CALIFORNIA ENERGY COMMISSION

2005 INTEGRATED ENERGY POLICY REPORT

COMMITTEE DRAFT REPORT

SEPTEMBER 2005
CEC-100-2005-007-CTD

Arnold Schwarzenegger, *Governor*

CALIFORNIA ENERGY COMMISSION

Integrated Energy Policy Report Committee

John L. Geesman
Presiding Member

James D. Boyd
Associate Member

Melissa Jones, Advisor
Michael Smith, Advisor
Suzanne Korosec
Primary Authors

Carolyn Walker
Marilyn Davin
Editors

Kevin Kennedy
Program Manager

Sandra Fromm
Assistant Program Manager

B.B Blevins
Executive Director

Table of Contents

EXECUTIVE SUMMARY

California is the sixth largest economy in the world. To meet the needs of a growing population, California's economy depends upon having reliable, affordable supplies of electricity, natural gas, and transportation fuels. California's way of life is threatened by its growing dependence on oil and natural gas, spiraling energy prices, potential supply shortages, and an inadequate and aging energy delivery infrastructure.

Energy prices in California are higher than ever before. Gasoline prices reached record levels in September, consuming valuable dollars that could otherwise be spent on goods and services to help bolster California's recovering economy. With world oil prices exceeding $70 per barrel, it is unlikely that gasoline consumers will see any relief in the near future. Electricity rates, although not as erratic as during the 2000-2001 crisis, are still among the highest in the nation, forcing businesses to struggle to maintain profit margins as the cost of doing business in the state increases. California depends on natural gas to generate electricity, and natural gas prices that have more than doubled since 2000 are likely to keep electricity rates high.

Energy costs in all sectors will continue to rise as California's rapidly growing population and growing business sector continue to increase the demand for energy. Weather-adjusted electricity consumption in California increased an average of 2 percent over the last two years and is continuing to rise. Meanwhile, demand for transportation fuels has increased 48 percent over the last 20 years and is continuing to grow at an alarming rate despite record high gasoline and diesel prices. The state's dependence upon natural gas to generate electricity is also escalating along with demand for natural gas in the residential and commercial sectors, with California second only to Texas as the largest consumer of natural gas in the nation.

The development of new energy supplies is not keeping pace with the state's increasing demands. Construction of new power plants has lagged and the number of new plants applying for permits has decreased. In addition, development of new renewable resources has been delayed by a complex and cumbersome Renewable Portfolio Standard process. In the transportation sector, California's refineries are unable to keep up with the mounting need for petroleum fuels and must depend on increasing levels of imports to meet the state's needs. California also imports 87 percent of its natural gas supplies, which are threatened by declining production in most U.S. supply basins.

California's energy infrastructure is increasingly unable to meet the state's energy delivery needs. The most critical infrastructure issue is the state's electricity transmission system, which has become progressively more stressed in recent years. The state's systematic under-investment in transmission infrastructure is reducing system reliability and increasing operational costs. Last year, transmission congestion and related reliability services cost California over $1 billion, while this summer the state experienced numerous price spikes and several local outages during high peak load periods. Southern California also saw its first rolling outages since the 2000-2001 crisis. California's transportation infrastructure also faces challenges, including the inherent conflict between recognizing the need to expand the system to meet petroleum fuel demands and addressing concerns raised by local communities affected by such expansions. In the natural gas sector, California has made infrastructure improvements to increase the reliability and operational flexibility of the natural gas system but must still address the need for additional pipeline capacity to meet peak demand.

In the *2003 Energy Report* and the *2004 Energy Report Update*, the Energy Commission recommended a variety of strategies to reduce energy demand, secure additional energy supplies, transition to more sustainable technologies and fuel types, and build the necessary infrastructure to protect California from future supply disruptions and high prices. Unfortunately, the state has made only minimal progress in implementing many of these recommendations, and California's economic prospects are suffering as a result. The state must increase its efforts and take immediate action to address problems in the energy sector to meet the state's policy goal of ensuring adequate, affordable, and reliable energy.

Ensuring Adequate Electricity Supplies

As the state's demand for electricity intensifies, California could face severe shortages in the next few years. Of particular concern are the potential impacts of hotter-than-average summer temperatures, which can drastically increase the state's electricity demand, as well as potential shortages resulting from decreased hydroelectric supplies if there is lower-than-average snowfall. Either of these circumstances could result in dangerously low reserve margins and potential supply disruptions, particularly in Southern California. Reserve margins could also be affected by the retirement of aging power plants, upon which California continues to rely despite strong policy directives to diversify the state's electricity supplies.

The *2005 Energy Report* assessment of electricity supply and demand reinforces the conclusion that maintaining adequate electricity reserves will be difficult over the next few years. The state has made progress toward resource adequacy for investor-owned utilities and established a goal of 15-17 percent reserve margins. Jurisdictional authority over other load service entities is less clear. There is no formal mechanism to ensure resource adequacy for publicly owned utilities, which provide up to 25 percent of the state's electricity. The legislature should adopt resource adequacy requirements for all load serving entities and require them to report their supply situation to the Energy Commission so that their progress toward achieving resource adequacy can be assessed in future *Energy Report* proceedings.

California must also address its long-term electricity needs by bringing new generation on line. The lack of available long-term power contracts has stalled construction of more than 7,000 megawatts of plants already permitted, and sharply curtailed the amount of capacity seeking new permits. If unforeseen events cause electricity demand to rise sharply in the next few years, utilities may find themselves forced once again to enter into high-priced contracts that result in higher electricity prices for consumers. The utilities need to invest now for the long term to continue to avoid mistakes made during the 2000-2001 crisis that Californians are still paying for today. The Energy Commission recommends that the California Public Utilities Commission require utility long-term procurement that will cover both the annual “net short” and allow for the orderly retirement/repowering by 2012 of the aging power plants in the study group identified in the *2004 Energy Report Update.*

The utility procurement process also needs to be more open and transparent for all parties. The state’s investor-owned utilities continue to assert that much of the data used in resource planning is confidential. However, the Energy Commission has concluded that there are significant benefits from rigorous public scrutiny of and debate about the data and planning assumptions that form the basis of the California Public Utilities Commission’s decisions on resource procurement. The Energy Commission will participate in the California Public Utilities Commission’s rulemaking to revise regulations regarding disclosure of data, and recommends that the California Public Utilities Commission no longer rely on confidential procurement review groups.

An important alternative to building new central station generating plants is distributed generation, which is electricity produced on site or close to load centers that is also connected to the utility distribution system. The most efficient and cost-effective form of distributed generation is cogeneration or combined heat and power. Current state policy needs to change for California to tap into this potential generation source and retain its existing pool of combined heat and power facilities so critical to the reliable operation of the grid. Developers of new combined heat and power facilities have difficulty finding customers interested in purchasing their excess power at the wholesale level, and the state’s suspension of direct access hampers their ability to sell at the retail level. For existing facilities, the unwillingness of utilities to renew existing qualifying facility contracts has led some operators to remove their combined heat and power systems entirely and rely instead on less efficient boilers to meet their heating needs. There will be serious adverse consequences for electric reliability, natural gas demand, and air quality if this trend is allowed to continue.

There are three policy actions California can pursue to encourage further development of these facilities. First, access to wholesale energy markets must be improved, which could be achieved by requiring utilities to buy electricity at prevailing wholesale prices from combined heat and power operators. Second, the state should examine regulatory incentives that will reward utilities for promoting customer and utility-owned combined heat and power projects, such as the Earned Rate Adjustment Mechanism, that successfully kept utilities revenue-neutral for energy efficiency programs. Third, the adverse effects of current California Independent System Operator requirements could be mitigated by requiring and compensating the utilities to provide scheduling services to combined heat and power operators.

Reducing Energy Demand through Efficiency and Alternative Resources

Reducing the demand for energy is the most effective way to reduce energy costs and bolster California's economy. In addition, reducing demand also reduces the likelihood of supply shortages that can cause costly price spikes and affect reliability. For the foreseeable future, California will continue to depend upon petroleum fuels and natural gas to meet its energy needs. The state needs to act now to implement energy efficiency measures and increase its use of alternatives to reduce its reliance on these volatile fuel supplies. Efficiency and the use of renewable resources are top priorities in California's loading order policy for electricity, and the state needs to broaden this concept to California's transportation sector by reducing demand for petroleum fuels through efficiency and the use of alternative fuels.

Electricity

California continues to be a leader in its efficient use of electricity. While energy use per person in the rest of the nation has increased by 45 percent over the last 30 years California's per capita use has remained relatively flat as a result of the state's energy efficiency measures. In the *2003 Energy Report*, the Energy Commission concluded that California could achieve an additional 30,000 gigawatt hours of energy savings from energy efficiency programs over the next decade. In 2004 the California Public Utilities Commission adopted a set of aggressive energy savings goals to reach this potential, and authorized a significant increase in energy efficiency funding. Meeting these goals will reduce the utilities' need for additional electricity supplies between 2004 and 2013 by more than half.

One concern about current energy efficiency programs is that they tend to focus on energy savings rather than peak savings. Because California's electricity demand is characterized by short summer peaks, reducing peak demand is essential for electricity reliability and tempering price volatility, and to avoid the need for expensive power plants that operate only a few hours a year. The Energy Commission recommends an increased emphasis on energy efficiency programs that provide peak savings.

California's water infrastructure accounts for nearly 20 percent of the state's electricity consumption. If not coordinated and properly managed on a statewide basis, water-related electricity demand could affect reliability of the electric system during peak load periods when reserve margins are low. Conversely, without reliable and adequate supplies of electricity, water and wastewater agencies will be unable to meet the needs of their customers. More efficient water usage as well as efficiency improvements in the water infrastructure itself could reduce electricity demand in this sector. The Energy Commission, Department of Water Resources, the California Public Utilities Commission, state water agencies, and other stakeholders should explore and pursue cost-effective water efficiency opportunities that result in significant energy savings to decrease the energy intensity of the water sector. These should include assessing efficiency improvements in hot and cold water use in homes and businesses, water saving appliances and fixtures, devices that use and move water, and other viable options to maximize energy and water savings. Near-term opportunities should be identified for inclusion in the 2006-2008 investor-owned utility energy efficiency portfolios.

Demand response programs are the most promising and cost-effective options to reduce the peaking needs of California's electricity system. Although the California Public Utilities Commission set demand reduction targets in 2003 for investor-owned utilities, demand response programs have failed to deliver the savings targets established for each of the last three years, and appear unlikely to meet targets for next year. Given the huge cost of serving California's peak loads, the state's policy makers must redouble their efforts to implement demand response programs and rapidly install advanced meters for all customers. It must be recognized that new metering technology will be the primary platform for whatever mix of voluntary and mandatory demand response policies the state pursues in the future.

California is also a leader in its use of renewable energy. During the last 20 years, California has developed one of the largest and most diverse renewable generation mixes in the world. In 2002, California established a Renewable Portfolio Standard program with the goal of increasing the amount of renewable energy in the state's electricity mix to 20 percent by 2017. The *2003 Energy Report* recommended accelerating that goal to 2010, and the *2004 Energy Report Update* further recommended increasing the target to 33 percent by 2020. However, the current process for procuring renewable resources is overly complex, delaying the state's ability to achieve these renewable goals.

The California Public Utilities Commission, in collaboration with the Energy Commission, should work toward simplifying, streamlining, and expediting the Renewable Portfolio Standard process. In addition, the two agencies should collaborate to establish rules for participation in the Renewable Portfolio Standard program for energy service providers and community choice aggregators and allow limited trading of renewable energy certificates that would facilitate participation by these entities as well as help address transmission constraints preventing access to promising renewable resource areas in the state. As the Western Renewable Energy Generation Information System comes on line, this compliance mechanism should be expanded to include the entire Western Electricity Coordinating Council.

There are also several issues facing wind resources in California. The state needs to focus on repowering its aging wind facilities, both to increase the amount of renewable generation from these prime sites and reduce the number of bird deaths associated with the operation of wind turbines. The state also needs to pursue additional research and development activities at the Energy Commission and the California Independent System Operator to address the impacts of integrating intermittent renewables, such as wind, into the state's transmission system.

California also has opportunities to increase energy production from renewable resources associated with the state's water system. In-conduit hydropower — turbines installed within conduits to capture the energy from flowing water in pipelines, canals and aqueducts — is an attractive technology because of ease in permitting and fewer environmental impacts than large hydroelectric projects. Also, anaerobic digesters installed at or near wastewater treatment facilities, dairies, or food processing facilities can produce biogas which can be used to power on-site generation or be sold to the grid.

Many existing in-conduit facilities are facing challenges associated with the expiration of their standard offer contracts with the state's investor-owned utilities. In addition, existing rules do not credit power produced by a water or wastewater utility to that entity's total energy bills. Instead, wherever such self-generated power cannot be directly connected to an existing load, it must be sold into the wholesale bulk power market. The costs and complexities of participating in the wholesale bulk power and transmission markets are daunting, even for large generators, and can be prohibitive for very small generators. The Energy Commission recommends allowing water and wastewater utilities to self-generate and wheel power within their own systems, expediting and reducing the cost of utility interconnection, eliminating economic penalties such as standby charges, and removing size limitations for net metering.

Transportation

The *2003 Energy Report* concluded that the most cost-effective strategy to reduce petroleum demand in the transportation sector is to increase vehicle fuel efficiency. Unfortunately, efforts to spur the federal government to double the Corporate Average Fuel Economy standards for passenger cars and light trucks have so far been unsuccessful. The federal government has approved only a very minor increase in the light-truck standard and completely ignored the potential savings in the passenger car market. California needs to continue its efforts to form a coalition with other states and stakeholders to persuade the federal government to double the Corporate Average Fuel Economy standards.

In the meantime, the state must focus on other strategies to increase vehicle efficiency. One such strategy is the landmark greenhouse gas emission standard for cars and light trucks recently approved by the California Air Resources Board. Under this standard, new vehicles sold in California beginning with model year 2009 will use almost 30 percent less fuel than previous models while dramatically reducing greenhouse gas emissions. Other strategies include increasing the number of hybrid and plug-in hybrid vehicles in California, better marketing of low-rolling resistance tires, implementing anti-idling regulations for trucks and truck stop electrification, and integrating transportation and land-use planning.

The state should also continue to evaluate pricing options that increase the cost of driving to encourage customers to either reduce vehicle miles traveled or purchase vehicles with better fuel economy. These options include fuel tax increases, a per-gallon fee for vehicle miles traveled, variable fees or rebates for more fuel-efficient vehicles, and pay-as-you-drive automobile insurance. The Energy Commission believes that state government should evaluate these revenue options on a “revenue neutral” basis, with compensating reductions in other taxes.

Increased efficiency in new cars and light trucks alone cannot maintain the state’s overall petroleum reduction goal. California must also vigorously support the rapid deployment of alternative fuels for their petroleum reduction benefits and air quality benefits. The *2003 Energy Report* recommended a goal to increase the use of non-petroleum fuels to 20 percent of on-road demand by 2020 and 30 percent by 2030. Meeting these goals will take considerable effort given the current penetration level of only six percent of demand.

As directed by the Governor, the Energy Commission will take the lead in developing a long-term transportation plan by March 31, 2006, that will reduce gasoline and diesel use and increase the use of alternative fuels. The plan should consider a variety of strategies, including but not limited to: incentive programs to encourage consumers to choose more efficient transportation options; a Renewable Transportation Fuel Standard for gasoline and diesel; expedited permitting of ethanol fuel stations; working with local governments and regional planning organizations to identify ways to improve public transit and land-use planning; imposing a transportation public goods charge to fund a comprehensive transportation program; encouraging petroleum reduction in the off-road market; and sponsoring research and development for transportation technologies and fuels.

Natural Gas

In the natural gas sector, the *2003 Energy Report* recommended that the state increase funding for natural gas efficiency programs to decrease natural gas use. California has made excellent progress in this area. In 2004, the California Public Utilities Commission increased funding for natural gas efficiency programs in 2005 by $19.8 million and set aggressive goals intended to double annual gas savings by 2008 and triple those savings by 2013. The Energy Commission and the California Public Utilities Commission should continue to rigorously evaluate, measure, and monitor these programs to ensure that they produce the intended savings and that public funds are being well spent.

Another way to increase natural gas efficiency is to increase the role of combined heat and power facilities in meeting California’s electricity supply needs. By recycling waste heat, these systems are much more efficient than separately serving thermal and electric loads. They are also considerably more efficient than almost all conventional gas-fired power plants. California has more than 9,000 megawatts of combined heat and power systems throughout the state, representing approximately 17 percent of statewide generation. Most of these systems are larger than five megawatts, suggesting that the state should focus its efforts on large-scale projects which could provide more than 5,000 megawatts of additional generating capacity during the next 15 years.

Natural gas efficiency is also a priority in the Energy Commission's natural gas research, development and demonstration program. Approximately $1.3 million of the $12 million in funding available for 2005 has been preliminarily earmarked for efficiency research. The Energy Commission should continue its natural gas efficiency efforts and incorporate results from those efforts into the state's natural gas efficiency programs.

Improving the Energy Infrastructure

Electricity Transmission Infrastructure

In the *2003 Energy Report* and the *2004 Energy Report Update*, the Energy Commission highlighted existing problems with the state's transmission system and recommended improvements to the transmission planning and permitting processes to speed up approval of new transmission lines and upgrades to existing lines. However, the state still lacks a well-integrated transmission planning and permitting process that incorporates both generation and transmission needs, evaluates non-wires alternatives, plans for transmission corridors well in advance of need, and allows access to essential renewable resource areas of the state.

California policy makers must move aggressively to create a planning and permitting process that leverages the core responsibilities and strengths of the utilities, the Energy Commission, the California Independent System Operator, and the California Public Utilities Commission. The Energy Commission repeats the recommendation of the *2003 Energy Report* that the Legislature transfer the siting functions for transmission lines from the California Public Utilities Commission to the Energy Commission.

California currently lacks a formal process to plan for transmission corridors well in advance of their need. The Energy Commission recommends a corridor identification process that would identify the corridor needs of transmission owners; establish corridor priorities; identify major permitting, environmental and land-use issues associated with corridors; and ensure participation of all affected local, state and federal agencies and stakeholders. Further, the Legislature should give the Energy Commission authority to designate corridors so that utilities have a level of certainty allowing them to acquire land and easements, while also allowing the Energy Commission to proceed with environmental reviews that could significantly shorten the overall planning and permitting lead times for transmission. Further, the California Public Utilities Commission should revisit its five-year limitation on land banking for future transmission corridors within utilities' rate bases to allow for long-term corridor planning.

California must also encourage major investments in new transmission infrastructure to access remotely located renewable resources in the Tehachapi and Imperial Valley areas. Without such investment, it will be very difficult for California to meet its Renewable Portfolio Standard goals. In March 2005, Southern California Edison proposed a new category of transmission facility called a "renewable-resource trunk line" that would have interconnected large concentrations of potential renewable generation resources located within a reasonable distance from the existing grid, and be operated by the Independent System Operator. However, in July 2005, the Federal Energy Regulatory Commission denied Southern California Edison's request, removing the primary instrument the state could have used to address transmission constraints for renewables. This denial reinforces the need for the Energy Commission, the California Public Utilities Commission, and the Independent System Operator to investigate tariff changes to recognize this new category of transmission project, as was recommended in the *2004 Energy Report Update*.

Petroleum Infrastructure

California needs to expand its petroleum infrastructure. Despite recent and planned improvements in the state's petroleum infrastructure, California still needs to expand its marine terminal capacity, marine storage, and pipelines connecting marine facilities and refineries to main product pipelines. Most of the required expansion will be in the Los Angeles Basin, which faces a number of barriers such as scarcity of available land, pressure to remove existing facilities in favor of container cargo facilities, and new standards for marine terminals. In Northern California, timely dredging in the Suisun Bay Channel, Pinole Shoals, and other areas near refineries is essential to petroleum infrastructure operations by maintaining adequate shipping channel depth so that petroleum tankers can reach their destinations.

The *2003 Energy Report* identified the continuing need for modifying and expanding the state's petroleum infrastructure facilities to help meet increasing demand for petroleum fuels. A major barrier is the inefficient and often overlapping permitting bureaucracies characterized by lack of coordination among multiple agencies and long timelines. There is a general consensus among stakeholders that the Energy Commission should work with representatives of the petroleum industry and permitting agencies to develop "best permitting practice" guidelines to streamline and coordinate petroleum infrastructure permitting. The Energy Commission believes such guidelines should include: description of agencies involved and relationships between agency processes; critical path permitting timelines; information requirements; standardized permitting timelines; requirements for expedited permitting; mitigation requirements; concurrent and coordinated permit review; procedures for categorical exemptions and ministerial permits; and streamlined appeal processes.

Natural Gas Infrastructure

California imports 87 percent of its natural gas supplies, which are threatened by declining production in most U.S. supply basins. California has not experienced a widespread natural gas shortage in many years. However, colder-than-average weather, increased demand in other states, or natural disasters such as Hurricane Katrina could result in demand spikes that would draw down existing storage and affect the state's ability to meet its natural gas needs. It is difficult to determine potential peak demand with any precision or even the likelihood of such a peak, and the state needs to expand its analytical capability to examine this issue.

To prevent interruptions in natural gas supplies, the *2003 Energy Report* recommended that the state ensure existing natural gas storage is used to provide adequate supplies and protect prices. The state has made good progress toward increasing its current storage inventory and there are also plans to develop additional storage capacity next year. A margin of excess capacity will provide consumers a choice of supplies and is the critical foundation needed to support a competitive market and stabilize short-term pricing trends.

California has greatly improved the state's natural gas infrastructure by increasing intrastate pipeline capacity as well as in-state storage. Recent pipeline expansions over the last four years have helped ensure that the state can access conventional natural gas supply basins outside of the state. The state must make certain that existing infrastructure is maintained and retained. In addition, the state should continue to evaluate the need for additional pipeline capacity to meet the needs of consumers on the coldest days in winter or when there are interstate pipeline disruptions.

An important addition to natural gas infrastructure in North America is the construction of liquefied natural gas import facilities. These facilities will increase natural gas supplies available to the U.S. over the next ten years and also help meet California's additional natural gas needs. Currently, no liquefied natural gas terminals are located on the West Coast. The *2003 Energy Report* highlighted the need for development of these facilities and their associated infrastructure to serve the natural gas needs of the western U.S.

The cost of delivering natural gas to the West Coast via a liquefied natural gas project is well below the market prices that California pays at its borders and could have a dramatic effect on the market prices in the state. For example, if market prices dropped by 50 cents per million British thermal units, Californians would save more than $1 billion on their natural gas bills.

Several companies have recently proposed building liquefied natural gas import facilities in California and Mexico. In California, these include the Cabrillo Deepwater Port and the Clearwater Port, both of which are offshore projects, and the Long Beach LNG Import Project. In Mexico, three proposed facilities would be located near Ensenada, the Coronado Islands, and Sonora. Sempra Energy broke ground on its Costa Azul LNG receiving terminal near Ensenada in Baja California Norte in March of this year. For California to access new liquefied natural gas supplies, however, additional or modified pipeline infrastructure may be necessary.

Global Climate Change

California must also be cognizant of the environmental impacts of state energy policy. As the tenth largest emitter of greenhouse gases in the world, California must harmonize its energy policies with efforts to reduce statewide greenhouse gas emissions. In June 2005, Governor Schwarzenegger established greenhouse gas emission targets aimed at reducing emissions by 2010 to 2000 emission levels, by 2020 to 1990 emission levels, and by 2050 to 80 percent below 1990 levels. The Governor's Climate Action Team, led by the California Environmental Protection Agency, is charged with reporting progress made toward these targets, with the first report due to the Governor and Legislature in January 2006.

Global climate change could have severe effects on energy supplies in California. The state depends on hydroelectric power for 15 percent of its electricity on average, and a general warming trend could deplete the snow pack "reservoir" that provides water for hydropower. Earlier snowmelts could also increase flood protection releases, reducing storage for summer use.

In addition to reducing available hydroelectric generation, climate change could increase the demand for energy for heating and cooling in the state. This increase results from higher summer cooling demand that would cancel any decrease in winter heating demand resulting from warmer temperatures.

There are a number of strategies the state is exploring to reduce greenhouse gas emissions. The California Public Utilities Commission now requires investor-owned utilities to use a "greenhouse adder" of an initial $8 per ton in their long-term procurement plans to encourage them to invest in lower-emitting resources. The Energy Commission should continue to support the California Public Utilities Commission's efforts to fully internalize the benefits of reducing carbon generation.

Another strategy is California's Climate Action Registry which provides a forum to develop a uniform and comprehensive database for emissions from participating companies or facilities. The registry provides a reliable basis for companies to use in obtaining credit for emissions reductions. The Energy Commission should continue to support the registry's efforts to collect data on facility-level and entity-wide greenhouse gas emissions.

The Energy Commission also established the Climate Change Advisory Committee to evaluate the most equitable and efficient ways to implement national and international climate change requirements. The membership of the committee represents key economic sectors within California that will be affected by climate change. The state needs to consider the recommendations of the Climate Change Advisory Committee in evaluating state-level strategies. In addition, state agencies need to coordinate and use common assumptions in their strategic plans to address the impacts of global climate change. Uncoordinated state planning efforts using disparate climate scenarios could result in contradictory policy options and hamper meeting the Governor's greenhouse gas emission reduction targets.

Conclusions

California's economy depends on having reliable, affordable, and adequate supplies of energy. The rising cost of energy is having a negative impact on consumers who must spend an increasing percentage of their income to satisfy their energy needs, and on businesses whose profits shrink as their energy costs increase. At the same time, California's dependence on natural gas and petroleum fuels is continuing to increase, making the state vulnerable to supply disruptions and resulting price spikes.

The recommendations in the *2005 Energy Report* are intended to increase California's energy supplies, reduce energy demand, broaden the range of alternatives to conventional energy sources, and improve the state's energy delivery infrastructure. Many of these recommendations were first made in the *2003 Energy Report* and the *2004 Energy Report Update*. It is past time for California to implement these recommendations to address the many challenges facing the state's energy systems and safeguard its healthy economy.

CHAPTER 1: INTRODUCTION

This *2005 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 (Energy Commission) prepare a biennial integrated energy policy report (*Energy Report*). This report contains an integrated assessment of major energy trends and issues facing California'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.

This report was developed under the direction of the Energy Commission's 2004-2005 Integrated Energy Policy Report Committee (Committee). There are three companion reports to the *2005 Energy Report*. The *Draft 2005 Strategic Transmission Plan* was developed in response to Public Resources Code requirements to prepare a strategic transmission investment plan to be included in the *Energy Report* adopted on November 1, 2005. The plan identifies recommended near-term transmission projects, including the criteria used to select those projects, as well as a description of the benefits they provide.

The *Draft 2005 CPUC Transmittal Report* will identify the likely range of statewide and utility-specific need, issues relevant to this need, and responses to participant comments. The report will also identify the transmission projects necessary for investor-owned utilities to effectively conduct resource procurement and policy recommendations to the California Public Utilities Commission (CPUC) for addressing investor-owned utility transmission and resource needs.

Senate Bill 1389 also requires the Energy Commission to include in the *Energy Report* an assessment of the environmental performance of electric generation facilities in the state. The Draft *2005 Electricity Environmental Performance Report* was released in June 2005 and will be finalized after adoption of the *2005 Energy Report*.

The *2005 Energy Report* contains recommendations to further the goals of the state's *Energy Action Plan*, developed in 2003 by the Energy Commission, the CPUC, and the California Consumer Power and Conservation Financing Authority. The *Energy Action Plan* contains joint goals for California's energy future and commits to achieving these goals through specific actions. The plan was intended to be a "living document" that would change with time, experience, and need, with the overarching goal of ensuring that California's energy suppliers are adequate, affordable, technologically advanced, and environmentally sound.

The *2003 Energy Report* called on state government to reduce demand, secure additional energy supplies, give consumers more energy choices, and make needed infrastructure improvements to protect California from future supply disruptions and high prices. In 2004, the Energy Commission submitted an update to the Governor and the Legislature that reiterated the need for upgrading California's energy infrastructure by providing additional analyses and recommendations on reliability, transmission planning, and renewable energy development, as well as a summary of the state's progress toward the 2003 recommendations.

The state has made some limited progress toward the goals in the *2003 Energy Report* and the *2004 Energy Report Update*, primarily in utility efficiency programs and natural gas infrastructure. Much more remains to be done. The *2005 Energy Report* focuses on understanding the opportunities and obstacles faced in implementing strategies and accelerating progress along the path identified in the *2003 Energy Report* and the *2004 Energy Report Update.*

Report Preparation Process

In late 2004, the Committee released its scoping order identifying key issues to be addressed in the *2005 Energy Report*. The scoping order was followed by 53 Committee workshops held from the fall of 2004 through the summer of 2005 to seek input on the various key issues. A focus of these workshops was a series of staff white papers that discussed major energy issues in California and identified potential policy options to address those issues.

Throughout the workshops and development of the staff white papers, stakeholder participation was extensive. The Energy Commission staff worked with key federal, state, and local agencies in preparing the white papers, involving more than 600 public and private stakeholders (listed in Appendix B). The white papers and stakeholder comments submitted for the record comprise more than 25,000 pages of material.

In preparing this draft report the Committee carefully sifted through the extensive record to develop its various policy recommendations. This draft report will be the subject of Committee hearings to receive public input, after which a revised final report will be considered by the Energy Commission for adoption at its November 16, 2005 business meeting.

CHAPTER 2: TRANSPORTATION FUELS

Introduction

Roughly half of the energy Californians consume is for transportation. To meet that demand, the state relies almost exclusively upon petroleum. The California Energy Commission (Energy Commission) concluded in the *2003 Energy Report* that California's singular dependence upon petroleum has fueled volatility in retail gasoline and diesel prices. The Energy Commission also highlighted two potentially disturbing trends: an alarming rate of growth in petroleum demand and an in-state refinery capacity running past its limits and increasingly reliant upon imports. Any sustained problems in the state's fragile refining and distribution infrastructure would create certain and almost immediate supply problems and price spikes since California's largely insular market structure hobbles the timely delivery of domestic and foreign supplies when inevitable problems do occur.

To make matters worse, world oil markets have become volatile since 2003. Skyrocketing demand in China and other developing countries, coupled with political and social upheaval in key oil supply nations, are fast exacerbating the international supply/demand equation. Domestically, Hurricane Katrina's interruption of oil production and transport in the Gulf Coast contributed to subsequent $70 per barrel oil prices and highlighted the nation's dangerous reliance upon a single source of fuel. In the wake of this perfect storm of events, retail gasoline and diesel prices have soared past $3 per gallon in California.

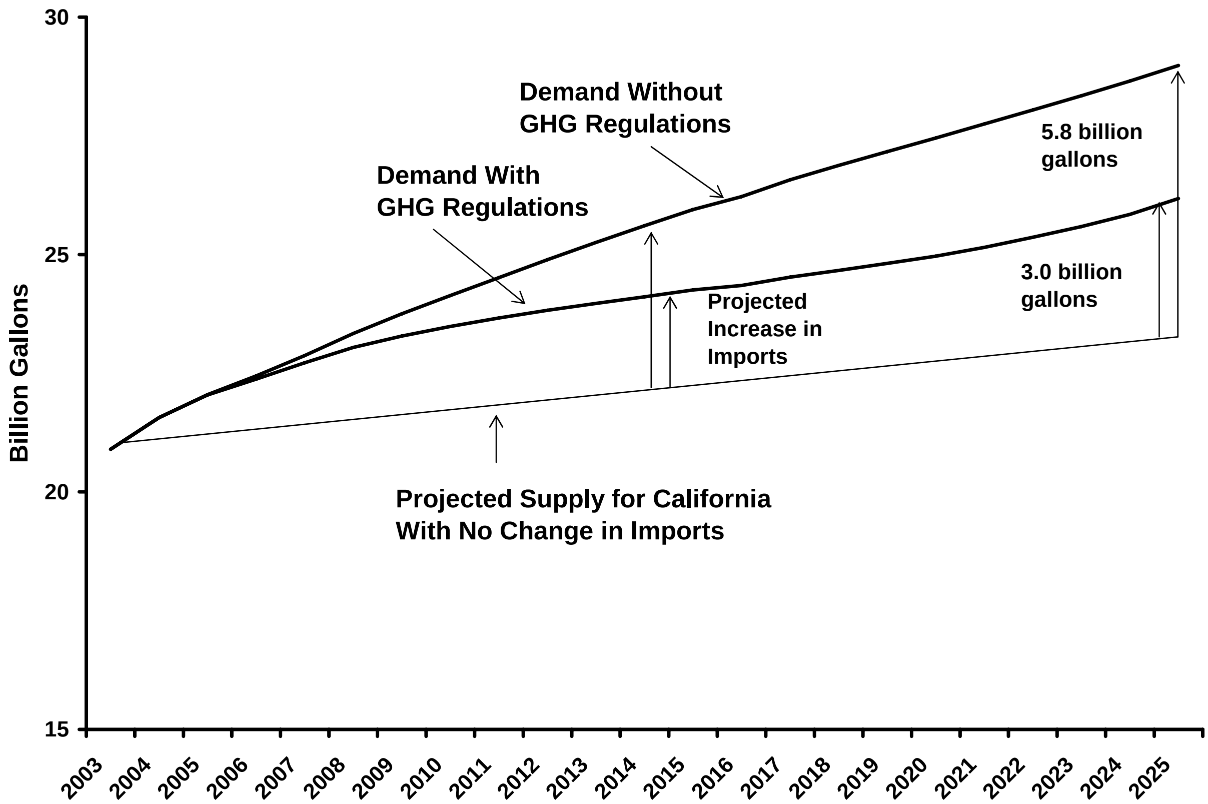
Current retail price spikes for petroleum top a long period of price volatility in California beginning in the late 1990s. In 2001, the Legislature asked the Energy Commission and the California Air Resources Board (CARB) to jointly develop a strategy to reduce California's dependence on petroleum. In their joint 2003 report, the two agencies demonstrated that it is possible to significantly reduce the use of petroleum and recommended that the state pursue demand reductions for on-road gasoline and diesel fuel with an achievable, cost-effective strategy.

The cornerstone of this strategy is the increased efficiency of new vehicles. The report revealed that the federal government could double the combined Corporate Average Fuel Economy (CAFE) standards for passenger cars and light trucks without sacrificing safety and customer choice. The Energy Commission and the CARB also concluded that broader use of non-petroleum fuels must be a critical complement to higher vehicle fuel economy if the state is to sustain any meaningful reduction in petroleum demand.

The Energy Commission, after further consideration and input from public workshops and hearings, incorporated recommendations from the joint report in the *2003 Energy Report* and recommended that the Governor and Legislature adopt the goals and strategy as state policy.

The CARB adopted regulations in 2004 limiting greenhouse gas (GHG) emissions from new vehicles sold in California, beginning in model year 2009. CARB evaluated a large slate of technology options that are available now and expected to be available in the future.[1] CARB developed an alternative compliance plan that allows for use of alternative fueled vehicles including compressed natural gas, liquid petroleum gas, ethanol, electric vehicles, and hydrogen fueled vehicles. An important secondary effect will be significant improvement of vehicle efficiency. New vehicles complying with this regulation will consume nearly 30 percent less fuel than vehicles built before 2009. Even this landmark regulation, however, does not go far enough for the state to achieve the Energy Commission's recommended CAFE target.

Figure 1: Projected Gasoline and Diesel Demand



---

[1] Near-term technologies include engine modifications (including valve timing and lift, turbocharging, cylinder deactivation, variable compression ratios, gasoline direct injection), transmission modifications (including higher gear automatics, aggressive shift logic, early torque converter lock-up, and continuously variable transmissions), modified auxiliaries (including electric power steering, improved alternators, electric accessories, air conditioners), and vehicle modifications (including less aerodynamic drag and lower rolling resistance tires). Mid-term technologies include camless valves, lean-burn gasoline direct injection, very mild hybrids (42-volt start-stop and integrated starter/generator motor assist) and diesel high-speed direct injection.

Little has been done at the federal level, where responsibility for setting fuel economy standards ultimately lies. Congress and the Administration unfortunately chose to ignore this issue in the recently enacted federal Energy Act of 2005. The Administration's recent proposal to increase fuel economy standards for some light trucks is little more than a drop in the ocean of pressing need for more efficient vehicles and will do little if anything to blunt growing national petroleum demand. Governor Schwarzenegger, however, has called for California to continue its efforts to promote federal doubling of CAFE standards through a coalition of states.

The Energy Commission recommended in the *2003 Energy Report* that California increase its use of non-petroleum fuels to 20 percent of on-road demand by 2020 and 30 percent by 2030. Consumption of non-petroleum fuels in California is currently stagnant at about 6 percent. Ethanol mixed with gasoline accounts for nearly all of this market, with small additional amounts of natural gas, biodiesel, propane, and electricity. In tandem with other renewable diesel fuels, gas-to-liquid fuels, battery-electric and hybrid-electric vehicles, and hydrogen-fueled vehicles, California could significantly reduce petroleum demand, criteria pollutants, toxic air contaminants, and greenhouse gas emissions. These fuels and technologies presently suffer from higher cost and/or limited availability and need to be more effectively integrated into energy and air quality policies.

California has needed a clear and decisive policy to reduce its dependence on petroleum fuels and a broad collaborative framework to move more non-petroleum options into the market. In Governor Schwarzenegger's response to the *2003* and *2004 Energy Reports*, he directed the Energy Commission to "take the lead in crafting a workable long-term plan by March 31, 2006 that will result in the significant reduction of gasoline and diesel use and increase the use of alternative fuels so that the State is working toward a set of realistic, achievable objectives with identifiable and measurable milestones."[2]

Given the growing gap between the supply of and demand for transportation fuels, California must create an efficient, multi-fuel transportation market to serve the future needs of its citizens. The Governor's California Hydrogen Highway Network that he announced in April 2004 will eventually move the state to a hydrogen transportation fuel economy. The Energy Commission believes the long-term plan must bridge the gap between today's technology and the transition to hydrogen fuels and vehicles. California must pursue a diverse portfolio of fuels and advanced transportation technologies that address both current supply and demand problems and build a sustainable foundation for the future.

In the meantime, demand is increasing despite record-high prices, and little has changed on the supply side since 2003. Some new storage facilities are being built and several smaller refineries are expanding their production capacities. These

---

[2] Letter from Governor Arnold Schwarzenegger to the Legislature, attachment: Review of Major *Integrated Energy Policy Report* Recommendations, August 23, 2005.

improvements, however, are inadequate in addressing the problem of the rapidly widening gap between demand for petroleum and its supply.

The Energy Commission also concluded in 2003 that petroleum infrastructure additions were being held up by local, state, and federal construction permitting delays. Layers of inefficient and overlapping responsibilities were found to contribute to a persistent shortage of storage capacity. The Energy Commission at the time recommended that the state establish a one-stop permitting process for construction of petroleum infrastructure. Legislation introduced to implement this recommendation did not pass. After conducting a series of workshops on this topic, the Energy Commission intends to work closely with local governments, air districts, and state and federal agencies to develop a “best practices” approach to permitting and building petroleum facilities.

As a group, petroleum refineries are among California’s largest consumers of electricity and natural gas. The state must work with the industry to make sure that refineries take advantage of all available energy efficiency and combined heat and power opportunities. This will minimize the environmental footprint of refinery operations, make the most efficient use of natural gas, improve local electricity reliability, and ensure continued transportation fuel production in the event of electricity shortages.

The economic future of California depends upon meeting the state’s transportation fuel needs. More urgently than even two years ago, California must achieve greater efficiency, diversify its fuel portfolio, and introduce advanced technologies including hybrids and electric fuel cell vehicles.

Demand for Gasoline and Diesel Fuel

Every day, Californians consume about 43 million gallons of gasoline and 8 million gallons of diesel fuel.[3] The state’s demand for transportation fuels has increased a staggering 48 percent over the last 20 years. This demand continues, even in the face of record petroleum prices, for several reasons:

- Population growth and more on-road vehicles.
- Low per-mile cost of gasoline for the past two decades.
- Lack of alternatives to gasoline and diesel.
- Consumer preference for larger, less fuel-efficient vehicles.
- Land-use planning that places jobs and housing farther apart without transportation integration.
- Lack of mass transit.

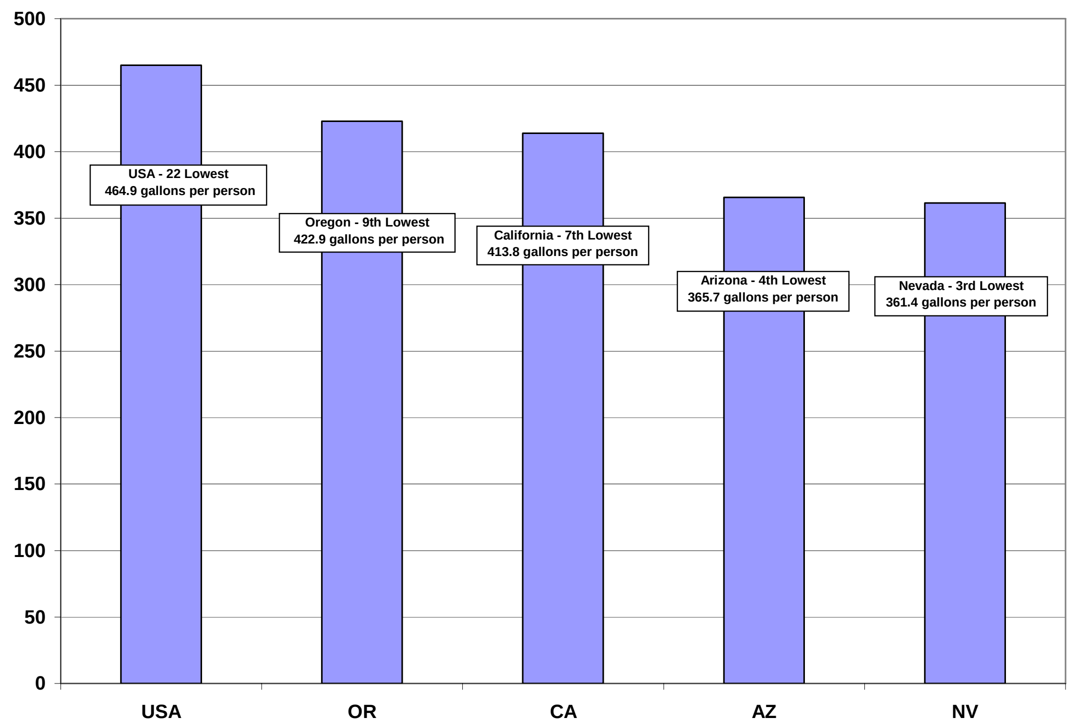
[3] Board of Equalization data for taxable sales. Includes all taxable use of gasoline and diesel, including on-road and off-road use.

If the state takes no further action to reduce its dependence on petroleum, the Energy Commission projects that demand for gasoline in California will reach 48.6 to 52.1 million gallons per day by 2025. For diesel, the projection ranges from 13.6 to 13.8 million gallons per day.[4] This forecast is lower than projected in the *2003 Energy Report* because of higher assumed fuel prices and lower estimates of population growth, but it still represents a substantial increase over current levels.

Notably, the Energy Commission's forecast covers only on-road, in-state demand and does not include off-road demand or demand for gasoline and diesel in neighboring states and Mexico that is met by California refineries and other petroleum infrastructure.

California is the center of a regional petroleum market. In-state refiners provide Nevada with almost 100 percent of its transportation fuel needs, Arizona with over 60 percent of its needs, and Oregon with 35 percent of its needs. Baja California Norte also relies upon California for a portion of its fuel needs, although no data is available as to the quantity.

Figure 2: 2004 Per Capita Gasoline Consumption
(gallons per person)



Fuel demand in Arizona and Nevada is growing at an even higher rate than in California. This demand growth will more tightly squeeze California's refineries over the next several years. If growth in these markets averages 3 percent over the next 10

---

[4] The range is based on staff's forecast with the California Air Resources Board greenhouse gas standards for cars and without the greenhouse gas emission standards.

years, regional demand could increase by nearly 5.5 million gallons per day by 2015. Increased demand for transportation fuels in these out-of-state markets further exacerbates California's supply/demand imbalance.

Economic Effects of the Price of Transportation Fuels

California's high gasoline prices are taking a toll on the state's struggling economy. California consumers are spending more of their household income on gasoline than ever before. High fuel prices also reduce profit margins for manufacturing and transportation sectors, which then pass along the higher cost of their goods and services. Californians are therefore not only paying higher prices for the gasoline they need, they are using what's left of their disposable incomes to pay higher prices for other products.

In early September, the average retail price for regular grade gasoline and diesel fuel reached record highs of $3.05 and $3.14 per gallon, respectively. Since September of last year, the monthly average price of gasoline has increased by more than 35 cents per gallon, costing consumers an additional $5.3 billion for gasoline, a staggering blow for both consumers and California's rebounding economy.

Crude oil is the single largest cost in the production of transportation fuels, accounting for between 42 and 56 percent of the price of branded regular gasoline in the last year.[5] Over the last two years, however, the price of crude oil has nearly doubled.[6]

Since crude oil is a global commodity, its price is dictated by worldwide supply and demand. The present global crude oil supply/demand balance is being squeezed by high growth rates in developing countries like China and India. Geopolitical uncertainty, weather, labor and social unrest in oil-producing countries, and devaluation of the dollar against foreign currencies have also affected the world price of oil.

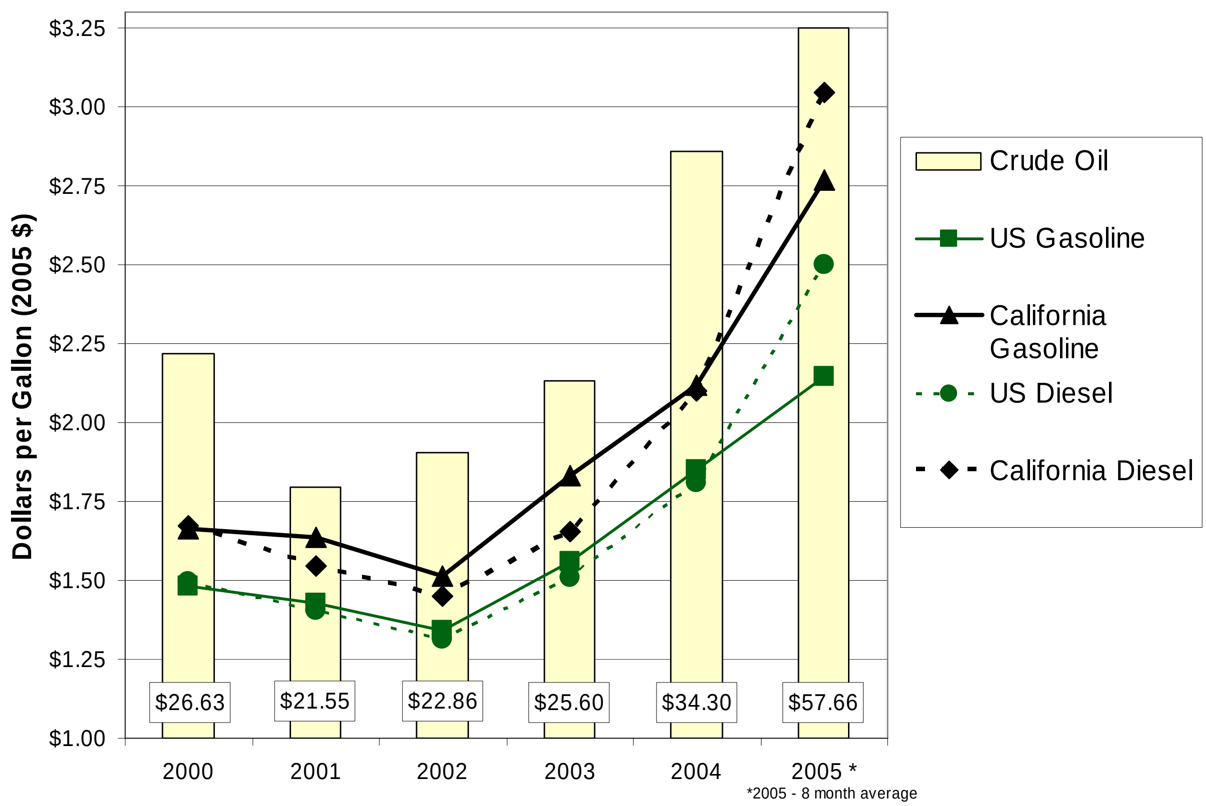
In the *2003 Energy Report*, the Energy Commission raised serious concerns about the retail price impact of the state's refineries' inability to meet current and future petroleum demand. California's supply of gasoline and diesel is highly vulnerable to breakdowns and outages at in-state refinery and pipeline facilities. Though there has not been an inordinately large number of unplanned refinery outages over the past few years, there have been more unplanned petroleum pipeline interruptions than usual. These incidents quickly tighten fuel supplies and create price spikes in this highly price-sensitive free market commodity.

The Energy Commission has also raised concerns about the impact of out-of-state outages on supplies and prices in California. For example, the combination of

[5] California Energy Commission, http://www.energy.ca.gov/gasoline/margins/index.html, accessed August 18, 2005.
[6] Refers to prices of Alaska North Slope crude oil, an important West Coast refinery feedstock. Source: Wall Street Journal.

unplanned refinery outages and pipeline maintenance in Washington in early 2005 tightened supplies of diesel fuel for both Washington and Oregon for more than 45 days, requiring additional deliveries of diesel from California and raising prices in this state.

Figure 3: Gasoline, Diesel, and Crude Oil Prices



The Energy Commission continues to be very concerned about the relationship between retail price spikes and weaknesses in the state's petroleum infrastructure, including the growing gap between in-state refining and demand in California and the region, limited storage capacity for crude oil and refined products, and declining import capabilities at Southern California ports. Since California is not directly connected by pipeline to other domestic refining centers, the industry cannot readily procure gasoline, diesel and other blending components when inevitable outages do occur, leading to higher and more prolonged price spikes.

The Urgent Need to Diversify Transportation Fuels

In 2003, the Energy Commission concluded that increasing federal fuel economy standards would be the most effective measure to reduce gasoline consumption, but would also be the most difficult to achieve. In the *2003 Energy Report*, the Energy Commission recommended that the state "Build a coalition with other states and stakeholders to influence Congress and the Department of Transportation to double the combined fuel economy of new passenger cars and light trucks by 2020. If the federal government fails to revise CAFE standards, California must reassess its petroleum reduction strategy."

Given inaction by both Congress and the Administration to increase CAFÉ standards, the state must now "…reassess its petroleum reduction strategy…" and redirect its efforts to actions it can directly affect. The first step in this policy redirection is to renew emphasis on diversifying the transportation fuel market.

The Energy Commission has examined a portfolio of non-petroleum fuel and technology options. None offer an ideal solution as each has costs and performance characteristics that will define its most effective application in California's expansive transportation energy market. Each was examined from economic, environmental, and consumer perspectives. The results are presented in Table 1 on the following page.

From a policy perspective, the state should pursue all reasonable non-petroleum fuel and technology options. Because of the urgent need to diversify fuels, those options that can be used in existing engine and fueling systems and that can be produced with in-state resources should be given a high priority. Other options are best suited in central fueling applications (for example, fleets) and the state should vigorously pursue those opportunities where they are cost-effective. Still other options require additional research and development and the state should provide all appropriate support.

Ethanol

Ethanol is blended with gasoline to make transportation fuels and has been used in California primarily as an oxygenate to comply with a federal requirement for minimum oxygen content in gasoline. Federal law allows up to a 10 percent ethanol blend for this purpose. However, refiners cannot economically produce gasoline with ethanol content greater than 5.7 percent under the current version of CARB's Predictive Model.[7] As a result, nearly 98 percent of all gasoline sold in California contains just 5.7 percent ethanol.[8] Although the Energy Policy Act of 2005 repealed the requirement for minimum oxygen content for gasoline, refiners will probably continue to add ethanol to 98 percent of the gasoline sold in California.[9]

[7] At least one refiner has, on occasion, produced gasoline with an ethanol content as high as 7.7 percent by volume.
[8] The San Francisco Bay Area is in attainment for carbon monoxide. Gasoline sold in that area, which represents a little more than 2 percent of the California market, does not contain ethanol.
[9] It is unlikely that refiners will produce and market non-ethanol gasoline because of minimum octane requirements; investments to date by refiners, terminal operators, independents, gasoline wholesalers, California's common carrier pipeline operator, and the railroads; long-term contracts for ethanol delivery by the railroads to refiners; and lack of segregated storage and pipeline facilities .

Table 1: Petroleum Reduction and Benefits for Very High Petroleum Price Scenario[a]

Alternative Fuel Option or Scenario	Displacement in 2025, billion gallons gasoline equivalent	Percent Reduction from Base Case Demand,[c]	Highest Cumulative Benefit or Change,[b] Present Value, 2005-2025, 5% discount rate, With GHG Standards, Billion $2005			
			A	B	C	A+B+C
			Direct Non-Environmental Net Benefit [f]	Direct Environmental Net Benefit	External Cost of Petroleum Dependency	Direct Net Benefit[g]
Electric Battery Technologies (NEV and CEV)	0.10	0.48	1.11	0.07	0.04	1.22
Grid-connected Hybrid Electric Vehicles (HEV20)	0.53	2.56	0.62	0.32	0.19	1.13
Grid-connected Hybrid Electric Vehicles (HEV60)	0.71	3.42	(1.29)	0.47	0.25	(0.58)
CNG for Light-duty Vehicles (Honda Case)	0.02	0.10	(0.29)	0.01	0.01	(0.27)
CNG for Light-duty Vehicles (Honda and GM Case)	0.08	0.40	(0.94)	0.02	0.05	(0.88)
Ethanol Blend (E10 reduced price case)	0.48	2.30	0.00	1.98	0.53	2.51
Ethanol Hi-Content Blend (E85)	1.61	7.73	0.00	0.20	0.42	0.62
LNG and CNG for Medium and Heavy-duty Vehicles (Aggressive Case)[d]	1.70	8.16	1.20	0.16	0.61	1.97
LNG and CNG for Medium and Heavy-duty Vehicles (Standard Case)[e]	1.70	8.16	(2.60)	0.16	0.61	(1.83)
Gas-to-Liquid (GTL) and Coal-to-Liquid (CTL) Fuels	1.64	7.87	0.00	0.10	0.77	0.87
Renewable Diesel (20%, $1.00/gallon federal tax subsidy)	1.00	4.80	0.00	0.96	0.52	1.48
Renewable Diesel (20%, $0.30/gallon federal tax subsidy)	1.00	4.80	0.00	0.96	0.52	1.48
Heavy-duty Hybrid Electric Vehicles (Aggressive Case)	0.05	0.24	(0.06)	0.03	0.01	(0.02)

a This analysis is an update from the previous work (AB 2076 report) performed by the Energy Commission and CARB and adopted by the two agencies in 2003; b Values in parentheses are negative; c Base Case is combined on-road gasoline and diesel demand; d This Aggressive Case employs a natural gas price from a long-term natural gas supply agreement (Clean Energy); e Standard Case employs the CEC natural gas price forecast; f In scenarios where the net benefit value is negative, consumers experience greater costs than for the business-as-usual choice; thus, the assumed penetration rate and resultant displacement are not likely to occur unless an additional consumer benefit or motivation is provided to offset the negative value; g This value is revenue neutral as it does not reflect the impact of the option on government revenue (e.g., program expenditures or fuel excise tax increases or decreases).

The 2005 Energy Policy Act also imposes new federal requirements for renewable fuel content, beginning in 2006, that set a higher standard of renewable content for all gasoline sold in the U.S., up to a maximum of 7.5 billion gallons in 2013. The Act also includes a provision allowing refiners to trade credits for volumes of unused ethanol. Until a federal administrative rulemaking is complete, the impact of the renewable fuel requirement on California is not known.

Since federal law allows ethanol blends up to 10 percent in gasoline, what can the state do to encourage refiners to blend greater amounts of ethanol in gasoline sold in California without backsliding on air quality? The answer is not straightforward and several important issues must be considered.

- The CARB needs to complete the update of its Predictive Model. The model is used to calculate nitrogen oxide emissions from gasoline sold in California. CARB last updated the model in 1999. A major benefit of the current version is that it provides flexibility by allowing refiners to offset emission increases related to one fuel with decreases in another. A major criticism is that the model's data base contains a limited sample of vehicles and does not include emissions from newer technologies. It therefore does not adequately represent the vehicle fleet on the roads today and may overstate total NOx emissions from light-duty vehicles.
- Recent studies show that the difference in NOx emissions between gasoline with 5.7 percent ethanol and gasoline with 10 percent ethanol is slight[10] and may be compensated by the effectiveness of newer vehicle emission control technologies, which operate well below respective certification levels for hydrocarbon, CO, and NOx. Even cars with high mileage maintain these extremely low emission levels.[11] Still in need of better understanding, however, is the magnitude of impacts from permeation — the migration of liquid fuel components into the soft portion of motor vehicle fuel systems, creating evaporative emissions.
- The use of ethanol, like other non-petroleum fuels, significantly reduces emissions for most criteria pollutants and toxic air contaminants, but is limited by a slight increase in NOx emissions. Further analysis is needed, but it may be possible to implement a more flexible regulatory structure that accounts for the total emissions benefits of all criteria pollutants and toxic air contaminants in order to accelerate adoption of non-petroleum fuels without backsliding on air quality or public health.

The most common gasoline/ethanol blends are E-10 (10 percent ethanol to 90 percent gasoline) and E-85 (85 percent ethanol to 15 percent gasoline). Ethanol/gasoline blends higher than E-10 can be used only in fuel flexible vehicles (FFVs) designed to operate on any ethanol blend of gasoline up to 80 percent and for which automakers receive federal fuel economy credits. E-85, a vehicle fuel used widely in other states, is not widely used in California. California has more than 250,000 FFVs. This fleet is growing

[10] Results of the Sulfur Oxygen Test Program supporting Phase 3 regulations, presented to the California Air Resources Board on September 17, 2001.
[11] A Summary of the "Study of Extremely Low Emitting Vehicles Operating on the Road in California," a presentation to the California Energy Commission on July 8, 2005.

at a rate of 45,000 to 50,000 vehicles each year and provides a sizeable potential sales base for E-85. Unfortunately, with only one E-85 refueling station in California, FFVs in the state use gasoline almost exclusively. In fact, many owners are not even aware that they have a vehicle with fuel options.

California produces very little ethanol. About 90 percent of the ethanol used in gasoline arrives in California by train from the Midwest and is produced from corn. The remaining 10 percent of California's ethanol comes by ship from Caribbean Basin Initiative countries and Brazil, where it is produced with sugar. California, however has tremendous potential to produce ethanol with biomass material such as municipal, agricultural, and forestry wastes. Producing ethanol from biomass material would provide a three-fold decrease in greenhouse gas emissions compared with corn-based ethanol and would be an economic boon for California.

Biodiesel

California fleets use about four million gallons of biodiesel fuel each year.[12] Twenty-seven commercial plants in the U.S. produce biodiesel fuel from vegetable oil, animal fat, and used cooking oil. Biodiesel fuel can also be made from several different technologies collectively known as thermal conversion processes (TCP), that use a broad range of feed stock including animal waste, animal carcasses, wood wastes, agricultural waste, plastics, tires, sewage sludge, and other waste containing hydrocarbons, fats, carbohydrates, or protein. Several TCP demonstration plants are operating in the U.S. and Europe.

Biodiesel is compatible with most diesel engine and fueling system components, and B-20 qualifies as an alternative fuel under requirements of the federal Energy Act of 2005. B-20 can be legally sold in California as long as it meets the CARB aromatic and sulfur requirements and Department of Food and Agriculture specifications (which limit retail sales of B-20). Sales of biodiesel fuel at concentrations higher than B-20 require a variance from the Department of Food and Agriculture. Although the initial market for biodiesel is likely B-20, this regulation could limit the future market growth of biodiesel fuel if cost and availability factors improve.

On the other hand, at very low concentrations, biodiesel could play an important role in the introduction of cleaner conventional diesel fuels and advanced diesel engines. Beginning in 2006, ultra-low sulfur diesel fuel regulations become effective, placing sulfur limits on all conventional diesel fuel sold in the United States at just 15 parts per million (ppm). Biodiesel is by its nature low sulfur, typically containing fewer than 2 ppm. New ultra-low sulfur diesel has very poor lubricity and requires additives. At concentrations of just 1 to 2 percent, biodiesel fuel can provide adequate lubricity for ultra-low sulfur diesel fuels. Likewise, advanced diesel engines entering the market

[12] Randall van Wedel, National Biodiesel Board, testimony at Committee Workshop on Proposed Transportation Energy Efficiency and Alternative Fuels Analyses, California Energy Commission, Sacramento, California, December 20, 2004.

between 2007 and 2010 will need ultra-low sulfur diesel fuel to meet their emissions targets.

In neat form or in a blend with conventional diesel fuel, biodiesel fuel provides emission reduction benefits for criteria pollutants, air toxics, and greenhouse gases. The single air quality issue with biodiesel is NOx emissions from existing engines. A U.S. Environmental Protection Agency (US EPA) analysis indicates that B-20 fuel does increase NOx emissions an average of 2 percent. This should not limit the expanded use of biodiesel fuel for several reasons:

- Recent testing using different protocols showed NOx reduction of about 4 percent in existing engines using B-20.
- New additives are being developed that will reduce NOx emissions.
- Advanced diesel engines introduced in 2007-2010 will reduce NOx by 90 percent, more than compensating for NOx concerns with biodiesel fuel.

Gas-to-liquid

Gas-to-liquid (GTL) is a synthetic diesel-like fuel that can be used in both conventional diesel engines and fueling systems. GTL fuel is made with a process that converts hydrocarbon gas to a liquid fuel (generally referred to as the “Fischer-Tropsch reaction”). GTL fuel is produced from coal and natural gas feed stocks, although new GTL plants planned and under construction will use natural gas. Other feed stocks including petroleum coke and biomass can also be used, but the technology is more costly and not commercially mature.

In neat form, GTL fuel is more expensive than conventional diesel fuel. But its superior fuel and emissions properties make GTL fuel ideal for blending with conventional diesel fuel. Tests in Europe show that GTL fuel blends between 30 to 50 percent substantially reduce emissions at comparable cost to conventional European diesel fuel. For California, the Energy Commission and the CARB found that blending 33 percent GTL fuel with 67 percent conventional US EPA diesel fuel produces a cost-competitive diesel fuel that can be used in existing engines that comply with the CARB’s strict diesel fuel specifications. It is worth noting that this blend is based on a retail diesel price of $1.84 per gallon. At the current average price above $3 per gallon, it is reasonable to expect that a higher percentage of GTL fuel could be used to produce a cost-competitive, CARB-compliant diesel fuel with even greater petroleum reduction benefits.

GTL fuel has occasionally been used as a blending component by California refineries. Expanding its use as a diesel fuel option requires addressing the feasibility of importing large quantities into California. Natural gas feedstock costs are generally more favorable overseas, so few if any GTL production plants are planned in the United States. As an imported product, GTL fuel would also face the same import facility constraints at the ports of Long Beach and Los Angeles now faced by imported crude and refined products.

Electricity

In 1990, the CARB adopted low-emission vehicle standards requiring automobile manufacturers to offer a minimum percentage of zero-emission vehicles (ZEV). It was thought that battery-operated electric vehicles would satisfy ZEV requirements, but the ZEV market did not develop as expected. The main barrier has been the slow pace of battery technology development. Persistent problems include limited range, slow charging time, low energy density, and high replacement costs. Recent advancements in lithium-ion battery technology, however, could significantly improve the performance of both full-electric and hybrid-electric vehicles. New generation lithium-ion batteries have a much longer life, can fully recharge in a few minutes, and provide greater power density.

Low-speed neighborhood electric vehicles (NEV) and city electric vehicles (CEV) are cost-effective alternatives to gasoline vehicles for short and stop-and-go trips. Whereas gasoline vehicle efficiency and performance drop significantly at slower speeds, and emissions are high under cold-start and stop-and-go conditions, NEVs and CEVs have been used with great success for several years for this purpose, and their strong performance has been virtually maintenance-free. NEVs and CEVs are highly maneuverable in tight conditions and produce no tailpipe emissions. Over 30,000 NEVs have been sold in the United States and Europe.

Another category of electric vehicle is non-road equipment — forklifts, airport ground support, and tow tractors, for example. Though this application reduces petroleum consumption, criteria pollutants, and greenhouse gas emissions, it unfortunately has no credit assigned under current state air emission reduction regulations or incentives.

Natural Gas

Natural gas is a completely non-petroleum fuel option. Natural gas is used in the form of compressed natural gas (CNG) and liquefied natural gas (LNG). Vehicles using compressed natural gas include both light-duty trucks and sedans and heavy-duty vehicles such as transit buses, street sweepers, and school buses. Liquefied natural gas is used also in heavy-duty vehicles such as refuse haulers, local delivery trucks, and transit buses. There are 365 CNG fueling stations and 29 LNG fueling stations in California, 40 percent of which are accessible by the public. None of these fueling stations are joint venture facilities with petroleum companies.

Natural gas vehicles have captured a small but significant share of the transportation market. Based on recent data from the California Department of Motor Vehicles, there are currently more than 30,000 natural gas vehicles on state roadways (5,000 heavy-duty vehicles and 25,000 light-duty vehicles). These vehicles displace 70 to 75 million gallons of petroleum fuel per year.[13] However, because Ford has stopped production of

[13] Mike Eaves, California Natural Gas Vehicle Coalition, “Natural Gas Vehicle Role in Fuel Diversity for California” presented at the Non-Petroleum Fuel Working Groups Conference, California Energy Commission, Sacramento, California, October 12, 2004.

its natural gas vehicles, it is unlikely that the number of light-duty natural gas vehicles in California will significantly increase. Today only General Motors and Honda include light-duty natural gas vehicles in the 2005 model year. Conversely, dozens of heavy-duty natural gas vehicles are available for order, but are constrained by a limited number of engine models. Heavy-duty CNG/LNG vehicles have been more expensive to purchase and operate than conventional diesel vehicles. At least one study, however, suggests that on a life-cycle basis, heavy-duty CNG/LNG vehicles are competitive with conventional diesel.[14]

Liquefied Petroleum Gas

While the number of liquefied petroleum gas (LPG) vehicles worldwide is 8 million and rising, the number of LPG vehicles in California is paradoxically decreasing. Today there is only one manufacturer with an engine certified for LPG operation, which is used mainly for shuttle buses and street sweepers. Outside California, several companies offer packages that convert a broad range of engines to LPG. However, California's certification procedure for conversions is costly, making it difficult for these companies to offer conversion packages in California markets.

Liquefied petroleum gas, or propane, is closer to gasoline than other alternative fuels.[15] LPG reduces vehicle maintenance costs, emissions, and fuel costs when compared with conventional gasoline and diesel.[16] Most propane in California is produced during the petroleum refining process, making it a domestic fuel source. Of the 1,500 LPG service stations in California, 900 are "motor vehicle friendly" and dispense LPG. LPG is also an attractive option for non-road vehicles like forklifts. There are 32,000 LPG forklifts in California though these vehicles face stiff competition from gasoline and electric forklift manufacturers.

Hydrogen

In April of 2004 the Governor signed an Executive Order intended to jump-start the use and operation of hydrogen-fueled vehicles in California. The Governor's Order, known as the Hydrogen Highways Network, calls for a public/private partnership that will, in his words:

> Support and catalyze a rapid transition to a clean, hydrogen transportation economy in California, thereby reducing our dependence on foreign oil, and protecting our citizens from health harms related to vehicle emissions.

---

[14] "Comparative Costs of 2010 Heavy-Duty Diesel and Natural Gas Technologies," final report, TIAX LLC, July 15 2005.
[15] [http://www.consumerenergycenter.org/transportation/afv/propane.html].
[16] "Propane as a Transportation Fuel," fact sheet, http://www.energy.ca.gov/2005publications/CEC-600-2005-015-FS/CEC-600-2005-015-FS.PDF, accessed August 8, 2005.

The Hydrogen Highway Blueprint Plan calls for a dramatic increase in the use of hydrogen-fueled vehicles and a network of hydrogen fueling stations and other infrastructure in three phases. The first phase calls for 50 to 100 fueling stations and 2,000 vehicles by 2010. It also promotes increased renewable resource use with a goal to use 20 percent renewable resources for both the energy source and feedstock used in hydrogen production by 2010.

Today, hydrogen is typically produced from natural gas, using steam methane for reforming. This feedstock is not easily produced from domestic sources in amounts that could support the amount of hydrogen needed for transportation use. Any reduction in petroleum imports could therefore very well be offset by a corresponding increase in natural gas imports.

With modifications, hydrogen can be used in both fuel cell vehicles and internal combustion engines (ICE). Hydrogen and natural gas blends could provide a logical transition to hydrogen-powered vehicles.

The most promising fuel cell under development for transportation fuel use is the Proton Exchange Membrane (PEM) fuel cell. The PEM fuel cell has high power density, operates at low temperatures, permits adjustable power output, and allows quick start-ups. Seven PEM fuel cell vehicles use gaseous or liquid hydrogen gas stored in tanks on the vehicles.

Fuel cell vehicles can use either direct hydrogen or on-board reformers using ethanol, methanol, or gasoline. Most available data addresses direct hydrogen (compressed or liquefied) use. This analysis focuses on this technology. However, it is possible that fuel cell vehicles using gasoline reformers will eventually be introduced. This would reap the benefits of both increased fuel economy and decreased emissions while still using existing gasoline fueling infrastructure. An additional benefit of fuel cell vehicle technology is the concept of a “skateboard” chassis with “snap-on” bodies. The possibility of an extremely compact all-electronic vehicle without mechanical parts could cut the cost of its production. The benefits of this fuel cell technology will be developed during its transition into the marketplace, expected between 2010 and 2020.

Increasing Vehicle Efficiency to Decrease Fuel Demand

Absent further regulatory action by the federal government to improve CAFE standards for passenger cars and light trucks, the state must take immediate steps to increase fuel efficiency and reduce fuel consumption in California. The state needs to urgently consider the following options.

Hybrid-Electric Vehicles

Hybrid-electric vehicles (HEVs) typically have almost double the fuel efficiency of average petroleum vehicles and overall lower tailpipe emissions.[17] The few hybrid models for sale by automakers carry a price premium of several thousand dollars above comparable gasoline models, although expected mass production will bring down their cost. There were only about 45,000 thousand hybrid vehicles on the road in 2004, out of a total state vehicle count of more than 26 million. [18] With average vehicle turnover at eight years for households and two and one-half years for business fleets,[19] influencing individual consumer preference may not be the most effective strategy to encourage their use. The rate of market penetration of hybrid vehicles could be accelerated by incenting or requiring public and private fleet owners to buy them. Public and private fleets in California currently have nearly 6,000 hybrid vehicles.[20]

Plug-In Hybrid-Electric Vehicles

Grid-connected, or plug-in, hybrid-electric vehicles (PHEV) use much of the same technology as current HEVs, but can also draw electricity from the grid to recharge their batteries. This gives the vehicles limited ability to travel long distances using electricity as their primary “fuel.” But when their all-electric range is exhausted, their petroleum-fueled HEV kicks in. Because 63 percent of consumer trips are fewer than 60 miles, a significant portion of PHEV use could be all-electric.

These vehicles offer optional connection to the grid for recharging, dramatically increasing range in all-electric mode. Drivers get the benefits of an electric car without the historic downside of limited range. While a hybrid vehicle gets about twice the fuel economy of a conventional car, a plug-in hybrid gets about twice the fuel economy of a hybrid.[21]

Light-Duty Diesels

Light-duty diesel (LDD) vehicles are cars, mini- and full-sized vans and small and full sized pickup trucks that use diesel fuel as opposed to gasoline. Today’s advanced LLDs offer turbo-charged high performance, high fuel economy and low emissions incomparable to past gasoline and diesel engines. These new LDDs provide 45 percent better fuel economy compared to the equivalent gasoline powered car. Consumer reaction where these cars are available is positive. Prior to 1998 diesel car sales in

---

[17] *California State Vehicle Fleet Fuel Efficiency Report, Volume II*, April 2004, CEC-600-03-004, http://www.energy.ca.gov/reports/2003-05-12_600-03-004-VOL2.PDF, accessed August 8, 2005.
[18] California Energy Commission, Joint Agency Department of Motor Vehicle Data Project, based on Department of Motor Vehicle’s October 1, 2004 Vehicle Registration Database.
[19] U.S. Department of Energy, Transportation Energy Data Book, Edition 24, Oak Ridge National Laboratory.
[20] California Energy Commission, Joint Agency Department of Motor Vehicle Data Project, based on Department of Motor Vehicle’s October 1, 2004 Vehicle Registration Database.
[21] [http://www.hybridcars.com/plugin-hybrids.html, accessed August 18, 2005].

Europe was typically 20 percent of the new automobile market. Since the introduction of LDDs in 1998, 48 percent of European new vehicles sales are LDDs. LDDs also offer higher torque (better response), and greater engine durability, that make them more attractive in California's market.

Due to California's stringent NOx emission standards limited LDDS were sold from 1998-2004 and no LDDs have been sold in California since 2004. LDDs cannot meet existing emission standards with the present high sulfur diesel fuels. Vehicle manufacturers have been working to meet the adopted emission standards and are demonstrating promising results. However, industry has not yet made a significant commitment to selling LDDs in America. In 2007, California will require ultra-low sulfur diesel fuel. With the availability of ultra-low sulfur diesel fuel, in combination with the advanced diesel engine technology, LDDs may succeed in meeting California's stringent NOx standards.

Issues that must be addressed to assist LDD market development include:

- Overcoming the initial higher purchase price (typically $1,000-$3,000 greater than the gasoline counterpart)
- Increasing the number of fueling stations with diesel fuel available for sale
- Industry will need to offer vehicle models acceptable to the consumer
- Consumer perception to a new fuel, technology and image

Expanded use of LDDs is important because the increased fuel economy could significantly relieve growing demand for gasoline fuels in California.
Increased use of diesel fuel increases refining capacity as a result of the improved refinery balance afforded from producing more diesel and less gasoline fuels.

Low-Rolling Resistance Tires

Tires that reduce road friction increase fuel economy. Studies show that a 10 percent reduction in rolling resistance can result in fuel savings of 1-2 percent.[22] Most automobile manufacturers routinely use low-rolling resistance tires on new vehicles to help meet federal fuel economy standards. In the replacement market, however, these tires are often available only by special order, and most consumers are unaware of either their benefits or their availability. About 237 million replacement tires are sold in the U.S. each year for passenger cars and light trucks, but none yet provide rolling resistance labels.[23]

[22] California Energy Commission, California State Fuel-Efficient Tire Program: Volume I - Summary of Findings and Recommendations, CEC-600-03-001F-VOL1, January 2003.
[23] http://www.greenseal.org/recommendations/CGR_tire_rollingresistance.pdf

Truck Anti-Idling

Many truckers idle their engines in order to operate heaters and air conditioners while they sleep in their trucks at truck stops. The CARB has adopted regulations limiting engine idling time to five minutes for school buses and trucks. The agency is considering applying the same standard to new heavy-duty vehicles. However, these regulations only apply in heavy traffic limiting their effectiveness.

One solution to idling truck engines is “electrification” of truck stops, which allows truckers to plug into heating, cooling and other services for an hourly fee. Another is “shore power,” which provides grid power for on-board electrical functions at truck stop parking places. A third option is an on-board auxiliary power unit, which typically is a small diesel-fueled generators mounted outside the cab that provides heat, air conditioning and electricity. Each of these offers significant emissions reduction and fuel savings possibilities, but also is limited by general knowledge within the industry and the required investments by the manufacturers, truck stop owners, or individual truckers.

Reducing Fuel Demand through Pricing Options

Mandating vehicle efficiency or substituting alternative fuels are not the only ways to reduce petroleum demand. Actions to increase travel cost can also reduce petroleum fuel demand.

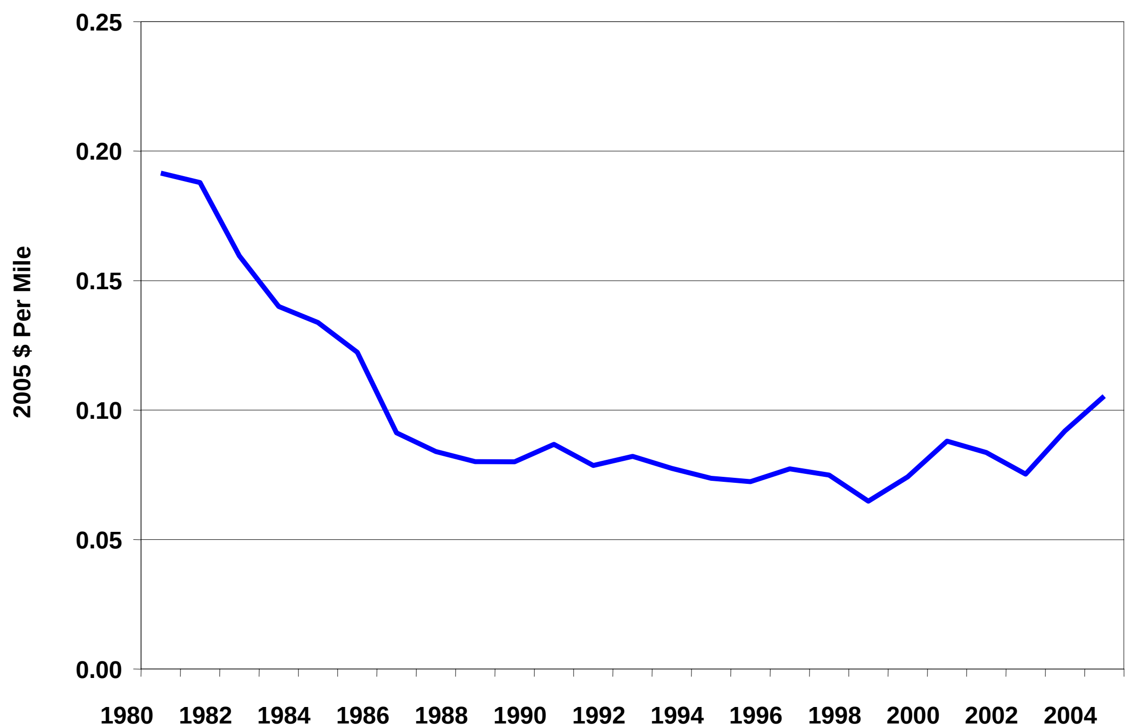
Gasoline has historically been a relatively inexpensive commodity in California. Since 1980, the real cost of gasoline has dropped by 40 percent while fleet-average fuel economy has nearly doubled. The average per-mile cost of gasoline is therefore actually less than half of what it was in 1980. This very likely has helped shape driving habits of California motorists and contributed to today’s increasing demand. It also helps explain why pricing measures may be effective in reducing demand. Figure 4 shows the average per-mile cost (in 2000 dollars) of operating a gasoline-powered light-duty vehicle from 1980 to 2004.

The Energy Commission has studied the costs and benefits of four pricing options:

- Fuel tax increase: Increasing fuel and diesel excise taxes by a dollar a gallon would almost certainly reduce travel and, over time, encourage consumers to buy more fuel-efficient vehicles. In order to be revenue neutral, other taxes would need to be identified for reduction.
- Per gallon fee for vehicle miles traveled: Replacing fuel excise taxes on a revenue neutral basis with a per gallon fee would increase the per-mile cost of driving and encourage consumers to travel less. However, this option would not provide sufficient incentive for consumers to buy more fuel-efficient vehicles unless set at a high level.

- “Feebate” for new light-duty vehicles: Applying a new vehicle variable fee or rebate pegged to the vehicle’s fuel efficiency or carbon emissions would encourage consumers to buy vehicles with greater fuel efficiency. Feebates would be revenue neutral.
- Pay-as-You-Drive automobile insurance: Instead of paying a fixed cost for auto insurance, a portion of its premium would be variable, depending upon miles traveled. When cost is directly tied to usage, consumers drive less and may choose to buy more fuel-efficient vehicles.

Figure 4: Average On-Road Gasoline Cost Per Mile California, 1980-2005



Pricing options are usually vilified as a “hidden tax increase,” and the Energy Commission recommends they be considered on a revenue neutral basis with compensating tax reductions to remove this onus. The focus should be on what activities government should tax, rather than crafting methods to increase government revenues.

At this point, all demand reduction, fuel switching, and pricing options should be on the table and receive further study. It is imperative that local, state and federal policy makers urgently make every effort to reduce fuel demand in today’s climate of rising demand, highly volatile prices, and heightened international competition for petroleum supplies.

Reducing Fuel Demand through Integrated Land Use Planning

Changing land use patterns to reduce miles traveled, air pollution, and fuel demand has been a topic of debate for at least a decade. To resolve this thorny issue, an information and policy bridge has to be built between regional transportation and city/county land use planning departments. Transportation plans typically account for regional growth in city and county general plans. Metropolitan planning organizations (MPOs) are caught in a Catch-22: they have the responsibility for transportation planning but lack the authority to authorize land use. Paradoxically, local governments do have land use authority but cannot directly affect fuel demand. The predictable result is today's urban sprawl. This stubborn and politically-charged disconnect, however difficult, must be addressed by policy makers.

The means to build this critical bridge exists: the Planning for Community Energy, Economic and Environmental Sustainability (PLACE3S) land use analysis methodology. This Energy Commission-supported methodology is the key analytical tool used by the Sacramento Area Council of Governments (SACOG) for BLUEPRINT, an award-winning regional transportation and land use planning program designed to resolve complicated growth issues in regions with 1.5 million or more people. Implementation of this plan would reduce vehicle miles traveled (VMT) by about 5.8 million per year while retaining almost $220 million a year in the regional economy (assuming a $2.45 per gallon petroleum price). Similar savings could be achieved throughout the state if each MPO embraced both the BLUEPRINT program and the PLACE3S technology. Because PLACE3S also addresses economic development, housing, infrastructure, open space and many other issues, the state would realize additional benefits in other areas while providing local governments with highly valuable and sought-after technical help.

Infrastructure for Transportation Fuels

California cannot meet rising fuel demand without a robust petroleum infrastructure including refineries, storage, pipelines, distribution terminals, and marine facilities. The Energy Commission noted constraints in parts of the state's petroleum infrastructure in the *2003 Energy Report,* particularly at marine facilities. These constraints will lead to supply problems, higher costs for both the industry and consumers, and prevent deliveries of critical fuel supplies during refinery outages or other disruptions.

Increased Infrastructure Needs

The state's petroleum infrastructure has improved slightly since 2003. The industry has committed to expansion of some elements of its infrastructure. In spite of these needed improvements, California must quickly expand marine terminal capacity, marine storage, and pipelines connecting marine facilities with refineries and pipelines in order to meet rising fuel demand. The most urgently needed marine terminal expansion and storage is in the Los Angeles (LA) Basin. Building these needed facilities faces stiff opposition on two fronts: available land is scarce, and local authorities do not recognize the urgency of the problem. The LA Basin's existing marine infrastructure could be further weakened by social pressure to remove the constrained facilities they already have in favor of container cargo facilities. New State Lands Commission standards for marine terminals known as the Marine Oil Terminal Engineering and Maintenance Standards (MOTEMS) could require substantial upgrades to a large percentage of the clean fuel receiving terminals primarily in Southern California. These upgrades are likely to require costly investments and could cause operational disruptions. It is possible that some companies may choose to close terminals rather than rehabilitate them to the new standards.

The LA Basin will need at least an additional 2.8 million barrels annually of marine storage and 46 million barrels of clean fuel marine terminal capacity by 2025.[24] Crude oil import capacity appears sufficient for the next 20 years. In the San Francisco Bay Area, marine clean fuels storage also appears sufficient for the next 20 years, but a clean fuels marine terminal capacity expansion of at least 11 million barrels a year is needed.[25] The Bay Area will also need additional crude oil marine terminal capacity equal to throughput of around 20 million barrels.[26]

Expected storage and throughput needs will more than double if the CARB's greenhouse gas regulations are overturned by the courts. The LA Basin will require additional storage of 7.3 million barrels and 99 million barrels of additional throughput per year. The Bay Area will require additional storage capacity of at least 700,000 barrels by 2025 and clean fuels marine capacity of at least 25 million barrels of throughput per year.[27]

Fast-growing demand for transportation fuel in Nevada, Arizona, and Baja California Norte could also have a significant effect on California's petroleum infrastructure. California supplies the bulk of Nevada and Arizona's transportation fuel, and demand in those rapidly growing regions is rising faster than it is in California. During 2004 alone, California delivered about 300,000 barrels of fuel per day to Nevada and Arizona.[28] If this demand grows just 3 percent per year over the next 10 years, the amount of fuel moving through California's petroleum marine terminals could easily double from today's level.

Recently announced pipeline expansion projects could relieve some of that pressure on California's infrastructure. Kinder Morgan Pipeline Company is expanding portions of its East Line, which is used to move petroleum from West Texas to Tucson and Phoenix. Completion of this expansion in the summer of 2006 will enable Texas-based refineries to send more fuel to Arizona.

---

[24] California Energy Commission, *An Assessment of Petroleum Infrastructure Needs, Staff Report,* April 2005, CEC-600-2005-009.
[25] Ibid.
[26] Ibid.
[27] Ibid.
[28] "California's Petroleum Infrastructure Needs," presentation by Gordon Schremp, May 16, 2005.

Permitting Issues

The *2003 Energy Report* identified inadequate permitting coordination among a potpourri of local, state, and federal agencies as a major barrier to infrastructure expansion. The Energy Commission therefore recommended that the state establish a one-stop permitting shop for refineries, import and storage facilities, and pipelines. The complexity of federal, state, and local agency permitting and planning processes reduces the petroleum industry's ability to build new facilities needed to meet California's growing petroleum demand. The fact that activities proceed with little or no input from the Energy Commission is a further disconnect. The Energy Commission needs to work hand-in-hand with federal and state agencies, cities, counties, and port and air districts to make sure their processes take into account the state's rising fuel demand and the critical need for new petroleum infrastructure.

Participants in the Energy Commission workshops agreed that the Energy Commission should work with the permitting agencies and the industry to develop "best practice" guidelines for local and state agencies to streamline and coordinate petroleum infrastructure permitting processes. The Energy Policy Act of 2005 grants US EPA similar authority to coordinate federal agency review of refinery applications and speed the concurrent review of applications with state agencies.[29]

The Energy Commission should initiate an effort to identify and develop permitting guidelines for petroleum infrastructure projects, including the following elements:

- Description of involved agencies and their interrelationships.
- Critical path permitting timelines.
- Information requirements.
- Standardized permitting timelines.
- Requirements for expedited permitting.
- Simplification of requirements.
- Concurrent and coordinated permit review.
- Procedures for categorical exemptions and ministerial permits.
- Streamlined appeal processes.

Air Quality Impacts

Over last 25 years emissions from the state's refineries have decreased, partially due to major improvements in refinery emission controls.[30] However, in 2002, refineries still accounted for about 5 percent of California's total greenhouse gas emissions. Refinery emissions come from a variety of sources, including process boilers and flares and so-

---

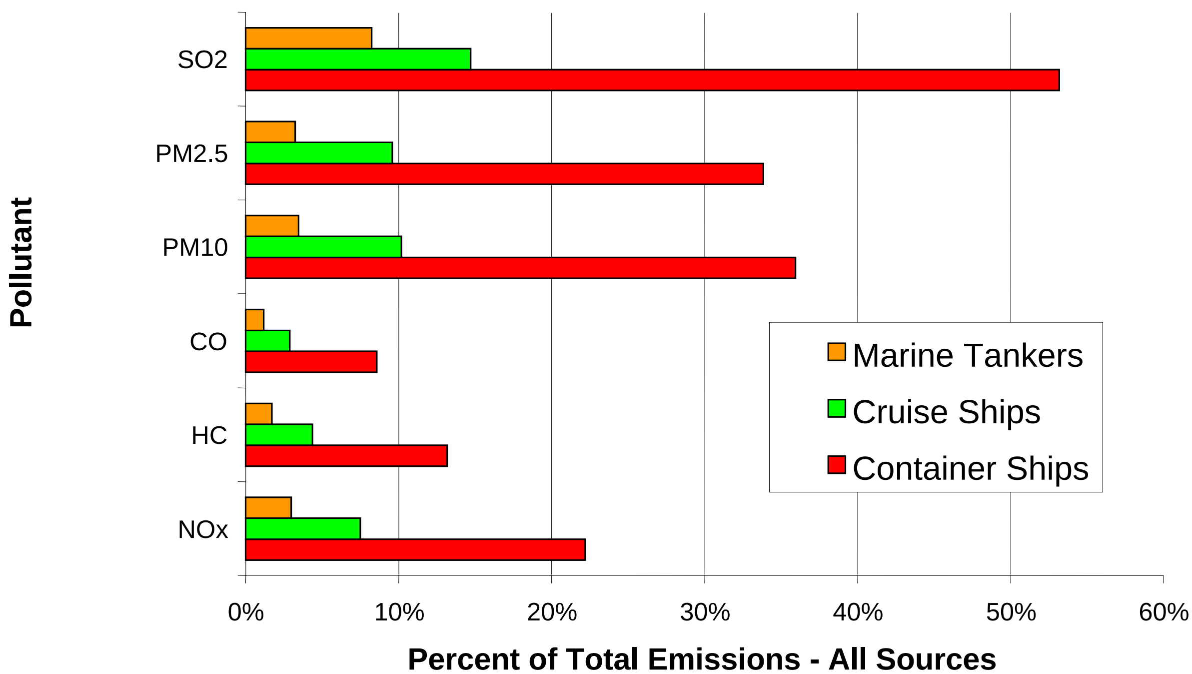
[29] Title III, Oil and Gas, Subtitle H, Refinery Revitalization.
[30] California Energy Commission, *Petroleum Infrastructure Environmental Performance Report*, June 2005, CEC-700-2005-012, page 43.

called “fugitive” emissions from small leaks in valves, pumps, tanks, pressure relief valves, and flanges.

Marine terminals generate high levels of pollution from diesel port equipment, truck and rail traffic, and largely unregulated marine vessels. Loading and unloading crude oil and petroleum products create fugitive emissions and emissions from diesel engines operated in the process. Fugitive emissions are also a concern at bulk storage facilities located at refineries, marine terminals, and stand-alone facilities. Most emissions from bulk storage facilities are from leaks and evaporation. Increased demand for refined petroleum products will require increased bulk storage, regardless of whether products are refined within California or imported through marine terminals. California may therefore need to strengthen current fugitive emission regulations to better control air pollution at these facilities.

Petroleum marine tankers in the Port of Los Angeles generate much less air pollution than other ocean-going vessels. According to a 2004 study, marine tankers generated between 1.2 and 8.2 percent of total air pollution in the Port of Los Angeles in 2001. Figure 5 shows relative air pollution contributions from the three main types of ocean-going vessels.

Figure 5: Emissions from Selected Ocean-Going Vessels Port of Los Angeles, 2001



Source: Starcrest Consulting Group, LLC, prepared for Port of Los Angeles, *Final Draft Port-Wide Baseline Air Emission Inventory 2001,* June 2004.

Given California’s rising thirst for petroleum, the state needs to frequently monitor emissions from its petroleum infrastructure. This is especially important since state and local agencies have little control over marine tanker emissions. More tanker traffic could exacerbate air pollution at California’s ports, but the projected increases in container ship cargoes are likely to be a far bigger emissions problem. Higher numbers of smaller tankers, in use because of port depth restrictions, could also increase emissions. This makes the timely and effective dredging and maintenance of shipping channels even more critical.

Dredging is an essential component of the safe passage of petroleum tankers into San Francisco Bay since two-thirds of the bay is shallower than 18 feet. Dredging in the bay has historically been done by the U.S. Army Corps of Engineers, the U.S. Navy, and private terminal operators. Through 2045, 80 percent of the dredging will still be done by the Army Corps and the Navy, but this task is dependent upon federal funding. Two critical dredging projects included in the Energy Policy Act of 2005 include:

- Annual Army Corps dredging of the Suisun Bay Channel to 35 feet ($5.132 million). This passage allows transport of crude oil and other bulk materials through the San Francisco Bay and Carquinez Strait to the Sacramento-San Joaquin Delta.
- Dredging the San Pablo Bay/Pinole Shoals/Mare Island Strait, a major sea artery for bulk cargo and oil tankers through the San Francisco Bay Area ($1 million).

Regular dredging in the San Francisco Bay is ongoing, with some refinery terminals requiring dredging several times a year. Agencies involved in permitting dredging include the Army Corps, US EPA, San Francisco Bay Conservation and Development Commission, San Francisco Bay Regional Water Quality Control Board, and the California Water Resources Control Board. These agencies established the Dredge Material Management Office to streamline multiple agency permitting of dredging and disposal of dredge materials using a single permit application reviewed concurrently by all agencies..

The Energy Commission should monitor the progress of dredging projects and either comment on or advocate for projects where needed to make sure that funding, permitting, and refinery access stay on track.

Environmental Justice Issues

Local communities close to oil refineries, port facilities, pipelines, and storage facilities believe that their communities bear an unfair share of the environmental, public health and safety risks of those facilities. They express concern over respiratory and other health problems from prolonged exposure to toxic, carcinogenic, and hazardous chemicals in addition to noise, traffic congestion, truck and train accidents, and upsets and accidents at the facilities. Local communities believe there is inadequate agency monitoring and reporting of refinery emissions, agency enforcement of permits, and public notification of accidents and other disruptions.

The Coalition for a Safe Environment represents many of these local communities and has called for a moratorium on continued operation or expansion of petroleum infrastructure facilities. Such a policy would be on a direct collision course with California's critical need to maintain and expand petroleum infrastructure to meet fast-growing state demand. Resolving this difficult and sensitive social conflict is essential to the health, welfare, and economy of California. The Energy Commission will continue to advocate for and support environmental justice initiatives and respond to public concerns about this issue by supporting and working closely with the following projects and organizations:

- The South Coast Air Quality Management District's environmental justice work plan and community initiatives including the Clean Air Congress, Clean School Bus Program, Asthma and Air Quality Consortium, Brain and Lung Tumor and Air Pollution Foundation, Neighborhood Environmental Justice Councils (all of which address specific air quality issues in targeted communities), the Multiple Air Toxics Exposure monitoring program, and investments earmarked to reduce toxic air pollutant levels in targeted communities.
- Support the Bay Area Air Quality Management District's expansion of its database of environmental justice stakeholders, work with community members on air quality publications, hold community meetings, and incorporate permit information on the District's website.
- The CARB's Environmental Justice Policies and Actions, which establishes a framework for incorporating environmental justice into its programs, research and data collection projects to reduce cumulative emissions, exposure, and health risks in all communities, especially low-income and minority communities.
- The joint Energy Commission/CARB project, using existing data and modeling results to create neighborhood maps of the health-related air quality effects of local emission sources, including oil refineries.

Increasing Energy Efficiency at Petroleum Refineries

California refineries currently operate at 98 percent capacity and use large volumes of electricity and natural gas to produce transportation fuels. Petroleum refining is the number one consumer of energy in California's manufacturing sector. Making sure that the state's refineries have reliable electricity is critical to meeting California's growing transportation fuel demand.

The petroleum refining industry is one of the largest users of cogeneration in the U.S. In 2001, U.S. refineries generated about 26 percent of their parasitic electricity, using a combination of refinery gas and petroleum coke produced on site and purchased natural gas. California refineries have an installed cogeneration capacity of about 1400 MW, and have the potential to increase their use of cogeneration technologies. Cogeneration at refineries improves the efficiency of natural gas use and helps insulate them from electric grid problems. In the event of a local electrical outage, refineries that can meet their own demand with on-site generation can also maintain production of vitally needed transportation fuels.

On the flip side, despite the clear benefits of cogeneration in providing on-site electricity and using process waste products for fuel, utility procurement issues and regulations limiting the export of surplus electricity continue to put a damper on cogeneration expansion at California's refineries.

Recommendations

Following the recent direction provided by the Governor, the Energy Commission will "take the lead in crafting a workable long-term plan by March 31, 2006, that will result in the significant reduction of gasoline and diesel use and increase the use of alternative fuels so that the State is working toward a set of realistic, achievable objectives with identifiable and measurable milestones." In preparing this long-term plan, the state should consider the following strategies:

- Establish flexible overarching policies to simultaneously reduce petroleum fuel use, increase fuel diversity and security, and reduce emissions of air pollution and greenhouse gases. Direct the state's energy, environmental, and transportation agencies to integrate statewide goals and policies in these three areas into their respective programs.
- Establish a Renewable Diesel Fuel Standard so that all diesel fuel sold in California contains up to 20 percent renewable content. The Energy Commission and the CARB also should conduct a study and prepare recommendations aimed at increasing the renewable content of fuel to greater than 20 percent.
- Expand the use of biodiesel fuels by: 1) conducting comprehensive tests to verify the emissions characteristics of biodiesel fuels in existing engines and their effectiveness when combined with particulate traps; 2) supporting research for development of after-treatment technology and fuel additives to improve the control of NOx emissions; 3) investigating the feasibility of requiring biodiesel fuel (B-20) in all state-owned diesel vehicles, partnering with other public and private fleets to create a market for biodiesel; and 4) working with engine and component manufactures to establish an acceptable biodiesel fuel standard that will preserve engine performance, durability, and warranties.
- Establish a California Renewable Gasoline Fuel Standard so that all gasoline sold in California contains a minimum of 10 percent renewable content.
- Establish a secure, long-term source of funding for a broad transportation program. Achieving the goals set out in this report and by the Governor requires the state to invest in a comprehensive transportation program providing not only infrastructure investment but funding for a broad range of technology and fuels research, analytical support, and incentive programs. Funding could come from a "public goods charge" either from refiners and distributors or at the retail pump on each gallon of gasoline and diesel sold.

- Continue working with other states to positively influence the federal government to double CAFE standards and amend Energy Policy Act fleet procurement requirements to include hybrid and other super-efficient gasoline and diesel vehicles.
- Establish a minimum fuel economy standard for the State of California's fleet of vehicles, doubling current federal standards for passenger cars and light trucks by 2009. Direct the Department of General Services to develop and implement a vehicle procurement process that achieves this standard. The California Energy Commission and Department of General Services should encourage local governments to adopt a minimum fuel economy standard and procurement process. The California Energy Commission should open a proceeding to investigate requiring that all public fleets adopt the minimum fuel economy standard and procurement process.
- Establish a procurement requirement for alternative fuels for the State of California's fleet of vehicles.
- Consider amendments to the Carl Moyer Program to include a criterion for petroleum reduction.
- Apply a "pollutant portfolio" approach for verifying alternative fuels under the CARB's programs. With this approach the total net reduction benefits across the entire suite of emissions, rather than a single focus on NOx reductions or increases, could be measured and used for comparison with non-petroleum fuels.
- Examine the feasibility of incorporating the emissions portfolio approach into the Predictive Model so that acceptance of a given fuel formulation is based more broadly on total emissions instead of solely upon its NOx contribution.
- Open a proceeding at the CPUC to investigate how investor-owned utilities can best develop the equipment and infrastructure to fuel electric and natural gas vehicles as required by Public Utilities Code Sections 740.3, 740.8, and 451.
- Establish a process to expand the use of E-85 in California by: 1) developing and certifying E-85-compatible fuel dispensing systems; 2) implementing a process to expedite the permitting of E-85 stations; 3) investigating the feasibility of requiring all or a portion of new cars sold in California to be FFVs; 4) establishing a collaborative state/industry working group to identify fuel infrastructure changes needed to increase production and distribution of E-85 gasoline and prepare a strategic/business plan to exploit opportunities to incorporate E-85 into the existing retail fueling system; 5) sponsoring a consumer notification and education program promoting the availability of FFVs and E-85 fuel; 6) evaluating incentive programs in other states to determine their applicability and usefulness for creating an E-85 retail infrastructure in California; and 7) supporting research for the development of technologies to convert biomass resources to ethanol.
- Sponsor consumer outreach and education programs on transportation energy choices, including a consumer education campaign on vehicle maintenance practices that maintain vehicle efficiency. Create an information clearinghouse on efficient alternative fuel choices for consumers, along the lines of an Internet shopping guide.

- Establish a strategic planning process with local governments and regional planning organizations to reduce transportation fuel consumption through improved public transportation and land use planning. Create a Center of Excellence for Regional Planning based upon the PLACE3S planning tool and provide technical assistance and training.
- Develop programs to: 1) reduce diesel idling including truck parking space electrification (at privately owned facilities and those owned by the California Department of Transportation), marine port electrification, airport electrification, and electric standby for truck and container refrigeration units; and 2) reduce diesel use in non-road vehicles including forklifts and other industrial vehicles. Closely coordinated these activities with other load management, energy efficiency, and greenhouse gas reduction programs.
- Establish a low-interest loan program funded through the California Pollution Control Authority or the California Alternative Energy Source and Advanced Transportation Funding Authority and administered by the Energy Commission to develop projects that reduce petroleum use and increase transportation fuel diversity.
- Encourage petroleum reduction in the off-road construction equipment market.
- Continue current work to explore establishing energy efficiency criteria and, if appropriate, efficiency standards for replacement vehicle tires.
- Establish incentive programs to influence consumer choice for more efficient transportation options such as pay-as-you-drive insurance and direct purchase incentives for fuel-efficient vehicles.
- Sponsor transportation technology and fuels research and development to: 1) expand the availability of engines and vehicles capable of using alternative fuels, new and retrofitted; 2); reduce engine and vehicle consumption of all fuels; 3) demonstrate alternative fuel engines and vehicles and improved efficiency technologies in on- and off-road applications; 4) and develop and demonstrate alternative fuel production technologies, emphasizing in-state resources.
- Continue to help to implement the California Hydrogen Highway Blueprint Plan, including: 1) use of renewable energy sources to produce hydrogen; 2) development of hydrogen fueling infrastructure and vehicular hydrogen technologies; and 3) use of “bridging technologies” that can accelerate the technological development of fuel cell vehicles while providing near-term emission reductions of greenhouse gases and other pollutants.
- Establish a state/industry working group to examine market opportunities and barriers to development and commercialization of hybrid-electric vehicles. Develop partnerships with original equipment manufacturers to demonstrate plug-in hybrid electric vehicles, assess consumer demand for these options, and support early incentives to reduce initial consumer cost.
- Work with the refinery industry and other agencies to identify opportunities for additional cogeneration to meet environmental goals. Work closely with electric utilities to resolve issues which currently prohibit or limit the sale of on-site cogeneration-generated electricity from refineries to outside customers.

Since gasoline and diesel will continue to be California's primary transportation fuels for the foreseeable future, it is critical to the state's economy that all reasonable measures be taken to ensure adequate supply as the state begins its transition away from petroleum dependence. The state should:

- Establish a committee led by the California Energy Commission, with the participation of the CARB, the State Lands Commission, Port Authorities for Long Beach and Los Angeles, and the South Coast Air Quality Management District. The committee should prepare and submit well-reasoned recommendations to the Governor and the Legislature that balance the statewide need for reliable supplies of petroleum, blending components, and refined products with local needs to manage port operations and achieve financial, environmental, and land use objectives.
- Confirm federal support to maintain safe shipping passage in San Francisco Bay.
- Establish a uniform decision-making process coordinating multi-agency review of infrastructure proposals, employing "best permitting practices."
- When infrastructure projects cross or conflict with jurisdictional boundaries, create an integrated process consolidating environmental review into a single process.
- Ensure that petroleum infrastructure permitting proceeds in a timely and environmentally sound manner.

CHAPTER 3: ELECTRICITY NEEDS AND PROCUREMENT POLICIES

Introduction

California's electric system, fueling the world's sixth largest economy, faces critical needs requiring swift and decisive action. State utilities and consumers alike face the specter of a precarious and fragile electric system where reserves are thin and unlikely to improve in the immediate future.

Following a period of flat to slow growth on the heels of the 2000-2001 crisis, California's demand is now growing, fueled by population growth and a rebounding economy. Coupled with increasing demand, the state's electric rates remain among the highest in the nation, with wholesale rates growing steadily from a low of $20 per megawatt hour (MWh) in late 2001 to around $50 per MWh today.

Although high rates remain a focus for the state, the challenge of ensuring adequate electricity supplies, especially during high-demand peak periods, has emerged as a critical issue over the past two years. The *2004 Energy Report Update* expressed serious concern over dangerously low reserve margins, especially in Southern California for the years 2005-2008, particularly when coupled with the prospect of aging power plant retirements.

Electricity supplies are not keeping up with demand. Construction of new power plants is not proceeding as planned, and the flow of new permit applications has noticeably decreased. Today California has over 7,000 MW of permitted power plants that have not moved into construction. Adding to the problem, investor-owned utility (IOU) procurement focuses primarily upon near- and mid-term contracts, which perpetuate reliance upon the existing fleet of aging power plants.

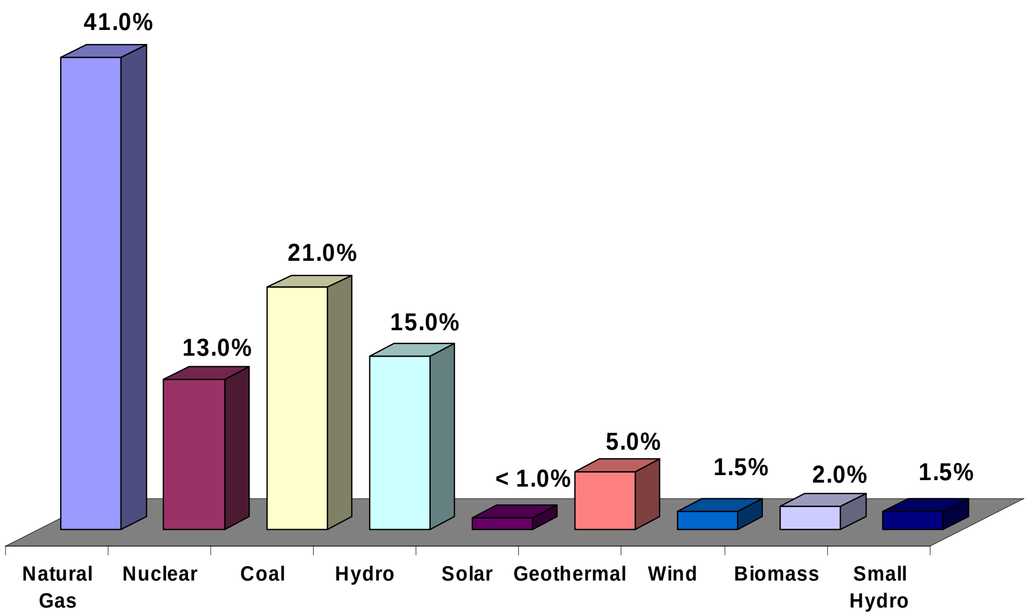
California's electric transmission system is rapidly becoming a costly energy bottleneck for consumers. Transmission-related reliability and congestion costs were more than $1 billion in 2004, up from $627 million in 2003. Transmission lines are frequently running to their capacity limits, forcing system operators to back down less costly generation to keep from overloading the system. In addition, transmission line outages caused rolling blackouts of roughly one half million customers in Southern California in August.

Local reliability is another casualty of the state's inadequate electric transmission system. Of special concern are the greater San Francisco Bay Area and San Diego regions, along with growing concerns over transmission capacity in the Los Angeles Basin. Without a modernized transmission grid, California's dependence upon aging, less efficient gas-fired plants to support local reliability and contribute to reserve margins will continue indefinitely.

Despite policy pronouncements to diversify California's electric supply, very little progress has been made. Current rate regulation and utility accounting regimes are indifferent to growing natural gas dependence because fuel costs are treated as a straight pass-through in electric rates. As a result, the state's dependence on natural gas for power generation grows unabated, from 30 percent in 1999 to 36 percent in 2002 to 42 percent in 2004.[31] Governor Schwarzenegger recently declared that increased diversity will provide for a more secure power base and help address future electricity supply and price concerns, urging a balanced portfolio of clean and diverse resources.[32]

In 2003, state policy makers initiated a transformational effort to curb demand and overcome the inertia that perpetuates the system's reliance on natural gas through identification of an investment "loading order." The loading order calls for optimizing energy efficiency and demand response, meeting new generation needs first with renewable resources and distributed generation then with clean fossil fuel generation, and improving the bulk transmission and distribution infrastructure.[33] Governor Schwarzenegger has embraced this loading order in California and has supported the specific recommendations to achieve its goals in the 2003 and 2004 *Energy Reports*.[34]

Figure 6: California's Diverse Supply, 2004



Source: California Energy Commission

[31] California Energy Commission, Net System Power Report for 1999, 2002, and 2004
[32] Letter from Governor Arnold Schwarzenegger to the Legislature, attachment: Review of Major *Integrated Energy Policy Report* Recommendations, August 23, 2005.
[33] California Energy Commission, CPUC and CPA *Energy Action Plan*, Spring 2003, p.4.
[34] Letter from Governor Arnold Schwarzenegger to CPUC President Mike Peevey, April 28, 2004 and Letter from Governor Arnold Schwarzenegger to the Legislature, attachment: Review of Major *Integrated Energy Policy Report* Recommendations, August 23, 2005.

Though the state's primary supply diversity strategy is the development of renewable resources, a lengthy and complex administrative and solicitation process hinders the state's ability to meet Renewable Portfolio Standard (RPS) targets. Similarly, distributed generation sources, especially combined heat and power facilities, have not received the focused regulatory attention necessary for their expanded development.

The following chapter outlines the California Energy Commission's (Energy Commission) assessment of electricity demand and supply trends, along with recommendations for IOU procurement. Chapter 4 outlines the steps the state must take to make sure that energy efficiency, demand response, and distributed generation goals are met. Renewable resource issues are examined in Chapter 5.

Electricity Demand

Electricity demand is measured in two ways: consumption and peak demand. Electricity consumption is the amount of electricity — measured in gigawatt-hours (GWh) — that consumers in the state actually use. Consumption is primarily a money question for consumers and businesses: how much am I being charged for and how much will it cost me? In contrast, peak demand — measured in megawatts (MW) — is the amount of generation needed to keep electrons flowing in the system and services provided at the moment of peak demand. Peak demand is primarily an operational issue for system operators — how much will be needed to keep the lights on under worst case conditions?

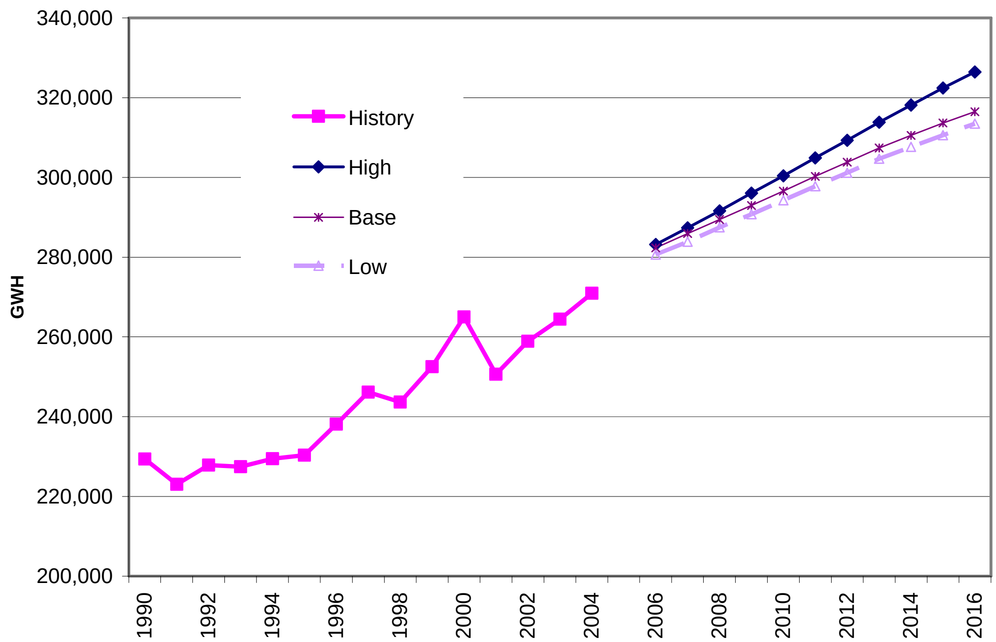
Electricity consumption in California grew from 250,641 GWh in 2001 to 270,927 GWh in 2004. The state's annual electricity consumption increased an average of 2 percent over the last two years, higher than forecast in the *2003 Energy Report*.[35] Consumption increased in all areas except the industrial sector, which remained relatively flat. Residential and commercial use increased an average of 4 percent over the same two-year period. Primary reasons for the increased growth include a shorter and milder recession than the 2003 forecast, along with diminished voluntary consumer conservation efforts from those achieved during the 2000-2001 electricity crisis.

Consumption is forecast to grow between 1.2 and 1.6 percent annually, from 264,424 GWh in 2003 to between 313,464 and 326,452 GWh by the end of the forecast period in 2016. Population is a key driver for residential consumption, commercial growth, demand for water pumping, and other services. The 2003 demand forecast assumed 1.4 percent population growth. The draft demand forecast for the *2005 Energy Report* projects consumption will be higher than in the 2003 forecast but the annual demand growth rate will be lower due to lower population forecasts from the Department of

[35] *California Energy Demand 2006-2016*, *Staff Energy Forecast*, June 2005, 400-2005-034-SD.

Finance (DOF).[36] The DOF forecast projects annual population growth at 1.2 percent and is based upon lower immigration and fertility assumptions than the 1998 DOF forecast. The highest consumption growth is forecast for the Sacramento Municipal Utility District (SMUD) control area and the Southern California portions of the California Independent System Operator (CA ISO) control area, reflecting strong population growth in those areas.

Figure 7: Statewide Electricity Consumption (1990-2016)



Source: California Energy Commission, revised staff demand forecast.

Another key driver of California's energy demand is personal income. The 2005 draft demand forecast used a 1.34 percent growth rate for per capita income, compared with 2.3 percent in the 2003 forecast, which projected a greater decline in personal income in the wake of the 2001 recession.[37]

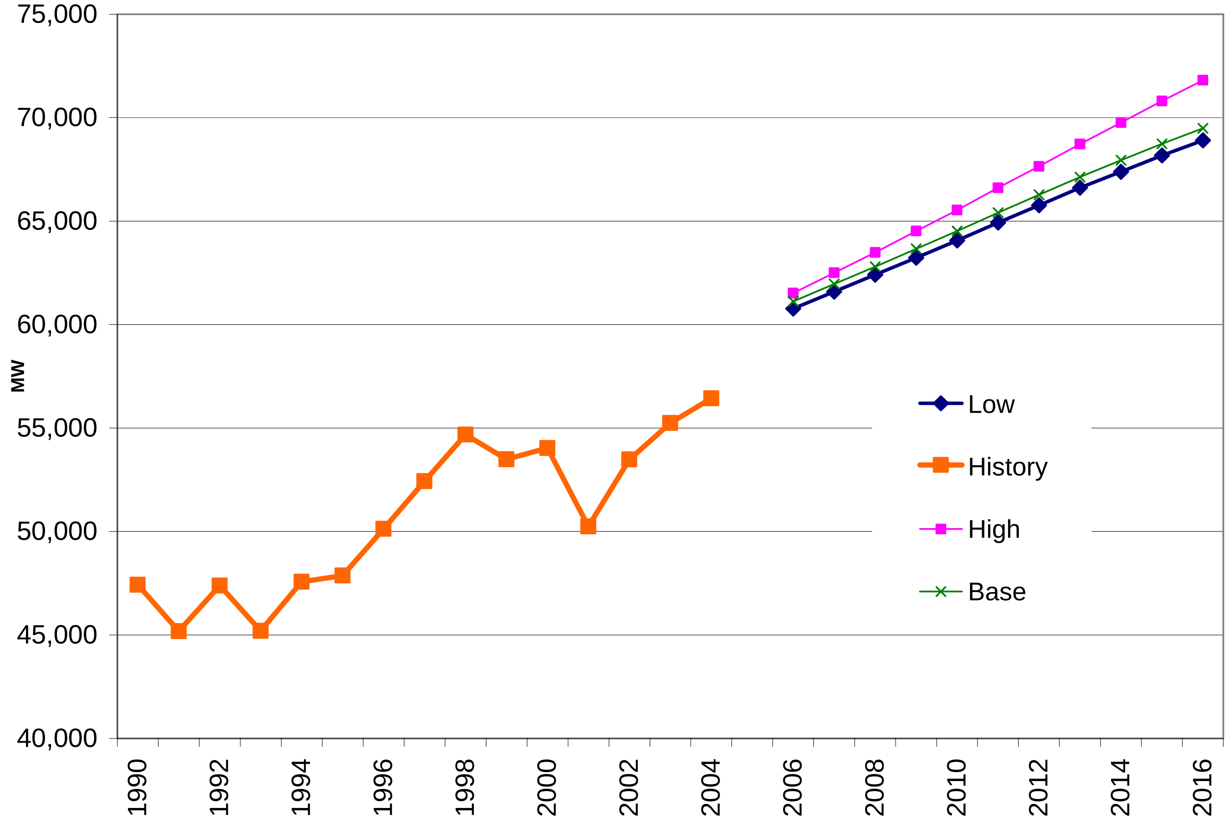
Statewide noncoincident peak demand reached 56,914 MW in 2004, up from 50,245 in 2001. Peak demand in California is forecast to grow between 1.7 and 2 percent, rising from 55,247 MW in 2003 to between 68,906 and 71,813 MW in 2016. On the peak demand side, the 2003 recorded peak was 3.6 percent higher than forecast, a

[36] State of California, Department of Finance, *Population Projections by Race/Ethnicity for California and its Counties 2000–2050,* Sacramento, California, May 2004. These population projections were prepared under the mandate of Government Code, Sections 13073 and 13073.5. In addition, the State Administrative Manual, Section 1100 on state plans, sets the general policy of …"(3) The use of the same population projections and demographic data that is provided by the State's Demographic Research Unit."

[37] The 2003 demand forecast was based on the September 2002. UCLA Anderson School of Business forecast, while the 2006 draft demand forecast relied on the December 2004 Economy.com forecast.

difference of almost 2,000 MW, or the approximate capacity of three of the state's largest fossil-fueled generators. The 2005 draft demand forecast uses this higher peak demand as its starting point. Over the ten-year forecast period, peak demand grows slightly faster than the 2003 demand forecast, primarily due to reduced peak demand expected from the 2005 federal air conditioning appliance standard.[38]

Figure 8: Statewide Peak Demand (1990-2016)



Source: California Energy Commission, revised staff demand forecast.

One of the difficulties in using long-term forecasts is that they are designed to project a growth rate in consumption and peak for use in the later years of the ten-year forecast. Estimating how much demand will actually grow in any given year in the forecast period requires adjusting for weather, which is extremely variable across the state. Given the unpredictability of weather, the actual consumption and peak, especially in the early years of the forecast, will almost always vary from the forecasted amount.

Given that California covers a large geographical area, with many diverse climates, adjusting the forecast demand data for weather on a statewide basis is difficult.

[38] Staff 2005 demand forecast reduced the peak savings assumed in the 2003 demand forecast based on analysis indicating that the move to the Seasonal Energy Efficiency Ratio (SEER) in the 2005 federal air conditioner standard will actually reduce peak demand.

Northern California usually has its hottest temperatures in July and August while Southern California usually has its hottest temperatures in late August and September.[39] Total statewide peak will be different when the temperature in San Jose is 95 and Burbank is 75 than when those temperatures are reversed, even though the average temperature is the same. It is much easier to adjust demand data for weather within planning areas because there is less geographical diversity.

A cornerstone of the Energy Commission's demand forecast is the reporting of electricity sales by economic sector for each retail electricity seller in the state. Since restructuring, unclassified sales — sales not identified by economic sector — have become the fastest growing category of consumption. For forecasting purposes, these sales must then be allocated to the various sectors, with improper allocation causing forecast errors. For example, because commercial and industrial customers have markedly different load shapes, assigning usage to the wrong customer class could result in a forecast of system peak that is either too high or low, with a possible difference of over 1,000 MW. The Energy Commission, in concert with the state's utilities, must continue efforts to address these unclassified sales discrepancies.

At the demand forecast hearing, participants identified several key uncertainties driving the differences between staff and utility forecasts, such as trends in commercial energy use and residential demographics, as well as currency of data. Staff forecast decreasing commercial electricity use per square foot, reflecting the effects of building and appliance standards, which most participants thought unlikely. In the residential sector, the utility forecasts generally assumed more growth in income and households than the staff forecast.

In response, the Integrated Energy Policy Report Committee directed staff to vary these key assumptions to develop a reasonable range of possible outcomes. The forecast ranges will also use more recent consumption data and new information on population and income. The resulting forecasts will be used in the *2005 Transmittal Report* to the California Public Utilities Commission (CPUC).

Another issue was the treatment of energy efficiency savings from IOU programs planned after 2008. The three IOUs included those impacts in their electricity demand forecasts. The Committee forecasts do not because the amount of these impacts is dependent upon future CPUC decisions that may modify the energy efficiency targets before approving funding for post-2008 programs.

Growing "Peakiness" in Demand

Electricity demand in California increases most dramatically in the summer with high air conditioning loads. The generation system must be able to accommodate these high

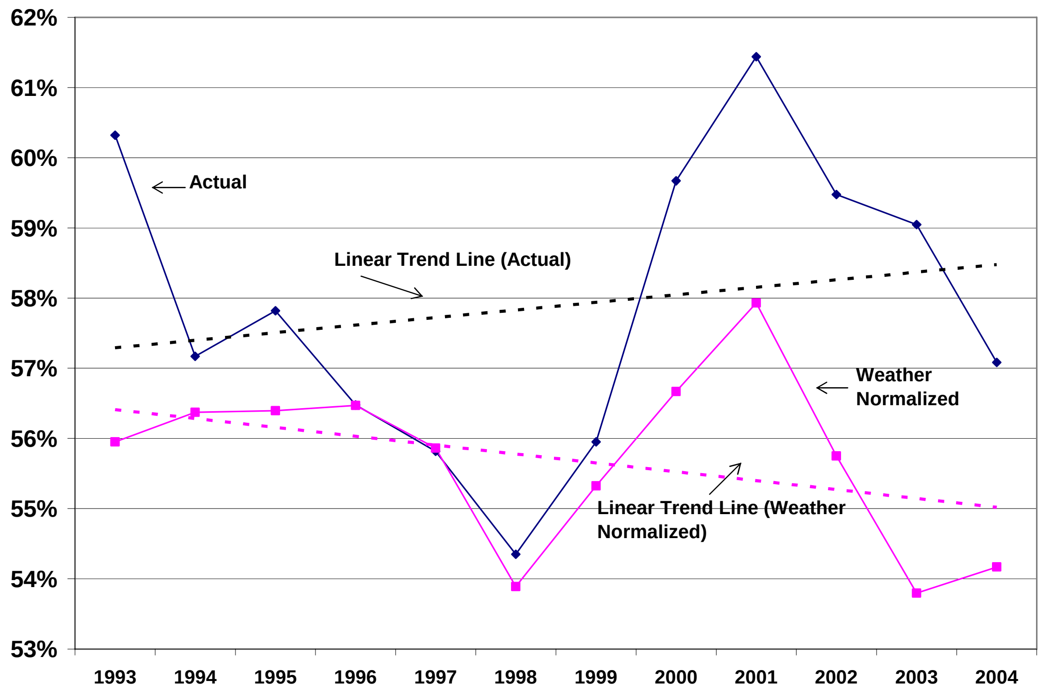
[39] The timing of peak is based on historical data. This year, it appears that Los Angeles Department of Water and Power had its peak much earlier in the summer in July, demonstrating the difficulty of predicting weather with any precision.

summer peaks in addition to demand swings caused by weather variability and the economy. Though peak demand periods typically occur only between 50-100 hours a year, they impose huge burdens on the electric system.

One measure of the "peakiness" of the electric system is load factor, which measures the relationship between annual peak in MW to annual consumption in MWh. If peak demand grows faster than the annual average consumption, the load factor decreases. As shown in Figure 9, weather-adjusted load factors in recent years have decreased as air conditioner loads increased.

Figure 9: Statewide Annual Weather-Adjusted Load Factors

(Based on sum of hourly load data for PG&E, SCE, SDG&E, SMUD and LADWP)*



Source: California Energy Commission.
* Pacific Gas & Electric, Southern California Edison, San Diego Gas and Electric, Sacramento Municipal Utility District, and Los Angeles Department of Water and Power.

One problem with meeting peak demand is that most new gas-fired power plants are combined-cycle units designed to run at high load factors where they are most efficient and can generate enough revenue to recoup investments. Combined-cycle plants also have less capability to ramp up and down to meet peak demand than the older steam boiler units which make up the majority of California's fleet of aging power plants. While some utilities have invested in simple-cycle peaking plants that run just a few hours each year, virtually all of the state's new power plants are combined-cycle and are not well matched to swings in system demand. California must quickly and thoughtfully craft solutions for meeting its increasingly "peaky" demand.

Electricity Supply

Though the Energy Commission has certified and approved construction for 22,386 MW of capacity since deregulation was implemented in 1998, only 13,091 MW have actually come on line. [40] Meanwhile, statewide electric loads increased an average 2 percent per year over the last two years.[41] Since November 2003 alone, the Energy Commission has permitted 11 power plants totaling 5,750 MW of capacity, primarily natural gas fired. However, California has 7,318 MW of approved power plant projects that have no current plans to begin construction because they lack the necessary power purchase agreements to secure financing.

Table 2: California's New Generation and Power Plant Applications

Year	New MW on Line[a]	New Power Plant Applications (MW)	Number of Plants
1995	266.5	--	0 (no filings)
1996	240	--	0 (no filings)
1997	329	1,370	2
1998	--	3,151	5
1999	--	5,470	9 [c]
2000	--	5,740	17
2001	2,604	12,459	42 (15 peakers)
2002	3,276	1,137	4
2003	5,030	492	4
2004	61	401	3
2005	2,140	2,060	5
2006	2,552 [b]	--	--
2007	153 [b]	--	--
2008	1,401 [b]	--	--
2009	--	--	--
2010	--	--	--

[a] Siting Case History Database, 1995-2000, including only Energy Commission permitted plants more than 50 MW
[b] High Probability
[c] Application for Morro Bay repower project (530 MW submitted in 1999 and withdrawn the same year. A second application was resubmitted for 1,200 MW in October 2000.

Local agencies outside the Energy Commission's jurisdiction have also permitted 34 power plants totaling nearly 2,000 MW of capacity since November 2003. These plants are also primarily natural gas-fired, though renewable fuels make up about 30 percent. Twenty-two of these 34 permitted plants, totaling 1,200 MW, are operating, and the remainder are under construction. A total of 225 MW of wind capacity has also been added since 2003.

[40] California Energy Commission, 2004 Database of California Power Plants.
[41] *California Energy Demand 2006-2016, Staff Energy Forecast*, June 2005, 400-2005-034-SD.

In addition, needed transmission upgrades have lagged and congestion has increased in certain areas of the CA ISO control area. In 2004, 850 MW of capacity was mothballed, meaning operations are shutting down as the units are prepared for long-term storage.

The Energy Commission is concerned about local reliability in the San Francisco Bay Area and San Diego regions. In San Francisco, additional transmission capacity is needed to reduce Reliability Must Run (RMR) costs and allow shutdown of the city's aging power plants. Several proposed transmission projects would allow San Francisco and the Northern Peninsula to reliably meet loads through 2011, while allowing the shutdown of the Hunters Point and possibly the Potrero power plants. In San Diego, the majority of load is served by heavily congested transmission lines, which cannot alone meet this region's reliability needs by 2010. New transmission is urgently needed to meet increasing demand fueled by rapid population growth in the area. Two natural gas combined-cycle power plants are under construction in the San Diego area and will help ease San Diego's need for electricity. The Palomar Escondido Energy Project and the Otay Mesa Power Plant Project will together add more than 1,000 MW of capacity.[42] These plants are scheduled to be on line in 2006 and 2008, respectively.

By June 1, 2006, the CPUC will require that the state's IOUs maintain 15-17 percent planning reserve margins. However, projections indicate that in a one-in-ten case, even 15-17 percent reserve margins might not be enough to maintain system reliability in Southern California due to transmission constraints.[43] Unanticipated events like sustained periods of extreme hot weather or unplanned power plant and transmission outages could cause reserve margins to dip perilously low.

While sufficient generation may be available in aggregate, transmission and local reliability constraints may mean the generation cannot be delivered to where it is needed. This issue of deliverability is currently being addressed in a CPUC proceeding. The CA ISO has released a three-part deliverability assessment, including: 1) Deliverability of Generation to Aggregate Load; 2) Deliverability of Imports; and 3) Deliverability to Load (Local Area Capacity).[44] For the third part addressing deliverability to load, the CA ISO has identified that 25,044 MW of local generation is needed (in local reliability areas) for the CA ISO to reliably operate the grid.

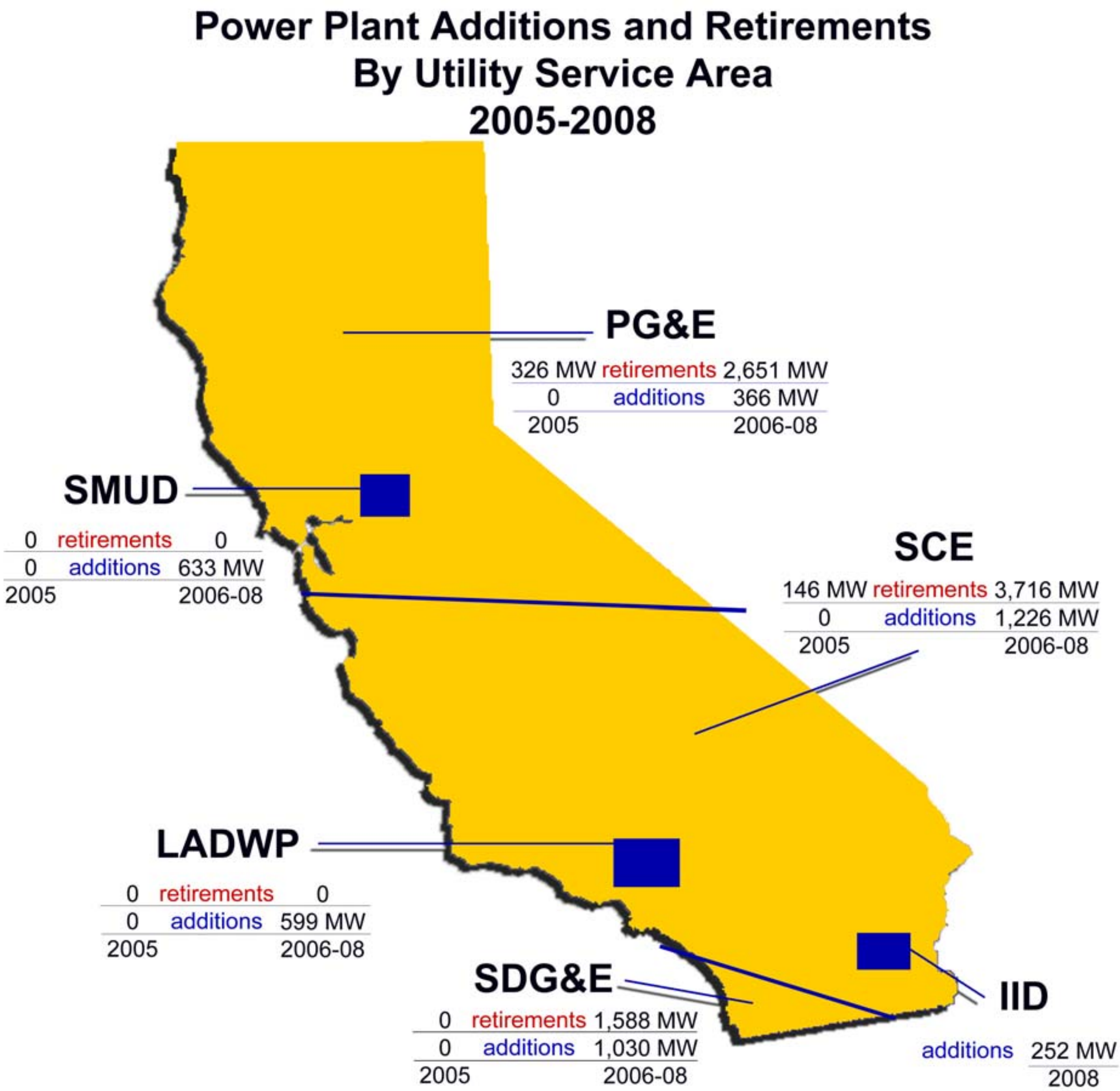
California's ability to maintain minimum reserve margins over the next five years will be largely determined by its ability to reduce demand, secure the resources to meet increased load, and offset capacity losses from the potential retirement of aging power plants, especially in Southern California. A key element of this challenge is relieving transmission bottlenecks to create a more resilient electricity grid.

---

[42] California Energy Commission, 2004 Database of California Power Plants.
[43] Presentation by David Ashuckian, Joint Agency Energy Action Plan Meeting, June 15, 2005, http://www.energy.ca.gov/energy_action_plan/meetings/2005-06-15_meeting/2005-06-15_ASHUCKIAN.PDF, accessed September 12, 2005.
[44] CA ISO presentations on deliverability, June 29, 2005

California will continue to rely heavily upon imported electricity from both the Southwest and Northwest. Surplus electricity from the Southwest has been California's main source of imported power in recent years, but that region's explosive growth could absorb future surpluses. The Northwest will continue to have a large surplus of electric capacity available for export to California and the Southwest in the summer, but a portion of this capacity will be stranded in the Northwest because of limited transmission access into California.

Figure 10



By 2016, California's utilities will need to procure approximately 24,000 MW of peak resources to replace expiring contracts, replace retiring power plants, and meet peak demand growth.[45] This megawatt total would serve retail loads, maintain a 15 percent reserve, and satisfy firm sales requirements.

Approximately 11,000 MW of Department of Water Resources (DWR) contracts will expire between 2009 and 2011 and another 9,000 MW of other contracts are expected to expire by 2016. During this same period, load is anticipated to grow by about 4,000 MW. The expiring contracts are comprised of a range of old and new power plants, and not all of the contracts are unit specific. To the extent that the utilities replace these contracts with long-term commitments to modern, clean and efficient projects, including renewables, efficiency, and demand response, the next ten years offer a major opportunity for the state to modernize and transform its electric generation supply mix.

Resource Adequacy Requirements

In 2005, the CPUC adopted a broad framework for resource adequacy that requires retail sellers, including IOUs and energy service providers, to meet a year-round planning reserve.[46] Under the adopted framework, each retail electricity seller must demonstrate that it has acquired sufficient resources to meet its expected peak load plus a 15 percent planning reserve.[47]

Commitments to meet 90 percent of load must be demonstrated one year ahead, while the remaining 10 percent must be demonstrated one month ahead. These resources must be made available to the CA ISO to provide reserve support if they are not already scheduled. Consistent with direction from Governor Schwarzenegger, these requirements become effective starting in June 2006.

The CPUC, in collaboration with the Energy Commission, has been working during 2005 to flesh out the adopted resource adequacy framework. Numerous workshops held between November 2004 and May 2005 resulted in a large workshop report. After receiving comments and reply comments, the inter-agency team is now working to develop a proposed decision scheduled for release in late September of this year.

The comments received cover a wide range of views and reveal the conflicting goals of the different stakeholders in trying to shape the details of a permanent resource adequacy requirement. In general, generators seek long-term contracts that provide all of the necessary revenue to cover going-forward fixed costs. Retail sellers prefer development of a future capacity market that allows customers to shop around among the various retail sellers with minimal financial consequences for the retail seller they leave. The CA ISO’s primary concern is ensuring that local area reliability needs, under a large range of contingencies, are covered. Not all of these objectives can be satisfied

[45] California Energy Commission, *Staff Draft Statewide Electricity Report*, July 2005.
[46] The resource adequacy requirement will be phased in starting in 2006 with full compliance by 2008.
[47] These load serving entities include the investor-owned utilities, electricity service providers registered by the CPUC, and community choice aggregators that may form pursuant to Assembly Bill 117.

in the first generation of resource adequacy requirements. To meet the June 2006 schedule and address near-term reliability concerns, some interim version must be adopted and implemented and then modified through time to improve performance.

The Energy Commission is collaborating with the CPUC and CA ISO in the review of annual compliance filings to ensure retail sellers are accurately covering approved load forecasts. The Energy Commission is assisting the CPUC by reviewing retail sellers' load forecasts and making adjustments to account for the impacts of coincident peaks, energy efficiency, demand response, and distributed generation programs that affect all customers.

A key element of resource procurement and resource adequacy is harmonizing deliverability requirements being developed at the CPUC with a new CA ISO transmission planning process.

The CPUC and the Energy Commission are making progress in establishing the one-year obligations for resource adequacy and in beginning to create a capacity market to provide flexibility in meeting resource adequacy requirements consistent with previous *Energy Report* recommendations. Although these efforts are useful to place a value on existing capacity, they are unlikely to economically induce construction of new power plants.

In previous *Energy Reports*, the Energy Commission has recommended that the Legislature establish comparable resource adequacy requirements for all retail sellers in the state including publicly owned utilities. These municipal utilities are an integral part of the state's electricity grid and as such should be providing sufficient resources and reserves to cover their own loads and contribute to statewide needs during system emergencies.[48]

Governor Schwarzenegger's recent response to the 2003 and 2004 *Energy Reports* endorsed the Energy Commission's recommendations to establish applicable resource adequacy requirements for all retail sellers in the state. The Energy Commission recommends that state policy makers provide a clear signal that all publicly owned utilities take on an explicit resource adequacy requirement.

IOU Resource Procurement

In 2004 and 2005 the CPUC approved IOU long-term procurement plans and a framework requiring load serving entities (LSEs) to maintain year-round reserve margins of 15-17 percent.[49]

[48] A review of publicly owned utilities with peak loads greater than 200 MW during this *Energy Report* proceeding discovered that some municipal utilities do not have sufficient resources to cover their peak loads plus a 15 percent planning reserve margin.
[49] The resource adequacy requirement will be phased in starting in 2006 with full compliance by 2008.

Each of the utilities has completed agreements to acquire power plants or purchase power from new facilities, including some that were outside a formal solicitation process. The following are publicly disclosed highlights of some of these agreements:

- Southern California Edison (SCE) signed a power purchase agreement with an affiliate company for the 1,054 MW Mountain View project in a one-on-one negotiated agreement approved by the CPUC.
- San Diego Gas and Electric (SDG&E) acquired two turn-key projects, the 550 MW Palomar project and the 45 MW Ramco project, and signed a power purchase agreement with the 570 MW Otay Mesa project under their 2003 grid reliability request for offers.
- Pacific Gas and Electric (PG&E) acquired the rights to construct the partially completed 530 MW Contra Costa 8 project as part of the Mirant settlement of claims from the 2000-2001 crisis.

In addition to the resources mentioned above, the three utilities have, to date, signed about 80 contracts for power deliveries beginning in 2004 or later. Of these, about 50 contracts have terms of one to three years; 10 contracts, of three to five years; and 20 contracts, of five years or longer. The total amount of contract (not dependable) capacity from these contracts is about 9,000 MW for the one-to-three year contracts, about 1,500 MW for the three-to-five year contracts, and about 2,000 MW for the five year-plus contracts.[50]

Over the last year, the Energy Commission and the CPUC have worked hard to better integrate the *2005 Energy Report* proceeding with the CPUC's upcoming 2006 IOU procurement proceeding through a number of rulings and orders. The two agencies established the *Energy Report* process as the primary forum for considering load forecasting, resource assessment, and scenario issues connected with the upcoming 2006 procurement proceeding. The rulings and orders require the Energy Commission to prepare a Transmittal Report, companion to the *2005 Energy Report*, to identify a likely range of statewide and IOU-specific needs, issues relevant to these needs, and responses to participant comments.

To help evaluate electricity demand and supply, in 2004 the Energy Commission directed LSEs with peak demands over 200 MW to file retail price forecasts, demand forecasts, resource plans, and related materials. PG&E, SCE, and SDG&E were asked to file a number of "resource plans" identifying their forecasted electricity peak demand, their energy requirements, and explanations as to how they plan to meet those requirements under a variety of contingencies.

These resource plans included anticipated savings from energy efficiency and demand response programs, assumed a 15 percent planning reserve margin, and included needs to meet the RPS goal of 20 percent renewable generation by 2010. While these

[50] These results include contracts that result from both Request for Offers and bilateral agreements.

resource plans generally reflect the loading order resource preferences and targets, they do not show what specific resources IOUs will actually procure. This will depend upon what projects are bid into the all-source solicitations and how well they meet the least-cost, best-fit selection criteria of the IOUs.

The 2005 Transmittal Report to the CPUC will provide the detailed basis for the Energy Commission's recommendations to the CPUC on the range of need and procurement policies for the IOUs to be addressed in the 2006 long-term procurement proceeding. The Energy Commission will release a draft Transmittal Report, conduct hearings, and adopt a final Transmittal Report in November 2005.

Confidentiality in Resource Planning and Procurement

One of the most troubling aspects of IOU resource planning and procurement is the IOU claim that resource planning data are confidential. This confidentiality issue sparked much discussion and debate in the *2005 Energy Report* proceeding and resulted in a lawsuit by SCE to prevent the Energy Commission from releasing bundled customer annual peak demand data.[51]

For the last several years, the CPUC's resource planning process has been shrouded with a significant degree of secrecy, with only a few individuals allowed to review and critique the data submitted by IOUs. While some "non-market" participants in the CPUC's resource procurement proceeding are allowed to review the data through non-disclosure agreements and protective orders, most other parties do not have access to the data. As a result, open public debate about the data, assumptions, and alternatives forming the basis of IOU resource planning decisions has been severely truncated. The Energy Commission strongly believes that this environment of secrecy undermines public confidence in regulatory decisions.[52]

Energy Commission staff has been allowed access to CPUC confidential IOU data upon signing non-disclosure agreements and participating in procurement review groups (PRGs). This practice is deeply troubling to Energy Commissioners since staff is effectively precluded from discussing resource procurement specifics with them. When Energy Commissioners are called upon to conduct demand forecasting and resource planning as critical inputs for IOU resource procurement, they are not privy to the details of utility solicitation processes, the application of least-cost, best-fit criteria that led to the selection of some bids over others, or the terms and conditions of those contracts.

[51] Bundled customers are those customers for which a utility provides both electricity and electricity distribution services, as opposed to customers who use their distribution service, but who buy their electricity from another retail seller.
[52] Policy comments re: R.01-10-024: ALJ's Ruling Regarding Confidentiality of Information and Effective Public Participation, signed by William J. Keese, Chairman, California Energy Commission, April 16, 2003.

In the case of RPS procurement, for example, Energy Commissioners ultimately make decisions about expenditure of supplemental energy payments (SEPs), essentially awards of public funds, to renewable project developers. Under current confidentiality constraints, Commissioners are not able to review or scrutinize detailed information about IOU RPS solicitations, the application of least-cost, best-fit criteria, the terms and conditions of the full range of bids considered, and the contracts ultimately forwarded to the CPUC for approval. It is difficult to see how Commissioners can effectively ensure that public funds contribute to the state's RPS goals or constitute an appropriate expenditure of limited subsidy funds for renewable resource development in this secretive environment.

For purposes of policy making for resource planning in the *2005 Energy Report* proceeding, relying upon information that is not publicly available hinders the Energy Commission's accountability to the public, the Legislature, and the Governor. If the Energy Commission cannot discuss the information that is the basis of its resource planning decisions, it damages its ability to be responsive to those with the right to understand those decisions.

The Energy Commission investigated the information sharing practices of other utilities in the West as part of its regulatory process to ensure release of at least aggregated summaries of this critical information.[53] All of the major western IOUs publicize as much or more demand forecast and resource plan information as the California IOUs wish to withhold from public scrutiny. Many of these utilities publish results at a much more disaggregated level.

California IOUs claim that unique conditions in the state justify their desire to withhold planning information from the public. The Energy Commission investigated this claim and found it without merit. Using several measures — the percentage of bilateral contracts of total resources entered into voluntarily, percentage of hydroelectric generation resources out of total resources, and the possibility of loss of load from competing suppliers — the Energy Commission found no correlation between these measures and utility information disclosure practices for western utilities.[54]

The measures listed above quantify uncertainties that affect the exposure of the IOU to the short term and contract purchase markets. The first measure evaluates the dependence of the IOU on intermediate term market purchases. The second measure evaluates the sudden changes that might occur if hydroelectric generation was better or worse than average. The third measures the possibility that load could disappear and leave the IOU with an excess of resources that would have to be sold into the market. Based on the Energy Commission's investigation, the notion that California IOUs are in some way different from other western utilities is unfounded.

[53] California Energy Commission Docket 04-IEP-1, Direct Testimony of Michael R. Jaske, July 8, 2005, pp. 4-6 and Table 2.
[54] California Energy Commission Docket 04-IEP-1, Rebuttal Testimony of California Energy Commission Staff, August 12, 2005, Attachment C.

The Energy Commission believes that public disclosure of demand forecasts and resource plans, in both energy and capacity terms, is critical to a sound, transparent planning process responsive to the public it serves. Greater disclosure is warranted for California IOUs in light of their size and the regulatory protection they enjoy as regulated monopolies. A more open environment is also consistent with the Public Records Act, which is designed to ensure the accountability of government to the public. It is broadly worded in favor of open access, and exceptions are narrowly defined.

The Energy Commission is committed to the rigorous public scrutiny of data and planning assumptions and believes that responsible and effective resource planning should not and cannot exclude the public. The 2005 Integrated Energy Policy Report Committee has therefore elected to rely exclusively upon publicly disclosed information as its basis for its assessments, findings, and policy recommendations in this proceeding. The Energy Commission believes that resource planning and procurement in California should be open and transparent and will work cooperatively with the CPUC through its rulemaking process to revise regulations governing disclosure of records.

Resource Procurement Policies

The CPUC established general capacity amounts and types of contracts to guide IOU resource procurement in its December 2004 procurement decision.[55] For PG&E, the CPUC approved PG&E's strategy to add 1,200 MW of capacity and new peaking generation in 2008 and an additional 1,000 MW of new peaking and dispatchable generation in 2010. The CPUC determined that SCE's primary need through 2011 is for peaking, dispatchable, and shaping resources and recommended that SCE rely mainly upon short-term and mid-term contacts, but also suggested it might be prudent to add some long-term contracts. The CPUC judged SDG&E to be essentially fully resourced through 2009, with the exception of needed investments in renewables to meet RPS targets.

While the CPUC did not prohibit IOUs from entering into long-term contracts, there has been little movement by utilities to do so. The CPUC left open the possibility that utilities might need to either enter into new contracts or build new capacity to ensure adequate resources toward the end of this decade. The CPUC further noted that, for these resources to come on line within this timeframe, construction needs to begin in the very near term.[56]

The Energy Commission believes the point has been reached where long-term procurement must move forward expeditiously. California should not rely primarily upon short- and mid-term contracts for the majority of its future electricity needs. While PG&E and SCE currently have RFOs on the street to procure ten-year contracts, some parties have asserted that the utilities have been unduly restrictive in the kinds of resources

[55] CPUC Decision 04-12-048, December 16, 2004, pp. 181-182.
[56] CPUC Decision 04-12-048, December 16, 2004, p. 185

they are specifying in their RFOs. California needs to move forward with the kind of open, competitive procurement that allows all resources to compete against each other.

Uncertainty from Departing Loads

In the *2005 Energy Report* proceeding California's IOUs identified the risk of departing load to energy service providers (ESPs), community choice aggregators (CCA),and municipal utilities as their single greatest source of uncertainty in planning for and procuring future resources. Utilities argued that unless this issue is ultimately decided, they cannot engage in significant long-term procurement since they cannot accurately predict the amount of load they may lose. Their concern is that if a significant portion of their load migrates to a different supplier, they could end up over-procuring resources and incur the stranded costs of those resources.

The CPUC acknowledged that while limiting procurement choices to short-term options could mitigate the risk of stranded costs, it could also lead to the rejection of longer term contracts, especially in the area of renewables, that could ultimately result in non-optimal resource portfolios and higher costs for all customers.[57] To address these concerns, the CPUC recommended a policy allowing IOUs to recover stranded costs, including both exit fees and other non-bypassable surcharges.[58] The CPUC determined this would require departing load to assume a fair share of IOU costs, consistent with the CPUC policy to hold captive ratepayers harmless.

The Energy Commission agrees with the CPUC's conclusion that establishing exit fees for departing load is the most equitable approach for meeting the goal for providing "the need for reasonable certainty for rate recovery" as well as ensuring that California meets its energy needs.[59] The Energy Commission believes that the CPUC policy of establishing exit fees is sufficient to eliminate the lion's share of uncertainty about departing load. The Energy Commission is troubled with IOUs using concerns over departing load to avoid securing significant long-term procurement required to meet California's growing electricity needs.

During the *2005 Energy Report* workshops, several parties indicated that establishing the "coming and going rules" for future direct access is the best way to reduce any remaining uncertainty about future IOU loads. The CPUC's Office of Ratepayer Advocates (ORA), SCE, PG&E, SDG&E, and The Utility Reform Network (TURN), generally agreed that there is more uncertainty about re-entry rights than there is about the departure of loads to retail sellers other than the IOUs.[60] Since utilities are the providers of last resort, the conditions for returning to IOU service were seen as the most critical element of these rules.

[57] CPUC Decision 04-12-048, December 16, 2004, p. 51
[58] CPUC Decision 04-12-048, December 16, 2004, pp. 52 and 185
[59] Ibid.
[60] Transcript from the *Energy Report* Committee workshops on June 29, 2005 on IOU Resource Plan Summary and July 7, 2005 on Electricity Policy Issues.

ORA suggested its preference for re-entry would be that once customers leave the utility, they should not be allowed to return. However, they did say they were open to solutions being pursued in other parts of the country to develop capacity markets and ISO back-stop strategies.[61] SCE and PG&E both indicated that while at times their companies have considered the "once you're gone, you can't return" policy, they recognize that is not consistent with what their customers want.[62] SDG&E called for reasonable switching rules to address departing load uncertainty.[63] TURN expressed concerns about the ability to enforce such a rule in a situation where the IOU is the only entity that can serve the load.[64]

Because the remaining uncertainty about coming and going rules, especially return rights, is inhibiting investment in new generation, the Energy Commission recommends that the CPUC begin immediately to establish appropriate coming and going rules for departing load. The CPUC should establish a schedule that would provide a sound set of departing load rules by the end of 2006.

Need for Long-Term Contracts

Utilities have released some RFOs for long-term contracts but they account for less than 20 percent of solicitations, totaling 2,000 MW out of the approximately 12,500 MW under current procurements. Since California faces increasing electricity demand growth and a compelling need to modernize the generation fleet, it is critical to have enough long-term commitments to bring new generation on line and repower existing aging power plants. This is necessary to meet future reliability needs and ensure moderate prices.

Arguing against long-term contracts, many parties point to the high cost of DWR contracts signed at the height of the electricity crisis. This concern is misplaced for several reasons. First, to the extent that the contracts were unit specific (most were not), the DWR contracts were with older, less efficient plants and did not focus on inducing new construction or modernization. Second, the vast majority of the DWR contracts assigned the risk of fluctuation in natural gas prices to the purchaser — as would be the case today — making the "lock-in" of prices only applicable to the non-fuel aspects of the contracts. All that was truly "locked-in" was a reliance on outdated, inefficient generating technology and a resulting chill on new construction due to the unavailability of long-term contracts.

The *2003 Energy Report*, using gas price projections in the low-to-mid $3 range, estimated that fuel costs would constitute 70 percent of the life cycle costs of a new

---

[61] Ibid, testimony of Scott Cauchois, Office of Ratepayer Advocates.
[62] Ibid, testimony of Stuart Hemphill, Southern California Edison, and of Harold LaFlash, Pacific Gas and Electric.
[63] Ibid, testimony of Robert Anderson, San Diego Gas and Electric.
[64] Ibid, testimony of Kevin Woodruff, The Utility Reform Network.

combined-cycle power plant.[65] At a $6 gas price, fuel would represent about 80 percent of life cycle costs, and at $9, about 85 percent. Because the futures market cannot provide a price hedge for much more than two years, the risk of gas price fluctuation is unavoidably absorbed by the electricity ratepayer. Despite only "locking in" the 15 to 30 percent of life cycle costs that are not fuel related, the value of long-term contracts is the shift to newer and more efficient generating technology that can produce material savings in the 70 to 85 percent of life cycle costs that are fuel driven. For example, at a gas price of $6, the fuel costs to produce one MWh from a plant with a heat rate of 11,000 British thermal units (Btu) per kilowatt hour (kWh) would be $66, compared to $42 from a plant with a heat rate of 7,000 Btu per kWh. At a $9 gas price, the comparison is $99 to $63.

It should go without saying that long-term contracts with renewable resources — which have no ongoing gas price exposure — turn the modernization concept into a true hedge against long-term natural gas prices. That is why the *2003 Energy Report* identified the Renewable Portfolio Standard as California's primary fuel diversification strategy and why the CPUC's 2004 procurement decision insisted that renewable resources be made the "rebuttable presumption" for all long-term procurement by the IOUs.

Perversely, maintaining so many older plants on life support at low capacity factors has prevented the construction of more efficient plants that should operate at higher capacity. Virtually all of the aging power plants are high heat rate capacity that would typically not be dispatched enough in the open market to cover their fixed costs and justify continued operation. Heat rates for aging power plants in the state range from 8,720 to 12,150 Btu per kWh, with an average heat rate for the fleet during 2003 of about 10,550 Btu per kWh.[66] This compares with a 7,000 Btu per kWh heat rate for a modern combined cycle power plant operating at high capacity factors.[67] The lower the heat rate, the less natural gas burned, and consequently the less costly each kWh is to produce.[68]

The Energy Commission identified a group of older power plants for use in studying the current and anticipated role of aging plants in the state's electricity system and their

[65] California Energy Commission staff report, *Comparative Cost of California Central Station Generation Technologies*, August 2003, CEC-100-03-001. The natural gas price forecast provided in the appendix to this staff report shows prices in nominal dollars, ranging from $3.94 in 2005 to $5.83 in 2013. The 'low-to-mid $3 range' price forecast noted in the text here is expressed in year 2000 $, as it was reported in the *2003 Natural Gas Market Assessment* (August 2003, CEC-100-03-006).

[66] *Resource, Reliability and Environmental Concerns of Aging Power Plant Operations and Retirement,* California Energy Commission, draft staff white paper, August 13, 2004, CEC-100-04-005D, p. 31.

[67] In 2003, new combined cycle plants were operating at low capacity factors, around 21-22 percent, where their efficiency is lower than 7,000 Btu per kWh.

[68] For example, at a gas price of $6, the fuel costs to produce one MWh for a plant with a heat rate of 11,000 Btu per kWh to produce one mWh would be $66, compared with $43 for a plant with a heat rate of 7,000 Btu per kWh.

impacts on the state's resources,[69] using criteria based on a combination of several attributes, including age, size, capacity factor, efficiency, and environmental considerations, to produce the list of plants in Appendix A as a preliminary study group for the aging power plant study. This group of 66 aging power gas-fired power plants represents larger plants with relatively higher heat rates (low efficiencies) and relatively higher operation (capacity factors).[70] The Energy Commission recommends an IOU procurement policy to cover their net short positions plus the retirement or replacement of this group of aging power plants.

While it is true that some aging plants are critical to address local reliability concerns, the state would be better served by repowering those that are locationally critical to the electricity system. Currently, these plants have RMR contracts that are an expensive mechanism for ensuring reliability that the utilities, the CPUC, and the Federal Energy Regulatory Commission (FERC) all have indicated California should move away from rapidly. The persistence of this dependence on RMR contracts more than seven years after restructuring is an indictment of California's regulatory effectiveness.

Continued short-term procurement for local area reliability prolongs the reliance on aging units that could otherwise be economically repowered through longer term arrangements, providing similar grid services at a more competitive price. Some of the RMR facilities could be eliminated altogether by transmission solutions, which will require a more proactive approach to transmission planning, as discussed in Chapter 4.

From the IOUs' perspective, as long as their resource adequacy requirements are met with a combination of RMR contracts and short-term contracts with aging power plants at prices slightly above their fixed operations and maintenance costs, IOU near-term costs can be deemed regulatorily reasonable. However, it is not clear that anyone is adequately considering the cumulative long-term economic impact on ratepayers, the reliability risk from continued reliance upon older less reliable plants, and increasing natural gas price exposure from perennial short-term contracts.

Future gas prices are highly uncertain and pose significant risks to utility ratepayers. While short-term variability in gas prices can be readily mitigated with gas storage and natural gas-hedging contracts, long-term fixed-price electricity contracts from gas-fired generators are not readily available given the difficulties in hedging the underlying fuel-price risk.[71] When utilities are allowed to simply pass fuel costs through to ratepayers, as is the case today, they are likely to place considerably less value on mitigating fuel price risk. This long-term risk exposure to ratepayers must be more effectively addressed in IOU long-term procurement.

---

[69] *Resource, Reliability and Environmental Concerns of Aging Power Plant Operations and Retirement*, California Energy Commission, Draft Staff White Paper, August 13, 2004, #100-04-005D.
[70] The study group included only natural-gas fired power plants of 10 MW or greater that were built before 1980. Peaking plants were excluded, as were any plants known to be scheduled for retirement in the near term. Of the resulting 66 power plants, 16 are owned by municipal utilities.

[71] *Balancing Cost and Risk: The Treatment of Renewable Energy in Western Utility Resource Plans*, Mark Bolinger and Ryan Wiser, Ernest Orlando Lawrence Berkeley National Laboratory, August 2005, p. 44

When aging power plants are secured under RMR contracts or short-term bilateral contracts, they are not required to compete in an open, competitive market environment against new construction. As long as they are not required to face head-to-head competition against new, more efficient power plants, the benefits of replacement or repowering will remain unrealized. An open planning forum to assess the locational value of these assets and the advisability of replacing them with new generation or transmission upgrades is paramount to statewide interests. In addition, the selection of replacement assets should be subject to competitive bidding. The CA ISO, in collaboration with the CPUC and the Energy Commission, should assess these needs in its new transmission and grid planning process, which is discussed in greater detail in Chapter 4.

Portfolio Performance and Least-Cost, Best-Fit Criteria

The CPUC established in its December 2004 resource procurement decision that it will rely upon a portfolio approach to balance obtaining adequate resources and procurement.[72] The decision outlined achievement of this through "a mix of resources, fuel types, contract terms and types, with some baseload, peaking, shaping and intermediate capacity, with a healthy margin of built-in flexibility and sufficient resource adequacy."[73] The CPUC found that a mixed portfolio of different contract terms and lengths will help prevent utilities from over-subscribing to long-term contracts that could crowd out future opportunities.[74]

IOUs currently employ least-cost, best-fit criteria when selecting bids from their solicitations. These appear to focus on ensuring that selected bids match the baseload, peaking and other physical characteristics of system needs. Utilities have developed individual methods to calculate or weigh these criteria, including resource or market value, portfolio fit, credit, viability, transmission impact, debt equivalence, and non-price terms and conditions. Yet even descriptions provided by utilities on least-cost, best-fit criteria are not universally transparent and require a high degree of subjective interpretation and judgment. The application of these criteria in bid selection is known only to utilities and individuals participating in PRGs.[75]

For example, SCE provides the following description of how it applies least-cost, best-fit criteria for renewables:

---

[72] CPUC Decision 04-12-048, December 16, 2004, p. 28
[73] CPUC Decision 04-12-048, December 16, 2004 pp. 39 and 181
[74] CPUC Decision 04-12-048, December 16, 2004, p. 180
[75] In its 2005 Request for Offers for renewables, Southern California Edison reserved the right to conduct the solicitation without procurement review group concurrence, subject to CPUC approval. Since all discussions with procurement review groups are confidential nobody outside the procurement review group can discern whether legitimate issues were raised by members and dismissed by the utility or even the extent to which the details of the least-cost, best-fit criteria are disclosed within the group.

> Specifically, the [least-cost, best-fit] analysis will employ a production simulation model to calculate the total system production benefits and costs associated with a renewable generating facility. By incorporating Effective Load Carrying Capacity values, transmission costs, and integration cost and benefits, this analysis will produce a benefit/cost ratio for each Proposal. This ratio will then be used to compare the Proposals received.[76]

Production cost simulations and benefit/cost ratios are extremely complex, involving literally hundreds of assumptions that are speculative and require judgment. Many parties have legitimate differences of opinion about the most appropriate assumptions for use in these analyses. The Energy Commission's experience with production cost modeling indicates that because critical assumptions in these models are highly speculative, such as future gas prices, the results from these models are far less precise than some would assert.

Developing a portfolio mix of different types of assets to economically meet base, intermediate, and peaking resource needs of utility load is the primary focus of the least-cost, best-fit criteria IOUs use for resource procurement. A review by the Energy Commission of evaluation criteria indicated that there are significant limitations in market value and portfolio fit criteria currently being used by utilities.[77] The market valuation looks at the present value of an asset compared to a market price assumption, where portfolio fit tries to compare an asset to its "short" or "long" positions. While these comparisons have value when looking at a single asset, they are less valid when examining a larger portfolio, because the portfolio changes the market price assumption.

The state's energy objectives may be broader than the way IOUs define least-cost, best-fit: they also include improving security of a cost-effective supply under a range of uncertain but reasonably anticipated events such as:

- Major disruptions in supply or extreme volatility in prices of a single fuel, such as natural gas.
- Loss of access to or extended outage of a significant portion of a single technology type, such as nuclear.
- Adverse hydro and/or extreme temperature conditions.

The Energy Commission recommends additional development of portfolio approaches and risk assessment to develop a more transparent and standardized method for determining what constitutes least-cost, best-fit. This would allow policy makers to

---

[76] Southern California Edison, 2005 Request for Proposals from Eligible Renewable Energy Resource Suppliers for Electric Energy: *Procurement Protocol*

[77] Transcript from July 28, *2004 Energy Report* Committee Workshop on Transmission, presentation by Eric Toolson and California Energy Commission staff report: *Upgrading California's Electric Transmission System: Issues and Actions for 2005 and Beyond*, July 2005, #700-2005-018, attachment 3, *Risk, Portfolio Theory and Transmission Planning*.

better ensure that IOU resource selections reflect the state's interest in addressing future electricity risk and uncertainty.

Before turning to key loading order policy issues, the Energy Commission believes that two recommendations relating to supply management from the *2004 Energy Report Update* should be reiterated:

- The Energy Commission should work with the utilities, the CPUC, and other agencies to identify cost-effective projects that would increase transfer capacity between the transmission system in the CA ISO control areas and the three other California control areas. This increased connectivity could both provide flexibility to control area operators to match generators to load and reduce the number of power plants needed to meet system-wide demand. Operators would also have greater flexibility during peak load conditions to import power from cooler regions with generation surpluses.
- California should establish a joint planning effort to take full advantage of complementary utility systems in California and the Pacific Northwest. California energy agencies should identify regional policies to guide IOUs and others in developing exchange contracts with Pacific Northwest energy entities.

CHAPTER 4: DEMAND-SIDE RESOURCES, DISTRIBUTED GENERATION, AND OTHER ELECTRICITY SUPPLIES

Introduction

In 2003, California's principal energy agencies established an energy resource loading order to guide energy decision making in the state. The loading order decreases electricity demand by increasing energy efficiency and demand response, and meeting new generation needs first with renewable and distributed generation resources and then with clean fossil-fueled generation. The loading order was adopted in the *2003 Energy Action Plan* prepared by the energy agencies and the Energy Commission's *2003 Energy Report* used the loading order as the foundation for its recommended energy policies and decisions.

To slow growth in electricity demand, the state outlined an aggressive strategy combining energy efficiency and demand response programs. Governor Schwarzenegger recently affirmed his support for previous *Energy Report* recommendations "to ensure that efficiency maintains its preeminent place in preferred energy resource additions."[78] While California is on track to meet energy efficiency targets established two years ago, existing programs may not be taking full advantage of opportunities to further reduce peak electricity demand.

Demand response programs, the most promising and cost-effective options to reduce the peaking needs of the state's electricity system, have failed to deliver savings targets established by state policy makers for each of the last three years. They appear unlikely to meet next year's targets as well. The Governor has stated his policy commitment to advanced meters and dynamic tariffs to achieve demand response goals. In addition, he has directed the California Public Utilities Commission (CPUC) to proceed promptly with investor-owned utility (IOU) plans to deploy meters for residential and commercial customers and has recommended that Southern California Edison (SCE) accelerate its planned efforts.[79]

The state's primary strategy to diversify supplies is through development of renewable resources, yet the administrative complexity and lengthy solicitation process that has emerged under the Renewable Portfolio Standard (RPS) program is hampering the state's ability to meet renewable targets. Additionally, distributed generation sources, including combined heat and power facilities and renewable technologies, have not received the regulatory attention and encouragement necessary to meet the desires of policy makers to see increasing reliance upon these resources. Governor Schwarzenegger has emphasized that the state should encourage distributed

[78] Letter from Governor Arnold Schwarzenegger to the Legislature, attachment: Review of Major Integrated Energy Policy Report Recommendations, August 23, 2005.
[79] Ibid.

generation and combined heat and power since "it can occur at load centers, reducing the need for further infrastructure additions."[80]

California policy makers must improve their efforts to reduce electricity demand growth and shave peak demand through energy efficiency and demand response programs. To bring sufficient generating resources on line to meet future needs, the state must vigorously pursue preferred resources such as renewables and distributed generation, followed by conventional generating resources. At the same time, California's bulk transmission system must be enhanced and fortified to ensure that resources can be delivered when and where they are most needed, as discussed in Chapter 5.

The following sections outline the measures the state must take to ensure that energy efficiency, demand response and distributed generation goals are achieved. Renewable resource issues are addressed in Chapter 6. These measures will help California avoid future black-outs, ensure reliable long-term supplies, decrease its growing dependence on natural gas, and reduce electricity costs for residential customers and businesses.

Energy Efficiency

Energy efficiency is the first priority in California's loading order. Energy efficiency programs reduce the state's reliance on natural gas and the need for new power plants by reducing the amount of energy consumed in the state. By decreasing peak demand, these programs can also increase the reliability of the electricity system while reducing environmental impacts and the cost of electricity.

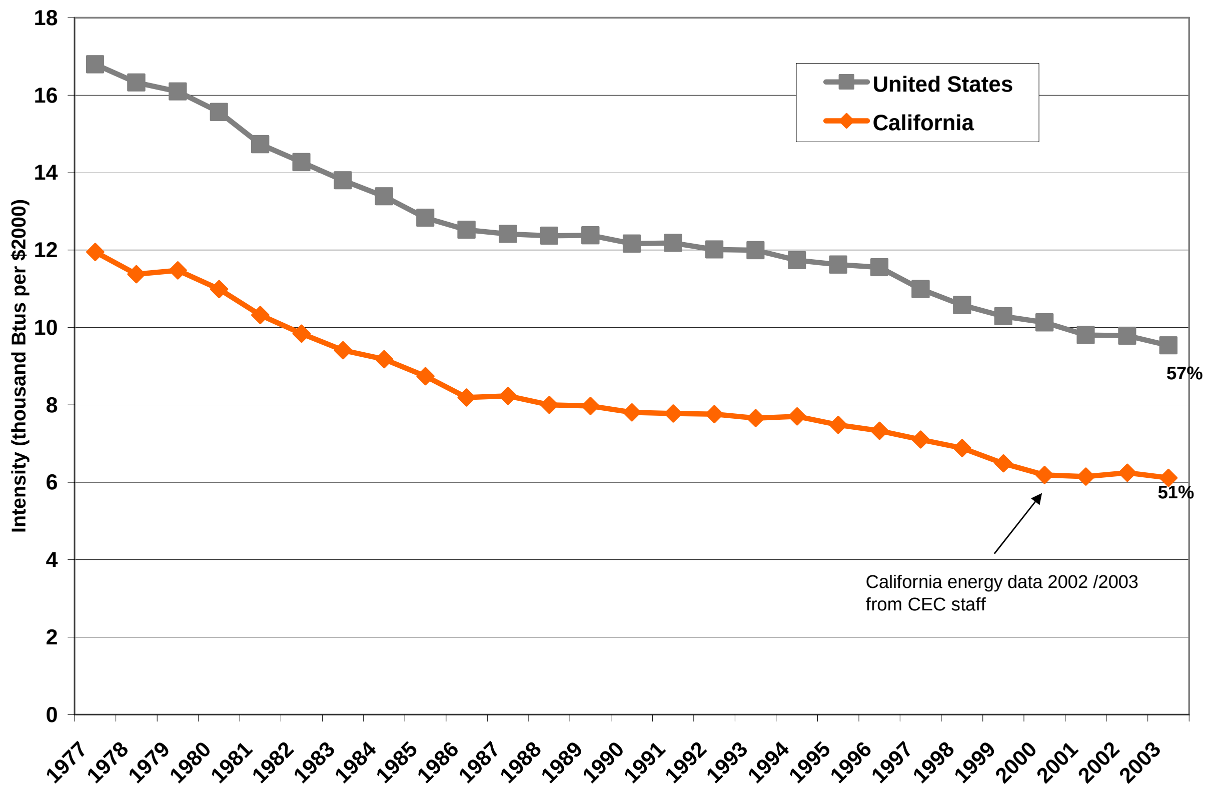
California leads the nation in its energy efficiency and conservation efforts. As a result, electricity use per person in the last 30 years has remained relatively flat, while electricity use per person in the rest of the nation has increased by 45 percent. Through 2003, California's programs have saved more than 40,000 gigawatt hours (GWh) of electricity and 12,000 megawatts (MW) of peak demand, equivalent to more than two dozen 500 MW power plants. These initiatives, principally mandatory efficiency standards, will continue to provide increased savings over time.

The *2003 Energy Report* concluded that the maximum achievable electricity savings from future energy efficiency programs over the next decade are an additional 30,000 GWh. In September 2004, the CPUC adopted aggressive energy savings goals designed to mine this potential. When these goals are realized, the energy savings will represent more than half the IOUs' need for additional electricity between 2004 and 2013. To achieve these goals, the CPUC significantly increased IOU energy efficiency funding to $823 million for 2004-2005,[81] and has proposed funding for 2006-2008 programs of $1.98 billion.

[80] Ibid.
[81] Decision 03-12-060, CPUC Energy Efficiency Rulemaking 01-08-028.

California's building and appliance standards have proven to be the state's most cost-effective efficiency measure. Since the first round of standards was adopted in 1975, the state has saved 6,000 MW in peak demand; these savings are expected to reach 10,000 MW by 2010. In addition, the Energy Commission adopted new appliance efficiency standards in 2004 that will reduce customers' utility bills by $3.3 billion during the first 15 years they are in effect. The Energy Commission should continue evaluating energy-using technologies for possible incorporation in periodic updates to the building and appliance standards.

Figure 11: U.S. and California Energy Intensity 1977-2003



Source: Energy Information Agency and Bureau of Economic Analysis except where otherwise noted.

While the Title 24 Building Efficiency Standards ensure that new buildings, additions, and alterations to existing buildings include energy efficiency in their designs, there is remarkably little regulatory attention to upgrading the energy efficiency of existing buildings. Although utility energy efficiency programs have generally promoted savings in existing buildings, there remains great potential for efficiency improvements in the existing stock, which turns over very slowly and dominates energy consumption. The Energy Commission is currently developing a report to the Legislature in response to Assembly Bill 549 (Longville), Chapter 905, Statutes of 2001, outlining options to upgrade existing buildings such as efficiency inspections when buildings are sold, and new utility pilot programs such as on-bill financing and building commissioning and retro-commissioning. Close coordination with the benchmarking effort of the state's Green Buildings Initiative will also enhance the possibilities for upgrading existing buildings.

IOU planners need to be able to confidently account for energy efficiency savings in their procurement planning processes and decisions. Energy efficiency programs must be prudently managed and measured to ensure that projected savings materialize and are recognized in the planning process. The CPUC has changed the way efficiency programs will be administered in the future by establishing a new framework under which the CPUC and the Energy Commission cooperatively manage and contract for all efficiency monitoring and verification studies. This will establish a clear separation between program evaluators and program administrators and implementers and help ensure that IOU intentions are translated into real energy and peak demand savings. The Energy Commission and the CPUC should continue to work collaboratively to ensure rigorous evaluation, measurement, and monitoring of energy efficiency programs. Doing so will give utility planners accurate information on expected efficiency savings on which to base their procurement plans, while also making certain that public funds are prudently spent.

For post-2005 efficiency programs, the CPUC has also changed how savings are quantified, evaluated, measured, and verified. The CPUC returned program choice and portfolio management roles for energy efficiency to IOUs, and directed IOUs to design and implement a portfolio of utility and non-utility administered energy efficiency programs. Recognizing the role played by private energy service companies, local government agencies, nonprofit organizations and other entities, at least 20 percent of the portfolio must be competitively bid to non-utility third parties. The rationale for this change is that these entities will improve overall portfolio performance by bringing proposals that will be both innovative and targeted toward specific market needs or niches.

The portion of the energy efficiency program portfolio bid to non-utility third parties initially shows a much-needed focus on programs that result in peak savings. Energy efficiency programs must meet specific cost-effectiveness rules, typically measured by energy savings for each dollar spent, which can drive efficiency program focus on energy savings rather than peak savings. Since California experiences high peak summer demand, shaving those peaks is essential to reducing electricity price volatility, safeguarding reliability, and reducing the need for peaking power plants that only operate a few hours a year.

The largest potential for peak savings is in residential space cooling, followed by commercial space cooling and lighting.[82] The CPUC recognized that preliminary IOU efficiency portfolios were overly reliant on high energy-using measures such as lighting,

[82] The Utility Reform Network comments at *2005 Energy Report* workshop on Energy Efficiency Policies, July 11, 2005.

at the expense of critical peak impact end uses such as air conditioning. In its April 2005 Decision 05-04-021, the CPUC stated that energy efficiency rules "should be modified to reflect the need to ensure reliability in the near term by encouraging aggressive programs that target measures with most of their energy savings during peak time periods."[83]

However, in its August 17, 2005 draft decision on 2006-2008 program funding, the CPUC rejected a proposal by The Utility Reform Network (TURN) for utilities to "rebalance" their portfolios toward heating, ventilation, and air conditioning (HVAC) savings, reasoning that a large portion of existing potential for these savings will be captured by efficiency increases in new residential air conditioners under the 2005 appliance standards, and utility programs have already increased funding for residential air conditioning programs compared to previous years. Notwithstanding the CPUC draft position, the Energy Commission reinforces the recommendation that energy efficiency portfolios need to focus more on programs that achieve peak savings, such as those available from reduced air conditioning use, to reach the state's goals for peak savings. This is particularly important in the near term in Southern California, where reliability margins are significantly tighter than in Northern California.

Emphasis on peak savings must be balanced by attention to another key reason for establishing energy efficiency goals, which is the potential contribution to global climate change targets established by Governor Schwarzenegger. In general, getting the most energy savings from the program portfolio may make the greatest contribution to reducing climate change gases from electricity generation. While much of California's electricity needs are served by natural gas-fired power plants, saving energy at different times of the day and year is likely to impact generation from power sources of different efficiencies and fuel types. The Energy Commission should analyze the effect of energy savings during different hours on climate change goals, and target programs to maximize reduction in climate change gases, in addition to achieving peak savings.

In the past, IOU energy efficiency programs were established on an annual basis and often individual programs would achieve a market response that would use up the funds for the program prior to the end of the year. This has two consequences. First, the state is not achieving the full amount of cost effective peak demand and energy savings in that year, and utilities must meet demand for energy with resources lower in the loading order. Second, the businesses that provide energy efficiency services and equipment in California face the risk of annual boom and bust cycles that disrupt their deal flow. The CPUC should alter this pattern by funding energy efficiency programs with enough budget flexibility to allow efficiency programs to meet market demand in a timely fashion. In some cases, this may simply involve the ability to transfer funds within the overall target budget from one program with low demand to a program with high demand.

[83] CPUC, April 21, 2005, Interim Opinion: Updated Policy Rules for Post-2005 Energy Efficiency and Threshold Issues Related to Evaluation, Measurement and Verification of Energy Efficiency Programs, D. 05-04-051.

The utilities' overall efficiency budgets should be established with a "balancing account" structure to accommodate full market demand for any program. The procurement flexibility that applies to generation — with utilities purchasing what is necessary to meet demand for electricity — should also apply at the top of the loading order. Utilities should be expected to procure as much cost-effective energy efficiency as the market can provide, without annual budget constraints.

Because publicly owned utilities (POUs) provide 20-25 percent of the electricity in California, energy efficiency efforts by these entities are essential to the state's overall goals for reducing electricity demand. Although the state has adopted efficiency goals for IOUs, POUs are not required to contribute to these goals. The Energy Commission should work with POUs to establish goals consistent with those adopted for IOUs, by the end of 2006.

As part of this effort, the Energy Commission needs better information about program plans and results. Currently, without publicly available data sources, it is difficult to determine on a statewide basis how much POUs spend on efficiency or how much energy they save. To allow for a transparent comparison between IOU and POU program designs, costs, and effectiveness, the Energy Commission should create a reporting requirement as part of its Common Forecasting Methodology regulations for customer-owned utilities to report the status and progress of their efficiency programs to the Energy Commission. These regulations should ensure that reporting requirements do not impose a cost burden on POUs while providing the necessary level of information to allow comparison with other energy efficiency programs in the state.

Demand Response

The *2004 Energy Report Update* highlighted the importance of demand response program consistency with CPUC and Energy Commission goals.[84] Demand response programs reduce peak demand in two ways. First, price-sensitive programs provide customers with financial incentives and metering technology to reduce electric loads when prices and demand for electricity are high. Second, reliability programs provide customers with a non-price signal indicating when system resources are strained and when demand reduction would be beneficial. Reducing load before the system reaches capacity constraints increases the reliability of California's electricity grid. By reducing the need for additional system infrastructure or peaking generation, demand response measures also lower consumer costs over the long term.

Both price-sensitive and reliability programs are important components of demand response. The state has relied on reliability programs in past instances of constrained supply, most recently this summer in Southern California. Advances in metering and communications technologies allow significant improvements in both price-responsive and signal-responsive programs. It must be recognized that new metering technology

[84] The *Energy Action Plan*, adopted by the Energy Commission and CPUC in 2003, laid out goals for demand response programs that were further endorsed in the *2003 Energy Report*.

will be the primary platform for the state's future demand response policies. Both types of programs are now being designed to allow significant customer control over the response – a key feature for increasing participation in these programs by allowing customers to be more comfortable with impacts on their homes and businesses.

Recent efforts in California to increase demand-response programs have focused on price-sensitive programs like dynamic pricing and demand bidding. Dynamic or "real-time" pricing increases prices to reflect high costs during times of heavy use, sending price signals to customers to cut back on electricity use. Large customers already have advanced meters that can take advantage of dynamic pricing rates. The state needs to implement default dynamic rates for these large customers. For dynamic pricing to be most effective, however, the state also needs to develop an advanced metering infrastructure for all customers, as recommended in the *2003 Energy Report* and the *2004 Energy Report Update*.

In 2003, the CPUC set targets for demand reduction for the IOUs. Although the utilities did not meet their goals for 2004, they did reduce demand by 556 MW, around 63 percent of the original target. In 2004, the CPUC ordered utilities to file applications for a new default rate with critical peak features. The proposed new rate was expected to address the lack of enrollment in voluntary demand response programs by large customers and the limited performance of customers enrolled in other programs. After reviewing utility applications, however, the CPUC concluded that more time was needed to analyze the variety of critical peak pricing rate proposals. Rather than implementing these rates to affect demand during summer 2005, the CPUC has ordered new rate proposals to be prepared for implementation in 2006.

In 2005, IOUs filed applications to implement default critical peak pricing tariffs for large customers beginning in summer 2006. The CPUC expects to issue a decision on these tariffs in early 2006. Along with the new tariff, IOUs will develop customer education, assistance, and incentive plans to ease the rate transition for large customers. This effort could bring IOUs closer to their demand response goals.

In addition to the advanced meters installed for large customers in the state, the CPUC has ordered IOUs to file business cases for applying advanced meters on a system-wide basis. These systems allow utilities to remotely read customer meters, support emergency reliability programs, and reduce the costs of billing, metering, and managing outages. Over the past year, IOUs completed an analysis of the costs and benefits of installing advanced metering networks. The CPUC and Energy Commission reviewed these analyses and encouraged the utilities to move forward with their applications.

Two of the state's IOUs filed plans aimed at quickly replacing their metering systems with advanced metering and communications systems able to support time-based rates for all customers. In contrast, SCE filed a plan directed toward development of a new metering infrastructure, with replacement of its metering systems lagging behind the other two utilities. Governor Schwarzenegger recently urged the CPUC to require SCE to expedite its plans to be commensurate with the other utilities. [85]

Reliability programs should also be pursued with the advent of advanced metering infrastructure and communication technology. Many of the state's long-standing demand response programs, including interruptible rates and air-conditioner cycling programs, act by merely "turning-off" customers or appliances in response to a signal. Advanced communication technologies allow less intrusive and more dispatchable demand changes through two-way communications with customer thermostats and other energy-using equipment. Rather than completely shutting down groups of air-conditioners in a program, managers can modulate the usage of these air-conditioners to provide a "shaped" demand impact when needed while allowing customers greater control and comfort. These new programs should be further explored as the state increases its reliance on demand response resources.

POUs are also exploring advanced metering infrastructures and demand response programs. Advanced metering and demand response efforts by these entities are essential to the state's overall goal to reduce electricity demand and mitigate resource constraints and high prices. The Energy Commission should work with these POUs to understand their demand response efforts and develop goals consistent with those adopted for IOUs, by the end of 2006.

As part of this effort with customer-owned utilities, the Energy Commission again needs better information about their program plans and results. The Energy Commission should include demand response information in the Common Forecasting Methodology reporting requirement recommended for energy efficiency programs, again without imposing an undue cost burden on these entities, while providing the necessary level of information to allow comparison with other demand response efforts in the state.

Advanced metering and dynamic pricing are likely to be the platform for California's future demand response programs. However, there are two efforts pending that will affect the ability of the CPUC to implement advanced metering and time-based electric rates. Under current approaches, customers who use high quantities of energy when wholesale prices are high are subsidized by customers who use low quantities of energy during the same times. Moving to a real-time pricing approach will remove that cross-subsidization, resulting in higher overall electricity costs for certain customers and lower costs for others.

Although demand response is currently a controversial subject, California must address the increasing number of peak load hours to improve system reliability and temper electricity price volatility. The Energy Commission and the CPUC need to make major efforts over the next few years to determine the appropriate mix of voluntary and mandatory demand response programs, as well as the right mix of price-sensitive and reliability programs.

---

[85] Letter from Governor Arnold Schwarzenegger to the Legislature, attachment: Review of Major Integrated Energy Policy Report Recommendations, August 23, 2005.

Distributed Generation and Cogeneration

An important alternative to building new central station fossil-fueled generation is the use of distributed generation (DG), which includes both cogeneration and self-generation.[86] DG is broadly defined as electricity produced on-site or close to a load center that is also interconnected to the utility distribution system. California has approximately 2,500 MW of small-scale renewable and non-renewable DG, and since 2001 has added an average of 100 MW of new DG capacity every year.

The benefits of DG go far beyond generation. DG reduces the need for new additions to the state's transmission and distribution infrastructure and improves the efficiency of the system by reducing losses at peak delivery times. Customers can use DG technologies as either peaking resources or for energy independence and protection against supply outages and brownouts. DG is also a key element of California's loading order strategy and will help meet the state's energy efficiency and renewable energy goals.

Cogeneration or combined heat and power (CHP) is the most efficient and cost-effective form of DG, providing numerous benefits to California including 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. There are more than 770 active CHP projects in California representing 9,000 MW,[87] with nearly 90 percent of this capacity coming from systems greater than 20 MW. Market potential for additional CHP is substantial, as high as 5,400 MW, despite higher natural gas prices.

The *2003 Energy Report* highlighted the importance of DG and CHP in meeting California's growing energy needs, and as an essential element of customer choice. It called for creation of a transparent distribution system planning process that addresses the benefits to utilities of DG and CHP. While some slight progress has been made, almost two years later there has been only a very small increase in the deployment of DG and CHP.

Despite policy preferences, DG and CHP deployment in California has struggled with major barriers to market entry and policy implementation in the context of traditional utility cost-of-service grid management. In fact, many larger-scale CHP systems in operation today, the result of generation contracts signed during the early 1980s following the national energy crisis of the late 1970s, are at risk of shutting down in the near future as these contracts expire. It is estimated as much as 2,000 MW is at risk of shutting down between now and 2010 due to inability of the owners to renew contracts with utilities.[88, 89]

---

[86] This is a working definition for distributed generation used in various policy activities at the California Energy Commission and the CPUC.
[87] *Assessment of California CHP Market and Policy Options for Increased Penetration*, California Energy Commission, Publication #CEC-2005-060-D, April 2005.
[88] Public comments by Rod Aoki, representing Cogeneration Association of California and the Energy Producers and Users Coalition, IEPR Loading Order Workshop, July 25, 2005.

The *2005 Energy Report* reaffirms its commitment to DG and CHP by separating the discussion of CHP from DG to provide more clarity to policymakers. As a first step, the Energy Commission funded the *Assessment of California CHP Market and Policy Options for Increased Penetration,* a study which identified a series of policy scenarios that would help focus policy direction for the effective deployment of future CHP.[90] The assessment produced a number of important findings.

First, California has more than 9,000 MW of CHP across the state. With statewide generation capacity at approximately 60,000 MW, CHP is a key component of the grid, representing approximately 17 percent of generation, and is often used to preserve the reliability of the electricity grid. Second, CHP systems smaller than 5 MW represent only about 3 percent of total CHP capacity in the state, while much of California's policy efforts during the past seven years have focused on smaller DG systems, including small-scale CHP. This finding suggests that the state should broaden its policy focus to include large-scale CHP, which could produce several thousand MW of additional generation capacity in the state during the next 15 years.

Clearly, current state policy must change for California to tap into this potential generation source and, equally important, retain the existing pool of CHP so critical to the reliable operation of the grid. CHP developers seeking to install new generation are presently discouraged from sizing their systems to satisfy their full thermal loads because they would then generate more electricity than they could consume onsite. In many cases, these developers have trouble finding a customer interested in purchasing "excess" power at the wholesale level. Lack of a robust, functioning wholesale market in California exacerbates potential CHP customer concerns over this risk.[91] Even if wholesale markets were functioning optimally, CHP owners would still struggle with the complexity and cost of complying with California Independent System Operator (CA ISO) tariff requirements (for example, scheduling exports hour-by-hour, installing costly metering and reporting equipment, etc.).

At the retail level, policy decisions such as the suspension of direct access hamper the ability to sell excess power to customers, as do the lack of distribution wheeling tariffs and restrictions of "over the fence" transactions by Public Utilities Code Section 218.[92] In one instance, Berry Petroleum physically removed its CHP systems entirely and installed traditional boilers to meet its heating needs because of the administrative difficulties of renewing long standing utility power purchase arrangements.[93] In another

---

[89] Comments by Cogeneration Association of California and the Energy Producers and Users Coalition, Docket No. 04-IEP-1E, August 1, 2005.
[90] *Assessment of California CHP Market and Policy Options for Increased Penetration*, California Energy Commission, Publication #CEC-2005-060-D, April 2005.
[91] Comments by Cogeneration Association of California and The Energy Producers and Users Coalition, Docket No. 04-IEP-01E, August 1, pp. 19-20.
[92] Comments by Kevin Duggan representing California Clean DG Coalition, Docket No. 04-IEP-1E, August 1, 2005, p. 2.
[93] Panel Discussion by Barry Lovell, Berry Petroleum Company, IEPR Combined Heat and Power Workshop, April 28, 2005.

example, owners of a 300 MW facility that has been reliably providing enough power to serve more than 400,000 SCE customers for two decades have been attempting to negotiate a new contract for more than two years.[94] In yet another example, Valero Refining Company has been attempting to secure a contract for over a year with PG&E to sell excess power, but has been unsuccessful because PG&E and the CA ISO are requiring Valero to execute a Federal Energy Regulatory Commission (FERC) jurisdictional interconnection agreement and be subject to the wholesale CA ISO tariff prior to being able to provide power to the utility.[95] Equally troubling is that Valero has received permits to install a second generating unit at its refinery, but is reluctant to do so because of the project's "regulatory limbo" between FERC and CPUC jurisdictions.[96]

Looking forward to the development of focused CHP policies, California must recognize that CHP owners are not in the business of producing or selling electricity. Rather, CHP owners choose to operate their businesses and produce electricity only when the economics are favorable. CHP policy therefore cannot be similar to policies developed for more traditional customer generators or merchant power plants. To illustrate this point, the CHP industry notes that "CHP resources are not and will never be fully dispatchable merchant facilities, designed solely for the purpose of producing power; CHP resources were built primarily to serve thermal energy load, or a combination of thermal and electric energy load".[97] Yet this is not problematic since not all merchant plants or IOU power purchases serve a single purpose in an IOU's generation portfolio. Instead, IOUs structure their portfolios to contain resources with varied term, shape, and operational characteristics.[98]

Based on the analysis conducted over the course of the *2005 Energy Report* and extensive input from industry, utilities, the public and others, the Energy Commission believes there are several key initiatives that California must pursue to enable construction of additional cost-effective DG and CHP installations. First, CHP is of such unique value in terms of meeting the loading order's efficiency and new generation objectives that CHP warrants its own designation in the loading order. Therefore, the Energy Commission and CPUC should separate CHP from DG in the next version of the *Energy Action Plan* so that CHP issues and strategies are not subsumed by broader DG issues and strategies.

Second, the state needs to improve access to wholesale energy markets and CHP owners' ability to secure long-term utility contracts to allow these owners to sell their excess electricity. This would provide CHP owners with enough certainty to guide their investment decisions to install or expand CHP operations to meet their full thermal needs. By the end of 2006, the CA ISO should modify its tariffs for CHP owners to

[94] Comments by Cogeneration Association of California and The Energy Producers and Users Coalition, Docket No. 04-IEP-01E, August 1, p. 7.
[95] Ibid, p. 7.
[96] Panel discussion by David Dyck, Valero Energy Corporation, IEPR Combined Heat and Power Workshop, April 28, 2005.
[97] Comments by Cogeneration Association of California and The Energy Producers and Users Coalition, Docket No. 04-IEP-01E, August 1, p. 14.
[98] Ibid.

recognize the unique operational requirements of CHP and allow owners to sell power to the grid at reasonable and appropriate prices. This is particularly important in light of the value that CHP provides IOUs and the CA ISO in addressing transmission congestion and local reliability issues. Additionally, utilities should be required to offer CA ISO scheduling services at cost to their CHP customers. Congestion and reliability issues will be compounded if California is derelict in addressing barriers for CHP owners and these strategic generation resources go away. Additionally, natural gas resources and infrastructure would be adversely affected, as would the environment, because of increases in boiler installations to meet thermal loads. Further, if companies decide to leave California because of energy costs and security concerns, it will have a detrimental impact on well-paying jobs in the industrial sector.

Regarding contracting issues, recent federal energy legislation suggests that the Public Utilities Regulatory Policies Act is likely to remain in effect in California due to the lack of a robust and functioning wholesale market in the state. By the end of 2006, the CPUC should require IOUs to buy, through standard offer contracts, all electricity from CHP plants in their service territories as delivered at the utility's avoided cost, as determined by the CPUC in R.04-04-025. The Legislature should pass legislation requiring similar requirements for municipal utilities, irrigation districts, and other electricity service providers. These long-term contracts should be of sufficient length to enable CHP owners to make well-informed investment decisions while providing appropriate assurances to the Energy Commission and utilities of their availability for long-range planning purposes. At a minimum, the terms of these contracts should be ten years; however, the Energy Commission and CPUC should work together to evaluate whether these contracts should have terms with the same economic life as avoided resources.

Third, IOUs need a reason to incorporate CHP into their systems and, more importantly, into their system planning. The Energy Commission's recommendation here is three-fold:

- As the Assessment of California CHP Market and Policy Options for Increased Penetration indicates, all CHP policy scenarios produce a utility revenue loss from the installation of CHP, even though society benefits as a whole. In order for California to attain its preference for DG and CHP, the IOUs should be compensated for revenue shortfalls to the point of making them at least neutral to the deployment of DG and CHP on their respective systems. California should look at regulatory incentives to reward IOUs for promoting public- and utility-owned CHP and DG projects. Approaches such as the Earned Rate Adjustment Mechanism, which were successful in keeping IOUs revenue-neutral for energy efficiency programs, could be implemented for CHP and DG. Additionally, California could implement regulatory approaches pursued in the United Kingdom where utilities are given an incentive to interconnect DG and CHP projects.[99] It should be noted that the United Kingdom provides even larger incentives to utilities for DG and CHP systems installed on

[99] Electric Distribution Price Control Review, Regulatory Impact Assessment for Registered Power Zones and the Innovation Funding Incentive, United Kingdom Office of Gas and Electricity Markets, March 2004.

constrained parts of their systems. The CPUC should immediately develop a framework for providing DG and CHP incentives to utilities to be implemented by the end of 2006.

- Relative to system planning, the Assessment of California CHP Market and Policy Options for Increased Penetration determined a realistic goal of 5,400 MW of CHP by 2020, which is attainable if policies recommended here are implemented. By the end of 2006, the Energy Commission and CPUC should work collaboratively to translate this goal into yearly procurement targets for IOUs. The Energy Commission and CPUC should establish mechanisms in the procurement process to ensure that existing CHP systems continue to be a baseload portion of the IOUs' portfolios. These mechanisms should rely on the cost/benefit methodologies currently being established in CPUC proceeding R.04-03-017 to ensure that California pursues the projects that provide net societal benefits.
- Regarding distribution system planning issues and policies related to DG and CHP systems, California must consider how significant DG and CHP deployment might affect distribution system operations, reliability, and safety. California utilities are looking at investing billions of dollars in the coming years in their distribution systems in order to keep up with load growth. Now is an opportune time to require infrastructure investments that include DG and CHP systems into utility distribution systems. A careful review of Denmark's system, where CHP and DG comprises over 50 percent of generation capacity, shows that distribution system operations can become expensive, complicated, and unpredictable if distribution systems are not designed to accommodate DG and CHP.100 California should require utilities to design and construct distribution systems that are more DG and CHP compatible. These designs must take advantage of the system benefits DG and CHP can provide such as voltage support, system restoration/reliability, and intentional islanding.

  Initial research from the Energy Commission's Public Interest Energy Research (PIER) program shows that DG and CHP can provide quantifiable benefits to utility systems. In recently completed research on Silicon Valley Power's system, results show that a majority of Silicon Valley Power's customers could install DG that provides varying degrees of utility benefits.[101] In this case study, the optimal portfolio is comprised of smaller DG systems, on average less than 160 kW. Additionally, some locations on the utility system are better than others if the utility is trying to optimize its system for voltage variability, losses, etc. The CPUC should require the utilities to implement comparable planning models to determine where DG and CHP is most beneficial from a systemic transmission and distribution perspective.

Fourth, the state should use CHP to effectively provide air quality and greenhouse gas reduction benefits while reducing transmission and distribution congestion. CHP

[100] Presentation on the operational impacts from large penetrations of CHP/DG, Paul-Frederick Bach, Eltra – Independent System Operator for Denmark, IEPR CHP Workshop, April 28, 2005.
[101] Presentation by Peter Evans, New Power Technologies, IEPR Distribution Planning Workshop, April 29, 2005.

facilities are located in local load centers where system operators struggle to assure adequate local reliability. In addition, CHP provides significant resources during peak demand periods which can help mitigate operational problems associated with meeting state electricity peaks. To maintain the environmental and transmission benefits, California should explore production credits for CO_2 reductions provided by CHP, and by the end of 2006, the CPUC should direct utilities to provide transmission and distribution capacity payments for CHP projects.

Other Electricity Supplies

Advanced Coal Technologies

California ratepayers currently derive some economic benefit from the relatively low-priced electricity generated from coal plants located in other western states. In 2004, some 19.8 percent of all retail electricity sales in California were derived from coal-fired generation. Most of this was attributable to the Los Angeles Department of Water and Power (LADWP) (51 percent of retail electricity sales from coal) and SCE (15 percent of electricity sales from coal). LADWP and several other Southern California municipal utilities own almost all of the Intermountain pulverized coal project in Utah, while LADWP, SCE and various California municipal utilities own significant interests in the Mohave, Navajo, San Juan, and Four Corners pulverized coal projects in Arizona and New Mexico. The California Department of Water Resources owns about one-third of the Reid Gardiner pulverized coal project in Nevada. The various California ownership interests in out-of-state coal projects total 4,744 MW.

The CPUC's 2004 long-term procurement decision raised concerns about the financial risk of future greenhouse gas (GHG) regulation, and requires California's IOUs to include an \$8 per ton CO_2 adder in evaluating procurement contracts over five years in length. This has focused attention on California's interest in mitigating ratepayer exposure to potential GHG retrofit (or offset) requirements applied at some future date to coal-fired power plants, as well as the role California utility procurement may play in influencing the development of "clean" advanced coal combustion technologies.

The term "clean coal" gained widespread use in the 1980s by the U.S. Department of Energy (DOE) and others in reference to plants with very low SO_2, NO_x, and particulate emissions relative to conventional pulverized coal plants of the time. In the 1990s, researchers began investigating processes for capturing 75-90 percent of the CO_2 at power plants from either combustion exhaust (flue gas) or processed fuel gas (synthesis gas). Such capture technologies are presently very energy intensive and their improvement is the subject of considerable research. This research now generally falls under a broadened definition of "clean coal." Today, the term also implies low emissions of mercury and other air toxics.

Plant types considered "clean" include integrated gasification combined cycle (IGCC); pulverized coal with "ultra-supercritical" main steam conditions, i.e., a thermodynamic state well above the pressure and temperature of the critical point of water (USC PC); and circulating fluidized-bed combustion plants with supercritical main steam conditions (SC CFBC). Each of these plant types may be designed with or without CO_2 capture. Numerous developmental technologies with integral CO_2 capture fall under the "clean coal" category as well, including oxygen-fired PC plants with CO_2 recycle (Oxyfuel), a more complex variant known as chemical looping, and rocket-engine-derived combustors.

IGCC technology has been the focus of many environmental advocates because of the perceived ease of extracting sulfur and other pollutants, as well as capturing CO_2, from the gas stream prior to combustion. Several demonstration plants are currently in operation, although not yet at full commercial scale. Experience with early demonstration projects suggests that electricity from the initial commercial scale plants will cost 15-20 percent more than electricity from pulverized coal plants with SO_2 and NO_x emission controls, assuming that current reliability problems can be overcome. The economics of current IGCC technologies are best using the higher-rank bituminous coal typical of many commercially mined deposits east of the Mississippi River, and less favorable for lower-rank coals such as subbituminous or lignite that predominate in the West. This difference may be at least partially mitigated by blending such lower-rank coal feed stocks with petroleum coke. Design changes or success with the advanced, dry-feed compact gasification systems now under development by the DOE and industry partners may eventually make IGCC more economical for lower-rank fuels.

IGCC's relative competitiveness with pulverized coal plants improves if CO_2 removal is required, but such a requirement significantly reduces the power output and increases the cost of both plant types. Studies by DOE, the Electric Power Research Institute (EPRI) and others have found that the incremental cost penalty for removing CO_2 from high-pressure IGCC syngas is about 25 percent on a levelized cost-of-electricity basis, while the cost penalty for removing it from the flue gas of a conventional pulverized coal plant is about 70 percent. Additional costs for transporting and sequestering captured CO_2 are not included in the calculation, but would be comparable for both plant types.

For regions like the West where lower-rank fuels predominate, USC PC and SC CFBC may be the most cost-effective advanced coal combustion options but lack the same opportunity for CO_2 capture offered by IGCC. Compared with the less than 38 percent efficiency of today's pulverized coal plants, new SC CFBC designs can achieve efficiencies of about 40 percent while future USC PC designs are projected to hit generating efficiencies above 45 percent and to reduce CO_2 and other emissions by 15-22 percent.

Governor Schwarzenegger's response to the *2004 Energy Report Update* addressed the challenge of technology choice in the "clean coal" arena: "It is not possible to predict which technologies will advance to commercial maturity most rapidly, so a variety of technology paths must be encouraged. Furthermore, given the diversity of regional electricity markets and the wide variation in regional coal properties, effective deployment of advanced coal power systems may entail the adoption of many different technologies, such as … IGCC … and … SC CFBC … , as well as technologies yet to be developed."

EPRI has developed a CoalFleet for Tomorrow Initiative, a consortium of utilities and suppliers (including three to five companies that have pledged to build IGCC or other advanced coal plants) working with the DOE. Participants believe that collaborative research, development, and demonstration among industry stakeholders can both hasten the deployment of current state-of-the-art advanced coal plants and spur the development of technical and operational improvements. Such advances are intended to boost availability, lower heat rate, and reduce emissions in the near term while leading to the commercial introduction of next-generation plant designs that are approximately 20-25 percent lower in capital cost.

The CoalFleet for Tomorrow Initiative strategy simultaneously addresses the research, development, and demonstration needs for three major timeframes:

- Near-term refinements or evolutionary technologies for IGCC, USC PC, and SC CFBC plants coming on line around 2010- 2012: the early deployment projects.
- Mid-term R&D requiring demonstrations that will conclude after the earlier commercial projects are built; this work will produce technologies that can be readily incorporated in plants coming on line between 2012-2015.
- Longer-term R&D on advanced concepts for IGCC, USC PC, and SC CFBC plants — including integration of CO2 capture systems — for plants coming on line after 2015-2020.

Consistent with the discussion in Chapter 9 on global climate change, California's efforts should focus on this third category of research which integrates the capture of CO_2 with development of advanced combustion technologies. In close coordination with the DOE, the Energy Commission is supporting a growing research program aimed at developing and validating options for sequestering CO_2 away from the atmosphere. The Energy Commission heads WESTCARB, one of the seven regional carbon sequestration partnerships co-funded by DOE, which is a consortium of 70 public agencies, private companies, and nonprofit organizations. WESTCARB characterizes the leak-proof geologic formations throughout the region which are suitable for storing CO_2 safely for centuries or longer. In some instances, such storage can yield co-benefits such as enhanced oil and natural gas production.

Findings to date suggest that the sandstone formations filled with saltwater deep beneath California's Central Valley could collectively store hundreds of years of CO_2 emissions at the current rate of emission by the state's power plants. Indeed, the Central Valley represents one of the largest potential onshore CO_2 "sinks" in the West. Suitable geologic reservoirs for CO_2 storage have also been identified in Arizona and other states to the east of California where new coal-fired power plants are proposed. WESTCARB is currently planning technology validation projects in California and Arizona to verify target reservoir properties, CO_2 injection and monitoring processes, and co-benefits where applicable. Such validation tests are essential to establish the viability of CO_2 capture from power plants (and other industrial point sources) as a GHG mitigation strategy.

As Governor Schwarzenegger indicated in his response to the *2004 Energy Report Update*, "I support continued clean coal technology research and development towards zero emission operation so that we can economically achieve reduced emissions of pollutants such as SO_2, SO_X, NO_X, and mercury and develop methods for capturing and storing significant amounts of CO_2, either as an integral part of the energy conversion process or in pairing with external CO_2 sequestration."

In the interim, California's utility procurement policy will be critical to achievement of its GHG reduction goals and may be a critical driver of "clean coal" technology development in the West. As discussed more fully in Chapter 9, because of the severe projected in-state impacts, California has a special interest in avoiding the consequences of severe climate change and compelling motivation to reduce GHGs. Without burdening interstate commerce or discriminating against particular technologies or fuels, the state should specify a GHG performance standard to be applied to all utility procurement, both in-state and out-of-state, both coal and non-coal. While more specific recommendations must await the January 2006 report of Governor Schwarzenegger's Climate Action Team, the Energy Commission recommends that any GHG performance standard for utility procurement be set no looser than levels achieved by a new combined-cycle natural gas turbine. Additional consideration is needed before determining what role, if any, GHG emission offsets should play in complying with such a performance standard.

Nuclear

A significant portion of California's electricity supply comes from in-state nuclear power plants located at Diablo Canyon and San Onofre and from out-of-state plants at Palo Verde. In addition to operating in-state nuclear facilities, California's utilities are responsible for decommissioning older shut-down reactors at Humboldt Bay, Rancho Seco, and San Onofre, and for safe storage of spent nuclear fuel from both operating and retired plants until the federal government takes possession of this highly radioactive material. Operators of the state's nuclear plants therefore face issues such as transportation and disposal of the spent fuel, potential extensions of operating licenses, and major capital additions such as replacing aging plant components.

New nuclear power plant construction in California is conditioned on assurances by the Energy Commission that a high-level nuclear waste[102] disposal technology has been demonstrated and approved by the appropriate federal agency. In 1978, the Energy Commission determined that these conditions had not been met, and no new nuclear plants have been approved or built in California since that time. In addition, the state's

[102] High-level nuclear waste includes the highly radioactive spent fuel from reactors and the high-level waste from nuclear weapons development.

existing nuclear plants face issues such as transportation and disposal of the spent fuel, potential extensions of operating licenses, and replacement of aging plant components.

Californians have contributed well over $1 billion to the federal waste disposal development effort. Although the U.S. Congress has selected the Yucca Mountain Project as a permanent deep geologic repository for the disposal of spent nuclear fuel, the federal waste disposal program remains plagued with licensing delays, increasing costs, technical challenges, and managerial problems. A recent Massachusetts Institute of Technology study, *The Future of Nuclear Power*, concluded that successful geologic disposal of high-level radioactive waste has yet to be demonstrated, although the authors did conclude that a high-level waste repository is likely to be commissioned in the U.S. within the next 10 to 20 years.[103] Therefore, the Energy Commission must reaffirm the finding made in 1978 that high-level waste disposal technology has neither been demonstrated nor approved. In addition, the Energy Commission recommends that some portion of the funds contributed by California ratepayers toward the federal disposal efforts should be returned to the state to defray ongoing costs of long-term on-site storage of spent fuel made necessary by the lack of a permanent disposal solution.

Given the high level of uncertainty surrounding the federal waste disposal program, California's utilities will likely be forced to retain spent fuel in storage facilities at currently operating reactor sites for an indefinite period of time. The state should evaluate the long-term implications associated with the continuing accumulation of spent fuel at California's operating plants, including a case-by-case evaluation of public safety and ratepayer costs of on-site interim storage of spent fuel versus transporting spent fuel offsite for interim storage.

Transporting spent fuel involves greater complexity, cost, and risk than leaving it in an on-site storage facility.[104] State of Nevada officials and the Alliance for Nuclear Responsibility raised concerns in the *2005 Energy Report* workshops about the potentially higher risks and radiation exposure associated with moving spent fuel shipments through heavily populated and congested urban areas in California. California officials have already expressed concern that DOE's rerouting has increased the number of nuclear waste shipments through California to avoid transport through Las Vegas and over Hoover Dam. In the future, an estimated 13-91 percent of truck shipments and 5-90 percent of rail shipments of spent fuel to the Yucca Mountain site could be routed through California.[105] The Energy Commission recommends that the state evaluate the implications of DOE's increasing use of California routes for shipments of nuclear waste to and from Nevada and the precedent this may set for route selection of future shipments to Yucca Mountain.

[103] Massachusetts Institute of Technology, 2003, *The Future of Nuclear Power*, p 86.
[104] Bunn, Holdren et al, Harvard University/University of Tokyo, *Interim Storage of Spent Nuclear Fuel: A Safe, Flexible, and Cost-Effective Near-Term Approach to Spent Fuel Management*, June 2001, p 18.
[105] "Spent Nuclear Fuel Transportation to Yucca Mountain: Implications for California," pp. 37-38, Bob Halstead, Nuclear Issues Workshop, California Energy Commission, August 15, 2005.

A comparison of fees assessed by California on transporters of spent fuel with fees assessed by other states suggests that California's fees may be insufficient to cover state costs associated with spent fuel shipments for shipment inspections, tracking, and escorts. The state should reexamine the adequacy of California's nuclear transport permit fees and federal funding programs to cover state activities associated with spent fuel shipments.

California also has an ongoing role in protecting public health and safety and assuring the economic cost-effectiveness of investments in electricity generation resources, including nuclear resources. Therefore, the state must consider potential extensions of operating licenses along with other resource options. IOUs are currently seeking approval to replace steam generators and other large plant components at the state's nuclear power plants and other large plant expenditures are likely to follow. Given the high cost of these projects — for example, $700 to $800 million for steam generator replacement costs — it is likely that IOU owners will seek to extend operating licenses at the units.

Communities located near reactor sites continue to be concerned about public health and safety, particularly with today's heightened awareness of terrorism risks. A recent report by the National Academies concluded that while successful attacks on spent fuel pools are difficult, they are a possibility and could lead to a release of large amounts of radioactive material.[106] Given the safety issues, as well as the long-term accumulation of spent fuel and adverse thermal impacts on the marine environment from the once-through cooling technologies used at coastal facilities, it is appropriate that the state undertake a careful and thorough review of the costs and benefits of license extensions. California's Legislature should develop a suitable framework for such a review, including delineation of agency responsibilities, scope of the evaluation, and criteria for assessment.

[106] Board on Radioactive Waste Management, National Academies. *Safety and Security of Commercial Spent Nuclear Fuel Storage: Public Report*, 2005 [http://bboks/nap.edu/catalog/11263.html], and "Safety and Security of Commercial Spent Nuclear Fuel Storage," pp. 7-8, Kevin Crowley, Nuclear Issues Workshop, California Energy Commission, August 15, 2005, [http://www.energy.ca.gov/2005_energypolicy/documents/2005-08015+16_workshop/presentations/panel-4].

CHAPTER 5: TRANSMISSION CHALLENGES

Introduction

California should waste no additional time in tackling its most vexing electricity infrastructure challenge: expanding and strengthening its electric transmission system. The state's more than 31,000 miles of transmission line are as essential to energy delivery as the body's arteries are to the movement of blood; without adequate transmission, electricity cannot move from its point of generation to the 37 million Californians who depend upon it. The consequences of transmission failure can be catastrophic, as the nation learned two years ago when an East Coast transmission failure blacked out New York City and large blocks of the East and Mid-Atlantic regions.

Though the California Energy Commission (Energy Commission) strongly recommended improvements to transmission infrastructure in both the *2003 Integrated Energy Policy Report* (*2003 Energy Report*) and the *2004 Integrated Energy Policy Report Update* (*2004 Energy Report Update*), little has been done. The situation has worsened since the Energy Commission concluded, in the *2004 Energy Report Update*, that California's systematic underinvestment in transmission has left the state's transmission lines congested, increasing the costs of electricity to consumers and reducing reliability. Fixing this problem has fast become a critical policy issue for the state.

The Governor recently agreed with 2003 and 2004 *Energy Report* recommendations on transmission, concluding that: "An effective transmission planning process should be at the bedrock of the state government's commitment to upgrading and expanding California's transmission infrastructure to promote competition, access low cost resources, increase reliability, meet renewable resource goals and assure resource adequacy."[107] The Governor agreed that generation and transmission planning should be linked and reinforced the need to examine generation, transmission, and non-wires alternatives, including energy efficiency, in developing an efficient, integrated, and dynamic electricity system. The Governor also agreed with the *Energy Report* recommendation to consolidate generation and transmission permitting within the Energy Commission. Finally, he agreed that the Energy Commission should have the authority to designate and preserve transmission corridors so that they will be available when needed.

California faces three urgent transmission issues:

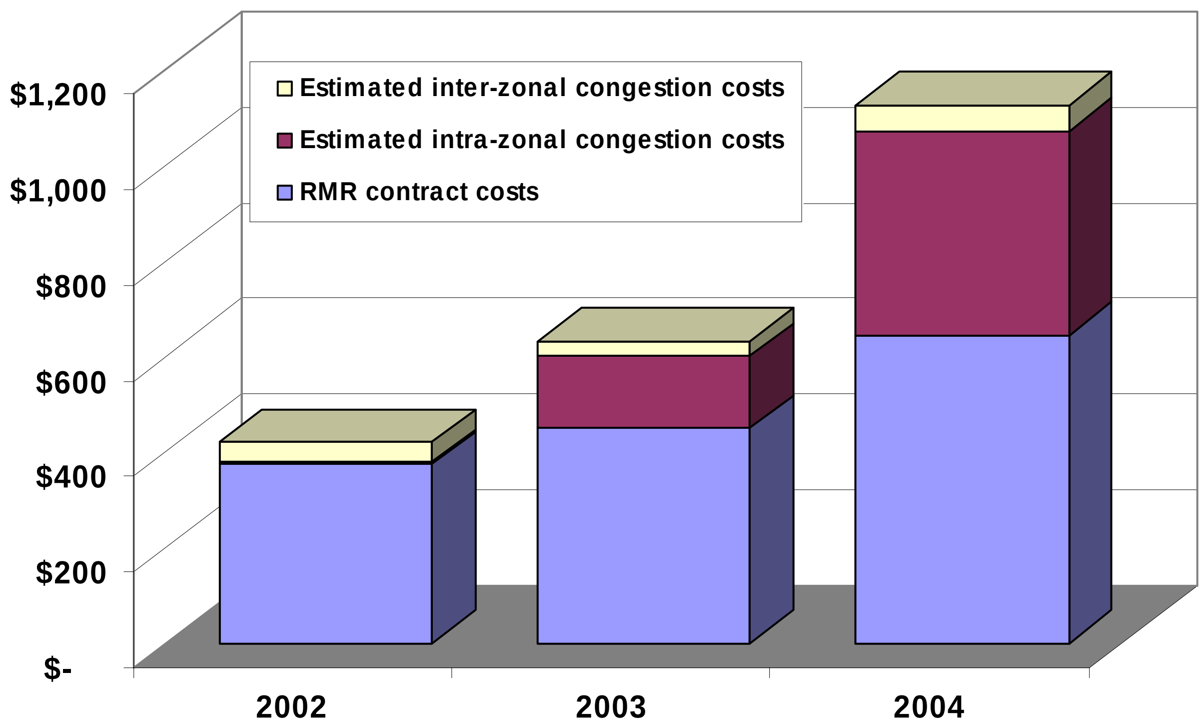
- The state lacks a well-integrated transmission planning and permitting process. Overlapping, sometimes conflicting roles and responsibilities between state and federal agencies cripple California's ability to effectively secure the investment needed to address dramatic increases in congestion costs and serious threats to electric system reliability.

[107] Letter from Governor Arnold Schwarzenegger to the Legislature, attachment: Review of Major *Integrated Energy Policy Report* Recommendations, August 23, 2005

- California urgently needs a formal, collaborative transmission corridor planning process to identify critical transmission corridors well in advance of need so utilities can identify and retain lands and easements and local governments can flag incompatible land uses.
- Without major investments in new transmission infrastructure to interconnect with remote renewable resources in the Tehachapi and Imperial Valley areas, California will not be able to meet its Renewable Portfolio Standard (RPS) targets.

As the transmission system becomes increasingly stressed and power lines become more congested, costs increase because less expensive electricity must be curtailed and replaced with more expensive sources. When transmission lines are heavily loaded, small transmission outages can easily grow into larger transmission problems and more extensive outages. As shown in Figure 12, last year's total cost for transmission congestion and related reliability services in the California Independent System Operator (CA ISO) control area totaled over $1 billion, up from a total of $628 million in 2003.[108]

Figure 12: Congestion and Reliability Costs



Source: Adapted from CA ISO, April 2005, *2004 Annual Report on Market Issues and Performance.*

California policy makers must quickly create an aggressive planning and permitting process to effectively leverage the core responsibilities and strengths of the utilities, the

[108] California Energy Commission, staff report on *Upgrading California's Electricity System: Issues and Actions for 2005 and Beyond*, July 2005, CEC 700-2005-018, p. 2.

Energy Commission, the CA ISO, and the California Public Utilities Commission (CPUC) to collaboratively solve this critical problem. Since the 2000-2001 crisis, the roles of these agencies have changed with the evolving regulation of the state's transmission system. These roles and responsibilities must be clarified, and duplication and conflicts resolved, in a revamped transmission planning and permitting process. Progress will not be possible without inter-agency cooperation and collaboration. Despite substantial efforts made in the *2005 Energy Report* process, the Energy Commission and the CPUC have not been able to resolve differences in this area. The Legislature should take speedy action to realign the jurisdictional roles of these state agencies.

The state also lacks a workable transmission corridor planning process that addresses the long-term planning needs of utilities for future transmission. A state corridor planning process would streamline identification of future transmission paths. This is especially important in light of inevitable local land use controversies that arise as available land in California becomes increasingly scarce. A formal, more inclusive corridor planning process would allow California to work more effectively with federal and state agencies, local governments and affected parties to plan future corridors. Emerging conflicts between the U.S. Forest Service and Southern California Edison (SCE) over the first segment of the Tehachapi transmission line graphically illustrate the challenge of effectively coordinating interagency planning objectives. A thoughtful and well-designed statewide corridor planning process would also allow environmental assessments early in the planning process to preclude the long lead times that plague the current process.

Finally, without major transmission infrastructure investment, California will not be able to reap the benefits of some of the state's most promising areas for renewable generation: the Tehachapi and Imperial Valley areas. California needs to develop these resources to meet accelerated statewide renewable generation goals. Transmission interconnection issues for renewable resources located in developed areas are further complicated by the number of developers competing for transmission capacity and their limited ability to finance large transmission facilities. The *2004 Energy Report Update* recommended the formation of transmission study groups for the Tehachapi and Imperial Valley areas to prepare phased development plans, and these groups have made good progress. However, immediate actions are still needed to remove financing barriers and assure utility cost recovery for renewable transmission projects, including amendments to the CA ISO tariffs which recognize the unique characteristics of these projects.

This chapter addresses the fixes that California policy makers must implement to adequately plan for, permit, and construct crucial transmission upgrades and expansions. It also lays out critical steps in establishing an effective corridor planning process and address renewable transmission needs for the state. Finally, the chapter identifies four major transmission projects that are needed in the near-term to address California's transmission problems.

Background

In the *2003 Energy Report,* the Energy Commission concluded that the existing planning and permitting processes lacked essential mechanisms to plan, permit, and build critically needed transmission in California. At that time, the state did not have an official role in transmission planning. However, in 2004 the Legislature partially corrected that problem by establishing a strategic transmission planning element within the Energy Commission's *Energy Report* process.[109] The *2005 Strategic Transmission Plan*, a companion to the *Energy Report*, identifies actions to encourage needed investments to ensure reliability, relieve congestion, and meet future growth in both load and generation, including renewable resources.

The *2004 Energy Report Update* outlined a more rational planning process that would identify needed transmission infrastructure investments, consider non-wires alternatives to transmission lines (such as generation and demand response measures), and approve those projects in a timely manner. Critical projects could then move directly to permitting so that the analysis required under California's Environmental Quality Act (CEQA) could more appropriately focus on alternative transmission routes, environmental impacts, and mitigation measures. The current hodgepodge system lacks some key components of this process while redundantly duplicating others.

The *2004 Energy Report Update* recommended a collaborative process integrating transmission planning with electricity assessment, resource planning, and energy policy. The *Energy Report* stressed the importance of bringing all parties together to eliminate current overlap and duplication between the Energy Commission, the CPUC, the CA ISO and the state's utilities.

In 2002 and 2003, the Legislature added new electricity resource and transmission planning responsibilities to the Energy Commission's *Energy Report* process. In 2002 the Legislature also assigned new responsibilities to the CPUC concerning investor-owned utility (IOU) procurement. The CA ISO has new management and, in recognition of the seriousness of the state's growing transmission problems, is proposing to revamp its transmission and grid planning processes. These agencies must work hand-in-hand with the Legislature to produce a proactive and forward-looking transmission planning and permitting process for California.

Because electricity deliverability and system reliability are entwined with electricity forecasting, assessment, and resource procurement, the *2005 Strategic Transmission Plan* provides the detailed assessment of transmission projects necessary for IOUs to effectively procure resources.[110]

This chapter provides a summary of the major policy issues and recommendations for transmission, as well as recommendations for critical transmission projects.

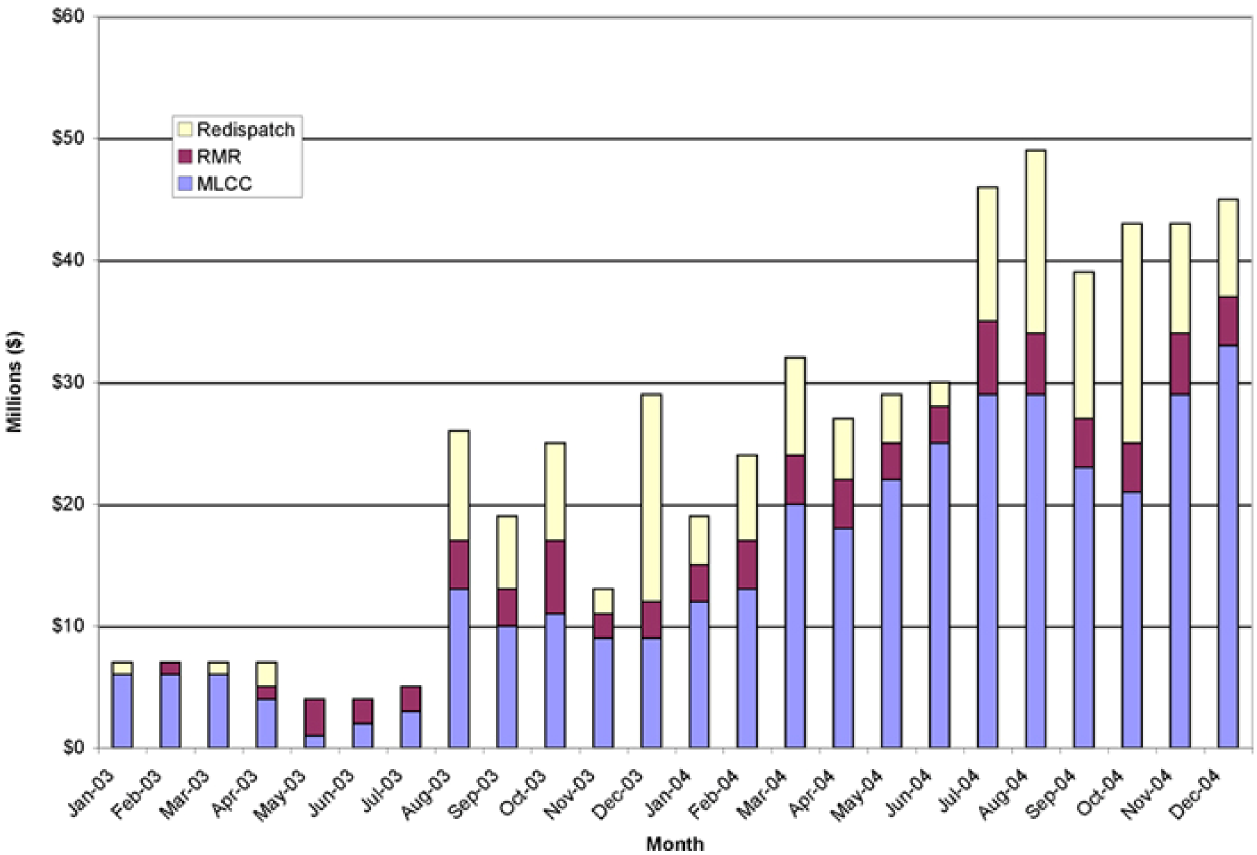
---

[109] Senate Bill 1565 (Bowen) Chapter 692, Statutes of 2004 was signed into law on September 22, 2004.
[110] CPUC Decision 04-12-048, December 16, 2004, p. 183 states: "To the extent an IOU believes that the range of need identified in the 2005 IEPR is sufficient to justify a transmission project then it may be identified as a specific proposal to satisfy need in the 2006 procurement proceeding filings."

Transmission Congestion and Reliability Concerns

In 2004, the cost of congestion and local reliability needs in the CA ISO system approximated $1.1 billion.[111] As recently as this summer, California experienced numerous costly price spikes and several local outages during high peak load periods. This situation is expected to further deteriorate in coming years.

Figure 13: CA ISO Monthly Total Intrazonal Congestion Costs for 2003 and 2004



Source: Adapted from CA ISO, April 2005, *2004 Annual Report on Market Issues and* Performance, p. ES-21, Table E.5, [http://www.caiso.com/docs/2005/04/28/2005042814580818934.pdf], (September 1, 2005.)

The San Diego region's transmission problems are acute and graphically illustrate the importance of adequate transmission. In 2001 San Diego Gas and Electric (SDG&E) identified transmission constraints and increasing congestion on its Mission-Miguel Line, a 230-kV line moving electricity from the southern part of its service territory to downtown San Diego. SDG&E at that time began the process of permitting and building upgrades to the line. By 2004, annual congestion costs totaled over $32 million, increasing to $48 million from July 2004 to July 2005.[112] Over the next year until the

[111] California Energy Commission, *Draft Committee Strategic Transmission Plan*, September 2005, CEC-100-2005-006CTD.

[112] Transcript of Testimony of San Diego Gas and Electric at the July 28, *2005 Integrated Energy Policy Report* Workshop on Transmission.

Mission-Miguel upgrade finally comes on line, congestion costs are expected to have exceeded $50 million. The Mission-Miguel No. 2 Line required only minimal regulatory approval since it was located in an existing right-of-way. Still, even under a creatively developed construction plan, it took SDG&E three years to permit and another two years to build this critically needed upgrade.

SDG&E's transmission situation today is so precarious that the loss of any single transmission line in the area can cause major interruptions. For example, while making repairs to damage on two towers supporting 138-kV lines feeding southern Orange County, SDG&E temporarily took one of the lines out of service.[113] On July 28, 2005, the second line went out, causing 35,000 customers in Laguna Niguel to lose power.

Local reliability issues have become even more complex and expensive as congestion has increased. Local reliability on the CA ISO grid has been historically addressed through either transmission investment or Reliability Must Run (RMR) contracts.[114] The CA ISO awards cost-based contracts to plants deemed critical to local reliability. Many power plants supporting this local reliability are old, inefficient, and slated for replacement or retirement. The challenge for policy makers, the CA ISO, and utilities is to identify the best balance of transmission and generation to create sustainable local reliability.

Both the Federal Energy Regulatory Commission (FERC) and the CPUC have strongly encouraged utilities to pursue alternatives to the expensive, inflexible RMR contracts that were developed eight years ago as temporary local reliability measures. Their continuing reliability role brings the adequacy of the current grid expansion process into sharp question. Despite significant additions to the transmission system over the last several years, California is still experiencing congestion and must rely upon costly RMR contracts for the foreseeable future.

The persistence and magnitude of congestion presents utilities, the CA ISO and regulators with a new set of deliverability issues. At the heart of deliverability is how utilities, the CA ISO, and regulators ensure the delivery of generation: long-term contracts or short-term purchases. Many of these issues are addressed in the CPUC's resource adequacy proceeding, which is discussed in Chapter 3 on electricity.

Integrating Transmission Planning and Permitting

Dysfunctional planning and permitting processes are exacerbating the state's worsening transmission problems. California needs a seamless process for quickly moving transmission projects through planning to permitting. Despite recent improvements in the CPUC's permitting application process, the illogical and cumbersome separation of generation and transmission planning and permitting still plagues the state.

---

[113] Ibid.

[114] The CA ISO conducts annual studies to determine power plants needed to meet reliability requirements and awards Reliability Must Run contracts.

The challenge for state policy makers is to marry the pivotal role of FERC regulation, focused on the CA ISO, with the policy objectives and CEQA requirements valued so highly by California. A dependable foundation for permitting transmission facilities can only emerge from the successful hand-in-hand coordination of the legal duties of both federal and state jurisdictional entities.

Transmission Planning Issues

The *2003 Energy Report* and the *2004 Energy Report Update* each made a number of recommendations to improve transmission planning following an extensive series of workshops with the CA ISO, the CPUC, utilities, and other concerned parties. In this *2005 Energy Report,* the Energy Commission also recommends changes to the transmission planning process designed to both meet objectives outlined in the earlier reports and satisfy new statutory requirements to develop a strategic transmission plan.

The *2005 Strategic Transmission Plan* assesses statewide transmission reliability and economic needs for projects, as well as those necessary for achievement of statewide policy goals, including RPS. Recommendations from this effort to approve projects are discussed in a later section of this chapter on near-term transmission projects. They are also examined in more detail in the *2005 Strategic Transmission Plan*.

Over the course of the Energy Commission's 2005 workshops, a number of suggestions and opportunities emerged that the Energy Commission believes could significantly improve transmission planning in California. Several concerned parties reinforced the importance of avoiding duplication, effectively leveraging limited human resources, and more closely coordinating various forums concerned with transmission planning.

Recognizing that under a FERC-approved procedure, the CA ISO has primary responsibility for planning the utility systems residing within its grid, it is critical that this process play a central role in the state's planning efforts. Although the CPUC is attempting to address transmission planning within its procurement process, a number of inadequacies make transmission an uneasy fit within the procurement process. These are explained in the following excerpt from SCE:

> Transmission investment decisions and retail procurement decisions generally serve two separate functions. Transmission investments are generally made to ensure a reliable and sufficient grid and an enhanced wholesale market. Transmission investments are recovered through FERC rates and are placed into wires charges that apply to all customers who benefit from the investment. Retail procurement is performed on behalf of a specific group of customers who require a specific amount of power at a given time. Retail procurement costs are recovered through CPUC rates and are collected from those customers for whom procurement is being performed. Since these functions have distinctly different objectives, different customers, and different cost recovery mechanisms,

transmission investment and retail procurement decisions should remain separate.[115]

One of the biggest problems with the existing approach to IOU transmission is its reactive nature and dependence upon IOU decisions and timing. The history of the Devers – Palo Verde No. 2 Transmission Line provides an example of the pitfalls of this reactivity, which is recounted in more detail in the *2005 Strategic Transmission Plan*. For the past 20 years, progress on this critical infrastructure has been entirely dependent upon the shifting business priorities of SCE, while the economic consequences of inaction have been absorbed by its ratepayers and other grid users. This project has been studied for several decades and a Certificate of Public Convenience and Necessity (CPCN) application is again pending before the CPUC. In 1985, SCE applied for a CPCN, receiving approval from the CPUC in 1988. SCE, however, decided to postpone construction at that time. In 1993, SCE requested abandonment of the project. SCE still later decided to pursue the project again and filed a new CPCN application with the CPUC earlier this year. Some of the current reserve margin and reliability problems in Southern California could well have been avoided had SCE moved forward when its initial application was approved.

The CA ISO also acknowledges that the existing transmission planning process is overly reactive and insufficiently forward looking. The current cumbersome and time-consuming process includes the following steps:

- Participating transmission owners (PTOs) submit annual transmission assessment and expansion plans for the coming five years, which are then reviewed by the CA ISO.
- CA ISO's management approves projects meeting their criteria and costing under $20 million; projects costing more than $20 million are submitted to the CA ISO board of directors for approval.
- The CA ISO performs an assessment of the combined PTO plans to make sure that projects do not "fall through the cracks."
- Finally, the CA ISO conducts studies to determine RMR generation requirements. [116]

The CA ISO notes it is forced to be reactive in part because it only acts upon projects submitted by PTOs. It further notes that the decision to either pay RMR costs or build facilities to avoid RMR costs has been largely left to the PTOs. The CA ISO also points out that, under this process, transmission expansion projects to ease congestion were completed only after significant congestion costs had already been incurred.

With the recent announcement that the CA ISO is proposing a new planning process, evolving from a reactive to a proactive role in transmission planning, there is a unique opportunity to better coordinate the activities of the three primary concerned state

[115] Southern California Edison filing in Docket No. 04-IEP-1D *2005 Energy Report*: Comments on Electricity Issues and Policy Options Workshop, July 5, 2005, Appendix A, Response to Question 2.
[116] *New CA ISO Transmission Planning Process*, A.J. Perez, CA ISO, August 1, 2004.

agencies: the CA ISO, the CPUC, and the Energy Commission. The Energy Commission strongly believes that a comprehensive planning process including the CA ISO, the CPUC, other key state and federal agencies, local and regional planning agencies, IOUs and municipally owned utilities, generation owners and developers, and other interest groups, should:

- Assess statewide transmission needs for reliability and economic projects and RPS goals.
- Examine non-wires alternatives (generation and demand side measures) to transmission.
- Approve beneficial transmission infrastructure investment that smoothly moves into permitting including:
  - Addressing right-of-way needs.
  - Conducting designation and environmental review of needed corridors.
  - Identifying necessary land and easement acquisition.
  - Assessing costs and benefits that recognize the long useful life of transmission assets.
  - Incorporating quantitative and qualitative methods to assess strategic benefits.
  - Using an appropriate social discount rate.

Transmission Permitting Issues

In the *2003 Energy Report* and the *2004 Energy Report Update*, the Energy Commission recommended that the state consolidate permitting of new bulk transmission lines within the Energy Commission, using the Energy Commission's power plant siting process as a model. Given the critical need to upgrade and expand California's transmission infrastructure, the Energy Commission recommended that the Governor expedite consolidation with his statutory reorganization power through the Little Hoover Commission.

In the *2004 Energy Report Update,* the Energy Commission, noting longstanding, continuing, and widespread criticism of California's permitting process, strongly restated the *2003 Energy Report* recommendation that permitting jurisdiction be urgently addressed. The Energy Commission did note that the CPUC reached favorable decisions on several important projects including Mission-Miguel and Jefferson-Martin.

Since adoption of the *2004 Energy Report Update,* the CPUC approved the Otay Mesa Power Plant Transmission Project and approved temporary modifications allowing the Mission-Miguel transmission upgrade to partially come on line a year ahead of schedule. Three additional critical transmission lines have pending CPCN applications, including two segments to enhance the Tehachapi and Devers – Palo Verde No. 2 transmission lines.[117]

[117] California Energy Commission, *Upgrading California's Transmission System: Issues and Actions for 2005 and Beyond*, staff report, July 2005, CEC #700-2005-018, p. 17.

While the CPUC has recently eliminated extensive delays in its CPCN application process, one of the drivers for the proposed transfer of transmission permitting from the CPUC to the Energy Commission is the recognition that state and federal restructuring of the electricity industry diminished the CPUC's oversight in financial regulation of IOU transmission investments. Before passage of California's electric industry restructuring law in 1996, the CPUC had primary responsibility for the regulation of all IOU investments, including transmission.

The FERC is now responsible for financial regulation of IOU transmission investments, including cost recovery, which is shared by all customers under the CA ISO umbrella. The CPUC's role in financial regulation of IOU transmission investments is now limited to that of an intervener in FERC rate cases, on behalf of California IOU ratepayers, and allocating FERC-approved transmission costs to different classes of retail customers.

Earlier this year, the Administration submitted a reorganization plan to the Little Hoover Commission and the Legislature that would overhaul California's energy agencies, including implementation of the *2003 Energy Report's* recommendation on transmission permitting.[118]

The Attorney General pointed out during review of the proposal, however, that the transfer of authority to issue a CPCN using the Little Hoover reorganization process was constitutionally inappropriate because of the role of the CPCN in the CPUC's constitutionally conferred rate-making authority.[119] The Attorney General went on to note that the reorganization statute would permit transfers of authority that do not interfere with the CPUC's ratemaking function, citing as an example the Warren-Alquist State Energy Resources Conservation and Development Act (Warren-Alquist Act), where the Energy Commission has responsibility for the siting of thermal energy plants and their related transmission lines.[120] The Attorney General observed that the Energy Commission's power plant licensing responsibility does not extend to the rate-making functions included in siting and leaves the CPCN responsibility with the CPUC.

In light of this opinion, the Energy Commission recommends that the Legislature move this siting function from the CPUC to the Energy Commission, consistent with the Warren-Alquist Act framework. Under this proposal the siting of transmission lines would fall under the auspices of the Energy Commission through Applications for Certification (AFC), which must be obtained before an IOU can apply to the CPUC for a CPCN. This process has been highly successful for licensing new power plants since passage of the Warren-Alquist Act in 1974 and remains in place for utility-owned generation construction proposals today. It is critical to note that this process has not created duplicative requirements in the Energy Commission's siting and CPUC's CPCN reviews, which could slow down construction of critically needed transmission facilities.

[118] *A Vision for California's Energy Future*, June 2005, p. 6.
[119] Letters from the Attorney General to the Little Hoover Commission regarding Inquiry Regarding Governor's Energy Agency Reorganization Plan, June 22 and 23, 2005.
[120] Public Resource Code Sections 25500, 25119. 25110, 25120. 25107.

Transmission Corridor Planning

California currently lacks a planning process that identifies transmission corridors before they are needed. Comprehensive long-term transmission planning should allow utilities to acquire needed lands and easements ahead of time. It also should make room for upfront environmental assessments that would streamline the current process and shorten lead times for bringing transmission on line. A formal corridor planning process would also more effectively deal with land use concerns by coordinating with local, state, and federal agencies and other parties.

The *2004 Energy Report Update* recommended that the Legislature authorize the Energy Commission to designate needed transmission corridors and conduct appropriate environmental assessments as part of its new transmission planning responsibilities. It also recommended that the CPUC extend the time IOUs are allowed to keep their investments in future transmission corridors in their rate bases.

Based on the extensive testimony and input of parties in the 2005 Energy Report process, the Energy Commission identified three essential components of a successful corridor planning process for California:

- A corridor identification process.
- State corridor designation authority.
- Corridor land acquisition and banking.

The first element, a corridor identification process, would allow all stakeholders and the public to raise concerns and address issues early in the planning process. Under this proposed structure the Energy Commission would identify the corridor needs of transmission owners; establish corridor priorities; identify major permitting; environmental and land use issues; and ensure participation of all affected local, state, and federal agencies and other concerned parties.

A second element, designation of corridors, would allow IOUs to retain investments in future lands and easements in their rate bases for a longer period of time, providing them with greater financial certainty. Corridor designation would require local planning agencies to avoid incompatible uses and would also allow the Energy Commission to proceed with environmental reviews, significantly shortening the overall planning and permitting lead times for transmission. The designation process would be separate from the *Energy Report* process.

The third element, IOU land acquisition and banking for future corridors, would allow IOUs to retain investments in their rate bases for a longer period of time. The CPUC's current five-year limit on IOU investment of lands in rate base is insufficient for long-term corridor planning, and needs to be extended.

Transmission for Renewable Resources

The *2004 Energy Report Update* described the critical importance of transmission upgrades for interconnecting remote sources of renewable generation. Transmission upgrades in the Tehachapi wind and the Imperial Valley geothermal resource areas are needed to reap the benefits of some of California's most promising renewable resources. The Tehachapi Transmission and Imperial Valley Transmission groups convened following recommendations in the *2004 Energy Report Update*, are making progress in developing plans for transmission upgrades. Yet despite their efforts and the efforts of utilities and the renewables industry, California remains stymied in its efforts to increase renewable transmission investment.

Possibly the single greatest blow to renewable transmission development is the FERC's recent rejection of SCE's renewable trunk line proposal. SCE developed an innovative renewable resource "trunk line" concept that would interconnect a large concentration of potential renewable generation and be operated by the CA ISO. The trunk line proposal included several linked segments in the Tehachapi area and would have allowed SCE, Pacific Gas and Electric (PG&E), SDG&E, and other CA ISO grid users access to as much as 1,100 MW of renewable resources. Despite support by California's primary energy agencies, the FERC disapproved the application. The FERC ruled that the third segment SCE identified as a "renewable resource trunk facility" was ineligible for rolled-in rates since the segment resembles more of a "generation tie" than a "network upgrade."[121]

Current FERC policy effectively bars the advanced planning and construction of transmission facilities necessary through the which-came-first "chicken and egg" nature of renewable transmission development. Renewable projects cannot secure contracts under RPS procurement procedures without prior knowledge of whether existing transmission will be able to accommodate them. Utilities are leery of investing in renewable transmission without assurances of cost recovery. This poses a major impediment to renewable resource development.[122]

Even when a renewable developer requests new transmission capacity, the present system assigns the lion's share of its cost to the developer with the project that first pushes the transmission system beyond its existing capability. Transmission upgrades would be much more efficiently built through a phased-in development plan anticipating future renewable generation instead of additions of relatively small, individual projects. But phased-in development requires the pre-building of portions of transmission lines, currently not allowed under FERC regulation.

[121] *Southern California Edison Co.*, 112 FERC ¶ 61,014 (2005).
[122] The Federal Energy Regulatory Commission's abandoned plant policy means that Southern California Edison is exposed to the risk that it could be left with sizeable quantities of unused transmission and must assume liability for 50 percent of these "abandoned" costs. Southern California Edison Company, March 23, 2005, "Southern California Edison Company's Petition for Declaratory Order," United States of America, Before the Federal Energy Regulatory Commission, Docket: EL05-80-000, http://www.ferc.gov/docs-filing/elibrary.aso, accessed April 15, 2005, see pp. 18-19.

Because of the FERC's denial of the renewable trunk line concept, the Energy Commission strongly believes that its *2004 Energy Report* recommendation that the Energy Commission, the CPUC, and the CA ISO implement changes to the CA ISO tariff is even more necessary today for meeting California's renewable goals than it was a year ago.[123]

Near-Term Transmission Projects

The Energy Commission examined the need for transmission investment in detail in the *2005 Strategic Transmission Plan.* This transmission need was summarized in three broad categories:

- Projects needed for reliability.
- Projects needed to relieve transmission congestion.
- Projects needed to meet future load growth and generation, including renewable resources.

The *2005 Strategic Transmission Plan* focuses on near-term projects that would improve reliability, help mitigate congestion costs, access economic generation, assist in meeting RPS goals, and be on line by 2010. The Energy Commission has identified the four projects below as vital near-term transmission additions critical to meeting California's rapidly growing transmission needs. These projects are examined in greater detail in the *2005 Strategic Transmission Plan*.

San Diego 500-kV Project

The proposed San Diego 500-kV project is a 500-kV transmission line connecting the Imperial Valley to SDG&E's service territory featuring a potential northern interconnection to SCE's service territory. The proposed project would reduce congestion and the cost of meeting load growth in the San Diego area. The northern 500-kV interconnection to SCE's service territory would both improve overall reliability of California's transmission system and increase the ability to import lower-cost power from Arizona, Mexico, and the desert Southwest. The proposed 500 kV project would also allow SDG&E to meet its reserve requirements for many years, depending upon growth in the region and retirement of local aging power plants, and is also a key component of SDG&E's strategy to meet RPS goals.

[123] CA ISO Tariff Section 3.2.1.1 outlines the requirements for a need determination for economically driven projects, while Section 3.2.1.2 outlines the requirements for a need determination of reliability projects. Neither of the categories adequately accommodates the unique circumstances of renewable transmission projects.

The Energy Commission strongly believes that this proposed project offers significant benefits and recommends that it move forward expeditiously so that the residents of San Diego and all of California can begin realizing these benefits by 2010.

Because San Diego faces significant land use constraints that will require resolution, the Energy Commission also recommends formation of a collaborative Corridor Study Group to quickly address concerns of local, state, and federal agencies, landowners, and other interested parties.

Imperial Valley Transmission Upgrade Project

The Imperial Valley Transmission Upgrade Project, proposed by Imperial Irrigation District (IID), would increase transmission capacity by an additional 2,000 MW and provide access to valuable renewable resources needed to meet future load growth and RPS goals. The Imperial Valley is one of the state's most promising sources of renewable generation. Geothermal resources today produce around 450 MW in the Imperial Valley area, and developers estimate that an additional 1,350 to 1,950 MW could be developed over the next 15 years. The proposed Imperial Valley Transmission Upgrade Project would provide a much needed interconnection to these renewable resources, support California's RPS goals, and provide significant near-term system reliability. The Energy Commission therefore believes the proposed project offers significant benefits and recommends that it move forward expeditiously.

Since IID faces significant land use constraints requiring speedy resolution before completion of the project, the Energy Commission recommends that the Imperial Valley Study Group immediately coordinate with local, state, and federal agencies, landowners, and other interested parties.

Palo Verde – Devers No. 2 500-kV Transmission Project

The SCE-proposed Palo Verde – Devers No. 2 (PVD2) 500-kV Transmission Project consists of a new 500-kV transmission line from the Palo Verde area of Arizona to Southern California. This project would occupy the same corridor as the existing Palo Verde – Devers 500-kV transmission line and significantly reduce congestion on transmission lines linking California to Arizona. It would also provide access to lower-cost out-of-state generation, even in the face of rapid growth in the Southwest.

The proposed project would provide strategic benefits to California ratepayers, including valuable insurance against abnormal system conditions and power outages. It would increase operating flexibility for California grid operators, reduce market power for generators, and reduce the need for additional infrastructure. The Committee therefore believes that this proposed project offers significant benefits and recommends that it move forward expeditiously so that California can begin realizing these benefits by 2010.

The Energy Commission also recommends formation of a Corridor Study Group to review existing land uses along the existing Interstate 10 transmission corridor and coordinate with local, state, and federal agencies, landowners, and other interested parties.

Tehachapi Transmission and Expansion of Path 26

The Tehachapi area transmission projects proposed by SCE are critical for development of wind resources needed to meet RPS targets and would also reduce congestion on transmission lines serving Southern California. The project would allow interconnection with over 4,000 MW of new wind generation, which represents a significant portion of the renewable generation that California utilities need to meet RPS by 2010. The Tehachapi Collaborative Study Group (TCSG) developed a conceptual transmission plan that would connect and deliver approximately 4,500 MW of Tehachapi wind generation to loads in California.

Another component of the conceptual plan is an interconnection to PG&E's system. An interconnection with PG&E would both give PG&E access to Tehachapi renewable resources and potentially expand Path 26 transmission capacity into Southern California. The TCSG is examining this proposed interconnection.

The TSG conceptual transmission plan includes facilities that would collect power from Tehachapi area wind projects and interconnect it with the state's transmission grid. Network upgrades would enable delivery to load centers. Transmission facilities would be built in four phases:

- Phases 1 and 2 would connect 1,600 MW of new wind resources to the Southern California grid.
- Phases 3 and 4 would allow interconnection of an additional 2,900 MW.

Because of its critical role in meeting RPS goals, the Energy Commission believes this proposed project offers significant benefits and recommends that all phases move forward expeditiously. CPCNs for Phases 1 and 2 are pending before the CPUC. The Energy Commission believes that the record developed on these projects in the *Energy Report* proceedings should be used to supplement the record developed at the CPUC to bolster additional support for this much needed project.

CHAPTER 6: RENEWABLE RESOURCES FOR ELECTRICITY GENERATION

Introduction

California needs to increase its use of renewable resources to diversify the state's electricity system and reduce its growing dependence on natural gas. Over the past two decades, California has developed one of the largest and most diverse renewable generation mixes in the world. In 2004, 10.6 percent of the state's electricity came from renewable sources, excluding large hydroelectric power. The Energy Commission estimates that the state has near-term economic potential for an additional 6,000 MW of renewables which, if developed, would nearly double California's renewable generating capacity.[124]

To meet its ambitious goals for increasing the percentage of electricity derived from renewable energy sources, California must overcome four major barriers:

- The lack of long-term purchase agreements for power.
- The need for new and/or upgraded transmission to access renewable resources in many areas of the state.
- The impact of integrating large amounts of intermittent renewable resources into the electricity grid.
- The need to repower aging wind facilities and reduce the number of bird deaths associated with the operation of wind turbines.

The Renewable Portfolio Standard (RPS) program is central to meeting California's renewable resource goals. Established in 2002, RPS was designed to address the lack of long-term power purchase agreements which prevent developers from getting the financing needed to build their projects. After three years of implementation, however, the RPS is plagued by a lack of transparency, overly complex rules, and inconsistent application among retail sellers. As a result, only a small number of contracts have been signed for renewable projects, many of which will not even begin operation until the end of 2006.[125]

Even if sufficient contracts were signed to assure meeting the state's renewable resource goals, transmission upgrades are required to take advantage of resources in the Tehachapi wind and the Imperial Valley geothermal resource areas. Although the

---

[124] California Energy Commission, July 2005, *Implementing California's Loading Order for Electricity Resources*, CEC-400-2005-043, page 26.
[125] Southern California Edison, March 25, 2005, "Advice 1876-E-A to Public Utilities Commission of the State of California Energy Division, Supplement to Submission of Contracts for Procurement from Renewable Resources Pursuant to California Renewables Portfolio Standard Program," and Pacific Gas and Electric Company, Advice Letter 2678-E to the CPUC, "Contract for Procurement of Renewable Energy Resources Resulting from PG&E 2004 Renewable Portfolio Standard Solicitation," June 21, 2005.

Tehachapi and Imperial Valley Transmission Groups have made progress in developing plans for transmission upgrades, the Federal Energy Regulatory Commission (FERC) recently rejected Southern California Edison's (SCE) renewable trunk line proposal. The FERC's action removed the primary instrument the state could have used to address transmission constraints for renewables.

California has substantial wind resources likely to play an important role in meeting the state's RPS goals. However, significantly increasing the amount of wind resources in California's electricity mix could have negative impacts on the state's transmission system. California must also address barriers to repowering aging wind facilities, particularly in the Altamont Pass area. Replacing older turbines with modern, more efficient turbines will not only increase the amount of renewable energy available to meet RPS goals, but could also reduce bird deaths associated with wind turbine operation.

California also has significant biomass resources, with 1,000 MW of generating capacity accounting for more than 2 percent of the state's electricity mix. Biomass has strategic value as a renewable resource that can help meet the state's RPS goals while also capturing social, economic and environmental benefits and improving transmission reliability. In his response to the *2003 Energy Report,*[126] Governor Schwarzenegger called for an integrated and consistent state policy on biomass development.

While the *2003 Energy Report* and *2004 Energy Report Update* identified strategies to promote the development of renewable resources in California, additional work and legislative action is needed to overcome barriers facing these resources and ensure that the state's RPS goals are met.

Background

When the RPS program was established in 2002, it required the state's investor-owned utilities (IOUs) to increase their use of eligible renewable resources by at least 1 percent of sales per year with a target of 20 percent renewable resources by 2017. The *2003 Energy Report* recommended accelerating the goal of meeting the RPS target to 2010 because of the perceived significant progress already made toward the 20 percent goal. The report also recommended developing more ambitious post-2010 goals to maintain the momentum for continued renewable energy development, expand investment and innovation in technology, and bring down costs.

The *2004 Energy Report Update* further recommended an increased goal of 33 percent renewable by 2020, arguing that IOUs with the greatest renewable potential should have a higher RPS target. Because SCE has three-fourths of the state's renewable

[126] Letter from Governor Arnold Schwarzenegger to the Legislature, Attachment: Review of Major Integrated Energy Policy Report Recommendations, August 23, 2005.

technical potential and had reached 17.04 percent renewable by 2002,[127] the report recommended a new target for SCE of 35 percent by 2020.

The California Public Utilities Commission (CPUC) reinforced the importance of renewable energy as an integral part of the state's loading order policy by directing IOUs in their long-term procurement plans to consider renewable resources as "the rebuttable presumption."[128] IOUs must file long-term procurement plans every two years, starting in 2004, and justify any selection of fossil generation over renewable generation. Renewable generators must be responsive to IOU power needs for specific products and be cost-effective compared with fossil generators when a greenhouse gas adder is included.

The *2003 Energy Report* also recommended extending the RPS to all retail sellers of electricity, including publicly owned utilities (POUs). In the RPS statute, retail sellers include electric service providers (ESPs), and community choice aggregators (CCAs). While ESPs and CCAs have the same RPS obligations as IOUs, there are no rules in place for their participation. To meet the state's goals for renewable energy, the state needs to develop rules for these entities to ensure that RPS targets, eligibility requirements, and compliance dates are applied consistently among all participants. The absence of rules for ESPs and CCAs is delaying the state from reaching its 20 percent renewable target by 2010.

Because POUs provide 20-25 percent of the state's electricity, the *2004 Energy Report Update* argued that applying the accelerated and increased RPS targets to these entities was crucial for meeting the state's goals for renewable energy. However, attempts to pass legislation that would require POUs to comply with RPS targets have been unsuccessful.

While California's renewable resources offer the potential to decrease the state's dependence on fossil fuels, significant transmission upgrades are needed to take advantage of resources in the Tehachapi wind and the Imperial Valley geothermal resource areas to move that energy from its source to the customers. In addition, integrating large amounts of intermittent resources such as wind into the transmission system will require greater flexibility in system operations. In the near term, the state has determined that operational constraints posed by the intermittent nature of renewable resources are manageable and do not significantly increase costs. As the penetration of intermittent wind resources increases over time, however, additional measures will be needed to integrate these resources into the electricity system.

Taking advantage of California's substantial wind resources to meet RPS goals requires that two significant and related issues be addressed: repowering the state's aging wind

[127] California Energy Commission, July 2005, *Implementing California's Loading Order for Electricity Resources*, CEC-400-2005-043, Appendix A, Section 14.
[128] CPUC, "Opinion Adopting Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company's Long-term Procurement Plans," D.04-12-048, pp. 2 and 69, December 16, 2004.

facilities, particularly in the Altamont Pass area, and mitigating the number of bird deaths associated with the operation of wind turbines. Repowered wind facilities with existing standard offer contracts cannot receive federal tax incentives unless they amend their contracts so that generation above historical production is paid at the utilities' current short-term avoided cost, which is much lower than current contract prices. Without the ability to recover additional costs through their contracts, wind facilities have little incentive to repower.

In the *2004 Energy Report Update*, the Energy Commission highlighted repowering as a primary option for reducing bird deaths associated with wind turbines, particularly in the Altamont Pass area. Preliminary research indicates that replacing a number of small turbines with fewer, larger turbines could likely reduce avian mortality. However, planning officials in the Altamont area have placed a moratorium on permits for both new and repowered wind facilities until they are confident that steps have been taken to reduce bird deaths.

Improving the Renewable Portfolio Standard Program to Meet Goals

Clearly, statewide renewable procurement is not proceeding as quickly as needed to reach RPS goals by 2010. Contracts from SCE's 2003 RPS solicitation were not approved until mid-2005, and the facilities are not expected to come on line until the end of 2006. Pacific Gas and Electric's (PG&E) first contracts from its 2004 RPS solicitation were not approved by the CPUC until July 2005, and contracts from San Diego Gas and Electric's (SDG&E) 2004 solicitation are still being negotiated. In July 2005, the CPUC approved the IOUs' long-term procurement plans and draft requests for offers (RFOs) for the 2005 RPS solicitation. PG&E released its 2005 RPS solicitation on August 4, 2005.

The primary problems with the RPS program are:

- The lack of transparency in the bidding, ranking, and contracting processes.
- The administrative complexity of the program.
- The uneven application of RPS targets to all retail sellers in the state.

Increasing Program Transparency and Efficiency

One of the main problems with the RPS program is the lack of transparency for program participants and the public. Because public funds are used to support the RPS program, it is essential that all parties understand how these funds are allocated. The least-cost, best-fit method used by IOUs to rank RPS bidders is particularly unclear. The intent of the least-cost, best-fit process was to ensure that IOUs did not arbitrarily select projects without taking into consideration the full range of benefits provided by renewable generators. The CPUC defines "best fit" as "the renewable resources that best meet the utility's energy, capacity, ancillary service, and local reliability needs."[129] Each IOU has its own distinct least-cost, best-fit methodology but those methodologies are only broadly described and use qualitative as well as quantitative components, making it impossible for policy makers to determine whether IOUs are selecting projects that are truly least cost and best align with the state's policy to provide long-term benefits to the system.

Transparency is also needed in the bid evaluation process for contracts. Currently, bid results are confidential except for a select group of parties within the procurement review group (PRG). As a result, decision makers at the Energy Commission are not privy to confidential information revealed to the PRG but must still approve allocation of supplemental energy payments to cover the above-market costs of contracts resulting from RPS solicitations. Without more clarity regarding the RPS bid evaluation process, the Energy Commission cannot be certain that supplemental energy payments will be used most efficiently to help meet the state's RPS goals.

Another example of the lack of transparency in the RPS program is its administrative complexity. The RPS statute requires the CPUC to establish a benchmark price for energy to determine the need for public funds to cover the above-market costs of procuring renewable energy.[130] This "market price referent" (MPR) is intended to be a proxy for the cost of developing conventional energy sources. The process for determining the MPR, however, is convoluted and continues to increase in complexity. Reaching consensus among parties on the assumptions used to calculate the MPR takes considerable time and resources. In addition, assumptions used to derive the MPR may be significantly different from assumptions used in the CPUC's all-source procurement efforts, making the two procurement processes inconsistent. The potential use of multiple MPRs to reflect different products and contract terms also complicates administration of supplemental energy payments for above-market contracts.

Recommendations to Simplify RPS Administration

Several options could simplify administration of the RPS program. One option would be to make RPS procurement the same as all-source procurement, eliminating the market price referent and supplemental energy payment processes. To contain RPS program costs, the CPUC could apply the same reasonableness review to renewable contracts applied to non-renewable procurement. Another option is to follow the structure used in interim RPS procurement. In interim procurement, the CPUC publicly announced a single cut-off contract price below which contracts were judged reasonable, with costs recoverable in utility rates. This option would avoid much of the current complexity of multiple MPRs as well as the need for separate supplemental energy payments. Advantages of this option include proven success, simplicity, and transparency.

---

[129] CPUC, June 19, 2003, Decision 03-06-071, "Order Initiating Implementation of the Senate Bill 1078 Renewable Portfolio Standard Program," p. 28, [http://www.cpuc.ca.gov/word_pdf/FINAL_DECISION/27360.pdf], accessed April 19, 2005.

[130] Senate Bill 1078 (Sher), Chapter 516, Statutes of 2002, codified in pertinent part in Public Utilities Code Section 399.15, Subdivision (c).

A third option is to award public funds for RPS contracts through auctions for production incentives, with awards conditioned on receiving contracts through the RPS solicitation process. The Energy Commission used the auction process to award funds to renewable energy developers when the public goods charge for renewable energy development was initially authorized in 1997.[131] All information submitted in the bids was publicly available, as were the criteria used in the bid selection process. The Energy Commission held three auctions for production incentives between 1998 and 2001, resulting in 400 MW of new renewable projects coming on line. Several stakeholders have recommended a return to the auction process, citing its simplicity and success.

The CPUC, in collaboration with the Energy Commission, should investigate options for developing an alternative RPS framework and propose legislation that would adopt a simpler and more transparent RPS process by next year. In the meantime, the CPUC should allow for changes to the current program that can be accomplished under existing RPS law. In addition to changes to transmission cost adders, addressed later in this chapter, the CPUC should allow and encourage inter-utility trades under flexible compliance, the use of shaped products, and more flexible delivery requirements.

California needs to encourage shaped or firmed renewable products to provide the necessary flexibility for renewable generators to structure their RPS contracts to keep transmission costs low and better meet IOU energy profile needs. The CPUC should clarify that utilities can enter into RPS contracts for shaped products, such as the storage and shaping service offered by the Bonneville Power Administration which stores hourly wind energy generation in the federal Columbia River Hydroelectric System and delivers it to purchasing customers a week later.

To avoid under-procurement of renewable energy, the CPUC should require IOUs to procure a prudent contract-risk margin. There are many legitimate reasons for cancellation and delay of otherwise sound RPS contracts. These include unanticipated difficulties with getting required land easements; higher turbine and equipment prices than anticipated in contracts; uncertainty about whether it is possible to get projects on line before incentives are fully subscribed; and difficulty in securing financing. These are all possible "force majeure" events. In the state's experience with contracts for qualifying small power production facilities, one-third of the projects did not result in actual energy procurement. A 30 percent contract-risk reserve margin above the IOUs' annual procurement targets would be a prudent starting point to prevent under-procurement. In the longer term, as experience is gained with renewable solicitations, the margin should be revised to reflect actual versus contracted energy.

The CPUC, in collaboration with the Energy Commission, should also develop standard power purchase contracts to speed up the contract negotiation process between IOUs and renewable bidders. Provisions relating to definitions, construction milestones, penalties, force majeure, operating reporting requirements, security, and other non-commercial terms should be standardized for three contract types (baseload, as-

[131] Senate Bill 90 (Sher), Chapter 905, Statutes of 1997, codified in pertinent part in former Public Utilities Code Section 383.5, Subdivision (c).

available, and peaking) while commercial terms such as term, delivery point, contract price, and contract quantity would remain subject to negotiation.

Applying RPS Targets Consistently

Another major problem with the RPS is that RPS procurement targets are not being met uniformly among the various load serving entities (LSEs) in the state. The state needs to act now to ensure that RPS standards, including eligibility, targets, and compliance dates, are applied to all retail sellers within the state. Because POUs are not subject to the same implementation rules as IOUs, their RPS programs include varying targets, timelines, and eligibility standards. Also, even though hydroelectric projects larger than 30 MW are not considered eligible renewable resources under the RPS program for IOUs, many POUs still count generation from these projects toward their renewable energy targets.

POUs are not required by statute to conform to all the RPS requirements established for IOUs, including definitions of eligible renewable resources and requirements for MPRs and supplemental energy payments, least-cost, best-fit criteria, standard contract terms and conditions, and other administrative details associated with procuring renewables. Because of the difficulties associated with these complex administrative requirements for IOUs, they should not be applied to POUs. However, the targets, timelines and eligibility standards established for IOUs should be applied consistently to POUs since those entities are intended to contribute to statewide renewable goals.

Applying consistent statewide RPS rules to POUs will require legislative action. The need to bring POUs into the RPS is underscored by data indicating that the amount of renewables in California's electricity mix has actually dropped since 2002, from 11 percent to 10.6 percent statewide. Based on data submitted by IOUs on their progress toward RPS compliance, the shortfall appears to be from non-IOU retail sellers such as POUs, ESPs, and CCAs. Although a number of POUs already report more than 20 percent eligible renewables, in 2003 the state's largest POUs, Los Angeles Department of Water and Power and the Sacramento Municipal Utility District, reported only 1.5 percent and 7 percent renewables, respectively. The newly-elected mayor of Los Angeles, however, recently committed to reaching 20 percent by 2010. [132]

The *2004 Energy Report Update* recognized that for smaller POUs, there may be difficulties in complying with RPS goals because of contractual obligations, small load, slow growth rates, and the lack of locally available renewable resources. The state should therefore establish an exemption process to avoid overly burdensome requirements for these POUs consistent with the Energy Commission's earlier recommendations.

---

[132] "Villaraigosa Appoints New DWP Board," August 16, 2005, http://www.latimes.com/news/local/la-me-dwp16aug16,1,3786019.story?coll=la-headlines-california, accessed August 16, 2005.

For ESPs and CCAs, the lack of rules for RPS compliance is hampering their participation in the RPS program. RPS rules for IOUs, such as calling for electricity delivery, long-term contracts, and procurement oversight by the CPUC, do not fit typical ESP and CCA business models. Therefore, the state needs new regulatory structures for ESPs and CCAs. Under the RPS statute, the CPUC must determine how these entities will participate in the RPS and be "subject to the same terms and conditions" as IOUs. The CPUC made some progress toward developing RPS procurement and compliance requirements for ESPs and CCAs by issuing a draft decision in June 2005 setting forth the basic parameters for RPS participation by ESPs, CCAs, and small and multi-jurisdictional utilities.[133]

The CPUC draft decision proposes that ESPs and CCAs not needing public goods charge funds to meet their RPS requirements could be excused from some of the requirements imposed on the IOUs such as submitting renewable resources plans and using the least-cost, best-fit methodology to evaluate renewable bids. They would, however, still be required to meet annual procurement targets, the 20 percent target by 2010, and reporting and tracking requirements. If an ESP or CCA needs public goods charge funds, then it would be subject to all the same rules that apply to IOUs. Further progress to establish and implement RPS rules must be achieved in the near term for ESPs and CCAs to begin achieving RPS goals.

Recommendations to Apply RPS Goals and Targets Statewide

One way to facilitate participation of all LSEs in the RPS is to allow limited use of renewable energy certificates (RECs) for RPS compliance, with the associated electricity sold into the California Independent System Operator (CA ISO) real-time market or bilaterally to retail sellers. RECs allow the sale of the "greenness" of renewable electricity separate from the energy itself, called "unbundling." California's RPS program currently does not allow the use of unbundled RECs for RPS compliance. However, several stakeholders identified tradable RECs as an important tool that IOUs, POUs, ESPs and CCAs could use to meet their RPS compliance obligations.

As outlined in the *2004 Energy Report Update,* unbundled RECs represent a potential advantage for California because they could reduce the need for new transmission lines, relieve transmission congestion, and help meet renewable energy goals. Though RECs can help utilities transfer renewable attributes between utilities, ESPs, CCAs and POUs, RECs would not eliminate the need for transmission investments to interconnect and access renewable resources. Even with these potential transmission constraints, unbundled RECs may be a reasonable means for LSEs to increase the amount of renewable resources in the state. Because some parties raise concerns that RECs

---

[133] See CPUC Rulemaking R. 04-04-026, Draft Decision of ALJ Allen, "Opinion on Participation of Energy Service Providers, Community Choice Aggregators, and Small and Multi-Jurisdictional Utilities in the Renewables Portfolio Standards Program," mailed June 29, 2005, and scheduled for consideration on September 8, 2005 meeting at the CPUC [http://www.cpuc.ca.gov/word_pdf/COMMENT_DECISION/47469.doc], accessed July 5, 2005.

could invite market manipulation or double-counting, the development of adequate safeguards should be pursued to allow REC use in California.

By allowing limited use of RECs in the near-term, California can gain experience and make necessary adjustments to ensure that RECs achieve intended advantages. Until the Western Renewable Energy Generation Information System (WREGIS) is developed and in place to electronically track the transfer of RECs and help verify RPS compliance and prevent manipulation and double counting, the state should proceed with RECs on a limited basis. In the longer-term, however, California should move toward full REC trading in the state and western region once WREGIS is in place and operational, and establish requirements including provisions to prevent double counting, assure energy is actually delivered, and prevent market manipulation.

The Energy Commission already has experience in tracking and verifying RECs on a limited basis. Though not used for RPS compliance purposes, the Energy Commission was among the first regulatory agencies in the U.S. to recognize RECs by allowing their use for verification in the Customer Credit Program. The Customer Credit Program provided incentives to customers who purchased renewable energy through direct access contracts with energy suppliers and marketers. To provide a high level of flexibility in determining the best way to develop the renewables market, suppliers and marketers had the freedom to trade RECs on the wholesale level and procure RECs from registered generators or wholesalers. Because RECs alone did not qualify under the program, the RECs were then re-bundled with energy deliveries. Over the four-year life of the program, the Energy Commission was able to successfully track and verify the use of RECs to substantiate qualifying sales of renewable energy.

The CPUC should move forward with a decision establishing rules that allow ESPs to proceed with RPS procurements. The decision should include a flexible compliance option allowing ESPs to enter into transfers or exchange arrangements with other LSEs that would function as an interim and limited use of RECs. In addition, the decision should allow, but not require, ESPs and CCAs to use a procurement agent if that is the preferred method to procure renewables. Finally, the CPUC should develop additional details for an expedited schedule to implement the ESP and CCA RPS decision.

Addressing Other Barriers to Developing Renewable Resources

California must also address a number of other issues affecting the development of renewable resources in the state, including:

- The need for new or upgraded transmission access for renewable resources.
- The impact of integrating large amounts of intermittent renewables into the transmission system.
- The need to repower the state’s aging wind facilities.

- The need to reduce the number of bird deaths associated with the operation of wind turbines.

Transmission for Renewable Resources

Wind resources in the Tehachapi area and geothermal resources in the Imperial Valley are some of the state's most promising resources and could be a vital component in meeting targets for renewable energy development in California. However, the state needs to resolve transmission constraints in those areas to access those resources. In March 2005, SCE proposed a new category of transmission facility called a "renewable-resource trunk line." The trunk line would interconnect large concentrations of potential renewable generation resources located within a reasonable distance from the existing grid, and be operated by the CA ISO. In July 2005, however, the FERC denied SCE's request.[134] This denial removed the primary instrument the state could have used to address transmission constraints for renewables. The FERC's denial of the renewable trunk line concept reinforces the need for the Energy Commission, the CPUC, and the CA ISO to investigate changes to the CA ISO tariff to recognize this new category of transmission project, as recommended in the *2004 Energy Report Update*. This recommendation is discussed in greater detail in Chapter 3 on transmission issues.

California also needs a new approach to assessing transmission costs in the bid solicitation and while evaluating renewable bids under the least-cost, best-fit process. The CPUC's current approach does not account for network benefits, which some parties argue offset the transmission upgrade costs attributable to renewable projects. Other parties believe that the cost of transmission upgrades should not automatically be assigned to RPS projects since those projects can compete for existing transmission capacity under the CA ISO's open access policies.

The current approach also allocates the entire cost of transmission upgrades needed to connect bidders in each solicitation to the projects bidding into that solicitation.[135] This approach fails to capitalize on the economies of scale that can be achieved by sizing transmission for multiple generators in rich pockets of potential renewable energy instead of pursuing a piecemeal approach with individual generators. Overly complex administrative burdens associated with developing transmission cost adders for use in IOU RPS procurement are presenting barriers to renewable development.

Perhaps the most troubling aspect of transmission cost adders is the assertion by some parties in the CPUC proceeding that the current transmission cost adder approach actually penalizes renewable projects. Under the current structure, all existing users of transmission, primarily fossil-fueled generators, are essentially given priority for current transmission capacity while renewable generators are required to upgrade transmission

---

[134] Order on Petition for Declaratory Order re Southern California Edison Company, Docket No. EL05-80-000, 112FERC61,014, July 1, 2005.

[135] If another bidder in the same area has also bid into that solicitation, transmission costs could be spread among the other bidders.

to gain access to the grid. This perspective is difficult to reconcile with the state's preferred loading order.

The Energy Commission's *2005 Strategic Transmission Plan* addresses additional transmission issues associated with renewables in more detail.

Recommendations to Address Transmission Barriers

The CPUC, Energy Commission and the CA ISO should immediately investigate changes to the CA ISO tariff that would allow recognition of transmission needs not only for reliability and economic projects, but also to access renewable projects to meet RPS goals. This recommendation is discussed in greater detail in Chapter 3 on transmission issues.

In addition, the CPUC, Energy Commission, and the CA ISO should cooperate to revise the transmission cost adder process for RPS procurement, including considering clustering approaches, to more accurately reflect transmission costs and reduce existing disincentives for renewables.

Integrating Renewable Resources into California's Electricity System

Given existing problems in California's transmission system, adding significant quantities of intermittent renewables envisioned in the RPS is likely to require greater flexibility in system operations, although the effects are likely to be local rather than statewide.[136] The CA ISO has made progress addressing this issue through the Participating Intermittent Renewables Program. As part of the program, the CA ISO uses wind forecasts to anticipate wind energy delivery and settles energy imbalance costs (charges for occasions when delivered energy differs from the scheduled amount) with participating wind energy generators on a net monthly basis.[137] Wind generators pay a forecasting service fee of $0.1 per megawatt hour to the CA ISO to participate in the program.[138]

However, more needs to be done to ensure that intermittent renewable resources are integrated into the state's system, while mitigating possible effects on reliability or system operations. The Consortium for Electric Reliability Technology Solutions (CERTS) issued a report in July 2005 identifying changes in CA ISO system operation

---

[136] California Energy Commission, April 2005, *Assessment of Reliability and Operational Issues for Integration of Renewable Generation*, Consultant Draft Report, prepared by Electric Power Group, LLC, and Consortium for Electric Reliability Technology Solutions, CEC-700-2005-009-D, [http://www.energy.ca.gov/2005_energypolicy/documents/index.html#051005].

[137] See also "Amendment 42 Docket No. ER02-922-000 (Intermittent Resources; CT 487; Intra-zonal Congestion; and Real Time Pricing)," [http://www.CA ISO.com/docs/2002/02/01/200202011116576547.html], accessed April 15, 2005, and "Participating Intermittent Resource Program (PIRP) - Background/Documentation," [http://www.CAISO.com/docs/2003/01/29/2003012914271718285.html], accessed April 15, 2005.

[138] See CA ISO Tariff Section 11.2.4.5.4 and Schedule 4 of Appendix F. [http://www.CA ISO.com/docs/2005/06/30/2005063008591817859.pdf], accessed July 7, 2005.

needed to support the state's goal of 20 percent renewables by 2010.[139] The study identified a number of problems faced by control area operators. For example, control area operators may need to reduce generation output during high run-off and high-wind periods, especially during early morning hours when electricity loads are light. This could be mitigated by coordinating pumped storage hydroelectric generation to create load during these times.

The CERTs report also found that changing the mix of renewable resources can affect system stability. With significant wind energy in the mix, the need for controllable generation is larger. By increasing the amount of solar energy in the mix, however, load swings could be almost completely mitigated because of the high correlation between electricity production and load. SCE has recently signed a 20-year power purchase agreement for development of a 500 MW solar project, representing the first major application of Stirling dish technology in the commercial electricity generation field.[140] SDG&E has also announced plans for a 300 MW solar project using the same technology.[141] Based on conclusions from the CERTs research, these solar projects could help address the impacts of integrating a large volume of wind into California's system while roughly tripling U.S. solar electric generating capacity.

Recommendations to Integrate Renewables into the System

The state needs to increase its research and development efforts to better understand and address the impacts of integrating large amounts of intermittent renewable resources into California's system. Over the next year, the Energy Commission's Public Interest Energy Research program will build on the CERTS work. In the meantime, policy makers should continue to work with utilities to identify options to improve the planning, monitoring, and operation of the CA ISO system in support of the state's accelerated RPS goals.

The Energy Commission, in collaboration with the Department of Energy, should also increase its research agenda for expanding the state's energy storage options. Given California's increasing commitment to intermittent sources of electricity, it is in the state's best interest to explore energy storage opportunities to increase the operational flexibility of the state's electricity and transmission systems and accommodate the impacts of intermittent resources on those systems.

---

[139] California Energy Commission, July 2005, *Assessment of Reliability and Operational Issues for Integration of Renewable Generation*, Consultant Report, prepared by Electric Power Group, LLC, and Consortium for Electric Reliability Technology Solutions, CEC-700-2005-009, [http://www.energy.ca.gov/2005_energypolicy/documents/index.html#051005].

[140] "Major New Solar Energy Project Announced by Southern California Edison and Stirling Energy Systems, Inc.," August 9, 2005, [http://www.edison.com/pressroom/pr.asp?id=5885], accessed August 31, 2005.

[141] "SDG&E to Buy Solar Electricity," September 8, 2005, San Diego Tribune, [http://www.signonsandiego.com/news/business/20050908-9999-1b8solar.html], accessed September 9, 2005.

The state needs to pursue the following research and development activities:

- The CA ISO should undertake a research initiative addressing the attribute requirements of its system. This should focus on defining current and future control area attribute requirements. In addition, the CA ISO should undertake a research initiative to address minimum load issues, including forecasting future minimum load problems, the number of annual events, and the depth of the problem.
- The Energy Commission and the CA ISO should sponsor a joint initiative, with the participation of utility and industry stakeholders, to research and test alternative pricing schemes for operating attributes, integrating those into market design.
- The CA ISO should undertake a research initiative to address load as a provider of resource attributes, including the determination of: the resource attributes that could be provided by dispatchable load, pricing of those key attributes, infrastructure requirements to integrate load as a controllable device, and automatic load control requirements. Further, the Energy Commission should explore options to enhance availability of hydroelectric generation for automatic load control.
- The Energy Commission should develop a research, evaluation and deployment initiative to improve production forecasting including investigating best practices and tools for wind energy forecasting, identifying errors in wind production forecasting, identifying wind monitoring requirements, and deploying needed monitoring equipment.

Repowering Wind Resources and Reducing Bird Deaths

California's nearly 1,000 MW of aging wind facilities were installed 20 years ago using turbines that are less efficient and more costly to operate and maintain than the current generation of turbines. As recommended in the *2004 Energy Report Update*, replacing these older turbines can substantially increase wind production while decreasing the number of turbines and impacts on the environment. Repowering takes advantage of land already developed with access roads and transmission rights-of-way. In addition, new turbines are quieter and reduce noise impacts typically associated with wind facilities.

Equally important, reducing the number of older wind turbines at particular locations in California can reduce deaths of raptors and other birds protected by domestic and international law, particularly in the Altamont area. The *2004 Energy Report Update* recommended repowering California's older wind sites to increase wind efficiency and reduce bird deaths. California has an important opportunity to more carefully site new turbines based on knowledge of bird flight patterns, thereby reducing and avoiding bird deaths from wind turbines. [142]

[142] See: California Energy Commission, December 2004, *Repowering the Altamont Pass Wind Resource Area (APWRA): Forecasting and Minimizing Avian Mortality Without Significant Loss of Power Generation* [http://www.energy.ca.gov/pier/final_project_reports/CEC-500-2005-005.html#ExecutiveSummary], accessed April 21, 2005.

The *2004 Energy Report Update* also recommended using findings from the Energy Commission's avian mortality studies to evaluate permits for new and repowered wind turbine facilities. Since publication of that report, an extremely polarized debate has emerged between the wind industry, the Energy Commission staff and consultants, and environmentalists who believe there have been inadequate efforts to reduce the number of birds killed by wind turbines in the Altamont Pass Wind Resource Area. A focal point of that debate has been the statistical reliability of the research cited in the *2004 Energy Report Update* and the subsequent use of that research by Energy Commission staff and consultants.

The Energy Commission believes that the earlier research, *Developing Methods to Reduce Bird Mortality in the Altamont Pass Wind Resource Area*, represents an important initial effort to craft a methodology to prescribe mitigation measures, but that it should not be misused to form the sole basis for such mitigation measures. Inadequate access to certain turbines, time lapses between surveys, length of survey period, and various extrapolation techniques deprive it of the evidentiary value which the Energy Commission would require as the basis for mitigation measures in a power plant siting case. The scientific value of ongoing Energy Commission research into avian mortality prevention should not be jeopardized by misapplication of what are essentially experimental results.

To date, California has made only limited progress toward repowering wind facilities, with only 37 MW of repowered wind contracts submitted by SCE to the CPUC as of July 2005. Repowering efforts in the Altamont area have been hindered by a moratorium placed on wind development by Alameda County in 1998. The county will not approve additional permit applications to increase electricity production above the current cap of about 580 MW. Currently, neither Alameda County nor the wind industry proposes to repower the entire Altamont Pass; both are focused instead on renewing existing permits, with a proposed condition that repowering would only occur over 13 years.[143]

In addition, there are current limitations on federal tax incentives for wind projects. The Federal Production Tax Credit, recently extended to December 31, 2007, provides much needed financial incentives for wind repowering. However, provisions in the U.S. Tax Code (Section 45) prevent repowered wind facilities with existing standard offer contracts from qualifying for the production tax credit unless the contract is amended so that any wind generation in excess of historical production levels is either sold to the utility at its current avoided cost or sold to a third party.[144] This provision discouraged wind operators from repowering because utility avoided costs are much lower than current contract prices.

[143] Alameda County is currently processing the reissuance of conditional use permits for the maintenance and operations of existing wind turbines in the Altamont Pass Wind Resource Area.
[144] Standard offer contracts were instituted by the CPUC to establish prices, terms, and conditions for investor-owned utility purchases from independent generators, including renewable generators, in the 1970s and 1980s in response to the federal Public Utility Regulatory Policies Act of 1978.

Recommendations to Mitigate Avian Mortality

As recommended in the 2004 Energy Report Update, the Energy Commission continues to believe that repowering existing wind sites offers the best opportunity to harness prime wind resources more efficiently and mitigate or prevent bird deaths. The Energy Commission also recommends that the CPUC quickly develop new Qualifying Facility contracts to overcome impediments to repowering and take advantage of the Federal Production Tax Credit. The Energy Commission also recommends developing statewide protocols for studying avian mortality to address site-specific impacts in each individual wind resource area.

Realizing the Strategic Value of Biomass Resources

California has a large, diverse, and widespread biomass resource which could be tapped to realize its economic potential. Biomass resources include residues from forestry and agriculture, municipal solid waste, and organic materials in wastewater. These resources could support much greater use in electricity generation, fuels and chemicals, manufacturing, and the production of various co-products. The strategic value of using California's untapped biomass is the ability to solve two problems at once: waste disposal and environmental problems, such as increased fire risk, air pollution, and climate change.[145]

In his response to the *2003* and *2004 Energy Reports*, Governor Schwarzenegger expressed his support for the California Biomass Collaborative and charged the Interagency Working Group on Bioenergy with developing an integrated and consistent state policy on biomass. Developing the energy generation potential for biomass will require a concerted approach on the part of state and federal agencies and other stakeholders to address the technical, economic, environmental, and institutional challenges associated with its production and use.

To realize the potential economic, social and environmental benefits of sustained biomass development, the state should:[146]

- Develop a "road map" to guide future biomass management and development in California, including efforts to address technical, economic, environmental, and institutional challenges.
- Adopt clear and consistent policies for sustainable biomass development.
- Collaborate with federal agencies to leverage state and federal funding for biomass research, development and demonstration projects.
- Develop biomass education and public outreach programs on the benefits and opportunities of this resource.

[145] California Energy Commission, *Biomass Strategic Value Analysis, June 2005.*
[146] California Energy Commission, *Biomass in California: Challenges, Opportunities and Potentials for Sustainable Management and Development,* Public Interest Energy Research California Biomass Collaborative Report, June 2005.

- Establish state and local procurement and construction programs to increase biomass use.
- Coordinate state agency efforts on recommended actions for sustainable management and development.
- Encourage biomass-fueled electricity facilities to participate in competitive RPS requests for offers.

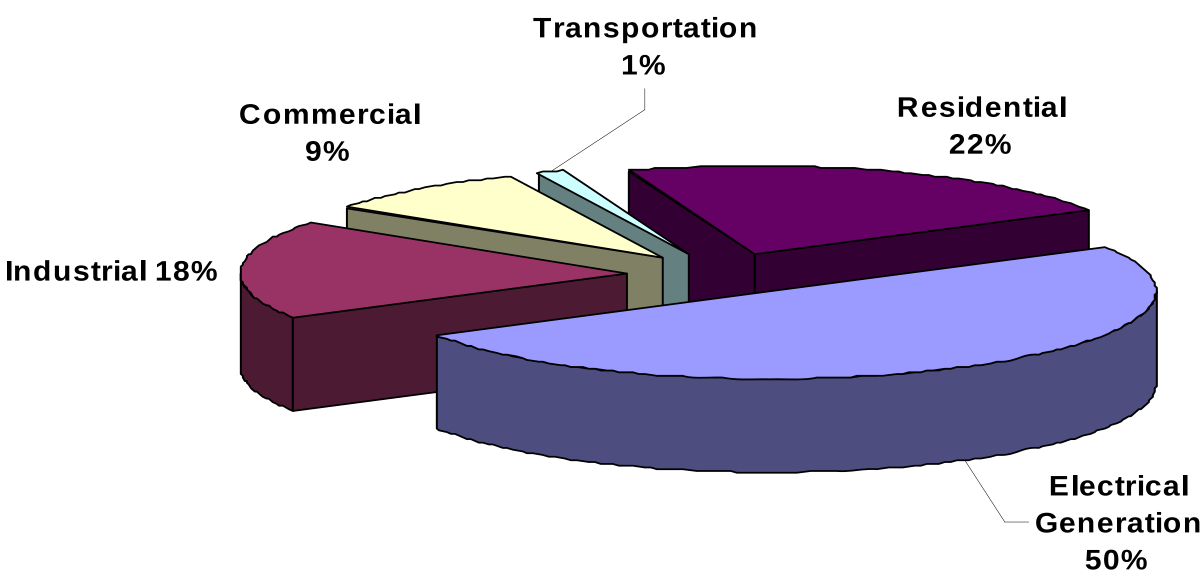
CHAPTER 7: THE CHALLENGES AND POSSIBILITIES OF NATURAL GAS

Introduction

In the largely deregulated natural gas arena, California competes on a theoretically level playing field with the entire North American market. This poses significant challenges to securing adequate and reliable supplies of natural gas at reasonable prices. Even California's position as the nation's second largest consumer of natural gas does not provide the priority benefits often accrued a major player. California's geographic location — literally "at the end of the pipeline" — exacerbates its inability to secure this increasingly in-demand resource.

Natural gas plays a critical role in California's energy market, with power generation accounting for half of the gas consumed in California. Consequently, any disruptions to supply or spikes in price directly affect the state's ability to generate electricity and to do so at competitive prices.

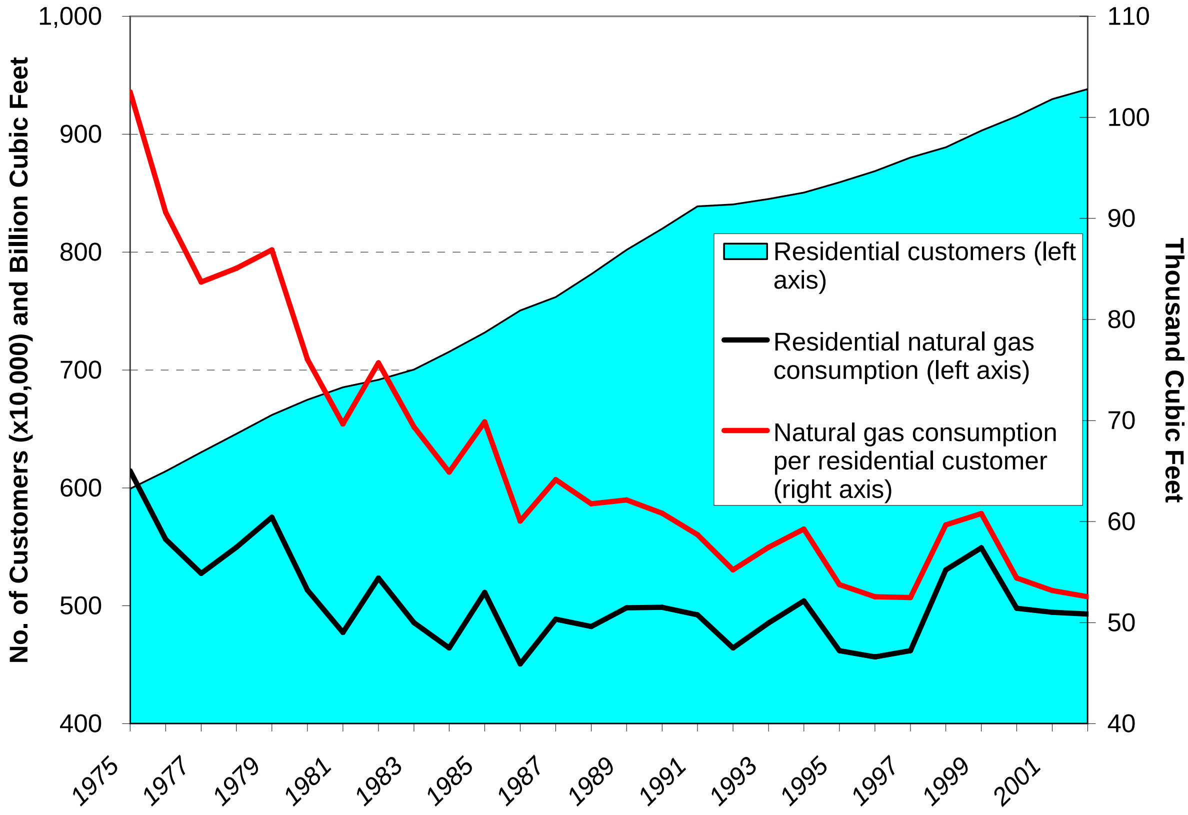
Figure 14: 2004 Natural Gas Use in California



Source: California Energy Commission

California's natural gas demand growth is expected to be slower than the rest of the nation's. Nevertheless, it is increasing steadily despite efforts to decrease natural gas use through energy efficiency measures and the use of renewable fuels for electricity generation. In-state production, however, satisfies only about 13 percent of statewide demand. The resulting reliance on imports makes the state vulnerable to supply disruptions and price shocks that can negatively affect California's residents and its economy.

Figure 15: Residential Natural Gas Consumption



Source: California Energy Commission

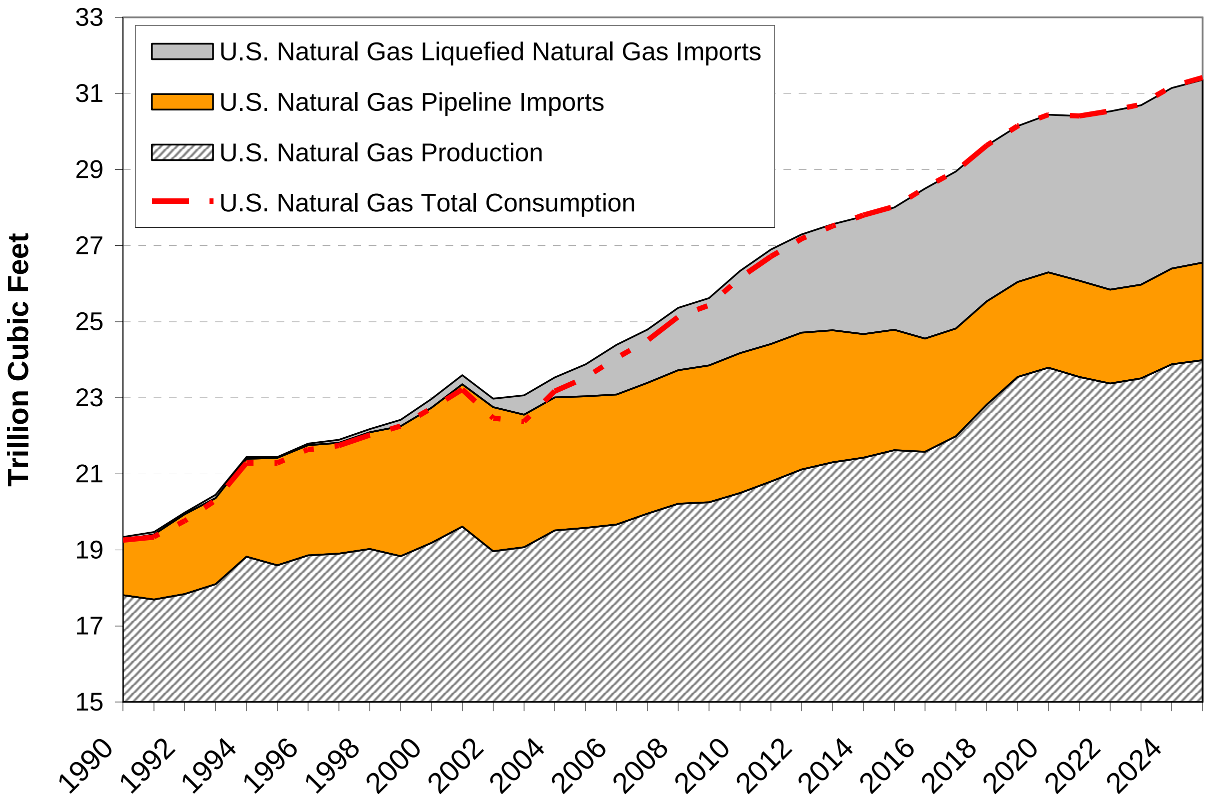
Natural gas supplies are dwindling nationally, and the gap between demand and supplies is widening each year. Recent infrastructure improvements have reinforced California's pipeline capacity and ability to meet average annual demand. Ironically, an even greater challenge may be California's ability to keep the pipeline full enough to meet daily peak needs. Natural gas supplies to California are affected by natural gas demand in other states, as well as Canada and Mexico. As Canada and Mexico increasingly turn to natural gas to satisfy their own growing demand for electricity, traditional drilling and exploratory activities will not be able to keep up with the growing demand for natural gas, further intensifying competition for already dwindling supplies.

More recently, reductions in production in the Gulf of Mexico, due to Hurricane Katrina, will cause lower storage levels nationally at a time when natural gas utilities would ordinarily be storing significant volumes of the resource in anticipation of peak winter demand.

Competition for the limited supply of natural gas is driving prices higher, and California has little direct influence over market prices. Though wholesale natural gas prices in

California are lower than those in most of the rest of the nation, they have more than doubled since 2000. Natural gas consumers spent more than $11 billion for natural gas in 2004 and are expected to spend even more this year.[147] Higher natural gas prices inevitably mean higher electricity prices.

Figure 16: Projected U.S. Natural Gas Supply/Demand Balance



Source: U.S. Energy Information Administration.

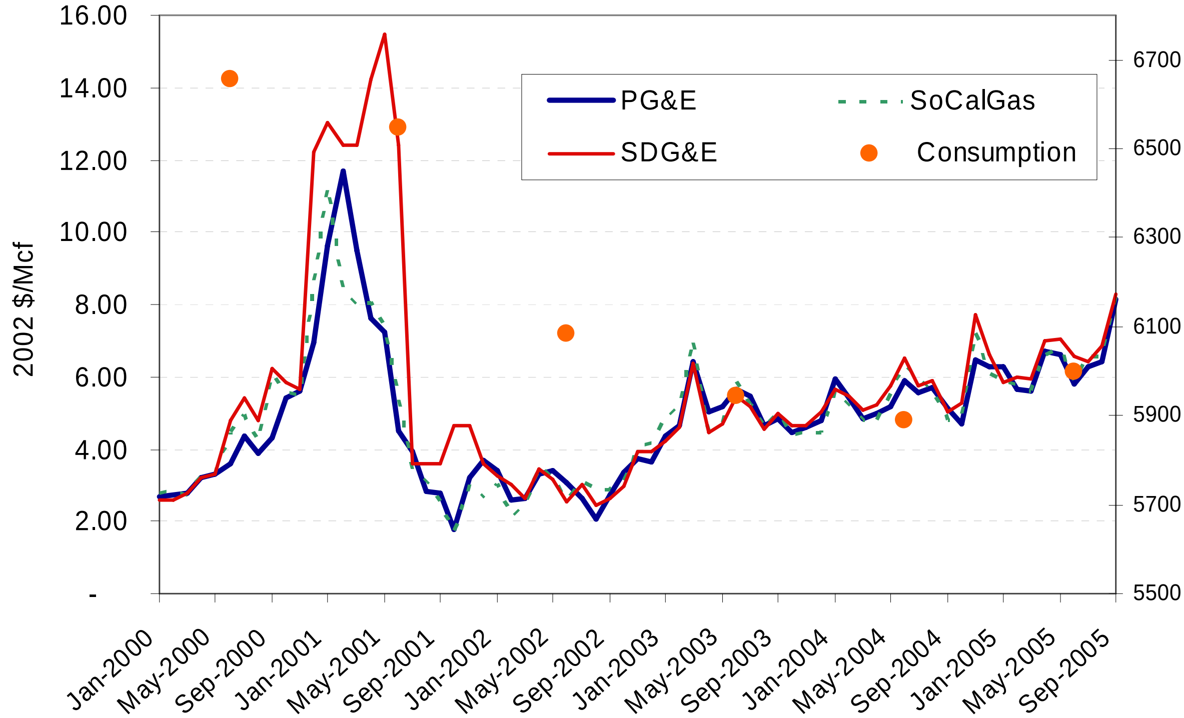
The uncertainty of supplies and increases in prices underscore the need for California to focus on actions within its control, specifically to find alternative sources of natural gas. Liquefied natural gas (LNG), in particular, offers significant potential. The possibility of importing natural gas molecules across the water from virtually any source worldwide has the potential to provide large volumes of adequate and reliable supplies and consequently hold down prices. Importing LNG is not without its challenges, however, particularly in siting receiving terminals.

---

[147] California Energy Commission, *Preliminary Reference Case in Support of the 2005 Natural Gas Market Assessment,* June 2005, CEC-600-2005-026.

Figure 17: California Gas Utilities Weighted Average Cost of Gas and California Consumption

(MMcfd, monthly)



Weighted Average Cost of Gas: the weighted average cost of gas (commodity) and interstate pipeline volumetric charges.

Source: Pacific Gas and Electric, Southern California Edison, and San Diego Gas and Electric.

Natural Gas Demand

Natural gas use in the power generation sector accounts for the bulk of the state's increasing demand for natural gas. Although Californians are continuing to use electricity more efficiently, total electricity demand is growing, requiring additional power plants to meet the state's needs. Since November 2003 alone, the state has permitted 11 power plants totaling 5,750 MW of capacity, primarily natural gas-fired.

Electricity demand in the short term can fluctuate dramatically depending on the weather. Hot temperatures in the summer increase electricity demand for air conditioning and natural gas fuel requirements; cold temperatures in the winter directly increase natural gas demand for heating. Variations in rainfall and snow pack in the mountains affect the availability of hydroelectric power, with additional natural gas-fired generation required when adequate hydroelectric supplies are not available.

As the population continues to increase over the next decade, natural gas demand for uses other than electricity generation is also expected to increase. The California Energy Commission (Energy Commission) expects residential natural gas use to increase by 1.4 percent per year and commercial natural gas use to increase by 2 percent per year. Industrial natural gas demand, however, is expected to be flat or decline in nearly all of the western states because industrial customers are the most sensitive to currently rising natural gas prices. [148]

California's ability to meet its natural gas needs will also be affected by rising demand in the rest of the U.S. and in neighboring countries. Natural gas demand throughout the U.S. (excluding Alaska and Hawaii) is expected to increase by 1.7 per year from 2006 to 2016. Similarly, in Canada and Mexico natural gas consumption is expected to grow annually by 1.3 percent and 2.9 percent, respectively.[149] Three-quarters of total demand growth in North America stems from increased natural gas consumption for power generation.

With the ongoing success of California's efficiency programs, natural gas demand growth in the state is expected to be lower than in the rest of the nation over the next decade. California is a model of energy efficiency and has reduced natural gas use per household by more than half since 1975.[150] Total natural gas demand in California is projected to increase by 0.7 percent per year from 2006 to 2016, with strong growth in the residential and commercial sectors offset by declining industrial gas demand and slower growth in gas consumption by power generators than has been observed in recent years.

Until recently, demand for natural gas for power generation was projected to increase more quickly than demand in other sectors.[151] Now, however, the demand for gas in California's electricity sector is expected to grow at a relatively modest rate of 1 percent per year through 2016. California's overall electricity demand is expected to increase more slowly than in the past. Without the addition of new, more efficient power plants to reduce the state's dependence on older, less energy efficient facilities that use more natural gas, California's dependence on natural gas for electricity generation will continue to grow unabated. California's Renewable Portfolio Standard (RPS) will reduce the electricity generating load from gas-fired facilities and associated gas use, particularly with the acceleration of the RPS goal of 20 percent renewable generation by the year 2010.

The overall increase in gas prices over the past several years has sparked a renewed interest in coal-fired electricity generation. New coal facilities are included in the resource plans for several western states, which could cause projected natural gas demand growth for electricity generation in those states to decrease. Greater interest in renewable generation in other western states could also reduce their natural gas demand for power generation.

---

[148] California Energy Commission, *Preliminary Reference Case in Support of the 2005 Natural Gas Market Assessment*, June 2005, CEC-600-2005-026. These numbers are likely to change slightly and will be updated in a revised reference case report.
[149] California Energy Commission, Preliminary Reference Case in Support of the 2005 Natural Gas Market Assessment, June 2005, CEC-600-2005-026.
[150] Ibid.
[151] California Energy Commission, *Natural Gas Market Assessment*, CEC-100-03-006, August 2003.

Because California's natural gas pipeline and storage capacities have increased faster than demand over the past five years, California's gas utilities are in better shape to avoid a widespread curtailment today than they were in 2000. Unfortunately, the conditions affecting natural gas supply adequacy are highly variable, including weather in the short-term and greater reliance in the western U.S. on gas-fired plants in the long-term. As a result, California cannot determine with any precision the potential peak demand in the state under extreme conditions or the likelihood of such an extreme peak.

The Energy Commission currently evaluates natural gas adequacy under average conditions and normal peak conditions. However, there is a need to evaluate potential responses to extreme conditions to avoid costly natural gas curtailments. The Energy Commission needs to devote resources to secure the necessary data and increase its analytical ability to ensure that the natural gas infrastructure will continue to be adequate in the future under all conditions.

Effect of Natural Gas Prices on Demand

The price of natural gas is of major concern to state energy policy makers. Futures prices currently exceed $10 per million British thermal units (mmBtu), and gas price volatility has become a regular feature of the natural gas market. Hurricane Katrina dramatically affected prices in both the short and long term: national prices rose from $7.51 per mmbtu on July 27, well before storm damage was expected, to a peak of $12.70 per mmBtu on September 1. During this same time, California's wholesale prices at the Southern California border rose from $6.57 per mmBtu to $10.07 per mmBtu. Although California's wholesale prices increased due to the hurricane, they did not increase as much as the rest of the nation. The state's aggressive energy efficiency and natural gas management programs helped keep its wholesale prices below the national benchmark. The discount to the national average which California consumers have lately enjoyed widened from $0.94 per mmBtu to $2.63 per mmBtu during this same time period.

At the customer level, high natural gas prices mean higher natural gas bills, especially for customers using natural gas to meet their heating needs. The U.S. Energy Information Agency forecasts that consumers' natural gas heating bills for this winter will be at least 20 percent higher than last winter. At the wholesale level, higher natural gas prices mean higher costs to generate electricity, which translate into higher costs for electricity ratepayers.

California has little influence over national natural gas market prices. Even when California's own demand is moderate, in-state prices can spike in response to extreme weather conditions in other parts of the country. In the past two years, natural gas prices have dramatically increased and short-term natural gas market prices are now highly volatile. Although there will be short-term drops in natural gas prices reflecting the introduction of large new supplies into the market, the Energy Commission expects a general increase in natural gas wellhead prices over the next decade. The general increase reflects the increasing difficulty of producing gas in the nation's conventional gas producing regions, but does not account for market volatility and short-term price spikes.

Residential customers in California pay the highest natural gas prices in the state because of the cost involved in serving millions of dispersed customers in each utility service area. Over the next decade, the Energy Commission estimates that residential gas prices will fluctuate between $9.75 and $13.71 per thousand cubic feet (Mcf).

Commercial customers can expect to pay between $8.64 and $11.91 per Mcf for natural gas over the same period, depending upon the service territory. Natural gas prices for industrial customers follow the same trends as those for other California customers, but at a much lower price level. There are fewer industrial customers, and most purchase their own natural gas, pipeline capacity, and storage services, making it less costly for utilities to provide service. Industrial customers can expect to pay between $6.50 and $9.00 per Mcf over the next ten years.

Natural gas prices for electricity generators are expected to fluctuate between $5.75 and $8.75 per Mcf over the next 10 years, and vary based upon whether or not the generator is served by a natural gas utility or takes its fuel supplies directly from another source, such as an interstate pipeline or local gas producer, as well as where the generator is located and when the facility began operation.

Using Efficiency Measures to Reduce Demand

Increased efficiency in all of the state's energy sectors is the highest priority for meeting demand, consistent with the state's loading order policy. The *2003 Energy Report* recommended that the state decrease natural gas use by increasing funding for natural gas efficiency programs. California has made significant progress in this area. California's Building and Appliance Standards continue to help meet natural gas efficiency goals by reducing annual natural gas use. More importantly, in 2004, the California Public Utilities Commission (CPUC) authorized an additional $19.8 million in funding for natural gas efficiency programs in 2005.[152] The CPUC has also set aggressive goals to double annual natural gas savings by 2008 and triple savings by 2013. When these goals are met, the cumulative savings will be equivalent to the amount of natural gas consumed by one million households.[153] As with other energy efficiency programs, the CPUC and the Energy Commission will have to rigorously evaluate, measure, and monitor these programs to ensure that they produce the intended savings and that public funds are being well spent.

---

[152] CPUC, December 2, 2004, "Decision D.04-12-019: Order Granting Petition to Modify Decision 03-12-060," in Order Instituting Rulemaking to Examine the CPUC's Future Energy Efficiency Policies, Administration, and Programs. Rulemaking 01-08-028.
[153] CPUC Decision 04-09-060, September 23, 2004, Interim Opinion: Energy Savings Goals for Program Year 2006 and Beyond.

To increase natural gas efficiency in the future, combined heat and power facilities should play a much larger role in meeting California's electricity supply needs. By recycling waste heat, these systems are much more efficient than conventional fossil-fueled power plants.

Although California's natural gas wholesale prices fluctuate more in response to national demand and supply than in-state demand and supply, more efficient use of natural gas within California will directly benefit consumers who reduce their consumption. Efficiency improvements in the electricity sector will also provide benefits to natural gas consumers since one-half of the state's natural gas demand is for power generation.

Natural gas efficiency is also a priority in the Energy Commission's natural gas research, development, and demonstration program.[154] In 2005, the Energy Commission, with the concurrence of the CPUC, initiated a Public Interest Energy Research program (PIERNG) on natural gas. The 2005 budget for PIERNG was $12 million, which may increase by $3 million annually to a cap of $24 million. Approximately $1.3 million of the 2005 funding has been preliminarily earmarked for energy efficiency projects. Depending on the priorities of the research agenda, additional dollars could be dedicated toward energy efficiency projects. Research results will be linked to state natural gas efficiency programs.

Natural Gas Supplies

Gas producers across North America are struggling to keep pace with the growing demand for natural gas. Although the number of natural gas wells drilled in the U.S. and Canada is at an all-time high, conventional production from most of the mature supply basins in North America has declined or increased only modestly since 1990.[155] More importantly, the amount of gas produced per well is declining, and each well is being drained faster.

Production from newer supply basins in the Rocky Mountains, East Texas, and the deep water in the Gulf of Mexico has helped offset this decline. Supplies from some of these basins are produced from unconventional resources such as coal bed methane, tight sands gas, shale gas, and in very deep water, which all cost more to develop and produce and have raised the relative cost of natural gas across the continent.

Hurricane Katrina further affected natural gas supplies. For one week, from August 29 through September 6, natural gas production in the Gulf of Mexico was reduced by 83 percent of its usual volume — more than what California consumes in an average day. Releases from natural gas storage facilities made up for the loss of production. Production resumed at half its normal pace, with nearly full production expected to

---

[154] CPUC R.02-10-001.

[155] California Energy Commission Staff Report, June 2005, *Preliminary Reference Case in Support of the 2005 Natural Gas Market Assessment*, CEC-600-2005-026.

resume in the days ahead. Some small portion may remain shut down due to severe damage to the production infrastructure.

A second effect, however, is longer term. The reduced production from the Gulf of Mexico comes at a time when natural gas utilities begin to store a significant volume of natural gas in underground storage facilities in anticipation of peak winter demand. Hurricane Katrina, by causing reduced production, is also causing reduced storage injections. Making up for these reduced injections in the few months before winter starts will be difficult, meaning that U.S. national storage levels will be lower than they otherwise would have been. This will lead to tighter supplies this winter, greater price volatility, and possibly higher overall prices. Again, California is affected, but less so. California natural gas utilities and storage operators had already added to their storage inventories and increased levels well above the five-year average for this time of year. The Energy Commission expects California utilities to continue adding to their storage inventories to ensure California starts the heating season well prepared, although the newly purchased natural gas will cost more than expected.

Domestic natural gas production is expected to increase over the next decade by about 1.6 percent per year but will not keep up with national growth in demand. This problem will be compounded by the decline in imports from Canada because of its own increased demand for natural gas. Though Arctic natural gas production could be available by 2013, it will require approving and building a new major pipeline to move remote supplies to markets in Canada and the lower 48 states.

California's situation is exacerbated because the state relies upon imports for 87 percent of its natural gas supplies. With the exception of the late 1990s when Occidental purchased the Elk Hills field from the federal government, in-state natural gas production has been steadily declining and will continue to do so despite efforts by government and industry to increase production.

California needs to increase the diversity of its natural gas supply portfolio. Being at the end of a long interstate pipeline network, California must also have access to a variety of sources.

Impact of Rising Demand in Neighboring States

Demand for natural gas in other states affects natural gas supplies to California. In Arizona, 43 new power plants totaling more than 8,000 MW have come on line since 2001. These are intermediate load and peaking power plants that often ramp up quickly to meet changing electricity demand. As a result, they may take more natural gas from the pipeline and do so faster than expected. Under normal conditions, this practice is not troublesome if the pipeline system can be balanced by taking gas out of storage. In the Phoenix area, however, the nearest storage facility is hundreds of miles away, and it is becoming increasingly common for pipeline pressure to drop during periods of high and rapidly increasing demand. If the gas pressure gets low enough, it could cause curtailments that could affect natural gas delivery into California. In addition, reducing gas deliveries to Arizona's power plants could cause a ripple effect through that portion of the electric grid that could ultimately reduce the reliability of electricity deliveries from out of state to Southern California.

Adding storage capacity in the Phoenix area could resolve this issue, but a proposed private storage facility near Phoenix was never developed because of unfavorable cost recovery rules at the Federal Energy Regulatory Commission (FERC). To address this problem, the FERC is exploring the option of granting market-based rates to new independent storage developers that are not affiliated with existing pipelines. A less direct approach to resolve the issue would be to promote the development of a storage facility inside California directly tied to one of the pipelines coming from Arizona, but this is less desirable than adding storage in the Phoenix area and raises complex regulatory and contractual issues.

The Potential of Liquefied Natural Gas to Increase Supplies

California clearly needs to diversify its natural gas supply sources and seek additional natural gas supplies from more cost-competitive and reliable sources. LNG has that potential. Chilling and pressurizing natural gas reduces it to a liquid form, condensing its volume by 600 percent, thus enabling bulk shipping and storage before the liquid gas is revaporized into its gaseous state without any change to its chemical properties. This significant reduction in volume frees importers to transport the liquefied gas over water, expanding supplies exponentially.

LNG import facilities in North America that are under construction will increase natural gas supplies available to the U.S. over the next ten years, and will help meet California's additional natural gas needs by increasing total U.S. supplies.

At present, the U.S. has five existing LNG receiving and regasification terminals, but no terminals are located on the West Coast. The *2003 Energy Report* highlighted the need for the development of LNG facilities and associated infrastructure to serve the natural gas needs of the western U.S. and suggested that California continue to support the development of LNG facilities on the West Coast, consistent with environmental protection requirements. Several companies have recently proposed to build LNG import facilities in California and Mexico. In California, these include the Cabrillo Deepwater Port and the Clearwater Port, both of which are offshore projects, and the Long Beach LNG Import Project. In Mexico, three proposed facilities would be located near Ensenada, the Coronado Islands, and Sonora. Sempra Energy broke ground on its Costa Azul LNG receiving terminal near Ensenada in Baja California Norte in March of this year. For California to access new liquefied natural gas supplies, however, additional or modified pipeline infrastructure may be necessary.

The costs to deliver natural gas to the West Coast via an LNG project are well below the market prices that California pays at its borders. This potential new supply source close to or in California could have a dramatic effect on the market prices in California. For example, if West Coast LNG supplies cause market prices to drop by $0.50 per mmBtu, then Californians would save over $1 billion on their natural gas bills. This magnitude of potential savings drives California's interest in LNG.

However, actual prices to consumers will depend upon the contracts signed between suppliers and consumers, or their representatives. The CPUC will be examining very closely any potential contracts proposed by the regulated gas utilities to ensure potential benefits from LNG flow to consumers. Such contracts should incorporate measures to help lower overall prices and moderate price volatility, and address terms of access of suppliers to terminals to maximize reliability of deliveries.

LNG simultaneously presents natural gas supply opportunities, additional infrastructure capacity into the West Coast, and coastal industrial development challenges. In considering LNG projects currently proposed for California, the state must address safety, environmental, and gas quality issues associated with these projects in an efficient and equitable manner. California has established the LNG Interagency Permitting Working Group, composed of 17 state, local, and federal agencies. In a recent letter to the U.S. Coast Guard, the Energy Commission detailed its concerns and requested a response to three major areas regarding an LNG facility proposed for the Port of Long Beach:

- The potential impact on petroleum infrastructure in the San Pedro Harbor as a result of a catastrophic incident.
- The loss of operational transit time in the San Pedro Harbor due to the security zones that will be associated with movement and berthing of liquefied hazardous gas tank vessels.
- Elevated threat levels invoked by the Department of Homeland Security and the potential diminishment of movement by marine vessels in the San Pedro Harbor.

Although the letter to the Coast Guard deliberately focused narrowly on issues associated with petroleum infrastructure, both the Energy Commission and the LNG Interagency Permitting Working Group recognize the group's mission to ensure that any LNG development is consistent with the state's energy policy of balancing environmental protection, public safety, and local community concerns to ensure protection of the state's population and coastal environment.

Potential Supplies from Alternative Sources of Natural Gas

To further diversify California's natural gas supply sources, the state can examine the feasibility of increasing natural gas production from more innovative sources. For example, California is rich in biomass resources that are suitable as feedstock for gasification technologies. Landfills in California currently produce natural gas, some of which is captured, cleaned, and used. Agricultural waste can be converted to synthetic natural gas. Underground gaseous reservoirs contain natural gas that does not meet pipeline specifications but could still be converted to useful energy. Technological and cost challenges remain in all areas to ensure that produced gas meets quality specifications and environmental protection requirements, challenges that are appropriate subjects of the state's natural gas research and development program.

Using Infrastructure to Ensure Adequate Natural Gas Supplies

At the same time California seeks adequate supplies of natural gas, it must also ensure that its infrastructure can both convey and store supplies. California has made great strides in addressing a variety of natural gas infrastructure shortfalls that plagued the state at the height of the 2000-2001 crisis. The state has increased intrastate pipeline capacity by approximately 0.906 billion cubic feet (bcf) per day since 2001 and added an additional 2.2 bcf per day of delivery capacity to deliver supplies from Canada, the Rocky Mountains, and the Southwest.

To guard against interruptions in natural gas supplies, the *2003 Energy Report* recommended that the state ensure that existing natural gas storage capacity is used appropriately to provide adequate supplies and protect prices. California has added 38 billion cubic feet of storage capacity, which provides increased reliability to meet peak needs and adds operational flexibility across the state. During the past two years, users of those storage facilities have been placing natural gas into storage at record rates, and the state's inventory is at the high end of the five-year average. Plans exist to develop additional storage capacity next year.

California will benefit from expected modifications to the Transportadora de Gas Natural pipeline that links future natural gas supplies from proposed LNG facilities in Baja California Norte to San Diego, as well as a reversal of the Baja Norte pipeline which currently transports natural gas from Arizona to the Baja California Norte market, if LNG projects are developed in Baja California Norte. A reversal of the pipeline would also allow natural gas from LNG facilities in Baja California Norte to serve markets in Northern and Southern California or Arizona. While these two infrastructure options both provide pathways for new supply sources from Baja California Norte to reach California, modifying the Transportadora de Gas Natural pipeline would provide additional capacity into the state while reversing the Baja Norte pipeline does not increase capacity into the state. The CPUC is expected to ensure that ratepayers will only be charged for project costs that are commensurate with the benefits that actually flow to them.

With its recent expansions, California has adequate in-state pipeline infrastructure over the next decade to move gas to load centers on an annual average basis. However, the state must make certain that existing infrastructure is maintained and retained. In addition, the state should continue to evaluate the need for additional pipeline capacity to meet the needs of all consumers to meet peak summer and winter demand when there are interstate pipeline disruptions, or to resolve regional congestion. A margin of excess capacity will provide consumers a choice of suppliers and is the critical foundation needed to support a competitive market and stabilize short-term pricing volatility.

Other projects are being considered that will further strengthen the natural gas infrastructure in California. The CPUC is working with gas utilities to modify the portfolio of natural gas pipeline capacity contracts to better match current and future market conditions and achieve consumer savings, although several important issues remain unresolved.

Ensuring the Quality of Natural Gas Supplies

The *2003 Energy Report* recommended that the state initiate legislative hearings to examine the issue of gas quality and gas gathering as it relates to California gas production and to determine whether additional legislative action is warranted to resolve the issues.

Expansion of gas field production in California will depend on improving the quality of natural gas delivered to the pipeline network. The major component of gas quality that is of concern is total energy content, or heating value. Most end-use appliances, from water heaters to power plants, will not operate properly outside a relatively narrow heating value range. Gas supplies in different parts of the state and the western U.S. can have very different heating values, requiring blending and/or treatment before the gas can be used.

Gas quality is a concern not only for in-state production but also for imported supplies of LNG. The chemical composition of potential imported LNG may be significantly different from traditional supplies. The gas quality issue is potentially resolvable using known technologies and by setting requirements for imported LNG supplies. However, because gas quality also affects air emissions, the state must carefully evaluate this issue to prevent unwanted impacts on air quality. The 2005 PIERNG program has funded more than $3 million in research devoted to understanding and resolving gas quality issues. Further research efforts are planned in 2006 to determine the effects of variable natural gas quality on large industrial end users.

The Energy Commission has been working cooperatively on this issue with the CPUC, the California Air Resources Board (CARB), and the Division of Oil, Gas, and Geothermal Resources. The agencies have held a number of hearings, workshops, and public meetings over the past year involving natural gas utilities, producers, pipeline and storage operators, and consumers, as well as LNG project developers to accelerate resolution of natural gas quality issues in California. As a result, the CARB has initiated a regulatory process to revise its natural gas specification affecting vehicles, which also indirectly affects pipeline supplies. The CPUC has also initiated a regulatory proceeding to examine requirements for pipeline natural gas quality. In addition, the Energy Commission has provided funding for research and development to address outstanding technical issues. Consequently, the issue of natural gas quality is expected to be resolved by mid-2006. The Energy Commission will continue to monitor progress on the issue and may recommend legislative hearings in the future if a resolution is not accomplished as expected.

CHAPTER 8: INTEGRATING WATER AND ENERGY STRATEGIES

Introduction

The link between energy and water use in the state is an important facet of California's energy system. While the most recognizable aspect of this link is hydroelectric generation at large scale dams, the amount of energy used by the state's water infrastructure is equally important.

California's water infrastructure uses a tremendous amount of energy to collect, move, and treat water, dispose of wastewater, and power large pumps that transport water supplies throughout the state. California consumers also use energy to heat, cool, and pressurize water for use in their homes and businesses. Combined, these water-related end uses account for roughly one-fifth of the state's electricity consumption, costing California consumers about $2 billion, one-third of the non-power plant natural gas consumption, and about 2.7 percent of diesel fuel consumption.

The state's growing population is increasing the demand for water and, consequently, for energy used to deliver and treat that water. These urban water and energy demands are growing at about the same rate and in many of the same geographic areas. However, water-related electricity use is likely to grow at a faster rate because of: increased and more energy-intensive water treatment requirements; conversion of agricultural diesel pumps to electric; increased long-distance water transfers, which often have the impact of shifting water from agricultural to urban users; and changes in crop patterns which require more energy-intensive irrigation methods.

If not coordinated and properly managed on a statewide basis, water-related electricity demand could affect the reliability of the electric system during peak load periods when reserve margins are low. Conversely, without reliable and adequate supplies of electricity, water and wastewater agencies will be unable to meet the needs of their customers. Significant opportunities exist to improve the performance of both systems by focusing on areas of mutual benefit. Particularly significant is that two-thirds of the state's population lives in the southern part of the state, while Northern California receives two-thirds of the precipitation. Because of the distances involved in bringing water to Southern California, reducing water use there will afford greater energy savings than will reductions in other parts of the state.

Although California's opportunities for new hydroelectric dam projects are extremely limited, the state's hydroelectric system provides valuable peaking reserve capacity, spinning reserve capacity, load following capacity, and transmission support — all at low production costs. In addition, pumped storage facilities are generally considered to be the only current commercially viable method for large-scale storage of electricity.

A significant volume of water in the state is used for power plant cooling. The *2003 Energy Report* adopted a policy requiring new power plants to use degraded or recycled water or air cooled systems to reduce the amount of fresh water used for power plant cooling systems. California has a number of power plants, located along the state's bays and coast, that use once-through cooling technology. California has the opportunity to more comprehensively study once-through cooling impacts on the marine environment as part of the Governor's California Ocean Protection Council efforts and the State and Regional Water Quality Control Board's review of impacts under Section 316(b) of the federal Clean Water Act.

California can implement strategies now to increase water use efficiency and increase the energy efficiency, peak operational flexibility, and the renewable generation capability of the state's water and wastewater infrastructure.

Water Sources and Supplies

California derives its water from two sources: surface and groundwater. Surface water includes natural lakes and streams as well as reservoirs and canals or aqueducts. Groundwater supplies about 30 percent of the state's average water needs, but can supply as much as 60 percent during an extended drought. California's groundwater aquifers store several hundred million acre feet of water, compared with approximately 45 million acre feet in California's 1,200 surface water reservoirs.[156] Pumping water from groundwater storage uses significant amounts of energy. Many of the state's groundwater aquifers are in decline or overdrafted, meaning the water must be pumped from greater depths, requiring still more energy.[157]

Water storage in the state relies upon surface impoundments, especially those associated with the major water projects, in the Sierra snow pack and groundwater. The Sierra is a key element in both the state's water supply and energy production. Snow packs store water that is released slowly during the spring and summer months into reservoirs, many of which are used for flood control. Stored water is used later in the summer to provide hydroelectric generation.

The fastest growing new source of water is actually recycled water from wastewater systems. California's increasing population puts great pressure on municipalities to secure sufficient water supplies to meet that growth. Faced with limited water supplies, many agencies are turning to recycled water to meet their non-potable needs. Recycled water can be treated to the point where it can substitute for fresh water in applications like power plant cooling or landscape irrigation, or be used to replenish groundwater aquifers.

---

[156] Association of California Water Agencies [http://www.acwa.com/mediazone/waterfacts/view.asp?ID=44]. An acre-foot is equal to about 325,850 gallons of water, or enough to cover an acre to a depth of one foot.
[157] Personal communication with Naser Bateni.

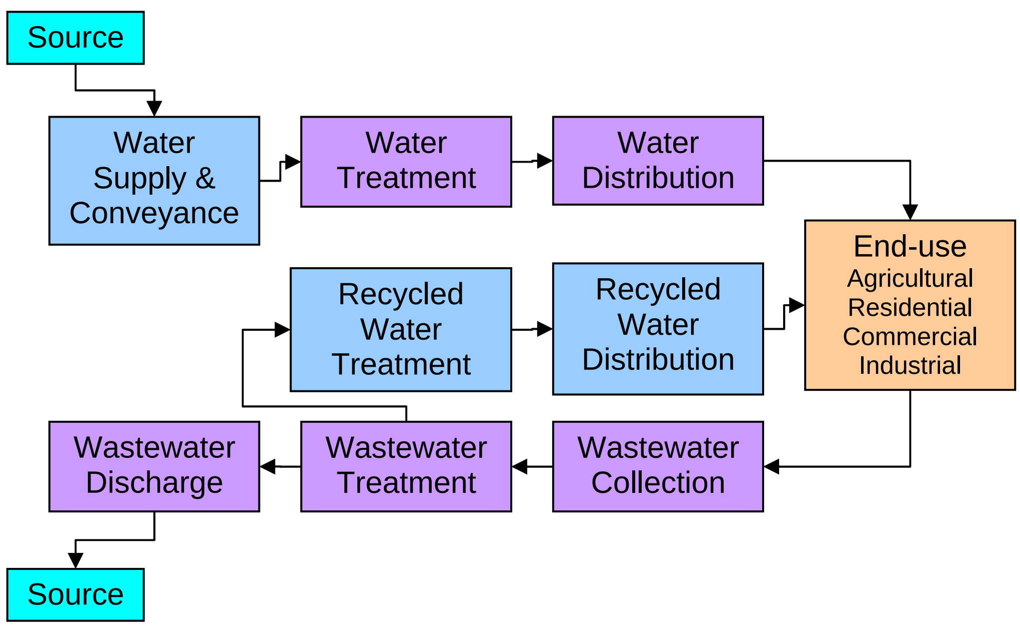
Another option that many cities are considering to meet their future water demand is desalination, the removal of salt from brackish or seawater. Because it is one of the very few options for increasing present water supplies, water agencies may build and operate many such facilities in the future. Desalination facilities may make more economic sense in areas that have high energy costs for current water supplies, such as in the urban areas of Southern California.

California will face reduced water supplies in the future because of enforcement of the Colorado River compact. In the past, California was allowed to use more than its allocation of water under the compact because other states were not using their full entitlements. Now, water demands in the Colorado River basin and Arizona are increasing dramatically, reducing the amount of water available to California. This will significantly impact water agencies, particularly in the southern part of the state.

Energy Use in California's Water Cycle

Figure 18 shows California's water cycle. California uses about 14 trillion gallons of water in a normal year, with about 79 percent used for agriculture and the remainder in the urban sector.

Figure 18: California's Water Cycle



Source: California Energy Commission

Once water is collected or extracted from a source, it is conveyed to water treatment facilities and distributed to end users. Wastewater from urban end uses is collected, treated, and then discharged back to the environment where it becomes a source for other uses. In general, wastewater from agricultural end uses is not treated (except for holding periods to degrade chemical contaminants before release to the environment) and is discharged directly to the environment, either as runoff to natural waterways or into groundwater basins. There is a growing trend in recycling some portion of the wastewater stream and redistributing it for non-potable end uses, such as landscape irrigation or industrial process cooling.

Because electric and gas meters do not measure water-related uses separately, it is difficult to determine the amount of water-related energy consumed by end users. Better information is available about energy consumption by water and wastewater utilities.[158] As shown in Table 3, total water-related energy consumption is large — roughly 19 percent of all electricity used in California, approximately 32 percent of all natural gas, and some 2.7 percent of diesel fuel. These numbers are, however, preliminary and are being refined through a Public Interest Energy Research (PIER) program research project with results expected in early 2006. Question marks in the table indicate areas where additional information is needed.

Table 3: 2001 Water-Related Energy Use in California

<table>
<tr><th></th><th>Electricity (GWh)</th><th>Natural Gas (Mill. Therms)</th><th>Diesel (Mill. Gallons)</th></tr>
<tr><td>Water Supply and Treatment</td><td></td><td></td><td></td></tr>
<tr><td>Urban</td><td>7,554</td><td>19</td><td>?</td></tr>
<tr><td>Agricultural</td><td>3,188</td><td></td><td></td></tr>
<tr><td>End Uses</td><td></td><td></td><td></td></tr>
<tr><td>Agricultural</td><td>7,372</td><td>18</td><td>88</td></tr>
<tr><td>Residential</td><td rowspan="3">27,887</td><td rowspan="3">4,220</td><td rowspan="3">?</td></tr>
<tr><td>Commercial</td></tr>
<tr><td>Industrial</td></tr>
<tr><td>Wastewater Treatment</td><td>2,012</td><td>27</td><td>?</td></tr>
<tr><td>TOTAL</td><td>48,012</td><td>4,284</td><td>88</td></tr>
<tr><td></td><td></td><td></td><td></td></tr>
<tr><td>2001 Consumption</td><td>250,494</td><td>13,571</td><td>?</td></tr>
<tr><td>Percent of Statewide Energy Use</td><td>19%</td><td>32%</td><td>?</td></tr>
</table>

Each element of the water use cycle has unique “energy intensities.” Table 4 illustrates the considerable variability in the range of these intensities and is followed by a description of each segment of the water cycle.

Supply and Conveyance — Water must be transported long distances and over great elevations to reach the urban centers of Southern California, which imports about 50 percent of its water supplies from the Colorado River and the State Water Project. Conveying water to Southern California communities can use 50 times as much energy

[158] Meters are typically installed to record the electricity or natural gas used by an entire household, building or other type of facility.

as it takes to convey water to communities in Northern California, where the energy intensity of raw water supplies can be near zero for gravity-fed systems from the Sierra to urban areas in Northern California and agricultural districts in the Central Valley.

Table 4: Energy Intensities in the Water Cycle

	Range of Energy Intensity (kilowatt hours/MG)	
Water Cycle Segments	Low	High
Supply and Conveyance	0	16,000
Treatment	100	1,500
Distribution	700	1,200
Wastewater Collection and Treatment	1,100	4,600
Wastewater Discharge	0	400
TOTAL	1,900	23,700
Recycled Water Treatment and Distribution	400	1,200

Treatment — The volume of electricity required to treat water to drinkable standards varies tremendously within the state, ranging from water supplies that need little treatment to those that require treatment to remove contaminants and refined chemicals and hazardous compounds. Proposed regulations[159] for more stringent water quality requirements could potentially increase electricity demand.

Distribution — Electricity use to distribute treated water to customers is primarily for pump motors and varies depending on the topography of the area served and the total pipe length, water use, age, and size of the system.

Wastewater Collection, Treatment, and Discharge — Wastewater treatment consumes electricity in three stages: transport to the facility, treatment, and disposal/recycling, all primarily from the use of electric pumps and blowers. Wastewater pumps require more energy because they must pump both liquids and solids. Recycled wastewater requires even more energy.

Recycled Water — Most wastewater treatment facilities in the state treat their effluent to a secondary standard, making it possible to recycle this water and expand available water supplies for non-potable uses.

Energy Consumption by Water End Users

Combined, agricultural, residential, commercial, and industrial water-related end uses account for 58 percent of all water-related electricity and 99 percent of the water-related natural gas use.

[159] To comply with the Safe Drinking Water Act and the Clean Water Act.

Agriculture

Each year, California's agricultural sector consumes more than 10,000 GWh of electricity along with diesel fuel and natural gas to pump and move roughly 34 million acre feet of water. Although most agricultural electricity use occurs during the summer months, many agricultural operations are year round. Shifts in agricultural crops and irrigation methods, such as drip irrigation that uses additional electricity to pressurize the system, may increase the amount of electricity used in the agricultural sector. Incentives to convert diesel-engine pumps to electric motors could also increase electricity use.

Residential, Commercial, and Industrial

The residential sector accounts for 48 percent of both the electricity and natural gas consumption associated with urban water use. Urban water use in California tends to be more energy intensive than in the agricultural sector because urban water systems use energy for wastewater treatment, which is not generally required for agriculture, and because interbasin transfer systems are used primarily for urban water supplies. Residential energy uses include everything from water filtering and softening to heating to cooling to circulating water in a spa pump and, in some cases, groundwater pumping of private wells. In the residential sector, the major water-related end uses that use electricity are water heating and clothes drying. Water heating is also the major use for natural gas.

Commercial water-related energy use represents 30 percent of the electricity and 6 percent of the natural gas associated with urban water use. Industrial water-related energy use represents 22 percent of electricity and 45 percent of natural gas use. Commercial and industrial water uses include all those found in residences, plus hundreds more. Some of the more energy intensive applications include high-rise supplemental pressurization to serve upper floors; steam ovens and tables; car and truck washes; process hot water and steam; process chilling, equipment cooling; and cooling towers. The petroleum industry is a major user of electricity and natural gas in its refineries and for enhanced oil recovery, and also produces wastewater that must be treated before reuse or disposal.

Recommendations for Energy Savings by End Users

The California Energy Commission (Energy Commission), the California Department of Water Resources (DWR), the California Public Utilities Commission (CPUC), water agencies, and other stakeholders should explore and pursue cost-effective water efficiency opportunities that result in significant energy savings to decrease the energy intensity of the water sector. This should include assessing efficiency improvements in hot and cold water use in homes and businesses, water saving appliances and fixtures, devices that use and move water, and other viable options to maximize energy and water savings. Near-term opportunities should be identified for inclusion in the 2006-2008 investor-owned utility (IOU) energy efficiency portfolios.

Producing Energy from Water

The most widely recognized aspect of the water-energy relationship is power production in large scale hydroelectric power plants and pumped storage facilities. However, water and wastewater utilities have other opportunities to develop energy supplies. These include water storage for peak shifting, in-conduit hydroelectric generation, biogas cogeneration at wastewater treatment plants, and development of local renewable resources on water and wastewater utilities' extensive watersheds and rights-of-way.

However, existing tariffs and operating rules limit the full development of self-generation by water and wastewater utilities. Interconnection constraints and current market rules impede customer self-generation. Limitations on net metering and constraints on service account aggregation also prevent self-generation for geographically dispersed customer loads.

Hydropower

California is served by a vast system of reservoirs and dams, pumped storage, and run-of-river facilities. These facilities are operated by IOUs, publicly-owned utilities (POUs), state and federal agencies, irrigation districts and other entities, mostly to serve multiple purposes including power generation, water supply, recreation, and flood control. California's combined total hydroelectric capacity is over 14,000 MW,[160] or about one-fourth of in-state generating capacity. In 2004, hydroelectric generation was about 29,000 GWh, or 13 percent of in-state generation.[161] California's hydroelectric system provides valuable peaking reserve capacity, spinning reserve capacity, load following capacity, and transmission support, all at low production costs.[162]

Opportunities for new hydroelectric dam and storage projects are extremely limited in California. Most economically viable sites have already been developed, and development in remaining suitable sites faces restrictions due to lack of unallocated water rights, environmental issues, and political opposition. More than a third of California's hydroelectric capacity is expected to be relicensed by the Federal Energy Regulatory Commission (FERC) between 2000 and 2015. Because FERC licenses only come up for renewal every 30 to 50 years, the relicensing process offers an excellent

---

[160] California Energy Commission, *2003 Environmental Performance Report. Appendix D, "California Hydropower System: Energy and Environment*," CEC-100-03-018, March 2003, p. D-6.

[161] California Energy Commission, Potential Changes in Hydropower Production from Global Climate Change in California and the Western U.S., June 2005, Consultant Report, Prepared in support of the 2005 Integrated Energy Policy Report, Publication No. CEC 700-2005-010.

[162] California Energy Commission staff report, *"California Hydropower System: Energy and Environment, Appendix D, 2003 Environmental Performance Report";* prepared in support of the Electricity and Natural Gas Report under the *Integrated Energy Policy Report* Proceeding (02-IEP-01), October 2003 CEC-100-03-018.

opportunity to reduce or resolve ecological impacts from these facilities. The *2003 Energy Report* recommended continuing Energy Commission efforts in helping state and federal agencies understand the effects of these facilities on regional and statewide electricity supply.

The most contentious issue for almost all relicensing projects is the allocation of water between in-stream flows necessary to sustain a healthy aquatic ecosystem and the amount of water diverted for hydroelectric generation. As understanding of freshwater aquatic ecosystems has improved, there has been increasing pressure for larger and more variable in-stream flows, which often means less water is available for hydroelectric generation. The Energy Commission's PIER program has proposed research to improve, through the development and demonstration of new tools or the enhancement of existing tools, how in-stream flow determinations are conducted. Such research holds the promise of ensuring better environmental protection while reducing unnecessary curtailment of hydropower production.

Opportunities exist to enhance hydroelectric generation at existing facilities without causing further environmental damage through improving runoff forecasting and decision support models. Hydroelectric operators can benefit from the better understanding of climate and hydrologic conditions, and from decision support models that allow operators to balance conflicting demands for water supplies. The PIER program is supporting research to develop probabilistic forecasts on an hourly to seasonal basis and develop decision support models for multi-purpose reservoirs.

In-Conduit Hydropower

In-conduit hydropower uses turbines or generating devices installed in conduits to generate electricity from water flowing in the pipelines, canals, and aqueducts in the state's water conveyance system. Most of the state's large water conveyance projects already take advantage of this technology but additional opportunities remain to develop new or retrofitted generation in the state's water systems if costs and risks can be minimized. A recent PIER study estimated the statewide potential of hydropower capacity in man-made conduits at about 255 MW with annual production of approximately 1,100 GWh. The potential was fairly evenly split between municipal and irrigation district systems.[163]

In-conduit hydropower facilities are attractive because they are generally easier to license and, because they are generally small, are more likely to meet requirements of the state's Renewable Portfolio Standard (RPS) program which limits eligibility to hydroelectric facilities of 30 MW or less. In most cases, in-conduit hydropower potential ranges from 1-2 kW to about 1 MW. However, many existing in-conduit facilities are facing challenges associated with the expiration of their standard offer contracts with the state's IOUs. Existing rules do not credit power produced against the water or

[163] California Energy Commission, *California Small Hydropower and Ocean Wave Energy Resources*, Mike Kane, Public Interest Energy Research program, April 2005.

wastewater utility's total energy bills. Instead, wherever such self-generated power cannot be directly connected to an existing load, it must be sold into the wholesale bulk power market. The costs and complexities of participating in the wholesale bulk power markets are daunting, even for large generators, and can be prohibitive for very small generators.

Existing energy efficiency programs can be tailored for special circumstances using customized incentives and standard performance contracting. In-conduit hydropower could be treated similarly and included as an element in these tailored programs. Again, the issues of interconnection, sale, or applying the power to multiple accounts will need to be addressed.

Biogas Recovery

Some of the electricity needed to process wastewater can be provided by anaerobic digesters installed at or near wastewater treatment facilities to produce digester biogas, which can then be used to self-generate or be sold into the grid. Currently, about 50 percent of sewage sludge, 2 percent of dairy manure, and less then 1 percent of food processing wastes and wastewater generated in the state are used to produce biogas. California has 311 sewage wastewater treatment facilities, 2,300 dairy operations, and 3,000 food processing facilities. Converting these wastes into energy can help operating facilities offset the purchase of electricity and provide environmental benefits by reducing discharge of air and ground water pollutants.

Current rules discourage full use of available biogas for self-generation or to serve offsite loads. Provisions under regulated tariffs enable dairy operations to produce electricity from biogas resources at one location and use it to offset electricity use at multiple locations, under multiple accounts for one customer. This same approach would significantly increase opportunities for biogas generation in water and wastewater agencies.

Storing Electricity for Peak Generation and Peak Load Shifting

California has a number of pumped storage facilities where water is pumped to a higher reservoir during off-peak times and used to generate electricity when needed. Pumped storage is generally considered the only commercially viable method for large-scale storage of electricity. California has more than 4,000 MW of pumped hydro storage capacity, with about 2,700 MW in the California Independent System Operator (CA ISO) control area.[164] Two pumped storage projects that would add as much as 900 MW of

[164] CA ISO, "Role of Energy Storage in California ISO Grid Operations," presented by David Hawkins, Manager, Special Projects Engineering at CEC/DOE Workshop on Energy Storage, February 24, 2005, [http://www.energy.ca.gorv/pier/notices/2005-02-24_workshop/03%20Hawkins-CA-ISO%20presentation.pdf], accessed April 30, 2005.

generating capacity are also in the planning stage but face the scrutiny of water resource, biological, visual, wilderness, and recreational impacts.

Pumped storage can minimize the system impacts of integrating large volumes of intermittent wind renewable resources into the state's power grid by creating load during high wind periods to use generation output that would otherwise cause operational problems for system operators.[165] Pumped storage can also be used in concert with wind resources to shift delivery of wind energy from off-peak to on-peak periods during the day and smooth production spikes.[166] One example is the Sacramento Municipal Utility District's proposed 400 MW pumped hydro storage facility in El Dorado County, intended to make the utility's wind energy projects dispatchable.[167] Outside of California, Bonneville Power Administration offers a storage and shaping service that integrates and stores hourly wind energy generation in the federal Columbia River Hydroelectric System.

One possibility for developing new pumped-storage projects is to connect two existing reservoirs or lakes with new pipelines for pumping and generating operations. A U.S. Department of Energy study has identified dozens of such reservoir pairs in California that could yield as much as 1,800 MW of new pumped-storage. This option avoids construction of new reservoirs but still faces challenges involved with bringing large pipelines through difficult terrain on protected lands.

Water storage can also be used to reduce peak load. For example, the El Dorado Irrigation District reduced its on-peak electrical usage by more than 60 percent by allowing its tanks to drop to a lower minimum level and installing an additional 5 million gallon storage tank. Water agencies could save an estimated 250 MW of peak demand statewide by the creative use of water storage, such as by refilling water storage tanks during off peak times. In addition, increased treated water storage in urban areas could save an added 1,000 MW of peak demand. Together, these savings would represent more than a third of peak load from the water cycle.

Water for Power Plant Cooling

California has 21 coastal power plants that provide nearly 24,000 MW of generating capacity. These plants use "once through cooling" technology in which up to 17 billion gallons of water per day of seawater is passed once through a heat exchanger and then

[165] California Energy Commission, April 2005, *Assessment of Reliability and Operational Issues for Integration of Renewable Generation*, Consultant Draft Report, prepared by Electric Power Group, LLC, and Consortium for Electric Reliability Technology Solutions, CEC-700-2005-009-D, [http://www.energy.ca.gov/2005_energypolicy/documents/index.html#051005].

[166] CA ISO, "Role of Energy Storage in California ISO Grid Operations," presented by David Hawkins, Manager, Special Projects Engineering at CEC/DOE Workshop on Energy Storage, February 24, 2005, [http://www.energy.ca.gov/pier/notices/2005-02-24_workshop/03%20Hawkins-CA-ISO%20presentation.pdf], accessed April 30, 2005.

[167] Sacramento Municipal Utility District, "Relicensing Hydro UARP FERC. No. 2101: Proposed Iowa Hill Pumped Storage Development," [http://hydrorelicensing.smud.org/docs/docs_iowa.htm], accessed April 30, 2005.

returned to its source." Recent studies, however, indicate that the use of once-through cooling can contribute to declining fisheries and the degradation of estuaries, bay and coastal waters.[168] When ocean water is drawn through a power plant the process kills eggs, larvae, and adult fish, while adult fish and invertebrates are trapped and killed on water intake screens. Once-through cooling also affects the coastal environment by releasing heated water, which affects early life stages of fish and shellfish.

In 2004, Governor Schwarzenegger established the Ocean Protection Council (Council) in order to implement the new California Ocean Protection Act and coordinate the work of state agencies related to the "protection and conservation of coastal waters and ocean ecosystems." As part of its broader agenda, the Council is interested in understanding and addressing the impacts of coastal power plants' use of once-through cooling on California's threatened coastal marine ecosystem. The Energy Commission has an opportunity through working with the Council to coordinate with other local, state and federal agencies, including the Santa Monica Bay Restoration Commission, the Coastal Commission, the State Water Resources Control Board, the Department of Fish and Game, and others, to address once-through cooling issues in the broader context of protecting the state's coastal marine ecosystem. The Energy Commission recommends working collaboratively with other agencies in support of the Council to conduct research on and develop better methods for assessing and mitigating the direct and cumulative impacts of once-through cooling on California's coastal marine ecosystem.

In September 2004, the U.S. Environmental Protection Agency (US EPA) released a new federal rule under Section 316(b) of the Clean Water Act to reduce environmental impacts from existing power plants that use once-through cooling. Although the new 316(b) regulations recently issued by the US EPA set forth performance standards affecting power plants using once-through cooling, there is no guidance that applies to California on appropriate sampling designs or impact analysis methods. There is a critical need for collaborative research to support the development of the most appropriate protocols and guidelines to assess the effects of once-through cooling on coastal and estuarine ecosystems. The Energy Commission's PIER program should continue to conduct collaborative research with the State Water Resources Control Board, the Regional Water Quality Control Boards, the Department of Fish and Game, and other stakeholders to develop sampling and other analytical protocols and guidelines that will provide clear, consistent approaches to assessing the ecological effects of once-through cooling technology. These research efforts should also address an innovative, cost-effective approach to minimizing or avoiding adverse effects associated with the use of once-through cooling technology.

In addition, the Energy Commission should update its current Memoranda-of-Understanding Agreement with the State Water Quality Control Board, Regional Water Quality Control Boards, and the California Coastal Commission to develop a consistent regulatory approach for the use of once-through cooling in power plants, including the

[168] California Energy Commission, June 2005, *Issues and Environmental Impact Associated with Once-though Cooling at California's Coastal Power Plants.* Staff Report, CEC-700-2005-013, [http://www.energy.ca.gov/2005_energypolicy/documents/index.html#051005].

use of Best-Available Retrofit Technology to help minimize impacts to the marine environment. The Energy Commission should also actively participate in the 316(b) reviews of coastal power plant once-through cooling impacts.

The Energy Commission's existing data adequacy regulations for power plant licensing applications do not provide sufficient guidance regarding the type and extent of data needed to complete an analysis of power plants proposing to use once-through cooling technologies. Updating data adequacy regulations is also needed, consistent with the Commission Staff's 2005 Memorandum of Understanding with the Coastal Commission, to provide a current and site-specific analysis of entrainment impacts and a discussion of the project's compliance with California Coastal Act Section 30413(d).

The Impact of Water Efficiency on Energy Use

Agricultural Water Use Efficiency

Because of the large amounts of energy used in California's water cycle, reducing water use can also save energy. Efficient irrigation techniques hold promise for substantially reducing the amount of water delivered. Agricultural water conservation can lead to increased on-farm energy requirements, such as the energy required to pressurize drip and microspray irrigation systems, but can be more than offset by increasing on-farm irrigation system efficiency and operation and by reductions in the energy associated with delivering reduced volumes of water. Utilities and agencies are also addressing agricultural energy use through several energy efficiency programs. The Agricultural Pumping Efficiency Program is funded by a public goods charge on utility bills and provides free pump efficiency evaluations for farmers and irrigation districts served by the state's three largest IOUs.

Large numbers of both Pacific Gas and Electric (PG&E) and Southern California Edison (SCE) agricultural customers have signed time-of-use (TOU) electric rate schedules. In the PG&E service area 81 percent of agricultural revenues and 89 percent of agricultural kWh sales are on TOU rates, representing 40,000 of a total of 80,000 agricultural accounts.[169] In the SCE service area, 71 percent of agricultural kWh sales are on TOU rates, generated by 18 percent of customer accounts.[170]

Although a large number of accounts use TOU rates, farmers cannot always meet TOU requirements to take advantage of the lower rates. When necessary, they use energy during peak period hours to provide water to crops when needed, in the proper amount and using high distribution uniformity to achieve optimal crop growth. Agricultural electricity end users would benefit from energy policies that offer voluntary options for customers to choose the demand response practices that best meet the nature of their

[169] Communication between Ricardo Amon and Keith Coyne, Pacific Gas and Electric, August 4, 2005.
[170] Communication between Ricardo Amon and Cyrus Sorooshian, Southern California Edison, August 11, 2005

businesses. The industry will be more inclined to invest in peak load reduction measures when given flexibility as well as strong, consistent price signals.

Energy Savings from Efficient Urban Water Use

In 2003, the Pacific Institute estimated the potential for cost-effective urban water conservation to be about 651 billion gallons per year.[171] In early 2005, the California Urban Water Conservation Council (CUWCC) posted the results from 32 percent of the agencies that signed their memorandum of understanding to institute best management practices (BMPs) in their water agencies. Taking only those BMPs for which water savings could be quantified, the reporting agencies saved more than 27.5 billion gallons of water in 2004 and more than 234 million kWh of electricity. Over the lifetime of each measure the net present value of the avoided cost totals more than $200 million dollars.[172] However, these energy savings were not recognized by either the CPUC or by the energy utilities as a fundable energy conservation measure.

Members of the Energy Commission's Water-Energy Working Group presented testimony on water use cycle energy savings and sought to establish the magnitude of potential energy savings associated with water savings. Table 5 compares energy efficiency programs in years 2004-2005 with those planned for 2006-2008, with water use efficiency programs savings and program implementation costs reported for the best management practices.

Table 5: Comparison of Energy Efficiency Programs Resource Value to Water Use Efficiency

	Energy Efficiency Programs		
	2004-2005	2006-2008	Water Use Efficiency (WUE)
GWh (annualized	2,745	6,812	6,500
MW	690	1,417	850
Funding ($ million)	762	1,500	826
$/Annual kWh	0.28	0.22	0.13
WUE Relative Cost	46%	58%	

Significant untapped energy savings potential exists in programs focused on water use efficiency. Energy savings from such programs would achieve 95 percent of the savings

[171] Waste Not, Want Not. The Potential for Urban Water Conservation in California. Pacific Institute. November 2004.

[172] The saved energy was computed using the energy intensity of the water use cycle for urban water users of 4,000 kWh/MG in Northern California and 12,700 kWh/MG in Southern California. The computations were done separately for Northern and Southern California and then were aggregated to arrive at the statewide totals shown in the table. Resource values are produced using the E3 Avoided Cost Methodology adopted by the CPUC in the April 7, 2005 Decision 05 04 024. Rulemaking (R.) 04-04-025.

expected from the 2006-2008 energy efficiency programs at 58 percent of the cost. Peak savings could account for 60 percent of planned-for reductions in demand.[173]

Increasing Water and Wastewater Treatment Efficiency

All water and wastewater treatment processes represent opportunities for reduced energy use. Industry experts estimate that untapped energy efficiency opportunities in water and wastewater treatment range from 5 percent to 30 percent. In the mid-1990s, the Electric Power Research Institute and HDR, Inc. conducted an audit of the energy savings potential for water and wastewater facilities in California. At that time they estimated that more than 880 GWh could be saved by implementing a variety of measures such as load shifting and high efficiency motors and pumps.

Time-of-Use Water Tariffs and Meters

The idea of TOU water tariffs and meters was raised several times during the *2005 Energy Report* proceedings as a way to encourage customers to reduce their water use by providing a more accurate assessment of the time value of water. Though water agencies are on standard TOU and demand rates, the incremental costs between on- and off-peak were not large enough to affect their decision-making until the 2000-2001 crisis raised awareness about hourly energy costs in the highly volatile bulk power market.

At the retail level, it is important to recognize that many water customers in the state do not have water meters, though current legislation will change that. In addition, there are currently no time-of-use water meters. Water agencies are grappling with how to develop tariffs and rate schedules that properly reflect the value of water at different times during the day and the need to account for delays between energy consumption and the time of water use. The Energy Commission is funding a PIER research project to look at the feasibility of such meters and associated tariffs.

Investing in Water and Energy Efficiency

California currently has programs to increase the energy efficiency of existing water and wastewater utility operations. These programs include building and appliance standards, technical support and loan programs, and incentive programs funded through the state's energy utilities. The state also conducts research to modify existing treatment processes, develop more efficient water and wastewater treatment and water supply technologies.

---

[173] The numbers for the energy programs come from CPUC documents:2004-2005, CPUC Rulemaking R.01-08-028, Decision D.03-12-060, 2005-2006, CPUC Rulemaking R.-01-08-0228, Decision D.04-09-060. The numbers for the water use efficiency program are discussed in detail in Appendix D of the Water-Energy Relationship Staff Report. The energy savings have been apportioned to Northern and Southern California based on population. The cost for the water efficiency measures assumes an average of $384 per acre-foot, based on a range of $58-$710.

The state's largest energy utilities have no authority to invest in programs that save cold water, regardless of whether the programs are recognized as yielding an energy benefit. Because of the potential for reduced energy demand from these programs, the Energy Commission, the CPUC, utilities, and stakeholders should more carefully examine investment in cold water savings.

Water utilities do, of course, invest in programs that save water. Water and wastewater utilities also participate in programs to increase the efficiency of their operations. Given the interconnectedness of water and energy resources in California, the fact that cost-effectiveness is determined from the perspective of a single utility and a single resource poses barriers to achieving greater energy savings from water efficiency programs. Water utilities only value the cost of treating and delivering water. Wastewater utilities only value the cost of collection, treatment, and disposal. Electric utilities only value saved electricity. Natural gas utilities only value saved natural gas. This causes underinvestment in programs to increase the energy efficiency of the water use cycle, to increase agricultural and urban water use efficiency and to increase generation from renewable resources by water and wastewater utilities.

Recommendations for Energy Savings in Water Use

The Energy Commission's PIER program should evaluate and conduct research to better understand the interaction of water and energy within the state and identify new and innovative technologies and measures for achieving energy and water efficiency savings. Research should address potential savings throughout the water cycle, especially in Southern California where the energy intensity of water is greatest.

The state, in collaboration with water utilities, wastewater districts and stakeholders, should assess and develop a comprehensive policy to promote self-generation, including examining all cost-effective, environmentally preferred in-conduit, biogas and other renewable options for water and wastewater systems. Attention should be given to the following:

- Allowing water and wastewater utilities to self-generate and wheel power within their own systems.
- Expediting and reducing the cost of interconnection, eliminating economic penalties such as standby charges, and removing size limitations for net metering.
- Identifying and implementing cost-effective retrofits in the water system that increase efficiency and provide both energy and peak savings.
- Examining opportunities to shift loads off-peak by maximizing use of storage in existing pumped hydro facilities, increasing use of water storage tanks and conveyance systems throughout the state, developing TOU water tariffs and meters, and increasing flexibility in water deliveries.

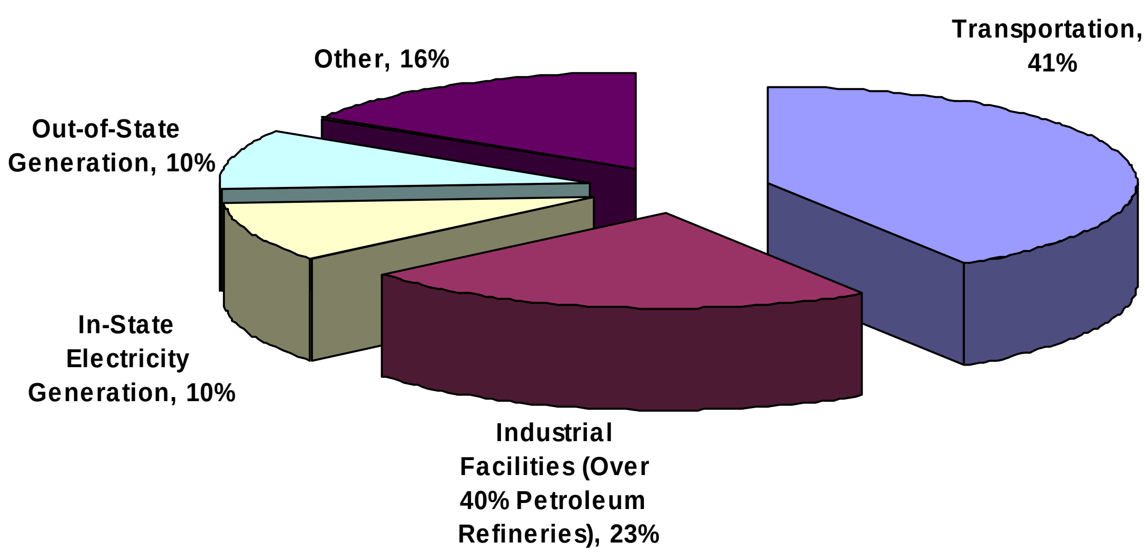
CHAPTER 9: GLOBAL CLIMATE CHANGE

Introduction

Climate change is a worldwide phenomenon that has significant implications for all sectors of the state's economy and natural resources. Most scientists now agree that climate change is occurring, is caused by human activities, and could severely affect natural ecosystems and the economy.

California is the tenth largest emitter of greenhouse gases (GHG) in the world,[174] with more emissions than any state in the nation except Texas.[175] GHG emissions in California are increasing mainly because of both population and economic growth. From 1990 to 2002, total GHG emissions rose nearly 12 percent; if current trends are permitted to continue, GHG emissions would increase by 24 percent from 1990 to 2020.

Figure 19: Greenhouse Gas Emissions



Source: California Energy Commission

The primary source of GHG is the burning of fossil fuels in motor vehicles, refineries, industrial facilities, and power plants.[176] In California, the transportation sector is the

---

[174] Legislative Analyst's Office, "Cal Facts 2004: California's Economy and Budget in Perspective," www.lao.ca.gov/2004/cal_facts_econ.htm

[175] California Energy Commission, Inventory of California Greenhouse Gas Emissions and Sinks: 1990 to 2002 Update, Publication CEC-600-2005-025, June 2005.

[176] According to the Natural Resources Defense Council, in its April 5, 2005 Comments to the Energy Commission, California's CO_2 emissions in 1999 were 346 $MMTCO_2$ from in-state sources and 73

largest source of GHG emissions, producing 41 percent of the state's total emissions. Industrial facilities are the second largest source, producing nearly 23 percent of total emissions. Within this sector, petroleum refineries account for about 43 percent of total emissions. Electricity generation is the third largest GHG category, producing just under 20 percent of total emissions. While imported electricity is a relatively small share of California's electricity mix, out-of-state electricity generation sources contribute 50 percent of the GHG emissions associated with electricity consumption in California.

In spite of its size, California ranks among the better states and countries when considering per capita emissions of GHGs. This is primarily due to the aggressive building and appliance standards put in place over the years by the California Energy Commission (Energy Commission) that have limited power plant generation growth as well as the stringent air quality standards applied to power plants that have moved them from burning oil to burning cleaner natural gas.

In its *2003 Energy Report*, the Energy Commission recommended the following actions to address climate change:

- Account for the cost of GHG emission reductions in utility resource procurement decisions.
- Require the reporting of GHG emissions as a condition of state licensing of new electricity generating facilities.
- Use sustainable energy and environmental designs in all State of California buildings.
- Require all state agencies to incorporate climate change mitigation and adaptation strategies in planning and policy documents.[177]

Since 2003, state agencies have begun to take significant action in addressing these recommendations.

Resource Procurement

The California Public Utilities Commission (CPUC), in a December 2004 decision, recognized the importance of reducing GHG emissions and directed the state's investor-owned utilities (IOUs) to account for climate change risk in their long-term resource procurement plans. Under this decision, the utilities are required to use a "greenhouse adder," with an initial value of $8 per ton to reflect the amount of CO_2 that would be emitted by an electricity generating unit under the terms of a contract. This adder represents an estimate of the likely future cost of purchasing CO_2 offsets to comply with future mitigation regulations. The adder also corresponds to the financial

---

MMTCO_2 due to imported electricity, which places California tenth in the ranking of world countries in 2004.

[177] California Energy Commission, *2003 Integrated Energy Policy Report*, Publication #100-03-019, December 2003, page 42.

risk associated with likely future regulation of GHG emissions. This adder encourages utilities to invest more in lower-emitting resources, such as efficiency and renewable sources, and less in high-emitting resources such as conventional coal.

Power Plant Licensing

The Energy Commission is conducting a rulemaking to revise current regulations for power plant licensing and compliance to require power plant developers to report GHG emissions as an important first step in identifying mitigation opportunities.

State Buildings

Commercial buildings use about 36 percent of the electricity in California and, therefore, account for a significant portion of GHG emissions. The Governor's Executive Order 20-04 implemented the Green Building Initiative with an overall goal to reduce energy consumption in the commercial sector by 20 percent by the year 2015.

The Initiative involves the California Energy Commission, State agencies under the direct authority of the Governor, the Department of General Services, and the Division of the State Architect. It also urges other entities such as the University of California, California State Colleges, Community Colleges, constitutional officers, legislative and judicial branches, the Public Employees Retirement System, and the CPUC to actively participate in helping to achieve the reduction goal.

State Planning Documents

In the State Water Plan, the Department of Water Resources (DWR) recognizes the long-term effects of changing climate on the quantity and timing of water availability and snowmelt. The plan also encourages water planning agencies to monitor and model the hydrology effects of changing climate. The California Department of Transportation, in its most recent update of the State Transportation Plan, similarly encourages regional and local transportation plans to recognize the benefits and risks of climate change. The State Transportation Plan encourages state and local policies on transportation system efficiency, mode shifts, alternative fuels, and the fleet purchase of hybrid vehicles, which have important climate change co-benefits.

The Governor's Greenhouse Gas Emission Reduction Targets

In June 2005, Governor Schwarzenegger signed Executive Order S-3-05,[178] establishing the following statewide greenhouse gas emissions targets:

[178] Executive Order S-3-05 by the Governor of the State of California, June 1, 2005, [http://www.climatechange.ca.gov.]

- By 2010, reduce statewide GHG emissions to 2000 emission levels.
- By 2020, reduce statewide GHG emissions to 1990 emission levels.
- By 2050, reduce statewide GHG emissions to 80 percent below 1990 levels.

To meet the targets, the Governor directed the California Environmental Protection Agency to coordinate with the Business, Transportation and Housing Agency; the Department of Food and Agriculture; the Resources Agency; the California Air Resources Board; the Energy Commission; and the CPUC. The Governor's Climate Action Team is made up of representatives from these agencies to implement global warming emission reduction strategies and report on the progress made toward meeting the statewide greenhouse gas targets established in the Executive Order. The first report is due to the Governor and the Legislature in January 2006 and bi-annually thereafter.

Energy Impacts

Climate change could significantly affect energy supply in California. Today, California relies on hydroelectricity for 15 percent on average of the electricity used in the state. Depending on hydrological conditions, the temperature and precipitation effects from global climate change could alter future hydrologic conditions, which affect hydroelectric supply.

With the expected warming trends, a decreased snow pack during the spring and summer months could deplete the "reservoir" of snow that provides water for hydropower.[179] Increased winter flows could increase flood protection requirements, which could reduce storage for summer use.

Preliminary studies suggest that hydroelectric generation may increase under the increased precipitation scenarios, but generation will decrease from 10 to 30 percent if the dry scenarios materialize. The degree of precipitation as a result of climate change is a key uncertainty which still needs to be addressed. Further study is needed on the changes in runoff and changes in hydropower output from climate change.

Earlier snowmelts could also result in water being diverted from hydropower facilities to avoid damage as well as water released from reservoirs to prevent flooding. With reservoir capacity well below the majority of generating capacity less runoff will be captured for summer peaking power demand.

Increased runoff in winter would result in increased hydro generation at a time when demand related to space heating, particularly in the Pacific Northwest, would be decreased due to overall warming trends. Conversely, decreased runoff in the summer

---

[179] California Energy Commission, staff presentation on "Climate Change Effects on Hydropower" in support of the *2005 Integrated Energy Policy Repor*t, June 20, 2005.

would decrease hydro generation at a time when peak power is most needed to meet air conditioning loads that will be higher due to increased warming.

The effects from climate change may not be evenly distributed. The changes in flows may vary both across geography and by elevation. If snowmelt occurs earlier at higher elevations, facilities that rely on the snow pack as an effective reservoir for spring and summer flows will see those flows diminished. The result would be reduced summertime hydropower availability.

Climate change could also increase the energy demand in California by increasing the demand for heating and cooling, but the degree of this increase depends on the actual level of warming. Californians currently spend about $30 billion for natural gas and electric heating and cooling each year. Climate change could increase state energy expenditures for cooling and heating by about $2 billion in 2020.[180] This increase results from higher summer cooling demand that cancels any decrease in winter warming demand from warmer temperatures.

Increased energy demand would result from higher usage for residential units, commercial buildings, and water pumping for urban and agricultural use. Under a worst case scenario (a rise in 1.9 degrees Centigrade), the state's electricity requirements would increase by about 7,500 gigawatt hours of energy and by 2,000 megawatts of peak capacity in 2010.[181] Global climate change is also expected to reduce the amount of surface water available for irrigation.

Water agencies can be instrumental in mitigating the effects of climate change because of the close relationship between water use and energy consumption. Water agencies are the single largest electricity users in California, consuming 3,200 megawatts of peak electricity. Reducing this demand is possible by making changes in pump scheduling and storage, by adding more storage, and by encouraging water users to shift usage to off-peak periods. Over the longer term, changes in electricity rate design, financial incentives, and demand response programs are recommended.[182]

Climate Change Activities at the Energy Commission

The Energy Commission and the Center for Clean Air Policy (CCAP) have conducted and compiled "bottom-up" assessments of measures that can reduce GHG emissions in California. The goal of this effort was to identify and quantify a range of GHG emissions reduction and sequestration opportunities in the state, the potential costs of these reductions, and policy options that might be used to encourage implementation.

---

[180] Mendelsohn, R., *The Impact of Climate Change on Energy Expenditures in California*. 2003, California Energy Commission, pp. 1–43.

[181] Baxter, L.W. and K. Calandri, "Global warming and electricity demand: A study of California." *Energy Policy* 1992: 233–244.

[182] Lon W. House, Ph.D., "There is No Electricity Crisis in California (That) The Water Agencies Can't Solve – Or Make Worse," June 21, 2005.

The cost-effectiveness and reduction potential for GHG mitigation options in the transportation and cement sectors were evaluated as well as options for sequestering CO_2 emissions in the forestry and agricultural sectors. This work was combined with a series of sector-specific GHG mitigation analyses conducted by ICF Consulting for the Energy Commission's PIER program that evaluated measures to reduce high global warming potential gases in the landfill, natural gas, semi-conductor, dairy, and other sectors.

In total, the measures analyzed have the potential to reduce GHG emissions by 44 million tons of CO_2 equivalent ($MMTCO_2e$) in 2010 and 117 $MMTCO_2e$ in 2020. These measures do not include the electric generation and oil refining sectors. These sectors contribute significantly to the state inventory[183] and have the potential to contribute significant emissions reductions. Key findings and conclusions from this work are:

- Emission reductions are needed from multiple sectors of the California economy to achieve the Governor's targets.
- Cost-effective reductions are possible (less than \$10 to \$20 per ton) by 2010, but costlier options will be needed to achieve the 2020 target.
- Some options face technical or economic barriers or policy or political hurdles, which need to be overcome to fully realize the GHG reduction benefits.[184]

In all, based on a very preliminary baseline emissions estimate developed by the Energy Commission,[185] there appear to be sufficient emissions reduction opportunities available in the state to contribute significantly to the GHG reduction targets established by the Governor in June 2005.

As directed by the Legislature in Senate Bill 1771 (Sher), Chapter 1018, Statutes of 2000, the Energy Commission established the Climate Change Advisory Committee to advise the Energy Commission on "the most equitable and efficient ways to implement national and international climate change requirements." Its membership represents key sectors of the California economy that will be affected by climate change.

The Advisory Committee was charged with the task of reviewing the CCAP's sector analyses and providing recommendations to the Energy Commission for inclusion in the *2005 Energy Report*. The Advisory Committee established subcommittees for each sector. This body of work has been transmitted to the Secretary of the California

[183] According to the most recent state inventory, in-state power plants emitted about 44 $MMTCO_2e$ in 2002 and imported power accounted for about 52 MMTCO2e in 2002. A Center for Clean Air Policy analysis estimates that refineries emit 35 $MMTCO_2e$ in 2005.
[184] Ned Helme, Center for Clean Air Policy, presentation in support of the *2005 Integrated Energy Policy Report,* July 11, 2005.
[185] Preliminary projections for 2010 and 2020 are based on estimates by Gerry Bemis and Jennifer Allen published in *Inventory of California Greenhouse Gas Emissions and Sinks: 1990 to 2002 Update*, June 2005. The 2020 estimates were increased by Center for Clean Air Policy staff to reflect potential growth in other sectors beyond increases in gasoline demand. These projections should be considered placeholders until final state estimates are developed.

Environmental Protection Agency for use by the Climate Action Team. The following summarizes the recommendations from the respective subcommittees.

Electricity Generation

The majority of the subcommittee concluded that:

- All California utilities, independent power producers, other load-serving entities (LSEs), and regulators need to take the financial risks of GHG regulation explicitly into account in long-term resource planning and procurement decisions.
- Each IOU, municipal utility, and LSE should develop an action plan to meet the Governor's GHG reduction goals, implementation of which should be monitored by the Energy Commission and the California Environmental Protection Agency.
- California should pursue development of a program to determine and track GHG emissions throughout the Western Electricity Coordinating Council Region, in cooperation with the Western Governors Association and the Western Renewable Energy Generation Information System.
- Reductions under a mandatory GHG reduction program, should one be implemented, could be achieved faster, better, and cheaper through a well-designed, multi-sector cap and trade program, and electricity generated from in-state and out-of-state sources should be treated in a non-discriminatory fashion.
- California should seek credit for early actions in reducing GHG emissions in any future federal statutory or regulatory system and should take a leadership role in researching and developing low-carbon-emitting technologies.

A minority of the subcommittee took issue with several of the above positions and concluded that:

- Actions to address climate change will be most effective if implemented at the national and international level. Any mandatory state program should be done in concert with states in the WECC. Unilateral programs implemented by California will shift GHG emissions to generators in other states with which California is electrically linked, thus eliminating any overall reduction, and will result in higher prices and reduced reliability to California customers.
- The relative "carbon-efficiency" of California's electricity system compared to neighboring western states has been achieved by substantial investment by IOUs in energy efficiency and renewable energy. All LSEs should be required to meet the same Renewable Portfolio Standard goal.
- Early dramatic reductions in GHG emissions will be expensive and unnecessary if the state transitions to a low- or zero-carbon energy system over a longer timeframe.
- Since California will continue to rely on coal for some portion of its electricity, the state should take a leadership in developing technologies that capture and store CO_2.

Industry, Agriculture, and Forestry

A consensus of the subcommittee concluded that:

- All sectors take advantage of opportunities to reduce energy consumption through utility-sponsored programs, energy audits and cost-effective technologies such as benchmarking tools in the cement industry and occupancy sensors in commercial buildings larger than 100,000 square feet.
- New technologies are not being adopted because of bureaucratic barriers. For example, adoption of the ASTM C 150-04 standard for Portland cement and use of a carbon stock protocol for forestry, as well as small-scale biomass generators, could reduce GHG emissions.
- Performance-based incentives should be implemented for the adoption of new technologies that are not yet cost effective. Examples include concrete houses, curve sawing, and the use of net metering for methane digesters.
- A cap and trade at the state or focused on a single sector has inherent limitations. A cap and trade program should be regional or national in design.
- Require a California Environmental Quality Act-level analysis of climate change impacts for any conversion of forest land to non-forest use.
- The state should implement a public education campaign regarding the role of forests in climate change.
- The state should provide research funding to study the impacts of climate change on its forests: CO2 emissions caused by forest land conversion; climate mitigation opportunities.

Transportation Sector

A consensus of the subcommittee concluded that:

- Emission performance standards and fuel or carbon performance standards are the most direct approach to reducing GHG emissions from motor vehicles.
- Market-based incentives should complement standards to increase low- and no-emission strategies for the transportation sector.
- A coordinated approach to achieve climate change benefits is recommended, which are consistent with other state policy objectives, such as petroleum reduction, fuel diversity, air pollution reduction, and resource conservation.
- State policies should empower consumer choices of low- or-no-emission fuels, vehicles, and transportation options.
- New opportunities for reducing GHG emissions exist in public fleets, freight, and air travel and for reducing vehicle miles traveled through smart growth and sustainable development approaches.

- The state should empower local governments to support low-GHG strategies through partnership opportunities and by addressing environmental justice concerns.186

Cross-Cutting Issues

A consensus of the subcommittee supports:

- A well designed, fair, and equitable cap and trade program if the state has accepted a mandatory GHG reduction requirement, and the cap and trade program represents the best alternative to achieve cost-effective GHG reductions, and no other option will achieve more cost-effective and certain GHG reductions.
- California's efforts to independently pursue GHG reductions, but acknowledges that this approach is less than optimal. A broader regional, national, or international program would reduce "leakage" and expand the available set of cost-effective GHG control measures.
- A cap and trade program that can be readily adopted by neighboring states, would enable linking with other trading programs in the U.S. and abroad, is multi-sector, and would potentially serve as a model for the development of a national policy.

Value of Greenhouse Gas Emissions Inventory and Registry

The Energy Commission conducts a variety of activities in the greenhouse gas emissions policy area. Two of these activities have a degree of similarity that some may see as a duplication of effort, but they actually complement one another. The greenhouse gas emissions inventory activity is important for identifying overall trends in emissions while the registry activity is important for identifying emissions emanating from specific sources or companies and providing well defined documentation of these emissions.

Greenhouse Gas Emissions Inventory

GHG emissions inventories are used to determine overall GHG emissions associated with particular fuel use or economic sector activity. The data are translated into overall emissions using typical emissions factors that are generally accepted for the particular fuel or activity. GHG emissions inventories are used to look at overall trends and are often used for setting overall policy goals. Their strength lies in the fact that there is a systematic, comprehensive process in place to collect usage data and to aggregate it to protect its confidentiality. In addition, GHG emissions inventories are relatively complete data sets and can be used to identify data gaps to direct data collection efforts for specific facilities or entities.

[186] Transportation Subcommittee Statement, Climate Change Advisory Committee to the Energy Commission, August 16, 2005.

The weakness of the GHG emissions inventory lies in its aggregation. It is not possible to associate all emissions from a particular facility or company because the data are typically aggregated by fuel type or process. For example, a facility that uses several fuels would have a portion of its emissions summed under one fuel and the remainder under each of the other fuels uses. It would not be possible to obtain an assessment of total emissions from that facility.

California Climate Action Registry

A major benefit of a registry, such as the California Climate Action Registry, is that it provides a forum to develop a uniform and comprehensive data base or inventory for a facility or company. The database would be able to include all process emissions and fuel uses at the facility or company. In order to evaluate reductions made at a specific facility or within a specific company an emissions database or inventory needs to be comprehensive for the particular company or facility. In addition, a registry provides facilities and companies with a reliable source to obtain credit for their emissions reductions, since registry members must thoroughly document their emissions, including both direct and indirect emissions. The direct emissions can be aggregated on either a company or facility basis to protect proprietary information. Registry participants must allow an auditor to review their method of calculating their emissions. Once done, this registry-level inventory becomes the basis for obtaining credit for emissions reductions, including monetary valuation of emissions reductions.

Advancing the Science of Climate Change Assessment

The impacts of climate change have historically not been considered in strategic planning by State agencies. In the energy sector, the trade-offs and value of building and appliance efficiency standards is not fully captured in analysis before the Energy Commission because their benefits to reduce GHG emissions are not taken into account. For example, options to reduce or eliminate hydrofluorocarbon emissions from air conditioning and refrigeration systems are not considered when establishing appliance standards.

Some state agencies are addressing these concerns in their long-term planning documents. The need for coordination and common planning assumptions is increasing however, with integration of adaptation strategies across natural resources. Examples of this need for coordination include:

- The increased reliance on renewable energy as a GHG reduction strategy such as biomass-to-energy demands joint research with Department of Forestry to develop analytical tools to balance forest health with the removal of “fuel” for electricity generation. Although there are clear benefits to this removal, the methods and amounts much be consistent with the protection of sensitive species and habitat
- The potential for impacts to the snow pack has serious implications for the availability of hydroelectricity. Thus, the Department of Water Resources is critical to

the development of regional climate models designed to allow strategic planning for water availability and related planning for electricity supply.

These examples illustrate an important and growing trend for integrated analysis, and this trend will only increase with time given the increased level of activities on climate change within these agencies. Uncoordinated state planning efforts using disparate climate scenarios may result in the selection of contradictory policy options.

The California Climate Change Center sponsored by the Energy Commission is developing probabilistic climate projections for California at adequate level of geographical and temporal resolutions for planning purposes. The Energy Commission, through the Climate Change Center, should continue to develop data and methodologies for assessing the regional implications of climate change to inform planning activities in the state. The resulting climate scenarios should be made widely available for the aforementioned strategic planning for all State agencies.

Recommendations

The Energy Commission will:

- Continue to provide technical and analytical support to the Governor's Climate Action Team.
- Consider the advisory recommendations of the Climate Change Advisory Committee in evaluating state-level strategies.
- Improve the "top-down" statewide inventory on GHG emissions and support steps to evaluate the need for a mandatory reporting system.
- Support efforts by the California Climate Action Registry to collect data on facility-level and entity-wide GHG emissions.
- Support efforts by the CPUC to fully internalize the benefits of reducing carbon generation through a carbon adder required in utility resource procurement.

CHAPTER 10: ENERGY CONCERNS IN THE CALIFORNIA-MEXICO BORDER REGION

Introduction

The California – Baja California Norte border region is experiencing rapid population, commercial, and industrial growth. Growth in the region is substantially increasing the demand for energy, which in turn increases the need for new power plants, transmission lines, and natural gas facilities. New natural gas-fired power plants will be used predominantly to meet the growing demand for electricity, although attention is being given to developing renewable energy. Liquefied natural gas facilities are being developed in Baja California Norte to meet local demand and demand in California.

The border region is becoming an “energy corridor” as states on both sides of the border develop facilities not only to meet local needs, but also to export across state and international borders. The energy relationship between California and Baja California Norte is likely to become even more interdependent in the future with the growing need for new generation, transmission lines, and natural gas supply pipelines to meet the region’s increasing energy demands.

The growing demand for energy in the border region is adding to already significant air quality problems. Yet, there are fundamental differences in the regulatory approaches on both sides of the border. A bi-national policy is needed to coordinate energy and environmental issues in the border region. State and regional organizations, including the Border Governor’s Energy Worktable, Border Energy Issues Group, San Diego Association of Governments, and San Diego Regional Energy Office, are effectively engaged in a collaborative effort to address the myriad energy and environmental issues and improve the economic vitality and quality of life in the border region.

Growth in the Border Region

The California – Baja California Norte border region extends about 60 miles (100 kilometers) north and south of the border and links California and Mexico in a complex network of trade, cultural, social, and institutional relationships. The region includes San Diego and Imperial Counties in California and the Tecate, Tijuana, Mexicali, Rosarito, and Ensenada municipios in Mexico.

The current population of the border region is close to 5 million and is expected to increase to more than 7.5 million over the next 25 years. The major population centers in the border region are San Diego-Tijuana and Imperial Valley-Mexicali.

The driving economic force in the region continues to be the maquiladora industry, which are Mexican companies that manufacture or assemble a variety of products and equipment. The North American Free Trade Agreement (NAFTA) accelerated the growth of the maquiladora industry because U.S. companies located manufacturing plants in northern Mexico to reduce costs and complete finished products for export back into the U.S. or to other countries. NAFTA and trade relationships with Mexico and Canada were also instrumental in helping San Diego's economy to recover from its recession during the first half of the 1990s. Over 700 maquiladora plants have located in Baja California Norte.

Demand for Energy in the Border Region

Electricity

During summer 2004, peak energy demand in the San Diego Gas and Electric (SDG&E) service area reached record levels at 4,065 megawatts (MW). Between 2004 and 2009, the Energy Commission and SDG&E estimate average annual growth rates of 2 percent for system peak load and 2.0 to 2.1 percent for electricity demand. For Imperial Irrigation District (IID), peak electricity demand will increase from 740 MW in 2002[187] to about 1000 MW by 2013.[188]

Over the next ten years, the growth in electricity demand in Baja California Norte is expected to be the highest of any state in Mexico. To meet this demand, Baja California Norte will need to almost double its electricity capacity.[189,190] In its official 2004-2013 electricity demand forecast, Mexico's Comisión Federal de Electricidad (CFE) expects energy sales in Baja California Norte to increase by 7 percent on average and peak demand is expected to continue growing by 6.3 percent per year.

Natural Gas

Natural gas demand in the SDG&E service area is forecast to grow between 1.2 and 1.6 percent annually.[191] The primary driver for gas demand in the near-term is new power plants. Older plants that are repowered, however, could produce a net reduction in demand due to higher plant efficiencies. Another driver for demand growth is the anticipated increase in the use of natural gas for cogeneration.

Demand for natural gas in Baja California Norte is driven mainly by power generation, a handful of industrial customers, and one local distribution compact (LDC) in Mexicali.

---

[187] Jorge Barrientos, Imperial Irrigation District, January 17, 2003, presentation to California-Arizona Regional Transmission Study.
[188] California Energy Commission, February 11, 2003, *California Energy Demand 2003-2013 Forecast*, draft staff report, California Energy Commission, Sacramento, CA, CEC-100-03-002SD.
[189] *California-Mexico Border Energy Issues* staff report, prepared in support of the *2005 Integrated Energy Policy Report* Proceeding, July 2005.
[190] Western Governors' Association, April 2004, *Energy Efficiency in the Border Region: A Market Approach*, The Western Governors' Association, Denver, CO, pp. 6-10.
[191] Science Applications International Corporation, December 30, 2002, *San Diego Regional Energy Infrastructure Study*, San Diego Regional Energy Office, p. 3-2.

Interdependencies in the Border Region

California and Baja California Norte share considerable natural gas and electricity infrastructure within the border region. Baja California Norte is geographically isolated from mainland Mexico, with no connection to Mexico's natural gas pipeline system and only limited connections to the Mexican national power grid.

Natural Gas

Several high-capacity natural gas pipelines crisscross the border region. The Baja Norte Pipeline, completed in 2002, runs from Ehrenberg, Arizona through Mexicali and interconnects with the Transportacion de Gas Natural (TGN) pipeline in Tijuana. Pacific Gas & Electric (PG&E) owns the U.S. segment (North Baja Pipeline), and Sempra Energy controls the segment in Mexico (Gasoducto Bajanorte). The Gasoducto Bajanorte segment serves the La Rosita and Thermoelectrica de Mexicali power plants in Mexicali and industrial customers in northern Baja California Norte and Southern California.

Sempra's TGN pipeline runs from Otay Mesa in Tijuana to Playas de Rosarito, where it supplies natural gas to CFE's Presidente Juarez Power Plant. Through a separate pipeline, Sempra also supplies natural gas to a small distribution system in Mexicali that serves about 25,000 customers.

Without local sources of natural gas, Baja California Norte must import its gas from the U.S. through the TGN and Baja Norte pipelines. The development of one or more proposed LNG gasification and storage facilities will diversify natural gas supply sources for the area and make Baja California Norte a net exporter of gas to the U.S. Sempra's Energia Costa Azul project is under construction and Chevron's Terminal GNL Mar has received initial permits. The Energia Costa Azul Project is expected to operate in 2007, providing an average capacity of 1,000 million cubic feet per day (MMcfd) of natural gas. Chevron's plant will produce 700 MMcfd and is scheduled to go on line in 2007.

Sempra is planning an expansion of its Baja Norte and TGN pipelines to transport natural gas from the Energía Costa Azul liquefied natural gas (LNG) terminal. It is unclear, however, how SDG&E and SoCalGas will plan and pay for future pipeline upgrades and coordinate cross-border delivery of gas into California. Other uncertainties are the amount and specific use (for example, power plants, commercial, residential) of the LNG supply dedicated for California, Baja California Norte, and other parts of the U.S.

In San Diego and Imperial counties, SDG&E distributes natural gas from SoCalGas and moves it south to load centers. The total capacity of the SDG&E natural gas transmission system is 620 MMcfd in winter and 600 MMcfd in summer.[192] Accepting LNG supplies from Mexico at Otay Mesa will require infrastructure improvements to

[192] CPUC, November 2001, *California Natural Gas Infrastructure Outlook, 2002-2006*, California Public Utilities Commission.

reverse the flow of the gas in the SDG&E system. Other improvements may also be necessary to the SDG&E system, depending on the levels of LNG supplies delivered to Otay Mesa.[193]

Electricity

SDG&E consumes 3.5 times more power than Baja California, cannot meet customer demand with local generating capacity, and must import about 60 percent of its electricity from outside the region.[194] SDG&E's generating capacity is about 2,570 MW. Currently, two new power plants are under construction in San Diego County which will add more than 1,000 MW of capacity to SDG&E's system.

Electricity is imported through the Miguel Substation from the east and south and the San Onofre switchyard to the north. SDG&E can import electricity from out of state through the 500-kilovolt (kV) Southwest Power Link transmission line and from Mexico through two 230-kV transmission lines (Path 45).[195] In 2004, the CPUC approved the Miguel-Mission #2 230-kV Transmission Line, which is expected to be operational by June 2006. The project will increase the system's ability to transfer electricity from the two power plants in Mexicali, Mexico, and from new generation in Arizona scheduled into the Cal-ISO control area in Palo Verde.[196]

In contrast, the Imperial Irrigation District (IID) has typically been a net exporter of electricity. IID provides 468 MW of capacity and connects its transmission system with SCE through the Valley and Devers substations, with SDG&E through the Miguel and Imperial Valley substations, and with the Palo Verde hub in Arizona. It is also interconnected with Mexico through the Miguel substation.

The Baja California Norte power system has 3,862 MW of generation capacity with 2,652 MW dedicated to satisfy CFE's public service load and 1,210 MW intended for export to the California market. With 720 MW of geothermal generating capacity, Baja California Norte satisfies a significant portion of its energy needs with renewable energy. The balance of its energy generation comes from natural gas-fired combined-cycle facilities (985 MW), oil-fired steam-cycle plants (620 MW), and oil-fired gas turbines (326.9 MW). Between 2008 and 2013, CFE plans to build an additional 1,282 MW of generating capacity in Baja California Norte. Most of the planned capacity is likely to be natural gas-fired.

---

[193] San Diego Gas & Electric Co., November 2003, *Responses to CPUC Data Requests, OIR to Establish Policies and Rules to Ensure Reliable, Long-Term Supplies of Natural Gas to California*, R.04-01-025.
[194] Western Governors' Association, April 2004, *Energy Efficiency in the Border Region: A Market Approach*, The Western Governors' Association, Denver, CO, p. 6.
[195] San Diego Gas & Electric Company, July 9, 2004, *Long-Term Resource Plan of San Diego Gas & Electric Company (U 902 E)*, direct testimony of Linda P. Brown, California Public Utilities Commission, pp. 2-3.
[196] California Public Utilities Commission, Decision 04-07-026, *Application of San Diego Gas & Electric Company (U 902 E) for a Certificate of Public Convenience and Necessity for the Miguel-Mission 230kV #2 Project,* Application 02-07-022, p. 19.

Path 45 is the backbone of the transmission system in the Baja California Norte area, connecting Baja California with San Diego and the Imperial Valley and allowing power transfers between northern Mexico and Southern California. One transmission line runs between SDG&E's Miguel Substation and CFE's Tijuana Substation, and the other between SDG&E's Imperial Valley Substation and CFE's La Rosita Substation. Additional study is needed to determine the potential to upgrade the East-West transmission line in Baja California between the Path 45 cross border paths.

Renewable Energy in the Border Region

SDG&E is required to have a 20 percent renewable portfolio mix by 2017. The utility has committed to achieving this goal by 2010. A recent study identified significant solar energy, biomass, geothermal, and wind power opportunities in the California-Mexico border region.[197] This is an important first step, and more detailed assessments are needed to stimulate additional renewable energy projects in this area.

Obtaining renewable energy from Baja California Norte is more problematic because it would require costly upgrades to the existing transmission system to bring power across the border from the Cerro Prieto geothermal field and potential wind resources in La Rumorosa.

As a municipal utility, IID is not required to meet the specific targets and timelines of the state's Renewable Portfolio Standard (RPS), but has voluntarily adopted its own RPS. IID currently produces 635 MW of renewable energy. To reach its renewable goals, IID is negotiating to purchase approximately 200 MW of energy from Cal Energy's Salton Sea Unit 6, now under construction.[198] Another 270 MW of geothermal and 80 MW of biomass are proposed for development in Imperial County.

Baja California Norte satisfies a large portion of its energy needs with renewable energy. The Cerro Prieto Geothermal Field provides 720 MW of geothermal generating capacity, and studies show potential for additional capacity there and elsewhere in the region. The area also has promising potential for wind development, although further studies will be necessary to fully understand the resource potential. Mexico has set a goal for the country to bring another 1,000 MW of renewable energy on line by 2006.

Transportation

The 150-mile border between California and Mexico contains six ports of entry: San Ysidro, Otay Mesa, and Tecate in San Diego County and Calexico, Calexico East, and Andrade in Imperial County. In 2003, 47 million people crossed the border northbound

[197] *Potential for Renewable Energy in the San Diego Region*, San Diego Regional Renewable Energy Group, August 2005.
[198] Imperial Irrigation District, Press Release: *IID Energy Honored for Geothermal Excellence* September 9, 2001. Found at: [www.iid.com/pressbox/press.read.php3?which=454].

through the San Ysidro port, which is the busiest land crossing in the world and handles the largest number of passenger vehicle and pedestrian crossings.[199]

Cross-border trade between California and Mexico has increased substantially since the passage of NAFTA in 1993. In 2003, total trade activity was almost $30 billion, with an estimated 98 percent of this trade transported by truck through the Otay Mesa, Tecate, and Calexico East ports of entry.[200] There were two million truck crossings at the border during 2003; the number of crossings is expected to increase to 5.6 million crossings in 2030. Most of the trade transported by truck across the California-Mexico border at the three main entry ports originates or is destined for locations outside of San Diego and Imperial counties, such as the Long Beach and Los Angeles ports or Los Angeles and Ontario airports.[201]

Idling cargo trucks emit harmful pollutants that affect the air quality on both sides of the border. In addition, these trucks usually refuel in Mexico with fuel that can contain many times the amount of sulfur as fuel sold in California.[202] Shifting some of the cargo and freight movement to railroads and switching to cleaner burning diesel and non-petroleum fuels may reduce congestion and diesel use and improve air quality. Establishment of Clean Cities programs in the San Diego-Tijuana and Calexico-Mexicali areas and the imposition of a per-truck border crossing fee are potential mechanisms to raise and distribute funding for cross-border transportation projects.

Air Quality and Cross Border Emissions Trading

The major source of emissions in the border region is the transportation sector. Because the region is subdivided into two bi-national air sheds that span the international border, neither government alone is able to address regional air quality problems. Air quality in the border region violates most ambient air quality standards in both the United States and Mexico for ozone and particulate matter. Carbon monoxide levels on the Mexican side of the border also violate established standards. Increasing population in the border region and associated increases in the number of automobiles and cargo trucks will worsen air quality impacts over time.

Cross-border emission trading has proven effective in other international applications and can potentially reduce emissions in the border region. The concept faces some challenges including the legality of establishing international air basins, the enforceability of international credits, the fact that Mexico does not currently have an existing emission credit program, and the fact that air quality monitoring data is not consistent on both sides of the border. This may require additional air quality monitoring

[199] California/Mexico Border Briefing, p. ii.
[200] Ibid, pg. V-3
[201] Caltrans, pg. 2-3.
[202] Kazimi et al. 1997 (C. Kazimi, F. Cuamea, J. Alvarez, A. Sweedler and M. Fertig). Emissions from Heavy-Duty Trucks at the San Diego-Tijuana Border Crossing. San Diego State University and Universidad Autonoma de Baja California. San Diego, California and Tijuana, Baja California. San Diego State University Press. February 1997.

programs. More investigation of this issue is clearly needed, but available information indicates a strong potential for environmental and economic benefits on both sides of the border.

Efficiency in the Border Region

There is significant potential to reduce electricity demand on both sides of the border through demand reduction and combined heat and power (CHP) projects. A study conducted by the Western Governors' Association estimated potential energy efficiency savings for manufacturing facilities in Baja California Norte as being the highest in the region. Average energy savings were estimated at 26 percent, and projected payback periods range from 1.3 to 6.0 years.[203] The study also estimates that implementing energy efficiency projects could result in as much as a 10 percent demand reduction in Baja California Norte.

While there is awareness and interest in energy efficiency and load management already in the Baja California Norte, state and local energy efficiency assistance programs lack sufficient technical and financial resources to have a significant overall impact on the supply-demand balance of the region.

Recommendations

The state should establish a cross-border, bi-national policy to: 1) ensure that planning, permitting, construction and operation of electricity and natural gas infrastructure in the border region are coordinated and comply with the highest level of environmental requirements; 2) implement a common methodology to forecast energy demand in the border region; 3) implement a "loading order" to encourage development of the most efficient, clean, and cost-effective energy options to meet demand; 4) develop programs to reduce demand and develop indigenous renewable resources; 5) implement a cross-border emissions credit trading and offsets program; and 6) provide opportunities to improve the overall efficiency of transportation systems and goods movement and expand the use of non-petroleum fuels.

[203] *Energy Efficiency in the Border Region: A Market Approach*, Western Governors' Association, April 2004.

APPENDIX A: AGING POWER PLANT STUDY GROUP

California must also address its long-term electricity needs by bringing new generation on line. The lack of available long-term power contracts has stalled the construction of more than 7,000 megawatts of plants already permitted and sharply curtailed the amount of capacity seeking new permits. If unforeseen events cause electricity demand to rise sharply in the next few years, utilities may find themselves forced once again to enter into high-priced contracts that result in higher electricity prices for consumers. The utilities need to invest now for the long-term to continue to avoid the mistakes made during the 2000-2001 crisis that Californians are still paying for today.

As part of the *2004 Energy Report Update*, the Energy Commission identified a group of older power plants for use in studying the current and anticipated role of aging plants in the state's electricity system and their impacts on the state's resources,[204] using criteria based on a combination of several attributes, including age, size, capacity factor, efficiency, and environmental considerations, to produce the following list of plants as a preliminary study group for the aging power plant study. This group of 66 aging power gas-fired power plants represents larger plants with relatively higher heat rates (low efficiencies) and relatively higher operation (capacity factors).[205] In this *2005 Energy Report*, the Energy Commission recommends that the state's utilities undertake long term planning and procurement that will allow for the orderly retirement or repowering of the aging power plants in this study group by 2012.

The study group list presented here is taken directly from last year's draft staff white paper. No attempt has been made to update the information, which reflects the status of reliability must-run (RMR) contracts as of August 2004.

[204] *Resource, Reliability and Environmental Concerns of Aging Power Plant Operations and Retirement*, California Energy Commission, Draft Staff White Paper, August 13, 2004, #100-04-005D.
[205] The study group included only natural-gas fired power plants of 10 MW or greater that were built before 1980. Peaking plants were excluded, as were any plants known to be scheduled for retirement in the near term. Of the resulting 66 power plants, 16 are owned by municipal utilities.

	Unit Identification		ER 94 ESPAR[1]		2002 Operating Data						Other Information						
	Plant	Unit	In-Service Year	Capacity (MW)	Output (MWh)	Fuel Use (MMBtu)	NOx Emitted (pounds)	NOx Rate (lb/MMBtu)	Heat Rate (Btu/ kWh)	Capacity Factor	RMR[2]	ISO or MUNI[3]	Air Basin[4]	Once-Through Cooled[5]	Redev-elop-ment Plan[6]	SCR[7]	County
1	Contra Costa	6	1964	340	876,534	8,635,012	395,697	0.0458	9,851	0.294			SF	YES	NO	NO[a]	Contra Costa
2	Contra Costa	7	1964	340	1,148,685	11,231,342	103,704	0.0092	9,778	0.386	RMR		SF	YES	NO	YES	Contra Costa
3	Humboldt Bay	1	1956	52	194,615	2,427,851	868,937	0.3579	12,475	0.427	RMR		NC	YES	NO	NO[b]	Humboldt
4	Humboldt Bay	2	1958	53	190,383	2,496,030	872,666	0.3496	13,111	0.410	RMR		NC	YES	NO	NO[b]	Humboldt
5	Hunters Point	4	1958	163	514,614	5,320,219	198,976[c]	0.0374[c]	10,338	0.360	RMR		SF	YES	YES	NO[c]	San Francisco
6	Morro Bay	1	1956	163	30,826	343,384	20,521	0.0598	11,140	0.022			SCC	YES	NO	NO[d]	San Luis Obispo
7	Morro Bay	2	1955	163	80,218	852,057	51,193	0.0601	10,622	0.056			SCC	YES	NO	NO[d]	San Luis Obispo
8	Morro Bay	3	1962	338	503,361	4,776,954	159,684	0.0334	9,490	0.170		ISO	SCC	YES	NO	NO[d]	San Luis Obispo
9	Morro Bay	4	1963	338	1,000,637	9,545,492	336,051	0.0352	9,539	0.338		ISO	SCC	YES	NO	NO[d]	San Luis Obispo
10	Moss Landing	6	1967	739	2,276,079	20,879,237	182,344	0.0087	9,173	0.352		ISO	NCC	YES	NO	YES	Monterey
11	Moss Landing t	7	1968	739	1,730,249	16,032,235	281,251	0.0175	9,266	0.267		ISO	NCC	YES	NO	YES	Monterey
12	Pittsburg	5	1960	325	547,082	5,652,989	132,775	0.0235	10,333	0.192	RMR		SF	YES	NO	YES	Contra Costa
13	Pittsburg	6	1961	325	703,877	7,523,108	88,369	0.0117	10,688	0.247	RMR		SF	YES	NO	YES	Contra Costa
14	Pittsburg	7	1972	720	2,760,981	27,536,340	1,113,654	0.0404	9,973	0.438	RMR		SF	YES	NO	NO[a]	Contra Costa

	Unit Identification		ER 94 ESPAR[1]		2002 Operating Data						Other Information						
	Plant	Unit	In-Service Year	Dependable Capacity (MW)	Output (MWh)	Fuel Use (MMBtu)	NOx Emitted (pounds)	NOx Rate (lb/MMBtu)	Heat Rate (Btu/kWh)	Capacity Factor	RMR[2]	ISO list or MUNI[3]	Air Basin[4]	Once-Through Cooled[5]	Redev-elop-ment Plan[6]	SCR[7]	County
15	Potrero	3	1965	207	570,643	5,927,227	325,825	0.0550	10,387	0.315	RMR		SF	YES	NO	NO[a]	San Francisco
16	Encina	1	1954	107	152,068	1,671,418	34,264	0.0205	10,991	0.162	RMR		SD	YES	NO	YES	San Diego
17	Encina	2	1956	104	191,628	2,142,231	43,916	0.0205	11,179	0.210	RMR		SD	YES	NO	YES	San Diego
18	Encina	3	1958	110	195,769	2,143,917	43,950	0.0205	10,951	0.203	RMR		SD	YES	NO	YES	San Diego
19	Encina	4	1973	293	933,529	10,730,897	219,983	0.0205	11,495	0.364	RMR		SD	YES	NO	YES	San Diego
20	Encina	5	1978	315	1,051,716	10,982,456	225,140	0.0205	10,442	0.381	RMR		SD	YES	NO	YES	San Diego
21	South Bay	1	1960	147	459,135	4,654,531	60,028	0.0129	10,138	0.357	RMR		SD	YES	YES	YES	San Diego
22	South Bay	2	1962	150	466,098	4,400,057	52,738	0.0120	9,440	0.355	RMR		SD	YES	YES	YES	San Diego
23	South Bay	3	1964	171	319,847	3,312,646	42,271	0.0128	10,357	0.214	RMR		SD	YES	YES	YES	San Diego
24	South Bay	4	1971	222	84,940	1,023,633	42,206	0.0412	12,051	0.044	RMR		SD	YES	YES	YES	San Diego
25	Alamitos	1	1956	175	142,973	1,809,301	56,448	0.0312	12,655	0.093			SC	YES	NO	YES	Los Angeles
26	Alamitos	2	1957	175	167,808	2,164,441	52,874	0.0244	12,898	0.109			SC	YES	NO	YES	Los Angeles
27	Alamitos	3	1961	320	1,043,989	11,092,851	206,735	0.0186	10,625	0.372	RMR		SC	YES	NO	YES	Los Angeles
28	Alamitos	4	1962	320	710,764	7,777,048	122,890	0.0158	10,942	0.254			SC	YES	NO	YES	Los Angeles
29	Alamitos	5	1969	480	1,433,863	14,778,258	92,473	0.0063	10,307	0.341			SC	YES	NO	YES	Los Angeles
30	Alamitos	6	1966	480	619,790	6,626,709	104,371	0.0158	10,692	0.147			SC	YES	NO	YES	Los Angeles
31	Coolwater	1	1961	65	86,692	920,494	45,130	0.0490	10,618	0.152		ISO	SDT	NO	NO	NO[e]	San Bernardino
32	Coolwater	2	1964	81	108,811	1,122,952	100,371	0.0894	10,320	0.153		ISO	SDT	NO	NO	NO[e]	San Bernardino
33	Coolwater	3	1978	241	924,133	8,879,376	934,507	0.1052	9,608	0.438			SDT	NO	NO	NO[e]	San Bernardino
34	Coolwater	4	1978	241	781,626	7,657,460	819,318	0.1070	9,797	0.370			SDT	NO	NO	NO[e]	San Bernardino
35	El Segundo	3	1964	335	1,061,387	10,399,010	58,862	0.0057	9,798	0.362			SC	YES	NO	YES	Los Angeles
36	El Segundo	4	1965	335	1,340,186	13,301,719	99,620	0.0075	9,925	0.457			SC	YES	NO	YES	Los Angeles

	Unit Identification		ER 94 ESPAR[1]		2002 Operating Data						Other Information						
	Plant	Unit	In-Service Year	Dependable Capacity (MW)	Output (MWh)	Fuel Use (MMBtu)	NOx Emitted (pounds)	NOx Rate (lb/MMBtu)	Heat Rate (Btu/kWh)	Capacity Factor	RMR[2]	ISO list or MUNI[3]	Air Basin[4]	Once-Through Cooled[5]	Redev-elop-ment Plan[6]	SCR[7]	County
37	Etiwanda Generating Station	3	1963	320	543,179	5,969,559	69,468	0.0116	10,990	0.194			SC	NO	NO	YES	San Bernardino
38	Etiwanda Generating Station	4	1963	320	258,695	3,019,710	50,263	0.0166	11,673	0.092			SC	NO	NO	YES	San Bernardino
39	Huntington Beach	1	1958	215	647,852	7,405,994	81,300	0.0110	11,432	0.344	RMR		SC	YES	NO	YES	Orange
40	Huntington Beach	2	1958	215	699,436	7,633,953	87,194	0.0114	10,914	0.371	RMR		SC	YES	NO	YES	Orange
41	Long Beach	8	1976	303	81,883	939,891	94,578[f]	0.1006[f]	11,478	0.031		ISO	SC	YES	NO	NO[f]	Los Angeles
42	Long Beach	9	1977	227	31,254	362,036	36,421[f]	0.1006[f]	11,584	0.016		ISO	SC	YES	NO	NO[f]	Los Angeles
43	Mandalay	1	1959	215	499,331	4,710,452	23,304	0.0049	9,434	0.265			SCC	YES	NO	YES	Ventura
44	Mandalay	2	1959	215	564,964	5,144,509	31,252	0.0061	9,106	0.300			SCC	YES	NO	YES	Ventura
45	Ormond Beach	1	1971	750	1,189,349	12,028,916	93,498	0.0078	10,114	0.181		ISO	SCC	YES	NO	YES	Ventura
46	Ormond Beach	2	1973	750	1,210,342	12,059,181	93,552	0.0078	9,963	0.184			SCC	YES	NO	YES	Ventura
47	Redondo Beach	5	1954	175	83,476	1,127,491	79,601	0.0706	13,507	0.054		ISO	SC	YES	YES	YES	Los Angeles
48	Redondo Beach	6	1957	175	47,302	670,001	24,897	0.0372	14,164	0.031		ISO	SC	YES	YES	YES	Los Angeles
49	Redondo Beach	7	1967	480	965,701	9,843,859	130,365	0.0132	10,193	0.230		ISO	SC	YES	YES	YES	Los Angeles
50	Redondo Beach	8	1967	480	984,254	9,695,744	92,965	0.0096	9,851	0.234		ISO	SC	YES	YES	YES	Los Angeles
51	Grayson	3	1953	19	[h]	[h]	[h]	[h]	[h]	[h]		MUNI	SC	NO	NO	NO[h]	Los Angeles
52	Grayson	4	1959	44	63,853	864,829	14,693	0.0170	13,544	0.166		MUNI	SC	NO	NO	NO[h]	Los Angeles
53	Grayson	5	1969	42	70,442	950,925	21,418	0.0225	13,499	0.191		MUNI	SC	NO	NO	NO[h]	Los Angeles
54	Grayson	8	1977	95	8,385	134,416	16,066[i]	0.1195[i]	16,031	0.010		MUNI	SC	NO	NO	YES	Los Angeles
55	El Centro	3	1952	44	47,419	585,886	96,064	0.1640	12,355	0.124		MUNI	SDT	YES	NO	NO[g]	Imperial
56	El Centro	4	1968	74	162,881	2,013,284	439,453	0.2183	12,360	0.252		MUNI	SDT	YES	NO	YES	Imperial

	Unit Identification		ER 94 ESPAR[1]		2002 Operating Data						Other Information						
	Plant	Unit	In-Service Year	Dependable Capacity (MW)	Output (MWh)	Fuel Use (MMBtu)	NOx Emitted (pounds)	NOx Rate (lb/MMBtu)	Heat Rate (Btu/kWh)	Capacity Factor	RMR[2]	ISO list or MUNI[3]	Air Basin[4]	Once-Through Cooled[5]	Redev-elop-ment Plan[6]	SCR[7]	County
57	Haynes	1	1962	222	464,105	4,731,220	57,391	0.0121	10,194	0.239		MUNI	SC	YES	NO	YES	Los Angeles
58	Haynes	2	1963	222	592,599	6,061,029	69,419	0.0115	10,228	0.305		MUNI	SC	YES	NO	YES	Los Angeles
59	Haynes	5	1967	341	482,782	4,643,557	48,018	0.0103	9,618	0.162		MUNI	SC	YES	NO	YES	Los Angeles
60	Haynes	6	1967	341	581,001	5,727,857	36,530	0.0064	9,859	0.194		MUNI	SC	YES	NO	YES	Los Angeles
61	Scattergood	1	1958	179	449,830	4,508,090	26,317	0.0058	10,022	0.287		MUNI	SC	YES	NO	YES	Los Angeles
62	Scattergood	2	1959	179	523,083	5,234,260	24,232	0.0046	10,007	0.334		MUNI	SC	YES	NO	YES	Los Angeles
63	Scattergood	3	1974	445	259,997	2,568,005	15,980	0.0062	9,877	0.067		MUNI	SC	YES	NO	YES	Los Angeles
64	Broadway	B3	1965	66	70,886	849,285	19,605	0.0231	11,981	0.123		MUNI	SC	NO	NO	YES	Los Angeles
65	Olive	1	1959	46	19,535	244,391	22,738	0.0930	12,511	0.048		MUNI	SC	NO	NO	YES	Los Angeles
66	Olive	2	1964	55	48,249	580,744	45,567	0.0785	12,037	0.100		MUNI	SC	NO	NO	YES	Los Angeles
Total				17,126	36,993,000	377,117,000	10,186,000										

Notes
[1] 1994 Electricity Report, Electricity Supply Assumptions Report (ESPAR), Part III, The Availability, Price and Emissions of Power from the Southwest and Pacific Northwest.
[2] RMR - 2004 Reliability Must-Run unit.
[3] ISO List or MUNI - on the CA ISO list of units with reliability concerns or owned by a municipal utility.
[4] Air Basin
NC = North Coast
NCC = North Central Coast
SC = South Coast
SCC = South Central Coast
SD = San Diego
SDT = Southwest Desert
SF = SF Bay Area
[5] Plants that use Once-Through Cooling (OTC) and may be potential sites for desalination facilities.
[6] The facility has a city- or county-formulated site reuse plan (SRP) which indicates local priorities for future use of the site.
[7] SCR Installed as of 2004. Emission factors in columns to the left are for 2002 and may not represent emissions levels with the use of SCR.

- [a] Bay Area APCD Rule 9-11 has a staggered implementation schedule. Mirant, the owner of Potrero, Contra Costa, and Pittsburg boiler units has opted to comply via a "system cap, where all their boilers are held to an instantaneous cap. Currently, some units are cleaner than others and can be used to "balance" out the units that have not yet installed SCR. The final cap, in force 1/1/05, limits the boiler units to a combined 0.018 lbs NOx/mm Btu.
- [b] SCR installation is not required by an air district BARCT rule or SIP.
- [c] Bay Area APCD Rule 9-11 has a staggered implementation schedule. PG&E, the owner of the Hunters Point boiler opted, to comply via a "system cap, where all the boilers units are held to an instantaneous cap. Currently, the only operating boiler unit at Hunters Points is Unit 4. The final cap, in force 1/1/05, limits the unit to 0.018 lbs NOx/mm Btu. PG&E has purchased and surrendered to the district Interchangeable Emission Reduction Credits (IERCs) to comply with the system cap. The NOx emission factor shown is for 2000. The NOx emissions are calculated using the 2000 emission factor and the 2002 fuel use.
- [d] San Luis Obispo County APCD Rule 429 limits NOx emissions from all four boiler units to 2.5 tons per day, resulting in an effective emission factor of 0.0209 lbs/mmBtu. Emission controls (e.g., SCR) or operations limits or some combination of the two could be used to comply with the daily mass cap.
- [e] Mojave Desert AQMD Rule 1158 requires that after December 31, 2002, NOx emissions from all units at the Coolwater facility (boilers and CTCC) be capped at 1,319 tons per year. SCR is not currently required to comply.
- [f] South Coast BARCT Rule 2009 only requires steam injection on the seven combustion turbines at the Long Beach combined-cycle facility. The 2002 NOx emissions are calculated using the 2002 fuel use and the average 2003 emissions factor.
- [g] NOx emissions limited by Imperial District prohibitory Rule 400.
- [h] Units 3, 4, and 5 burn landfill gas, which is incompatible with SCR. No data was available for Unit 3, but the Grayson facility is subject to District Rule 1135 and is limited to a system cap of 0.2 lbs NOx/MWHR or 390 lbs NOx/day.
- [i] No NOx emission data available. NOx emissions calculated with 2002 fuel use and permit limit of 30 ppm

APPENDIX B: PARTICIPANTS

PUBLIC ENTITIES

AC Transit
Baja, California, Mexico State Government
Bureau of Reclamation, U.S. Dept. of Interior
Calstart
California Air Resources Board
California Bay-Delta Authority
California Dept. of Food and Agriculture
California Dept. of Water Resources
California Independent System Operator
California Municipal Utilities Association
California Polytechnic State University, Irrigation Training and Research Center
California Public Utilities Commission
California Regional Water Quality Control Board
California State Parks
California State University Fresno/Center for Irrigation Technology
California Water Resources Control Board
City of Berkeley
City of Del Mar
City of Imperial Beach
City of San Diego
Comision Federal de Electricidad (CFE)
East Bay Municipal Utility District
Imperial County Air Pollution Control District
Imperial Irrigation District
Inland Empire Utilities Agency
Lawrence Berkeley National Laboratory
Lawrence Livermore National Laboratory
League of California Cities
Los Angeles Dept. of Water and Power
Metropolitan Water District of Southern California
Placer County Water Authority
Rice University
San Diego Air Pollution Control District
San Diego Association of Governments
San Diego County Water Authority
San Diego State University
Santa Clara Valley Water District
Sacramento Municipal Utilities District
South Coast Air Quality Management District
Stanford University
University of California Berkeley
University of California Cooperative Extension Service
University of California Davis
University of California Irvine
University of California Merced
U.S. Air Force
U.S. Bureau of Land Management
U.S. Bureau of Reclamation, Mid-Pacific Region
U.S. Dept. of Energy, National Energy Technology Lab, Water for Energy Initiative
U.S. Environmental Protection Agency
U.S. Navy, Region Northwest, California Government Affairs
Yolo Energy Efficiency Project

PRIVATE ENTITIES

Alcantar & Kahl, LLP
Alliance for Retail Energy Markets
Alliance to Save Energy
APS Energy Services
Aqua Metrics, LLC
Arvin-Edison Water Storage District
Baker & McKenzie
B&B Holdings, LLC
Beckley Singleton
Behnke, Erdman and Whitaker Engineering
Berry Petroleum
BioEnergy Producers Association
Biosphere Environmental Energy
Border Power Plant Working Group in Tijuana
Braun & Blaising, P.C.
British Petroleum
Caithness Energy, LLC
California Cogeneration Council
California Electric Transportation Coalition
California Independent Oil Marketers Association
California Natural Gas Vehicle Coalition
California Refuse Removal Council
California Renewable Fuel Partnership
California State Automobile Association
California Urban Water Conservation Council

PRIVATE ENTITIES CON'T

California Wind Energy Association
Calpine Corporation
Center for Energy Efficiency and Renewable Technologies
Center for Energy Research and Technology
Chevron Texaco Products Company
Clean Fuel USA
Consortium for Electric Reliability Technology Solutions
Constellation Energy
Cyrnel, LLC, Environemental Entrepeneurs
Cyto Culture Environmental Biotechnology
Davis Power Consultants
Delta Liquid Energy
DTE Energy
EBC Company
Electramix
Electric Power Research Institute
El Paso Western Pipeline
Electric Power Research Institute
Ellison, Schneider & Harris, LLP
Energy Conversion Devices, Inc.
Energy Independence Now
Energy Solutions
Electric Power Research Institute
General Electric
Geothermex
Gravely and Associates
Grupo de Ecologia y Conservacion de Islas, A.C.
Heschong Mahone Group
Independent Energy Producers Association
Infotility
Ingersoll-Rand
JBS Energy, Inc.
Kearns & West
LD Bond & Associates
League of Women Voters of California
Los Alamos National Lab
3M Corporation
MidAmerican Energy Holdings
National Ethanol Vehicle Coalition
National Gas Vehicle Coalition
National Hydropower Association
National Refinery Reform Campaign
National Renewable Energy Laboratory
Natural Resources Defense Council
New Car Technology
New Power Technologies
NRG Energy Center San Diego, LLC
Oak Creek Energy Systems, Inc.
O'Connor Consulting Services, Inc.
Pacific Energy Partners
Pacific Ethanol/California Renewable Fuels Partnership
Pacific Gas and Electric Company
Power Generation Administration
Pacific Institute
Phoenix BioIndustries
Pillsbury Winthrop, LLP
Powers Engineering
Powerwheel Associates
PPM Energy
Primen
Judd Putnam, Engineering Services
RCM Digesters, Inc.
RealEnergy
Reflective Energies
Regulatory and Cogeneration Services, Inc.
Rosenblum Environmental Engineering
RW Beck
San Diego Border Area Energy Issues Group
San Diego Gas and Electric Company
Semitropic Water Storage District
Sempra Energy
Sierra Club
Solar Turbines
Southern California Edison
State Water Project Contractors
Sustainable Earth Enterprises
Sustainable Conservation
Swan Biomass
Swette Associates
The Gas Company
Teco-Gen, Inc.
Tehachapi Study Group
TransCanada
Trans-Elect
Union of Concerned Scientists
U.S. Combined Heat and Power Association
Utility Wind Interest Group
Valero Energy Corporation
Valley Air Solutions, LLC
Vulcan Power Company
Water & Energy Consulting/ACWA
Western Resources Advocates
Western States Petroleum Association
Worldwater & Power Corporation
Zaninger Engineering