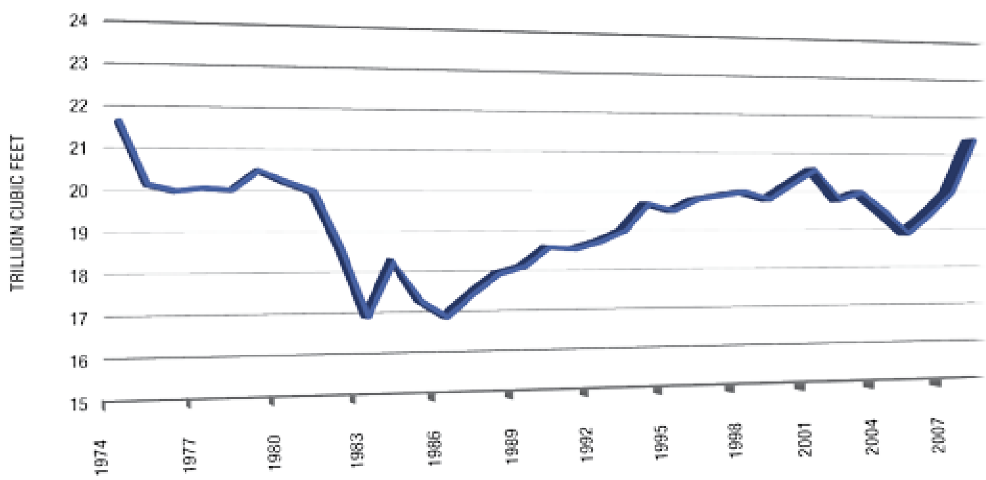
The Western Governors' Association (WGA) has recently asserted western policies that urge Congress to guide centralized regional transmission planning, implemented through actions and policies of federal agencies such as FERC, BLM, and DOE. Its policy letters explicitly urge Congress to require a regional transmission plan, chosen and approved by WGA, which could be enforced by DOE and FERC through mechanisms such as incentives, federal corridor designation, National Interest Electricity Corridor Designation, possible siting preemption/backstop authority, and prescriptive cost allocation under methods specified by the FERC.[177] The detailed implementation of the WGA policy statements will to a significant degree depend on what, if any, legislation is approved by Congress in 2009-10 (or beyond).

Another economic issue that is specific to the Energy Commission's transmission corridor designation process is California IOUs' uncertainty of cost recovery for land purchased within an Energy Commission-designated corridor for future transmission projects. The current FERC declaratory order requires that an IOU obtain a CPCN from the CPUC for a specific transmission project within a designated corridor to qualify for cost recovery for land purchases. This requirement is a potential barrier to the successful implementation of the Energy Commission's transmission corridor designation program. To eliminate this barrier the IOUs need assurance from FERC that they will be allowed to recover in their electric rates the cost of land purchased

176 For more information on the California Transmission Planning Group and its role in statewide transmission planning, see chapters 2 and 4 of the 2009 *Strategic Transmission Investment Plan*, September 2009, CEC-700-2009-011-CTD, available at: [http://www.energy.ca.gov/2009publications/CEC-700-2009-011/CEC-700-2009-011-CTD.PDF].

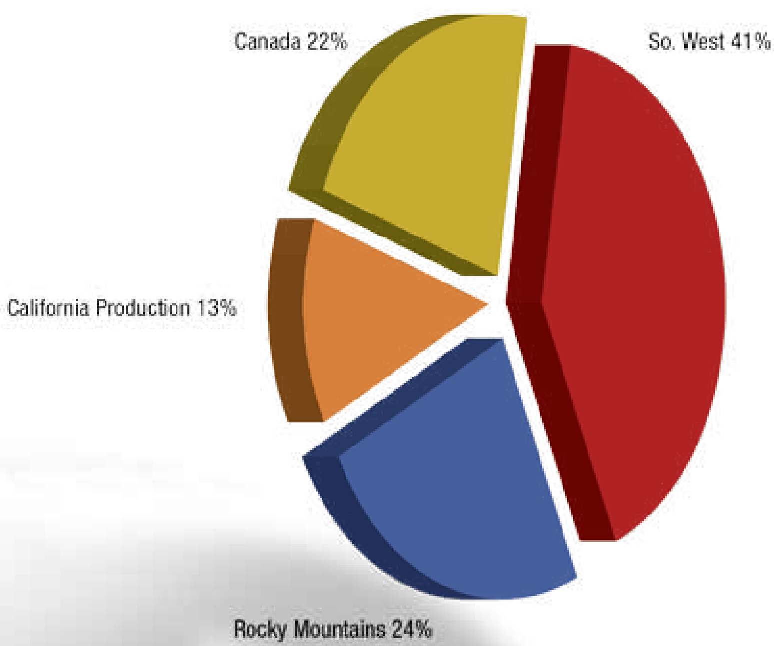
177 Western Governors' Association, Letter to the Honorable Jeff Bingaman, May 1, 2009, available at: [http://www.westgov.org/wga/testim/transmission5-1-09.pdf].

FIGURE 13: U.S. DOMESTIC NATURAL GAS PRODUCTION



Source: Energy Information Administration, *Annual Energy Outlook*

FIGURE 14: 2007 CALIFORNIA NATURAL GAS RECEIPTS BY SOURCE



Source: Pipeline and Utility Filings with the California Energy Commission within an Energy Commission-designated corridor. The Energy Commission believes that FERC should allow an IOU to qualify for cost recovery if the land is set aside for one or more transmission projects that may be constructed 10–15 years in the future and is within an Energy Commission-designated corridor.

Natural Gas

Natural gas provides almost one-third of the state's total energy requirements and continues to be a major fuel in California's supply portfolio. Natural gas is used in electricity generation, space heating for homes and commercial buildings, cooking, water heating, industrial processes, and as a transportation fuel.

Natural Gas Supplies

California's supply of natural gas comes from four areas: in-state production, southwestern United States, the Rocky Mountain region, and Canada, with 87 percent of the state's natural gas coming from out-of-state sources. After nearly a decade of relatively flat or declining U.S. natural gas production, domestic production in the lower 48 states began rising in 2006, and by 2008 returned to levels last seen in 1974 (Figure 13).[178]

Twenty years ago, California produced 20 percent of the state's supply of natural gas, the Southwest provided nearly 60 percent, and the rest came from Canada and other basins. However, in-state natural gas production has been declining over time (Figure 14), and the downward trend may continue from the current 825 million cubic feet per day (MMcf/d) to possibly 700 MMcf/d by 2020.

178 Domestic natural gas production was 21.60 trillion cubic feet (Tcf) in 1974 and 21.40 Tcf in 2008.

Production from conventional natural gas basins that provided the majority of domestic supply began to decline in the late 1990s and early 2000s, but as natural gas prices have increased, so have exploration and production. There have also been advances in horizontal drilling, a more efficient and cost-effective method for recovery of domestic unconventional natural gas reserves that provides the potential for greater gas production per well. Finding and development costs of a typical vertical well average $1.71 per thousand cubic feet (Mcf), while costs for a horizontal well average between $1.06/Mcf and $1.34/Mcf.[179]

Natural gas from out-of-state is delivered into California using the interstate natural gas pipeline system. Five interstate pipelines bring gas to California: Gas Transmission-Northwest pipeline carries Canadian natural gas; El Paso, Transwestern, and Questar's Southern Trails transport gas from the Southwest; and the Kern River pipeline system moves Rocky Mountain production to market. Except for Southern Trails, each of these pipelines serves other customers before reaching California. Figure 15 shows natural gas pipelines and resource areas in western North America.

Interstate pipelines and California production currently have the capacity to supply California consumers up to 10,230 MMcf/d. However, because of upstream demand and utility multiple receiving points, the state can only rely on receiving 8,315 MMcf/d of supply from pipelines and native production. Simply because an interstate pipeline has a certain delivery capacity does not mean that all of its capacity is available to California. Each pipeline serving California has firm delivery

179 California Energy Commission, *Shale-Deposited Natural Gas: A Review of Potential*, May 2009, CEC-200-2009-005-SD, available at: [http://www.energy.ca.gov/2009publications/CEC-200-2009-005/CEC-200-2009-005-SD.PDF].

FIGURE 15: NATURAL GAS RESOURCE AREAS AND PIPELINES

Source: *2008 California Gas Report*

In Operation

1. El Paso Natural Gas
2. Gasoducto Bajanorte (GB)
3. Gas Transmission Northwest (GTN)
4. Kern River Pipeline
5. Mojave Pipeline
6. North Baja Pipeline
7. Northwest Pipeline
8. Paiute Pipeline
9. Pacific Gas Electric Company
10. Questar Southern Trail Pipeline
11. Rockies Express (REX)
12. San Diego Gas &Electric Company
13. Southern California Gas Company
14. Transportadora de Gas Natural (TGN)
15. TransCanada Pipeline
16. Transwestern Pipeline
17. Tuscarora Pipeline

Proposed

18. Bronco Pipeline
19. Ruby Pipeline
20. Kern River Expansion
21. Sunstone Pipeline

contracts not only for California customers but also for customers upstream from California. Because of these upstream commitments, not all of a pipeline's capacity is available for delivery to the state.

If demand exceeds reliable supply, utilities and noncore customers will still be able to meet demand up to the pipeline delivery capacity, but prices would increase dramatically. To meet their needs, California utilities and noncore customers would then have to purchase natural gas that otherwise would have been delivered to customers outside of California. To attract the supply, they would have to pay elevated prices that would drive California prices above current market levels and cost the state's consumers an unknown amount.

Once natural gas arrives in California, it is distributed by the natural gas utility companies. The three major utilities – Southern California Gas Company (SoCal Gas), SDG&E, and PG&E – collectively serve 98 percent of the state's natural gas customers. The remaining 2 percent are served by municipal and smaller or out-of-state utilities.

The amount of available natural gas storage is also important. PG&E's storage fields have the ability to cycle small quantities of gas through the year. The utility needs most of the injection period to fill its storage to meet winter demand. PG&E has indicated that it may maintain a 1,451 MMcf/d withdrawal rate through the winter. Although SoCal Gas has good natural gas cycling capabilities, the independent, nonutility Lodi and Wild Goose facilities have better cycling abilities. Each may withdraw and inject several times throughout the year and may also hold the same delivery levels as volumes of gas in storage are extracted. SoCal Gas asserts that it can maintain up to 2,225 MMcf/d[180] of gas withdrawals throughout all levels of storage.

A potential additional source of natural gas supply is liquefied natural gas (LNG). In the near future, California could receive natural gas from an LNG facility located at Costa Azul, Mexico. The construction of the Costa Azul LNG terminal was completed last year and still awaits the first of its commercial deliveries. LNG is available, but suppliers at the moment are reluctant to enter the lower-priced Pacific Coast market. When supply does start to flow, North Baja Mexico will have first choice to receive up to 300 MMcf/d to meet its industrial and power plant needs. Any excess in supply would add to California's supply mix. Under normal conditions, this would lead to price competition for market share. However, LNG is a price taker, meaning it does not set the price; with the reluctance for deliveries to the Pacific Coast, it is unclear what impact Costa Azul will have on supply and price.

Another option for new supplies of natural gas is shale gas.[181] Natural gas accumulates in three types of formations: limestone, sandstone, and shale. Before 1998, limestone and sandstone formations produced nearly all domestic supplies of natural gas. Exploration and production companies, however, have long known about the potential for natural gas in shale formations. This potential led the industry to pursue the engineering innovations needed to access these natural gas resources.

180 *2008 California Gas Report,* p. 90, available at: [http://www.socalgas.com/regulatory/documents/cgr/2008_CGR.pdf].

181 California Energy Commission, *Shale-Deposited Natural Gas: A Review of Potential*, draft staff paper, May 2009, CEC-200-2009-005-SD, available at: [http://www.energy.ca.gov/2009publications/CEC-200-2009-005/CEC-200-2009-005-SD.PDF].

In the mid-1990s, shale-deposited natural gas provided about 1 percent of production in the lower 48 states.[182] The development of three-dimensional and four-dimensional seismic surveys, improved drilling technologies, and technological innovations in well completion and stimulation has increased the productivity of wells drilled into shale formations so that by mid-2008, shale production represented almost 10 percent of production from the lower 48 states (Figure 16). The Natural Gas Supply Association believes that production from the shales "…could double in the next 10 years and provide one-quarter of the nation's natural gas supply."[183]

Natural Gas Demand

As a state, California is the second largest natural gas consumer in the United States, representing more than 10 percent of national natural gas consumption.[184] Customers in the residential and commercial sectors, referred to as "core" customers, accounted for 29 percent of the state's natural gas demand in 2008. Large consumers such as electricity generators and the industrial sector, referred to as "noncore" customers, accounted for about 71 percent of demand in the same year. California remains heavily dependent on natural gas to generate electricity, which accounted for more than 40 percent of natural gas demand in 2008.[185]

Most of the natural gas used in the residential sector is for space and water heating. Since 1970, the number of households in California has almost doubled, which has increased overall natural gas consumption, but as a result of California's building and appliance efficiency standards, the average amount of natural gas consumed per household has dropped more than 36 percent.

In 2009, the Energy Commission staff prepared a comprehensive forecast of natural gas demand by end users (excluding electricity generation) as part of the *2009 IEPR*.[186] Table 6 compares the 2009 natural gas forecast with the 2007 forecast for selected years.

The 2009 staff forecast is lower in the near term (2010) because of current economic conditions and because actual consumption in 2008, the starting point for the 2009 forecast, was lower than the forecasted 2008 consumption that was used in the 2007 forecast. By 2018, consumption is expected to be about 8 percent lower than in the prior forecast. As the economy recovers, projected annual growth in natural gas consumption is expected to exceed California Energy Demand 2007 forecast growth for 2010–2018.

Although the method to estimate energy efficiency impacts has been refined, the staff draft forecast uses essentially the same methods as earlier long-term staff demand forecasts. A more detailed discussion of forecast

182 "Lower 48"excludes Alaska and Hawaii.

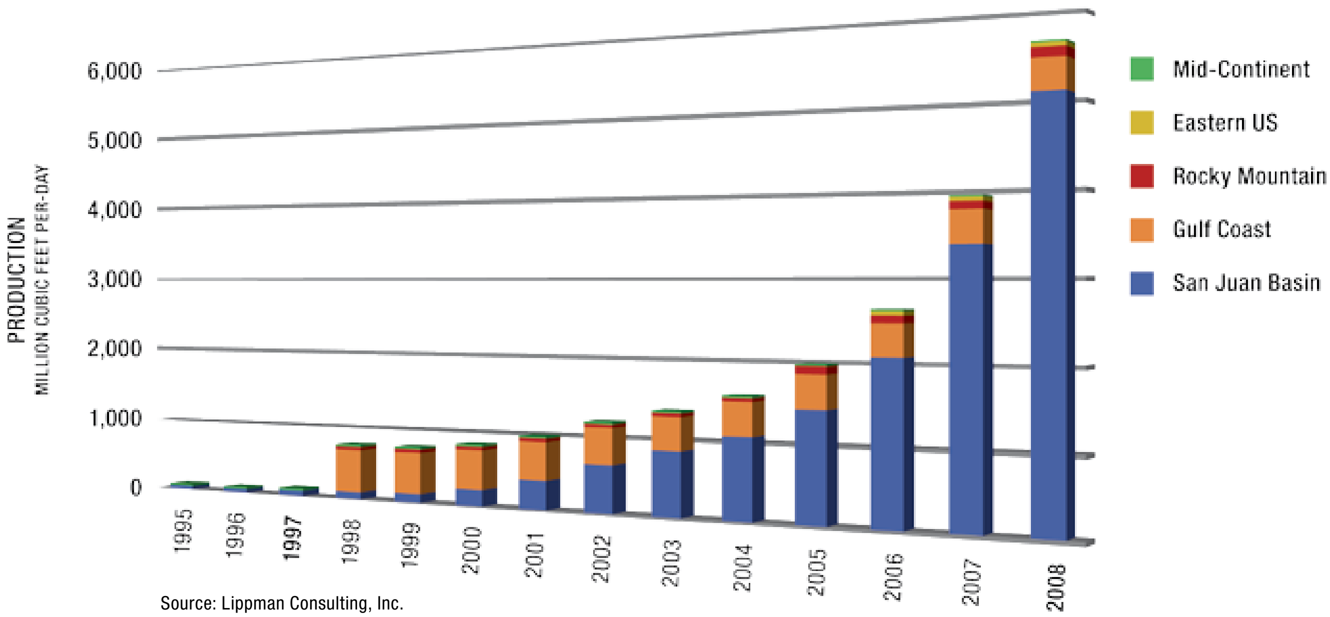
183 Natural Gas Supply Association, News Release, October 8, 2008, "Natural Gas from Shale Could Double in Next Ten Years," available at: [http://www.ngsa.org/newsletter/pdfs/2008%20Press%20Releases/22%20-%20Natural%20Gas%20from%20Shale%20to%20Double%20w%20graphic.pdf].

184 Energy Information Administration, *Natural Gas Annual 2007*, available at: [http://www.eia.doe.gov/pub/oil_gas/natural_gas/data_publications/natural_gas_annual/current/pdf/table_002.pdf].

185 Southern California Gas Company, *2008 California Gas Report*, available at: [http://www.socalgas.com/regulatory/documents/cgr/2008_CGR.pdf].

186 California Energy Commission, *California Energy Demand 2010–2020 Adopted Forecast*, December 2009, CEC-200-2009-012-CMF, available at: [http://www.energy.ca.gov/2009publications/CEC-200-2009-012/CEC-200-2009-012-CMF.PDF].

FIGURE 16: LOWER 48 SHALE NATURAL GAS PRODUCTION



Source: Lippman Consulting, Inc.

TABLE 6: STATEWIDE END-USER NATURAL GAS CONSUMPTION

	MM THERMS		
	CED 2007	CED 2009 (HIGH-RATE CASE)	PERCENT DIFFERENCE
1990	12,893*	12,893*	0.00%
2000	13,913*	13,913*	0.00%
2007	13,445	12,494*	-0.07%
2010	13,616	12,162	-10.68%
2018	14,058	12,894	-8.28%

* Historic Values

	ANNUAL AVERAGE GROWTH RATES	
1990–2000	0.76%	0.76%
2000–2008	-0.43%	-0.89%
2008–2010	0.63%	-1.34%
2010–2018	0.40%	0.73%

Source: California Energy Commission, 2009 methods and data sources is available in the *Energy Demand Forecast Methods Report*.[187]

Energy Commission staff also evaluated winter peak day natural gas demand trends and the effect of that demand on pipelines and natural gas storage, using demand data from the *2008 California Gas Report*[188] and from utility and pipeline filings made to the Energy Commission. Winter demand is driven primarily by heating requirements in the residential and commercial sectors, while natural gas for electricity generation represents about 14 percent of winter demand. Demand from the industrial sector has very little seasonal variation.

The state is shifting to renewable energy sources to provide a larger share of the electricity generated to meet California's needs. Unless they are paired with on-site energy storage technologies, certain renewable generation technologies are not dispatchable to follow load and may not be available to meet peak day requirements. Solar thermal and photovoltaic generation better match load than does wind generation. To ensure reliable service during peak demand periods, natural gas-fired generation will be needed to meet peaking requirements, provide load following and backup services for the renewable generation, and provide baseload services.

The type of natural gas unit needed to supplement renewable generation will affect the need for natural gas. While older units have heat rates in excess of 10,000 British thermal units (Btu) per kWh, the newer combined cycle facilities are more efficient and operate at approximately 7,500 Btu per kWh. A 40 percent loss of renewable generation would be equivalent to an increase of 480 MMcf/d in combined cycle fuel use. However, peaking units are less efficient and, depending on the age of the unit, will use 50 to 100 percent more gas per megawatt-hour (MWh) than a new combined cycle unit. Replacing renewable generation with a peaker plant would therefore increase gas demand by 770 MMcf/d.[189]

Natural Gas and the Environment

The shift to a greater reliance on horizontal, rather than vertical, wells in shale formations elevates the issue of potential environmental impacts. While regulatory agencies and environmental groups highlighted these issues in the past, in the last 10 years the increased activities in shale formations brought greater focus on the potential environmental impacts, which can occur in any of five areas: surface preparation, drilling and completion, production and clean-up, transmission and distribution, and consumption. As a result, the increased development and production of natural gas in shale formations has raised four primary environmental concerns: surface disturbance, GHG emissions, other air contamination, and potential leakage of chemicals into the groundwater.

Surface preparation before drilling any natural gas well can create environmental stress in sensitive areas. The potential impact on wildlife habitat and wilderness areas has led to moratoriums on natural gas drilling in the Rocky Mountains and other sensitive areas of the lower 48 states. Drilling operations can also have significant impacts, and some states, including New York and Pennsylvania, have issued restoration requirement rules.

187 California Energy Commission, *Energy Demand Forecast Methods Report,* June 2005, CEC-400-2005-036, available at: [http://www.energy.ca.gov/2005publications/CEC-400-2005-036/CEC-400-2005-036.PDF].

188 *2008 California Gas Report*, see [http://www.socalgas.com/regulatory/documents/cgr/2008_CGR.pdf].

189 California Energy Commission, *Natural Gas Infrastructure*, May 2009, CEC-200-2009-004-SD, available at: [http://www.energy.ca.gov/2009publications/CEC-200-2009-004/CEC-200-2009-004-SD.PDF].

Because natural gas is made up mostly of methane (a GHG), small amounts of methane can sometimes leak into the atmosphere from wells, storage tanks, and pipelines. The Energy Information Administration says that methane emissions from all sources account for about 1 percent of total United States GHG emissions, but about 9 percent of the "greenhouse gas emissions based on global warming potential."[190]

The industry is attempting to address some of the environmental impacts of natural gas extraction by using smaller rigs that reduce surface disturbance. The use of horizontal and directional drilling allows producers greater flexibility about where drilling rigs are located.[191] The shift to horizontal drilling and away from vertical drilling can also lessen surface disturbance by requiring fewer wells to recover an equivalent amount of resource.

On a per million Btu (MMBtu) basis, total emissions from natural gas produced from shale formations differ little from those of natural gas from conventional sources. However, the carbon footprint of the horizontal wells used to extract shale gas far exceeds that of a typical vertical well since the drilling process, the completion process, and the production stimulation process (hydraulic fracturing) require more carbon-based fuels, more drilling mud, and more water. Further, running the required equipment and pumps produces more emissions.

Developing equivalent amounts of natural gas resources, though, requires two to three times more vertical wells than horizontal wells. For example, extracting 20,000 million cubic feet of natural gas may require up to 30 vertical wells but only 10 horizontal wells. The

190 An indicator of the carbon dioxide equivalent.

191 Natural Gas Supply Association, see [http://www.naturalgas.org].

natural gas industry uses both well types to reach potential natural gas resources located thousands of feet beneath the Earth's surface, but each horizontal well recovers more natural gas on average than a vertical well. As a result, the overall carbon footprint for the entire development of a shale formation may not differ from that of an equivalent-sized formation developed using vertical wells.

There are also environmental issues associated with the water used in shale gas extraction. The hydraulic fracturing process used to extract natural gas from shale formations uses hundreds of thousands of gallons of water treated with chemicals. In the development of an entire field, the amount of water injected into a shale formation could reach into the hundreds of millions of gallons. The volume of water used in the development of natural gas from shale formations raises other environmental concerns, including the consumption of large water quantities and recovered water disposal. Although field operators retrieve most of the injected water once the hydraulic fracturing is completed, a significant quantity of water and chemicals remain within the formation.

When development of shale formations occurs near major population centers, environmentalists, with concerns that potential leakage of chemicals used in the hydraulic fracturing process could pose a health and safety risk, are calling for stricter regulation. Some states have developed regulatory requirements for development of shale formations. For example, New York has issued regulations that include guidelines for the use and disposal of water, the protection of groundwater, and the use of chemicals.[192] Pennsylvania has also instituted rules governing the extraction of natural gas from shale formations, noting that, " ... developing our energy resources cannot come at the expense of our environmental resources – our water, our land and our ecosystems."[193] In 2008, inspectors from the state's Department of Environmental Protection ordered the partial shutdown of two drilling sites after discovering violations of state regulations.[194]

Investigation into the environmental issues raised by natural gas exploration and production is an ongoing effort that will continue to be addressed by Energy Commission staff. Shale gas is only the latest addition to a portfolio of natural gas extraction technologies that the Energy Commission staff monitors. Staff will continue to monitor and report on developments in all forms of natural gas exploration and production.

Another natural gas supply source with potential environmental issues is LNG, which tends to contain higher-Btu-content hydrocarbons that have not been processed out, as is typically done with domestically produced natural gas. This can cause increased particulate emissions and has raised some health and environmental concerns about the use of LNG. However, there appears to be a growing consensus that the carbon footprint for LNG, on a life cycle basis, is smaller than that of coal-fired generation.[195]

192 Department of Environmental Conservation, New York State, *Final Scope for Draft Supplemental Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program, February 2009*, available at: [http://www.dec.ny.gov/docs/materials_minerals_pdf/finalscope.pdf].

193 Kathleen McGinty, Secretary of Pennsylvania's Department of Environmental Protection, speaking at a department-sponsored summit, June 2008.

194 Environmental News Service, June 16, 2008.

195 Jamarillo, P., W. Griffin, and H. Matthew, "Comparative Life-Cycle Air Emissions of Coal, Domestic Natural Gas, LNG, and SNG for Electric Generation," *Environmental Science and Technology,* 2007, Vol. 41, No. 17, 6290 and PACE (2009). Life Cycle Assessment of Greenhouse Gas Emissions from Liquified Natural Gas and Coal Fired Generation Scenarios: Assumptions and Results.

In the Energy Commission's report, *Potential Impacts of Climate Change on California's Energy Infrastructure and Identification of Adaptation Measures*, staff reported potential impacts of climate change on the natural gas infrastructure. It appears that sea level rise as a result of climate change will have little impact on natural gas availability since most of the supply comes from basins located in Alberta, the Rockies, and the southwestern United States. Also, potential new sources of shale gas are located in regions that cannot be affected by rising sea levels. However, climate change could cause changes in consumer energy demand based on temperature (for example, increased need for air conditioning because of warming trends) and could decrease hydroelectric production because of changes to precipitation patterns and snowpack. A major change in consumer demand and hydro availability could affect the general pattern of natural gas withdrawal from storage facilities. If utilities cannot keep up with traditional storage levels, consumers could be impacted by higher costs.

Reducing the environmental footprint of natural gas use in California should follow the loading order approach used in the state's electricity system. First and foremost is improving residential, commercial, and industrial energy efficiency, as well as the efficient use of natural gas as a transportation fuel, to reduce emissions associated with consumption of natural gas. An example of California's successful energy efficiency efforts are the previously mentioned statistics that the average California home consumed 120 Mcf of natural gas per year 40 years ago, but today consumes less than 50 Mcf per year. The second priority is to accelerate the adoption of clean alternatives to conventional natural gas resources, such as biogas for both the electricity and transportation sectors, as well as improved technologies. Finally, the performance and reliability of the natural gas system and infrastructure must be improved.

Natural Gas and Reliability

California's dependence on natural gas as an energy source requires the state to maintain a reliable natural gas delivery and storage infrastructure. Eighty-seven percent of California's natural gas supply is from out-of-state and delivered by pipelines that extend deep into Canada, the Rocky Mountains, and the U.S. Southwest production areas.

California needs adequate delivery pipelines and utility receiving capacity to ensure the state has supply to meet its needs at competitive prices. The consequences of inadequate natural gas infrastructure were particularly apparent during the 2000–2001 energy crisis. Interstate pipelines delivering natural gas to California were running at or near capacity for more than a year. The utilities' receiving, local transmission delivery systems, and storage operations were at their limits. Because there were no supply options available, California incurred natural gas costs that were double those paid in the years just prior to the crisis.

During and after the crisis, California increased its interstate pipeline delivery capacity, utilities improved their receiving ability, and the utility and independent storage owners enhanced their storage operations to meet future high-demand day conditions. These improvements have given California utilities the flexibility to choose supply sources in their day-to-day operations, which has forced production areas to compete for a share of the state's natural gas market.

There are concerns about whether increased natural gas demand for electricity generation in the Southwest will reduce the amount of natural gas available for California. Along El Paso's southern pipeline system, more than 10,000 MW of natural-gas fired power plants have been built. If all of these plants ramp up at the same time to meet electricity demand, it could affect the ability of the pipeline to meet the natural gas demand for those plants, possibly leading to unstable natural gas supplies for California. Kern River pipeline also makes upstream deliveries in Utah and Nevada that effectively reduce its ability to deliver full capacity to California.

Natural gas storage is an important piece of California's natural gas infrastructure. Without it, the supply pipelines would have to increase in size to meet winter demand, leaving a huge investment standing idle during half of the year. Storage fields are basically depleted natural gas fields that have had injection and withdrawal wells already drilled and compression and processing equipment added to clean up extracted natural gas. Natural gas is withdrawn from storage during periods of high demand, such as in the winter for space heating and in the summer for power generation. Natural gas is injected into storage during the spring and fall when overall demand is low, making pipeline capacity available to bring in additional natural gas to fill the storage facilities.

California does have potential new sources of natural gas from an existing LNG import facility in Baja, Mexico, along with pipeline projects on the horizon. Three pipeline projects should significantly increase the flow of natural gas to the state:

- The Ruby Pipeline project is planning to deliver natural gas from Opal, Wyoming, to California at a rate of 1.2 billion cubic feet per day (Bcf/d). This pipeline is scheduled to be in service by 2011, and will deliver natural gas to Malin, Oregon.

- The Sunstone Pipeline plans to deliver 1.2 Bcf/d of natural gas from Opal, Wyoming to Stansfield, Oregon. This pipeline is planned to be on-line in 2011 and could displace much natural gas in Oregon, thus freeing up supplies for California.

- The Kern River pipeline expansion project will increase delivery of natural gas from Wyoming to Southern California by 0.2 Bcf/d. The expansion of the existing pipeline is scheduled to be completed in 2010.

In the *2007 IEPR,* staff projected that as much as 20 percent of North American natural gas requirements might be met with LNG by 2017. However, United States LNG imports in 2008 were significantly lower than the amounts projected by Energy Commission staff and others, owing to a range of market developments, both global and domestic. In addition, United States and West Coast LNG terminal development appears to be slowing, and there is a new sense that the United States may not have to rely on LNG to make up previously projected supply deficits. The number of LNG facilities previously proposed for California has been reduced to two, only one of which has filed applications for building permits.

Natural gas is also used in the transportation sector in a broad range of applications, including personal vehicles, public transit, commercial vehicles, and freight movement. Natural gas vehicles may use compressed natural gas or LNG. The number of California on-road, light-duty vehicles powered by natural gas has increased since 2001 from 3,082 to 24,810 in 2008. While these numbers are small compared to the total vehicle population, increasing alternative transportation fuels to help meet the state's GHG reduction goals will require careful evaluation of the impacts on the natural gas supply system.

Natural Gas and the Economy

Wide and frequent swings in natural gas prices affect natural gas consumers, producers, and investors. Natural gas price volatility, measured as the magnitude and rate of changes in a commodity price over a given period, affects the national economy as a larger portion of gross domestic product is consumed by rising energy costs. As natural gas prices rise, they can have a negative impact on residential consumers by consuming more of a household's discretionary income. Consumers are also affected because volatility adds uncertainty in the electricity generation industry, which ultimately affects the price of electricity. Volatility also makes budgeting and cost management more difficult for commercial and industrial consumers that use significant amounts of natural gas in their operations. For natural gas producers, volatility contributes to the boom-bust cycle of drilling activity, ultimately affecting available natural gas supplies. Natural gas price volatility also affects the energy planning process because the added uncertainty in predicting market movements affects the ability to accurately forecast natural gas prices.

During 2008, natural gas spot prices – the price of natural gas for next-day delivery at a specific location – traded as high as $13.32 per Mcf and as low as $5.63/Mcf. The large price fluctuations in 2008 increased the focus on price volatility and its impacts on natural gas market participants. Factors that influence natural gas prices and price volatility include weather, supply and demand imbalances, infrastructure issues, unreliable data, regional and global economic conditions, speculative trading, and market manipulation.

The impacts of natural gas price changes vary for different consumers. For example, residential and small commercial core customer demand tends to be somewhat less affected by price swings. Demand by these customers is largely driven by heating needs during cold weather, and because core customers are often unaware of natural gas price changes until a monthly bill arrives in arrears, there is little opportunity for them to reduce consumption in response to price changes. In addition, the rates that utilities charge these core customers are still subject to oversight by government agencies and are not subject to daily price changes.

However, longer term wholesale price changes do affect the retail rates these customers pay when utilities receive approval to adjust their natural gas tariff rates to reflect a change in costs. These increased prices negatively affect core customers, especially low-income households, resulting in more residential customers that are unable to pay their monthly bills, increasing the number of consumers that require assistance through programs such as the Low-Income Home Energy Assistance Program.

Industrial, or noncore, consumers of natural gas tend to be much more sensitive to price volatility. These consumers typically purchase large quantities of natural gas directly from the market and are immediately affected by changing prices, making budgeting and cost management more difficult. For example, nitrogen fertilizer manufacturers use significant amounts of natural gas, the cost of which can account for 90 percent of the total manufacturing costs. Price volatility can therefore have a dramatic impact on their manufacturing operations. Also, because industrial consumers often are large users of natural gas, significant changes in natural gas prices can influence many operational decisions. If prices become too high or are extremely volatile, industrial users might consider switching to a different fuel if possible or even shutting down their operations.

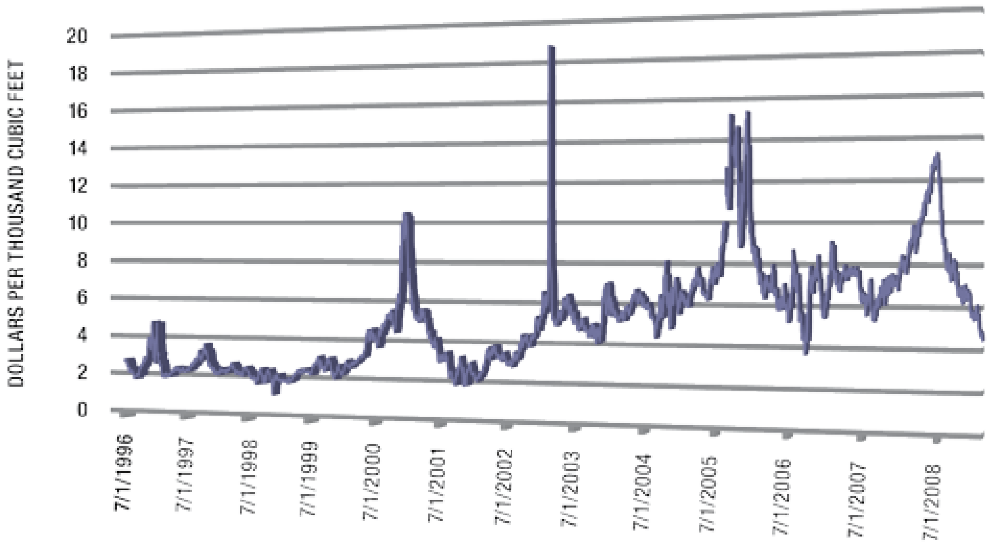
While price volatility can have material consequences for the industrial sector, some large industrial consumers have the ability to take advantage of hedging opportunities to reduce risk. Large users potentially could purchase and store natural gas when prices are low, enter into long-term fixed price contracts, or use financial instruments like options to lower the risk and uncertainty of changing prices.

The electricity generation sector is the largest consumer of natural gas, both nationally and in California,[196] so natural gas price volatility significantly affects this sector and ultimately the price of electricity. Natural gas price volatility leads to increased uncertainty for both regulated utilities and merchant power firms about the ongoing costs of operating natural gas-fired power plants, both existing and new. Increased uncertainty also heightens concern regarding investment in new natural gas-fired plants, which may be seen as more risky when compared to other generation technologies that use coal or renewable fuels.

Natural gas producers are also affected by price volatility, making project evaluation and investment decisions less certain. Price volatility can trigger concerns by lenders and investors and increase the cost of capital as lenders and investors demand greater returns because of increased uncertainty. Price volatility also contributes to recurring boom-bust production cycles and associated operational problems, such as employee turnover and expensive start-up and shutdown costs. The current period of falling natural gas prices provides a good example. Natural gas production is largely a capital intensive venture during well development but has lower marginal production costs once the well is producing gas. During periods of low prices, active wells can remain profitable to operate but, in the longer term, declining prices can lead to reduced production when the number of drilling rigs is reduced in response to sustained lower prices. Since prices peaked in July 2008,

196 Energy Information Administration, Natural Gas Consumption by End Use data, available at: [http://tonto.eia.doe.gov/dnav/ng/ng_cons_sum_dcu_nus_a.htm].

FIGURE 17: HENRY HUB SPOT PRICES 1996–2008



Source: Natural Gas Intelligence data

United States drilling rig numbers dropped each week as prices continued to decline.[197]

Figure 17 shows a period of relatively stable natural gas prices in the late 1990s, followed by several periods of large price spikes after 2000. Henry Hub[198] spot prices traded within a $2/Mcf to $3/Mcf band throughout the late 1990s and early 2000s, rose to $4/Mcf, and surpassed $6/Mcf by the middle of the decade. One key factor that caused price increases was the growth in domestic demand that exceeded United States domestic production capabilities because North American basins were maturing and producing less gas. The combination of increasing domestic demand and declining domestic production resulted in natural gas prices moving higher.

There have been four major price spikes since 2000 that were caused by many of the physical and financial market factors mentioned earlier in this section. However, each price spike was influenced to different degrees by the various factors. For example, a severe cold winter storm played the significant role in the February 2003 price spike, and back-to-back hurricanes played the significant role in the fall 2005 price spike. The price spikes of winter 2000–2001 and summer 2008 were the result of a number of different factors, including market manipulation and market speculation.

197 Energy Information Administration's April 23, 2009, *Natural Gas Weekly* update reports that the domestic drilling rig count is down over 50 percent from its high in August 2008, reached in response to July 2008 peak prices.

198 Henry Hub is located in Louisiana and is North America's main natural gas trading hub and most widely quoted natural gas pricing point. It interconnects four intrastate and nine interstate pipelines that can transport enough natural gas to satisfy about 3 percent of total United States demand.

The flexibility from having extra infrastructure, coupled with supplies from lower-priced production areas, helps shield the state from the brunt of price volatility. Since California is part of an international natural gas market that includes Canada, the United States, and Mexico, a disruption in one area ripples though the rest of the market. California is not immune to the ripples, but the ripples are much smaller now when they reach the state. Prices of natural gas at California's border are among the lowest in the nation, with current prices considerably less than the Henry Hub price.

Fuels and Transportation

Although the fuels and transportation energy sector is responsible for producing the greatest volume of GHG emissions – nearly 40 percent of California's total – the issues confronting this sector go far beyond climate change. Reducing California's dependence on petroleum in general and foreign crude oil in particular are equally pressing issues. Doing so would not only reduce GHG emissions, but would also mitigate the effects that global demand, geopolitical events, crude oil refining capacity and outages, and petroleum infrastructure challenges have on fuel prices and the average cost of production of goods and services, both of which directly affect the state's economy and gross state product.

Assembly Bill 32 does not directly address GHG emissions reduction in the transportation sector, but legislation at both the state and federal level does. California's AB 1007 (Pavley, Chapter 371, Statutes of 2005), AB 118 (Núñez, Chapter 750, Statutes of 2007), AB 1493 (Pavley, Chapter 200, Statutes of 2002), California's Low Carbon Fuel Standard (LCFS), and the federal Energy Independence and Security Act's revisions to the Renewable Fuel Standard (RFS2) set policies and standards that will ultimately change vehicle and fuel technologies and accelerate the market for low carbon fuels well beyond the current level of demand.

The following section summarizes the Energy Commission's 2009 transportation supply and demand forecast. Providing this data will give decision makers a snapshot of the state's future fuel demand and supply for petroleum, as well as renewable and alternative fuels and vehicles. This data is imperative to understanding future fuel supply and infrastructure needs that could have a major impact on consumer reliability and the environment. In past *IEPR*s, the Energy Commission forecast has only included projections for petroleum transportation fuels. For the *2009 IEPR* cycle, staff expanded the list of transportation fuels to include demand forecasts for E85 (a blend of 15 percent gasoline and 85 percent ethanol), B20 (a blend of 80 percent diesel and 20 percent biodiesel), electricity, compressed natural gas (CNG), and LNG, with more limited analysis of hydrogen and propane.

Transportation Fuels Supply and Demand

In its transportation forecasts, the Energy Commission analyzes trends of transportation demand-related indicators, as well as demographic and economic variables. The transportation demand forecasts encompass four primary transportation sectors:

- Commercial and residential light-duty vehicles (under 10,000 pounds)
- Medium- and heavy-duty transit vehicles, including rail (over 10,000 pounds)

- Medium- and heavy-duty freight vehicles, including rail

- Commercial aviation

Each of these sectors is associated with a distinct forecasting model that estimates the demand for that transportation sector. The California Conventional Alternative Fuel Response Simulator, Freight, Transit, and Aviation models represent each of the corresponding transportation sectors. Staff used a range of fuel price cases, as well as economic and demographic projections from the Department of Finance (DOF) and Moody's Economy.com to cover the forecast period.

Demographics

Demographic growth trends are key indicators of future consumer travel demand. For the next 20 years, DOF forecasts growth in California's population of 25 percent, and Moody's Economy.com forecasts growth in personal income of 76 percent. Between 2009 and 2030, population is projected to increase at an annual compound average rate of 1.15 percent, compared with a growth rate of 2.94 percent in real personal income over the same period. These growth rates indicate that travel demand in California will also likely increase over the forecast period.

To provide historical context, California's gross state product (GSP) increased by 40 percent in real terms from 1998 to 2008. During that same period, employment growth was only 10 percent. The impact of the economic recession is evident in that both GSP and employment decreased between 2008 and 2009. The GSP is projected to return to a positive growth rate by 2010, while total non-farm employment projections do not begin to exhibit positive growth until 2011. Non-farm employment is projected to grow by 20 percent during the forecast period of 2009–2029, in contrast with higher projected growth rates for both population and GSP.

The Energy Commission's draft staff report, *Transportation Energy Forecasts and Analyses for the 2009 Integrated Energy Policy Report* contains more details on these demographic findings.[199]

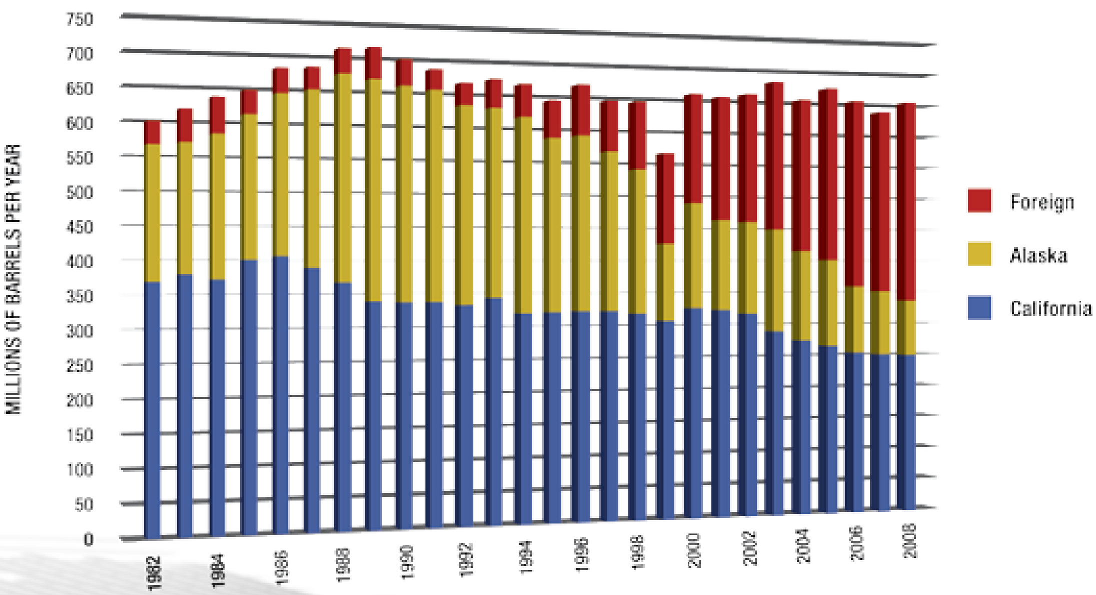
Fuel Supply and Demand

The recession has had a significant impact on the state's transportation sector. Consumer demand for gasoline and diesel fuels continues to decline. Job growth and industrial production – drivers of air travel – are also declining, causing the aviation sector to experience a drop in air traffic. In response to this and higher fuel prices, the aviation sector has reduced the number of planes in service and taken the least efficient aircraft out of service. In addition, the freight sector (rail and trucking) is experiencing a decrease in container movement at the state's three major marine ports – Los Angeles, Long Beach, and the Bay Area.

The early years of the Energy Commission's transportation fuel demand forecast show a recovery from the recession. Because the economic and demographic projections used in these forecasts indicate a return to economic and population growth, fuel demand in the light-duty, medium- and heavy-duty vehicles and aviation sectors tends to resume historical growth patterns. However, the mix of fuel types is projected to change significantly as the state transitions from gasoline and diesel to alternative and renewable fuels.

199 California Energy Commission, *Transportation Energy Forecasts and Analyses for the 2009 Integrated Energy Policy Report,* August 2009, CEC-600-2009-012-SD, available at: [http://www.energy.ca.gov/2009publications/CEC-600-2009-012/CEC-600-2009-012-SD.PDF].

FIGURE 18: CRUDE OIL SUPPLY SOURCES FOR CALIFORNIA REFINERIES



Source: Annual crude oil supply data from the California Energy Commission's Petroleum Industry Information Reporting Act database

Petroleum

Although the state's 20 crude oil refineries processed more than 1.8 million barrels a day of crude oil in 2008, California crude oil production continues to decline, despite record crude oil prices and increased drilling activity greater than at any point since 1985. Since 1986, California crude oil production declined by more than 41 percent at an average rate of 3.2 percent per year over the last 10 years and slowed to an annual average of 2.2 percent between 2006 and 2008. Figure 18 indicates the decline in California-sourced oil and the increasing reliance on marine imports, primarily from foreign sources, as Alaska production also declines. The state's refinery capacity is expanding at a slower rate than that of the United States and the rest of the world. Refinery capacity growth, known as refinery creep, is relatively low and expected to increase at an annual average rate between zero and 0.45 percent per year through 2030.

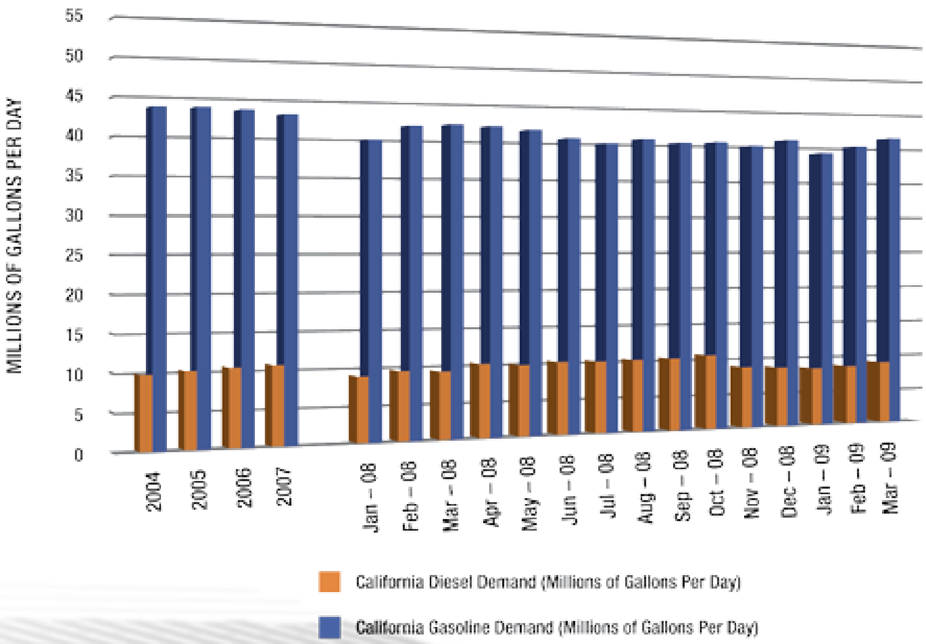
Increased exploration and drilling in state and federal waters could reverse the continuing decline of the state's crude oil production, but any significant production of off-shore oil is at least a decade away. In 2008, the federal government lifted the moratorium on drilling in the Outer Continental Shelf off the coast of California. It is uncertain if off-shore drilling will proceed because of numerous environmental and economic concerns. If expanded off-shore exploration and development is allowed to proceed, however, crude oil production off the coast could increase from 110,000 barrels per day in 2008, to approximately 310,000 barrels per day by 2020, and 480,000 barrels per day by 2030.[200]

200 U.S. Department of Energy/Energy Information Administration *Annual Energy Outlook 2009 and U.S. Energy Security*, Deputy Assistant Secretary, Office of Petroleum Reserves, Washington, D.C., February 2009 presentation, data from slide 6. Pacific Region is assumed to include only California.

Crude oil imports are determined by trends in consumer demand, California refinery output, and exports of petroleum products to neighboring states. In 2008, California refiners imported 406 million barrels of crude oil. Differences in crude oil import forecasts result from contrasting assumptions on the production capabilities of California's refineries and the production of California crude oil.

In the staff's Low Crude Oil Import forecast, refinery production capabilities remained constant over the forecast period, and California crude oil production declined at a rate of 2.2 percent. The High Crude Oil Import forecast assumed refinery production capabilities increased at a rate of .45 percent a year and California crude oil production declined at a rate of 3.2 percent. Under the Low Crude Oil Import forecast, annual crude oil imports increased by 34 million barrels between 2008 and 2015, by 55 million barrels by 2020, and by 91 million barrels by 2030 (a 22.5 percent increase compared to 2008). Under the High Crude Oil Import projection, annual crude oil imports rose by 70 million barrels between 2008 and 2015, by 113 million barrels by 2020, and by 190 million barrels by 2030 (a 47 percent increase compared to 2008). It should be noted that most crude oil imports now come from foreign sources. This means that even under a low-import case, the state's dependence on imported crude oil would grow. During the forecast period, the changes in levels of transportation fuel imports are determined by trends in consumer demand, California refinery output, and exports of petroleum products to neighboring states. The staff forecast shows that California's gasoline imports would decrease significantly over the next 15 years (under the High Petroleum Product Import Case), while imports of diesel and jet fuel would still rise to keep pace with growing demand for those products. Under the Low Petroleum Product Import Case scenario, the growing imbalances between gasoline and

FIGURE 19: HISTORIC CALIFORNIA GASOLINE AND DIESEL DEMAND



Source: California Energy Commission staff-adjusted Board of Equalization sales data

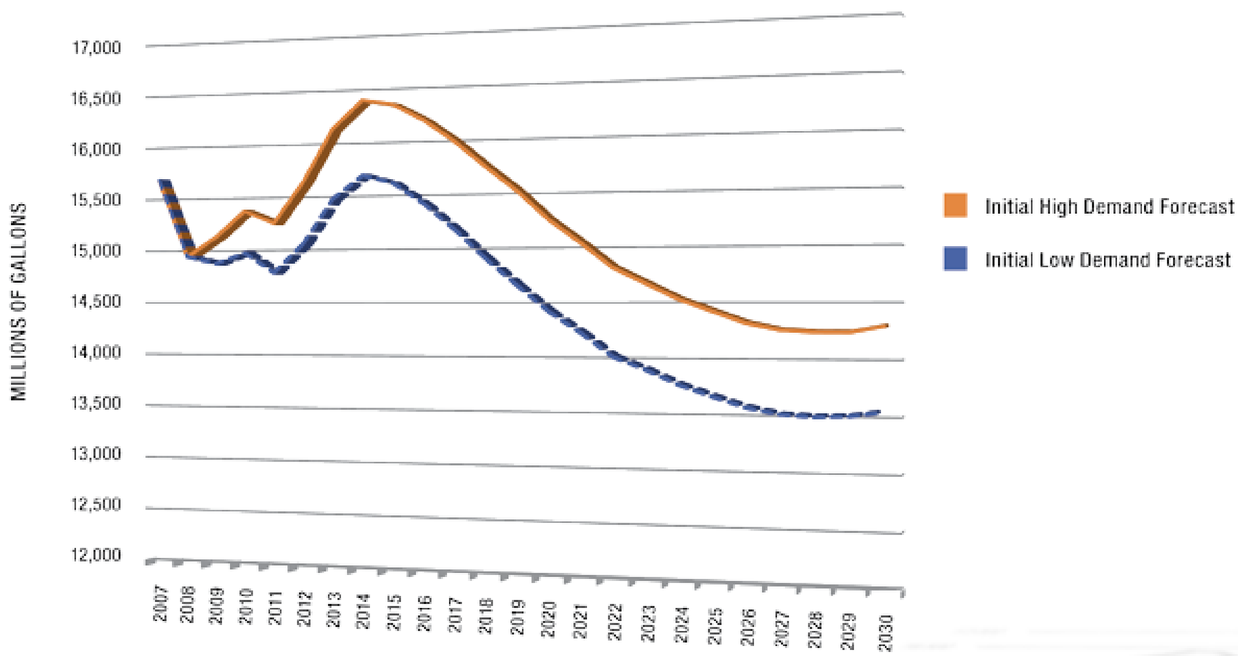
the other transportation fuels are even more extreme, resulting in a total net decline of imports of at least 116,000 barrels per day by 2025, whereby California's gasoline supply balance would switch from a net import of over 51,000 barrels per day in 2008 to a net export of over 218,000 barrels per day in 2025. The latter outcome is unlikely since refiners would adjust operations to decrease the ratio of gasoline components produced from each barrel of crude oil processed.

The Energy Commission staff recently analyzed taxable fuel sales data from the Board of Equalization to determine consumption trends as shown in Figure 19.

Overall, California is experiencing a downward trend in sales for gasoline, diesel, and jet fuel. For example, California's average daily gasoline sales for the first four months of 2009 were 2.1 percent lower than the same period in 2008, continuing a reduction in demand observed since 2004. Daily diesel fuel sales for the first three months of 2009 were 7.7 percent lower than the same period in 2008, continuing a declining trend since 2007. Recent demand trends for jet fuel (8.9 percent decline in 2008) are similar to diesel fuel and reflect the impact of the economic downturn and higher fuel prices.

Staff expects annual gasoline consumption to decrease over the forecast period, largely because of high fuel prices, efficiency gains, competing fuel technologies, and mandated increases of alternative fuel use. The estimate of future gasoline and diesel fuel demand for California was the result of two

FIGURE 20: INITIAL CALIFORNIA GASOLINE DEMAND FORECAST – NO RFS2 ADJUSTMENT

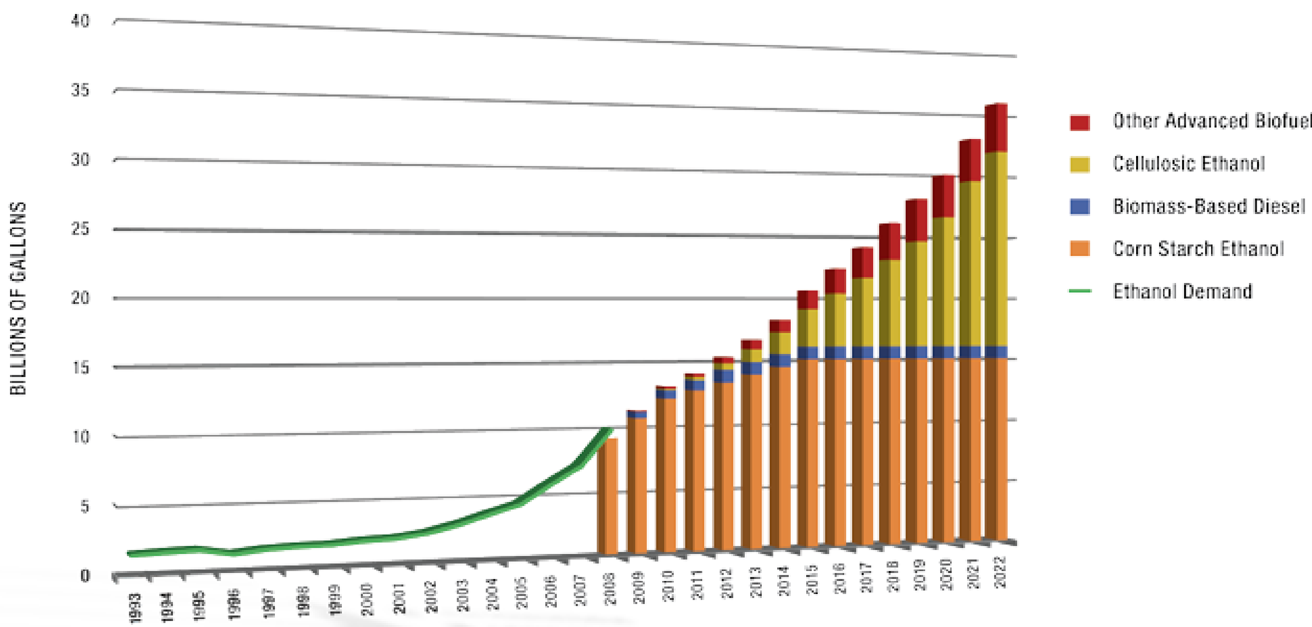


Source: California Energy Commission

distinct stages of analysis. The first step was to quantify demand levels using in-house computer models for both traditional fuels (gasoline and diesel fuel) and specific types of alternative fuels. The second step was to determine the impact of the federal renewable fuel mandates (discussed later in this section) that will likely result in even higher levels of ethanol and biodiesel use beyond the levels initially forecast during the first step of the analysis. Higher levels of renewable fuels calculated in the second step of the analysis would result in slightly lower levels of gasoline and diesel fuel demand for all modeling scenarios.

In the initial results of the forecast's Low Petroleum Price Case (High Demand), the recovering economy and lower relative prices led to a gasoline demand peak in 2014 of 16.40 billion gallons before falling to a 2030 level of 14.32 billion gallons, 4.0 percent below 2008 levels (Figure 20). The initial High Petroleum Price Case (Low Demand) forecast projects a gasoline demand peak of 15.69 billion gallons in 2014 before declining to 13.57 billion gallons by 2030, a decrease of 9.0 percent compared to 2008. Between 2008 and 2030, staff expects total diesel demand in California to increase 49.8 percent in the initial results of the High Petroleum Price Case (Low Demand) to 5.14 billion gallons and 57.4 percent in the Low Petroleum Price Case (High Demand) to 5.40 billion gallons. Between 2008 and 2030 staff expects that jet fuel demand in California will increase by 62.8 percent to 5.12 billion gallons in the High

FIGURE 21: U.S. ETHANOL USE AND RENEWABLE FUEL STANDARD OBLIGATIONS 1993–2022



Sources: Energy Information Administration, U.S. Environmental Protection Agency, and California Energy Commission

Petroleum Price Case (Low Demand) and 82.9 percent to 5.75 billion gallons in the Low Petroleum Price Case (High Demand).

Renewable and Alternative Fuels

Policies mandating increased renewable fuel use are projected to play a significant role in reducing the state's dependence on petroleum. At the federal level, the current Renewable Fuel Standard (RFS1) program, implemented under the Energy Policy Act of 2005, amended the Clean Air Act by establishing the first national renewable fuel standard. The Energy Independence and Security Act of 2007 made changes to the goals of RFS1, mandating increased use of ethanol and biodiesel. These new requirements, known as the RFS2, establish new specific volume standards for cellulosic ethanol, biomass-based diesel, advanced biofuel, and total renewable fuel that must be used in transportation fuel each year. The RFS2 also includes new definitions and criteria for both renewable fuels and the feedstocks used to produce them, including new GHG thresholds for renewable fuels. The U.S. EPA is in the process of a rulemaking, and the target date for changes to take effect is January 1, 2010.[201]

Specifically, the RFS2 will require refiners, importers, and blenders to achieve a minimum level of renewable fuel use each year either through blending or purchasing of Renewable Identification Number credits from other market participants who blend more renewable fuel than needed for their individual obligations. For 2009, the California RFS2 obligation is just over 10 percent and assumes that 11.1

201 United States Environmental Protection Agency, see [http://www.epa.gov/OMS/renewablefuels/420f09023.htm].

billion gallons of renewable fuel will be blended into gasoline and diesel fuel nationally. Figure 21 depicts these renewable fuels obligations.

In recent years, the increased use of ethanol as a transportation fuel has resulted in an expanded domestic production capacity, fluctuating quantities of imports, and inventory build or draws as necessary to balance out demand. As of June 2009, there was an estimated 2.2 billion gallons of surplus ethanol production capacity in the United States. This oversupply of domestic ethanol is primarily responsible for the recent climate of sustained, poor production economics, which brought about the closure of several national and all California ethanol production operations. However, this development will likely be temporary as demand for ethanol is forecast to increase significantly over the next several years because of the RFS2 regulations.

This oversupply of ethanol, along with relatively low ethanol prices in the United States, has reduced ethanol imports to modest levels. Imports of ethanol play a lesser role in California's supply picture, but this could change because of carbon intensity requirements, the state's LCFS, and the fuel obligations of RFS2. Specifically, California is expected to start importing more ethanol from Brazil, as it has lower carbon intensity relative to Midwest ethanol and will meet the LCFS policy requirements.

As for biodiesel, production has increased dramatically in the United States since 2005 in response to federal legislation that included a $1 per gallon blending credit for all biodiesel blended with conventional diesel fuel. As of July 2009, there was more than 2.3 billion gallons of biodiesel production capacity for all operating United States facilities, along with another 595 million gallons per year of idle production capacity and another 289 million gallons per year of capacity under construction. Even though the LCFS will greatly increase the use of biodiesel as a blending component (because of its lower carbon intensities), it appears there will still be sufficient domestic supply from biodiesel production facilities to meet the RFS2 blending requirements for several years.

Increased output of biodiesel, due to the blending credit and attractive wholesale prices, has resulted in increased United States exports to the European Union (EU). In 2008, United States producers exported nearly 70 percent of their supply to the EU. However, in July 2009 the EU officially imposed import duties on United States biodiesel for the next five years. Because of this ruling, United States exports to the EU are likely to decline dramatically.

As already shown, a projected impact of the RFS2 is that it would increase ethanol and biodiesel demand in California. Under the High Petroleum Price Case (Low Demand) for gasoline, staff forecast total ethanol demand in California to rise from 1.2 billion gallons in 2010 to 2.1 billion gallons by 2020. Under the Low Petroleum Price Case (High Demand) for gasoline, staff projects total ethanol demand in California to rise from 1.2 billion gallons in 2010 to 2.6 billion gallons by 2020. Staff also forecast that ethanol demand would exceed an average of 10 percent by volume in all gasoline sales between 2012 and 2013. However, because of various fuel specification and vehicle warranty limitations, it is unlikely that the low-level ethanol blend limit in California would be greater than the current 10 percent by volume (E10), even if the U.S. EPA ultimately grants permission for United States refiners and marketers to blend E15 gasoline.

To meet RFS2 requirements, the availability of E85 at retail sites will need to increase dramatically to ensure that sufficient volumes can be sold. This scenario would require significant increases in both the number of E85 dispensers and flex-fuel vehicles (FFVs). For example, assuming a 10 percent ethanol blending limit, or "blend wall," E85 sales in

California are forecast to rise from 2 million gallons in 2010 to 1.3 billion gallons in 2020 and 1.6 billion gallons by 2030 under the Low Petroleum Price Case (High Gasoline Demand). E85 consumption required to meet the RFS2 is shown in Figure 22; Figure 23 shows the impact of the RFS2 on the final Low Gasoline Demand forecast. However, the pace of this expansion still may not be enough to achieve compliance because of specific infrastructure challenges and lack of incentives (see the Infrastructure Adequacy section below for more details).

As for biodiesel demand, the High Petroleum Price Case (Low Demand) shows biodiesel "fair share," or California's share of mandated biodiesel use proportional to its share of total United States diesel use, would increase from 38 million gallons in 2010 to 57 million gallons by 2030. Under the Low Petroleum Price Case (High Demand), biodiesel fair share ranges from 37 million gallons in 2010 to 58 million gallons by 2030. Based on these projected volumes, California's average biodiesel blending concentration is not expected to be higher than 1.8 percent. However, California's LCFS requirements are anticipated to increase the level of biodiesel use to significantly higher levels that have yet to be fully quantified.

Infrastructure Adequacy

California needs sufficient fuel infrastructure to ensure reliable supplies of transportation fuels for its citizens. Petroleum and alternative and renewable fuels face significant infrastructure issues from the wholesale and distribution level to the end user. The petroleum infrastructure is strained at marine ports and throughout the distribution system. In the case of alternative and renewable fuels, much of the infrastructure that will soon be necessary is not even in place. It is critical that the state expand upon the current petroleum fuel infrastructure to ensure a continued supply of transportation fuel for California and neighboring states and that it build new infrastructure to ensure that California can meet its mandated renewable and alternative fuel goals.

The following two sections describe the most pressing issues and barriers affecting development of the petroleum and renewable and alternative fuels infrastructures in California.

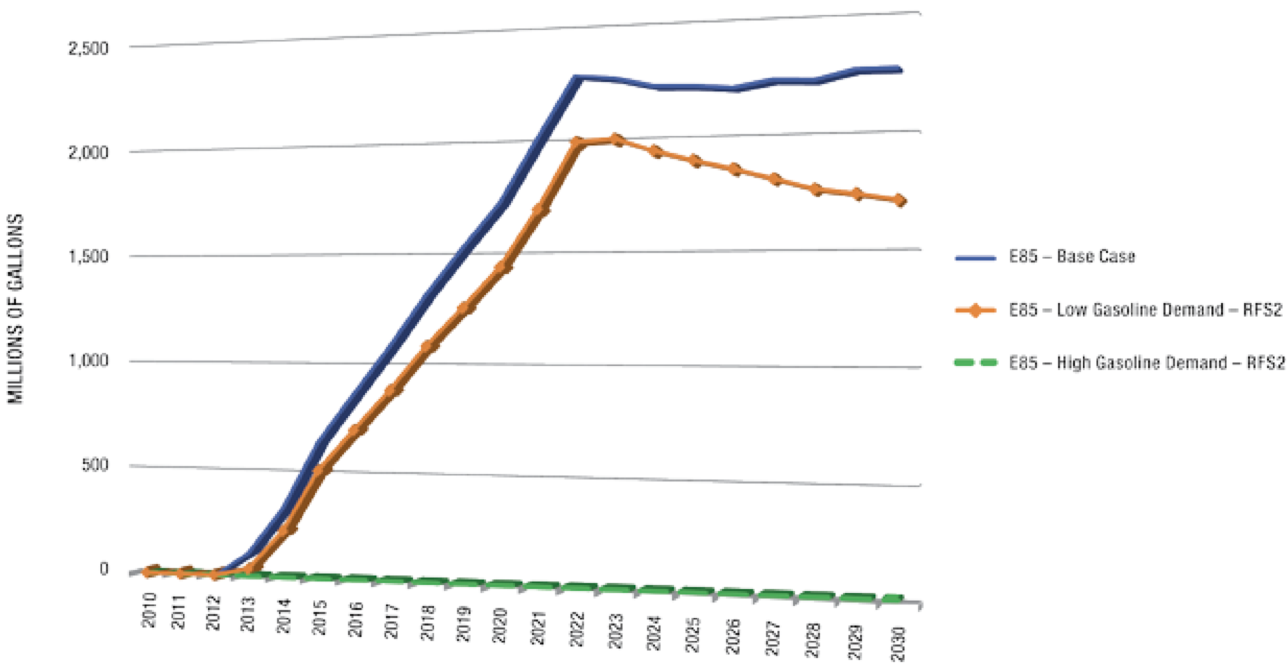
Petroleum Infrastructure

The Energy Commission forecasts that crude oil imports will continue to increase, requiring expansion of the existing crude oil import infrastructure. This infrastructure is critical in ensuring a continued supply of feedstocks to enable refiners to operate their facilities and maintain a reliable supply of fuel for California and neighboring states.

The Energy Commission forecasts that the existing crude oil import infrastructure in Southern California must expand to avoid shortages in supplies for refinery operations. Although progress has been made on developing a facility at Pier 400, Berth 408 in the Port of Los Angeles, the permitting process to start construction has stretched to more than four years. In fact, Plains All-American, the project developer, still does not have all of the requisite approvals to start construction.

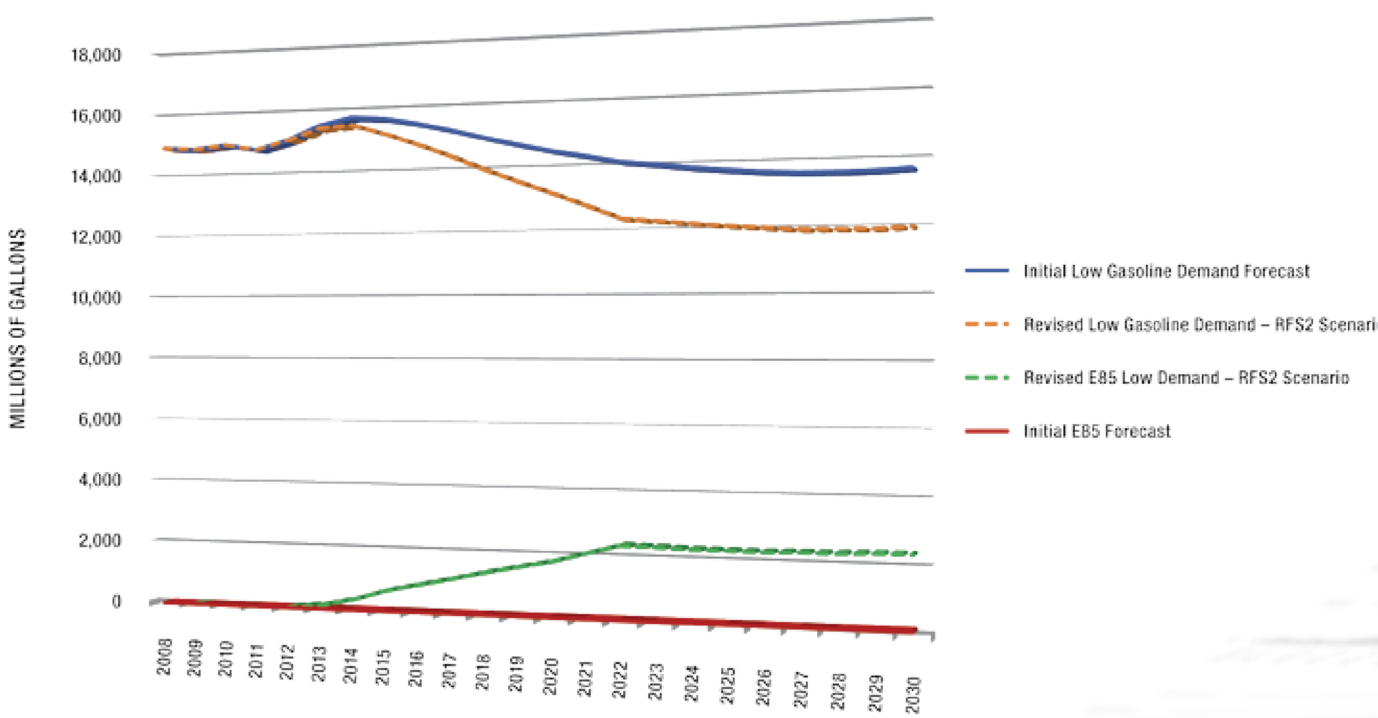
To add further strain, especially in Southern California, staff expects the increased imports of crude oil to result in a greater number of marine vessels arriving in California ports, with 46 to 272 additional arrivals per year by 2030. Additional storage tank capacity beyond that already identified as part of the Berth 408 project must be constructed to handle the incremental imports, and it is unclear where these can be located given the competition for land in and around the ports. Also, the opening of off-shore drilling along California's coast could require additional infrastructure in the way of platforms, interconnecting pipelines, crude oil trunk lines, and pump stations. It is

FIGURE 22: CALIFORNIA E85 DEMAND FORECAST 2010–2030



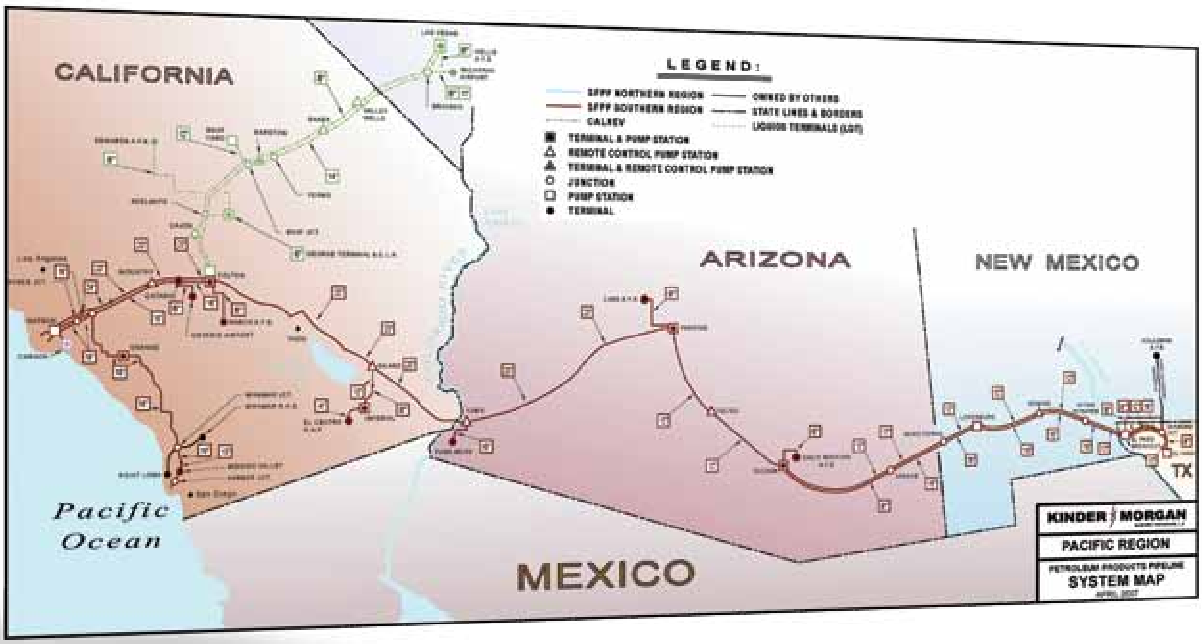
Source: California Energy Commission, *Transportation Energy Forecasts and Analyses for the 2009 Integrated Energy Policy Report*

FIGURE 23: REVISED LOW DEMAND FORECAST 2010–2030



Source: California Energy Commission

FIGURE 24: KINDER MORGAN INTERSTATE PIPELINE SYSTEM



Source: Kinder Morgan Pipeline Company

recognized that some near-term offshore drilling projects using existing platforms or shore-based operations would mostly be able to use existing crude oil distribution infrastructure.

California exports large amounts of transportation fuels to Nevada and Arizona. Pipelines that originate in California provide nearly 100 percent of the transportation fuels consumed in Nevada and approximately 55 percent of fuels consumed in Arizona. Kinder Morgan's recent East Line pipeline expansion from Texas to Arizona (see Figure 24) caused a drop in Arizona's demand for California fuel exports in 2008, as refiners and marketers shifted to Texas and New Mexico for supply. If Kinder Morgan does not make additional expansions to the pipeline distribution systems, the continued growth of transportation fuel demand in Nevada could exceed pipeline capacity, but not until 2021. Overall, the near- and long-term forecast periods indicate that transportation fuel demand growth in Nevada and Arizona could place additional pressure on California's refineries and petroleum marine import infrastructure.

Renewable and Alternative Fuels and Vehicles Infrastructure

To meet the requirements of RFS2 and the LCFS, several issues must be resolved regarding the adequacy of additional biofuel supplies and the infrastructure needed to receive and distribute increased quantities of ethanol and biodiesel to California consumers. The primary challenges faced by makers of alternative fuel vehicles include a lack of infrastructure in both fuel production and refueling, the need to develop technologies to reduce battery costs, the need for standardized testing, and consumer acceptance of vehicles. Simply stated, the refueling infrastructure has to be in place when the vehicles arrive. Moreover, these refueling sites must meet consumer expectations for access, convenience, and fuel quality assurance.

Flex-fuel vehicles are designed to run with either gasoline or a blend of up to 85 percent ethanol (E85). As shown in Figure 25, the number of FFVs registered in California must increase from 382,000 vehicles in October 2008 to as many as 2.4 million by 2020 to provide demand for enough E85 to be sold to meet the RFS2. However, California's current retail infrastructure is not adequate to handle an increase in E85 sales. The general public only has access to about 25 E85 stations in California today, so a vast majority of FFV owners are fueling with regular gasoline. Retail station owners and operators are not required to make E85 available for sale to the public under RFS2.

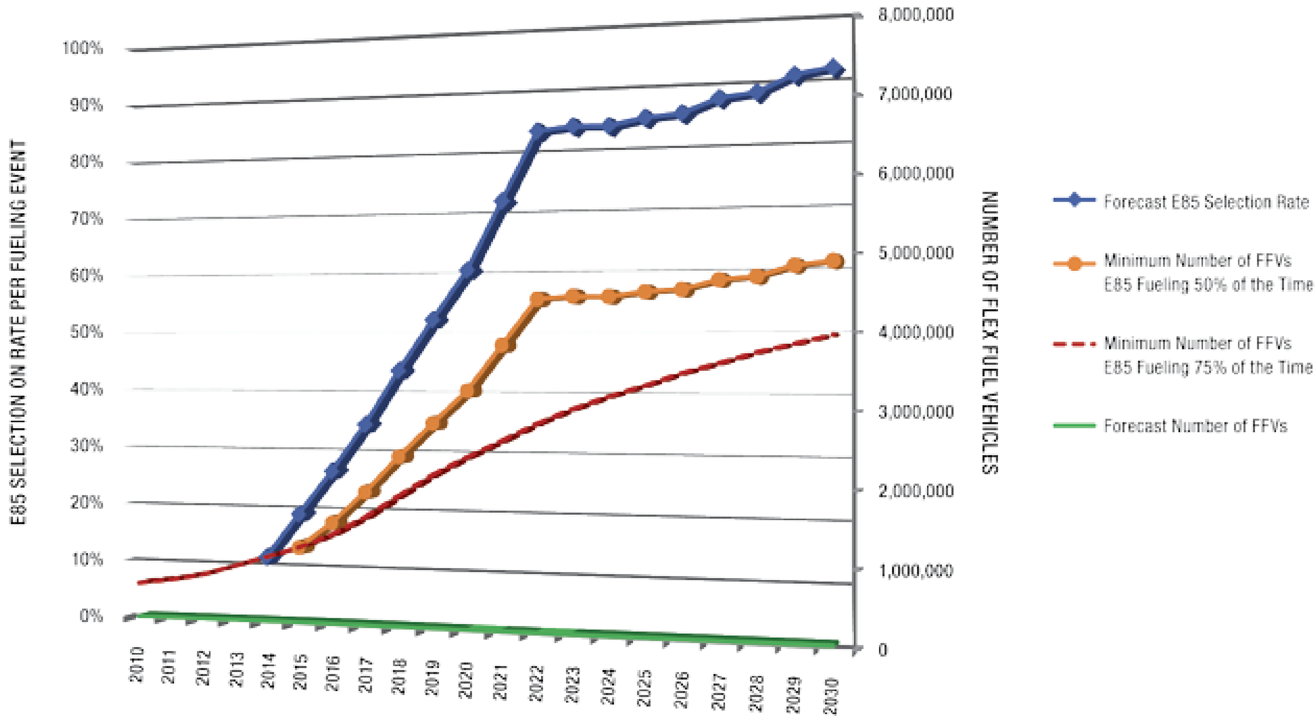
Consumers may continue to buy more FFVs, but that will have little impact on decreasing petroleum consumption or meeting RFS2 standards if E85 is not available at fueling stations. Depending on the average quantity of fuel sold by a typical E85 dispenser, California could require between 3,200 and 23,300 E85 dispensers by 2020 (Figure 26). E85 retail infrastructure is expensive. Costs for installing a new underground storage tank, dispenser, and associated piping range between $50,000 and $200,000. Statewide, the E85 retail infrastructure investment costs could be as low as $192 million, to upward of $4.7 billion between 2009 and 2020. Between 2009 and 2030, the E85 dispenser infrastructure costs could range from $251 million to $6.1 billion. One approach to reduce this anticipated infrastructure cost is for the California Legislature to consider requiring new building code standards that all gasoline-related equipment (underground storage tanks, dispensers, associated piping and so on) be E85 compatible for construction of any new retail stations or replacement of any gasoline-related equipment beginning January 1, 2011. This approach would increase the likelihood of success of renewable fuel penetration policy goals.

The state's current retail infrastructure can handle biodiesel blends at concentrations of 5 percent (B5) or less. On the wholesale and retail receipt and distribution levels, expanded use of biofuels (ethanol and biodiesel) can use the existing network of storage tanks and retail dispensers with little to no modifications for low-level blends (E10 and B5). However, higher concentrations of ethanol (E85) and biodiesel (B20) would require significant infrastructure modifications requiring the installation of thousands of new dispensers and underground storage tanks. In addition, wholesale distribution terminal operators would need to install additional storage tanks to enable the blending of biodiesel at B5 or B20 levels.

The Energy Commission's PIER transportation subject area is pursuing two classes of research initiatives that may allow the use of existing fuel infrastructure to reduce the cost of implementing renewable and alternative fuels. The first class is research into technologies or methodologies such as additives, blending techniques, and thermal thresholds for making renewable and alternative fuels compatible with the existing infrastructure. PIER is initiating a solicitation titled "Research for Biofuels Infrastructure Compatibility." The second is the development of alternative fuels designed for conventional fuel compatibility. PIER is investigating large molecule alternative fuels, such as renewable diesel or "green gasoline," which contain mixtures of complex chemicals and mimic the properties of conventional fuels. Many are fungible with standard petroleum fuels. Therefore, the emerging field of large molecule research and development holds out the potential for biofuels that require little or no new infrastructure or engine modification and are transparent to their end users.

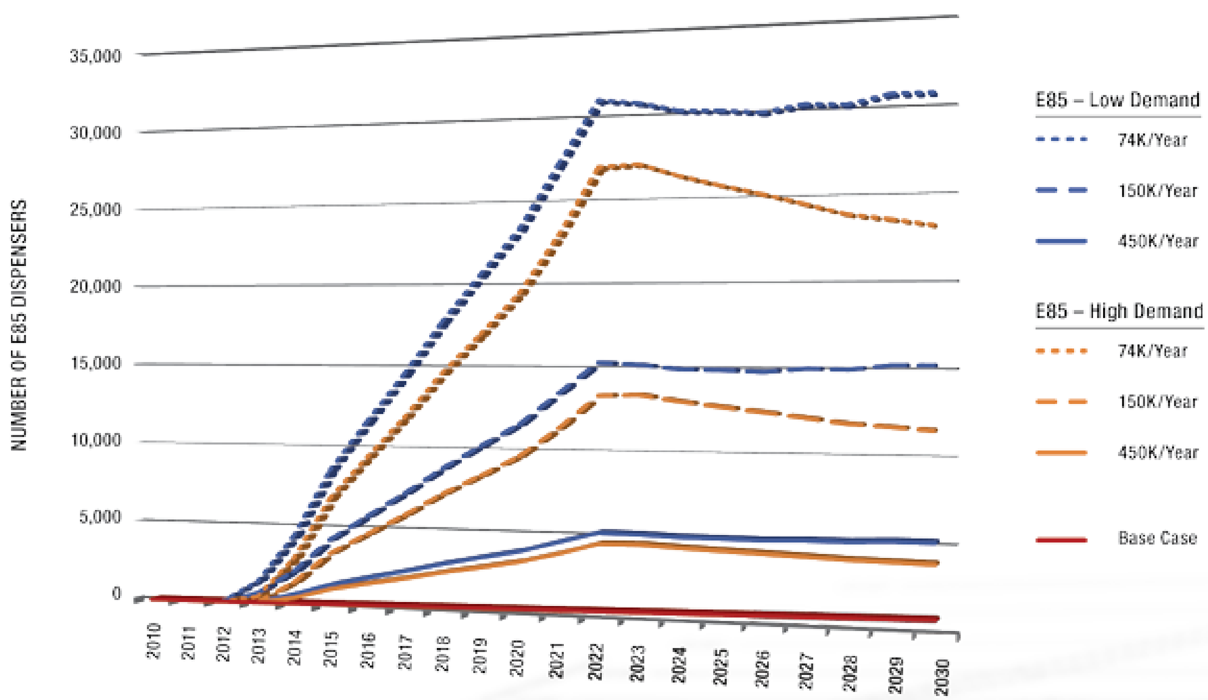
Compressed natural gas or LNG vehicles run on natural gas and have been in use in California for more than 20 years. In 2008, there were 24,810 light-duty CNG vehicles

FIGURE 25: CALIFORNIA FLEX-FUEL VEHICLE LOW DEMAND FORECAST 2010–2030



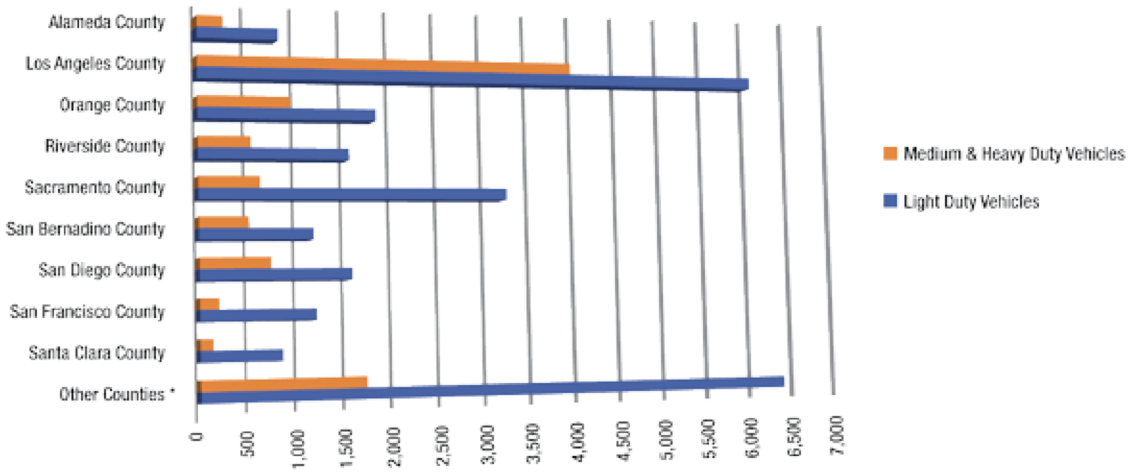
Source: California Energy Commission, *Transportation Energy Forecasts and Analyses for the 2009 Integrated Energy Policy Report*

FIGURE 26: CALIFORNIA E85 DISPENSER FORECAST 2010–2030



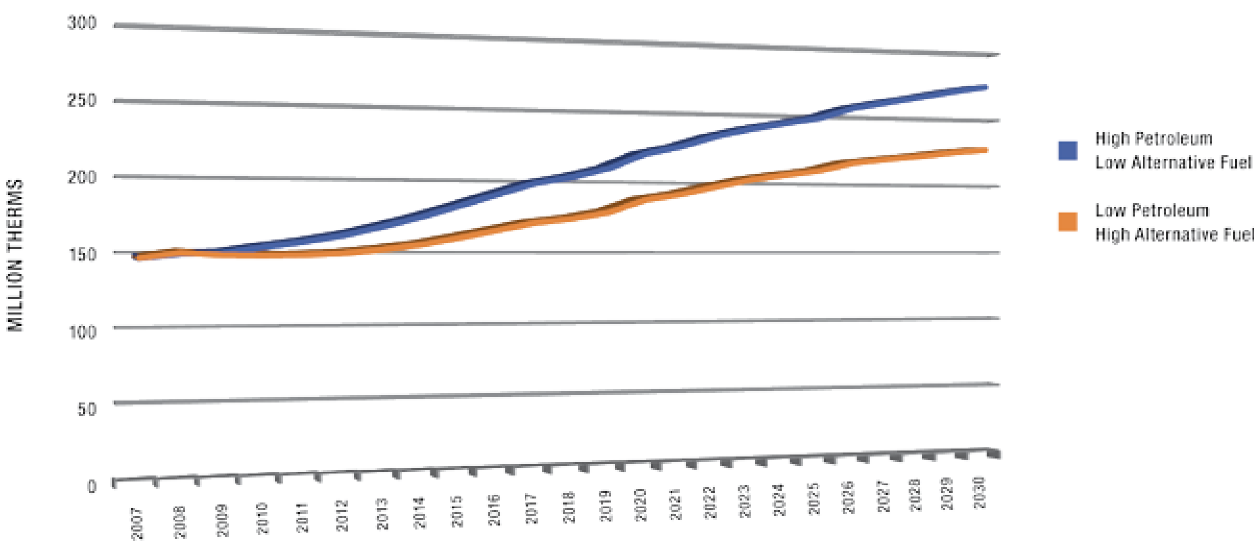
Source: California Energy Commission, *Transportation Energy Forecasts and Analyses for the 2009 Integrated Energy Policy Report*

FIGURE 27: NATURAL GAS VEHICLE COUNTS BY SPECIFIC COUNTIES, OCTOBER 2008



Source: California Energy Commission analysis of DMV Vehicle Registration Database
*The Other Counties category is composed of counties with less than 500 light duty natural gas vehicles

FIGURE 28: CALIFORNIA TRANSPORTATION NATURAL GAS DEMAND FORECAST



Source: California Energy Commission

registered and operating in California; half of these vehicles (10,747) were registered to individual owners.[202] This represents a significant increase over 2000 totals of 3,082; however, the light-duty natural gas vehicle population has been relatively flat since 2001. State and local governments accounted for 31 percent of the ownership of light-duty CNG vehicles with 78 percent of those vehicles existing in government vehicle fleets of 1,000 vehicles or more. In addition, there were 9,674 medium- and heavy-duty natural gas vehicles registered in California in 2008, with 7,144 of those vehicles being CNG-powered buses.

Figure 27 illustrates natural gas vehicle counts for specific California counties.

The state had more than 460 natural gas stations at the beginning of 2009, with more than one-third of those stations offering public access.[203] Compressed natural gas refueling options could be increased through the use of a refueling appliance located at an owner's home.[204] This refueling process takes on average anywhere between five to eight hours to fill 50 miles worth of natural gas and requires the owner to have access to a natural gas line.

California's use of natural gas in the transportation sector is forecast to increase substantially. As measured in therms, the forecast shows demand rising from 150.1 million therms in 2007 to 270.3 million therms by 2030 under the High Petroleum Price Case (High Natural Gas Demand Case) and 222.9 million therms by 2030 under the Low Petroleum Price Case (Low Natural Gas Demand Case, Figure 28). The number of CNG vehicles is expected to grow from approximately 17,569 in 2007 to 112,025 by 2020 and 206,071 by 2030.

In 2008, the Energy Commission's PIER vehicle technologies completed the Natural Gas Vehicles Research Road Map, which identified initiatives and projects that research, develop, demonstrate, and deploy advanced fuel-efficient natural gas-powered transportation technologies and fuel-switching strategies that result in a cost-effective reduction of petroleum fuel use in the short and long term.[205] This PIER subject area is also completing a light-duty vehicle research road map that will advance science and technology to enable alternative-fueled vehicle deployment. Initial road map findings have identified near-term research initiatives to increase vehicle efficiency. For example, PIER vehicle technologies will target research to develop efficiency feedback systems, which will provide drivers with real-time fuel consumption and efficiency information to influence driving behavior and reduce fuel use. This strategy will also help with the deployment of alternative fuel vehicles. While the technology is largely developed, there is an opportunity for research to address system optimization to determine the most effective interface between the driver and feedback system.

There were 14,670 full-electric vehicles (FEVs) operating in California in 2008. Although this is a substantial increase over the 2,905 operating in 2001, it is substantially less than the 23,399 in operation in 2003. Since 2004, this population has remained relatively flat. These FEVs are primarily neighborhood electric vehicles and sub-compacts.

202 For this discussion, dual fuel compressed natural gas/gasoline vehicles are considered as compressed natural gas vehicles in vehicle counts. All vehicle counts come via the Department of Motor Vehicles' database.

203 See [http://www.cngvc.org/why-ngvs/fueling-options.php].

204 See [http://www.pge.com/myhome/environment/pge/cleanair/naturalgasvehicles/fueling/].

205 See [http://www.energy.ca.gov/2008publications/CEC-500-2008-044/CEC-500-2008-044-D.PDF].

Figure 29 shows FEV counts for specific California counties. According to SCE, the utility is expecting between 400,000 and 1.6 million electric vehicles by 2020.[206] Plug-in hybrid electric vehicles (PHEVs) combine the benefits of electric vehicles (that can be plugged in) and hybrid electric vehicles (that have an engine) and are scheduled for mass production as early as 2011. The Energy Commission forecasts the number of FEVs and PHEVs to reach nearly 3 million by 2030.

Several infrastructure barriers must be overcome to stimulate greater penetration of electric vehicles into the marketplace. Utilities will have to develop procedures, standardized equipment, and rates that meet the needs of vehicle users. Initially, utilities should probably focus on in-home recharging. Most consumers would be comfortable with home charging if time-of-use metering rates and equipment were available, as recharging could easily be accomplished in mostly off-peak hours. Consumers could be further motivated if they were able to receive the carbon credits that accrued with the use of this energy source.[207]

To help overcome infrastructure barriers, the Governor signed Senate Bill 626 (Kehoe, Chapter 355, Statutes of 2009) into law on October 11, 2009. This bill will modify current law to require the CPUC, in consultation with the Energy Commission, the ARB, utilities, and the motor vehicle industry, to evaluate policies that will help develop an infrastructure sufficient to overcome barriers to the widespread use of plug-in hybrid and electric vehicles. The CPUC is required to adopt rules to address this issue by July 1, 2011.

As the electric vehicle population grows, the recharging system can expand to the workplace and to public recharging stations. Compatible and consistent standards will need to be developed for recharging connectors and other equipment, including 120/240-volt compatibility and smart chargers. Training of workers to install and service recharging equipment needs to increase, since today's expertise is limited to a few specialized technicians connected with electric vehicle dealers.[208] Additionally, utilities will need to evaluate and update their distribution infrastructure to accommodate the increased electricity demand.

California's use of electricity in the transportation sector is forecast to increase substantially, primarily as a result of the anticipated growth in sales of PHEVs. As measured in GWhs, demand is forecast to rise from 828 GWhs in 2008 to nearly 10,000 GWhs by 2030. As Figure 30 illustrates, the surge in transportation electricity use under the High Petroleum Price Case (High Electricity Demand Case) is mainly from PHEVs and to a lesser extent full-electric vehicles. The number of PHEVs is expected to grow from 32,756 in 2011 to 1,563,632 by 2020 and 2,847,580 by 2030. Electricity use for transit is nearly flat over the forecast period. The transportation portion of statewide electricity demand is expected to rise from 0.29 percent in 2008 to between 1.57 and 1.79 percent in 2020.

There are 400 to 500 hydrogen-powered vehicles in the United States,[209] with about 190 on the road in California.[210] These vehicles

206 Testimony of Robert Graham, Southern California Edison, at the April 14, 2009, IEPR workshop, available at: [http://www.energy.ca.gov/2009_energypolicy/documents/2009-04-14-15_workshop/2009-04-14_Transcript.pdf].

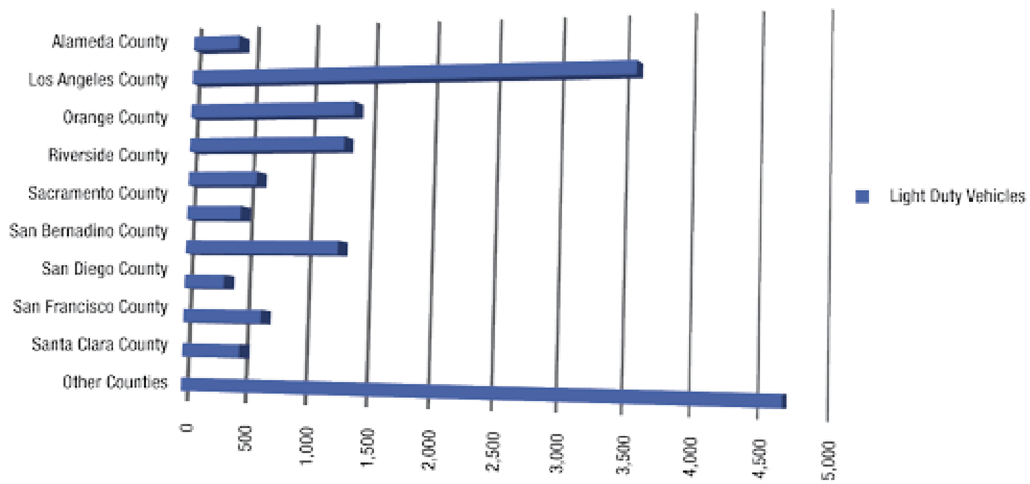
207 Ibid.

208 Ibid.

209 Energy Information Administration, see [http://www.eia.doe.gov/oiaf/aeo/otheranalysis/aeo_2009analysispapers/ephev.html].

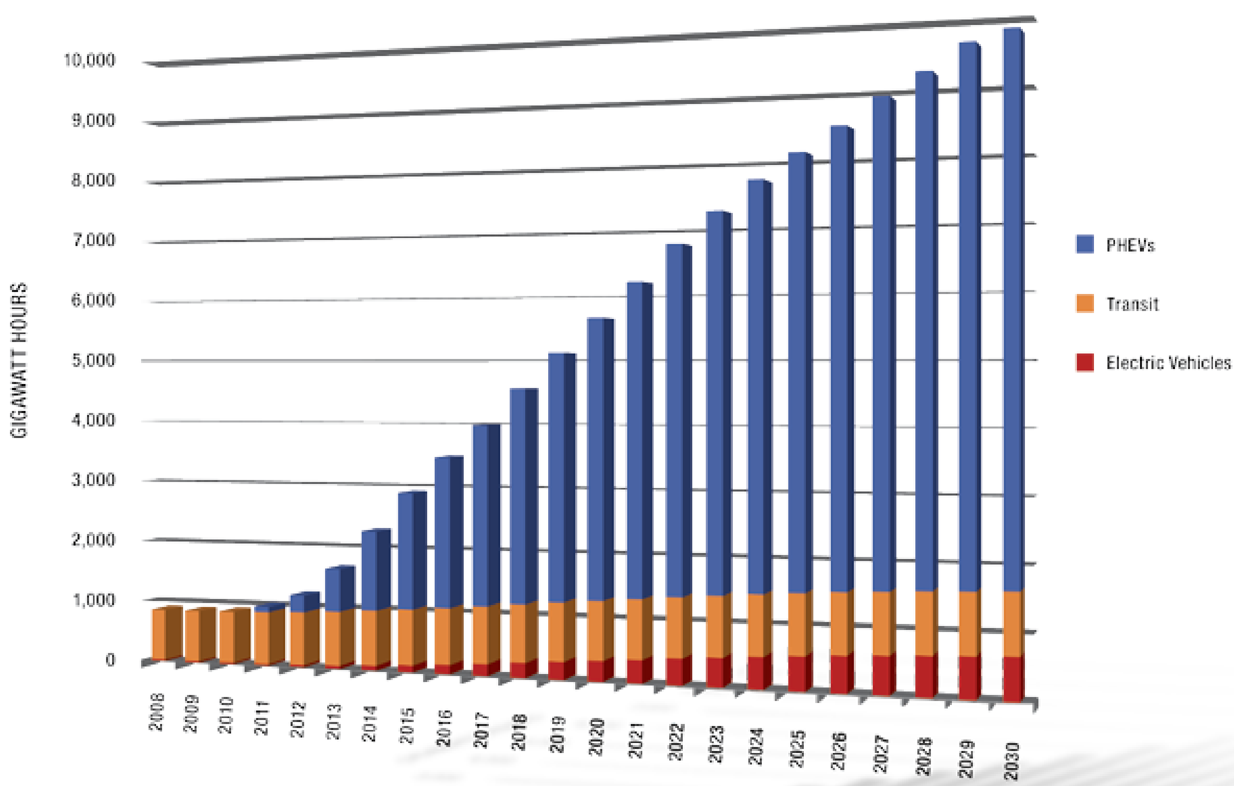
210 See [http://www.cafcp.org/sites/files/Action%20Plan%20FINAL.pdf].

FIGURE 29: FULL ELECTRIC VEHICLE COUNTS BY SPECIFIC COUNTIES, OCTOBER 2008.



Source: California Energy Commission analysis of DMV Vehicle Registration Database
*The Other Counties category is composed of counties with less than 300 electric vehicles

FIGURE 30: CALIFORNIA TRANSPORTATION ELECTRICITY – HIGH DEMAND FORECAST



Source: California Energy Commission

California's Leadership Role in Environmental Sustainability

AB 118 was created to help transform California's transportation market by reducing California's dependence on petroleum and helping California meet climate change goals. While increasing alternative fuels is a key strategy, projects around the world have discovered that producing new fuels can sometimes harm the environment. "A rapid transition to alternative fuels has the potential to encourage environmentally destructive production practices," said Energy Commission Chair Karen Douglas. "We have developed sustainability goals and criteria for AB 118, and will consider sustainability in every funding decision we make."

California is one of the first states in the nation to use sustainability as a basis to fund energy projects. The Energy Commission is taking a leadership role in working closely with state partners and global organizations in advancing the state-of-science in this emerging field. To receive AB 118 funding, proposed projects must meet the sustainability goals and evaluation criteria outlined in the Alternative and Renewable Fuel and Vehicle Technology Program regulations. The first goal is to substantially reduce GHG emissions, and the second is to protect the environment while striving to achieve superior environmental performance. The third requirement is to achieve project goals in accordance with certified sustainable production practices.

Preference is given to projects that use certified sustainable feedstocks and create alternative fuels that will be in accordance with sustainability certification standards.

By integrating sustainability in all aspects of fuel production, the Energy Commission is encouraging the next generation of alternative and renewable fuel makers as the state transitions away from fossil fuels.

use stored hydrogen, which is combined with oxygen (from the atmosphere) through an electrochemical reaction in a fuel cell to produce electricity that powers an electric motor. This technology is still relatively expensive because of high production costs of both fuel cells and the hydrogen, yet it is seen as an attractive technology because of its clean emissions capabilities.

While hydrogen has air quality benefits, it currently has no fuel quality or measurement standards for consumption and sale.[211] National and in-state standards need to be developed that address fuel quality, testing and certification methods, and sampling techniques, as well as the method of retail sale, dispensing facilities, and even the unit used to measure a sale. Fire regulations address most of the safety standards in the permitting process.

Existing hydrogen stations in the state cannot sell hydrogen at their pumps because of the lack of metering systems and dispensing rules approved by California Department of Food and Agriculture's Department of Weights and Measures.

Transportation and the Environment

Currently, high fuel prices and the recession have reduced consumer demand for gasoline, thereby benefitting the environment. These economic factors are also causing more citizens to choose transit over vehicle travel. However, to significantly reduce petroleum consumption in the longer term and achieve the state's climate change targets, California must make large strides in making renewable and alternative fuels available for consumers.

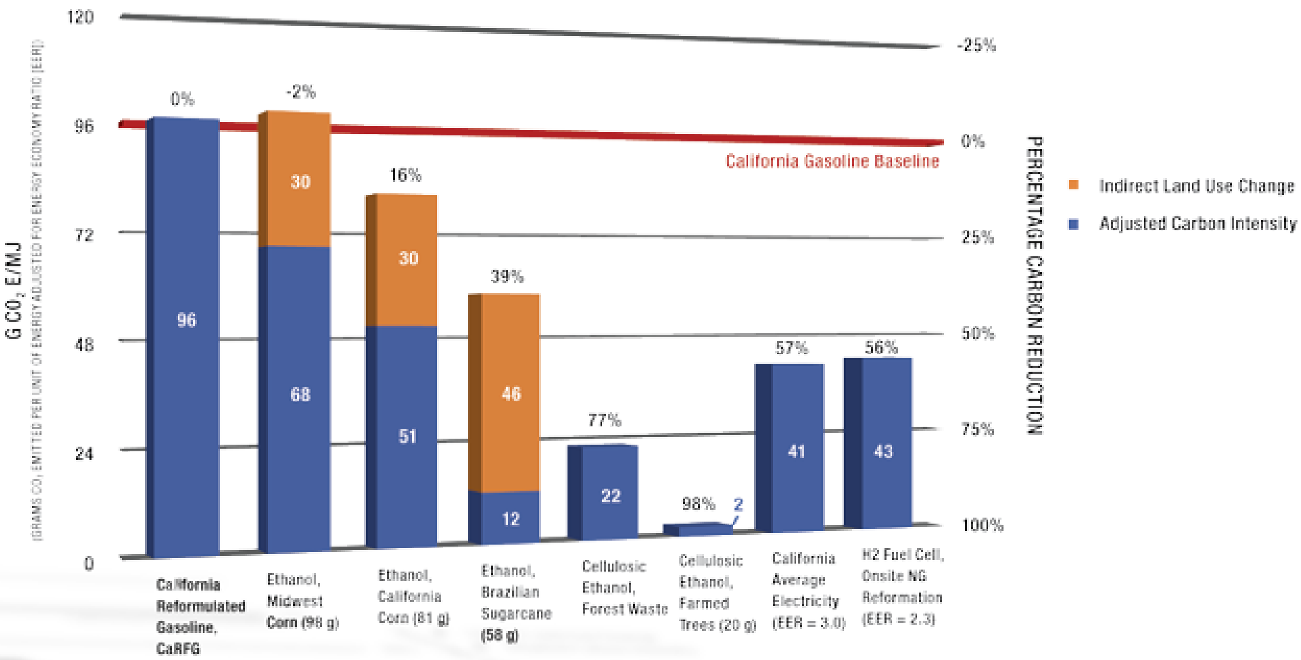
The *State Alternative Fuels Plan* set targets for the use of alternative and renewable fuels in the California market, and the *Bioenergy Action Plan* set aggressive goals to accelerate in-state biofuels production. These goals help to frame California's strong support for alternative fuels and a concerted and meaningful transition away from petroleum fuels and toward alternative fuels' attendant economic and environmental benefits.

Meeting the 2022 target in the *State Alternative Fuels Plan* would increase annual demand for alternative and renewable fuels to approximately 4 billion gallons. Reaching this goal would require the addition of more than 1 million gallons of new alternative and renewable fuels per day into the California market for the next 13 years. The Energy Commission recognizes that introducing these large volumes of alternative and renewable fuels carries the risk of encouraging or promoting environmentally and socially destructive production practices in California, North America, and throughout the world.

To gauge the environmental impacts of various transportation fuels, the Energy Commission employs a technique known as a "full fuel cycle assessment" or FFCA. Since 1989, the Energy Commission has relied on FFCA to develop policies supporting the use of alternative transportation fuels. The FFCA is used to evaluate and compare the full energy, environmental, and health impacts of each step in the life cycle of a fuel including, but not limited to, feedstock extraction, transport, and storage; fuel production, distribution, transport, and storage; and vehicle operation, refueling, combustion, conversion, and evaporation. The Energy Commission and ARB have developed a common FFCA methodology that is used as a basis for investment decisions in the Alternative and Renewable Fuels and Vehicle Technol-

211 Testimony of John Mough, California Department of Food and Agriculture, Division of Weights and Measures, at the April 14, 2009, IEPR workshop.

FIGURE 31: LIFE-CYCLE ANALYSIS CARBON INTENSITY VALUES FOR GASOLINE AND SUBSTITUTES



Source: Air Resources Board Low Carbon Fuel Standard

ogy Program and the LCFS.[212] The focus of this FFCA work has been in comparing GHG emissions of alternative and renewable fuel options with those of gasoline and diesel fuels.

The value of FFCA is determined by the underlying data, models, methodologies, and treatment of uncertainties in the development, presentation, and use of results. These areas are proving to require additional work. A key area of interest to researchers is the treatment of indirect emissions in general and land use change emissions in particular. The inclusion of indirect GHG emissions in any FFCA can significantly alter the outcome and potential public policy support for various fuel options. This effect is illustrated in Figure 31.

The nascent nature of this work creates uncertainty as to the best approach for treating indirect emissions in a policy, programmatic, regulatory, or market framework. In adopting its initial LCFS regulation in 2008, the ARB included indirect land use change emissions in determining carbon intensity values, but only for biofuel. However, all fuels must be evaluated equally. The ARB will reassess this aspect of the LCFS in 2010, and the Energy Commission and the ARB are continuing joint research into this topic.

As shown in Figure 31, not all biofuels are created equal. Depending on the origin of the fuel, the feedstock, and the type of energy

212 See [http://www.energy.ca.gov/2007publications/CEC-600-2007-004/CEC-600-2007-004-REV.PDF].

used in its production, the GHG implications of a given biofuel on an FFCA basis can vary dramatically. Ethanol is currently the dominant biofuel of choice today and will be needed to achieve federal energy and environmental policy mandates and goals. However, traditional corn-based ethanol originating from facilities in the Midwest is estimated by ARB to have full-fuel-cycle assessment GHG emissions roughly equivalent to gasoline produced at California refineries.

To help achieve compliance with the LCFS, obligated parties will need to lower carbon ethanol. Producing corn-based ethanol in California provides roughly a 16 percent reduction in GHG emissions compared to gasoline. However, sugarcane-based ethanol (for example, produced in Brazil and imported to California) or "second generation" cellulosic ethanol (for example, using biomass such as nonfood parts of crops and municipal, agricultural, and forest waste material as a feedstock) will reduce GHG emissions by 79 percent over gasoline.

Similarly, biomass-based diesel fuels (including biodiesel and renewable diesel, as well as specific feedstock- and process-based diesels such as algae-based diesel, biomass-to-diesel, and diesel from thermal depolymerization of industrial and processing waste) could be significant contributors to reducing GHG emissions in California. Of these fuels, only biodiesel is commercially available in California and the United States today.

Biodiesel produced today in California reduces GHG emissions by 10 to 50 percent compared to diesel that meets ARB's diesel fuel regulations. These facilities use recycled cooking oil (yellow grease) as their lowest-cost feedstock option, but also use more expensive and abundant soybean, palm, and a variety of plant and animal oils. Moving beyond these oils and into facilities using cellulose, waste, and algae are necessary to achieve deeper GHG emission reductions. Depending on the feedstock, fuel production process, blend concentration, and vehicle type, these biodiesel and renewable diesel fuels could reduce GHG emissions by 61 to 94 percent compared to conventional diesel fuel meeting ARB's regulations.

Full-electric vehicles and PHEVs have numerous benefits that make them attractive in addressing carbon reduction and petroleum dependence. Based on the California average electricity mix, FEVs have the potential to reduce GHG emissions by 57 percent; the reductions from PHEVs will be less due to the partial reliance on an internal combustion engine. However, several utilities in California rely on electricity imports from out-of-state coal-fired plants. This will affect the GHG reduction potential and needs careful consideration in formulating broad public policies supporting FEVs and PHEVs. Use of substantial numbers of these vehicles would also provide localized air quality benefits by reducing criteria pollutant emissions compared to conventional vehicles.

Natural gas vehicles emit 30 to 40 percent less GHG emissions than gasoline- and diesel-powered engines. The environmental profile of natural gas can be further improved through advancements in biomethane or biogas, which are renewable sources for the production of natural gas. Biomethane can be produced by capturing methane from landfills, dairy farms, and wastewater treatment plants and by anaerobic digestion of organic matter such as municipal solid waste. The use of biomethane in state-of-the-art natural gas vehicles has a much greater GHG benefit, reducing emissions by as much as 97 percent. California biomethane resource potential is estimated to provide transportation fuels for up to 250,000 vehicles per year from dairy operations, representing roughly 1 percent of the existing population of light-duty vehicles in the state as of October 2008.[213]

Natural gas is currently the primary feedstock needed for manufacturing hydrogen and results in a reduction of GHG emissions by about 56 percent compared to gasoline. The use of electrolysis to produce hydrogen (a process where hydrogen is separated from water) has the potential of reducing GHG emissions even further. However, this technique depends on the source of the electricity used for the process. Renewable power has the greatest potential to reduce the emissions to near zero. Hydrogen can also be created from biomethane to further improve its environmental profile.

Propane is produced as a by-product of refinery operations and is a coproduct in the extraction of oil and natural gas. Propane reduces GHG emissions up to 19 percent compared to gasoline. While not yet available commercially, studies are being conducted at Mississippi State University and Massachusetts Institute of Technology on the generation of renewable propane. Renewable propane can be derived from algae, row crops, and wood. While the GHG profile of renewable propane is not known at this time, production requires little additional energy and results in a product that contains the same energy content as propane derived from petroleum.

While considerable work is focused on understanding the carbon implications of various fuel options, FFCA methodologies do not typically reflect the notion of "embedded carbon." Regulatory and market incentive policies encourage the introduction of new vehicles to achieve GHG emission targets. The importance of this strategy is clear. However, the energy and raw material inputs involved in manufacturing new vehicles cause GHG emissions. A new more fuel-efficient vehicle may have to travel tens of thousands of miles to compensate for the emissions resulting from the manufacturing process. Embedded carbon also raises the question of the tens of millions of existing gasoline and diesel vehicles that will continue to emit carbon as new advanced vehicles are being introduced into the marketplace. A strategy that would provide incentives to retrofit segments of the existing fleet with low-carbon technologies should be examined from a public policy perspective.

It is clear that California will remain heavily dependent on petroleum, at least in the near term, as its primary transportation fuel. There will be a need for strategies to address the carbon emissions associated with petroleum refining. California has been conducting extensive research on carbon capture and sequestration as a GHG mitigation strategy for industrial sources, including oil refineries. On October 2, 2009, the DOE awarded $3 million in ARRA funding to C6 Resources, an affiliate of Shell Oil Company, to conduct a seven-month scoping study on a project that will sequester approximately 1 million tons per year of CO_2 streams from a Martinez, California, refinery and inject it into a saline formation more than two miles underground. At the end of the study, C6 Resources will submit a proposal for the actual project.

Transportation and Reliability

As production from California's crude oil fields continues to decline, and as California's oil refineries continue to expand their production capacity, refiners will turn to importing additional volumes from sources outside the state. Since Alaska crude oil production has declined at a greater rate than California production, refiners must seek substitute crude oil from foreign sources. There is concern about the political stability of oil-producing nations such as Iraq and Nigeria and its potential impact

213 Biomethane Resource Potential, CALSTART, Steven Sokolsky, IEPR Workshop, April 15, 2009, slide 6.

on crude oil availability. Offshore drilling could increase the domestic supply and help ensure reliability. However, environmental concerns with drilling activity in sensitive marine habitat could prevent or delay new production. These factors, along with an inadequate marine import infrastructure, could significantly impact fuel security and reliability for California and neighboring states.

Uncertainty regarding future supplies of crude oil represents an opportunity for the state to move more aggressively in expanding the use of alternative and renewable fuels. However, these fuels are not without their own challenges. Unless the state takes concerted steps to grow the alternative and renewable fuel industry domestically, policy makers may be faced with similar potential supply interruptions from an over-reliance on foreign sources of fuel and feedstock. To compound the issue, the LCFS could push the industry to import commercial quantities of lower carbon-intensity fuels, further stressing California's marine infrastructure. Increasing reliance on foreign sources of renewable fuels also creates uncertainty as to the true carbon intensity of the fuel and therefore brings into question the suitability of the fuel for the California market.

Increasing imports of renewable and alternative fuels will require additional infrastructure including new off-take terminals, storage and distribution, and retail sites. Also, buyers of alternative and renewable fuel vehicles must be assured that fuel or recharging stations are available and that they have access to vehicle parts, maintenance, and manufacturer warranties.

As California transitions from conventional biofuels to more advanced second generation biofuels, a great emphasis will be placed on identifying sustainable feedstocks. California's municipal, agricultural, and forest biomass waste stream is a massive unused resource that could be used as a feedstock for biofuels. California currently produces a total of 83 million gross bone dry tons per year (BDT/y) of combined biomass waste; this is projected to increase to 99 million BDT/y by 2020. However, only about 32 million BDT may be accessible as an energy feedstock because of economic and environmental limitations. At the current rate of use of just 5 million BDT/y, this is an under-used resource. Still, biofuel producers will be competing with operators of biomass-fired power plants and users of nonenergy bioproducts. It is imperative to determine if there will be sufficient biomass waste to meet these growing and competing demands. Preliminary data suggest that there may be sufficient biomass waste in the near term for competing energy uses, but more thorough and in-depth analysis is needed for both the biofuels and electricity industries.

Alternatively, purpose-grown crops may be an important complement to biomass waste as an energy feedstock. Biodiesel can be derived from oil crops, cellulosic sources, and algae. The ethanol industry has been looking at sugarcane, sugar beets, sweet sorghum, grain sorghum, and cull fruits. These crops also may represent new sources of income in economically depressed communities. If energy crops are used as a biomass source, additional analysis will be needed to determine life cycle carbon implications, including both direct and indirect land use changes, and to ensure that crops are being grown in a certifiably sustainable manner using best management practices.

Transportation and the Economy

The economic recession has impacted the transportation industry at almost every level. At the consumer level, behavior changes are evident. Consumers are reducing vehicle trips and cutting back on personal spending in response to higher gasoline prices and the recession. In addition, consumers are showing a purchasing trend of smaller cars, along with more FFVs and hybrids (Table 7). This has resulted in an overall shift in production to more fuel efficient vehicles. In difficult economic times, price and fuel cost are significant factors in vehicle choice, suggesting that California consumers are aware of the tradeoff between these cost factors.

Consumers are particularly affected by fuel price volatility. Last year, crude oil prices rose to over $140 per barrel in July 2008, declined sharply to a level below $30 in December, and then steadily climbed again to about $70 in September 2009. These events led to volatile gasoline prices, impacting consumers directly at the pump. At its highest peak, in June 2008, the U.S. Energy Information Administration reported the average price of California regular-grade motor gasoline was $4.48 per gallon. By December 2008, the price fell to $1.82, before rising again to $3.10 in September 2009. Consumers responded to this price volatility and overall economic conditions by reducing gasoline consumption; according to Board of Equalization data, California sales of gasoline fell by 6.2 percent from 2004 to 2008.

For the *2009 IEPR* transportation fuel forecast, staff developed high and low crude oil price forecasts for California transportation fuels and used these as the basis for California-specific high and low case regular-grade gasoline and diesel price forecasts. The Energy Commission's High Petroleum Price Case starts at $2.90 per gallon for gasoline and $3.09 for diesel in 2009, jumps to $4.36 and $4.43, respectively, in 2015, and then continues to rise to $4.80 and $4.87 by 2030 (all prices are in 2008 dollars to adjust for inflation). The Energy Commission Low Petroleum Price Case price forecasts start at $2.34 for gasoline and $2.42 for diesel per gallon in 2009, climb to $3.17 and $3.19, respectively, in 2015, and then hold constant until 2030. If the High Petroleum Price Case forecast holds true, the state could see more consistent and sustained behavior changes in citizens related to driving patterns, gasoline demand, and vehicle purchasing decisions.

Cheaper fuel sources would be a major motivating factor for consumers to choose alternative fuel vehicles. The alternative fuel price forecasts show most of these fuels costing about the same (or sometimes more) than gasoline or diesel, but there are considerable uncertainties in these projections. Moreover, other factors, such as the efficiency with which the vehicle technology uses the energy in its fuel as well as insurance and maintenance costs, will also affect total operating costs. Finally, the purchase price of many alternative fuel vehicle types exceeds that of conventional gasoline vehicles.

The downturn of the economy has greatly affected the biofuels industry. All seven of the ethanol production plants in California are currently sitting idle. California ethanol producers cite the primary reason for ceasing production as poor market conditions and the economics of producing ethanol. On May 17, Pacific Ethanol, one of the larger California ethanol producers, filed for Chapter 11 bankruptcy protection. Ethanol producers in other parts of the country, particularly the Midwest, are feeling strain from the economy, but the effects are not as detrimental as those felt in California. Midwest states support agriculture, corn production, and ethanol plants simultaneously, and California may need to take a similar role for its ethanol industry to survive. Also, companies have ceased construction on a number of biofuel projects because of their inability to secure financing. Financial institutions are not funding unique biofuel infrastructure projects, which all pose risks.

The California biodiesel plants are also struggling. The SWRCB prohibition of biodiesel in underground storage tanks (which was rescinded in May 2009) and the recession created detrimental economic hurdles. California has nine biodiesel plants with a

TABLE 7: SUMMARY OF CALIFORNIA ON-ROAD LIGHT-DUTY VEHICLES

	LIGHT DUTY VEHICLE COUNTS					
	GASOLINE	DIESEL	HYBRID	FLEX FUEL	ELECTRIC	NATURAL GAS
2001	22,779,246	316,872	6,609	97,611	2,905	3,082
2002	23,384,639	334,313	15,159	129,734	11,963	25,682
2003	24,516,071	364,411	24,182	183,546	23,399	17,228
2004	24,785,578	391,950	45,263	195,752	14,425	21,269
2005	25,440,904	424,137	91,438	269,857	13,947	24,471
2006	25,741,051	449,305	154,165	300,806	14,071	24,919
2007	25,815,758	465,654	243,729	340,910	13,956	25,196
2008	25,654,102	463,631	333,020	381,584	14,670	24,810
Compound Average Growth Rate	**1.71%**	**5.59%**	**75.06%**	**21.50%**	**26.03%**	**34.71%**

Source: California Energy Commission analysis of California DMV data

State and Federal Funding Efforts Stimulate Electric Vehicle Market

California is home to start-up companies like Tesla Motors, Aptera Motors, and Fisker Automotive that are promising to bring upscale all-electric vehicles to market soon. Today, major manufacturers including Ford, Chrysler, BMW, Toyota, Mitsubishi, Subaru, and General Motors are actively exploring electric technology with the help of federal funding.

California is providing state funding support as well. Through AB 118, the Energy Commission is offering $9 million to manufacturers of electric vehicles and electric vehicle components willing to locate in California. The incentives will create several thousand green California jobs and help to boost local economies. Overall, AB 118 offers a total of $46 million in state funds to support electric transportation.

As automobile manufacturers in Asia, Europe, and the U.S. rush to capture a growing worldwide market for more efficient, environmentally friendly vehicles, California and the federal government are helping American companies compete in the race to develop vehicles for the 21st century.

combined 2009 theoretical capacity of 63 million gallons; these plants will likely produce less than 25 million gallons. Today, six biodiesel plants are idle.[214] The biodiesel industry has to work doubly hard to re-establish itself from the rescinded prohibition to store biodiesel in underground storage tanks during the recession. The added uncertainty from ARB's LCFS treatment of indirect emissions further exacerbates the lack of economic support for biofuels.

To move high levels of biofuels into California's predominantly gasoline market, incentives may be needed to stimulate in-state production as well as infrastructure investments. It is important that California efficiently maximize the benefits from federal grants as well as assistance with state funding and assistance resources. This will be a key aspect of leveraging AB 118 monies with federal stimulus funding.

Economic barriers to wider-spread purchase of FEVs and PHEVs include the lack of commercially available models and delays in delivery, their higher price, and concerns about their size and range.[215] These perceptions of FEVs by potential vehicle purchasers may be intensified by a lack of familiarity with the technology and uncertainties over how the vehicles would be recharged or the expense of replacing batteries. Battery cost could be reduced through mass production of batteries, but there is still a great deal of research,

214 Docket Comments by the California Biodiesel Alliance, February 16, 2009.

215 A recent study completed by the Government Accountability Office describes the various challenges facing increased use of plug-in hybrid electric vehicles (PHEVs), as well as elaborating on specific developments that would be necessary for PHEVs to be competitive. Government Accountability Office, *Plug-in Vehicles Offer Potential Benefits, but High Costs and Limited Information Could Hinder Integration into the Federal Fleet*, June 2009, GAO-09-493, available at: [http://www.gao.gov/new.items/d09493.pdf].

development, and demonstration taking place to improve vehicle range. Improving performance is important because as the technology currently stands, it is not possible to exceed vehicle range without a lengthy pause to recharge the battery. Overall, the initial costs of electric vehicles (EVs) are higher than for gasoline vehicles because of the additional cost of the battery and home recharging installation.

Several different vehicle manufacturers have produced light-duty CNG vehicles, but currently only the Honda GX CNG is offered for sale in the United States. A lack of vehicle offerings was identified by the *State Alternative Fuels Plan* as one of the primary hurdles to natural gas becoming a major publicly used transportation fuel in California.[216] Another barrier is that light-duty CNG vehicles often require more frequent refueling due to having approximately 25 percent less range than gasoline or diesel vehicles per one tank of fuel. And like electric vehicles, natural gas vehicles are so unfamiliar to the majority of consumers that they are unable to generate favorable impressions among many potential car buyers.

The price of natural gas fuel can be attractive to high-volume purchasers, but vehicle cost can be a barrier to more light-, medium-, and heavy-duty vehicle purchases unless alleviated by declining production costs driven by on-board fuel storage needs or consumer incentives. The Energy Commission's *State Alternative Fuels Plan – AB 1007 Report* also identified several actions that would encourage the development of the industry: develop new utility rate structures for home refueling appliances; stimulate the development of biomethane/biogas for use in natural gas vehicles and as a feedstock for hydrogen; improve on-board storage technology to improve the range and costs of natural gas vehicles; develop natural gas hybrid electric technology; and use the GHG emission benefit credits in investment and business operation plans.

The ARRA includes multiple elements to advance alternative fuel and vehicle technologies. For example, Ford received $5.9 billion in loans from the U.S. DOE to help it retool its plants to produce 13 fuel-efficient models, including as many as 10,000 EVs a year beginning in 2011. Nissan received $1.6 billion in loans to retool its Tennessee plant to make EVs. In August 2009, Ford, GM, Chrysler, and others received $2.4 billion in federal grants to encourage the development of HEVs and EVs. The grants include $1.5 billion for battery makers, $500 million for companies developing electric motors and drive components, and $400 million to test a recharging system for electric cars. The grants are part of the federal government's $787 billion economic stimulus program.

As its population continues to grow, California must plan to ensure it has enough fuel to keep its economic engine running, while protecting the state's public health and natural resources. Regulations already in place demand that the state's energy supply become increasingly sustainable as Californians work to cut GHG emissions. Sustainability is becoming ever more important as the United States tries to wean itself from constrained resources like foreign oil. The state must avoid, however, trading one vulnerability for another, such as becoming dependent on electric automobile batteries that require rare lithium from other, perhaps less-than-friendly countries. The recession makes it increasingly important that California develop United States resources and provide United States jobs in a sustainable way.

216 *State Alternative Fuels Plan – AB 1007 Report* - Docket # 06-AFP-1, see [http://www.energy.ca.gov/ab1007/index.html].

CHAPTER 3
THE FUTURE OF CALIFORNIA'S ELECTRICAL SYSTEM

California's numerous energy policy goals must balance the need to minimize environmental impacts while maintaining reliability and affordability of electric power. Those goals include increasing the use of preferred resources (energy efficiency, demand response, renewable energy, combined heat and power, rooftop photovoltaic, and other distributed renewables), decreasing the use of once-through cooling technologies in power plants, retiring aging power plants, and modernizing the state's system of power lines. Overlaying these goals is the state mandate to reduce greenhouse gas (GHG) emissions. Because electricity generation is the second largest source of California's GHG emissions after transportation, making changes in the electricity sector is critical.

Thus far, these goals have been only weakly integrated. To coordinate planning, procurement, and permitting of power plants into an integrated system, decision makers must reconcile priorities, identify tradeoffs, and transform broadly framed objectives into concrete measures. Forming a unified vision and translating that vision into a blueprint of specific goals and objectives will provide a foundation for in-depth planning for specific generation and transmission projects. Clearly identifying which generation projects are needed (and which are not) will ease concerns from environmental advocates that the state has not fully embraced a future driven by GHG emission reductions. More efficient and coordinated transmission planning will avoid contentious, lengthy, and ineffective processes that can delay the transmission needed to meet the state's environmental goals. Further, an integrated process will minimize duplication among the state's energy agencies and provide complementary and reinforcing forums for integrating the various analyses and other efforts underway at those agencies. "Integration" in this context refers not only to the state's actual generation and distribution resources, but also to the substantial number of policies, laws, and regulations that govern the system, as well as the multiple agencies involved in establishing and executing those mandates.

This chapter is organized in three parts. The first identifies the major challenges resulting from the effects of the State Water Resources Control Board's once-through cooling mitigation policies on coastal power plants, the extreme scarcity of air credits in the South Coast Air Basin that is inhibiting development of replacement power plants, and impacts of these issues on Energy Commission power plant licensing. The second section discusses implementation issues associated with the preferred resource additions that are a key element of the vision for a new electricity system of the future. The final part addresses the institutional coordination challenges of getting all of the affected parties to efficiently study, plan, and act to steer infrastructure development toward a common future vision.

Issues Affecting Power Plants

In its *2005 Integrated Energy Policy Report (2005 IEPR)*, the Energy Commission called for the retirement, replacement, and/or repowering of aging power plants in the state. These plants operate at high heat rates when compared with new generation technologies and result in less efficient use of natural gas and higher levels of air pollutants, including GHG emissions. The Energy Commission also recommended that the California Public Utilities Commission (CPUC) ensure that long-term resource procurement explicitly take into account the retirement, replacement, and/or repowering of aging power plants – including those in the Los Angeles Basin – with cleaner, combustion-based technologies that operate at higher efficiencies. In its 2006 Long-Term Procurement Plan (LTPP) decision, D.07-12-052, the CPUC included substantial retirements in determining future investor-owned utility (IOU) needs.

In addition to this policy goal, the following four external forces continue to exert major influence over the electricity industry:

- Policies to reduce or eliminate the use of once-through cooling in power plants.
- The scarcity and high cost of emissions credits needed for new power plants.
- The need to shift the mix of resources toward demand-side resources and renewables and away from fossil power plants in response to global climate change initiatives.
- Multiple jurisdictions responsible for permitting power plants.

Effects of Once-Through Cooling Mitigation Policies

At the end of 2008, 19 power plants (20,400 MW) in California used once-through cooling (OTC) technologies. In June 2009, the State Water Resources Control Board (SWRCB) published a draft policy that establishes closed-cycle wet cooling towers as the benchmark for compliance with OTC mitigation requirements.

The draft policy also proposes a compliance schedule based on the suggestion by the Energy Commission, the CPUC, and the California Independent System Operator (California ISO) on how to address reliability concerns given the proposed timeline for OTC mitigation compliance.[217] The three energy agencies agreed that a fixed-year outer bound on OTC mitigation compliance can be established, provided it allows for the orderly development of necessary replacement infrastructure and can be amended if conditions such as permitting and construction delays indicate such change is needed to ensure reliability.

The proposed compliance schedule for each OTC plant is based on the time required to create replacement infrastructure. A wide range of circumstances exists within the OTC fleet. As new facilities become operational, some OTC power plants are losing their importance for local reliability. For others, the proposed schedule incorporates the construction timeline for replacement infrastructure when that is already underway. For many power plants, substantial analysis of the options, decisions among the energy agencies, and then procurement, permitting, and construction create long lead times before replacement infrastructure can be operational. The complexities of these analyses differ from one region to another, with the Los Angeles Basin being the most problematic given severe limitations on the air credits needed for new generation development. For this reason, the schedule of dates for replacement infrastructure may occur further into the future for the existing OTC plants located in the Los Angeles Basin.

217 California Energy Commission, California Public Utilities Commission, and California Independent System Operator, *Implementation of Once-Through Cooling Mitigation through Energy Infrastructure Planning and Procurement*, July 2009, CEC-200-2009-013-SD, available at: [http://www.energy.ca.gov/2009publications/CEC-200-2009-013/CEC-200-2009-013-SD.PDF].

It is critical to integrate the perspective of environmental regulators into reliability concerns. The SWRCB must establish a policy with a fixed deadline to force action by the plant operators and to allow regional boards to issue permits to existing plants with knowledge that OTC mitigation will occur on a fixed schedule. At the same time, the energy agencies strongly believe that implementation of an OTC mitigation policy for existing generators has to be integrated with planning and development of the replacement infrastructure necessary to support system reliability.

In the joint energy agency proposal to the SWRCB, the energy agencies provided estimated operation dates for new infrastructure. The energy agencies must review and update these dates periodically, which are then reviewed by the SWRCB. Where significant changes have been made, the SWRCB must use them as the basis for changing the permits for existing OTC plants. The energy agencies are committed to working together and with the SWRCB to achieve this objective, and SWRCB staff's draft proposed policy incorporates the joint agency proposal.

Factors Affecting Once-Through Cooling Replacement Infrastructure

Within the broad umbrella of linking OTC mitigation to the development of replacement infrastructure, the state could propose many alternative plans. State agency policies emphasize preferred resource types, including energy efficiency and demand response, renewables, and distributed generation. Including these resources in the analysis will likely result in a set of proposed replacement plants that do not rely strictly on conventional fossil power.

The energy industry's compliance with the California Air Resources Board's (ARB) *Climate Change Scoping Plan* regulations will presumably lead to a lower electricity demand forecast because additional energy efficiency measures will reduce demand, and rooftop photovoltaic (PV) and other distributed generation resources will displace sales of electricity from the bulk power system to end users. A lower demand forecast would require fewer central station generating facilities within load pockets to satisfy reliability criteria. Compliance with climate change regulations presumably also strengthens the role of renewable power generation, which encourages more transmission development to interconnect remote renewable resources, lessening the need for energy from traditional fossil generation but simultaneously increasing the need for dispatchable facilities (those that have the ability to control their output) to provide reliability services. Recognizing these likely consequences could lead to changes in both the mix and capabilities of fossil generation needed in load pockets, whether from repowered OTC plants or from new facilities that are electrically equivalent.

In addition, air permitting issues in the South Coast Air Quality Management District (SCAQMD), discussed in more detail in the next section, will affect the type of replacement power that could be built. The Superior Court decision voiding the SCAQMD's Priority Reserve Rule will result in serious limitations on power plant development in the South Coast Air Basin and nearby areas for some time.[218] SCAQMD's air quality permitting processes affect 7,500 megawatts (MW) of existing fossil capacity in the Los Angeles local capacity area of the California ISO and the Los Angeles Department of Water and Power (LADWP). New facilities totaling 1,750 MW in capacity have power purchase agreements with

218 Natural Resources Defense Council, Inc., et al. vs. South Coast Air Quality Management District, Superior Court of the State of California, County of Los Angeles, Case No. BS 110792.

Southern California Edison (SCE) but cannot be licensed because they do not have access to the Priority Reserve. If this issue remains unresolved, these facilities will not be available to reduce the reliability threat from the proposed limitation on the use of OTC. This would significantly increase the challenge of siting new power plants needed to implement the OTC policy and require solutions that rely on transmission system upgrades to access remotely located generation.

The state must also consider local capacity requirements when discussing replacement power. The Energy Commission, CPUC, and California ISO are developing enhanced local capacity requirements analyses for each local capacity area, or load pocket, within the California ISO balancing authority area. Some areas lack excess capacity and must develop replacement capacity to meet increases in peak load or power plant retirements. Others have surpluses and could therefore tolerate some retirements. Based on load and resource assumptions, the local capacity requirement analyses will extend current requirements to 10 years and identify the amount and various operating characteristics needed to plan for OTC retirement in some load pockets.

The results will be used as key inputs for an OTC power plant infrastructure replacement plan that would produce specific reliability designations, or retirement dates for specific power plants, as determined by the physical requirements in the load pocket and expected timing of replacement infrastructure development. The plan would identify, for each region, the required actions for eliminating reliance upon a power plant or unit using OTC. Most importantly, this plan would identify the complete set of infrastructure additions that, once operational, would allow OTC to be eliminated.

Recognizing these problems, the Legislature proposed multiple bills in its 2009 session to address OTC mitigation and restoration of a functioning air quality credit mechanism for new power plants in the South Coast Air Basin. Of these, only AB 1318 (V. Manuel Perez, Chapter 285, Statutes of 2009) and SB 827 (Wright, Chapter 206, Statutes of 2009) passed through the Legislature and were signed by the Governor. Assembly Bill 1318 will require the ARB, in consultation with the CPUC, the Energy Commission, the California ISO, and the SWRCB, to submit a report to the Legislature and Governor evaluating the electric system reliability needs of the South Coast Air Basin and recommend strategies to meet those needs while ensuring compliance with AB 32, OTC mitigation requirements, state and federal air pollution laws and regulations, resource adequacy requirements, and renewable and energy efficiency requirements. Assembly Bill 1318 would also authorize issuance of air credits to specific plants satisfying eligibility criteria. Similarly, SB 827 would authorize SCAQMD to issue needed air credits for a limited number of specific plants meeting eligibility criteria, but those criteria are different than those in AB 1318. These bills were signed into law by the Governor on October 11, 2009, but do not provide a comprehensive solution to the lack of air credits for power plants in the South Coast Air Basin.

Planning for Once-Through Cooling Replacement Infrastructure

The state will have to make significant decisions regarding the planning, procurement authorization, and permitting of specific energy infrastructure projects to accomplish the retrofit, repowering, or retirement of what amounts to more than 30 percent of the state's power generating capacity that OTC plants represent.[219] All of the 19 generation plants with OTC units are located in the California ISO and the LADWP control areas. Of the 16 OTC plants in the California ISO control area, 13 are located in transmission-constrained regions. Transmission constraints also influence the need for and options among refitting, repowering, and replacing the three OTC plants within the LADWP balancing authority. Thus, the CPUC, the California ISO, and the Energy Commission have recommended, rather than follow a fixed compliance schedule, that regions with less need for complex analyses and more advanced possible solutions reduce OTC harm more quickly than regions with more extensive constraints on implementing solutions.

The proposal submitted to the SWRCB encompasses three broad efforts. First, the agencies would conduct a series of studies examining the consequences of retiring individual or clusters of existing OTC power plants under a range of alternative futures and transmission system configurations to identify generation and transmission options for replacing each OTC facility. These futures would encompass increased efforts to reduce load through demand-side policy initiatives and alternative ways in which high renewable generation could be developed through time. The Energy Commission would facilitate a review of the LADWP power plants, which are outside the jurisdiction of both the CPUC and the California ISO.

Second, the agencies would review key analytic results to determine a strategy that is compatible with broad energy policy preferences. The ARB's AB 32 *Climate Change Scoping Plan* incorporates a number of the broad energy policy initiatives being pursued by the energy agencies as far back as the *2003 Energy Action Plan*. Assessment of alternative futures that are compatible with these elements of the *Climate Change Scoping Plan* and system/local reliability requirements can identify options for reducing reliance upon fossil generation (either new green field plants or repowered existing plants) through these preferred resources or transmission system upgrades. When results are available, they would be entered into the 2010 or 2012 CPUC LTPP proceeding for further analysis by the IOUs and consideration by the CPUC, with the objective of issuing procurement guidance to IOUs to acquire resources, and to the California ISO annual transmission planning process to identify specific transmission projects.

Finally, the CPUC would approve necessary power plant additions and transmission projects. The Energy Commission would license the power plant projects. Staff of the energy agencies would monitor progress, periodically report to the SWRCB, and as appropriate, recommend changes.

Some power plant operators suggested they may retrofit their power plant to satisfy SWRCB's proposed draft policy. For particular units, this might make sense, especially if the investments are lower than for repowering and the expected life of the unit makes such investments cost-effective to ratepayers. Since AB 32 encourages deployment of renewables to the extent feasible, retirements are being delayed, compared to earlier *IEPR* recommendations, to synchronize with renewable development schedules. The Energy Commission first articulated its policy in favor of retiring aging power plants in the *2005 IEPR* and then modified it to explicitly encompass repowering in the *2007 IEPR*. Therefore, it is appropriate that the Energy Commission modify the policy here to support limited retrofitting of units to

219 Retrofitting or refitting refers to the installation of a cooling system that complies with the proposed SWRCB policy. Repowering entails replacement of the existing boiler with advanced generation technology – improving thermal efficiency – and installing a compliant cooling technology. Retirement may, and often does, require replacement of the foregone capacity with generation at another location.

those most efficient and useful to integration of renewables and other system support functions. For the 2020 time horizon and beyond, the state should still pursue the goal of retiring or repowering these aging facilities.

Emission Credits for Power Plants

The second major issue affecting the electricity sector is the scarcity of emissions credits for new power plants. New generating capacity development to replace aging or OTC power plants is critical to achieving reduced GHG emissions from more efficient use of natural gas. However, recent court rulings limiting the supply of air emissions credits in the SCAQMD present new challenges for California to achieve its environmental goals while ensuring sufficient generating supplies for system resource needs and local area reliability.

Southern California air basins have some of the worst air quality in the nation, resulting in stringent local air quality requirements, including offsetting new sources of emissions with reductions in emissions from existing sources. These offsets, or emission credits, are in short supply in the SCAQMD, making it difficult to license new power plants or repower existing aging plants in Southern California. In 1990, the SCAQMD established a Priority Reserve of emission credits set aside for use by entities serving a public interest, but did not explicitly include power generation as an eligible industry.

In August 2007, the SCAQMD amended its Priority Reserve Rules to allow offsets to be purchased for new power plants licensed by the Energy Commission. The SCAQMD, under Rule 1309.1, limited these power plant credits, requiring developers to have a one-year power sales contract and a license from the Energy Commission to construct their facility before the SCAQMD board would release any credits. Plants being proposed by municipal utilities were allowed only enough credits to build projects to serve their native load. The SCAQMD also limited the total amount of new electricity generating capacity that could access Priority Reserve credits to no more than 2,700 MW.

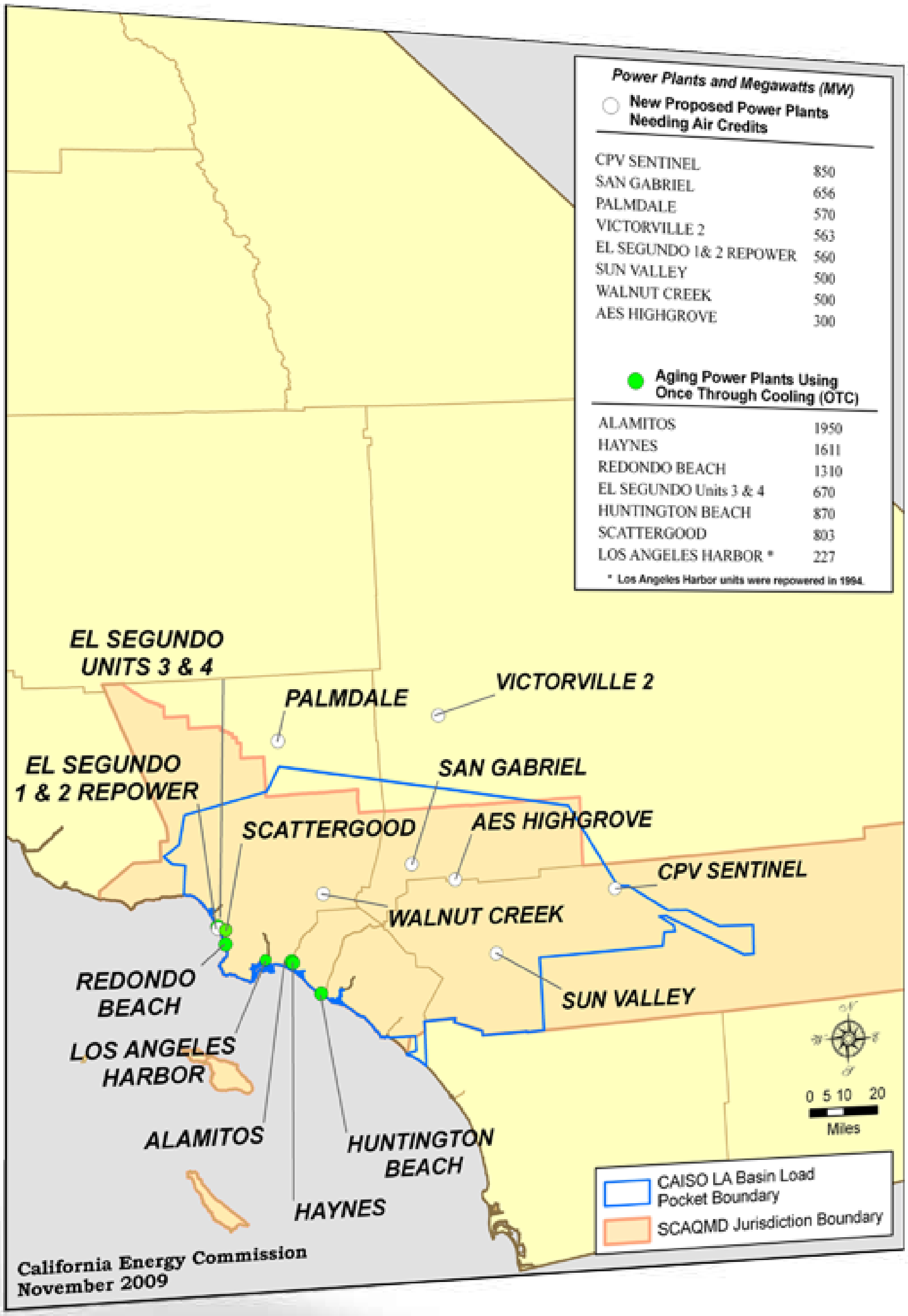
The SCAQMD Priority Reserve Rule was challenged in Los Angeles County Superior Court and in July 2008, the court decision found the air district's California Environmental Quality Act (CEQA) analysis inadequate and indicated that a sufficient environmental document would require significant new analysis that the SCAQMD believes it cannot reasonably provide. As a consequence, the SCAQMD is unable to issue any offsets for power plants or for any facilities requiring a permit for emissions. The SCAQMD is now working to modify its regulations to allow permits for nonpower plant facilities, but has no specific plans to develop new rules specific to power plants. Instead, power plant proponents and SCAQMD sponsored legislation in the 2009 session that would overturn the state court ruling. Staff is conducting analyses to identify the need for resource additions in the Los Angeles Basin under various sets of future conditions that will allow a more analytically based debate about means to find the corresponding air credits needed. Initial results of this effort were discussed at a September 24 workshop.[220]

Figure 32 shows the geographic location of the existing OTC power plants impacted and those currently in the Energy Commission licensing process affected by SCAQMD's problems issuing air credits to new power plants.

If new gas-fired power plants cannot be licensed in the Los Angeles Basin because

220 Energy Commission staff presentation, available at: [http://www.energy.ca.gov/2009_energypolicy/documents/index.html#092409].

FIGURE 32: POWER PLANTS AFFECTED BY AIR CREDIT LIMITATIONS IN SOUTH COAST AIR BASIN



Source: California Energy Commission

air emission credits from the SCAQMD Priority Reserve are unavailable and other rules favorable to power plant development are disallowed, system reliability will require continued and ongoing operation of aging, less efficient, higher emission power plants to maintain planning reserve margins between 15 and 17 percent. Most of these are also OTC plants, so the SWRCB's draft policy encouraging replacement by new infrastructure would likely be delayed. Eventually, the shortage of emission credits could have a negative impact on Southern California's ability to meet the California ISO summer peak and local capacity requirements if no new fossil plants can be built and if demand-side preferred resources cannot overcome load growth year after year. Local capacity requirements are designed by the California ISO to ensure that there is sufficient generation to provide uninterrupted service during all hours even if a major power plant or transmission line fails. In 2008, the Los Angeles Basin is meeting nearly half of its electrical load with local generating capacity, including aging power plants.

Impacts on Power Plants Licensed by the Energy Commission

The Energy Commission has permitting jurisdiction for all thermal power plants with capacity of 50 MW or greater. The Energy Commission's permitting process does not substitute for the requirements of other entities, so the difficulties in acquiring air credits in the South Coast Air Basin mean that projects that would normally get a permit from the Energy Commission have been delayed. Three power plants licensed by the Energy Commission are located in the Los Angeles Basin load pocket and could, if developed, allow retirement of some of the existing aging power plants.

- Sentinel Units 1 and 2 totaling 800 MW nameplate[221] completed its Energy Commission review, but depended on Priority Reserve credits and had to await resolution of this issue. With the passage of AB 1318, Sentinel is likely to acquire air credits and complete the Energy Commission process.

- The owner of the existing El Segundo power plant, NRG Energy, secured a license for repowering of Units 1 and 2 from the Energy Commission in 2005 (nameplate capacity of existing units is 350 MW; license was granted for a repowered facility with nameplate capacity of 630 MW). In June 2007, NRG petitioned to amend its license so it could shift from an OTC technology and build a 560-MW air-cooled facility. With the change in facility size, NRG did not have sufficient emission reduction credits to move forward with construction of its El Segundo repower project with a nameplate capacity of 560 MW. Passage of SB 827 may allow the owners of El Segundo to make use of SCAQMD's Rule 1304 to avoid purchasing air credits if they decide to retire another of the older units at the facility.

- Walnut Creek Energy Center (nameplate capacity 500 MW) received a permit from the Energy Commission in summer 2008 using the SCAQMD Priority Reserve credits. The facility is currently on hold with construction to start in late 2009, pending resolution of the air credit issues. Walnut Creek is not helped by either AB 1318 or SB 827, and a comparable bill, SB 388 (Calderon), created to authorize air credits for it, did not pass the Legislature in 2009.

221 "Nameplate" refers to the manufacturer's rating for output of power plant equipment.

TABLE 8: SOUTHERN CALIFORNIA EDISON CAPACITY IMPACTED BY SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT RULE

YEAR	FACILITY	CAPACITY (MW)	CUMULATIVE (MW)
2010	Sentinel I	455	
2011	El Segundo Repower – Units 1&2	550	1005
2012	Sentinel II	273	1278
2013	Walnut Creek	479	1757

Source: California Energy Commission

TABLE 9: STAFF PLANNING ASSUMPTIONS AND RESERVE MARGIN RESULTS FOR SOUTHERN CALIFORNIA USING HIGH RETIREMENTS (MEGAWATTS)

Supply/Demand Forecast	2010	2011	2012	2013	2014
Peak Demand	27,995	28,363	28,800	29,256	29,620
Existing Generation	22,927	22,927	22,927	22,927	22,927
Net Imports	10,100	10,100	10,100	10,100	10,100
DR & Interruptable	1,491	1,512	1,534	1,547	1,551
New Thermal	995	1,707	1,992	1,992	1,992
New Renewable	162	251	533	965	1,157
Retirement	(354)	(354)	(354)	(354)	(708)
Total Generation	35,321	36,142	36,731	37,177	37,020
Reserve Margin w/o OTC Requirements	26%	27%	28%	27%	25%
Surplus over 15%	3,127	3,525	3,611	3.532	2,957
Add'l Retirements (CPUC Decision)	(1850)	(3,050)	(4,500)	(5350)	(5,350)
Reserve Margin w OTC Retirements	20%	17%	12%	9%	7%
Surplus over 15%	**1,277**	**475**	**(889)**	**(1,818)**	**(2,393)**

Source: California Energy Commission

Other power plants currently in the licensing process at the Energy Commission could, if permitted and brought on-line, allow even more aging power plant retirement. However, at this time there is no clear path forward for these units.

SB 827, by allowing use of SCAQMD's Rule 1304 exemption for repowering projects, creates an incentive for repowering in place that cannot be matched by new greenfield power plants. It is unclear whether such repowering will take place. The plaintiffs in a second lawsuit against SCAQMD's permitting practices continue to express concerns about whether the air credits in SCAQMD's internal accounts are valid (accumulated through shutdowns and other orphan uses never converted into marketable renewable energy credits). SCAQMD asserts that U.S. EPA's review of its Rule 1315 establishes federal satisfaction over its internal account. Others may be ready to test this belief in federal court. Repowering projects that satisfy Rule 1304's exemption requirements would not increase capacity, so they may not be under the Energy Commission's licensing jurisdiction. Such plants would be licensed by local authorities, and some plants have well organized opposition groups that seek conversion of these sites into other uses. In sum, whether SB 827's reopening of SCAQMD's Rule 1304 for repowering exemptions creates a pathway to assure sufficient capacity of the right kind and right location of power plants is still very much in doubt.

Impacts on Specific Utilities

Any substantial delays in the construction of new fossil fuel facilities proposed in the Los Angeles Basin will impact the electricity supplies available to meet summer peak loads. SCE is the major utility in the Los Angeles Basin; however, many municipal utilities are also located there including: LADWP, Burbank Water and Power, Glendale Water and Power (all in the LADWP control area) and Anaheim, Riverside, Pasadena, and other smaller municipals in the California ISO control area. SCE likely will be the most affected by the SCAQMD ruling. The SCAQMD ruling threatens 1,757 MW of the capacity that had been expected to come on-line from 2010 to 2013 (Table 8).

Energy Commission staff evaluated the supply-demand balance in the South of Path 26 region (SP26).[222] The resulting staff paper used Southern California Edison and other utility assumptions since the *2009 IEPR* had not yet been compiled. The paper computed two alternative retirement scenarios juxtaposed against the limited amount of new additions that could be permitted given the SCAQMD air credit limitations. An updated analysis using staff's planning assumptions and planning reserve margin calculations for the Southern California region over the next five years was presented at the September 24 workshop on SCAQMD air credit issues.[223] The results using the CPUC procurement authorization assumptions are shown in Table 9. The Southern California portion of the California ISO control area has more capacity than necessary to sustain a 15 percent reserve margin through 2011, but falls below that level in 2012 and gets progressively worse. This increases vulnerability to situations like unexpected outages, which the full 15 percent planning reserve margin is designed to address. Fortunately, this assessment is no longer realistic since the SWRCB,

222 California Energy Commission, *Potential Impacts of the South Coast Air Quality Management District Air Credit Limitations and Once-Through Cooling Mitigation on Southern California's Electricity System*, February 2009, CEC-200-2009-002-SD, available at: [http://www.energy.ca.gov/2009publications/CEC-200-2009-002/CEC-200-2009-002-SD.PDF].

223 A further update using the final demand forecasts adopted by the Energy Commission in this IEPR proceeding has been made to the results provided in this chapter, but the demand forecast changes are sufficiently small that there is no material change in the conclusions reached.

in consultation with the energy agencies, has delayed the compliance dates for OTC power plants in the Los Angeles Basin to allow time for replacement infrastructure to be developed and brought on-line.

By revising the OTC retirement assumptions to match the schedule proposed by the energy agencies and accepted by SWRCB staff in its draft OTC policy, the deficits relative to the designed planning margin are eliminated, and there are comfortable surpluses throughout the five-year period. Table 10 shows these results. The negative impacts of a fast retirement schedule, in light of air credit limitations on new power plant development, which the energy agencies were able to get SWRCB to accommodate, allows time for the air credit issues to be resolved. However, once the full OTC retirements occur in later years, the 15 percent planning reserve margin cannot be satisfied unless additional resources are brought on-line.

The SCAQMD court ruling has had similar impacts on publicly owned utilities in the Southern California portion of the California ISO control area. LADWP has three power plants totaling over 2,000 MW of capacity that use OTC and apparently intends to repower most of the units in these plants in order to comply with SWRCB draft OTC policy. In securing air quality permits, LADWP has faced the same challenges as other entities within the SCAQMD's jurisdiction, since its ability to use SCAQMD's Rule 1304 exemption from providing air credits for its repowers has been blocked by the court ruling. SB 827 would apparently restore repowering exemptions via Rule 1304, so LADWP's strategy of OTC compliance through repowering may no longer be blocked by air credit limitations. This analysis shows the strong interdependencies of the likely consequences of the SWRCB's OTC mitigation policies with air credit availability to support new power plant development. In the Los Angeles Basin there is a clear conflict. This conflict has been shifted out beyond 2014 – the near-term period requiring immediate action – toward the end of the 2010 decade.

The 2009 legislative "solutions" have not addressed the full issue, but have sanctioned use of air credits at a limited number of specific power plants already well into the licensing process. The workshop conducted September 24 revealed strong interest in a comprehensive solution to this issue, rather than a series of piecemeal attempts to license specific power plants. Staff's analytic project is on the right track and should be continued in conjunction with inputs from other stakeholders. The reliability study required by AB 1318 can build upon staff's initial work and perhaps become the basis for broader recognition of the scale of the problem.[224] Eventually legislation is probably required, but it should provide for a systematic, even-handed method for determining which power plants are able to obtain scarce air credits,[225] while the environment is protected from excessive criteria pollutant emissions. That other sources in the Los Angeles air shed have to be regulated more tightly to allow for needed power plant capacity may be the price this region needs to pay to secure reliable electricity services.

224 AB 1318 (V. Manuel Perez, Chapter 285, Statutes of 2009), requires the Air Resources Board, in consultation with the Energy Commission, CPUC, California Independent System Operator, and State Water Resources Control Board, to complete a reliability study of the South Coast Air Basin by July 2010.

225 When air credits are procured from market sources, or a special program open to all categories of power plant, then all power plants pay for them on the basis of the prospective missions from the facility. Exemptions for repowering and legislative gifts of credits to specific power plants tilt away from a level playing field, with the potential for unintended consequences and suboptimal outcomes.

TABLE 10: STAFF PLANNING ASSUMPTIONS AND RESERVE MARGIN RESULTS FOR SOUTHERN CALIFORNIA USING STATE WATER RESOURCES CONTROL BOARD ONCE THROUGH COOLING RETIREMENTS (MEGAWATTS)

Supply/Demand Element	2010	2011	2012	2013	2014
Peak Demand	27,995	28,363	28,800	29,256	29,620
Existing Generation	22,927	22,927	22,927	22,927	22,927
Net Imports	10,100	10,100	10,100	10,100	10,100
DR & Interruptable	1,491	1,512	1,534	1,547	1,551
New Thermal	995	1,707	1,992	1,992	1,992
New Renewable	162	251	533	965	1,157
Retirement	(354)	(354)	(354)	(354)	(708)
Total Generation	35,321	36,142	36,731	37,177	37,020
Reserve Margin w/o OTC Requirements	26%	27%	28%	27%	25%
Surplus over 15%	3,127	3,525	3,611	3.532	2,957
Add'l Retirements (SWRCB OTC)	0	0	0	0	0
Reserve Margin w OTC Retirements	26%	27%	28%	27%	25%
Surplus over 15%	**3127**	**3525**	**3611**	**3532**	**2957**

Source: California Energy Commission

Preferred Resource Additions

California has long pursued a path to use more environmentally sensitive technologies to satisfy consumer energy needs. Even during the enthusiasm for markets in the mid- and late-1990s, public goods charges were established to ensure that funding for energy efficiency and renewables would continue to achieve goals for these preferred resources. The Energy Action Plan process signaled inter-agency support for these technologies. The more recent motivation to mitigate climate change accentuates these past efforts.

Because the electricity sector represents a significant source of GHG emissions, it is viewed as a source for major emission reductions to satisfy the state's GHG emission reduction goals. California's continuing emphasis on energy efficiency and shifting the mix of generating resources from fossil plants to renewable resources will provide the bulk of the reductions from the electricity sector. Additional reductions will come from moving to more efficient fossil sources like combined heat and power (CHP) and state-of-the-art natural gas plants.

Uncommitted Energy Efficiency Goals

Since the original *Energy Action Plan*, energy efficiency has been assigned the highest priority among all preferred resources. Prior *IEPRs* and now the ARB *Climate Change Scoping Plan* hold out high aspirations for additional energy efficiency impacts beyond those included in the baseline demand forecast. The *2007 IEPR* called for "achieving all cost effective energy efficiency." In late 2008, the ARB adopted high goals for additional energy efficiency as part of its *Climate Change Scoping Plan*.[226]

The *2008 IEPR Update* described the review of the approach of segregating between committed and uncommitted energy efficiency and only including what the Energy Commission calls "committed" impacts in the baseline demand forecast. The Energy Commission did this to call attention to the need for numerous actions before broad, uncommitted goals can be achieved – for example, programs have to be designed and funded, utilities and other program administrators have to successfully implement programs, end users have to participate either voluntarily through utility programs or involuntarily through mandated standards, technologies must meet or exceed the technological development rates assumed in broad projections, and the general scope and pace of economic development has to continue as assumed when making estimates of program potential and participation. Many things can and do deviate from the expected when hundreds of thousands, or millions, of end-use customers have to participate in order to generate the savings estimated in potential studies and savings goal decisions.

As noted later in this chapter, the degree to which the high goals established for uncommitted energy efficiency are achieved interacts strongly with the goals for renewables. Simply said, the amount of renewable energy required under a 33 percent by 2020 Renewables Portfolio Standard (RPS) formula is nearly 50 percent higher without the impacts of additional efficiency. Assuming renewables are pursued in a reasonably logical manner of easiest, cheapest first, the success of energy efficiency aspirations determines whether the

226 California Air Resources Board, *Climate Change Scoping Plan*, December 2008, available at: [http://www.arb.ca.gov/cc/scopingplan/document/scopingplandocument.htm].

state has to construct the difficult and more expensive subset of renewable potential. Thus, the success of achieving the 33 percent renewables goal by 2020 may depend on whether energy efficiency goals are achieved.

Chapter 2 described the efforts that Energy Commission staff is pursuing to develop estimates of the incremental impacts of three scenarios of uncommitted energy efficiency program initiatives derived from CPUC D.08-07-047. The CPUC wishes to use these estimates in its forthcoming LTPP proceeding as adjustments to the baseline demand forecast. The CPUC intends to require the IOUs to evaluate the alternative futures implied by these three "managed" demand forecasts (baseline less incremental, uncommitted impacts) when conducting its portfolio analyses. Examining three alternative futures is highly commendable, but these three do not reflect the full range of uncertainty about the incremental impacts of uncommitted energy efficiency. The three scenarios established by the CPUC reflect differences in the breadth of programs that are imagined to unfold through time via funding for utility programs, number and strength of ratchets in building standards, federal appliance mandates, and pursuit of net zero building designs. There are numerous other sources of uncertainty about incremental impacts that the staff's analytic effort is not examining. Among these are:

- Willingness of customers to participate in voluntary programs.
- The extent to which high efficiency buildings, appliances, and production processes encourage high levels of use thus "taking back" some portion of engineering estimates of savings.
- Measures of technological performance through time.

As the Energy Commission staff develops a capability to project incremental impacts of a less highly structured set of energy efficiency proposals, these other elements of uncertainty should be addressed in the method and assumptions used in making the projections.

On September 24, 2009, the CPUC unanimously adopted a $3.1 billion, three-year Strategic Plan for Energy Efficiency, to be administered by the state's IOUs. Implementing the plan will avoid the need for three additional 500-MW power plants. It will also create between 15,000 and 18,000 new jobs, launch the nation's largest home retrofit program, and provide $175 million to launch California's Big Bold Energy Efficiency Strategies for zero net energy homes and commercial buildings. The plan was dedicated to Energy Commissioner Arthur Rosenfeld in recognition of his contributions to the field of energy efficiency. During 2010, the triennial AB 2021 (Levine, Chapter 734, Statutes of 2006) process of establishing long-term energy efficiency goals for each utility will be revisited. This effort provides another opportunity for the Energy Commission and CPUC to work collaboratively in setting goals that can reduce forecast loads in ways that are achievable and cost effective.

The Energy Commission collaborates with California's publicly owned utilities to promote cost-effective energy efficiency activities. As required by AB 2021, each year the publicly owned utilities report their efficiency expenditures and energy savings to the Energy Commission, which evaluates progress. In addition, every three years, publicly owned utilities identify all potentially achievable cost-effective electricity energy savings and establish annual targets for energy efficiency savings and demand reduction for the next 10-year period. Coordinating with the CPUC for the IOUs and the publicly owned utilities, the Energy Commission develops statewide energy efficiency potential estimates and adopts targets for California's IOUs and publicly owned utilities.

Renewables Portfolio Standard Goals

A major issue in implementing climate change policy is how to meet the RPS goal of 33 percent renewable energy by 2020, given the challenges of integrating such large amounts of renewable energy into the system.[227] While some renewable resources like geothermal and biomass can operate much like conventional baseload power plants, intermittent and remotely located renewable generation presents new challenges for matching the power produced with consumer demands. Intermittency of production means that capacity is derated from nameplate values as part of the resource adequacy process, and it also means that dispatchable resources are required to ramp up or down to match the characteristic daily patterns and sudden changes in electricity production from wind and solar resources. Integrating higher levels of renewables into the electricity system must also be integrated with other state policies to reduce the negative impacts of OTC, reduce waste through energy efficiency and combined heat and power, modernize the transmission and distribution grids, and use electricity as an alternative transportation fuel.

A primary question is the amount of added renewable energy needed to meet the RPS goal, referred to as the renewable "net short." This is an issue because the existing RPS law focuses on renewables as a percentage of retail sales. Anything that reduces retail sales – energy efficiency program savings, rooftop solar PV, and other customer-side-of-the-meter distributed generation – reduces the renewable requirement. As shown in Figure 33, assumptions about the resource mix of future renewable additions varies widely, and no studies have examined a scenario that would maximize the use of baseload biomass and geothermal resources rather than variable wind and solar technologies.[228]

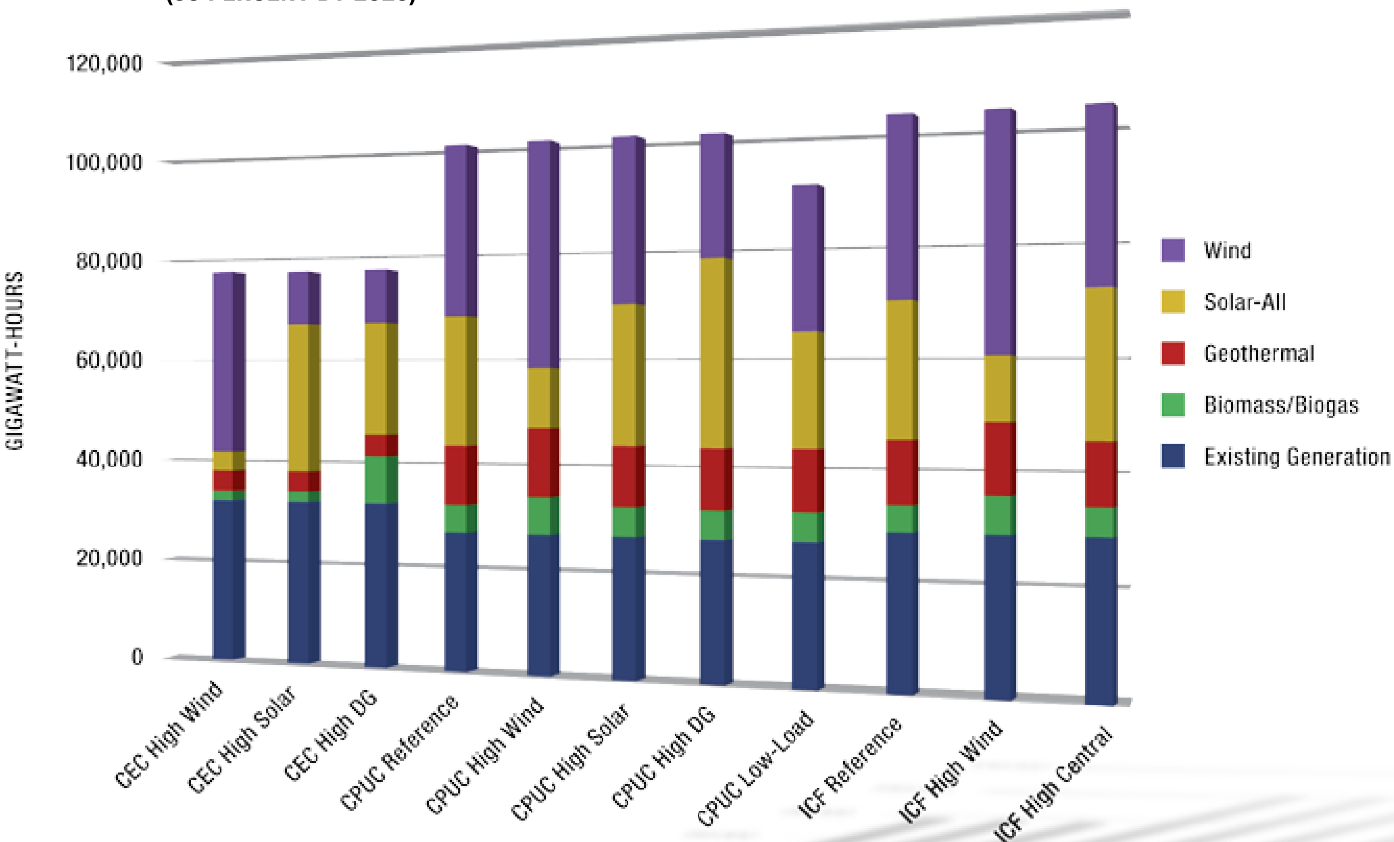
Recent estimates of the 2020 renewable energy net short vary from 45,000 gigawatt hours (GWhs) to almost 75,000 GWhs, depending on forecasted electricity demand along with the amount of expected energy efficiency, CHP, rooftop solar, and existing renewables included in the analysis. Since the RPS target is based on retail sales of electricity, estimates of the renewable net short will change over time as forecasts of electricity demand change. Similarly, meeting the state's targets for energy efficiency, CHP, and rooftop solar will affect the amount of renewable energy ultimately needed.

Needed additions will also depend on how much renewable power is already flowing into the system. Estimates of existing renewable generation vary from 27,000 to 37,000 GWhs, depending on the vintage of the estimate, the amount of out-of-state renewable generation attributed to publicly owned utilities, and the amount of unclaimed renewables (renewable generation not claimed as eligible for the RPS)

227 The challenges of accomplishing this integration are very similar whether the details of the program are defined by statute or by regulation.

228 The Energy Commission study and presentations of the ICF International study are available at: [http://www.energy.ca.gov/2009_energypolicy/documents/index.html#062909]; the California Public Utilities Commission study, underlying calculator, and supporting white papers are available at: [http://www.cpuc.ca.gov/PUC/energy/Renewables/hot/33implementation.htm].

FIGURE 33: COMPARISON OF RECENT SCENARIOS FOR INCREMENTAL AND EXISTING RENEWABLE ENERGY
(33 PERCENT BY 2020)



Source: California Energy Commission

that is included in the estimate.[229] The wide variation between estimates illustrates the need for common assumptions and counting conventions so that the public can be confident in both the targets and reported progress.

Implementing the OTC mitigation policies discussed earlier in the chapter will affect the integration of renewables because it is unclear what characteristics replacement power will have and therefore how it could support renewable integration. OTC units may need to be replaced within the same local capacity area, elsewhere on the grid, or not at all. Replacement plants could be combustion turbines with relatively few hours of operation or new, efficient combined cycle plants that would operate more hours per year than the plants they replace. In addition, the strict regulation of criteria air pollutants in the South Coast Air Basin will restrict the amount of in-basin replacement power, increasing the amount of generation needed from outside the area. The amount of energy imported to meet load in the South Coast Air Basin could be reduced with increased amounts of wholesale distribution-level renewables, although some amount of gas-fired generation or other types of "spinning reserves" may still be needed to

229 The studies discussed at the June 29, 2009, IEPR workshop used the *2007 Net System Power Report* as the basis for their estimates of existing renewables, but varied in the way the data from the report was used. The California Public Utilities Commission had the lowest estimate of existing Renewables Portfolio Standard renewable; the *Renewable Energy Transmission Initiative Phase 1B Report* had the highest estimate.

allow transmission lines to continue to bring in electricity from outside the area.

Expiring coal contracts will also affect California's system mix and the operational attributes replacement plants will need. Coal contributed about 56,000 GWhs of energy in 2008, with more than 11,000 GWhs of coal-fired generation provided through contracts that will expire by 2020.[230]

Reserve margins are also an issue. To ensure system reliability, utilities are required to have a minimum planning reserve margin of 15 to 17 percent. Reserve margins cover uncertainties in load forecasting, forced and planned outages, largest single contingencies and other operational problems. Planners want enough reserves on hand to handle contingencies, but do not want so much extra capacity that ratepayers end up paying for unused generating units or transmission lines. Because resources like wind and solar may produce a large amount of energy at times other than system peak, conventional resources, technology improvement in power plants, or storage may be needed to provide the necessary reserves.

Natural Gas Plants

In designing a future low carbon electricity system, questions have been raised regarding why new natural gas units are needed, if they are needed in specific locales, if they are a help or a hindrance to the development of other preferred resources, and generally what role natural gas will play in the transformed electricity resource mix. The Energy Commission chose to investigate the role of natural gas, both in its function as the siting agency for thermal units over 50 MWs and as part of its integrated resource planning infrastructure for generation, transmission, storage, and pipelines. Natural gas generation has many features that complement rather than compete with variable resources such as wind and solar and is therefore part of the suite of options to help create a low carbon system.

What type of natural gas facilities might be added and when they are needed is complicated. If high levels of energy efficiency are achieved, less overall energy will be needed, though capacity requirements may still be hefty. If combined heat and power units are built instead of central station gas generation, different system attributes will be affected. Finally, policies other than supporting incremental renewables are affecting the type and timing of new natural gas-fired units. These include reducing use of OTC at existing plants, meeting local area capacity requirements, and abiding by the criteria pollutant limits in the SCAQMD.

As part of the multi-agency efforts to understand the impacts of integrating higher levels of renewables into the grid, Energy Commission staff analyzed the potential impacts on natural gas use and generation.[231] The study used a reference case that did not include the ARB *Climate Change Scoping Plan* policies and only assumed that the 20 percent RPS goal was met by 2012 statewide. Staff developed two "bookend" cases that included the *Climate Change Scoping Plan* policies and meeting the 33 percent RPS target by 2020. The two bookend cases included a high solar and a high wind case. Including the demand-

230 Total utility out-of-state coal generation comes from the 2007 self-reported claims from the utilities for the Power Source Disclosure Program. Los Angeles Department of Water and Power claimed around 10,000 GWhs of imported coal generation from the Navajo plant, and California Department of Water Resources contracts around 1,300 GWhs of coal generation from Reid Gardner.

231 California Energy Commission, *Impact of Assembly Bill 32 Scoping Plan Electricity Resource Goals on New Natural Gas-Fired Generation*, June 2009, CEC-200-2009-011, available at: [http://www.energy.ca.gov/2009publications/CEC-200-2009-011/CEC-200-2009-011.PDF].

reducing policies from the *Climate Change Scoping Plan* and reducing the amount of incremental renewables required to reach 33 percent of retail sales added only 45,000 GWhs of incremental renewables compared to the 75,000 GWhs added in studies that did not include the *Climate Change Scoping Plan* measures.

The study found that the potential impacts of adding large amounts of intermittent renewables on natural gas-fired generation were affected by two programs that had significant direct impacts on natural gas use and the type of plants to be built. The *Climate Change Scoping Plan*'s energy savings targets translated into an incremental 4,700 MW of CHP in the staff's model. By 2020, CHP consumed 20 percent of all California's natural gas used for power generation. This amount of CHP reduced electricity sales to end-use customers but did not create a proportional reduction in natural gas use. It also added a large amount of baseload generation to Southern California, where 60 percent of potential host sites for large CHP are located.

OTC policies also affected the potential impacts of intermittent renewables in the model because much of the generation needing retrofit or replacement serves local functions that continue to be supported by generation located in local reliability areas. Of the 15,069 MW of existing OTC units, 964 MW were retained, 1,450 MW have recently been repowered, and 7,758 MW were replaced with new, efficient units. By 2020, depending on the case, between 11 and 23 percent of natural gas-fired generation in California is from power plants associated with the OTC issue. Once CHP targets and OTC replacements were made, only a few new natural gas plants had to be added to meet local capacity and energy needs. Those were in the Sacramento Municipal Utility District, Turlock Irrigation District, and Imperial Valley control areas, which have no OTC and limited numbers of large host industrial or commercial facilities for new CHP. The amount of natural gas units added did not change between the base case and the two bookend cases. This suggests that the CHP additions and those used for OTC policies provided enough gas flexibility so that more units were not needed even in the more intermittent wind cases. But the capacity factors for generic additions and OTC replacement combined cycles, which start out at normal baseload levels, drop much lower by 2020 in the two bookend cases, making the long-run cost-effectiveness of these combined cycles questionable. This suggests that the sample compliance path used in this study was not optimal if the large amount of CHP baseload is added. Baseload energy from "must take" CHP resources reduces the need for energy from combined cycle merchant plants, thus shifting them into a load following pattern of operations, which may not justify the incremental cost of combined cycle versus simple cycle combustion turbines. Thus, a key finding of the study is that none of these policies should be assessed in isolation. To test these conclusions, additional model runs could be done that lower the amount of must-take CHP and switch some of the OTC combined cycles to combustion turbines.[232]

For electricity generation, the Western Electricity Coordinating Council (WECC) systemwide amount of natural gas did decrease by 15 percent in both of the bookend cases. However, the reductions were not distributed evenly, with at least 70 percent of the gas reductions occurring out of state. In-state gas-fired generation decreased by 10 percent in the high wind case and 13 percent in the

232 Subsequent to the June 29, 2009, IEPR workshop, technical staff of the agencies participating in the California Independent System Operator 33 percent renewable integration study developed and agreed to assess a combination of renewable development and demand-side policy initiatives to better understand the interactions between these policies.

TABLE 11: CALIFORNIA USE OF NATURAL GAS IN POWER PLANTS IN BILLION CUBIC FEET PER DAY (BCF/D)

	2012	2016	2020 CHANGE FROM CASE 1
Case 1 Reference Case RPS	2.36	2.57	
Case 2 High Solar	2.34	2.45	-12%
Case 3 High Wind	2.34	2.48	-10%

Source: Energy Commission, Electricity Analysis Office

high solar case. In contrast, out-of-state gas-fired generation dropped 21 and 20 percent, respectively. This suggests that out-of-state natural gas is the marginal resource and that in-state gas is used for local reliability or ancillary services.

The study also found that a resource mix with a high proportion of wind required more in-state natural gas generation than the high solar case. In addition, more impacts were seen in Southern California than in Northern California. While wind is distributed across the state, solar resources are almost completely concentrated in Southern California. OTC units and potential CHP sites are also concentrated in the southern part of the state. This indicates that there may be more system impacts and potential system stressors in the southern transmission grid.

While gas used for serving retail load dropped, total gas use increased. As Table 11 shows, between 2012 and 2020, total natural gas consumption rose slightly in all cases. The increases in the high wind and high solar cases were more modest, but still increased as large amounts of CHP fueled by natural gas were added to the system. Those increases were less in the high solar case than in the high wind case when compared to the reference case.

In contrast to the Energy Commission staff study, a recent study by ICF suggested that 33 percent renewables could lead to an increase of 3,000 MW of gas-fired capacity between 2009 and 2020, but a net decrease of 11,000 GWhs of in-state gas-fired generation. The different result in the two studies was the result of different modeling assumptions; for example, the Energy Commission study included local reserve and area reliability requirements, including publicly owned utility reserve requirements for new gas-fired capacity needed to modernize the OTC fleet. In addition, the

Energy Commission study included 32,000 GWhs of gas-fired CHP, consistent with the target in the ARB's *Climate Change Scoping Plan*, while the ICF study did not add any CHP. Finally, ICF assumed that total natural gas use in the WECC would rise over the forecast period and that California would import more power generated using natural gas, but that the increase in total in-state use would exceed any increase in imports.

The Energy Commission's study results indicate that at least three areas deserve further research because of the affect of study assumptions on the type of proxy generation needed to firm and back up intermittent renewables. First, alternative levels of CHP should be tested, since the addition of baseload power in-state and in Southern California may be difficult to achieve with existing emission credit problems and the lack of a mechanism to make it happen. Second, alternative assumptions about compliance with OTC mitigation requirements should be tested because the interactions of all the *Climate Change Scoping Plan* programs lead to unrealistic capacity factors in the replacement of OTC combined cycles by 2020.

Finally, the possibility of overgeneration, a condition when more generation is provided than there is available load, will require additional analysis. In the June 29, 2009, IEPR Committee workshop on renewable integrating issues, SCE reported that a Nexant study suggests a possible overgeneration problem in April and May as the state moves to 2020 if there is high solar incidence in the desert, high generation of wind, and the need to spill water stored in dams to make room for snow melt. In addition, parties at the July 23, 2009 IEPR workshop on CHP issues noted the risk of overgeneration when large amounts of both renewables and CHP are added to the system mix.

Energy Storage

To the extent that natural gas remains a low-cost fuel, gas-fired generation can help the electricity system absorb the costs of transitioning to higher levels of renewable energy. However, looking forward, some of the firming services provided by gas-fired generation will need to come from existing and emerging energy storage technologies that allow generators and transmission operators to fill the gap between the time of generation (off-peak) and the time of need (on-peak) for intermittent renewable energy. Energy storage systems can respond quickly – in less than a second – to the needs of the electric grid system when compared to conventional gas-fired generation, which takes minutes to tens of minutes, and potentially reduce the overall amount of energy needed to balance the system needs. The fast response of energy storage also suits the variability of renewable energy systems such as wind, and this combination can allow grid operators to use increased levels of renewable energy and still maintain desired levels of reliability and control.

Examples of energy storage technologies commercially available and under development include advanced technology batteries, flywheels, compressed air energy storage, pumped hydroelectric energy storage, capacitors, and others. These technologies can provide value at each level in California's electric grid – generation, transmission and distribution, and end use – with storage technologies varying in type and size depending on the level of service needed. Generation-level energy storage focuses on the ancillary services market[233] and renewable integration, with grid frequency regulation becoming an area of

233 Ancillary services support the transmission of electricity from its generation site to the customer. Services could include load regulation, spinning reserve, nonspinning reserve, replacement reserve and voltage support.

interest of substantial technological advancements over the last few years. Storage at the transmission and distribution level focuses on load shifting, transmission congestion relief, reliability, and capital deferral. For end users, storage at commercial and industrial facilities can provide peak shaving, electricity backup, and increased reliability.

Energy storage continues to be one of the more promising application areas to make renewable generation available when needed. Energy storage technologies will allow better matching of renewable generation with electricity needs as well as address the severe ramping rates observed with wind and PV. The use of energy storage technologies can also reduce the number and amount of natural gas-fired power plants that would otherwise be needed to provide the firming characteristics the system needs to operate reliably. Energy storage systems can respond rapidly to the needs of the electric grid, and Energy Commission research indicates that smaller amounts of energy storage can smoothly and effectively integrate renewable energy when compared to the amount of natural gas-fired power plants required to meet the same response times. California should seize this opportunity and encourage developers to install energy storage to support commercial scale solar and wind farms and reduce the need for new natural gas-fired plants as an energy-firming source.

California can use storage to support renewables in several applications. Storage can provide the ancillary services needed for integrating large amounts of renewables into the system that would otherwise be provided by conventional generating resources. Also, the state can use grid-connected utility-scale energy storage to avoid cutting back on remote wind farm production in response to transmission limits. Another application is to use large-scale energy storage to shift renewable production to times of higher value and demand, which can help address overgeneration by storing excess renewable energy and sending it back to the grid when needed. Finally, fast-response storage can improve electricity system stability and reduce stability and frequency response issues that may occur with high penetrations of renewables.

Research completed by the Energy Commission indicates these utility-scale energy storage systems can provide the grid system a variety of benefits. The energy storage systems can respond rapidly to grid system reliability issues and improve the overall operation of the grid. They can also improve the dispatchability and availability of renewable generation systems by responding to the intermittent nature of wind and solar renewable systems. Additionally, energy storage systems can provide the grid operators ancillary services such as frequency response and spinning reserve. Grid operators need a mixture of many types of generation, demand management, and energy storage capabilities to effectively manage the utility grid. When properly integrated, energy storage and automated demand response can offer critical capabilities currently provided by conventional natural gas generation.

Energy storage is typically measured as a combination of time increments and capacity (in kW or MW) and can range from a few minutes up to many hours. Batteries and flywheel systems are examples of short-duration storage that can compensate when passing clouds block the sun and cause generation to drop substantially in less than a minute and jump back to full generation a few minutes later.[234]

234 Curtright, Aimee E. and Jay Apt, *Progress in Photovoltaics: Research and Applications*, 16: 241-247, "Applications: The Character of Power Output from Utility-Scale Photovoltaic Systems", 2008, available at: [http://www.clubs.psu.edu/up/math/presentations/Curtright-Apt-08.pdf]. See also, presentation by Dan Rastler, EPRI, at the April 2, 2009, IEPR workshop, available at: [http://www.energy.ca.gov/2009_energypolicy/documents/2009-04-02_workshop/presentations/0_3%20EPRI%20-%20Energy%20Storage%20Overview%20-%20Dan%20Rastler.pdf].

The Electric Power Research Institute reports that sodium sulfur batteries and lithium ion batteries can provide frequency regulation to mitigate these kinds of fluctuations in PV generation.[235] In addition, the Energy Commission's Public Interest Energy Research (PIER) program has demonstrated that short-term energy storage systems such as flywheel technology can provide this capability.

The U.S. Department of Energy (DOE) recently provided American Recovery and Reinvestment Act (ARRA) loan guarantees to a PIER frequency demonstration project company, permitting it to construct a 20-MW facility. Other energy storage projects have been proposed to DOE that, if awarded ARRA funding, could result in the construction of several major utility-scale energy storage projects in California over the next few years.

For longer duration storage needs, pumped hydropower uses low-cost off-peak energy to pump water from lower to higher elevation reservoirs, and the water is then released during higher-cost peak times to generate electricity. However, most of the existing water infrastructure that could be used for this purpose must compete with irrigation, flood control, in-stream flow requirements, and other demands placed on the state's water systems. Developing dedicated reservoirs for pumped storage is extremely difficult.[236] Also, under current tariff structures for energy services, there is inadequate support for pumped hydropower systems to cover costs, resulting in only a limited number of operational systems in California. In addition, pumped hydropower has its own set of environmental challenges, which may limit its use going forward.

In IEPR workshops on energy storage and smart grid, stakeholders indicated that paying for these technologies is a significant barrier to increasing the amount of utility-scale energy storage in California. In many cases, energy storage systems provide utility grid services that cannot be recovered within existing rates and tariffs. Stakeholders recommended that the Energy Commission, California ISO, and the CPUC consider new rates and tariff options to permit adequate reimbursement to the energy storage system for all the services it provides to the grid. System cost-effectiveness models can be developed to more accurately reflect the true value energy storage systems provide to the utility grid for renewable integration, system reliability improvements, and ancillary services markets.

To help in this effort, the PIER program is developing system performance models for several energy storage technologies to help identify more revenue sources for energy storage systems. Because energy storage is not considered generation, transmission, or load, new information is needed to properly integrate these technologies into the utility grid system. Once developed and demonstrated, these system performance models can be used to assist the California ISO in integrating them into the ancillary service and other potential markets operated under the new Market Redesign Technology Upgrade grid management system. In addition, the PIER program is developing similar models for the load reduction capabilities provided by automated demand response systems.

California ISO recognizes the important role of energy storage in integrating renewables into the electricity system, and in September 2009, it released an issue paper about nongenerator resources, including energy storage resources, participating in ancillary

235 Transcript of the April 2, 2009, IEPR workshop, EPRI presentation, pp. 27–32, available at: [http://www.energy.ca.gov/2009_energypolicy/documents/2009-04-02_workshop/2009-04-02_TRANSCRIPT.PDF].

236 Examples of trying to create dedicated pumped-storage reservoirs include Lake Elsinor Pumped Storage and the Eagle Crest facilities, both in Southern California.

services markets.[237] The California ISO is also developing an energy storage pilot program to analyze the performance of storage devices and identify and eliminate barriers to increased deployment.[238] This work should be further expanded in time to encourage installation of storage in the 2015 to 2020 time frame as the state ramps up to the 33 percent level of renewable energy.

Other Renewable Technologies

Baseload renewable technologies such as biomass, biogas, and geothermal also will play an important role in reducing the potential need for gas-fired generation to firm up renewable energy.[239] Geothermal facilities currently provide 42 percent of California's renewable energy and generally operate as baseload; however, in combination with storage, geothermal facilities can offer load following or peaking services as well.

Biomass and biogas provide about 20 percent of California's renewable energy, with solid-fuel biomass providing the largest share. Executive Order S-06-06 requires meeting 20 percent of the state's RPS with bioenergy resources. Depending on the availability of fuel, biomass and biogas can provide baseload, load following, or peaking energy products.[240] Biopower could help displace the amount of new gas-fired generation needed to integrate higher levels of renewable energy, but because many of the existing biomass generators are operating at a financial loss under their current contracts, it is unclear whether providing load following or peaking support will be cost-effective for these facilities.

Improved Production Forecasting for Renewables

Another tool used by system operators to help integrate renewables into the system is production forecasting. Much as load forecasters use data analysis techniques to develop short-term load forecasts, system operators use production forecasting tools to anticipate the amount of renewable energy that will be delivered from various resources. Errors in load forecasting reduce the ability of system operators to anticipate the amount of energy needed to meet demand. If the amount of delivered renewable generation is different than the amount forecasted, system operators will need to increase or decrease generation from other sources of energy to make up the difference, which decreases the value of renewables to the system and increases costs.[241]

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237 California Independent System Operator, *Issue Paper for Participation of Non-Generator Resources in California Independent System Operator Ancillary Services Markets*, September 1, 2009, available at: [http://www.caiso.com/241c/241cd4af47ca0.pdf].

238 California Independent System Operator, see [http://www.caiso.com/2337/2337f16064bc0.pdf].

239 For example, see comments by ICF, IEPA, and Covanta Energy from the June 29, 2009, IEPR workshop, transcript, pp. 146, 172, and 190.

240 "For solid-fuel biomass facilities, which are unique among renewables in having a significant fraction of their total cost of electricity production in the category of variable operating cost (mostly fuel cost), it might be possible to develop feed-in tariff contracts that have elements of load following that would increase their value to the utility at little or no cost to the biomass generator." Written comments by Green Power Institute, May 28, 2009, IEPR workshop, pp. 9–10, available at: [http://www.energy.ca.gov/2009_energypolicy/documents/2009-05-28_workshop/comments/Green_Power_Institute_TN-51936.PDF].

241 California Energy Commission, *2008 IEPR Update*, p. 21, available at: [http://www.energy.ca.gov/2008publications/CEC-100-2008-008/CEC-100-2008-008-CMF.PDF].

Work at the Energy Commission and the National Renewable Energy Laboratory has led to improvements in the characterization of wind areas for planning purposes. In addition, forecasting day-ahead and hour-ahead generation from wind facilities has improved, due in part to the California ISO's Participating Intermittent Resource Program. A recent study by the North American Electric Reliability Corporation suggested that system operators expand their use of wind forecasting and conduct plant scheduling on intervals shorter than hourly to increase the ability of the electricity system to respond to changes in generation from wind energy resources.[242] Building on this progress, further work is needed to improve the accuracy of five-minute, hourly, and day-ahead forecasts for electricity demand and solar energy.

Less progress has been made in the development of forecasting models for PV and solar thermal electric generation, which still result in large errors. Cloud cover can cause generation from PV systems to drop by 50 percent in a minute or less.[243] More data is needed to improve forecasting of solar energy generation, especially data on variation on the scale of five-minute intervals and minute-to-minute generation from large-scale PV fields. The need for advances in this area is becoming more urgent because of the increasing number of utility-scale PV fields under development and the growing interest in wholesale distributed PV systems. The California ISO plans to add solar to its Participating Intermittent Resource Program later this year.[244]

Beyond the needs of transmission system operators addressed above, real-time web-based wind speed and solar radiation data and forecasts will be needed much more broadly throughout the state's future smart grid as community- and building-based systems are operated to respond to pricing signals and local and building demand. It is unlikely that current deployment of anemometry and radiation sensors will be enough to adequately support the need for accurate real-time local forecasts. PIER has identified and is developing plans to address this long-term need.

Distributed Resources

Although improvements are underway to streamline siting and permitting for transmission and renewable energy facilities, there is a risk that a resource mix depending heavily on utility-scale solar electric projects in remote areas may be delayed beyond 2020. Shifting to a resource mix including both large-scale central station projects and distributed generation (DG) would help the state meet its goal of 33 percent of retail sales from renewable energy by 2020 and lay the foundation for achieving the Governor's Executive Order goal of 80 percent reduction in greenhouse gas emissions from 1990 levels by 2050.

Distributed renewable resources include ground-mounted solar projects up to 20 MW in size; distributed biogas capacity from wastewater processing, landfill gas, animal

242 Center for Energy Efficiency and Renewable Technologies, June 29, 2009, IEPR workshop, transcript pp. 165–166. For further information, see North American Electric Reliability Corporation, *Special Report: Accommodating High Levels of Variable Generation*, April 2009, available at: [http://www.nerc.com/files/IVGTF_Report_041609.pdf].

243 This point was raised by Southern California Edison at the June 29, 2009, IEPR workshop, transcript p. 54. Clean Power Research, *Quantifying PV Power Output Variability*, Thomas E. Hoff and Richard Perez, May 2, 2009, available at: [http://www.cleanpower.com/research/capacityvaluation/QuantifyingPVPowerOutputVariability.pdf].

244 For more information, see the California Independent System Operator Participating Intermittent Resource Program website at: [http://www.caiso.com/docs/2003/01/29/2003012914230517586.html], including California Independent System Operator Participating Intermittent Resource Program Solar Telemetry Requirements, Draft Version 1.2, August 2009, available at: [http://www.caiso.com/2403/2403c293428c0.pdf].

manure digester gas, and food processing; distribution-scale solid fuel biomass; other clean stand-alone technologies; and distribution-level CHP that reduces GHG emissions through the joint production of electricity and energy needed to meet industrial and commercial thermal loads. Renewable projects that interconnect to the grid at the distribution level can come on-line faster than large projects (greater than 20 MW) that interconnect to the transmission system directly. Typically they do not require new transmission investment, extensive environmental reviews, or a lengthy permitting process.

Recent studies indicate substantial technical potential for distribution-level generation resources located at or near load. A 2007 estimate from the Energy Commission suggests that there is roof space for over 60,000 MW of PV capacity, although the study did not factor in roof space that is shaded or being used for another purpose.[245] The California *Renewable Energy Transmission Initiative Phase 1B Final Report* (*RETI Phase 1B Report*) included a preliminary estimate suggesting that as much as 27,500 MW of 20-MW ground-mount PV projects could be located at substations in California.[246] The California Biomass Collaborative estimates that there is technical potential for about 1,700 MW of distributed biogas capacity in California from wastewater processing, landfill gas, animal manure digester gas, and food processing.[247]

Studies by the CPUC and the Energy Commission have included scenarios of high penetration of distributed resources. The CPUC Energy Division Preliminary 33 Percent Implementation Analysis included a scenario with about 14 gigawatt (GW) of PV systems under 20 MW and also included about 250 MW of distributed biogas capacity.[248] Energy Commission staff analysis included a scenario that met one-fifth of the 33 percent goal with biopower, consistent with the Governor's Executive Order S-06-06. This scenario included about 8 GW of distributed solar and about 190 MW of distributed biopower, although this excludes biomass projects identified by the *RETI Phase 1B* report as having fuel to support more than 20 MW of solid-fuel biomass capacity.

Simulations and system analysis have shown that a significant amount of wholesale distributed renewable energy could be integrated into the California distribution grid. A recent analysis by E3 for the CPUC Energy Division found that approximately 69 percent of the California IOU substations can interconnect projects of 10 MW or smaller. Another study by General Electric on the effect of distributed renewable energy on feeder lines found that limits could range from 15 percent to 50 percent of feeder capacity depending on location and distribution. In addition, preliminary staff analysis suggests that about 10 GW to 11 GW

245 California Energy Commission, *California Rooftop Photovoltaic (PV) Resource Assessment and Growth Potential by County*, September 2007, CEC-500-2007-048, available at: [http://www.energy.ca.gov/2007publications/CEC-500-2007-048/CEC-500-2007-048.PDF].

246 RETI Coordinating Committee, *Renewable Energy Transmission Initiative Phase 1B Final Report*, pp. 1–10, 6–23 through 6–25, January 2009, RETI-1000-2008-003-F, available at: [http://www.energy.ca.gov/2008publications/RETI-1000-2008-003/RETI-1000-2008-003-F.PDF].

247 California Biomass Collaborative, *An Assessment of Biomass Resources in California, 2007*, March 2008, available at: [http://biomass.ucdavis.edu/materials/reports%20and%20publications/2008/CBC_Biomass_Resources_2007.pdf].

248 California Public Utilities Commission, *33 Percent Renewables Portfolio Standard, Implementation Analysis, Preliminary Results*, June 2009, available at: [http://www.cpuc.ca.gov/NR/rdonlyres/1865C207-FEB5-43CF-99EB-A212B78467F6/0/33PercentRPSImplementationAnalysisInterimReport.pdf].

of wholesale distributed renewable energy could be connected at the distribution level, at substations, or on distribution feeders.

So far, the potential for distributed resources to contribute to the RPS goals remains largely untapped. As of July 2009, there are more than 560 MW of PV and more than 300 MW of biopower installed in California at the distribution level (20 MW or less per project). While most of the currently installed PV is not eligible for the RPS, much of the biopower is. IOUs have active RPS contracts for more than 180 MW of projects 20 MW and smaller; this is less than 2 percent of IOU RPS contracts. Publicly owned utilities have active RPS contracts for almost 150 MW of projects 20 MW and smaller; this is about 14 percent of publicly owned utility RPS contracts.

Although there is clearly potential for adding large amounts of distributed renewable generation on distribution systems throughout the state, doing so presents significant challenges. Currently, the state's electric distribution systems are not designed to easily accommodate large quantities of randomly installed distributed generation resources at customer sites. Accomplishing this objective efficiently and cost-effectively will require the development of a new transparent distribution planning framework that allows for the active participation of all stakeholders.

Transportation Electrification

Parties have raised the issue of the effect increased electrification of the transportation system may have on electricity demand and therefore the amount of renewable energy needed to meet statewide targets. Even though the demand forecasts adopted in this *2009 IEPR* include some limited amounts of plug-in hybrid electric vehicles and electric vehicle electricity loads, at this time the extent and pace of transportation and industrial electrification is highly speculative. Generally the impacts of a substantial shift in transportation energy usage toward electricity are viewed as beyond the 10-year time horizon that the electricity industry is accustomed to. Stretching planning and analysis efforts out to 20 years and beyond seems necessary, and initial efforts to do so have begun; however, it is less clear how to make decisions about time periods 10 to 20 years into the future.

Issues Affecting Transmission and Distribution

As the population grows and electricity supply portfolios change, new transmission facilities will be needed to maintain system reliability and deliver electricity – including increasing amounts of renewable energy – to consumers. Conceptual planning identifies such potential transmission facilities for detailed study. Power flow modeling and production cost simulations performed by the California ISO and electric utilities then determine which projects are necessary for reliability and make economic sense and how they must be configured electrically. An implementation plan is developed only after such detailed study and only after land use and environmental implications have been fully considered for specific transmission routes.

The *2009 Draft Strategic Transmission Investment Plan* released in September 2009 provides a detailed discussion of initiatives, trends, and drivers affecting California's transmission system and planning efforts, which are briefly summarized here. First among these is RETI. In August 2009, RETI released its Phase 2A conceptual transmission plan. Phase 3 of the project will focus on developing detailed plans of service for high-priority components of the statewide transmission plan.

The RETI conceptual transmission plan identifies additional transmission capacity necessary to access and deliver renewable energy to meet the state renewable energy goals in 2020, and evaluates the relative usefulness of potential lines for accessing renewable energy. The plan identifies potential transmission network lines for further detailed study by the California ISO and electric utilities. Finally, the plan builds in environmental considerations and high level screening of conceptual transmission lines and incorporates a wide range of stakeholder perspectives.

The second issue affecting transmission planning is Governor Schwarzenegger's Executive Order S-14-08, which established an RPS target for California that directs all retail sellers of electricity to serve 33 percent of their load with renewable energy by 2020.[249] The order directs state government agencies "to take all appropriate actions to implement this target in all regulatory proceedings, including siting, permitting, and procurement for renewable energy power plants and transmission lines." Activities to implement the provisions of the Executive Order are being closely coordinated with RETI and with the Bureau of Land Management's Department of Energy Solar Programmatic Environmental Impact Statement (Solar PEIS).

The Solar PEIS is the result of requirements in the Energy Policy Act of 2005 for the Secretary of the Interior to plan for installing at least 10,000 MW of renewable generation capacity on public lands in six western states. In 2008, the BLM and the U.S. Department of Energy announced they were preparing a Solar PEIS to cover development of large-scale, grid-connected solar electric facilities in Arizona, California, Colorado, Nevada, New Mexico, and Utah. The Energy Commission is a cooperating agency for the Solar PEIS. The purpose of the Solar PEIS is not to eliminate the need for site-specific environmental review, but instead to identify best management practices and environmental mitigation strategies that proposed projects should follow. The Solar PEIS will also consider whether new transmission corridors are needed on land managed by the Bureau of Land Management to interconnect solar electric facilities to the grid.

Another effort that will affect transmission is the CPUC's proceeding to consider issues related to the development of transmission infrastructure to provide access to renewable energy resources for California.[250] In February 2009, the CPUC held a prehearing conference and staff workshop to consider whether the output of the statewide RETI could be used to support cost recovery for transmission planning and the CPUC's standards for determining need within the transmission permitting process. In its comments, the California ISO noted that competitive renewable energy zones (CREZs) have been identified by RETI and may provide a basis for certification. The California ISO and other parties also addressed 1) the use of RETI results in the California ISO long-term transmission planning process; 2) whether a rebuttable presumption of need should be afforded to renewable transmission projects studied and approved by the California ISO; and 3) how project development costs

249 Office of the Governor, Executive Order S-14-08, November 17, 2008, available at: [http://gov.ca.gov/executive-order/11072/].

250 California Public Utilities Commission, Order Instituting Rulemaking on the Commission's Own Motion to actively promote the development of transmission infrastructure to provide access to renewable energy resources for California, March 2008, available at: [http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/80268.htm].

can be recovered by project proponents. The CPUC has not yet issued a proposed decision or subsequent notice.

The California Transmission Planning Group (CTPG), composed of electric utilities and the California ISO,[251] is working toward finding transmission solutions for meeting California's environmental, reliability, economic, and other policy objectives. The group plans to produce its draft 2009 Study Plan in December 2009, with a final report expected in January 2010.

California's transmission infrastructure is an intrinsic component of the high-voltage Western Interconnection, making the state both an essential participant and a partner in several regional and federal planning and permitting initiatives that will alter the way transmission planning and permitting take place in the future.

Expected provision of new federal funding in 2010 for regional transmission planning will result in interconnection-wide 10-year and 20-year transmission plans for the WECC. These plans may identify projects and/or corridors that are needed, and these will become candidates for Federal Energy Regulatory Commission (FERC) ratemaking and possibly other federal incentives. It is critical that California engage in defining what these plans are and ensuring that they reflect California's policies and assumptions accurately. Concerns include:

- If advocates of federal legislation that would establish new FERC authority for siting and cost allocation succeed in passing a bill in 2009–2010, the pressure to site a new interstate line or lines will increase, with associated controversy over siting processes and impacts on environmental resources, both in and out of state. If FERC mandates a cost allocation method, California could be required to pay for projects not consistent with RETI, RPS goals, and carbon reduction policies.

- In addition, transmission system upgrades and additions anywhere in the Western Interconnection will affect the operation of existing lines, including those owned by California utilities and private companies. Proactively participating in WECC analyses of new lines and path ratings is critical to ensure continued high performance levels of key paths such as the California-Oregon Intertie.

- With federal funding, western sub-regional transmission planning groups are taking on enhanced planning roles, including preparation of an integrated 10-year subregional transmission plan. Successful development and engagement of the CTPG and participation of the California ISO are essential to find consensus on projects and analyses reflective of California interests.

- Greatly increased federal funding for the Western Governors' Association Western Renewable Energy Zone Phase 3 and 4 projects (described below) will continue to promote geographically constrained low-carbon resources and large-scale transmission to move remote resources to distant loads. If California policy prefers to procure more resources locally, as reflected in RETI, conflict among states seeking to export and in-state development interests will emerge.

251 The California Independent System Operator, California Municipal Utilities Association, Imperial Irrigation District, City of Los Angeles Department of Water and Power, Pacific Gas and Electric Company, Southern California Edison Company, San Diego Gas & Electric Company, and the Transmission Agency of Northern California.

- Major project developers continue the trend of pursuing large transmission projects to deliver power to coastal and desert load centers. Significant resources are being spent to evaluate feasibility and siting for these projects. California needs to be involved in these efforts to provide feedback to project developers on whether these projects are needed or desirable for the state.

Role of the California Smart Grid

The Energy Commission's PIER program is completing research, development, and demonstration (RD&D) efforts to help bring to market new and innovative solutions to the issues facing the California transmission system and the challenges caused by the integration of more renewables into the utility grid system. In addition to research on energy storage, automated demand response, distributed generation, CHP, and improved renewable technologies, the PIER program is leading a very aggressive effort to encourage the implementation of the California smart grid of the future, which will be driven by existing and future energy policies being implemented in California. Some of the current key policies are:

- A 33 percent Renewables Portfolio Standard by 2020.

- Implementing advanced metering infrastructure by the IOUs for residential customers. Current plans by the CPUC include the installation by the of more than 12 million "smart meters" in the next two to five years.

- Implementation of 100 percent of the cost effective energy efficiency by 2016.

- Demand response implementation goals.

- AB 32 GHG emission reductions goals.

In addition to these specific state policies, other technology improvements are rapidly progressing in California, the nation, and the world. Some of these are:

- Substantial increase in the number of electric vehicles and plug-in-hybrid electric vehicles projected over the next decade.

- Commercial growth of home area network technologies in California residences.

- Field implementation of a wide range of two-way communications technologies.

- Automation of demand response (ADR) and implementation of a common OpenADR standard in California.

- Field implementation of high speed synchrophasor data collection and reporting systems.

- Advancements in the automated management of the utility distribution system.

- Increased emphasis on the need for new cyber security capabilities.

The California smart grid will take advantage of these and many more technologies and capabilities as the smart grid system is fully implemented over the next decade. The national smart grid effort is being driven by the requirements in the Energy Independence and Security Act of 2007 and the efforts of DOE to implement a national smart grid. One key driver for the rapid expansion of these technologies is the amount of ARRA funding for smart grid. The DOE is expected to fund more than $4 billion in smart grid projects nationally over the next 12 to 14 months, representing more than 10 times the normal rate of investments this area has seen in the past. California could easily receive $400 to $600 million in smart grid funding from DOE. Because projects require 50 percent match funding by the utilities and commercial companies requesting these funds, California could have more than $1 billion in smart grid projects over the next few years. This level of funding in California and the high level of national smart grid project funding will result in the very rapid growth of smart grid technologies and capabilities.

The implementation of the smart grid in California is expected to provide new opportunities to meet current and future energy policy goals such as:

- Utility system data reporting capabilities based on synchrophasor technology, advanced metering infrastructure, distribution automation, and new home area network technologies. These systems are expected to allow the utilities and California ISO to more rapidly recognize and analyze system problems, develop possible solutions, and repair or recover grid problem areas more quickly than with the current grid system. Consumers can expect the smart grid of the future to have fewer failures and faults, more rapid recoveries when problems do occur, and more efficient and cost-effective operation.

- The smart grid will provide new methods and technologies to implement energy efficiency and demand response capabilities in the future. The new data collection capabilities, increased two-way communication, smarter consumers, and wide range of energy savings tools and products will allow consumers to make much smarter individual energy management decisions.

- The smart grid will provide expanded abilities to integrate higher penetrations of renewable technologies. The management of energy storage, distributed generation, automated demand response, distribution level renewables and other capabilities will allow the grid to accept much higher amounts of renewables while maintaining high levels of reliability and controllability.

- The smart grid will allow high numbers of electric vehicles and plug-in hybrid electric vehicles on the roads and, with smart charging systems, permit these vehicles to operate effectively without causing major disruptions on the utility grid. Some electric or plug-in hybrid vehicles could actually be used as grid assets and provide ancillary services for grid operators when parked in facilities where commercial energy service providers can aggregate their loads into one single energy response system.

- The smart grid will provide better tracking of GHG emissions and will help California meet future emission goals by increasing the use of renewables, energy efficiency, and electric vehicles and by reducing the number of power plants needed to support the grid by using demand response and energy storage as alternative sources of energy for the grid management.

The *2007 IEPR* dedicated a chapter to California's electric distribution system. The information covered and recommendations provided are still relevant and are not repeated in the *2009 IEPR*. The smart grid is expected to provide new opportunities to address the issues facing the distribution system and can help with areas such as upgrading distribution system reliability, integrating higher levels of distributed generation, and allowing a higher penetration of distribution level renewables on the California grid system.

Senate Bill 17 (Padilla, Chapter 327, Statutes of 2009) requires the IOUs to develop and submit a smart grid deployment plan to the CPUC for approval by July 1, 2011. The Energy Commission will work actively with the CPUC and the California ISO to help develop these smart grid deployment requirements and ensure that the issues and concerns of state utilities, both publicly and investor-owned, are considered when developing the statewide requirements.

Role of Research and Development

One expected challenge for the smart grid is to address the interaction of rapid deployment of new technologies while ensuring the California smart grid is interoperable both within the state and with other national systems. The PIER program is actively working with other state agencies, industry, and the academic community to identify key standards, protocols, and reference designs that will help ensure that the smart grid operates smoothly. The smart grid standards being implemented nationally will provide significant guidance in this area, but it is expected that California may lead the nation in the implementation of a smart grid and therefore will need to make some initial decisions to ensure the state has the interoperability and commonality needed in the future.

Another area where additional RD&D efforts are needed is renewable energy secure communities. Community-based energy systems are attracting investment, policy attention, and public support nationally and around the world, as community leaders respond to public interest in climate change, sustainable growth, job creation, reducing energy imports, and managing the economic impacts of fossil fuel price escalation and volatility. California is providing leadership in RD&D to identify technical solutions communities can use to optimize their energy supply and integrate building and community-scale energy sources with energy efficiency solutions and programs and smart grid capabilities. The Energy Commission held a solicitation for renewable energy secure community technical integration projects resulting in 50 proposals. The DOE has followed suit with its own solicitation on this topic, and other states and countries are exploring policy mechanisms that allow communities to actively participate in the development of the best energy investment strategy for their individual community.

For utility-scale renewables, additional RD&D is needed on integration challenges with solar energy, since it now appears that solar will play a larger role than originally assumed when the Energy Commission completed its Intermittency Analysis Project. The Energy Commission's PIER program should define and complete a study that builds on previous utility-scale renewable energy integration studies.

PIER has adjusted the emphasis of its renewable energy RD&D investments to better address technical integration issues and solutions related to RPS implementation as well as the need for technical solutions enabling community- and building-scale renewable energy deployment. In addition, the Energy Commission is providing seed funding to the California Renewable Energy Collaboration for development of an integrated renewable energy systems program. When fully funded, the program will conduct and coordinate cutting-edge studies addressing the major technical, economic, and policy questions facing the state as it deploys additional renewable energy supply throughout its electricity and energy end-use infrastructure.

Further research is also needed to understand what parts of the distribution system can best tolerate renewable generation and what role wholesale renewable distributed energy can play in providing local reliability. Research should also focus on the interaction of energy policies affecting the distribution grid, including on-site renewable generation, distributed energy storage, electrification of vehicles, energy efficiency, demand response, and zero net energy homes and buildings. For example, distribution lines may need to be reinforced with technology that can meet demand when on-site distributed renewable energy is not generating electricity. At the same time, upgrades, storage, or other resources may be needed to accommodate two-way flows from intermittent renewable power that is not dispatchable and is placed where it is convenient to the customer, but not to the grid.

Research should also focus on the technical feasibility of adding large amounts of wholesale distributed renewable energy to help the state meet 33 percent of retail sales with renewable energy by 2020, including review of the logistics of upgrading distribution grid infrastructure to meet this timeline. Better understanding of the amount of wholesale distributed renewable energy that is technically feasible by 2020 can help guide studies of market designs supporting smart grid communities, such as feed-in tariffs for CHP and renewable energy.

In addition, integrating increased quantities of distributed generation will require California's energy agencies to work together to develop a comprehensive understanding of the importance of distribution system upgrades not just to assure reliability but also to support the cost-effective integration and interoperability of large amounts of distributed energy for both on-site use and wholesale export. Utilities will need to assess where on their systems distributed generation, both for on-site use and for export to the grid, would be of the greatest value and provide that information to the energy agencies. These studies should identify which operational characteristics have the highest value; what tools, data, and criteria are used to select these locations; and what obstacles exist to deploying specific types of distributed generation.

Infrastructure Investment

The hybrid electricity market established through AB 1890 (Brulte *et al.*, Chapter 854, Statutes of 1996) created multiple entities that invest in and operate specific facilities that are part of the overall electricity infrastructure in California. Merchant generation has a strong position in California. IOUs and various forms of publicly owned utilities continue to dominate the distribution and transmission elements of the electric grid, but even here niche participants have appeared. The Trans Bay Cable from Pittsburg to San Francisco is a good example of a transmission investment made by a public-private partnership. The large and growing number of distributed generation facilities satisfying end-user load, but exporting some of their production to the grid, represents an alternative type of investor. Each of these categories of investor makes decisions about securing capital and constructing facilities using different financial perspectives, accounting rules, tax liabilities, and risk mitigation preferences. Explicit legislation and regulatory agency decisions must guide these investors to make decisions compatible with the vision that the state has for the electricity grid.

Forward Energy or Capacity Markets

In the California ISO balancing authority area, the California ISO and the CPUC have established a one-year ahead forward capacity requirement for all load-serving entities under their various jurisdictions. By establishing a capacity requirement to satisfy reliability needs, a distinct value for capacity will emerge that covers a substantial portion of the investment in a power plant, and the needs for energy will be satisfied through less regulated market decisions. For several years the CPUC has been investigating whether this structure is adequate to provide signals to a competitive industry that additional generation is needed. Advocates of both a central capacity market and a bilateral forward market have put forward the merits of their proposals. At the July 28, 2009, IEPR workshop on OTC issues and in comments following, several generators urged consideration of their forward capacity market construct submitted to the CPUC. They asserted that this would be the best mechanism to surface replacement generation proposals.

On November 3, 2009, the CPUC issued a proposed decision in R.05-12-013 that endorses a multi-year forward extension of the current bilateral contract form of capacity obligation. By this means, the CPUC hopes to both identify future electricity system requirements and induce load-serving entities to contract with existing and new generation to satisfy such obligations. In addition, the proposed decision highlights the need for a standardized capacity product and an electronic bulletin board that would facilitate trading of capacity resources as load migration among load-serving entities shifts responsibility for future obligations.

The proposed decision notes that the existing one-year ahead resource adequacy process makes use of the capabilities of the Energy Commission and California ISO in developing the planning assumptions and suggests that continuation of such a coordinated planning process would utilize the expertise of the energy agencies. The Energy Commission supports this approach regardless of the final decision and will work with other agencies to support a forward capacity mechanism.

Forward Generation Investment by Publicly Owned Utilities

The Energy Commission is required by AB 380 (Nuñez, Chapter 367, Statutes of 2005) to oversee the resource adequacy efforts of all publicly owned utilities in California. The legislature has authorized a limited "review and report" form of oversight, which allows the Energy Commission to collect information from these utilities and biennially report results of its review as an adjunct to the *IEPR*. Energy Commission staff collected such information during 2009 and presented its results at a workshop on August 6, 2009.[252]

Collectively, and almost without exception, publicly owned utilities are resource adequate several years into the future. As integrated utilities responsible to oversight boards, the various publicly owned utilities have incentives to acquire resources to cover expected loads. As discussed elsewhere in this report concerning the various elements of demand-side or supply-side resource choice, publicly owned utilities have traditionally emphasized low cost options. As a consequence, their collective exposure to out-of-state coal, either through fractional ownership shares or wholly owned facilities, is now at odds with state policy to reduce GHG emissions. As state policy emphasizing preferred resource additions becomes more directly applicable to publicly owned utilities, a shift in resource mix is expected requiring publicly owned utilities to commit to long-term contracts or invest directly in such resources. This will increase total investment or credit requirements.

Investment in Transmission and Distribution

Utilities are expected to make sizeable investments in additional transmission infrastructure, both to facilitate use of remote renewables in satisfying load concentrated in urban centers and to upgrade transmission facilities within these urban centers to reduce local capacity requirements. At the July 28, 2009, IEPR workshop on OTC, SCE strongly cautioned that long lead-time transmission investments could be rendered not useful and thus not recoverable if short lead-time generation investments substituted for transmission at the last moment.[253] It appears that SCE wanted to communicate the message that the OTC replacement infrastructure proposal made jointly by the energy agencies to SWRCB should be followed through fully all the way to the final ratemaking actions by the CPUC.

The *2009 Strategic Transmission Investment Plan* provides an in-depth review of near-term and longer term issues associated with transmission needed to achieve renewable development. However, as noted in this chapter, there are still many uncertainties affecting the

252 The transcript and presentations from the August 6, 2009, IEPR workshop are available at: [http://www.energy.ca.gov/2009_energypolicy/documents/index.html#080609].

253 Comment by Pat Arons, Southern California Edison, at the July 28, 2009, IEPR workshop.

transmission needed to support this renewable development. Among these are:

- The amount of renewable development that will be required to satisfy an RPS formula of 33 percent of retail sales by 2020 given various demand-side policy preferences.

- Whether, and to what extent, out-of-state renewables will be eligible to contribute toward RPS goals.

- What mix of renewable resource types, especially wind versus solar, is likely to emerge since the transmission lines and routing are largely different among various development scenarios.

Fortunately, the transmission revenue requirement issues associated with FERC treatment of transmission to support state energy policy goals seems to have been resolved. On January 25, 2007, the California ISO filed a petition with FERC for a declaratory order seeking conceptual approval of a new financing mechanism to aid the construction of interconnection facilities for location-constrained resources (primarily remotely located renewables). On April 19, 2007, FERC granted the California ISO's petition and accepted the design concepts proposed therein, thus paving the way for the California ISO to file tariff language implementing this initiative. The California ISO filed a tariff amendment for the Location Constrained Resource Interconnection on October 31, 2007. FERC approved the amendment on December 21, 2007.

The rollout of smart meters by IOUs and some publicly owned utilities and related smart grid technologies will also require substantial investments.[254] While the infrastructure itself will be deployed by utilities (or commercial entities under long-run contract to utilities), once the system is in place end-use customers will need to make investment themselves to make full use of some of the new capabilities.

End-Use Customer Investments

Pursuing energy efficiency, customer-side-of-the-meter distributed generation, and demand response as preferred resources substituting for conventional generating facilities places substantial investment requirements on end-use customers. Customers are asked to make investments that will reduce expected energy purchase costs, hopefully saving money in the long run. The turmoil in credit markets stemming from the housing crisis of 2008–2009 and its spillover into the stock market and tightening of all forms of lending bodes ill for expectations that end users can easily provide the investment capital required. Early monitoring data from 2009 IOU energy efficiency programs suggest that IOUs are not making the energy savings goals established for them by the CPUC and that customers are simply not as willing to make the required investment despite the incentives provided through IOU programs authorized by the CPUC.[255]

The energy agencies need to carefully review policies that depend upon consumer investments and determine whether new forms of assistance are required, how this might be provided, and what coordination among other

254 On October 27, 2009, the U.S. Department of Energy announced that the Sacramento Municipal Utility District will be awarded about $135 million to install a smart metering system for all end-use customers.

255 IOUs provide monthly and quarterly reports to the CPUC providing data on customer installations. In the reports through June 2009, Pacific Gas and Electric was installing only one-half the measures achieved in the comparable period of 2008, while Southern California Edison and San Diego Gas & Electric were matching the prior year's successes. See *California Energy Demand 2010–2020 Adopted Forecast*, CEC-200-2009-012-CMF, available at: [http://www.energy.ca.gov/2009publications/CEC-200-2009-012/CEC-200-2009-012-CMF.PDF].

state and local institutions is appropriate. If end-use customers cannot uphold expectations implicit in current demand-side program goals, then either programs need to be redesigned to increase incentives or program goals need to be scaled back in the near term or long term.

Integrating Policy and Planning

This chapter has outlined the numerous challenges that California faces in integrating the many overlapping and often conflicting energy policy goals related to the electricity sector. First there is the overarching goal of reducing GHG emissions from the electricity sector, through strategies such as achieving all cost-effective energy efficiency and demand response measures, meeting the state's RPS goals of 33 percent by 2020, adding 3,000 MW of solar through the California Solar Initiative by the end of 2016, and increasing CHP by 4,000 MW. Next are other environmental goals like retiring or repowering plants that use OTC to reduce the impacts of electricity generation on marine life, reducing the impacts of siting solar plants in the California desert, and improving air quality in nonattainment areas of the state such as Southern California. OTC mitigation is likely to reduce the amount of flexible fossil resources available to integrate renewables, so newly constructed power plants will be needed to support such integration. But air quality regulations strongly penalize new power plants compared to the continued operation of existing power plants, so licensing the amounts of new fossil generation needed for renewable integration will be extremely difficult in some regions of the state. Another potential area of conflict is the need for new transmission lines to access remote renewable resources that may have land use, environmental, visual, or cost impacts. Finally, there is the long-standing policy to reduce the state's dependence on natural gas and natural gas imports, as well as the Energy Commission's mandate to develop energy policies that ensure electricity reliability, sufficiency, affordability, and public health and safety.

In the California ISO balancing authority area, formal resource adequacy requirements established by both the CPUC and California ISO provide a framework for evaluating reliability. However, the need for dispatchable power plants in specific locations to support the California ISO's local reliability needs remains analytically opaque and there is, as yet, no mechanism to ensure that the needed resources will be built. As the recent joint energy agency proposal to SWRCB concerning development of OTC replacement infrastructure makes clear, all these entities support reliability goals, but converting that common policy sentiment into concrete action steps resulting in operational power plants and transmission lines remains a challenge.

These GHG reduction, environmental protection, and reliability goals must be integrated so that the state can set priorities and better understand tradeoffs when goals are in direct conflict. Policy makers need to understand the interactions between goals and make decisions that reconcile or prioritize these goals. Planning processes must consider how realistic policy goals and their target dates are and whether they will be achieved in full and on schedule and if not, plan accordingly. This could lead to more resources than are actually needed, which could be preferable to supply shortages that reduce system reliability or to resorting to expensive emergency actions in an attempt to "catch up."

At the same time, energy agency planning, procurement, and permitting decisions must consider technological, financial, and environmental constraints. On the engineering side, dispatchable power plants are needed to meet hourly, daily, and seasonal fluctuations in electricity demand and supply that can result from changes in weather, hydroelectric or natural gas supplies, variable renewable generation, planned outages for maintenance, or equipment failure. System operators also have to account for adequate electricity resources in specific areas of the state, known as load pockets, so that transmission limitations into and out of those areas do not lead to operational problems or even outages. Also, transmission and generation are sometimes complementary, such as when transmission additions are needed to allow the development of remote renewable resources, and sometimes substitutes, as when transmission upgrades allow the retirement of certain power plants that provide local reliability functions in load pockets.

On the financial side, both electric utilities and private developers make decisions based on reasonable expectations of profits, which will affect how much investment in new infrastructure will be made at any one time. It is also a reality that all of California's preferred resources (energy efficiency, demand response, renewables, and distributed generation) have costs as well as benefits, and those costs must be taken into account when making decisions about policy tradeoffs. Further, since the state's overall industry structure is dependent upon private entities responding to state energy plans to motivate their investments, the state energy agencies need to provide clear and convincing messages about the type and timing of investments.

Planning in the Electricity Sector

There are numerous agencies within California involved in electricity planning. The Energy Commission, CPUC, and California ISO each conduct electricity planning processes that provide general guidance on policies and specific guidance on a limited range of electricity topics unique to the responsibilities of each agency. Some degree of coordination already exists, but more will be necessary going forward. For example, the Energy Commission forecasts statewide electricity demand in its biennial *IEPR*, while the CPUC oversees investor-owned utility procurement of the resources needed to meet that demand. The California ISO analyzes and approves plans for the transmission needed to reliably bring those resources to customers and uses the Energy Commission demand forecasts in such analyses. However, while portions of the California ISO's analyses rely upon Energy Commission studies, other parts are less well-coordinated with state energy policy goals. In addition, publicly owned utilities conduct their own planning and procurement processes to meet resource needs in their service territories. Overlaying these planning processes, the ARB identifies strategies for achieving emission reductions in the electricity sector needed to help the state meet its GHG emission reduction goals.

State and regional environmental agency processes can also have a major effect on the electricity sector. For example, the SWRCB implements federal Clean Water Act provisions related to the use of ocean water in power plants, with the authority to approve and set conditions for permits without which those plants cannot operate. Withdrawing such permits can shut down an existing power plant, something that none of the energy agencies has authority to do. Another example is the

SCAQMD, which determines which power plants get air credits. As noted earlier, current legal issues surrounding those credits have created a temporary moratorium on power plant licensing in the Los Angeles Basin.

On the transmission side, IOUs and publicly owned utilities plan for their own service territories. IOUs submit their planning considerations to the California ISO annual transmission planning process, while publicly owned utilities submit their future transmission priorities to the Energy Commission as part of the development of the *Strategic Transmission Investment Plan*.

The California ISO's annual plan addresses only the California ISO-controlled grid and is limited to electrical system planning requirements, so land use and environmental considerations are not included. The annual plan captures a 10-year time horizon and does not assess needs well into the future for a longer term view. The plan establishes the need for new transmission infrastructure proposals for IOUs who in turn seek permits for those facilities at the CPUC.

The Energy Commission is involved in transmission through the development and adoption of the *Strategic Transmission Investment Plan* as part of the requirements of the biennial *IEPR* to assess all aspects of energy supply, which includes transmission. The plan identifies and recommends actions needed to implement transmission investments needed for reliability, congestion relief, and future load growth. The plan also describes transmission challenges and provides recommendations to address those challenges and also identifies high priority transmission projects that are then integrated into the California ISO's annual transmission plans.

Lastly, the informal RETI process is influencing formal transmission planning. The RETI effort undertaken by stakeholders obviously brings together renewable generation development with the transmission lines needed to gather such power and move it to load centers. The electric utilities, the California ISO, and the Energy Commission have all committed to consider RETI results in their transmission planning processes. Because the RETI process only addresses the interconnection of renewable energy, it will not result in a complete and detailed California transmission plan of service. However, it is a first step toward a detailed statewide transmission plan because it articulates the requirements associated with connecting renewable resources to the transmission system, which is the most important and difficult requirement for future transmission infrastructure in California. More importantly, it balances electric considerations with land use and environmental considerations in a stakeholder process to create broad support for new infrastructure needs.

All of these complementary and often overlapping electricity and transmission planning processes are only loosely coordinated among the many agencies involved. The CPUC's biennial LTPP proceeding uses information developed in the Energy Commission's *IEPR* to provide procurement guidance to the IOUs, and the CPUC's Energy Division staff has proposed expanding the scope of the LTPP to address "system requirements" rather than just IOU-bundled customer needs. If accepted as proposed, this "straw proposal" would be implemented during 2010–2011. The California ISO conducts an annual transmission planning process to evaluate both conceptual transmission developments and specific project proposals, and its study of local reliability is used to determine local capacity requirements for both CPUC-jurisdictional load-serving entities and those publicly owned utilities governed by the California ISO's resource adequacy tariff. These key elements guide requirements for transmission owners and load-serving entities today.

Publicly owned utilities have their own processes that are even more loosely connected.

Despite periodic efforts to coordinate these processes, the dynamics of independent institutions mean that only partial coordination has been sustained through time.

There have been some efforts to integrate the various statewide electricity planning processes. Senate Bill 1389 (Bowen and Sher, Chapter 568, Statutes of 2002) completely revised the electricity and natural gas planning responsibilities of the Energy Commission. It established the biennial *IEPR* and directed the Energy Commission to consider the input of nine named state agencies in developing its assessments. It also requires these nine agencies to use *IEPR* information and analyses in carrying out their own energy-related activities. The CPUC then established a biennial LTPP process conducted in even-numbered years to follow immediately upon the Energy Commission's *IEPR*. In a process known as integrated planning and procurement mechanism, the Energy Commission, CPUC, and California ISO negotiated how their respective planning and procurement activities would dovetail. By fall 2004, detailed flowcharts and narrative descriptions of process integration had achieved some degree of success. However, this process terminated by spring 2005 without reaching a formal agreement.

In decisions in 2004 and 2005, the CPUC directed that the *2005 IEPR* demand forecast be used as the basis for the 2006 LTPP proceeding and that the *2005 IEPR* policy recommendations be considered in the forthcoming CPUC LTPP rulemaking. The Energy Commission provided the CPUC with a special transmittal report containing the electricity demand forecast, net short results, and policy recommendations from the *2005 IEPR*. Despite opposition from IOUs and delays that deferred conclusion beyond the expected time frame, the CPUC issued a decision in the 2006 LTPP rulemaking to use the *2005 IEPR* demand forecast and accept the spirit of the aging power plant retirement policy established in the *2005 IEPR*. This process was not repeated for the *2007 IEPR* and the 2008 LTPP proceeding because the CPUC decided to devote the 2008 LTPP proceeding to reviewing and upgrading the methods used in LTPP portfolio analyses and other elements of the planning process that would then be used in the 2010 LTPP proceeding.

The next opportunity for coordination between the Energy Commission's *IEPR* and the CPUCs LTPP proceeding is the *2009 IEPR* and the 2010 LTPP. The CPUC has clearly stated its intention to use the demand forecast adopted in the *2009 IEPR*. Further, the CPUC has determined that it will use the Energy Commission's analysis of the incremental impacts of uncommitted energy efficiency projections as the source of modifications to the Energy Commission's baseline load forecast. These adjustments result from calculating the additional energy efficiency previously established within the CPUC energy efficiency goal setting process that should be used to adjust the baseline forecast. The 2009 IEPR proceeding has agreed to provide such a product to the CPUC consistent with the CPUC's required schedule.

Although the discussions regarding coordination between the three energy agencies broke down in spring 2005, continuing discussions with the California ISO regarding coordinated planning resulted in proposals that the California ISO use the Energy Commission's long-term demand forecast as the basis for transmission planning. Since that time, the California ISO has used the *IEPR* demand forecast as the basis for its transmission planning studies and requires participating transmission owners to do the same. However, Energy Commission staff is unaware whether the California ISO modifies the baseline demand forecasts to reflect potential decreases in electricity demand as a result of the goals in the ARB's *Climate Change Scoping Plan* for increased energy efficiency and use of distributed generation resources. The California ISO also uses Energy Commission short-term demand forecasts in developing one-year-ahead local resource adequacy requirements, which the CPUC reviews and adopts each year as part of its resource adequacy requirements.

Statewide collaboration with regard to formal transmission planning does not exist and remains elusive. In the final analysis, transmission plans developed by formal transmission planning organizations in California are disjointed and uncoordinated and do not adequately address future transmission infrastructure requirements on a statewide basis. There is no single transmission planning process that addresses the state's complete transmission system or grid, even though all elements are part of the overall Western Interconnection. None of the existing transmission planning processes adequately considers transmission line routing and related land use and environmental implications, and existing planning processes do not adequately consider long-term needs well beyond the 10-year time horizon.

Given the challenges facing California's electricity system in the next decade, the state requires tighter coordination among energy agencies to address these challenges and avoid unnecessary duplication of effort for both the agencies and the stakeholders they serve. Lack of this coordination, let alone full integration, means that some efforts are duplicated while others are inconsistent or not receiving the attention they deserve. For example, numerous efforts examining various implications of 33 percent by 2020 were presented at an Energy Commission IEPR workshop on June 29, 2009. However, the most fundamental work to understand the amounts of flexible, dispatchable resources to complement the intermittency of some renewables is still needed.

Another example is the use of alternative planning assumptions in various forums, including licensing proceedings, to evaluate specific generation or transmission projects. There are known discrepancies in these assumptions compared to state policy goals. Although the California ISO considers the Energy Commission adopted demand forecast in its annual transmission planning process, it does not modify the load forecast to account for the impacts of the demand-side resource goals adopted by the state for incremental energy efficiency, demand response reductions at peak, or distributed generation. Omitting these impacts leads to conclusions that electricity demand will be higher, thus making more projects cost effective. This conservative approach may make sense from a "reliability first" perspective, but if it extends from just analysis to actual project proposals, such practices may increase the number of interventions in transmission licensing proceedings because some parties may feel proposed transmission lines would not be needed if the preferred demand-side policies were taken into account in the analyses.

Finally, no energy agency is systematically examining the long-term future. Electricity demand patterns may be very different 15 to 25 years into the future, and power plants that will be licensed and built in the ensuing years will still be viable and not yet fully depreciated. Transmission planning beyond the normal 10-year horizon is needed to prevent short-term infrastructure decisions from interfering with longer term needs or creating additional land use and environmental conflicts. Achieving the GHG emission reductions called for in Executive Order S-20-06 for 2050 will involve much more complex tradeoffs between fuels and electricity. Electricity demand may increase as a result of higher penetration of electric vehicles or increased electrification of industrial processes to help those sectors meet their GHG emission reduction goals. While it is too early to make firm commitments to power plants on the basis of this speculative electrification, it is not too early to begin identifying how larger electricity demand might be met by expanding the transmission system to access more sources, establishing transmission corridors to assure that transmission can be expanded in the future, and evaluating whether "energy parks" ought to be planned in advance to support electrification to the extent it is needed. Further, differences in demand patterns may alter the current mix of resources, relying either more or less than today on "peaking" resources that might be satisfied by storage technologies. A future which relies to a greater extent on electricity as the energy "source" for end-user equipment (homes, businesses, factories, and transportation) should motivate all energy agencies to evaluate whether reliability requirements for electricity generation, transmission, and distribution must evolve as well.

Need for Statewide Planning

Finding ways to coordinate and streamline the collective responsibilities of the energy agencies will be essential in meeting the state's important policies and policy goals.[256] Public Resources Code 25302(e) suggests that the Energy Commission seek input from the CPUC and the California ISO, as well as stakeholders and other agencies, in the Energy Commission's IEPR proceedings on future electricity infrastructure needs and requirements and by consolidating recommendations on future needs.

256 The California Energy Commission staff prepared an integrated planning paper and distributed it among various agencies during August 2009. Feedback from these agencies has been mixed.

Senate Bill 1389 establishes the Energy Commission's *IEPR* as the forum for establishing energy policy. It is expected that the Energy Commission's forecasts and assessments are to be relied on by other agencies, including the CPUC, in carrying out their energy-related functions. There have been efforts to better link and coordinate the *IEPR* with the CPUC's LTTP. However, in recent years, the scope of the LTTP has grown in response to direct legislative mandates and under the CPUC's general interpretation that minimizing ratepayer costs requires it to make choices that balance resource preference goals with just and reasonable rates.[257]

Recently, the Legislature also gave the Energy Commission greater authority over publicly owned utilities to ensure they also follow the broad resource policy preferences established by the Energy Commission and CPUC or required by the Legislature. Similarly, the Energy Commission has been granted authority to designate transmission corridors to smooth the way toward specific transmission line projects in the future, which would presumably be evaluated, approved, and, once constructed, operated by the California ISO.

The recent proposed decision in CPUC R.05-12-013 signals a possible close to the long-standing issue of whether load-serving entity-specific forward capacity requirements to satisfy a multi-year forward resource adequacy requirement will be set as they are today in a bilateral contract manner or through a centralized capacity market auction. Importantly for coordinated planning, the proposed decision suggests that the planning analyses that will determine new capacity require-

257 A California Public Utilities Commission Energy Division straw proposal for the 2010 LTPP cycle, released July 1, 2009, proposes to add a "system plan" element alongside direct IOU-bundled customer procurement to identify needed resource additions. The straw proposal explains that undertaking this new scope would add to the length and complexity of the LTPP proceeding.

ments should continue to be established in a coordinated manner using the capabilities and expertise of the Energy Commission and the California ISO as is the case today for the year-ahead requirements. The Energy Commission supports the development of common planning assumptions and results and hopes the final decision will include these provisions.

The Energy Commission has long required all load-serving entities with peak loads above 200 MW to submit their demand forecast and resource plans to the Energy Commission for review. This includes IOUs, publicly owned utilities, and CPUC-jurisdictional load-serving entities. The CPUC has similar requirements for the IOUs. While the CPUC's focus on IOUs is important, it does not cover efforts by its own regulated electric service providers or publicly owned utilities located in the transmission areas served by SCE or PG&E.[258] Similarly, while the California ISO is the largest system operator and transmission planning organization in the state, there are four other balancing authorities in California that play similar roles. Among these, LADWP is the most important of those with autonomy from the CPUC as a publicly owned utility and from the California ISO as an independent operator of a balancing authority area. This issue cannot be solved by the CPUC and California ISO alone. LADWP is an important player in developing its own plans to use scarce air quality credits that new or repowered generators will need in the overall Los Angeles Basin as the power generating fleet complies with the SWRCB's once-through cooling mitigation policy.

Now that the joint agency proposal has been accepted by SWRCB staff and incorporated into the draft OTC mitigation policy issued for formal public comment,[259] the energy agencies need to confront the details of how the proposed analyses will be accomplished in a timely manner and how existing decision-making processes will be modified to make tough choices. While the proposal emphasized the broad steps leading to the product the SWRCB needs – a schedule for OTC power plant replacement – it did not lay out changes needed in planning process or decision-making practices to achieve the collaborative analyses and broad decisions about preferred options. Recent modifications made by SWRCB to its proposed OTC mitigation policy clarify the ongoing need of the energy agencies to review the preliminary schedule provided to SWRCB and to update it periodically.[260] The energy agencies must align their processes in order to make the best and most expeditious decisions to determine which OTC power plants will be repowered, retired, or retired with the capacity replaced remotely and/or with transmission system upgrades.

258 Senate Bill 695 (Kehoe, Chapter 337, Statutes of 2009) authorizes an expansion of retail choice and thus may once again create splits between the interests of IOU-bundled service customers and those of customers provided energy services through an electric service provider.

259 Jaske, Michael R. (Energy Commission), Dennis C. Peters (California Independent System Operator), and Robert L. Strauss (CPUC), *Implementation of Once-Through Cooling Mitigation Through Energy Infrastructure Planning and Procurement*, California Energy Commission, July 2009, CEC-200-2009-013-SD, available at: [http://www.energy.ca.gov/2009publications/CEC-200-2009-013/CEC-200-2009-013-SD.PDF].

260 The State Water Resources Control Board staff issued a revised once-through cooling mitigation policy proposal on November 23, 2009. Many of the changes formalized in the once-through cooling policy itself the implicit understandings that the energy agencies had received from SWRCB staff about the implementation of the policy through time. The State Water Resources Control Board conducted a public workshop on these changes on December 1, 2009.

The New Electricity System

Numerous discussions have been taking place among the affected energy and environmental agencies to develop plans to achieve the "new electricity system." The ARB AB 32 Climate Change Scoping Plan implementation, SWRCB once-through cooling policy implementation, SCAQMD air credit allocations among scarce facilities, and Desert Renewable Energy Conservation Plan are examples. Each stems from some vision of a future electricity system that is substantially different from the one that exists today. Unifying these disparate visions and then translating them into the level of detail necessary to create and sustain multi-year implementation plans is a daunting task.

Discussions among agencies and stakeholders about developing blueprints for future resources that identify desired quantities of specific resource types and determining whether a specific project matches those needs requires common terminology to allow effective communication. Potential definitions are offered below:

Vision: A view of the future electricity system incorporating the preferred policy elements (renewable generation, demand-side initiatives) and supporting infrastructure (transmission, smart grid, distribution components) that both achieve GHG emission reduction goals and assure reliability standards.

Blueprint: A semi-quantitative plan, guide, or framework that translates the vision by juxtaposing the resource policy preferences against reliability standards, thereby resolving conflicts, reflecting priorities among policy preferences where they interact or conflict, indicating which entities are guided by the plan, and establishing how agencies coordinate with one another. A blueprint provides the basis for developing detailed plans. Borrowing from architecture, the Energy Commission refers to this specific translation of the general vision as a "blueprint," the blueprint being the detailed specifications a contractor would need to execute a more general architectural rendering or "vision."

Infrastructure assessment: A process of quantitatively evaluating the state's blueprint using current and expected electricity demand, new supply additions, possible retirements of existing power plants, operating requirements, and necessary transmission to guide decisions about the future energy system mix to determine the necessary attributes and locations of necessary power plants, and in what time frame.

Developing a Blueprint for the Future

Numerous elements describing the future electricity system were identified as far back as the original *Energy Action Plan*. Most of these original policy preferences have been ratified, along with new elements, in the ARB *Climate Change Scoping Plan*. What remain to be added to these are the reliability and system efficiency objectives that are called out in state law, decisions of the agencies, and federal requirements. While it is reasonably straightforward to enumerate a long list of elements describing a vision for this future electricity system, specifying which objectives are preferred and determining the numerous tangible actions needed to accomplish them are much less clear.

The Energy Commission refers to this specific translation of the general vision as a "blueprint." Increasing the specificity from that appropriate for a vision to that necessary for a blueprint requires that policy interactions be recognized and resolved. Ambiguities unimportant in stating a general goal may have to be resolved to actually achieve the goal, and there may be preferences of one path over another once the consequences of alternative interpretations are recognized.

An example of interactions that must be resolved is the specification of a renewable development path and the amount of incremental energy efficiency that will be achieved by a specific year while pursing an ultimate goal of all cost-effective potential. First, any incremental energy efficiency impacts that are achieved diminish the aggregate amount of renewables that must be developed to achieve a 33 percent RPS goal. Figure 33 showed the implications of alternative assumptions about incremental energy efficiency and the amount of net short renewables needed in 2020. The range is actually wider than Figure 33 reveals when the full set of demand-side policy initiatives are considered (additional energy efficiency programs, CHP, and distributed generation).

Second, the development pattern of renewables is crucial for identifying the amount and type of supplemental generating facilities and transmission development. Determining whether renewables will be concentrated in preferred zones or widely dispersed will impact infrastructure needs. Additionally, a development path that emphasizes in-state renewables means more in-state transmission and more firming generation to be located in California than does a development path that has higher amounts of renewables imported from the rest of WECC, where the local balancing authority provides firming resources.

Numerous scientific and analytic studies are necessary to develop a blueprint level of specificity, some of which are already underway. Examples include:

- The California ISO study of the generation requirements to achieve 33 percent renewables by 2020.

- The inter-agency OTC study to ascertain the amount and type of both flexible generation and transmission system upgrades needed to replace existing capacity in a manner that assures local and system reliability, while maximizing use of the resources already committed toward achieving AB 32 goals.

- The Energy Commission/CPUC study of the incremental impacts of energy efficiency initiatives developed for the CPUC in the *2008 Goals Update Report* as the foundation for IOU goals in D.08-07-047.

- The Energy Commission, Department of Fish and Game, Bureau of Land Management, and U.S. Fish and Wildlife Service Desert Renewable Energy Conservation Plan, currently in development, a science based conservation strategy to identify and establish areas for potential renewable energy development and conservation in the Colorado and Mojave deserts. The plan's goal is to reduce the time and uncertainty associated with licensing new renewable projects on both state and federal lands.

While each of these efforts is being pursued on its own timeline and with a specialized team, all of the efforts must be coordinated and reasonably consistent for them to be integrated into the blueprint later. In addition, since there is much uncertainty about the future, the emphasis should be on conducting analyses of multiple, plausible futures (including futures in which 33 percent RPS or other policy goals are not reached "on a straight line"), estimating the magnitude of the resources likely to be needed in the next 10 years, and defining what could be built without regret over five to eight years.[261] Assumptions about the development of other system components, as well as habitat and land use constraints, will be essential to these analyses. Such analyses would translate into statewide planning guidance disaggregated and quantified to some set of defined areas, including perhaps the ISO control area, utility service areas, planning areas, and/or local reliability areas.

Infrastructure Assessment

Assuming one has a clear translation of the vision into a blueprint, one can determine specific elements to achieve this blueprint. Again, the consequences of interacting elements have to be closely integrated. It is well understood that the California ISO's 33 percent renewable study will determine the amount of flexible capacity that provide incrementing, decrementing, ramping, and spin and nonspin reserve services. It is also understood that the consequences of the SWRCB's once-through cooling mitigation policy will lead to the loss of some of the resources that provide these services, such as aging OTC power plants. Thus, the combined effect of the 33 percent renewables goal and an OTC mitigation requirement that leads to retirements is the need for a large amount of flexible resource development, both to replace that lost through OTC power plant retirement and the additional amount needed to accommodate renewable development. Finally, to the extent that incremental energy efficiency policy initiatives can be relied upon to produce firm savings, fewer flexible fossil resources will be needed.

The resulting infrastructure assessment for flexible, dispatchable generation would be spelled out in amounts, location, and specific services required. Similarly, there are considerable differences in transmission development to achieve different ways of satisfying local capacity requirements. Developing transmission system elements within some urban load centers would diminish the need for local capacity and increase the locational options for needed generation development. This would likely be beneficial from both a market power and a power plant permitting perspective. As a result, there is interaction between generation and transmission system infrastructure not just because of alternative paths of renewable development, but between generation versus transmission. Resolution of these uncertainties in the development of a blueprint allows the next stage to focus on the specific facilities or sets of facilities that are needed. This level of detail can then become the basis for tracking whether resource additions are progressing as necessary, or whether corrective action of some sort must be taken to return to the resource additions called out in the infrastructure assessment.

The infrastructure assessment should be broad in scope, yet detailed enough to be relevant for all jurisdictions in specifying the types and sizes of power plants. For example, a local air pollution control district evaluating a 49-MW geothermal plant – below the 50-MW size threshold of the Energy Commission's licensing jurisdiction – must recognize that the generation from such a plant would displace emissions from natural gas and coal power plants that have much greater GHG emissions per unit of production. Similarly, while major central station solar power plant proposals that use PV technologies are outside the Energy Commission's jurisdiction, many of the permitting issues the local agency must consider are the same as those considered by the Energy Commission for a solar thermal power plant. The statewide infrastructure assessment should be used to guide each agency's infrastructure approval and licensing respon-

261 "Without regret" means the amount of power plant development foreseen to be necessary under all reasonably likely sets of future conditions.

sibilities and thus maximize coordinated action to achieve state energy policy goals.

Generation Infrastructure Assessment

The Energy Commission is the permitting agency for thermal power plants greater than 50 MW in size. Although some renewable generating technologies are permitted by local agencies, the majority of power plant capacity additions are permitted by the Energy Commission. Intervenors in recent cases have explicitly raised need issues even though the legal construct of the licensing process does not call out infrastructure assessment. The Energy Commission is exploring generation infrastructure assessment issues through an Order Instituting Investigation concerning how to treat GHG emissions as part of the CEQA process for its power plant licensing process. The report issued by the Energy Commission's Siting Committee called for several follow-up studies, as well as a further review in the 2009 IEPR proceeding.[262] This makes the Energy Commission's permitting process one of the principal clients of a generation infrastructure assessment product. From the narrow perspective of providing a foundation for possible Energy Commission generation infrastructure determinations for larger fossil power plants, the critical component of the infrastructure assessment is analysis that indicates what fossil or other resources would be needed under different futures.

A comprehensive compilation of resource policy preferences was accomplished through

262 California Energy Commission, *Committee Guidance on Fulfilling California Environmental Quality Act Responsibilities for Greenhouse Gas Impacts in Power Plant Siting Application*, March 2009, CEC-700-2009-004, available at: [http://www.valleyair.org/programs/CCAP/documents/CEC-700-2009-004.pdf].

a contractor report,[263] which suggested that a dispatchable gas plant could serve one or more of five roles. Some roles required that a power plant be located in specific geographic areas, such as the local capacity areas identified by the California ISO through its local capacity requirements studies. Other roles required power plants that could provide the sorts of services now being studied by the California ISO in its 33 percent renewables integration study, such as incrementing, decrementing, ramping, fast start, and related services. Plants possessing such capabilities are perceived to be more useful and necessary to the future electricity system than plants without these characteristics.

In several IEPR workshops, it became clear that siting fossil power plants will be increasingly difficult in California, suggesting that plants that are successfully permitted should be the ones with the characteristics that are most needed. However, parties to these workshops raised two fundamental questions:

- To what extent should the Energy Commission licensing process help to skew the limited number of additional fossil power plants that can be constructed toward those that are really needed?

- What is the appropriate sequence between achieving an Energy Commission permit and a long-term contract via a procurement process of a load-serving entity (or decision to construct by a load-serving entity itself)?

263 MRW & Associates, *Framework for Evaluating Greenhouse Gas Implications of Natural Gas-Fired Power Plants in California*, Consultant Report, May 2009, CEC-700-2009-009, available at: [http://www.energy.ca.gov/2009publications/CEC-700-2009-009/CEC-700-2009-009.PDF].

These questions could not be resolved in the 2009 IEPR proceeding, but are at the core of deciding how formally the Energy Commission's licensing process will incorporate a need conformance element in the future. Further effort is needed to make a decision and to craft a legislative proposal for the next session of the Legislature.

Transmission Infrastructure Assessment

Addressing the need for transmission infrastructure takes place in transmission development, mostly between the California ISO and the CPUC but also under ad hoc arrangements frequently created for specific projects. Even though the California ISO reviews specific transmission projects proposed by transmission owners and other entities and determines whether they are needed, larger transmission projects requiring a CEQA determination from the CPUC often encounter strong opposition in the permitting process, and need conformance is frequently a fundamental issue. As an example, opponents of the Sunrise Powerlink in San Diego asserted that urban rooftop PV could substitute for the transmission line and the power it would import. In their perspective, the proposed transmission line was not needed. Another example occurred when publicly owned utilities proposing a transmission line from Northern California renewable developments to Central California encountered resistance from land owners along the route, who contested that their land should not be used for a transmission line clearly intended to serve others that also did not provide the landowner with any policy or monetary benefit. From the opponents' perspective, the need for the line was not justified.

The *2009 Strategic Transmission Investment Plan* proposes a consolidated statewide transmission plan that could help resolve some of these concerns. First, planning would be divided into two time frames: a short-term, 10-year planning horizon and a second time frame that looks at the 10- to 30-year horizon. In the short-term planning process, each IOU would submit its planning perspective to the California ISO, and publicly owned utility balancing authorities would submit planned projects of statewide significance to the CTPG. Projects without statewide significance would go directly to permitting because they would not affect statewide planning. Next, the California ISO would develop its Annual Plan, which addresses the California ISO-controlled grid.

The CTPG could then work to develop a single statewide transmission plan, with the IOUs and the publicly owned utility balancing authorities acting in a fully coordinated manner. To adequately reflect stakeholder interests, the plan must have broad stakeholder support through all phases of plan development, particularly with regard to RETI. While consensus is not realistic on a statewide basis, the goal should be to achieve broad enough stakeholder support that transmission permitting will be less contentious and have a greater likelihood of success.

The CTPG statewide plan could then be submitted for evaluation to the Energy Commission's Strategic Transmission Investment Plan proceeding. The objective is to ensure that state interests regarding state policy goals and objectives are evaluated in a public forum. Projects conforming to state policy goals and objectives would be given greater weight in the permitting process. The *Strategic Transmission Investment Plan* also targets transmission projects for the Energy Commission's corridor designation process, and this step envisions recommending multiple projects identified in the CTPG statewide plan for simultaneous designation, rather than a piecemeal approach of one corridor designation proceeding at a time.

The final step is permitting, which is the most controversial stage of transmission development because it has the highest level of analysis and scrutiny. The CPUC has jurisdiction over IOU transmission line projects, and the publicly owned utility balancing authorities have jurisdiction over transmission line projects proposed for their service territories. As pointed out, an inadequate transmission planning process compromises the permitting process because transmission line owners seeking permit approvals for their projects will likely fail for lack of support and because of active stakeholder resistance. This step assumes that need for new transmission is ultimately determined during the permitting process. However, this process envisions that analyses in support of need determination are being carried out during each of the preceding steps.

Assuming the CTPG statewide plan secures broad stakeholder support, this permitting step envisions stakeholders' support for transmission project permit applications that are consistent with the CTPG plan. For projects largely facilitating renewable development, the RETI stakeholders understand the benefits of such a project and can presumably be relied upon to express support for such projects. For others, however, such as upgraded transmission lines facilitating reduced reliance upon OTC power plants, support from stakeholders is less obvious and will have to be marshaled.

For longer term planning, it is impossible to produce a 30-year plan with the same level of detail as the 10-year California ISO Annual Transmission Plan. Instead, the long-term plan would build on the 10-year California ISO plan and CTPG statewide plan and would consider the RETI conceptual plan and Western Renewable Energy Zone initiative planning output. The Energy Commission would prepare and vet the long-term plan in the Strategic Transmission Investment Plan proceeding, with the cooperation of electric utilities and interested stakeholders. The long-term plan would feed back into subsequent RETI conceptual transmission planning cycles, which this planning approach assumes would be undertaken every two years. The objective of subsequent RETI cycles would be to update the conceptual transmission plan completed two years previously. In addition, like the 10-year transmission planning proposal, the long-term plan would signal transmission corridor needs for the Energy Commission's corridor designation program.

This type of far-reaching planning horizon would not seek precision, but it would offer a vision of possible future transmission needs for California significantly into the future. In addition, it would help ensure that shorter term planning by the California ISO, electric utilities, and the RETI collaborative stakeholder process do not preclude or conflict with longer term transmission options for California beyond the customary 10-year planning horizon.

Integrated Generation/ Transmission Planning

For too long, the generation and transmission planning processes have operated as parallel, not integrated, mechanisms. Assessing the options for retirement of existing OTC generation is another area in which tradeoffs and complementary roles for generation and transmission have to be assessed. Part of the joint proposal of the Energy Commission, the CPUC, and the California ISO to the SWRCB is an agreement to conduct analyses that identify the options for retiring each OTC power plant and specifying the necessary replacement infrastructure. Both the renewable generation and the OTC replacement topics illustrate the need for and the beginning of efforts to bring generation and transmission analyses together. This is a good first step, but what is needed now is a more explicit electricity infrastructure planning process where decisions make use of such analyses.

The complexity of the issues involved in deciding what infrastructure is needed, coupled with the number of moving parts within the electricity sector including demand- and supply-side options and goals, calls for a new, more integrated planning process in California. The stakes of making isolated choices that may preclude other more electrically and economically advantageous choices are high. Generation, transmission, smart grid, and storage technology are rapidly evolving. The best strategies for meeting environmental goals – including achieving GHG reductions and reducing OTC impacts and air pollution emissions, as well as protecting biological and cultural resources – are still developing. In addition, the tradeoffs involved in choices about the power plants, transmission lines, and other approaches necessary to improve California's electricity infrastructure to meet our environmental challenges are only now becoming more clear. California must develop a more streamlined and integrated process for examining options and making decisions on electricity infrastructure needed to meet the state's future policy goals. The Energy Commission plans to work with the CPUC, California ISO, ARB, SWRCB, and a broad set of stakeholders to develop such a process.

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CHAPTER 4
RECOMMENDATIONS

California's energy systems must constantly respond to changes in energy supply and demand, new policy priorities, and technological advances. Although the current economic downturn has reduced projected energy demand in the short term, demand is expected to increase over time as the population continues to grow and the economy recovers. Energy system planning must be flexible enough to respond to changes in energy markets, new technologies, evolving policy direction, and economic fluctuations.

At the same time, California needs to maintain reliable and cost-effective energy supplies while also incorporating new environmental policies and regulations. Policy makers consider the costs of providing clean and reliable energy to both energy providers and consumers while they balance the short-term costs of doing so against the long-term costs and impacts of catastrophic climate change.

The primary policy driver for energy in both the short and long term is the state's goal of reducing greenhouse gas (GHG) emissions. The state has identified near-term strategies for its 2020 goals, but more aggressive policies and actions will be needed to meet the longer term goal of reducing GHG emissions to 80 percent below 1990 levels by 2050. To achieve this target will require fundamental changes in the way energy is produced and used as well as extensive efforts to develop new technologies to meet the challenges that lie ahead.

As California moves toward less carbon-intensive energy sources to meet its climate change goals, the state needs to identify emerging technologies that can help address the challenges facing the various energy sectors. Because of the long lead times associated with research and development efforts, the state must begin now to identify the most promising areas of research and development on which to focus its efforts and ensure that research and development activities are used to further the state's energy policy goals. In addition, the state needs to continue its research on how climate change will affect the state's energy infrastructure and its ability to serve the citizens of California.

Chapters 2 and 3 discussed some of the major issues facing California's transportation, electricity, and natural gas sectors. This chapter identifies recommendations that the California Energy Commission believes should be implemented immediately to ensure that the state's energy systems continue to meet the needs of California's citizens.

Recommendations for Electricity

Energy Efficiency and Demand Response

California needs to increase its efforts to achieve all cost-effective energy efficiency in the state to meet the GHG emission reduction requirements in California law and the recommended actions in the California Air Resources Board's (ARB's) *Climate Change Scoping Plan*. Strategies to achieve these GHG reductions include zero net energy new buildings, increased building and appliance standards along with better enforcement of those standards, and increased efficiency of the state's existing building stock. With the prospect of expanding population growth in drier, hotter inland areas and the resulting increase in air conditioning loads, California must continue its efforts to reduce peak electricity demand to reduce the need for expensive and higher-emission peaking power plants. In addition, the Energy Commission needs to continue its efforts to accurately reflect energy efficiency impacts in its electricity demand forecast.

Zero Net Energy Buildings

To achieve the goal that all new residential construction in California be zero net energy by 2020 and all new nonresidential construction be zero net energy by 2030, the Energy Commission recommends that by December 2010, it establish a statewide task force that includes state agencies, local governments, utilities, industry, enforcement bodies, and technical experts to address and develop recommendations on issues such as:

■ The definition of zero energy – for example, zero net energy, zero peak energy, and zero net carbon.

■ Whether progress toward the goal should be measured by individual home or nonresidential building, by neighborhood, by community, or by climate zone.

■ The optimal level of energy efficiency needed before installing on-site renewable resources and how to incorporate that into building codes.

■ The most important aspects of residential and nonresidential design and construction techniques that need attention in enforcement efforts and code upgrades to stay on the zero net path.

■ Lessons learned from national efficiency code programs and appliance standards.

■ The role of land use planning and neighborhood design and the need for continuing dialogue with local governments.

■ The role of reach standards, green building codes, and other voluntary programs.

■ Ways to better integrate and compensate distributed generation through zero net energy buildings, neighborhoods, and other developments.

■ Potential pilot program design and implementation.

Because the goal of zero net energy buildings will involve not just efficiency but also building-based energy supply, the Energy Commission's standards for building energy efficiency should be expanded to address building-scale renewable energy solutions.

Building and Appliance Standards

To improve the contribution of the state's building and appliance standards to statewide energy efficiency goals, the Energy Commission will:

- Adopt and enforce building and appliance standards that put California on the path to zero net energy residential buildings by 2020 and zero net energy commercial buildings by 2030.

- Increase the energy efficiency achievements of the building standards by an average of 15 percent in each cycle of the standards in order to achieve zero net energy by 2020 for residential and 2030 for nonresidential construction.

- Expand the scope of building standards to include process loads, laboratories, refrigeration systems, and high energy-using commercial building types.

- Continue to adopt appliance standards for consumer electronics, general lighting, irrigation controls, and refrigeration systems.

- Work toward meeting the Governor's commitment to achieve 90 percent compliance with the building and appliance standards by 2017, by improving enforcement and compliance with building standards. The Energy Commission will work with building departments and provide them with the education and tools needed to increase their compliance rates and will expand work on appliance standards through partnering with the state's attorney general and municipal offices of the district attorney.

- Expand collaboration with the Contractors State Licensing Board to take action to investigate and discipline unlawful activity by licensed and unlicensed contractors that results in noncompliance with the building energy efficiency standards.

Efficiency in Existing Buildings

To take advantage of the significant potential for energy efficiency savings from California's existing residential and commercial buildings, the Energy Commission recommends the following:

- The state should require home energy ratings and energy efficiency retrofits at point of sale, remodel, or refinancing as one approach in a package of strategies to significantly improve energy efficiency in the existing building stock. Energy Commission staff will develop the necessary infrastructure to ensure that such an approach is successful, with the goal of developing incentives by 2013 that include funding for home energy ratings and maximum levels of required expenditures for retrofits to avoid dissuading homeowners from selling or making improvements to their homes. Additional strategies will also be explored and closely coordinated with the current utility programs, stimulus fund programs, and the upcoming proceeding directed by AB 758 (Skinner, Chapter 470, Statutes of 2009) to ensure a comprehensive and coordinated approach that captures all cost-effective energy efficiency in existing buildings.

- Legislation, utility incentives, and local ordinances should require quality installation and maintenance of heating, ventilation, and air conditioning equipment, employing qualified technicians and third-party verification, and providing public information regarding the benefits achieved through quality installation and how to engage contractors who provide quality installations.

- The Energy Commission and the California Public Utilities Commission (CPUC) will work together to develop and implement audit, labeling, and retrofit programs for existing buildings that achieve all cost-effective energy efficiency measures, maximize the benefit of existing utility programs, and expand the use of municipal and utility on-bill financing opportunities.

- For rating nonresidential buildings as part of AB 1103 (Saldaña, Chapter 533, Statutes of 2007) performance disclosure requirements, the Energy Commission will develop a California Energy Performance Tool to provide a performance rating for energy usage by building size and type; an asset rating for the building shell, heating/ventilation/air conditioning, boilers, and other equipment; and a carbon rating for renewable energy generation on-site that offsets electricity or natural gas use by 2012. The European Union's Energy Performance of Buildings Directive will be considered as a model.

- Because the energy performance disclosure requirements under AB 1103 apply only to entire buildings, the Energy Commission will develop regulations by 2012 to address how to obtain meaningful building performance data for tenant-leased spaces.

- To capture all cost-effective energy savings in existing buildings, the CPUC will encourage the energy and water utilities to transform the market from near-term savings to sustained long-term strategies and activities through performance-based incentives, comprehensive packages of energy-saving strategies, and decoupling of earnings from energy and water sales.

- The Energy Commission's Public Interest Energy Research program will target and support research efforts in new and emerging energy efficiency technologies and techniques as well as building maintenance and commissioning.

Publicly Owned Utility Energy Efficiency Programs and Reporting

To ensure that publicly owned utilities are making progress toward achieving the statewide goal of 100 percent cost-effective energy efficiency savings, the Energy Commission recommends the following:

- Publicly owned utilities should apply integrated resource planning to compare demand-side resources with supply-side resources using cost-effectiveness metrics. This approach should result in increased funding for energy efficiency from utility sources beyond the public goods charge (that is, procurement) and should increase future energy savings enough to reach adopted targets.

- To demonstrate this commitment, the publicly owned utilities should provide additional information in their March 15, 2010 annual report to the Energy Commission on the role of energy efficiency in their integrated resource planning and the details of how increased funding will help to meet adopted energy efficiency targets.

- Each publicly owned utility should continue to complete evaluation, measurement, and verification studies to show that energy savings have been realized; should fund these studies consistent with their importance as a significant resource; and should report on evaluation, measurement and verification plans, studies, and results in their next annual AB 2021 (Levine, Chapter 734, Statutes of 2006) submittal to the Energy Commission due March 15, 2010.

- To provide confidence that publicly owned utilities are achieving their energy efficiency targets with bona fide program savings, publicly owned utilities should increase the transparency of information on energy efficiency activities, expenditures, savings estimations, and cost-effectiveness calculations. In addition, they should provide to the Energy Commission staff the data used to create their annual status reports. The Energy Commission will work toward developing protocols for the publicly owned utilities to provide information that explains 1) year-to-year differences in budget and savings accomplishments and 2) methodologies and assumptions for estimating and verifying annual savings, as well as for determining feasible AB 2021 potential and targets. Energy Commission staff will develop a draft outline of specific data requirements for comment by publicly owned utilities and other parties by late January 2010.

- Energy Commission staff will establish a working group that incorporates appropriate parties to discuss successful energy efficiency portfolio and resource planning approaches and to provide a collaborative forum that identifies not only existing barriers, but also solutions for overcoming the most significant barriers that publicly owned utilities face when attempting to capture all cost-effective energy efficiency.

Demand Response

To help the state meet its goal of reducing peak demand by 5 percent through demand response measures, the Energy Commission recommends the following:

- All utilities, including publicly owned utilities, should install meters capable of recording hourly consumption and should publish their time-varying electric rates in an actionable and open source format. Status reports on the progress of meter installation should be included in the *2011 Integrated Energy Policy Report (IEPR)*.

- All customers with advanced meters should have no-cost access to near real-time information about their energy use in a format that is both meaningful and easy to understand.

- All utility price signals should use open source, nonproprietary formats.

- The Energy Commission will continue efforts to adopt a statewide load management standard requiring all utilities in the state to adopt default but optional time-varying pricing for customers that have advanced meters. In developing load management standards, the Energy Commission will continue collaboration with the CPUC, the California Independent System Operator (ISO), and publicly owned utilities.

- The Energy Commission's Public Interest Energy Research program will continue to pursue research and development that supports load management standards.

Incorporating Efficiency in the Demand Forecast

To integrate efficiency into future demand forecasts, the Energy Commission recommends the following:

- Energy Commission staff will actively participate in CPUC's evaluation, monitoring, and verification activities for the investor-owned utilities, as well as similar activities for the publicly owned utilities, to get insight into determinations of program savings and potential for future savings, which are closely related to Energy Commission demand forecast responsibilities.

■ The Energy Commission will use the 2009 adopted forecast as a starting point to estimate the incremental impacts from future efficiency programs and standards that are reasonably expected to occur, but for which program designs and funding are not yet committed. Staff is planning to use and possibly modify Itron's forecasting model, SESAT, for this new purpose, with Itron to provide training for the model in early 2010. The Energy Commission, in cooperation with the CPUC, the investor-owned utilities, and the publicly owned utilities, will devote sufficient resources to develop in-house capability to differentiate these future energy efficiency savings from energy efficiency savings that are already accounted for in the demand forecast.

■ Energy Commission staff will work closely with CPUC staff in establishing feasible statewide energy efficiency goals as part of the periodic AB 2021 requirements, as well as other forums.

Renewable Resources

Producing electricity from renewable resources provides a number of significant benefits to California's environment and economy, including improved local air quality and public health, reduced global warming emissions, a diversified state energy supply, improved energy security, enhanced economic development, and creation of green jobs. California has and can access some of the best renewable resource areas in the world. State policy makers should continue to lead the nation and the world in creating policies that maximize the cost-effective development of renewable energy generation.

Increasing the portion of California's electricity that comes from renewable power will be essential to achieving statewide GHG emission reductions from the electricity sector. However, the state has encountered significant roadblocks in its effort to meet the 20 percent by 2020 Renewables Portfolio Standard (RPS) goal that continues to present challenges to achieving 33 percent renewables. Major issues associated with meeting the larger target include difficulty in securing financing, delays and duplication in siting processes, time and expense of new transmission development, the cost of renewable energy in a highly fluctuating energy market, integration of large amounts of renewable resources into the electricity grid, and challenges in maintaining the state's existing renewable facilities.

In September 2009, after unsuccessful negotiations on legislation that would have codified the 33 percent renewable target, Governor Schwarzenegger issued Executive Order S-21-09, which directs the ARB to act as lead agency under the authority of AB 32 (Núñez, Chapter 488, Statutes of 2006) in implementing a policy consistent with the achievement of a 33 percent Renewable Energy Standard. The ARB is directed to adopt the policy by July 2010, and will work closely with the CPUC and the Energy Commission to draft the regulations.

Renewables Portfolio Standard Targets

To support efforts to achieve RPS goals, the Energy Commission recommends the following:

■ The state should pursue codification of the 33 percent renewable target, drawing upon efforts that are underway to implement Executive Order S-21-09 and to accelerate the permitting of renewable energy infrastructure and facilities in California.

■ The Energy Commission, the ARB, the CPUC, and the California ISO must continue to work together to implement a 33 percent renewable electricity policy that applies to all load-serving entities and retail providers. The Energy Commission encourages the ARB to keep the market for renewable energy in California stable by ensuring that the 33 percent policy is similar in rules and structure to the 20 percent RPS. In addition, the ARB effort should use the analyses and findings from the *2009 IEPR* as the starting point in developing regulations.

■ Because of the importance of achieving the state's 33 percent RPS goals, the Energy Commission recommends, as it has in past *IEPR*s, that the CPUC ensure that investor-owned utilities meet RPS targets and that it consider the imposition of strong penalties for noncompliance.

Renewable Integration

To facilitate integrating renewable energy into California's electricity system while maintaining reliability, the Energy Commission recommends that the following actions be completed by the end of 2011:

■ To avoid overbuilding new gas-fired power plants in the near term that will not be needed in the longer term, the Energy Commission will work with the CPUC, the California ISO, the ARB, utilities, and other stakeholders to coordinate implementation of energy efficiency, combined heat and power, renewable energy, and once-through cooling requirements.

■ The Energy Commission will conduct further analysis to identify solutions to integrate increasing levels of energy efficiency, smart grid infrastructure, and renewable energy while avoiding infrequent conditions of surplus or overgeneration in which more electricity is being generated than there is load to consume it. Potential solutions include better coordination of the timing of resource additions and the mix of resources added to efficiently meet customer needs and maintain system reliability. In addition, there will be efforts to determine what new, more flexible, and efficient natural gas technologies best fit into an electricity grid in transition. The Energy Commission will complete an initial study of the surplus generation issue to identify specific resource and data needs as part of the *2010 IEPR Update*, with the in-depth analysis as part of the *2011 IEPR*.

■ Achieving 33 percent renewable energy will change the resources needed to maintain electricity system reliability, including local ramp rates, inertia, and other transmission-related ancillary service functions. To prepare for these changes, the Energy Commission will continue to share input assumptions and analysis from previous Energy Commission studies with the California ISO to inform its ongoing work to understand operational impacts of large amounts of intermittent renewable resources.

■ The Energy Commission's Public Interest Energy Research program will develop tools to forecast operational performance of solar energy generation facilities. The tools will be designed to examine whether forecasting errors in load magnify errors in forecasting wind and solar energy production, as well as the benefits that power plant-based storage can provide to reduce errors in forecasting solar energy production. As part of this effort, the program will develop a publicly available dataset that project developers can use to estimate electricity that can be produced in California from roof-top, community-scale, and utility-scale photovoltaic systems and solar thermal electric systems with and without storage.

■ Energy storage is a key strategy for accommodating the intermittent nature of some renewables. However, a separate tariff or incentive is needed to create market incentives to encourage the development of large energy storage projects. The Energy Commission will coordinate with the California ISO and with Federal Energy Regulatory Commission, as well as utilities and other interested parties, to determine how best to incentivize storage, including determining whether storage can be allowed to participate in the ancillary services market.

■ The Energy Commission will continue to research storage technologies to reduce cost and determine the best placement and sizing of new facilities to maximize electric system value.

Smart Grid

To support the integration of renewables, California needs to implement a smart grid. To do so, standards must be adopted to ensure that the smart grid provides an open architecture that allows access to a wide variety of technologies. The Energy Commission recommends the following:

■ The Energy Commission will work with the CPUC to develop a regulatory framework for adopting National Institute of Standards and Technology (NIST) Smart Grid interoperability and cyber security standards consistent with Federal Energy Regulatory Commission rulings to ensure national and international compatibility.

■ The Energy Commission, the CPUC, and the California ISO should participate in the NIST Smart Grid Interoperability Panel to ensure that California smart grid activities are shared nationally and that California can learn from smart grid activities in other states. In addition, there should be continued coordination with NIST on smart grid standards such as Open Automated Demand Response.

■ The Energy Commission will continue to coordinate with the CPUC, the California ISO, utilities, and stakeholders to develop smart grid plans, consistent with the requirements in SB 17 (Padilla, Chapter 327, Statutes of 2009), as described in Chapter 1.

■ The Energy Commission will continue Public Interest Energy Research program research on technologies that mitigate or resolve intermittency of renewable resources, as well as research on bidirectional power flows and power quality issues resulting from increased use of renewable resources.

Maintaining Existing Renewable Facilities

To help maintain California's baseline of existing renewable facilities, the Energy Commission recommends the following:

■ The Governor's Bioenergy Action Plan should be updated to address continuing barriers to the development and deployment of bioenergy. These barriers include air quality permitting, expiring incentive programs, and lack of private project financing. The Bioenergy Action Plan should also be expanded to identify issues and potential solutions related to biogas injection and gas cleanup.

■ The Energy Commission will explore options to ensure that existing biomass facilities continue to operate, including continuation of the Existing Renewable Facilities Program, subsidizing biomass feedstocks, or developing a feed-in tariff for existing biomass facilities.

Supporting New Renewable Facilities and Transmission

To facilitate permitting of new renewable facilities and securing the necessary transmission corridors and lines to access those facilities, the Energy Commission recommends the following:

- The Energy Commission will work with the CPUC, the California ISO, the Bureau of Land Management, the Department of Fish and Game, and other agencies to implement specific measures to accelerate permitting of new renewable generation and the transmission facilities needed to serve that generation, including measures to eliminate duplication, shorten permitting timelines, and complete planning processes to balance clean energy development and conservation such as the Renewable Energy Transmission Initiative and the Desert Renewable Energy Conservation Plan.

- Energy Commission staff will actively participate in the CPUC Investigation and Rulemaking on Transmission for Renewable Resources and collaborate with the CPUC and other agencies to eliminate duplicative transmission needs determination and permitting processes.

- Energy Commission staff will continue to participate in the Renewable Energy Action Team's efforts to streamline and expedite the permitting processes for renewable energy projects, while conserving endangered species and natural communities at the ecosystem scale in the Mojave and Colorado Desert regions through the Desert Renewable Energy Conservation Plan. The Energy Commission staff will ensure that the generation findings in the Desert Renewable Energy Conservation Plan are considered in California ISO and CPUC transmission processes.

- The Energy Commission, California ISO, and the California Transmission Planning Group will prioritize transmission planning and permitting efforts for renewable generation and work to overcome barriers and find solutions that would aid their development.

- To meet the Governor's target of 20 percent of the state's renewable energy goals from biomass resources, the Energy Commission will facilitate and coordinate programs with other state and local agencies to address barriers to expanding biopower, including regulatory hurdles and project financing. The Energy Commission will also encourage additional research and development to reduce costs for biomass conversion, biopower technologies, and environmental controls.

- To leverage funding mechanisms for projects that simultaneously use biopower and biofuels, the Energy Commission's Public Interest Energy Research Renewable-Based Energy Secure Communities program will provide grants focusing on projects that capitalize on the synergies of co-locating electricity generation from biomass with the production of biofuel for use in the transportation sector.

- Local air pollution districts should be encouraged to become involved in the Interagency Biomass Working Group since they have key regulatory authority over biomass projects. Furthering the dialogue between air districts, the state's energy agencies, the Governor, and the Legislature can result in innovative solutions to mitigate air pollution while enabling California to meet its biomass/biogas energy goals.

- Energy Commission staff will conduct early outreach to local governments and other land use agencies to inform them of the planning initiatives that are under way to facilitate the development of renewable generation and to encourage their timely participation in planning for and designating transmission corridors to help meet the state's energy policy objectives.

Expanding Feed-In Tariffs

To facilitate lower-cost development of renewable resources, the Energy Commission recommends the following actions to expand the use of feed-in tariffs in California:

- To help meet the goal of the RPS and expand the amount of renewable energy located near load, the CPUC should require the investor-owned utilities to offer simplified and standardized contracts set at reasonable prices for renewable energy projects 20 megawatts or less in size. The contracts should be designed to help small businesses participate in the RPS, reduce the transaction costs of the RPS contracting processes, and provide gradually declining, publicly available, technology-specific (or product-specific) price signals to stimulate competition among manufacturers to lower the cost of renewable energy.

- To help reduce the environmental impacts of achieving 33 percent renewable electricity by 2020, the Legislature should consider requiring utilities or the California ISO to offer technology-specific (or product-specific) feed-in tariffs designed to effectively spur development and integration of renewable energy projects 20 MW and smaller in low-impact competitive renewable energy zones and along renewable-rich transmission corridors. These geographically specific feed-in tariffs should be offered for limited time periods to best coordinate the development of renewable energy with the timing of new transmission development.

- California should support clarification of federal law to ensure that states can implement cost-based feed-in tariffs for resources that help reduce health and environmental impacts of electricity generation, including GHG emissions.

Distributed Generation

The *2007 IEPR* identified the need to expand and upgrade California's distribution system to prepare for the resource mix needed to reach GHG emission reduction goals. With state policies that rely increasingly on preferred resources, the distribution system must be able to integrate and efficiently use distributed resources. With potentially billions of dollars being spent on distribution system upgrades, the state needs to ensure that those upgrades will facilitate meeting the goals for increased renewable resources.

To support the goal of integrating increased quantities of both renewable and nonrenewable distributed generation into the grid, the Energy Commission recommends:

- The Energy Commission and the CPUC should open a joint proceeding to develop a comprehensive understanding of the importance of distribution system upgrades, not only to assure reliability, but also to support the cost-effective integration and interoperability of large amounts of distributed energy for both on-site use and wholesale export. The proceeding should focus on the following:

  - Requiring utilities to provide an assessment of the areas or locations on their systems in which distributed generation for both on-site use and/or export would be of greatest value. The studies should report on operational characteristics that would have greatest value; tools, data and criteria used to select these locations; and obstacles to deploying specific types of distributed generation in these areas (for example, high density residential areas).

- Reviewing and requiring the use of distribution system operational models and economic/capital investment models in utility rate cases.

- Requiring utilities to use these tools to demonstrate that investments in advanced grid technologies will support grid modernization goals, including from a standpoint of cost-effectiveness.

- Implementing and validating open International Electrotechnical Commission (IEC) communication standards for distributed energy resources before proprietary solutions become established. Although these standards are not required in the United States, they are being implemented in Europe where most countries are mandated to use IEC standards. California can leverage European efforts to develop and implement these standards and ensure that the state benefits from the widespread use of communication standards. Once implemented for photovoltaic, the same communication standards can be used for other renewable systems, such as wind, fuel cells, and biomass, as well as for distribution automation equipment.

■ Because net metering is an essential tool for making renewable distributed generation a cost-effective choice for customers and for maximizing the development of in-state renewable generation that requires no transmission upgrades, the Legislature should require utilities to increase their net energy metering cap to 5 percent to allow reasonable growth and support for the deployment of renewable generation in California. The CPUC is required to report to the Legislature and the Governor by January 1, 2010, on the costs and benefits of net energy metering. Once that report has been completed and reviewed, increasing the cap beyond 5 percent can be evaluated.

Combined Heat and Power

Combined heat and power (CHP) provides benefits to the system through more efficient use of natural gas fuel, which also results in decreased GHG emissions. The barriers to increased penetration of CHP technologies have been identified repeatedly in past *IEPR*s, but little progress has been made.

Meeting Scoping Plan Targets for Combined Heat and Power

Based on a 2005 CHP market forecast, the ARB in its *Climate Change Scoping Plan* set a target of 6.7 million metric tons of carbon dioxide (CO_2) emissions reduction from CHP by 2020. This was translated into 30,000 gigawatt hours and 4,000 MW of new CHP. The new market forecast done for the *2009 IEPR* found that 5,500 MW of new CHP could be installed by 2020 with a combination of incentives, including export sales for CHP systems larger than 20 MW. This capacity represents 6.0 million metric tons of CO_2 emission reductions, about 90 percent of the targeted reduction. In addition, the future of existing qualifying facility contracts for CHP (representing about 6,000 MW of existing CHP) is in question. Also, recession has altered the economic landscape – natural gas prices are low, and economic growth estimates are reduced. Consequently the prospect for attaining system efficiencies, grid stability, and GHG reduction seems to be in jeopardy unless a combination of remedial policies and programs are implemented with urgent priority.

The development of new CHP can lead to a reduction in CO_2 equivalent emissions of 4 million metric tons per year by 2020. To realize these reductions, the Energy Commission recommends the following:

■ The Energy Commission will work with the ARB and the CPUC in the development of CHP to meet the state goals for emission reductions from these technologies. Actions include mandates to remove market barriers to the development of CHP facilities and provision of analytical support on efficiency requirements and other technical specifications so that CHP is more widely viewed and adopted as an energy efficiency measure.

■ The Energy Commission will work with the CPUC and the ARB to establish minimum efficiency standards, GHG emission criteria, and monitoring and reporting mechanisms.

■ Electric utilities should develop programs and solicit projects to promote CHP as a strategy to replace boilers, increase energy efficiency, and reduce emissions. Programs should include a mix of mechanisms such as energy audits, an electricity export sales tariff, and a pay-as-you-save pilot program for nonprofit organizations. Utility ownership is acceptable where it does not crowd out private investment.

■ Eligibility for CHP systems with a generating capacity of 5 MW or less that meet minimum performance, monitoring, and reporting standards should be re-instituted in the Self-Generation Incentive Program. The amount of the incentive should be based on efficiency and GHG reduction metrics rather than technology and fuel types.

■ California hospitals, correctional facilities, and military bases that support essential health, safety, and security functions should be targeted for CHP development. The Energy Commission and CPUC should establish information and incentive programs to support and encourage these critical facilities to install CHP as a way to ensure that their essential services continue to operate reliably, even if a major disruption of local or regional power occurs.

Renewable Combined Heat and Power

CHP systems installed at wastewater treatment facilities use biogas from sludge and provide multiple benefits. Besides reducing on-site energy needs, they reduce methane generated by the facility. Such CHP systems also help to meet RPS goals. Yet the near-term potential of these CHP systems remains unfulfilled due to conflicting regulatory requirements for air emissions.

Co-digestion of organic material at wastewater treatment plants can help to mitigate the GHG emissions emanating from California's multiple organic waste streams. In addition, co-digesting multiple biodegradable waste streams such as municipal waste sludge, food processor waste, restaurant leftovers, and dairy manure can add as much as 450 MW to the CHP potential in California.

The Energy Commission recommends that:

■ Energy and environmental regulatory agencies should collaborate to resolve conflicting regulations that result in the flaring of biogases that could be used productively for distributed generation and CHP operations. New approaches to balance criteria pollutant emission reductions against energy efficiency improvements and gas reductions from electricity generation should be developed.

■ The Energy Commission, the CPUC, and utilities should develop financing programs to fund the near-term potential of CHP systems that use biogas at wastewater facilities. Financing options should include, but not be limited to, grants, loans, or incentives for developing and expanding biowaste digester infrastructure, generation, and emission control equipment.

■ The Energy Commission will commit research dollars to develop a web-based database to provide location, volume, quality, and seasonality of biodegradable waste suitable for co-digestion at wastewater treatment plants. This could be done in collaboration with industry associations. The database will include waste from California's agriculture, food processing, and dairy industries.

- The Energy Commission will assess the economic and environmental benefits of GHG reduction and grid stability from co-digesting California's biodegradable waste from the dairy, agriculture, and restaurant industries at wastewater treatment plants. This assessment will include the benefits both to the state and to the individual industry contributing to the waste.

- The Energy Commission, the ARB, and the California Carbon Reduction Reserve (formerly Carbon Reduction Registry) must develop methodologies both for attaining and monitoring GHG reductions and low-cost protocols for verification of such reductions for biodegradable materials whose eligibility for GHG reduction credits is not yet established.

Nuclear Plants

In light of current policy and considerations regarding nuclear plants, the Energy Commission recommends the following:

- To help ensure plant reliability and minimize costs, Pacific Gas and Electric Company (PG&E) and Southern California Edison (SCE) should complete and report in a timely manner on all of the studies recommended in the *AB 1632 Report*, including those that the CPUC identified for completion as part of license renewal review. The utilities should make their findings available for consideration by the Energy Commission and to the CPUC and the U.S. Nuclear Regulatory Commission (NRC) during their reviews of the utilities' license renewal applications. The utilities should not file license renewal applications with the NRC without prior approval from the CPUC. These studies should include:

    - Reporting on the findings from updated seismic and tsunami hazard studies, including results of 3D seismic imaging studies, and assessing the long-term seismic vulnerability and reliability of the plants.

    - Summarizing the implications for Diablo Canyon Power Plant and San Onofre Nuclear Generating Station (SONGS) of lessons learned from the response of the Kashiwazaki-Kariwa nuclear plant to the 2007 earthquake.

    - Reassessing whether plans and access roads surrounding the plants, following a major seismic event and/or plant emergency, are adequate for emergency response to protect the public, workers, and plant assets and for timely evacuation following such an event.

    - Studying the local economic impact of shutting down the plants as compared to alternative uses for the plant sites.

    - Reporting on plans and costs for storing and disposing of low-level waste and spent fuel through 20-year license extensions and plant decommissioning using current and projected market prices.

    - Quantifying the reliability, economic, and environmental impacts of replacement power options.

- ◻ Assessing the options and costs for complying with the proposed State Water Resources Control Board once-through cooling policy. These studies should be included in the cost-benefit assessment of the plants' license renewal feasibility studies.

- ◻ Reporting on efforts to improve the safety culture at SONGS and on the NRC's evaluation of these efforts and the plant's overall performance (SCE only).

Requiring the utilities to complete these studies is consistent with the CPUC's General Rate Case Decision 07-03-044 regarding the state's important role in deciding whether to pursue license renewal. The General Rate Case decision required PG&E to incorporate the findings and recommendations of the Energy Commission's *AB 1632 Report* assessment in PG&E's license renewal feasibility study and to submit the study to the CPUC no later than June 30, 2011, along with an application on whether to pursue license renewal for Diablo Canyon. Letters on June 25, 2009, from the president of the CPUC to PG&E and SCE reiterated the requirements that each utility complete the *AB 1632 Report's* recommended studies, including the seismic/tsunami hazard and vulnerability studies, and report on the findings and the implications of the studies for the long-term seismic vulnerability and reliability of the plants. These studies are necessary to allow the CPUC to properly undertake its obligations to ensure plant and grid reliability in the event that either Diablo Canyon or SONGS has a prolonged or permanent outage and for the CPUC to reach a decision on whether to pursue license renewal.

■ The CPUC should assess the need to establish a SONGS Independent Safety Committee patterned after the Diablo Canyon Independent Safety Committee.

■ The Energy Commission will continue to monitor the NRC and the Institute of Nuclear Power Operations reviews of Diablo Canyon and SONGS, and in particular monitor plant performance and safety culture at SONGS.

■ The Energy Commission will continue to monitor the federal nuclear waste management program and represent California in the Yucca Mountain licensing proceeding to ensure that California's interests are protected regarding potential groundwater and spent fuel transportation impacts in California.

■ The Energy Commission will continue to participate in U.S. Department of Energy and regional planning activities for nuclear waste transportation.

■ The Energy Commission, CPUC, and the California ISO should assess the reliability implications and impacts from implementing California's proposed once-through cooling policy and regulations for California's operating nuclear plants.

■ To support the state's long-term energy planning, SCE and PG&E should report, as part of the *2010 IEPR Update*, what new generation and/or transmission facilities would be needed to maintain voltage support and system and local reliability in the event of a long-term outage at Diablo Canyon, SONGS, or Palo Verde Nuclear Generating Station. The utilities should develop contingency plans to maintain reliability and grid stability in the event of an extended shutdown at SONGS, Diablo Canyon, or Palo Verde.

■ The Energy Commission will continue to update information on the comprehensive economic and environmental impacts of nuclear energy generation compared with alternatives. These economic and environmental assessments will consider "cradle to grave," or life cycle impacts, including impacts from uranium mining; reactor construction; fuel fabrication; reactor operation, maintenance and repair; reactor component replacement; spent fuel storage, transport and disposal; and decommissioning.

- The SONGS' Seismic Advisory Board should include greater representation from independent seismic experts, such as university or government scientists and/or engineers with no current or prior employment with the plant owners or their consultants.

- The Diablo Canyon Independent Safety Committee should evaluate reactor pressure vessel integrity at Diablo Canyon over a 20-year license extension and recommend mitigation plans, if needed. This review should consider the reactor vessel surveillance reports for Diablo Canyon in the context of any changes to the predicted seismic hazard at the site.

Transmission

The *2009 Strategic Transmission Investment Plan* describes the immediate actions that California must take to plan, permit, construct, operate, and maintain a cost-effective, reliable electric transmission system that is capable of responding to important policy challenges such as achieving significant GHG reduction and RPS goals. The plan makes a number of recommendations intended to ensure that the critical link between transmission planning and transmission permitting is made so that needed projects are planned for, have corridors set aside as necessary, and are permitted in a timely and effective manner that maximizes existing infrastructure and rights-of-way, minimizes land use and environmental impacts, and considers technological advances.

The Energy Commission supports the many recommendations adopted in the *2009 Strategic Transmission Investment Plan* and highlights the following recommendations:

- The Energy Commission staff will work with the California ISO and the recently formed California Transmission Planning Group in a concerted effort to establish a 10-year statewide transmission planning process that uses the Energy Commission's Strategic Plan proceeding to vet the California Transmission Planning Group plan described in Chapter 4 of the *2009 Strategic Transmission Investment Plan*, with emphasis on broad stakeholder participation.

- The Energy Commission staff will work with the California ISO, the CPUC, investor-owned utilities, and publicly owned utilities to develop a coordinated statewide transmission plan using consistent statewide policy and planning assumptions.

- The Energy Commission, California ISO, and the California Transmission Planning Group will prioritize transmission planning and permitting efforts for renewable generation, as outlined in Chapter 6 of the *2009 Strategic Transmission Investment Plan*, and work on overcoming barriers and finding solutions that would aid their development.

- The Energy Commission will continue support for ongoing activities related to the Renewable Energy Transmission Initiative (RETI), including the Coordinating Committee, Stakeholder Steering Committee, and working groups, by providing appropriate personnel and contract resources.

- The Energy Commission staff will continue to coordinate with the RETI stakeholders group to incorporate RETI's new information in applying the method described in Chapter

6 of the *2009 Strategic Transmission Investment Plan* to reach consensus on the appropriate transmission line segments that should be considered for corridor designation to promote renewable energy development.

■ The Energy Commission will continue to participate in the Western Renewable Energy Zone process to ensure consistency with RETI results for both preferred renewable development areas and environmentally sensitive areas that should be avoided.

Coordinated Electricity System Planning

California faces challenges in implementing state policy goals to decrease the use of once-through cooling in power plants and retire aging power plants, given the need to maintain system reliability and the limitations on emissions credits for replacement plants in the southern part of the state. At the same time, the state needs to better coordinate its electricity policy, planning, and procurement efforts to eliminate duplication and to ensure that planners and policy makers understand the interactions and conflicts that may exist among state energy policy goals.

California has numerous agencies that are involved in electricity planning. While there is some degree of coordination among various agencies and processes, the state needs to find better ways to coordinate and streamline the collective responsibilities of those agencies to be able to achieve the state's GHG emission reduction, environmental protection, and reliability goals while reducing duplicative or contradictory processes. The Energy Commission recommends the following:

■ The Energy Commission will work with the CPUC and California ISO, along with other agencies and interested stakeholders, to develop a common vision for the electricity system to guide infrastructure planning and development. Such coordinated plans can be used to guide each agency's own infrastructure approval and licensing responsibilities and thus maximize coordinated action to achieve state energy policy goals.

■ The Energy Commission will continue its ongoing efforts to improve the quality and transparency of its demand forecasts, which are now used at the CPUC and California ISO for electricity system planning. The Energy Commission's Demand Analysis Office is engaged in an intensive review and evaluation of current modeling methods. This process places high priority on assessing whether current modeling tools are effectively matched to the purposes they are intended to serve. Once the existing model review stage to identify process improvements has been completed, active steps to incorporate model modifications or model replacements will be initiated in the 2011 IEPR cycle after these changes are fully tested and reviewed.

■ The Energy Commission will continue to work with the CPUC, the California ISO, and the State Water Resources Control Board to implement the joint energy agency proposal that establishes a schedule for complying with once-through cooling mitigation while addressing electric system reliability concerns.

■ The Energy Commission will conduct analysis to determine the amount of air credits needed in the South Coast air shed and work cooperatively with the South Coast Air Quality Management District, the ARB, and other appropriate agencies to design new methods to allocate scarce air credits to proposed power plants that best meet system and local needs.

- Through a public process with interested stakeholders, the Energy Commission will define a course of action that incorporates integrated planning results into the decision-making process for the power plants it licenses.

- The Energy Commission will focus its forecasting, planning, IEPR, and Strategic Transmission Investment Plan processes on conducting the statewide integrated planning that is clearly now required. Efforts will be coordinated with those of the CPUC and California ISO to reduce duplication.

- The Energy Commission's Cost of Generation model will be used where applicable as a transparent tool for upcoming integrated resource planning studies. A reasonable range of inputs will be used to generate a range of potential levelized cost estimates for the *2011 IEPR*.

Recommendations for Natural Gas

New technologies and resource finds, such as shale gas, have increased the availability of natural gas in North America. Natural gas is the cleanest of the fossil fuels and will continue to play a role in GHG reductions in the electricity sector. However, there are potential environmental impacts associated with exploration and development of shale gas as an additional source of natural gas supplies. Plentiful supplies of natural gas will moderate prices and make natural gas an attractive option throughout the West as the electricity industry starts to build a less carbon-intensive infrastructure. Because California is at the end of the gas supply pipelines, demand for natural gas "upstream" of California could increase competition and prices and reduce available supplies for California.

The Energy Commission recommends:

- The Energy Commission will continue to monitor the potential environmental impacts associated with shale gas extraction, including carbon footprint, volume of water use and risk of groundwater contamination, and potential chemical leakage. Specifically, the Energy Commission staff will coordinate and exchange information with energy agencies in states with shale gas development, such as New York, Texas, and other midcontinent states, and will report new findings in the *Integrated Energy Policy Report* and other Energy Commission forums.
- California should work closely with western states to ensure development of a natural gas transmission and storage system that has sufficient capacity and alternative supply routes to overcome any disruption in the system, such as weather-related line freezes, pipeline breaks, and so on. The state should support construction of sufficient pipeline capacity to California to ensure adequate supply at a reasonable price.

Recommendations for Fuels and Transportation

State and federal policies encourage the development and use of renewable and alternative fuels to reduce California's dependence on petroleum imports, promote sustainability, and reduce GHG emissions. The Governor's Executive Order S-06-06 established clear targets for increased use and in-state production of biofuels. California and the federal government also have policies to improve vehicle efficiencies and to reduce vehicle miles traveled in efforts to achieve the 2050 GHG reduction targets. Until new vehicle technologies and fuels are commercialized, however, petroleum will continue to be the primary fuel source for California's vehicles. The state will need to enhance and expand its existing petroleum infrastructure, particularly at in-state marine ports, as well as its alternative fuel infrastructure.

Since the Energy Commission published the *2007 IEPR*, additional actions have been taken to encourage alternative and renewable fuels. The Low Carbon Fuel Standard has been put in place to lower the carbon content of transportation fuels over the next 10 years. The federal government has granted a waiver allowing California to set emissions levels under the state's Passenger Motor Vehicle Greenhouse Gas Emission Standards and is setting considerably higher national fuel economy standards based on California's regulations. The state has created the Alternative and Renewable Fuel and Vehicle Technology Program, a comprehensive funding program to stimulate the development and deployment of innovative, low-carbon fuels and advanced vehicle technologies.

With these and other directives, the Energy Commission believes that California is well positioned to develop a system of sustainable, clean, and alternative transportation fuels. The state should continue on its present course of action by providing responsible agencies with the time and funding to implement these programs. Enactment of complementary federal transportation fuel and vehicle technology programs and financial incentives would accelerate innovations in low-carbon fuels and advanced vehicle technologies.

In addition, the Energy Commission recommends:

- To maintain energy security, state and local agencies need to ensure that there is adequate infrastructure for the delivery of transportation fuels. The state should modernize and upgrade the existing infrastructure to accommodate alternative and renewable fuels and vehicle technologies as they are developed and to address petroleum infrastructure needs to preserve past investments and to expand throughput capacity in the state.

- The Energy Commission will collaborate with partner agencies and stakeholders to develop policy changes to address regulatory hurdles and price uncertainty for alternative fuels, particularly biofuels, in California.

- California should support the development of alternative and renewable fuels that can provide immediate GHG emission reduction benefits and a bridge to the introduction of fuels that will result in deeper GHG emission reductions in the future.

- Transportation energy efficiency should be pursued through increased federal vehicle fuel economy standards and more sustainable land use practices, in conjunction with local governments.

- The state's Bioenergy Interagency Working Group should continue to coordinate the efforts of state government in order to maximize the use of California's abundant waste stream, including agricultural waste, municipal solid waste, and forest waste, to produce energy for transportation uses in a sustainable manner. The working group should examine appropriate forest thinning and fire risk-reduction strategies that have the potential to create large volumes of woody biomass waste materials that can be used as a feedstock for transportation fuels, but that also ensure the sustainability of California's private and public lands forests.

- The Bioenergy Interagency Working Group should investigate and develop economic methods for the sustainable harvest and transport of woody biomass materials.

- The Bioenergy Interagency Working Group should examine local permit and enforcement activities to help ensure that biofuel infrastructure is installed in a manner to meet growing demand for renewable fuels. The Working Group should examine the feasibility of requiring that new building code standards for all gasoline- and diesel-related equipment (underground storage tanks, dispensers, associated piping, and so on) be ethanol (E85) and biodiesel (B20) compatible for construction of any new retail stations or replacement of any gasoline- and diesel-related equipment beginning January 1, 2011.

Recommendations for Land Use and Planning

Land use planning and investment decisions are made at the local government level. Community design decisions impact transportation choices, energy consumption, and GHG emissions. The *2006 IEPR Update* stated that the single largest opportunity to help California meet its statewide energy and climate change goals resides with smart growth. The *2007 IEPR* further noted that to reduce GHG emissions, California must begin reversing the current 2 percent annual growth rate of vehicle miles traveled.

The Energy Commission is one of many state agencies working proactively with local and regional governments to foster sustainable land use planning and investment decisions. Caltrans coordinates regional and state planning through its Regional Blueprint Planning Program. Senate Bill 375 (Steinberg, Chapter 728, Statutes of 2008) requires the ARB to set regional emissions goals by working with metropolitan planning organizations. Senate Bill 732 (Steinberg, Chapter 729, Statutes of 2008) recognized the need for state agencies to work more closely together on land use issues when it created the Strategic Growth Council, a cabinet-level decision-making body composed of agency secretaries from Business, Transportation and Housing; California Health and Human Services; the California Environmental Protection Agency; and the California Natural Resources Agency, along with the director of the Governor's Office of Planning and Research.

In addition, SB 732 authorized the Strategic Growth Council to provide $90 million in Proposition 84 funds to local and regional governments for planning grants and planning incentives to encourage the development of regional and local land use plans that are designed to promote water conservation, reduce automobile use and fuel consumption, encourage greater infill and compact development, protect natural resources and agricultural lands, and revitalize urban and community centers.

These state policies require state agencies to coordinate more closely and to provide bond funding to help local governments achieve the benefits of coordinated land use planning and sustainable economic development. State government must actively engage with local governments to better understand the problems they face before adopting new state policies. This includes taking into account and addressing the fiscal constraints local governments face in these challenging economic times.

The Energy Commission makes the following recommendations related to land use planning and decisions:

- To reduce energy use and support the transportation GHG reduction goals, state agencies in collaboration with the Strategic Growth Council and local and regional governments will continue to conduct research, develop analytical tools, assemble easy-to-use data and provide assistance to local and regional government officials to help them make informed decisions about energy opportunities and undertake sustainable land use practices, while recognizing the different needs of rural and urban regions. The Strategic Growth Council is uniquely positioned to coordinate the many issues, programs, and activities of its members and those of other state agencies such as the Energy

Commission, California Department of Transportation, and the ARB. These issues include energy efficiency, renewable energy development, and energy supply.

- Local land use planners should have access to easy-to-use tools to help them make informed decisions about energy concerns and GHG reductions. To that end, the Energy Commission will revise and market editions of its *Energy Aware Planning Guide I* and its *Energy Aware Planning Guide II: Energy Facilities*, documents that detail the importance of energy in local planning processes and explain energy infrastructure licensing processes. The Energy Commission will also help market and distribute energy tools created in partnership with the San Diego Association of Governments. These include the *Sustainable Region Program Action Plan and Toolkit*, a guide to developing energy management plans and implementing cost-saving energy measures; the *Regional Alternative Fuels, Vehicles, and Infrastructure Report*, a report showing local governments and regional stakeholders how the San Diego region plans to increase penetration of alternative fuel vehicles and infrastructure; the *Final Regional Energy Strategy Update*, which includes a how-to guide for creating a model regional energy plan; and the Regional Climate Action Plan, a how-to guide for a model regional climate plan.

- The state should recognize that rural and urban regions differ and ensure that new sustainability, GHG, and energy requirements reflect these differences.

- The Strategic Growth Council should research and recommend a comprehensive and stable funding source to support further efforts by local and regional governments to prepare and implement land use policies and investments consistent with the requirements of AB 32 that contribute significantly to achieving the state's 2050 GHG reduction target.

Recommendations for Carbon Capture and Sequestration

California will need innovative strategies to address GHG emissions associated with energy production and use. One such strategy is carbon capture and storage, also known as carbon capture and sequestration. The *2007 IEPR* focused on geologic sequestration strategies for the long-term management of carbon dioxide, but there have been encouraging technology advancements and investments since then. Technology developers and policy makers who are examining carbon capture and sequestration applications have expanded from an initial focus on coal and petroleum coke to natural gas and refinery gas, the predominant fossil fuels used in California power plants and industrial facilities.

The expectation that more new western power plants may rely on natural gas has expanded the emphasis on CO_2 capture and storage research, development, and demonstrations to include natural gas combined cycle plants. Similarly, California's Low Carbon Fuel Standard could lead to application of CO_2 capture and storage in conjunction with natural or refinery gas-fired furnaces/heaters, boilers, and steam/power cogeneration units. Timely resolution of issues surrounding carbon capture and sequestration projects is important because several California project proposals have been awarded support funding from the U.S. Department of Energy, with funding and associated jobs creation dependent on projects being able to proceed expeditiously.

The Energy Commission recommends:

- As a mechanism for achieving state energy and environmental objectives, the Energy Commission will continue to support and conduct carbon capture and sequestration research to demonstrate technology performance and facilitate interagency coordination to develop the technical data and analytical capabilities necessary for establishing a legal and regulatory framework for this technology in California.

- The Legislature should establish the necessary legal structure to enable efficient means of site access for carbon capture sequestration projects similar to legislation in other states that has been established to clarify or define ownership rights for the pore space within geologic formations that could store CO_2 on a long-term basis as a GHG mitigation measure. The Legislature should also adopt limited-term measures to address legal ambiguities or barriers that could hinder early carbon capture and sequestration projects.

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ACRONYMS

AB	–	Assembly Bill
ARB	–	California Air Resources Board
ARRA	–	American Recovery and Reinvestment Act of 2009
Bcf/d	–	billion cubic feet per day
BDT/y	–	bone dry tons per year
BLM	–	Bureau of Land Management
Cal/EPA	–	California Environmental Protection Agency
California ISO	–	California Independent System Operator
Caltrans	–	California Department of Transportation
CCS	–	carbon capture and sequestration
CED	–	California Energy Demand
CEQA	–	California Environmental Quality Act
CHP	–	combined heat and power
CNG	–	compressed natural gas
CO	–	carbon monoxide
CO_2	–	carbon dioxide
CPCN	–	Certificate of Public Convenience and Necessity
CPUC	–	California Public Utilities Commission
CREZ	–	Competitive Renewable Energy Zone
CTPG	–	California Transmission Planning Group
DOE	–	(United States) Department of Energy
DOF	–	Department of Finance
DRECP	–	Desert Renewable Energy Conservation Plan
EISA	–	Energy Independence and Security Act of 2007
EPBD	–	Energy Performance of Buildings Directive
EU	–	European Union
EV	–	electric vehicle
FERC	–	Federal Energy Regulatory Commission
FEV	–	full electric vehicle
FFV	–	flex fuel vehicle
GHG	–	greenhouse gas
GSP	–	gross state product
GW	–	gigawatt
GWh	–	gigawatt hour
HVAC	–	heating, ventilation, and air conditioning
HERS	–	Home Energy Rating System
IEC	–	International Electrotechnical Commission
IEPR	–	Integrated Energy Policy Report
INPO	–	Institute for Nuclear Power Operations

IOUs	–	investor-owned utilities
ISFSI	–	independent spent fuel storage installations
kWh	–	kilowatt hour
LADWP	–	Los Angeles Department of Water and Power
LCFS	–	Low Carbon Fuel Standard
LIEE	–	low-income energy efficiency
LNG	–	liquefied natural gas
LTTP	–	Long-Term Procurement Plan
Mcf	–	thousand cubic feet
MMcf/d	–	million cubic feet per day
MSW	–	municipal solid waste
MW	–	megawatt
NOx	–	nitrogen oxide
NRC	–	Nuclear Regulatory Commission
OpenADR	–	Open Automated Demand Response
OTC	–	once-through cooling
PG&E	–	Pacific Gas and Electric Company
PHEV	–	plug-in hybrid electric vehicle
PIER	–	Public Interest Energy Research
PM	–	particulate matter
PURPA	–	Public Utility Regulatory Policies Act of 1978
PV	–	photovoltaic
RD&D	–	research, development, and demonstration
REAT	–	Renewable Energy Action Team
REC	–	renewable energy credit
RETI	–	Renewable Energy Transmission Initiative
RFS	–	Renewable Fuel Standard
RPS	–	Renewables Portfolio Standard
SB	–	Senate Bill
SCAQMD	–	South Coast Air Quality Management District
SCE	–	Southern California Edison Company
SDG&E	–	San Diego Gas & Electric Company
SMUD	–	Sacramento Municipal Utility District
SoCal Gas	–	Southern California Gas Company
Solar PEIS	–	Solar Programmatic Environmental Impact Statement
SONGS	–	San Onofre Nuclear Generating Station
SWRCB	–	State Water Resources Control Board
U.S. EPA	–	United States Environmental Protection Agency
WECC	–	Western Electricity Coordinating Council
WGA	–	Western Governors' Association

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