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This report is dedicated to the memory of
the Energy Commission's Editor

Elizabeth Parkhurst

July 8, 1953 – May 13, 2005

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EXECUTIVE SUMMARY

California is the sixth largest economy in the world. To meet the needs of its growing population, California's economy depends upon reliable, affordable, and environmentally sound supplies of electricity, natural gas, and transportation fuels. California's way of life is increasingly 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 have been spent on goods and services to help bolster the state's recovering economy. With world oil prices topping $70 per barrel, it is unlikely that gasoline consumers will see any meaningful relief in the near future. Electricity rates, although not as erratic as they were during the state's 2000-2001 energy 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 rises. California depends upon natural gas to generate about half of its electricity, so natural gas prices that have more than doubled since 2000 are likely to keep electricity rates high. The state's dependence on the increasingly volatile natural gas market for its electricity generation is a growing cause for alarm.

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 each of the last two years, and continues to rise. Meanwhile, state demand for transportation fuels has increased 48 percent over the last 20 years and continues to grow at an alarming rate despite record high gasoline and diesel prices. The state's dependence on natural gas to generate electricity is escalating along with the demand for natural gas in the residential and commercial sectors, with California's natural gas consumption second only to that of Texas.

Development of new energy supplies is not keeping pace with the state's increasing demand. Construction of new power plants has lagged and the number of new plant permit applications has decreased. In addition, the development of new renewable resources has been delayed by the state's complex and cumbersome Renewable Portfolio Standard process. In the transportation sector, California's refineries cannot keep up with the mounting need for petroleum fuels and consequently depend upon increasing levels of imports to meet the state's needs. California also imports 87 percent of its natural gas supplies, which are increasingly threatened by declining production in most U.S. supply basins and growing demand in neighboring states.

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 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 consumers over $1 billion. The state also experienced numerous price spikes and several local outages over the past summer. Southern California experienced its first rolling blackouts since the 2000-2001 energy crisis. California's petroleum import and refinery infrastructure also faces challenges including the inherent conflict between the need to expand import, refining, and storage facilities to meet transportation fuel demands and the environmental and social concerns of local communities affected by these needed expansions. In the natural gas sector, California has made infrastructure improvements that will 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 California Energy Commission recommended a broad range of strategies to reduce energy demand, secure additional energy supplies, move toward 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 continue to suffer 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, reliable, and environmentally-sound energy services for its citizens.

Ensuring Adequate Electricity Supplies

As the state's demand for electricity increases, California could face severe shortages in the next few years. Of particular concern are the potential impacts of higher-than-average summer temperatures, which can drastically increase the state's electricity demand, as well as shortages resulting from decreased hydroelectric generation in lower-than-average precipitation years. Either of these situations could cause dangerously low reserve margins and potential supply disruptions, particularly in Southern California. Reserve margins could also be affected by the retirement of aging natural gas-fired power plants, which remain critical components of California's generation fleet despite strong policy directives to diversify the state's electricity supplies.

The *2005 Energy Report* assessment of electricity supply and demand concludes that maintaining adequate electricity reserves will be difficult over the next few years. The state has made some progress toward resource adequacy for investor-owned utilities by requiring them to maintain year-round 15-17 percent reserve margins. Jurisdictional authority over other load serving entities is less clear. Until recently there was no formal mechanism to ensure resource adequacy for publicly owned utilities, which provide up to 30 percent of the state's electricity. In September 2005 the Legislature passed and the Governor signed AB 380 (Nunez), Chapter 367, Statutes of 2005, which requires publicly owned utilities to report their respective supply circumstances to the Energy Commission so that their resource adequacy progress can be accurately assessed in future *Energy Report* proceedings.

California must also address its long-term electricity needs by aggressively bringing new generation online. The lack of long-term power contracts has stalled construction of more than 7,000 megawatts (MW) of permitted plants and sharply curtailed the number of new permit applications. If unanticipated events cause electricity demand to rise sharply in the next few years, utilities could again find themselves forced to enter into high-priced contracts that will increase consumer electricity prices. Utilities need to invest now for the long-term to avoid the catastrophic mistakes made during the 2000-2001 energy crisis that Californians are still paying for today. California's dependence on natural gas to generate electricity is also increasing as utilities continue to purchase generation from the state's aging fleet of natural gas-fired power plants under short-term contracts. As part of the California Public Utilities Commission's (CPUC) 2006 long-term procurement, investor-owned utilities should sign long-term contracts that will cover both the annual "net short" and allow for the orderly retirement or repowering of the aging power plants identified in the *2004 Energy Report Update.*

The utility procurement process needs to be more open and transparent for all parties. The state's investor-owned utilities continue to claim that much of the data used in their resource planning and procurement are confidential. The Energy Commission, however, concludes that important benefits come from rigorous public scrutiny and debate about the data and planning assumptions the CPUC ultimately uses to develop its resource procurement decisions. The Energy Commission will participate in the CPUC's rulemaking to revise regulations regarding disclosure of data, and has initiated its own rulemaking to review data regulations for the next *Energy Report* cycle.

The Energy Commission strongly supports the following procurement recommendations:

- The CPUC should require investor-owned utilities to procure enough energy and capacity through long-term contracts to meet their net short positions and provide for the orderly retirement or repowering of aging plants by 2012.
- The CPUC should develop a set of "coming and going" rules for departing load by the end of 2006.
- The Energy Commission and the CPUC should establish open and transparent resource planning and procurement processes for all-source and renewable resources, and eliminate confidential procurement review groups.
- The CPUC and the Energy Commission should develop a more transparent and standardized method for addressing least-cost, best-fit criteria and consistently apply a renewable "rebuttable presumption" to all procurement.

An important alternative to building large new power plants is distributed generation, which is electricity produced on site or close to load centers that is also connected to a utility's distribution system. The most efficient and cost-effective form of distributed generation is cogeneration or combined heat and power. By recycling waste heat, these

systems are much more efficient than systems that separately serve thermal and electric loads. They are also considerably more efficient than almost all conventional gas-fired power plants. California has more than 9,000 MW of combined heat and power systems throughout the state, representing approximately 17 percent of statewide generation. Most of these systems are larger than 5 MW, suggesting that the state should focus its efforts on large-scale projects that could provide more than 5,000 MW of additional generating capacity over the next 15 years.

Current state policy must change for California to tap into this potential generation source and retain the existing pool of combined heat and power facilities so critical to reliable operation of the state grid. Developers of new combined heat and power facilities are struggling to find customers to purchase their excess power at the wholesale level, and the state's suspension of direct access hampers their ability to sell their excess power 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.

The Energy Commission strongly supports the following combined heat and power recommendations:

- The CPUC and the Energy Commission should establish annual utility procurement targets by the end of 2006.
- The CPUC should require investor-owned utilities to purchase electricity from these facilities at prevailing wholesale prices.
- The CPUC should explore regulatory incentives that reward utilities for promoting customer and utility-owned combined heat and power projects.
- The CPUC should require that investor-owned utilities provide CA ISO scheduling services for these facilities and be compensated for doing so.

A significant percentage of California's electricity supply comes from the in-state Diablo Canyon and San Onofre nuclear power plants. Operators at these nuclear plants face many issues involving the transportation and disposal of spent fuel, upcoming extensions of their operating licenses, and major capital expenditures to replace aging steam generators. New nuclear power plant construction in California was suspended in 1976 pending determination by the Energy Commission that a high-level federal nuclear waste disposal repository has been approved and built. The Energy Commission reaffirms its 1978 finding that a high-level nuclear waste repository has been neither approved nor built. Californians have contributed well over $1 billion to the federal waste disposal development effort, which remains plagued with licensing delays, increasing costs, technical challenges, public opposition, and managerial problems.

The Energy Commission strongly supports the following nuclear recommendations:

- The federal government should return some portion of the funds paid by California ratepayers for a permanent national repository for nuclear waste in order to pay for interim storage of waste at California reactor sites.
- The Legislature should develop a suitable state framework to review the costs and benefits of nuclear power plant license extensions.

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

Electricity

California continues to be the national leader in efficiency. 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 save an additional 30,000 gigawatt hours (GWh) of energy from energy efficiency programs over the coming decade. In 2004, the CPUC established aggressive energy savings goals 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. The recent passage of SB 1037 (Kehoe) Chapter 366, Statutes of 2005, further reinforces the state's energy efficiency policies by requiring all utilities to meet their unmet resource needs first with energy efficiency and demand reduction resources that are cost-effective, reliable, and feasible.

One concern about current energy efficiency programs is that they tend to focus on energy rather than peak savings. Because California's electricity demand is driven by short summer peaks, reducing peak demand is essential for improving electricity reliability, reducing price volatility, and delaying the need for expensive power plants that operate only a few hours a year. The Energy Commission recommends renewed emphasis on energy efficiency programs that provide peak demand 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 ultimately affect the reliability of the electric system during peak load periods when reserve margins are low. Water and wastewater agencies would similarly be unable to meet the needs of their customers without adequate electricity supplies. More efficient water usage, coupled with energy efficiency improvements in the water infrastructure itself, could reduce electricity demand in this sector. The Energy Commission, the Department of Water Resources, the CPUC, local water agencies, and other stakeholders should explore and pursue cost-effective water efficiency opportunities that would save energy and decrease the energy intensity in the water sector.

Demand response programs are the most promising and cost-effective options for reducing peak demand on California's electricity system. Although the CPUC adopted demand reduction targets for investor-owned utilities in 2003, demand response programs have failed to deliver their savings targets for each of the last three years and appear unlikely to meet their 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 ambitious demand response programs and install advanced meters for all customers as soon as practically possible. New metering technology is the primary platform for future voluntary and mandatory demand response policies.

The Energy Commission strongly supports the following energy efficiency and demand response recommendations:

- The CPUC and Energy Commission should closely monitor investor-owned utilities' energy efficiency programs to ensure that peak energy savings are captured in their respective efficiency portfolios.
- The CPUC, Department of Water Resources, the Energy Commission, local water agencies and other stakeholders should assess efficiency improvements in hot and cold water use in homes and businesses, and include these improvements in 2006-2008 programs.
- The Energy Commission should establish, consistent with SB 1037, reporting requirements for publicly owned utilities to ensure that their energy efficiency goals are comparable to those required of investor-owned utilities.
- The CPUC and the Energy Commission must vigorously pursue actions to ensure that the state's demand response goals are met.

California is also a national leader in the development of renewable resources. Over the past 30 years, California has built one of the largest and most diverse renewable generation portfolios in the world. In 2002, California established its Renewable Portfolio Standard program, with the goal of increasing the percentage 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 and cumbersome, hobbling the state's ability to achieve its renewable goals. The CPUC's 2004 directive that renewables be the "rebuttable presumption" for all investor-owned procurement remains ambiguous and untested.

The CPUC and the Energy Commission should work together to simplify, streamline, and expedite the state's Renewable Portfolio Standard process. The two agencies should also work together to establish simple rules for the Renewable Portfolio Standard program for both energy service providers and community choice aggregators. These rules should allow limited trading of renewable energy certificates, which would increase participation by these entities and help address the current transmission constraints that preclude access to promising renewable resource areas in the state. As the Western Renewable Energy Generation Information System begins operation, this compliance mechanism should be expanded to include the entire Western Electricity Coordinating Council.

There are several additional issues facing wind resource development in California. The state needs to focus on repowering aging wind facilities to increase the amount of renewable generation from these prime sites and reduce the number of bird deaths caused by wind turbines. The state also needs to conduct additional research and development at both the Energy Commission and the California Independent System Operator (CA ISO) to address current barriers to integrating intermittent wind resources into the state's transmission system.

California also has promising opportunities to increase energy production from renewable resources connected with the state's water system. In-conduit hydropower — turbines installed within conduits to generate electricity from flowing water in pipelines, canals and aqueducts — is an attractive possibility because it is relativly easy to permit and has fewer environmental impacts than large hydroelectric power plants. Anaerobic digesters installed at or near wastewater treatment facilities, dairies, or food processing facilities can also produce biogas, which can be used to either power on-site generation or be sold to the grid.

Many existing in-conduit facilities are facing the expiration of their standard offer power purchase contracts with the state's investor-owned utilities. Existing rules do not allow water or wastewater utilities to credit the electricity they generate to their energy bills. Therefore, if this electricity cannot be directly connected to an existing load, it must be sold into the wholesale bulk power market. The cost and complexity of selling into 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 expediting and reducing the cost of utility interconnection, eliminating economic penalties including standby charges, removing size limitations for net metering, and allowing water and wastewater utilities to self-generate and wheel power within their own systems.

The Energy Commission strongly supports the following renewable energy recommendations:

- The Energy Commission should ensure that publicly owned utilities meet the same Renewable Portfolio Standards targets for eligibility and compliance required of investor-owned utilities.
- The CPUC and the Energy Commission should establish a joint proceeding to develop a simpler and more transparent Renewable Portfolio Standard process by the end of 2006.
- The CPUC and Energy Commission should closely monitor the 2005 renewable procurement cycle to determine the potential value of greater contract standardization.
- The CPUC should require investor-owned utilities to procure a prudent contract-risk margin, starting at 30 percent, to prevent under-procurement.
- The CPUC should quickly develop new standardized contracts for wind repowering projects to more efficiently harness wind resources and reduce bird deaths.

Transportation

The *2003 Energy Report* concluded that by far the most cost-effective strategy to reduce petroleum demand in the transportation sector is to increase vehicle fuel economy. The Energy Commission recommended that the state take steps to influence the federal government to double the combined fuel economy standards for cars and light trucks. Efforts to spur the federal government to significantly increase the Corporate Average Fuel Economy standards for passenger cars and light trucks have not been successful. The federal government has proposed only a very minor increase in the light-truck standard and completely ignored potentially far-reaching savings in the passenger car market. California needs to intensify its efforts to forge a coalition with other states and stakeholders to persuade the federal government to double the Corporate Average Fuel Economy standards.

The state can pursue other strategies to increase transportation efficiency, including increasing the number of hybrid-electric, plug-in-hybrid electric, light-duty diesel vehicles in California, more effective marketing of low-rolling resistance tires, implementing anti-idling regulations for trucks and truck stop electrification, and integrating transportation and land-use planning.

Increased efficiency in new cars and light trucks alone cannot maintain the state's overall petroleum reduction goals. California must also vigorously support the rapid development and availability of alternative fuels so that their air quality and petroleum replacement benefits can be realized. 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 to 30 percent by 2030. The Energy Commission continues to strongly support these goals, though meeting them will take considerable and concentrated effort given the current low penetration level of only 6 percent.

As directed by the Governor, the Energy Commission will assume the lead in developing a long-term transportation plan by March 31, 2006, that will reduce gasoline and diesel use and increase alternative fuel use. This effort will be a prelude to a larger alternative fuel plan for the state required by AB 1007 (Pavley), Chapter 371, Statutes of 2005, that is due by June 30, 2007. The Energy Commission envisions that the alternative transportation fuel plan must bridge the gap between today's technologies and the transition to hydrogen fuels and vehicles called for in the Governor's Hydrogen Highway Network Blueprint Plan. 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.

The Energy Commission strongly supports the following transportation recommendations:

- The state should simultaneously reduce petroleum fuel use, increase fuel diversity and security, and reduce emissions of air pollution and greenhouse gases.
- The state should implement a public goods charge to establish a secure, long-term source of funding for a comprehensive transportation program including broad-based funding for infrastructure, technology and fuels research, analytical support, and incentive programs.
- The state should continue to work closely with other states to pressure the federal government to double vehicle fuel efficiency standards and enact fleet procurement requirements that include super-efficient gasoline and diesel vehicles.
- The state should establish a non-petroleum diesel fuel standard so that all diesel fuel sold in California contains a minimum of 5 percent non-petroleum content that would include biodiesel, ethanol, and/or gas-to-liquid components.
- The state should establish a state renewable gasoline fuel standard so that the pool of all gasoline sold in California contains, on average, a minimum of 10 percent renewable content.
- The state should investigate how investor-owned utilities can help develop the equipment and infrastructure to fuel electric and natural gas vehicles.
- The state should, for its fleet of vehicles, establish a minimum fuel economy standard and a procurement requirement for alternative fuels and vehicles, and examine the merits of using re-refined and synthetic oils.

Natural Gas

The *2003 Energy Report* recommended that the state reduce natural gas demand by increasing funding for natural gas efficiency programs. California has made progress in this area. In 2004, the CPUC increased 2005 funding for natural gas efficiency programs by $19.8 million and set aggressive goals intended to double annual gas savings by 2008 and triple them by 2013. The recently enacted SB 1037 also requires gas utilities to first meet their unmet resource needs with all available energy efficiency

and demand reduction resources that are cost-effective, reliable, and feasible. The Energy Commission and the CPUC should rigorously evaluate, measure, and monitor these gas efficiency programs to ensure that they produce their 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 as a way to meet California's rising electricity supply needs.

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

Improving the Energy Infrastructure

Electricity Transmission Infrastructure

In both the *2003 Energy Report* and the *2004 Energy Report Update*, the Energy Commission identified existing problems with the state's transmission system and recommended improvements to the transmission planning and permitting processes that would speed up approvals of new transmission lines and upgrades to existing lines. However, the state still lacks a well-integrated transmission planning and permitting process that considers 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 in 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 CA ISO, and the CPUC. The Energy Commission reemphasizes its recommendation in the *2003 Energy Report* that the Legislature transfer the siting functions for transmission lines from the CPUC to the Energy Commission.

California still lacks a formal process to effectively plan for transmission corridors well in advance of their need. The Energy Commission recommends a corridor planning process that would identify the corridor needs of transmission owners; establish corridor priorities; identify major permitting, environmental and land-use issues; and ensure full participation of all affected local, state and federal agencies and stakeholders. Further, the Legislature should authorize the Energy Commission to designate corridors so that utilities have a level of financial certainty that allows them to acquire land and easements, while also allowing the Energy Commission to proceed with the comprehensive environmental reviews that could significantly shorten overall planning and permitting lead times. The CPUC should also extend its current five-year limitation on investor-owned utility land banking for the cost of future transmission corridors within their rate bases.

California must urgently encourage major investments in the new transmission infrastructure needed to access remotely located renewable resources in the Tehachapi and Imperial Valley areas. Without this investment it will be difficult for California to meet its statewide Renewable Portfolio Standard goals. In March 2005, Southern California Edison (SCE) proposed to the Federal Energy Regulatory Commission (FERC) a new category of transmission facility, called a "renewable-resource trunk line," that would allow the interconnection of large concentrations of renewable generation resources located within a reasonable distance of the existing grid under operational control of the CA ISO. However, in July 2005, FERC denied SCE's request, eliminating a valuable regulatory instrument that could have overcome renewable transmission constraints. This denial clearly underscores the need for the CA ISO to change its existing tariff so that this new category of transmission project can be recognized by FERC. This recommendation was also made in the *2004 Energy Report Update*.

The Energy Commission strongly supports the following transmission recommendations:

- The Legislature should expeditiously transfer transmission permitting responsibilities from the CPUC to the Energy Commission, using the successful framework laid out in the Warren-Alquist Act for generation siting.
- The Energy Commission, the CPUC, and the CA ISO should collaborate to change the CA ISO tariff to encourage construction of transmission for renewable generation interconnections.
- The Legislature should assign the Energy Commission the statutory authority to establish a statewide corridor planning process and designate corridors for future use.
- The Energy Commission should actively participate in the federal corridor planning processes recently enacted as part of the federal Energy Act of 2005.

Petroleum Infrastructure

California urgently needs to expand its petroleum infrastructure. Despite recent and planned improvements, California still needs to expand its marine terminal capacity, marine storage, and the pipelines that connect marine facilities and refineries with main product pipelines. Most of the required expansion is needed in the Los Angeles Basin, which faces a number of barriers including scarcity of land, pressure to remove a portion of existing facilities in favor of container cargo facilities, and new standards for marine terminals. In Northern California, timely dredging of the Suisun Bay Channel, the Pinole Shoals, and other areas near refineries is critical to the efficient operation of petroleum infrastructure.

The *2003 Energy Report* identified the continuing need for modifying and expanding the state's petroleum infrastructure facilities to meet the state's rising demand for petroleum fuels. A major barrier is the inefficient and often overlapping responsibilities of permitting

bureaucracies which frequently result in unacceptably lengthy lead times. 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 the permitting process for new petroleum infrastructure. The Energy Commission believes these guidelines should include: the description of the agencies involved and their relationships in 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.

The Energy Commission strongly supports the following petroleum infrastructure recommendation:

- The Energy Commission should develop petroleum infrastructure permitting guidelines based upon a "best practices" approach following this inter-agency evaluation.

Natural Gas Infrastructure

California imports 87 percent of its statewide natural gas supply, which is threatened by declining production in most U.S. supply basins. Though California has not experienced a widespread natural gas shortage in many years, colder-than-average weather, increased demand in other states, or natural disasters like Hurricane Katrina could quickly create demand spikes that would draw down stored gas supplies and adversely affect the state's ability to meet consumer natural gas demand. California needs to expand its analytical ability to determine the adequacy of its natural gas infrastructure and likelihood of potentially destructive peak demand spikes.

To prevent interruptions in the state's natural gas supplies, the *2003 Energy Report* recommended the state ensure that existing natural gas storage be used to provide adequate supplies and protect against price spikes. The state has made good progress in increasing its current storage inventory, and also has plans to develop additional storage capacity in 2006. A margin of excess capacity will provide consumers a choice of supplies and is part of a critical foundation needed to support a competitive market and stabilize short-term pricing variations.

California has improved its natural gas infrastructure by increasing intrastate pipeline capacity and in-state storage. Pipeline expansions completed over the last four years have also 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 both maintained and retained. The state also needs to continue to evaluate the need for additional pipeline capacity to meet customer demand 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 planned construction of liquefied natural gas import terminals. These facilities will increase natural gas imports to the U.S. over the next 10 years and also help meet California's growing natural gas needs. Currently, no liquefied natural gas terminals are located on the West Coast. The *2003 Energy Report* endorsed the need to develop these facilities and their associated infrastructure to better serve the natural gas needs of the western U.S.

The cost of delivering natural gas to the West Coast through a liquefied natural gas project is expected to be well below the market prices that California currently pays at its borders, and could have a dramatic effect on gas 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, there are three proposed facilities including the Terminal GNL Mar Adentrode Baja and the Moss Maritime LNG, both of which are off-shore projects, and the Sonora LNG facility. Construction has begun on a fourth project, Energia Costa Azul, expected to be online in 2007.

Global Climate Change

California must continue to be highly aware of the environmental impacts of its energy policies. As the world's 17th largest emitter of greenhouse gases, California must incorporate its efforts to reduce greenhouse gases into its energy policies. In June 2005, Governor Schwarzenegger established greenhouse gas emission targets intended to reduce greenhouse gas emissions by 2010 to 2000 emission levels, by 2020 to 1990 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 developing the program that will achieve the Governor's targets. The first report of the Climate Action Team is due to the Governor and Legislature in January 2006.

The state is exploring a number of strategies to reduce greenhouse gas emissions. The CPUC now requires that investor-owned utilities use a carbon dioxide adder of an initial $8 per ton in their long-term procurement plans, encouraging them to invest in lower-emitting resources. In addition, the CPUC unanimously adopted a resolution directing its staff to develop an investor-owned utility greenhouse gas performance standard "that is no higher than the greenhouse gas emission levels of a combined-cycle natural gas turbine" for all procurement contracts longer than three years. In the case of coal-fired generation, the capacity to capture and store carbon dioxide safely and inexpensively is essential for meeting these standards. The Energy Commission endorses the CPUC's investor-owned utility greenhouse gas performance standard resolution and agrees that an offset policy must await a formal greenhouse gas regulatory system and must include a reliable and enforceable system of tracking emission reductions.

While more specific recommendations must necessarily await the January 2006 report from Governor Schwarzenegger's Climate Action Team, the Energy Commission recommends the following:

- A greenhouse gas performance standard for utility procurement should be set no higher than emission levels from new combined-cycle natural gas turbines.
- Additional consideration is needed before determining what if any role greenhouse gas emission offsets should play in complying with such a standard.

Border Energy

The California – Baja California Norte border region extends about 60 miles north and south of the California-Mexico border. Rapid population, commercial, and industrial growth in the region is substantially increasing the demand for energy. The border region is becoming an "energy corridor" as states on both sides develop facilities not only to meet local needs, but also to export across state and international borders. This cross-border energy relationship is likely to become even more interdependent in the future with the growing need for new generation, transmission lines, and natural gas supply pipelines. The growing demand for energy in the border region also is adding to already significant air quality problems and fundamental differences in the regulatory approaches on both sides of the border is hindering resolution of these environmental concerns.

The Energy Commission strongly supports the following border energy recommendation:

- The Energy Commission believes the state should work to establish a cross-border, binational policy to coordinate energy planning and development and address environmental concerns in the border region.

Conclusions

The health of California's economy depends upon reliable, affordable, adequate, and environmentally-sound supplies of energy. The rising cost of energy hurts consumers who must spend a greater percentage of their income on energy, and businesses who see their profits shrink as their energy costs rise. California's dependence on natural gas and petroleum fuels also continues to increase, making the state vulnerable to supply disruptions and painful price spikes.

Implementation of the recommendations in the *2005 Energy Report* will 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 made earlier in both the *2003 Energy Report* and the *2004 Energy Report Update*. It is well past time for California to implement these recommendations and urgently address the many challenges facing the state's energy systems to safeguard its economy and its environment.

CHAPTER 1: INTRODUCTION

This *2005 Integrated Energy Policy Report (Energy Report)* was prepared in response to SB 1389 (Bowen), Chapter 568, Statutes of 2002, which requires that the California Energy Commission (Energy Commission) prepare a biennial integrated energy policy 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 two 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 electricity 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.

SB 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 *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 supplies 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. The update, the *Integrated Energy Policy Report 2004 Update* (*2004 Energy Report*

Update), provided 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 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 two previous years' reports.

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 public 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.[1] The white papers and stakeholder comments submitted for the record comprise more than 30,000 pages of material.

The Committee prepared its draft report and policy recommendations based on this extensive record. The draft report was the subject of five Committee hearings during September and October 2005 to receive public input. This draft final report incorporates information received at those hearings and in writing from participants and will be considered by the Energy Commission for adoption at its November 21, 2005 business meeting.

[1] The list of participants will be included as Appendix B in the final adopted Energy Report.

CHAPTER 2: TRANSPORTATION FUELS

Introduction

Roughly half of the energy Californians consume is for transportation. To meet that demand, the state relies almost exclusively on petroleum. This singular dependence on petroleum has set the stage for the extreme volatility in retail gasoline and diesel fuel prices that California is experiencing. It also has established the need for aggressive action by the state to safeguard consumers against more severe supply disruptions.

Sustaining California's economic vitality in the near term depends on ample supplies of gasoline and diesel fuels at reasonable prices. However, the state's refineries are no longer able to meet current and future petroleum demand in California and the region. California must increasingly rely on imports, for which there is limited storage capacity, and must also increase marine terminal capabilities at Southern California ports.

California's petroleum infrastructure operates at near capacity. Breakdowns and outages at in-state refinery and pipeline facilities quickly tighten gasoline and diesel fuel supplies and create price spikes. Since California is not directly connected by pipeline to other domestic refining centers, in-state refiners cannot readily procure gasoline, diesel, and other blending components when outages do occur. This contributes to higher and more prolonged price spikes.

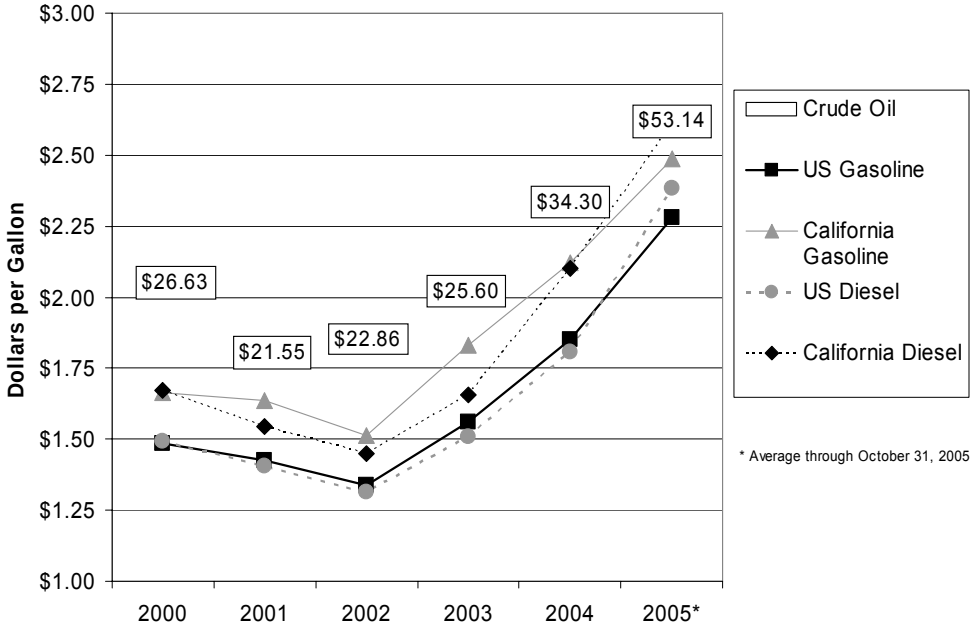
Difficulties with petroleum infrastructure in neighboring states also affect fuel supplies and prices in California. For example, the combination of unplanned refinery outages and pipeline maintenance in Washington in early 2005 tightened supplies of diesel fuel for both Washington and Oregon for more than 45 days, requiring additional deliveries of diesel from California and raising prices in this state.

World oil prices have nearly tripled in the last three years. Since crude oil is a global commodity, worldwide supply and demand dictate its price. Skyrocketing demand in China and other developing countries, coupled with political and social upheaval in key oil supply nations, is further taxing the international supply/demand equation. Hurricanes Katrina and Rita caused the interruption of oil production and transport in the Gulf Coast and contributed to subsequent $70 per barrel oil prices, highlighting the dangerous reliance upon a single source of fuel.

Crude oil is the single largest cost component in the production of transportation fuels, accounting for between 42 and 56 percent of the price of branded regular gasoline in the last year.[2] In early September, the average retail price for regular grade gasoline and diesel fuel reached record highs of $3.05 and $3.39 per gallon, respectively.

[2] California Energy Commission, [http://www.energy.ca.gov/gasoline/margins/index.html], accessed August 18, 2005.

Figure 1: Gasoline, Diesel, and Crude Oil Prices



California's high gasoline prices are taking a toll on the state's 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 pass the higher cost of their goods and services to consumers. Californians are therefore not only paying higher prices for the gasoline they need, they are using the rest of their disposable incomes to pay higher prices for other products. Since September of 2004, 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.

In the meantime, demand for gasoline and diesel fuels is increasing despite record-high prices, and little has changed on the supply side since 2003. The industry is building some new storage facilities, and several smaller refineries are expanding their production capacities. These improvements, however, are not sufficient to address the problem of the rapidly widening gap between demand for petroleum and its supply.

Clearly, California needs a decisive policy to reduce its dependence on petroleum fuels and a broad collaborative framework to introduce more non-petroleum options into the market.

Building a Vision for the Future

In 2003, the California Energy Commission (Energy Commission) and the California Air Resources Board (ARB) jointly adopted a strategy to reduce California's dependence on

petroleum.[3] The two agencies demonstrated that it is feasible to reduce the on-road use of gasoline and diesel fuel to 15 percent below 2003 levels by 2020, based on technology and fuel options that are achievable and cost-beneficial. The two agencies recommended that the state pursue the strategy by influencing the federal government to double the fuel economy of new vehicles and increase the use of non-petroleum fuels to 20 percent of on-road fuel demand by 2020. The Energy Commission incorporated the findings of the joint report into the *2003 Integrated Energy Policy Report (Energy Report)* and recommended that the Governor and Legislature adopt the goals and strategy as state policy.

The Energy Commission and ARB showed that the combined Corporate Average Fuel Economy (CAFÉ) standards for new passenger cars and light trucks can be doubled in a cost-effective manner and without sacrificing safety or consumer choice. However, little has been done at the federal level, where responsibility for setting fuel economy standards rests. Congress chose to ignore this issue in the federal Energy Act of 2005, and the Bush Administration's recent proposal to increase fuel economy standards for some light trucks will do little to blunt growing national petroleum demand.

Meanwhile, the ARB adopted landmark regulations in 2004 limiting greenhouse gas (GHG) emissions from new vehicles sold in California, beginning in model year 2009. New vehicles fully complying with this regulation will consume nearly 30 percent less fuel than vehicles built before 2009. Even this improvement, however, does not do enough to attain the level of fuel economy that the Energy Commission and ARB determined in 2003 is both "…achievable and cost-beneficial."

In his response to the *2003 Energy Report* and the *2004 Energy Report Update,* Governor Schwarzenegger called for California to continue its efforts to increase CAFÉ standards through a coalition of states and stakeholders. He also directed the Energy Commission to take the lead in crafting a workable long-term plan by March 31, 2006, to increase the use of alternative fuels.[4] Recent legislation also requires the Energy Commission, in partnership with the ARB and in consultation with the State Water Resources Control Board, Department of Food and Agriculture, and other relevant agencies, to develop and adopt a state plan by June 30, 2007, that will increase the use of alternative transportation fuels.[5]

The Energy Commission clearly recognizes the continuing role that petroleum will play in meeting the state's transportation needs. The Energy Commission also recognizes that the industry will need to permit and construct a certain amount of new infrastructure to import, store, and distribute these fuels. To this end, the state should work with the industry and local governments to ensure these infrastructure improvements are implemented.

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[3] *Reducing California's Petroleum Dependence*, Energy Commission and ARB, joint agency report, August 2003.

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

[5] AB 1007 (Pavley, Chapter 371, Statutes of 2005)

The Energy Commission believes strongly that California is at an important crossroads. First, the worldwide demand for petroleum is becoming a significant problem. Second, no matter how clean gasoline is with respect to criteria pollutants, its use produces significant carbon dioxide emissions, the primary GHG. Petroleum fuels account for nearly half of all GHG emissions in California, and reducing their use is a cornerstone of the Governor's energy and climate change policies.

Both the Energy Commission and the petroleum industry recognize that non-petroleum fuels are becoming viable and necessary alternatives to gasoline and diesel fuels. (The industry is on record supporting improved new vehicle fuel economy,[6] cost-effective non-petroleum fuels that do not require mandates or subsidies, and a prudent reduction of petroleum demand.[7]) Given the growing gap between in-state refining capacity and demand for transportation fuels and increasing concerns about global warming, the Energy Commission intends to accelerate the transition to an efficient, multi-fuel transportation market to serve the future needs of its citizens. It does not intend to arbitrarily restrict the petroleum industry's enterprise or to write off the state's leading source of transportation energy, which is petroleum. With its broad fuels expertise and extensive infrastructure, the petroleum industry is a critically important partner in this transition.

The Governor's California Hydrogen Highway Network, announced in April 2004, may eventually move the state to a hydrogen transportation fuel economy. The Energy Commission believes the alternative transportation fuel plan must bridge the gap between today's technologies and the transition to hydrogen fuels and vehicles. Consumption of non-petroleum fuels in California is currently stagnant at about 6 percent. The state must encourage the emerging non-petroleum fuel industry as suppliers of components for blended fuels and as developers of completely non-petroleum fuels and fueling systems. And, certainly, the state must establish a stronger relationship with the providers of the raw material needed for renewable fuels — California's agriculture, dairy, forest, and municipal sectors. This grand coalition is necessary to forge a new transportation sector that can make a significant contribution to meeting air quality, climate change, and energy security objectives.

Even more urgently than two years ago, 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. The health of California's future economy depends upon it.

[6] In fact, the industry supports doubling the CAFE standards as recommended by the Energy Commission and ARB.
[7] Comments by Joe Sparano representing the Western States Petroleum Association, transcript of September 29, 2005 hearing of the draft *Energy Report*, pp. 39, 48.

Recommendations

- The state should develop flexible overarching strategies that simultaneously reduce petroleum fuel use, increase fuel diversity and security, and reduce emissions of air pollution and greenhouse gases. The state's energy, environmental, and transportation agencies should integrate these strategies into their respective programs.
- The state should implement a public goods charge to establish a secure, long-term source of funding for a broad transportation program. Achieving the goals set out in this report and established by the Governor requires a comprehensive transportation program that provides funding for infrastructure investment, a broad range of technology and fuels research, analytical support, and incentive programs.

Demand for Gasoline and Diesel Fuel

In 2004, Californians consumed about 15.4 billion gallons of gasoline and 2.8 billion gallons of diesel fuel,[8] an increase of nearly 50 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 conventional gasoline and diesel fuels.
- 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.

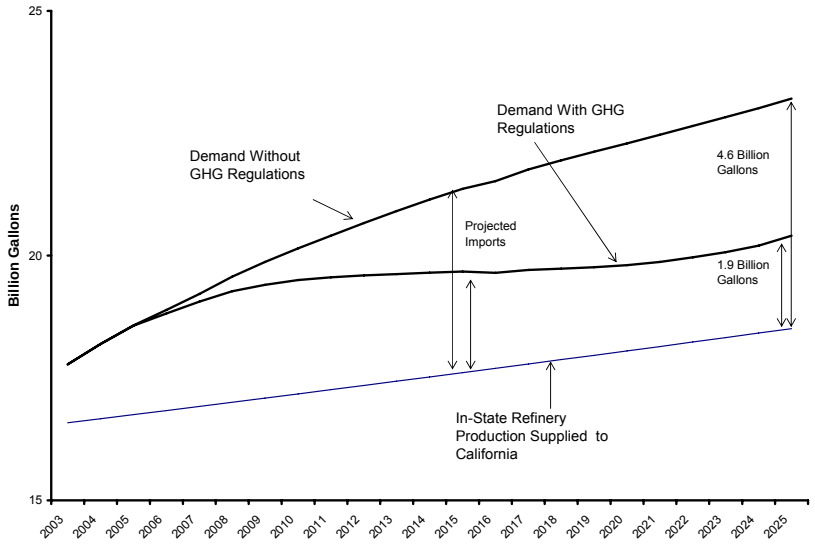
The Energy Commission projected on-road demand for gasoline and diesel fuels with and without the effects of ARB's greenhouse gas regulations. (See Figure 2.) If the state takes no further action to reduce petroleum use and current greenhouse gas regulations remain in place, demand for gasoline in California will increase to nearly 15.6 billion gallons per year by 2025. Without the regulations, demand is projected to grow to 18.2 billion gallons per year.

Whether the greenhouse gas regulations remain in place or not will have little effect on the demand for diesel fuel, which is projected to grow to 4.9 billion gallons per year by 2025.[9] This forecast is lower than projected in the *2003 Energy Report* because of

[8] *Forecast of California Transportation Energy Demand 2005-2025*, Energy Commission staff report, April 2005.
[9] *Forecast of California Transportation Energy Demand 2005-2025*, Energy Commission staff report, April 2005.

higher fuel prices and lower estimates of population growth, but it still represents a substantial increase over current levels.

Figure 2: Projected Gasoline and Diesel Demand



The Energy Commission also forecasts demand for non-petroleum fuels, specifically electricity and natural gas. The results show that usage on a percentage basis will nearly triple by 2025, but the actual petroleum displacement will remain quite low. In the transportation sector, the annual demand for electricity, primarily for transit, is expected to grow from 590 to 1,800 million kilowatt-hours (kWh) between 2002 and 2025. During the same period, the staff projects demand for natural gas in vehicles will increase from 75 to 200 million therms per year. Still, the projected increases for 2025 are only about 1 percent of total future electricity and natural gas demand.

The Energy Commission's forecast covers only on-road, in-state demand and does not include non-road demand or demand for gasoline and diesel in neighboring states and Mexico. This is a critical shortcoming since California is the center of a regional petroleum market. California refineries 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 on California for a portion of its fuel needs, although no data is available as to the quantity.

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 per year over the next 10 years, regional demand could increase by nearly 2 billion gallons per year by 2015. Increased demand for transportation fuels in these out-of-state markets further taxes California's transportation fuel infrastructure.

Recommendation

- The Energy Commission must develop the capability to forecast non-road and out-of-state demand for transportation energy. These sectors may offer substantial petroleum and emission reduction opportunities and could materially affect the operation of California refineries and other petroleum infrastructure.

Diversifying California's Fuel Supply

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. Given inaction by both Congress and the Bush Administration to materially increase CAFE standards, the state must now follow through and redouble its efforts to actions it can take to directly affect petroleum consumption. The first step in this policy redirection is to increase emphasis on diversifying the transportation fuel market.

AB 1007 recognizes the important relationships between transportation fuel use, air quality, and the continuing need for research and development. The state plan called for in AB 1007 provides a comprehensive framework to examine broad transportation fuel issues and effectively integrate transportation energy and air quality policies. The bill requires that:

- The plan shall include an evaluation of alternative fuels on a full fuel-cycle assessment of emissions of criteria air pollutants, air toxics, greenhouse gases, water pollutants, and other substances that are known to damage human health, impacts on petroleum consumption, and other matters the state board deems necessary.
- The plan shall set goals for the years 2012, 2017, and 2022 for increased alternative fuel use in the state that accomplishes all of the following:

  - Optimizes the environmental and public health benefits of alternative fuels, including, but not limited to, reductions in criteria air pollutants, greenhouse gases, and water pollutants consistent with existing or future state board regulations in the most cost-effective manner possible.
  - Ensures that there is no net material increase in air pollution, water pollution, or any other substances that are known to damage human health.

Several workshop participants indicated during the *2005 Energy Report* workshops on transportation that while non-petroleum fuels can, in many cases, significantly reduce emissions for most criteria pollutants and toxic air contaminants, some do increase NOx emissions. The participants suggested that the state consider a health-risk approach that quantifies the total net emissions benefits of all criteria pollutants and toxic air contaminants to accelerate adoption of non-petroleum fuels without backsliding on air quality or public health, similar to concerns addressed in AB 1007.

Recently, the ARB approved emergency regulations to accelerate the onset of winter fuel specifications for California's refiners in an effort to increase the supply of gasoline in the wake of Hurricane Katrina. The ARB recognized this could potentially increase emissions of volatile organic compounds by 50 to 75 tons per day.[10] While supportive of this emergency action, the Energy Commission is also quite concerned that until the state takes concerted action to diverge from its growing reliance on petroleum-based fuels, California will face this prospect more frequently, and the ability to maintain California's particular set of gasoline and diesel requirements will erode. The Energy Commission also acknowledges that the state should proceed cautiously with a health-based assessment of non-petroleum fuels. But time is of the essence, and an examination of the merits of this approach should be part of the process of preparing the state alternative fuels plan.

In preparing the plan, the state should pursue all reasonable non-petroleum fuel and technology options. High priority should be given to fuel blends (for example, non-petroleum fuels blended with gasoline and diesel) that can be used in existing gasoline and diesel engines without modification (or with technology additions to existing engine systems which are achievable in the near-term) without voiding manufacturer warranties and that can be dispensed through the existing fueling infrastructure. Renewable fuel blends should be of particular importance given the potential to produce these fuels from in-state resources. Initially, renewable resources could likely come from outside California with value-added processes occurring in-state to produce the fuels. Both scenarios would provide economic value to California.

Other fuel options, such as natural gas, require a separate fueling infrastructure and have been well suited to fleet or central fueling applications. Given the substantial greenhouse gas reduction and diversity benefits, the state should vigorously pursue these opportunities where they are cost-effective. Still other options, such as E-diesel, require additional research and development or testing and verification. The state should provide all appropriate support for these pursuits.

The Energy Commission has examined a portfolio of non-petroleum fuel and technology options. None represent a panacea. 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. The purpose of these results is not to define “winners” (with positive direct net benefit) and “losers” (with negative direct net benefit). Policy makers can and do use many criteria to determine which fuel and technology options to pursue. Table 1 evaluates some of the criteria, but not all. Further, the results of Table 1 are highly dependent on a number of assumptions that vary widely for a variety of reasons. Therefore, Table 1 is appropriately viewed as a policy guidance tool and not as a conclusion.

[10]Public hearings to consider an emergency regulatory amendment relaxing the Reid vapor pressure standard for California reformulated gasoline, September and October 2005, staff report, California Air Resources Board, September 6, 2005, p. 15.

Table 1: Analysis of Petroleum Reduction Options

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 (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 ARB 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 Energy Commission 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 (program expenditures or fuel excise tax increases or decreases, for example).

Ethanol

Ethanol is blended with gasoline to make transportation fuels. The two most common blends in California are E-5.7 (5.7 percent ethanol and 94.3 percent gasoline) and E-85 (85 percent ethanol and 15 percent gasoline).

Ethanol has been used in California primarily to comply with the now-rescinded federal requirement for minimum 2 percent oxygen content in gasoline. State and federal regulations allow refiners to blend up to 10 percent ethanol for this purpose. However, most refiners have chosen to produce gasoline with ethanol content of 5.7 percent, the minimum needed to meet the federal 2 percent oxygen requirement. Blending gasoline with higher levels of ethanol produces emissions increases that must be offset by other fuel property changes. Depending on the refinery and the market for ethanol and other blending components, these changes can add cost to producing gasoline. Also, gasolines with differing ethanol content cannot be co-mingled and must be stored and distributed separately under current regulations. As a result, nearly all gasoline sold in California has been blended with a standard ethanol content of 5.7 percent.[11]

Although the Energy Policy Act of 2005 repealed the requirement for minimum oxygen content for gasoline, it has imposed a new renewable fuel requirement beginning in 2006. The new provision does not specify a renewable content for gasoline. Instead, it requires refiners nationwide to use increasing amounts of ethanol up to a maximum of 7.5 billion gallons by 2012, nearly double the amount used today. A rulemaking is underway at the U.S. Environmental Protection Agency (EPA) that will prescribe the market share of ethanol each refiner will be required to use. The Act also will allow refiners using more ethanol than their market share to accrue credits which they can sell to refiners using less than their market share. California refiners likely will continue to use significant amounts of ethanol in the near term, but will now have the flexibility to produce non-oxygenated gasoline as well.[12] Until the federal rulemaking is complete, the impact of the renewable fuel requirement on California will not be known.

Since state and federal regulations allow up to 10 percent ethanol in gasoline, the question that policy makers need to ask is whether refiners can cost-effectively blend greater amounts of ethanol in gasoline sold in California without backsliding on air quality. The answer is not straightforward and requires better understanding of several important issues.
ARB is in the process of updating its Predictive Model. The model is used to ensure that all gasoline sold in California has acceptable emission levels. ARB last updated the model in 1999. A major benefit of the current version is that it provides flexibility by

[11] At least two refiners have produced gasoline with an ethanol content as high as 7.7 percent by volume and one as high as 10 percent. These refiners use proprietary storage and distribution systems to avoid co-mingling issues.
[12] 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.

allowing refiners to offset emission increases related to one gasoline specification with decreases in another. A shortcoming is that it does not accurately represent the vehicle fleet on the roads today because it relies on a limited sample of newer vehicles and does not adequately consider emissions from newer technologies or varied meteorological conditions. Recent studies show that newer vehicles are operating below respective certification levels for hydrocarbon, CO, and NOx.[13]

Equally important, the current Predictive Model does not consider the impact that ethanol has on permeation — evaporative emissions that result from the migration of liquid fuel components through the soft portion of motor vehicle fuel systems. Gasoline containing ethanol has been shown to increase permeation emissions relative to gasoline without ethanol. Due to the effectiveness of evaporative emission regulations in newer vehicles, permeation impacts are greatest in pre-2000 vehicles[14] and will diminish as these vehicles are retired. However, relying on fleet turnover is not an expeditious strategy. The merits of other forms of mitigation and offsets should be examined in the state plan.

ARB is updating the Predictive Model to reflect the vehicle fleet anticipated in 2010 and more recent NOx and permeation data. The Air Resources Board expects to approve the updated model in late 2005 or early 2006.

While gasoline blends up to E-10 are widely used in conventional automobiles, E-85 can be used only in specially designed vehicles known as fuel flexible vehicles (FFV). FFVs are designed to operate on any ethanol blend of gasoline up to 100 percent. FFVs also significantly reduce permeations emissions.

Automakers receive federal fuel economy credits for every vehicle sold, even in California where the E-85 fuel is largely unavailable. The federal Energy Act of 2005 extended the CAFE alternative fuel credit, which provides incentive for automakers to continue and even increase production of FFVs and provides incentives to install E-85 fueling stations. More than 250,000 FFVs operate in California, a number that is growing at a rate of 45,000 to 50,000 each year.[15] These vehicles represent a sizeable sales base for E-85. But with only three E-85 fueling stations in the entire state, FFVs in California operate almost exclusively on gasoline. The cost differential between producing an FFV and a conventional gasoline vehicle is minimal. In fact, many FFV owners are not even aware that they have a vehicle with fuel options.

ARB's Clean Fuels Outlets "trigger" offers a possible solution to this dilemma: major gasoline suppliers, as defined by the regulations, must equip an appropriate number of fueling stations to dispense clean fuels whenever automobile dealers expect to sell 20,000 clean alternative fuel vehicles in the state. The ARB Executive Officer has the

[13] A summary of the "Study of Extremely Low Emitting Vehicles Operating on the Road in California," a presentation to the Energy Commission on July 8, 2005.
[14] September 29, 2005 hearing, transcripts, p. 109.
[15] California Energy Commission's Joint Agency DMV Data Project in cooperation with the Department of Motor Vehicles.

discretion to identify the number of outlets that must be established. The regulation requires that the alternative fuel vehicles be cleaner than the comparable gasoline model with respect to criteria pollutant emissions. Consequently, with reformulated gasoline and cleaner vehicle technology, achieving the emissions differential required to "pull the trigger" has proven to be problematic.

Increasing the amount of ethanol in gasoline will result in a loss of fuel economy and require motorists to purchase more gasoline. For example, E-85 contains almost 30 percent less energy than gasoline, and retail prices should be set to reflect this disparity. In this way, retailers can offer E-85 at a gasoline equivalent value and build consumption volume in the early years of its introduction to better assure its sustainability over the long term.

About 90 percent of the ethanol used in gasoline arrives by train from the Midwest and is produced from corn. The remaining 10 percent comes by ship from Caribbean Basin Initiative countries and Brazil, where it is produced from sugar cane. California produces very little ethanol. Current production is approximately 40 million gallons per year. Several projects being permitted or under construction will boost the annual volume to over 120 million gallons within the next two years.

California has as-yet untapped potential to produce ethanol from cellulosic biomass material such as municipal, agricultural, and forestry wastes. Gasoline blended with ethanol produced from cellulosic biomass material provides a three-fold decrease in greenhouse gas emissions compared with gasoline blended with corn-based ethanol. In-state production of ethanol from biomass would also be an economic boon for California. In the past, the technology has not been seen as economical and has not been demonstrated on a commercial scale. This may soon change. Iogen Corporation is operating what may be the world's first cellulosic ethanol demonstration plant near Ottawa, Canada. The demonstration plant produces 260,000 gallons of ethanol per year from straw. Iogen may soon announce plans for the first commercial-scale plant with a capacity to produce up to 50 million gallons per year.

In the Governor's response to the *2003 Energy Repo*rt and *2004 Energy Report Update*, he specifically called on the Bio-Energy Interagency Working Group, led by the Energy Commission and composed of state agencies with important biomass responsibilities, to develop an integrated and comprehensive state policy on biomass. This policy should include electricity, natural gas, and petroleum substitution potential.

Biodiesel

In 2004, California fleets used about 4 million gallons of biodiesel.[16] Forty-two commercial plants in the U.S. produce biodiesel fuel from vegetable oil, animal fat, and

[16] 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.

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 blends as low B-2 (2 percent biodiesel and 98 percent conventional diesel) can play an important role in the introduction of cleaner conventional diesel fuels and advanced diesel engines. Ultra-low sulfur diesel fuel regulations become effective beginning in 2006, placing sulfur limits on all conventional diesel fuel sold in the United States at just 15 parts per million (ppm). Clean diesel engines entering the market between 2007 and 2010 will need ultra-low sulfur diesel fuel to meet their emissions targets. Ultra-low sulfur diesel has poor lubricity and requires additives. At concentrations of just 2 percent, biodiesel fuel can provide adequate lubricity for ultra-low sulfur diesel fuels. Today almost all vehicle and engine manufactures accept using up to B-5 with existing diesel engines, provided that the fuel complies with ASTM specifications.

Biodiesel blends at higher concentrations are compatible with most diesel engines and fueling system components. B-20 (20 percent biodiesel and 80 percent conventional diesel) qualifies as an alternative fuel under requirements of the federal Energy Act of 2005. However, only one vehicle or engine manufacturer currently recommends the use of biodiesel blends greater than B-5 (5 percent biodiesel and 95 percent conventional diesel). Biodiesel blends up to B-20 can be legally sold in California as long as they meet ARB's aromatic and sulfur requirements and Department of Food and Agriculture specifications.

Currently, ARB does not have a fuel specification for biodiesel as an alternative fuel. Furthermore, a regulatory conflict has existed for certain fleets (including the military) in California that, on the one hand, must comply with ARB's diesel retrofit requirements, but on the other hand, must use B-20 fuel to comply with federal fleet procurement requirements. Until recently, ARB has not allowed the use of bio-diesel fuel in the diesel retrofit program due to questions of compatibility with particulate traps. A new law,[17] however, states that

> Any federal, state, or local agency, or any regulated utility, or any owner or operator of a solid waste collection vehicle or collection vehicle, as defined in Section 2021 of Title 13 of the California Code of Regulations, may utilize a biodiesel blend fuel consisting of not more than 20 percent biodiesel in any retrofitted vehicular or off-road diesel engine certified by the state board, whether or not biodiesel is expressly identified as a fuel for use with the retrofit system.

Since this law sunsets in 2008, it offers only a temporary remedy. The state must still address the issue of compatibility on a permanent basis. In August 2005, ARB approved

[17] SB 975 (Ashburn), Chapter 365, Statutes of 2005.

the use of B-20 with one manufacturers' particulate trap. However, no particulate matter or toxicity reduction credit, is applied for the biodiesel portion used.

E-Diesel

Ethanol in diesel has been under active development with many demonstration and evaluation activities initiated in the late 1990s, and laboratory research before then. While both on-road and off-road applications have been explored, ethanol in diesel for general on-highway use in passenger cars and light-duty trucks appears unlikely for the foreseeable future. Automakers view this fuel as experimental and its use in passenger vehicles problematic due to fuel vapor flammability and related safety issues.

On the other hand, centrally fueled fleet applications are the logical place for this fuel, such as medium- and heavy-duty fleets and off-road equipment. In this environment fleet owners can undertake vehicle modifications, implementation of safety measures, training of personnel, and upgrading of supply tanks and associated equipment without the complexities (and costs) associated with dispersed use of the fuel in the larger petroleum infrastructure.

Since ethanol in diesel blends does not have an American Society for Testing and Materials (ASTM) specification, it is not considered a commercial fuel by California's fuel quality regulating agency. Nevertheless, several fleets are operating under Developmental Engine Fuel status, a designation provided by the Division of Measurements and Standards of the California Department of Food and Agriculture (CDFA) that permits use of the "developmental fuel" for a limited time in designated fleets.

Long Beach Container Terminal, Inc. is using e-diesel in operating 60 pieces of heavy equipment to move ship containers at the Port of Long Beach. Its annual consumption will be about 600,000 gallons. Other fleets using the same fuel are located in Tulare, Fresno, and the Los Angeles area and include refuse truck, transit, road maintenance, and construction activities.

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 currently produced from natural gas and coal feed stocks. Most 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 has not been seen as commercially mature and is more costly. However, there is increasing interest in these technologies. For example, Rentech Inc. has announced that next year it will break ground on a plant in Wyoming that will produce 33,000 barrels per day of diesel fuel made from coal.

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 ARB found that blending 33 percent GTL fuel with 67 percent conventional U.S. EPA diesel fuel produces a cost competitive diesel fuel that can be used in existing engines and that complies with ARB's strict diesel fuel specifications.

California refineries have occasionally used GTL fuel as a blending component. 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 and significant expansions are underway overseas. As an imported product, GTL fuel would face the same import facility constraints at the ports of Long Beach and Los Angeles now faced by imported crude and refined products. Also, the federal government has approved GTL as an alternative fuel only if it is produced domestically.

Electricity

The use of electricity as a transportation fuel, as a replacement for gasoline or diesel, produces very large reductions in emissions due to California's clean and diverse mix of generation resources as well as the inherent energy efficiency of electric drivetrains. For example, the California Air Resources Board has estimated that electric vehicles produce only about 6 percent of the air pollution of the cleanest new internal combustion cars available today, Advanced Technology PZEV hybrids.[18]

In 2002 approximately 300,000 units of electric transportation and goods movement equipment operated in California.[19] Industrial vehicles such as forklifts, industrial tugs, tow tractors, industrial sweepers and scrubbers, and burden and personnel carriers comprise most of this equipment. The category also includes neighborhood electric vehicles, electric-standby truck refrigeration units, and golf carts. All of this equipment has gasoline or diesel counterparts, so the choice of electric equipment displaces petroleum use and reduces emissions of criteria pollutants and GHG.

The number of electric transportation and goods movement technologies is expected to triple by 2020 (to between 900,000 and 1 million units). This growth is due not only to natural market growth, but also to known regulatory requirements and financial incentive programs that are encouraging the use of electric technologies because of their inherent emissions benefits.

Recent legislation requires the ARB to revise the Carl Moyer Memorial Air Quality Standards Attainment Program (Carl Moyer Program) to incorporate projects in which

[18] 2000 ZEV Program Biennial Review, California Air Resources Board staff, August 7, 2000.
[19] TIAX update to 2002 Arthur D. Little Electric Vehicle Market Assessment, letter to the California Electric Transportation Coalition, TIAX,LLC, June 30, 2005.

an applicant "scraps" internal combustion engine-driven non-road equipment and purchases new zero-emission non-road equipment.[20]

In 1990, the ARB 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 produce high emissions under cold-start and stop-and-go conditions, NEVs and CEVs have demonstrated 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.

Natural Gas

Natural gas is a completely non-petroleum transportation 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 passenger cars and light trucks, medium-duty delivery trucks, and heavy-duty vehicles such as transit buses, school buses, and street sweepers. 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 is a joint venture facility with petroleum companies.

These stations have been established over a period of several years in order to comply with federal requirements for alternative fuel vehicle procurements. It is important that the availability of the alternative fuel vehicles be maintained so that the state's, and the private sector's, investments in this infrastructure not become stranded due to lack of use. These station investments are important building blocks for the state's displacement of petroleum fuels and therefore must remain viable by fueling a consistent and reliable population of vehicles.

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, more

[20] SB 467(Lowenthal, Chapter 209, Statutes of 2005)

than 30,000 natural gas vehicles are currently on state roadways (5,000 heavy-duty vehicles and 25,000 light-duty vehicles). These vehicles displace 70-75 million gallons of petroleum fuel per year.[21] However, because Ford Motor Company and Chrysler have stopped production of its natural gas vehicles for the U.S. market (they still produce natural gas vehicles for the European market), 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. In a bid to boost sales of its dedicated natural gas vehicles, Honda has introduced a home-fueling system, "Phill," that is now being offered to its CNG vehicle customers. 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.[22] On the other hand, another source suggests that, at $52,000 per ton of NOx reduction, CNG-fueled refuse hauling trucks are not a cost effective strategy for reducing NOx emissions.[23]

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 only one manufacturer has an engine certified for LPG operation, which is used mainly for shuttle buses and street sweepers. Outside California, several companies offer "upfit" packages for a broad range of engines and vehicle models. However, these companies find it difficult to meet California's air quality certification requirement. Therefore, they do not offer fuel system upfitter packages for vehicles in the California market. The cessation of certified automaker/ fuel system upfitter offerings for propane vehicles limits the availability of viable alternatives to gasoline and diesel fuels.

Liquefied petroleum gas, or propane, is a domestically produced fuel that is closer to gasoline than other alternative fuels.[24] LPG carries the benefits of reduced vehicle maintenance costs, emissions, and fuel costs when compared with conventional gasoline and diesel.[25] Most propane in California is produced from natural gas wells; lesser amounts are produced during the petroleum refining process. Since it is not used in most California motor vehicles, LPG would displace gasoline and diesel fuels. Of the 1,500 LPG service stations in California, 900 are "motor-vehicle-friendly" and dispense

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[21] 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.
[22] *Comparative Costs of 2010 Heavy-Duty Diesel and Natural Gas Technologies*, final report, TIAX LLC, July 15 2005.
[23] Presentation by Sean Edgar, September 29, 2005, transcripts, p. 124.
[24] [http://www.consumerenergycenter.org/transportation/afv/propane.html].
[25] *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.

LPG to motor vehicles. LPG is also an attractive option for non-road vehicles like forklifts. There are 32,000 LPG forklifts in California, though this market faces stiff competition from gasoline and electric forklift manufacturers.

Hydrogen

In April of 2004, Governor Schwarzenegger signed an Executive Order intended to jump-start the use and operation of hydrogen-fueled vehicles in California. The Governor's Order called for a Hydrogen Highway Network, 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.

The Governor's Hydrogen Highway Blueprint Plan, which was released in May 2005, 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. The Governor's Plan places great importance on the development of "bridging technologies," which assist the development of fuel-cell technologies. Electric-drive technologies are bridging technologies, including hybrid, plug-in hybrid, and pure electric vehicles. Several non-petroleum fuels in use now and proposed for increased roles in California's transportation fuel mix are potential hydrogen carriers (that is, fuels that contain hydrogen and could be reformed to produce hydrogen for fuel cells in the future). Many state agencies are involved in implementing the Governor's plan.

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

Both fuel cell vehicles and, with modifications, internal combustion engines (ICE) can use hydrogen. Hydrogen and natural gas blends are in demonstration use now and 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, using gaseous or liquid hydrogen stored in tanks on the vehicles, are in active demonstration now in California.

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. While this report focuses on direct hydrogen technology, it is possible that fuel cell vehicles using on-board fuel reformers will eventually be introduced. This would reap the benefits of both increased fuel economy and decreased emissions while still using existing gasoline or liquid fuel 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.

Recommendations

- The state should establish a non-petroleum diesel fuel standard so that all diesel fuel sold in California contains a minimum of 5 percent non-petroleum content that would include biodiesel, ethanol, and/or gas-to-liquid components.
- The Biodiesel Working Group should prepare and submit recommendations to the Energy Commission for inclusion in the AB 1007 state plan to expand the use of B-20 fuel by:
  - Conducting comprehensive tests to verify the net emissions characteristics of biodiesel fuels in existing engines and their effectiveness when combined with particulate traps.
  - Supporting research for development of after-treatment technology and fuel additives to improve the control of NOx emissions.
  - Investigating the feasibility of requiring B-20 fuel in all state-owned diesel vehicles, partnering with other public and private fleets to create a market for biodiesel.
  - Working with engine and component manufactures to establish an acceptable biodiesel fuel standard that will preserve engine performance, durability, and warranties.
- The state should establish a California renewable gasoline fuel standard so that the pool of all gasoline sold in California contains, on average, a minimum of 10 percent renewable content.
- The Bio-Energy Interagency Working Group should prepare and submit recommendations to the Energy Commission for inclusion in the AB 1007 state plan to increase the use of E-85 fuel by:
  - Developing and certifying E-85-compatible fuel dispensing systems.
  - Implementing a process to expedite the permitting of E-85 stations.
  - investigating the feasibility of requiring all or a portion of new cars sold in California to be FFVs.
  - 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 plan to exploit opportunities to incorporate E-85 into the existing retail fueling system.

- Sponsoring a consumer notification and education program promoting the availability of FFVs and E-85 fuel.
- Evaluating various incentive options and programs in other states to determine their applicability and usefulness for creating an E-85 retail infrastructure in California.
- Supporting research for the development of technologies to convert California's biomass resources to ethanol.
- Examining the feasibility of establishing an ethanol pool, or reserve, to provide ethanol to E-85 fuel retailers at prices that are competitive to gasoline on a cents-per-mile basis.

- The state should consider amending the Carl Moyer Program to include criteria for reductions in petroleum use and greenhouse gas emissions.
- The state should open a dialog among the Energy Commission, the CPUC, the ARB, local air quality management districts, utilities, and other stakeholders 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.
- The Energy Commission should continue to help to implement the California Hydrogen Highway Blueprint Plan, including: 1) prioritizing the use of renewable energy sources to produce hydrogen; 2) developing hydrogen fueling infrastructure and vehicular hydrogen technologies; and 3) using bridging technologies that can accelerate the technological development of fuel cell vehicles while providing near-term emission reductions of greenhouse gases and other pollutants.
- The ARB should consider amending the Clean Fuels regulations to incorporate broader emission and/or petroleum reduction criteria in the Clean Fuels Outlet "trigger" provision and examine its authority to require automakers to produce as many FFVs as possible for the California market.
- The state should engage the automakers, and their selected fuel system "upfitters," to continue the production of the gaseous alternative fuel vehicles (natural gas and propane).

Increasing Vehicle Efficiency to Decrease Fuel Demand

Energy efficiency has always been the priority in California energy policy. The Energy Commission's efficiency standards and utility efficiency programs have been effective in moderating the growth in demand for electricity and natural gas. In the transportation sector, however, fuel economy standards for passenger cars and light trucks have been allowed to languish under the aegis of the federal government. Still, despite the significant market penetration of light-trucks and its dampening effect on overall fuel economy, as well as the substantial vehicle miles traveled each year, Californians are the ninth-lowest consumers of gasoline on a miles-per-gallon basis in the United States. That fact indicates Californians' propensity for fuel efficient vehicles relative to other

states.[26] The state must better understand and encourage this market preference for efficiency through a number of options that are becoming available in the marketplace.

Hybrid-Electric Vehicles

The fuel economy of hybrid-electric vehicles (HEV) is approximately double that of the average fuel economy of cars and light trucks in California today and have overall lower tailpipe emissions.[27] The few hybrid models for sale by automakers carry a price premium several thousand dollars above comparable gasoline models, although expected mass production will bring down their cost. Consumer awareness of HEVs is increasing, and automakers are responding, adding HEV models to current and future model lines. Only about 45,000 hybrid vehicles were on the road in 2004, out of a total state vehicle count of more than 26 million. [28] With average vehicle turnover at eight years for households and two and one-half years for business fleets,[29] influencing individual consumer preference may not be the most effective strategy to encourage their use. Providing incentives or requiring public and private fleet owners to buy HEVs could accelerate the rate of market penetration of hybrid vehicles. Public and private fleets in California currently have nearly 6,000 hybrid vehicles.[30]

Plug-In Hybrid-Electric Vehicles

There is increasing attention to grid-connected, or “plug-in,” hybrids as an on-road electric-drive technology option that can bridge the gap between today’s hybrids and the zero-emission vehicles of the future. Plug-in hybrids are like today’s hybrids, but with a larger battery pack and the capability to plug into grid-supplied electricity from a standard 110-volt outlet when available. Plug-in hybrids have the capability to provide 20 to 60 miles of all-electric battery-only (and zero-emission) range, before the internal combustion engine comes on to supply the remainder of the needed driving range. This is particularly important since 63 percent of consumer trips are fewer than 60 miles. In this way, plug-in hybrids address the limitations that all-electric vehicles have in terms of limited range and high battery cost. And because plug-in hybrids have substantial zero-emission range, they can produce significant reductions in petroleum, criteria pollutants, and GHG emissions – much more than the very efficient hybrid vehicles available today. Furthermore, optimizing the internal combustion engine of a plug-in hybrid to use a non-petroleum fuel, such as E-85, could result in a nearly petroleum-free vehicle. Several aftermarket companies are offering plug-in capabilities for hybrid-electric vehicles on a very limited basis. Although, at present, no automaker has publicly announced plans to produce plug-in hybrid models, the City of Austin, Texas, has initiated a national Plug-In Partners campaign to create a market for the vehicles. The state should join the national

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[26] Federal Highway Administration's Office of Highway Policy Information, based on data for 2000.
[27] *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.
[28] California Energy Commission, Joint Agency Department of Motor Vehicle Data Project, based on Department of Motor Vehicle’s October 1, 2004 Vehicle Registration Database.
[29] U.S. Department of Energy, Transportation Energy Data Book, Edition 24, Oak Ridge National Laboratory.
[30] California Energy Commission, Joint Agency Department of Motor Vehicle Data Project, based on Department of Motor Vehicle’s October 1, 2004 Vehicle Registration Database.

Plug-In Partners campaign and work with other government and private fleet operators in California to communicate to auto manufacturers an interest in placing future procurement orders for plug-in hybrid vehicles.

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 LDDs 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 Europe were 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 made significant investments in advanced technologies and are demonstrating prototypes that will meet the adopted 2007 standards. With the availability of ultra-low sulfur diesel fuel beginning in 2006, in combination with the advanced diesel engine technology, LDDs may succeed in meeting California's stringent NOx standards. To be a viable, fuel-efficient option, consumers will have to overcome the higher initial purchase price, estimated at $1,000 to $3,000, and the petroleum industry will need to increase the number of diesel fueling stations.

Low-Rolling Resistance Tires

Tires that reduce road friction increase fuel economy. Most automobile manufacturers routinely use low-rolling resistance tires on new vehicles to help meet federal fuel economy standards. Consumers are not aware that tires affect vehicle fuel efficiency based on their rolling resistance characteristics and that the tires sold on new cars are usually more fuel efficient than normally purchased replacement tires. In a 2003 report, the Energy Commission concluded that fuel-efficient tires could provide substantial fuel savings. Sufficient data, however, is not yet available to draw conclusions regarding the performance and characteristics of fuel-efficient tires.[31]

Tire manufacturers assert that any improvement in tire efficiency will compromise tire life, performance, and safety and/or increase cost significantly. Nevertheless, tire manufacturers routinely use forms of rolling resistance measurement in the engineering and the design process for developing new tires. The manufacturers have not published useful information on rolling resistance or on tire performance as a function of rolling

[31] California Energy Commission, California State Fuel Efficient Tire Program: Volume 1 – Summary of Findings and Recommendations, January 31, 2003, Publication # 600-03-001F-VOL1.

resistance. Without such information the Energy Commission cannot predict with any certainty the fuel consumption impact of low-rolling resistance tires.

Actual fuel economy performance of low-rolling resistance tires must be verified to ascertain possible trade-offs and to avoid unacceptable penalties associated with improving tire efficiency beyond current practices. Legislation passed in 2003[32] requires tire manufacturers to report to the Energy Commission the rolling resistance and relative fuel economy of replacement tires sold in California. With this information composed in a reportable format, consumers will for the first time be able to select tires relative to their fuel economy in addition to the existing parameters of use, cost, and longevity. The Energy Commission will also be required to adopt (if feasible) minimum fuel efficiency standards for replacement tires resulting in a fuel economy equal to or better than tires on new vehicles.

The Energy Commission, in partnership with the California Integrated Waste Management Board (CIWMB), initiated a fuel efficient tire study in March 2005 to substantiate the potential of low-rolling resistance tires to save fuel in real world conditions. Results from this study should be available in 2006. The National Highway Transportation and Safety Administration also is conducting a study of the fuel consumption, safety, tread life, cost, and disposal issues regarding fuel efficient tires. These findings should be available in December 2005.

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 ARB has adopted regulations limiting engine idling time for all heavy-duty trucks, except sleeper berth trucks, to five minutes. On October 20, 2005, ARB approved amendments to the regulation that limit the idling of the sleeper berth trucks to five minutes beginning January 1, 2008.

One solution to idling truck engines is “electrification” of truck stops, which allows truckers to connect their trucks 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 generator mounted outside the cab that provides heat, air conditioning, and electricity. Each of these three options 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.

In the spring of 2004, U.S. EPA convened the West Coast Collaborative as a multi-state effort to reduce emissions from diesel engines. Today the 700 Collaborative partners include federal, state and local government agencies, non-profit organizations, public and private diesel users, clean technology producers, and diesel, biodiesel and natural gas producers. The Collaborative has been tasked with implementing the West Coast

[32] AB 844, Chapter 644, Statutes of 2003.

Governors Global Warming Initiative's recommendations to establish a plan for the deployment of electrification technologies at truck stops in each west coast state on the I-5 corridor, on the outskirts of major urban areas, and on other major interstate routes. So far, the Collaborative has helped establish grant and loan programs in all three states and are installing electrified parking spaces, advanced truck stop electrification, and auxiliary power units.

Recommendations

- The state should intensify its efforts with other states and stakeholders to 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.
- The state should use the State of California's vehicle fleet as a model for efficiency and non-petroleum applications by: 1) establishing a minimum fuel economy standard that is based on doubling current federal standards for passenger cars and light trucks by 2009 and directing the Department of General Services to develop and implement a vehicle procurement process that achieves this standard; 2) implementing a procurement requirement for alternative fuels and vehicles; and 3) examining the merits of using re-refined and synthetic oils.
- The Energy Commission and Department of General Services should encourage local governments to adopt a minimum fuel economy standard and procurement process for both fuel efficient and alternative fuel vehicles. The Energy Commission should open a proceeding to investigate requiring that all public fleets adopt the minimum fuel economy standard and procurement process.
- The state should establish a combined state/industry working group to examine the markets for development and commercialization of plug-in hybrid-electric vehicles. The state should 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.
- The state should develop programs to: 1) reduce diesel engine 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 and gasoline use in non-road vehicles including forklifts and other industrial vehicles. The state should closely coordinate these activities with other load management, energy efficiency, and greenhouse gas reduction programs.
- The state should establish a low-interest loan program, funded through the California Pollution Control Authority, the California Alternative Energy Source and Advanced Transportation Funding Authority, or other sources and administered by the Energy Commission, to develop projects that reduce petroleum use and increase transportation fuel diversity.
- The state should continue current work to explore establishing energy efficiency criteria and, if appropriate, efficiency standards for replacement vehicle tires.

- The state should sponsor consumer outreach and education programs on transportation energy choices, including a consumer education campaign on vehicle maintenance practices that maintain vehicle efficiency. The state should create an information clearinghouse on efficient alternative fuel choices for consumers, along the lines of an Internet shopping guide.
- The state should sponsor transportation technology and fuels research, development, and demonstration 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; and 4) develop and demonstrate alternative fuel production technologies, emphasizing in-state resources.

Reducing Fuel Demand through Pricing Options

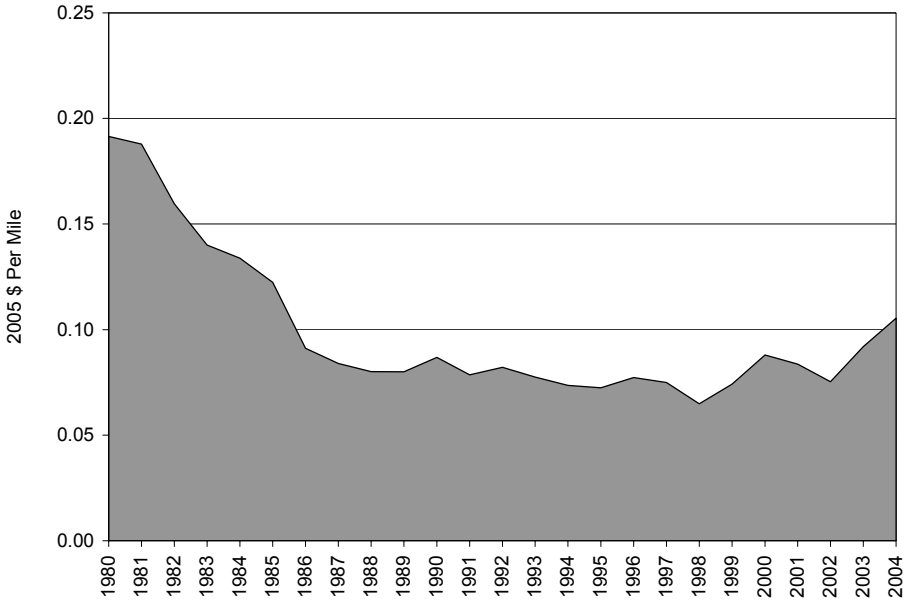
Mandating vehicle efficiency or substituting alternative fuels are not the only ways to reduce petroleum demand. Actions to increase travel cost can also reduce petroleum fuel demand.

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 in 2004 was nearly half 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 3 shows the average per-mile cost 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:

- 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.
- 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.

Figure 3: Average On-Road Gasoline Cost Per Mile California, 1980-2005



- Pay-as-you-drive automobile insurance: Offering to vary a portion of consumers' auto insurance premiums, depending upon miles traveled, instead of paying a fixed cost for auto insurance. When cost is directly tied to usage, consumers drive less and may choose to buy more fuel-efficient vehicles.
- Fuel tax increase: Increasing gasoline and diesel excise taxes by one 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, the state would have to identify other taxes for reduction.

Pricing options are usually vilified as hidden tax increases, 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, policy makers should consider all demand reduction, fuel switching, and pricing options and pursue further study. Local, state, and federal policy makers must 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.

Recommendation

- The state should explore 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.

Reducing Fuel Demand through Integrated Transportation and 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, state (Caltrans), regional, and city/county transportation and land use planning professionals must build an information and policy bridge between their departments. Transportation plans typically account for regional growth in city and county general plans. Metropolitan planning organizations are caught in a dilemma: 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. Policy makers must address this stubborn and politically-charged disconnection, however difficult it may be.

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 the Sacramento Area Council of Governments (SACOG) used 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 by some 5.8 million per year while retaining almost $220 million a year in the regional economy (assuming a $2.45 per gallon petroleum price). If each metropolitan planning organization embraced both the BLUEPRINT program and the PLACE3S technology, metropolitan areas throughout the state could achieve similar savings. 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.

Recommendation

- The state should 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. It should create a center of excellence for regional planning based upon the PLACE3S planning tool and provide technical assistance and training.

Infrastructure for Transportation Fuels

Gasoline and diesel will continue to be California's primary transportation fuels for the foreseeable future. California cannot meet rising near-term fuel demand without a robust petroleum infrastructure including refineries, storage, pipelines, distribution terminals, and marine facilities. It is critical to California's economy that all reasonable measures be taken to ensure adequate supplies of gasoline and diesel as the state takes all the necessary steps to diversify the transportation fuel market. 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 and 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 expand marine terminal capacity, marine storage, and pipelines connecting marine facilities with refineries and other pipelines to meet rising fuel demand. The most urgently needed marine terminal expansion and storage is in the Ports of Los Angeles and Long Beach. Building these needed facilities faces several hurdles, including scarcity of land and complex and overlapping permitting requirements. Social pressure and local port policies to remove portions of existing facilities in favor of container cargo facilities and open space could further threaten marine infrastructure.

Moreover, new State Lands Commission standards for marine terminals, known as the Marine Oil Terminal Engineering and Maintenance Standards (MOTEMS), may require substantial upgrades to a large percentage of the clean fuel receiving terminals primarily in Southern California. These upgrades are likely to require substantial investments and could create operational disruptions. Some companies may choose to close terminals rather than rehabilitate them to the new standards.

The Los Angeles Basin will need at least an additional 2.8 million barrels of storage capacity and 46 million barrels of clean fuel marine terminal throughput capacity by 2025.[33] Crude oil import capacity appears sufficient for the next 20 years, assuming proposed crude oil and import terminal projects are approved and constructed within the next three to five years. In the San Francisco Bay Area, marine clean fuels storage also appears sufficient for the next 20 years, but the Bay Area needs a clean fuels marine terminal capacity expansion of at least 11 million barrels a year.[34] The Bay Area will also need additional crude oil marine terminal capacity equal to increased throughput of around 30 million barrels by 2015 and 56 million barrels by 2025.[35]

[33] Energy Commission, *An Assessment of Petroleum Infrastructure Needs*, staff report, April 2005, CEC-600-2005-009.
[34] Ibid.
[35] Ibid.

Expected storage and throughput needs will more than double if the courts overturn the ARB's greenhouse gas regulations. The Los Angeles Basin will require additional storage of 7.3 million barrels and 99 million barrels of additional throughput per year, assuming the construction of 2 million barrels of recently permitted additional storage capacity. 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 additional throughput per year, again assuming the construction of 1.7 million barrels of already permitted storage.[36] However, these projected infrastructure requirements make no assumptions about demand growth in out-of-state markets presently served by California refineries.

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's 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 some 300,000 barrels of fuel per day to Nevada and Arizona.[37] 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.

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 overlapping and serial nature of federal, state, and local agency permitting and planning processes complicates 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, port and air districts to make sure their processes are conducted in a timely fashion and take into account the state's rising fuel needs 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

[36] Ibid.
[37] *California's Petroleum Infrastructure Needs*, presentation by Gordon Schremp, May 16, 2005.

infrastructure permitting processes. The federal Energy Policy Act of 2005 grants U.S. EPA similar authority to coordinate federal agency review of refinery applications and speed the concurrent review of applications with state agencies.[38]

The Energy Commission should initiate an effort to identify and develop permitting guidelines for petroleum infrastructure projects, with no reduction in environmental standards, that focuses on the following elements:

- Descriptions 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

Emissions from the state's refineries have decreased over the last 25 years, partially due to major improvements in refinery emission controls.[39] 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-called "fugitive" emissions from small leaks in valves, pumps, tanks, pressure relief valves, and flanges.

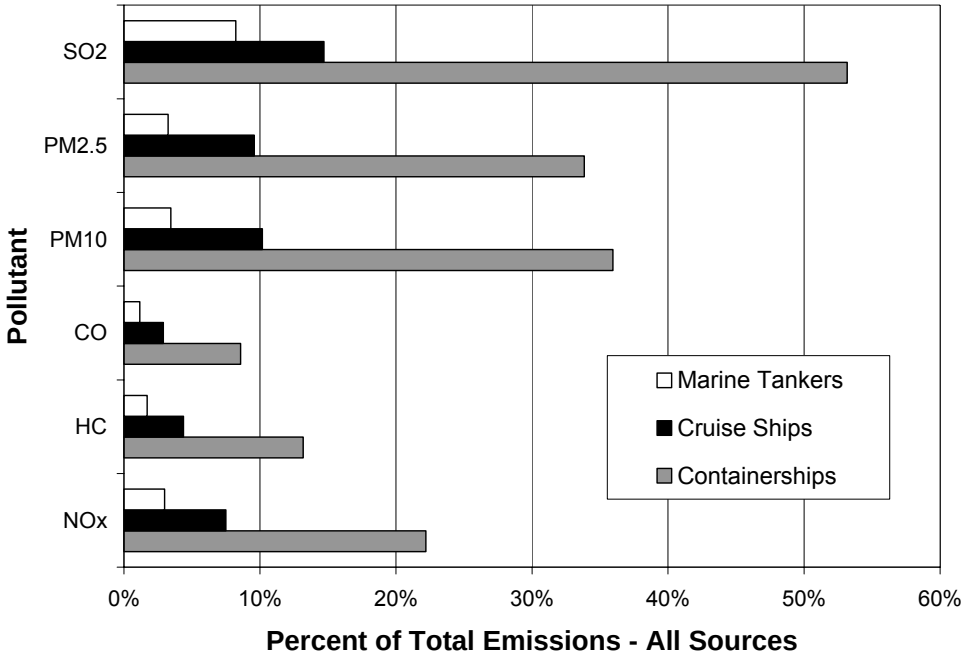
Marine terminals generate high levels of pollution from diesel port equipment, truck and rail traffic, and largely unregulated marine vessels. Loading and unloading crude oil and petroleum products creates fugitive emissions and emissions from diesel engines operated in the process. Fugitive emissions 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.

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

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 4 shows relative air pollution contributions from the three main types of ocean-going vessels.

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

Figure 4: 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.

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. The U.S. Army Corps of Engineers, the U.S. Navy, and private terminal operators historically have

dredged the bay. Through 2045, the Army Corps and the Navy are still projected to perform 80 percent of the dredging, 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. The Army Corps, U.S. EPA, San Francisco Bay Conservation and Development Commission, San Francisco Bay Regional Water Quality Control Board, and the California Water Resources Control Board are the agencies that provide permits for dredging. 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.

- The Bay Area Air Quality Management District's expansion of its database of environmental justice stakeholders, work with community members on air quality publications, community meetings, and incorporation of permit information on its website.
- The ARB'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/ARB 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. California refineries have an installed cogeneration capacity of about 1,400 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 the facilities 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.

As a case in point, the mid-September electricity outage in Los Angeles caused the shutdown of the Conoco Phillips, Shell, and Valero refineries in Wilmington for several days. These three refineries represent a significant percentage of Southern California's gasoline and diesel production. None of these facilities has sufficient on-site generation that would protect them from local electricity grid outages and allow continued operation of essential refinery processes. This experience points out the need for the state to move more concertedly with the industry to identify and develop refinery-based cogeneration opportunities. However, 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 hinder cogeneration expansion at California's refineries. The benefits to the grid itself would suggest the state ought to conduct electricity regulation in such a way that part of

the utilities' obligation to serve is to facilitate this type of self-generation. A more detailed discussion of cogeneration issues can be found in Chapter 4 of this report.

Recommendations

- The state should establish a committee — led by the California Energy Commission with the participation of the ARB, the State Lands Commission, Port Authorities for Long Beach and Los Angeles, Bay Conservation and Development Commission, Bay Area Air Quality Management District, and the South Coast Air Quality Management District — to prepare and submit 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.
- The state should confirm federal support to maintain safe shipping passage in San Francisco Bay.
- The state should establish a uniform decision-making process coordinating multi-agency review of infrastructure proposals and employing best practices permitting.
- The state should ensure that petroleum infrastructure permitting proceeds in a timely and environmentally sound manner.
- The state should work with the petroleum industry and other agencies to identify opportunities for additional cogeneration at refineries.

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 energy 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. While wholesale electricity prices have been relatively stable since the 2000-2001 energy crisis, those prices have gradually increased from an average of $20 per megawatt hour (MWh) in late 2001 to around $50 per MWh today.[40]

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, particularly in Southern California for the years 2005-2008 and especially in light of the expected retirement of aging power plants.

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 more than 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 perpetuates 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 2005.

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 apprehension over transmission capacity into the Los Angeles Basin. Without a modernized transmission grid, California's dependence upon

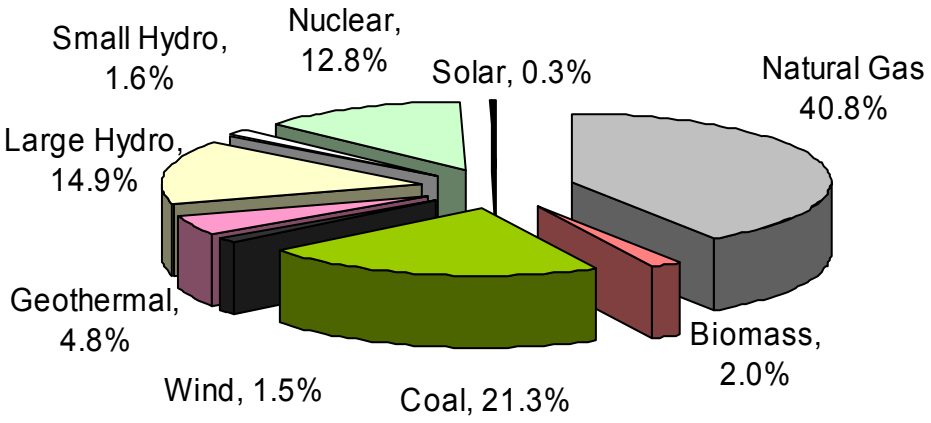
[40] *Energy Market Report,* a publication of Economic Insight, Inc. The $20 to $50 per megawatt hour is an average of NP15, SP15, COB, and Palo Verde prices.

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 41 percent in 2004, as shown in Figure 5.[41] 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.[42]

In 2003, state policy makers identified an investment loading order as a transformational effort to curb demand and overcome the inertia that perpetuates the system's reliance on natural gas. 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.[43] Governor Schwarzenegger has embraced this loading order for California and supported the specific recommendations to achieve its goals in the 2003 and 2004 *Energy Reports*.[44]

Figure 5: California's Electricity Supply, 2004



Source: California Energy Commission.

[41] California Energy Commission, Net System Power Report for 1999, 2002, and 2004.
[42] Letter from Governor Arnold Schwarzenegger to the Legislature, attachment: Review of Major *Integrated Energy Policy Report* Recommendations, August 23, 2005.
[43] California Energy Commission, CPUC and CPA *Energy Action Plan*, Spring 2003, p.4.
[44] 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.

The electricity and procurement policies recommended in this report are driven to a large extent by concerns about the need to diminish California's growing dependence on natural gas. 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. Untested thus far is the implementation of the CPUC's 2004 directive that renewables should be the "rebuttable presumption" for all IOU long-term procurement. 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 Energy Commission's 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 electricity am I being charged for and what will it cost me? In contrast, peak demand — measured in MW — is the amount of generation needed to keep electrons flowing in the system at any given moment of peak demand. Meeting peak demand is primarily an operational issue for system operators — how much will be needed to keep the lights on under worst case conditions?

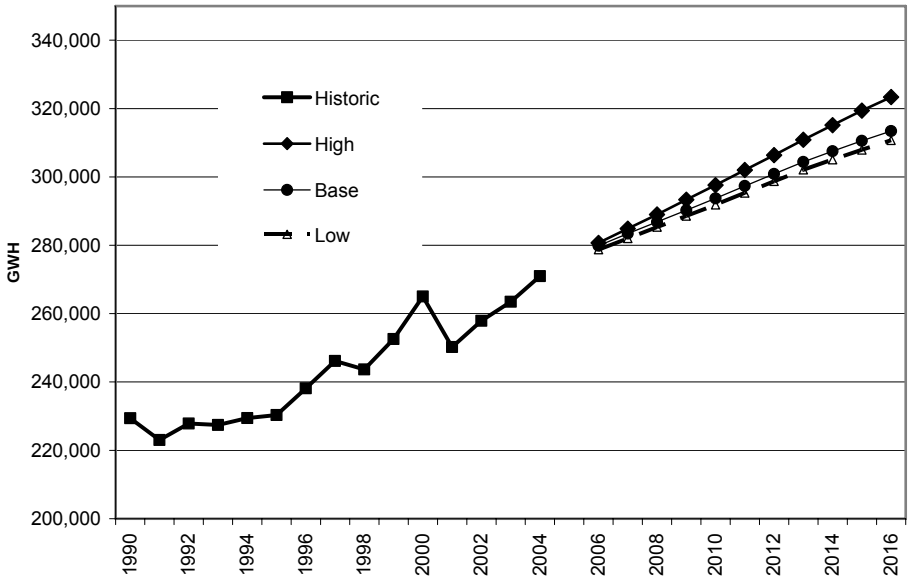
Electricity consumption in California grew from 250,241 GWh in 2001 to 270,927 GWh in 2004. The state's annual electricity consumption increased almost 3 percent over those three years, higher than forecast in the *2003 Energy Report*.[45] Over the same period, consumption increased in all areas except the industrial sector, which remained relatively flat. Residential and commercial use increased an average of 3.3 percent. Primary reasons for the increased growth include a shorter and milder recession than projected in the 2003 forecast, along with diminished voluntary consumer conservation efforts compared to those achieved during the 2000-2001 energy crisis.

As shown in Figure 6, consumption is forecast to grow between 1.2 and 1.5 percent annually, from 270,927 GWh in 2004 to between 310,716 and 323,372 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

[45] *California Energy Demand 2006-2016*, *Staff Energy Forecast, Revised September 2005*, September 2005, CEC-400-2005-034-SF-ED2, and *California Energy Demand 2003-2013 Forecast*, August 2003, 100-03-002.

forecast assumed 1.4 percent population growth. The 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 Finance (DOF).[46] The DOF projects annual population growth at 1.2 percent and is based upon lower immigration and fertility assumptions than its 1998 forecast. The highest consumption growth is forecast for the Sacramento Municipal Utility District (SMUD) control area and Southern California portions of the CA ISO control area, reflecting strong population growth in those areas. Another key driver of California's energy demand is personal income.

Figure 6: Statewide Electricity Consumption (1990-2016)

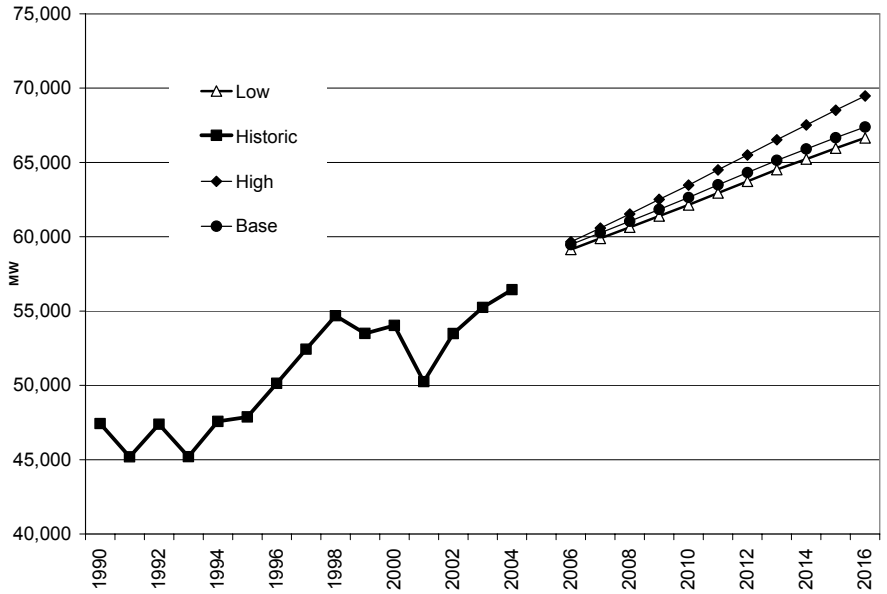


Source: California Energy Commission, *California Energy Demand 2006-2016*, *Staff Energy Forecast, Revised September 2005*, September 2005, CEC-400-2005-034-SF-ED2.

Statewide noncoincident peak demand reached 56,435 MW in 2004, up from 50,245 in 2001. Peak demand in California is forecast to grow between 1.4 and 1.75 percent, rising from 56,435 MW in 2004 to between 66,656 and 69,473 MW in 2016, as shown in Figure 7. On the peak demand side, the 2004 recorded peak was 3.3 percent higher than forecast, a difference of more than 2,000 MW, the approximate capacity of three of the state's largest fossil-fueled generators. The 2005 demand forecast uses this higher peak demand as its starting point.

[46] 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."

Figure 7: Statewide Peak Demand (1990-2016)



Source: California Energy Commission, *California Energy Demand 2006-2016*, *Staff Energy Forecast, Revised September 2005*, September 2005, CEC-400-2005-034-SF-ED2.

One of the difficulties in using long-term forecasts is that they are designed to project a *growth rate* in consumption and peak over a ten-year period. As shown in Figure 7, there is considerable variability in any given year. It can be quite misleading to simplistically apply a forecasted ten-year growth rate to predict demand in the early years of the forecast. The Energy Commission generally finds the staff's detailed end-use models more reliable in the long-term and the utilities econometric methodologies more useable in the near-term.

The Commission's forecasts project consumption and peak demand assuming average weather conditions. Because weather is unpredictable, the actual consumption and peak will almost always vary from the forecasted projection. To account for this, the Commission develops demand forecasts under hot-weather scenarios. In any given year, there is a 10 percent chance of temperatures that will increase statewide demand by 6 percent – about 3,600 MW in 2006.

Given that California covers a large geographical area, with many diverse climates, the demand forecast is adjusted for weather based on average temperatures and the relationship between demand and temperature within each planning area. Northern California usually has its hottest temperatures in July and August while Southern California's occur in late August and September.[47] 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.

[47] 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.

Depending on the temperature patterns across the state, the statewide or CA ISO coincident annual peak demand has been between 1 and 5 percent lower than the sum of the individual planning area peaks.

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 of the state's electric industry, unclassified sales — sales not identified by economic sector — have become the fastest-growing consumption category. For forecasting purposes, these sales must be allocated to one of the various sectors, and improper allocation can cause forecasting errors. For example, because commercial and industrial customers have very different load shapes, assigning their 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, with the state's utilities, must continue its 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, including trends in commercial energy use and residential demographics and the currency of data. Staff forecasts decreasing commercial electricity use per square foot, reflecting the effects of building and appliance standards, which most participants thought unlikely when the standards were adopted. In the residential sector, utility forecasts generally assumed more growth in income and the number of households than the staff forecast, but smaller household size.

In response to these factors, the *Energy Report* Committee directed staff to vary these key assumptions to develop a reasonable range of possible outcomes. These forecast ranges 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 CPUC.

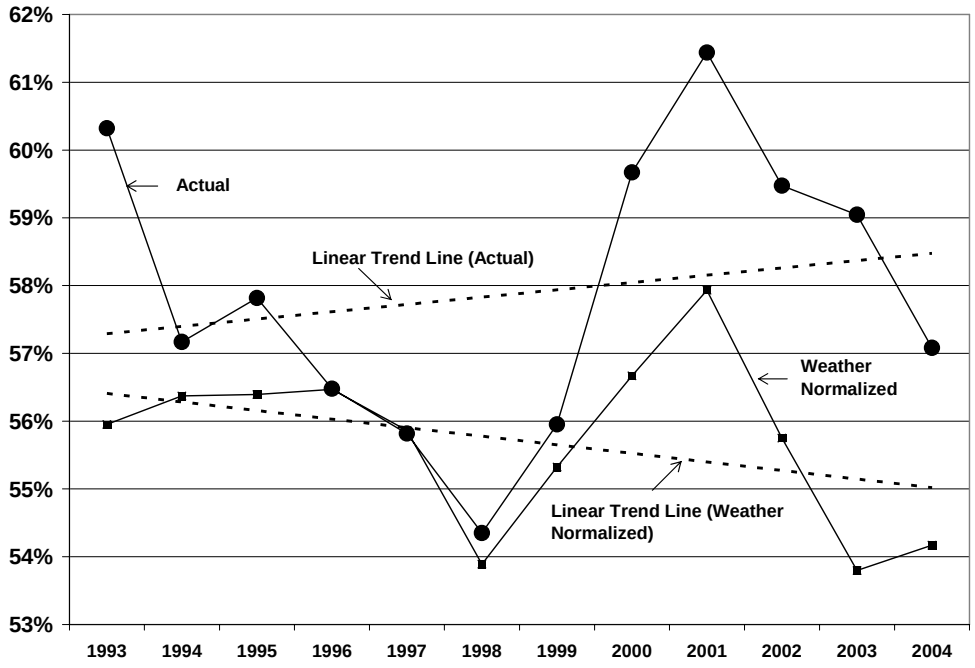
Another issue was the treatment of energy efficiency savings from IOU programs planned for later than 2008. The three IOUs included these impacts in their electricity demand forecasts. The revised staff forecasts do not include them because the significance of their impacts is dependent upon future CPUC decisions that could 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, driven by high air conditioning loads. The generation system must be able to accommodate these high summer peaks, in addition to the 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 and annual consumption, in MWh. If peak demand grows faster than annual average consumption, the load factor decreases. As shown in Figure 8, weather-adjusted load factors in recent years have decreased as air conditioner loads have increased.

Figure 8: Statewide Annual Weather-Adjusted Load Factors
(Based on sum of hourly load data for PG&E, SCE, SDG&E, SMUD and LADWP)*

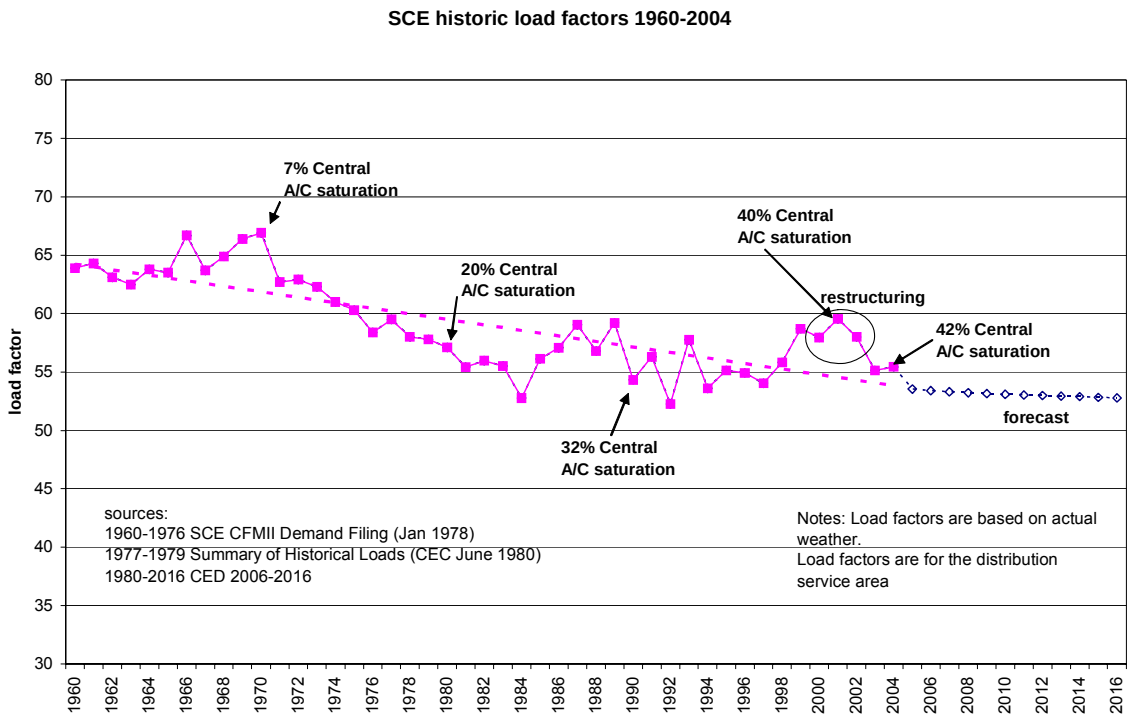


Source: California Energy Commission.
* Pacific Gas and Electric, Southern California Edison, San Diego Gas and Electric, the Sacramento Municipal Utility District, and the Los Angeles Department of Water and Power.

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 power plants. While some utilities have invested in simple-cycle peaking plants that run just a few hours each year, most of the state's new power plants are combined-cycle and are not well matched with swings in system demand. California must quickly and thoughtfully craft solutions for meeting this increasingly "peaky" demand.

SCE service area load factor has declined more rapidly than that of Pacific Gas and Electric (PG&E) over the past 34 years, as shown in Figure 9. SCE's current load factor is near 55, while PG&E's is just below 60. With increasing growth in residential and commercial construction in the Central Valley, it is possible that PG&Es future load factors may decline at a rate closer to SCE's.

Figure 9: SCE Historic Load Factors 1960-2004



Source: California Energy Commission.

Electricity Supply

Though the Energy Commission has certified and approved the construction of 22,386 MW of capacity since restructuring was implemented in 1998, only 13,805 MW have actually come online. [48] Meanwhile, statewide electric loads have increased an average 2 percent per year over the last two years.[49] 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 power purchase agreements needed to secure their financing.

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

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

remainder are under construction. A total of 225 MW of wind capacity has also been added since 2003.

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

Year	New MW online[a]	New Power Plant Applications (MW)	Number of Plants
1995	266.5	0	0
1996	240	0	0
1997	329	1,370	2
1998	0	3,151	5
1999	0	5,470	9[c]
2000	0	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	2,834[b]	2,060	5
2006	1,765[b]	No estimate	No estimate
2007	160[b]	No estimate	No estimate
2008	1,605[b]	No estimate	No estimate

[a] California Energy Commission, 2005 Database of Power Plants.
[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.

In addition, badly 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 that these plants were shut down and 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 urgently 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 still 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 the increasing demand fueled by rapid population growth in the area. Two natural gas-fired 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.[50] These plants are scheduled to be online in 2006 and 2008, respectively.

By June 1, 2006, the CPUC will require the state's IOUs to 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.[51] 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 that 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:

- Deliverability of Generation to Aggregate Load.
- Deliverability of Imports.
- Deliverability to Load (Local Area Capacity)[52] (The CA ISO has determined 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 needed resources to meet increased load, and offset capacity losses from potential aging power plant retirements, especially in Southern California. A key element of this challenge is relieving transmission bottlenecks, which would create a more resilient electricity grid.

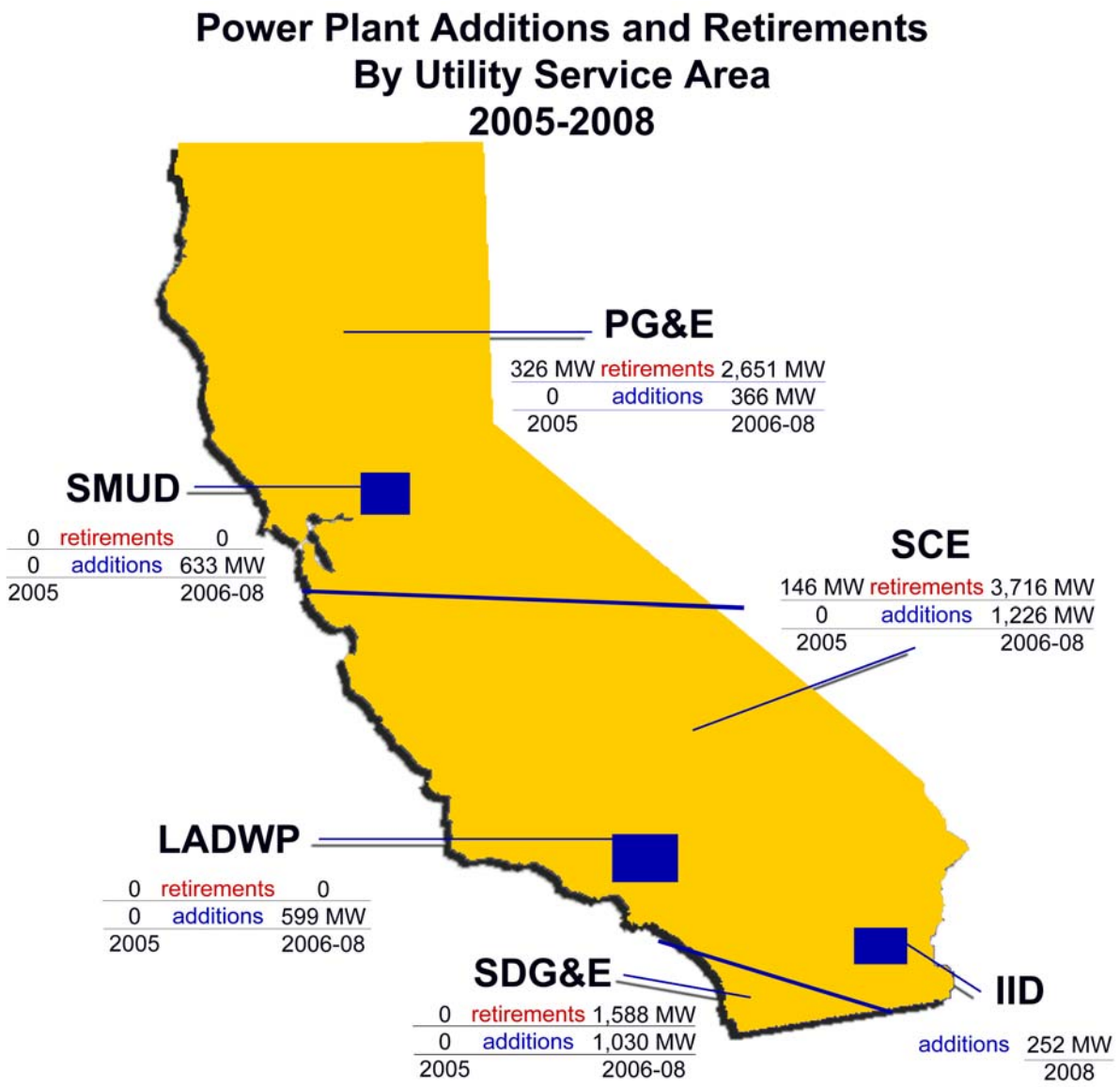
California will continue to rely heavily upon imported electricity from both the Southwest and the Pacific Northwest. Surplus electricity from the Southwest has been California's main source of imported power in recent years, but that region's explosive growth could reduce the availability of future surpluses. The Northwest will continue to have a large surplus of electric capacity available for export to both 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.

By 2016, California's utilities will need to procure approximately 24,000 MW of peak resources to replace expiring contracts and retiring power plants, and meet peak

[50] California Energy Commission, *2005 Database of California Power Plants*.
[51] 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.
[52] CA ISO presentations on deliverability, June 29, 2005, [http://www.caiso.com/docs/2005/06/28/2005062816522619093.pdf], accessed November 4, 2005.

demand growth.[53] This MW total would serve retail loads, maintain a 15-17 percent reserve margin, and satisfy firm sales requirements.

Figure 10



Approximately 11,000 MW of Department of Water Resources (DWR) contracts will expire between 2009 and 2011, with another 9,000 MW of other contracts expected to

[53] California Energy Commission, *Staff Draft Statewide Electricity Report*, July 2005.

expire by 2016. During this period, load is expected to grow by about 4,000 MW. The expiring contracts represent a range of old and new power plants, not all of which are unit specific. To the extent that utilities replace these contracts with long-term commitments to modern, clean, and efficient projects, including renewables, efficiency, and demand response, the next 10 years present a major opportunity for the state to modernize and transform its electric generation supply mix.

Although some parties in the *Energy Report* proceeding have advocated that getting the market design right is an essential prerequisite for securing long-term investment in new power plants and transmission lines, the Energy Commission remains sharply focused on the adequacy of the state's infrastructure. While market design is unquestionably important, the Energy Commission remains convinced that a robust infrastructure can better support a less-than-perfect market design than the reverse. The Energy Commission believes that requiring the state's utilities to engage in long-term procurement now is the highest priority for California to ensure an affordable, reliable, safe and environmentally sound electricity system.

Long-Term Statewide Need for Electricity Resources

The Energy Commission has estimated the need for the state's load serving entities (LSEs) to procure new resources, based on the staff's revised electricity forecast and resource plan information filed by load-serving entities in early 2005. The demand forecast includes a base forecast and high and low cases for both annual energy and peak demand. The supply information provided by LSEs includes data both on the energy and capacity of the physical resources they own or control and their existing contractual resources. The total statewide requirements shown in Figures 11 and 12[54] are based on the range of demand in the three cases of the revised staff forecast and the resource estimates provided by LSEs.

In Figure 11, the total energy demand includes LSE-reported "firm sales obligations," along with an incremental amount equal to the average generation for the years 2002 through 2006 from the state's 66 aging power plants listed in Appendix A. The Energy Commission recommends retirement of these plants by 2012. This total demand is compared with the existing physical and contractual resources currently held by the LSEs. The figure also shows estimates of the amount of preferred resources defined in the state's loading order. These include renewable resources identified by PG&E, SCE, San Diego Gas and Electric (SDG&E) and SMUD to meet their accelerated renewable generation targets, which will ultimately result in 33 percent or more renewables by 2020, and the uncommitted energy efficiency amounts needed to meet existing targets. The Energy Commission also recommends additional emphasis on distributed

[54] Figures 11 and 12 to be developed before adoption of the 2005 Energy Report based on input from the November 4, 2005 IEPR Committee Hearing on the *2005 Committee Draft Transmittal of 2005 Energy Report Range of Need and Policy Recommendations to the California Public Utilities Commission* and subsequent input from parties.

generation and combined heat and power (CHP) resources though this amount is not included in this graph since no specific annual goals have been set.

Figure 11: Statewide Annual Energy Range of Need

PLACEHOLDER

Figure 12: Statewide Annual Capacity Range of Need

PLACEHOLDER

Resource Adequacy Requirements

In 2005, the CPUC adopted a broad framework for resource adequacy requiring retail sellers, including IOUs and electric service providers (ESPs), to meet year-round planning reserves.[55] Under this framework, every retail electricity seller must demonstrate that it has acquired sufficient resources to meet its expected peak load plus a 15-17 percent planning reserve.[56]

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

The comments received in the resource adequacy proceeding cover a wide range of perspectives and reveal the conflicting goals of different stakeholders trying to shape the details of permanent resource adequacy requirements. In general, generators seek long-term contracts that provide the necessary revenue to cover their going-forward fixed costs. Retail sellers prefer a future capacity market that allows customers to shop around, with minimal financial consequences to the retail seller when they leave. The CA ISO's primary concern is that local area reliability needs are met under a large range of contingencies. Not all of these objectives can be simultaneously satisfied in this first version of resource adequacy requirements. To meet the June 2006 schedule and address near-term reliability concerns, an interim version must be adopted and implemented, then modified through time to improve its performance.

[55] The resource adequacy requirement will be phased in starting in 2006 with full compliance by 2008.
[56] 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 AB 117.

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

A critical element of resource procurement and resource adequacy is the juxtaposition of the deliverability requirements being developed by the CPUC with the CA ISO's new transmission planning process.

The CPUC and the Energy Commission are making good progress in establishing one-year obligations for resource adequacy. CPUC D.05-10-042, adopted on October 27, 2005, provides clarification of these requirements and the roles of the three regulatory agencies collectively charged with its oversight and compliance.[57] The capacity orientation and product language adopted in D.05-10-042 are foundational milestones on the road to creating a commercially tradeable capacity market that provides flexibility in meeting resource adequacy requirements consistent with previous *Energy Report* recommendations. As clearly shown in the numerous and diverse comments in the CPUC Staff *Capacity Markets White Paper*, California is still a long way from creating a formalized capacity market. Although efforts so far are useful for assigning a value to existing capacity and separating capacity-oriented resources from energy-oriented resources, the current one-year forward time horizon is not likely to financially induce construction of much-needed new power plants. The Energy Commission is continuing to actively support efforts to create a capacity market in California.

In previous *Energy Reports*, the Energy Commission recommended that the Legislature establish comparable resource adequacy requirements for all retail sellers in the state, including publicly owned utilities (POUs). POUs are an integral part of the state's electricity grid and should therefore provide sufficient resources and reserves both to meet their own loads and contribute to statewide needs during system emergencies.[58] Governor Schwarzenegger's recent response to the 2003 and 2004 *Energy Reports* endorsed the Energy Commission's recommendation to establish resource adequacy requirements for all retail sellers in California. In September 2005 the Legislature passed and the Governor signed AB 380, which directs POUs to prudently plan for and procure adequate resources to meet their respective planning reserve margins. It also requires POUs to provide information necessary for the Energy Commission to evaluate and report progress made by POUs to ensure resource adequacy in future *Energy Reports*. AB 380 does not, however, legally require POUs to make forward commitments or to make their resources available to the control area operator. The Energy Commission should evaluate POU progress in the next *Energy Report* cycle

[57] CPUC, "Opinion on Resource Adequacy Requirements," October 27, 2005, [http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/50731.htm], accessed November 6, 2005.
[58] A review of publicly owned utilities with peak loads greater than 200 MW during this *Energy Report* proceeding discovered that some publicly owned utilities have insufficient resources to cover both their peak loads plus a 15-17 percent planning reserve margin.

and, if sufficient progress is not achieved, work with the Legislature to establish mandatory resource adequacy requirements.

Recommendations for Resource Adequacy:

- The Energy Commission should continue to work with the CPUC and CA ISO to flesh out details and accounting conventions for the CPUC's adopted resource adequacy framework.
- The Energy Commission should evaluate POU progress in ensuring resource adequacy in the next Energy Report cycle and, if progress is insufficient, work with the Legislature to establish mandatory resource adequacy requirements.
- The CPUC should continue its efforts to develop a capacity market to provide flexibility in meeting resource adequacy requirements.

IOU Resource Procurement

In 2004 and 2005 the CPUC approved both IOU long-term procurement plans and a framework requiring LSEs to maintain year-round reserve margins of between 15 and 17 percent.[59]

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

- 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.
- 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 its 2003 grid reliability request for offers.
- 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 energy crisis.

In addition to the resources mentioned above, the state's three IOUs have signed about 80 contracts to date for power deliveries beginning in 2004 or later. Of these contracts, about 50 have terms of one to three years. Ten have terms of 3-5 years, and 20 are for 5 years or longer. The contracts' combined total capacity is about 9,000 MW for the 1-3

[59] The resource adequacy requirement will be phased in beginning in 2006, with full compliance by 2008.

year contracts, about 1,500 MW for the 3-5 year contracts, and about 2,000 MW for the 5-plus year contracts.[60]

Over the last year, the Energy Commission and the CPUC have worked hard, through a number of rulings and orders, to better integrate the *2005 Energy Report* proceeding with the CPUC's upcoming 2006 IOU procurement proceeding. The two agencies have established the *Energy Report* process as the primary forum for determining load forecasting, resource assessment, and scenario issues connected with the CPUC's upcoming 2006 procurement proceeding. The rulings and orders require the Energy Commission to prepare a transmittal report, a 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, the Energy Commission in 2004 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 respective forecasted electricity peak demand and energy requirements, and provide detailed explanations of 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, how utilities plan to meet the RPS goal of 20 percent renewable generation by 2010, and assumed a 15-17 percent planning reserve margin. While these resource plans generally reflect the state's loading order resource preferences and targets, they do not specifically reveal the resources IOUs will actually procure. This will depend upon which projects are bid into all-source solicitations and how well they meet IOU least-cost, best-fit selection criteria.

The *2005 Transmittal Report* to the CPUC provides a detailed basis of the Energy Commission's recommendations to the CPUC on the range of need and procurement policies that IOUs need to address in the CPUC's 2006 long-term procurement proceeding. The Energy Commission will 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 seeking to prevent the Energy Commission from releasing bundled

[60] These results include contracts from both Request for Offers and bilateral agreements.

customer annual peak demand data,[61] followed by a second lawsuit by all three IOUs attempting to block public release of similar supply data.

For the last several years, the CPUC's resource planning process has been shrouded in a high degree of secrecy, with only a handful of individuals allowed to review and critique data submitted by IOUs. While some non-market participants in the CPUC's resource procurement proceeding are allowed to review the data through signed non-disclosure agreements and protective orders, most other parties do not have access to this important data. As a result, open public debate about the data, assumptions, and alternatives that form the foundation 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.[62]

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

In the case of RPS procurement, for example, Energy Commissioners will ultimately make decisions about the expenditure of supplemental energy payments — awards of public funds — to renewable project developers. Under current confidentiality constraints, Commissioners are unable 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. In this secretive environment, it is difficult for Commissioners to effectively ensure that public funds actually contribute to the state's RPS goals or constitute an appropriate expenditure of the state's limited subsidy funds for renewable resource development.

For purposes of resource planning in the *2005 Energy Report* proceeding, reliance upon information that is not publicly available compromises the Energy Commission's accountability to the public, the Legislature, and the Governor. Being unable to openly discuss the information forming the basis of its resource planning decisions damages the Energy Commission's ability to be responsive to Californians who have the right to fully understand those decisions.

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[61] Bundled customers are customers for which a utility provides both electricity and electricity distribution services, as opposed to customers that use utility distribution service but buy their electricity from another retail seller.

[62] 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.

The Energy Commission investigated the information sharing practices of other western utilities as part of its regulatory process to ensure the release of, at minimum, aggregated summaries of this critical information.[63] All of the major western IOUs publicize much of the demand forecast and resource plan information that California IOUs seek to conceal from the public. Many of these utilities also publish these results at a much more disaggregated level.

California IOUs claim that unique conditions in California justify their need to withhold planning information from the public they serve. The Energy Commission investigated this claim and found it to be groundless. Using several measures — the percentage of bilateral contracts to total resources voluntarily entered into, the percentage of hydroelectric generation resources of total resources, and the possibility of load loss from competing suppliers — the Energy Commission found no meaningful correlation between these measures and the utility information disclosure policies of western utilities.[64]

The measures listed above illustrate the uncertainties that affect IOU exposure to the short-term and contract purchase markets. The first measure evaluates the dependence of IOUs upon intermediate-term market purchases. The second measure evaluates sudden changes that could potentially occur if hydroelectric generation is greater or less than average. The third measures the possibility that load could disappear and leave IOUs with an excess resources that would then 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 those in other western utilities is unfounded.

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 that is fundamentally responsive to the public it serves. Even greater disclosure is warranted for California IOUs because of their dominant 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 serves. It is broadly worded in favor of open access, and its exceptions are very narrowly defined.

In its public comments, the League of Women Voters identified confidentiality as an issue that "may be the most critical one that our state needs to address if there is to be any rationality in a comprehensive integrated planning process."[65] The League further noted that IOU claims of confidentiality include all information associated with the application of least-cost, best-fit criteria in the selection of bids and on details of

[63] California Energy Commission Docket 04-IEP-1, Direct Testimony of Michael R. Jaske, July 8, 2005, pp. 4-6 and Table 2.
[64] California Energy Commission Docket 04-IEP-1, Rebuttal Testimony of California Energy Commission Staff, August 12, 2005, Attachment C.
[65] Testimony of Jane Turnbull, League of Women Voters of California, Transcript of the October 7, 2005 IEPR Hearing on Electricity Needs and Procurement Policies, p. 111.

contracts. Without that available information, the League concluded that "the public cannot have confidence in the decision process." The League expressed its respect for the confidentiality of proprietary information, but added that they do not support "failing to disclose information that is to be used in defining resource planning decisions, if that information is directly relevant to the public good."

Some public interest groups don't recognize the impact the PRG process has had on resource planning transparency. For example, TURN points out in its comments on the RPS that the "program takes many complicated decision processes and makes them transparent by subjecting the evaluation methodologies used by the IOUs to public review and CPUC approval." [66] However, TURN's comments fail to note that only very general and opaque descriptions of least-cost, best-fit criteria and their application have been made public. No party, other than members of the PRGs, has any real understanding of how the principle of least-cost, best-fit is being used to shape the state's resource procurement. TURN does, however, identify what the Energy Commission believes is one of the primary downsides of inadequate public disclosure: "that IOUs would simply invent their methodologies, their own contract terms, and their own preferred solicitation protocols. Leaving it to the utilities to unilaterally decide these elements could have perverse results and undermine the goal of ensuring fair, transparent, and open competition…"[67]

TURN's comments about all source procurement deepen the Energy Commission's apprehension about the PRG process. At a time when the CPUC has placed considerable emphasis on requiring that renewables be the "rebuttable presumption" for all IOU procurement, TURN, a primary participant in and defender of the PRGs, has come to a different conclusion: "Based on experience reviewing recent all source RFOs, TURN believes that these solicitation are not likely to be effective vehicles for the selection of renewable resources. The metrics for comparing gas-fired resources with renewables are tricky, and the two sets of resources serve different purposes in IOU portfolios. Some of the benefits of fossil units (ramping, load following, ancillary services) are not available from renewables."[68]

Tricky or not, the Energy Commission believes these metrics deserve vigorous public debate and that the process would be better informed were it accessible to a full range of stakeholders, including the press, and not limited to IOUs and "non-market participants." These are fundamental aspects of public policy, better served by an open and transparent process rather than by a small elite, no matter how well-motivated.

The Energy Commission is committed to rigorous public scrutiny of data and planning assumptions and believes that responsible and effective resource planning cannot exclude the public. The 2005 *Energy Report* has elected to rely exclusively upon

[66] Comments of The Utility Reform Network on the Draft Committee Report, Docket No. 04-IEP-1, October 14, 2005, p.13.
[67] ibid
[68] Comments of the Utility Reform Network on the Draft Committee Report, Docket No. 04-IEP-1, October 14, 2005, p. 15.

publicly disclosed information for the basis of its assessments, findings, and policy recommendations. The Energy Commission believes that resource planning and procurement in California should be open and transparent to the public it serves.

The CPUC, through its rulemaking process, is reviewing its regulations governing the disclosure of records and the Energy Commission will work closely and cooperatively with the CPUC to remove additional barriers to transparency, as called for in the *Energy Action Plan II*. The Energy Commission has also initiated a rulemaking to review its data regulations for the next *Energy Report* cycle to ensure more open and transparent resource planning. Environmental Defense, the Natural Resources Defense Council, and the Union of Concerned Scientists jointly submitted comments early in the 2005 Energy Report process describing informational deficiencies in the 2004 IOU long-term procurement plans filed with the CPUC.[69] They recommended a robust assessment of alternative future supply portfolios for all LSEs using scenario analysis. Such a review would focus on portfolio cost, risk and emissions. Inadequate publicly available information, and the opaqueness of utility least-cost, best fit methodology in particular, severely curtailed the quality of scenario analysis performed in the 2005 Energy Report Cycle.[70] The Energy Commission is committed to correcting this deficiency in the next Energy Report cycle, and strongly believes that a rigorous portfolio analysis is a necessary cornerstone to integrated resource planning.

To ensure additional progress in creating an open and public review of resource planning and procurement, the Energy Commission makes the following recommendations:

- Beginning with the 2006 procurement proceeding, the CPUC should allow more public scrutiny and debate on utility resource solicitations, the application of least-cost, best-fit criteria for selecting resources, and utility choices for meeting long-term resource needs. In addition, the CPUC should discontinue its use of procurement review groups.
- The Energy Commission should ensure that portfolio analysis of future resource fuel types is a primary focus of the next *Energy Report* cycle and make the necessary changes in its Common Forecasting Methodology regulations to ensure appropriate information is collected from LSEs. Details of the evaluation methodologies used, as well as the analytical results, should be the subjects of public workshops or hearings.

[69] Comments of Environmental Defense, Natural Resource Defense Council, and Union of Concerned Scientists, filed in Docket 04-IEP-01-D, December 22, 2004.
[70] Comments of the Natural Resources Defense Council on the *2005 Integrated Energy Policy Report* Draft Committee Report, October 14, 2005, pp. 12-13, and the Union of Concerned Scientists, Docket No. 04-IEP-1,October 14, 2005, pp. 5-6..

Resource Procurement Policies

The CPUC established general capacity amounts and types of contracts to guide IOU resource procurement in its December 2004 procurement decision.[71] 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 would 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 their RPS targets.

While the CPUC did not prohibit IOUs from entering into long-term contracts, utilities have shown little interest in doing so. The CPUC raised 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 online within this timeframe, construction needs to begin in the very near future.[72]

The Energy Commission believes the the time has come when long-term procurement must aggressively move forward. California should not continue to rely primarily upon short- and mid-term contracts for the majority of its future electricity needs. While PG&E and SCE have each initiated requests for offers (RFO) on the street to procure 10-year contracts (SCE subsequently cancelled its solicitations), some parties claim that utilities have been unnecessarily restrictive in the kinds of resources they are specifying in their RFOs. The CPUC's directive that renewables are the "rebuttable presumption" in all long-term procurement raises the stakes for the solicitation process. California needs to move forward with a system of open, competitive procurement that allows all resources to compete with one another on a level playing field.

Uncertainty from Departing Loads

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

The CPUC acknowledged that while limiting procurement choices to short-term options could reduce the risk of stranded costs, it could also lead to rejection of longer-term

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

contracts, especially in the renewables area that could then result in non-optimal resource portfolios and ultimately higher costs for all customers.[73] To address these concerns, the CPUC recommended a policy allowing IOUs to recover their stranded costs that included both exit fees and other non-bypassable surcharges.[74] The CPUC determined this would require departing load to assume its 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 providing "the need for reasonable certainty for rate recovery" and ensuring that California meets its energy demand.[75] The Energy Commission believes that the CPUC policy of establishing exit fees is sufficient to eliminate the lion's share of IOU uncertainty about departing load, and is troubled that IOUs are using these concerns over departing load to avoid securing the significant long-term procurement California needs to meet California's growing electricity demand.

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 remaining uncertainties about future IOU loads. The CPUC's Office of Ratepayer Advocates (ORA), SCE, PG&E, SDG&E, and TURN generally agreed that there is more uncertainty about re-entry rights than there is about the departure of loads to other retail sellers.[76] Since utilities are the providers of last resort, the conditions under which departing load could return to IOU service were seen as the most critical element of these rules.

The ORA stated its preference for reentry is that once customers leave their utility, they should not be allowed to return. However, ORA did say it was open to solutions being explored in other parts of the country to develop capacity markets and ISO back-stop strategies.[77] 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 this is not what their customers want.[78] SDG&E called for reasonable switching rules to address departing load uncertainty.[79] TURN expressed concerns about the ability to enforce such a rule in a situation where the IOU is the only entity able to serve the load.[80]

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[73] CPUC Decision 04-12-048, December 16, 2004, p. 51.
[74] CPUC Decision 04-12-048, December 16, 2004, pp. 52 and 185.
[75] Ibid.
[76] Transcript from the *Energy Report* Committee workshops on June 29, 2005 on IOU Resource Plan Summary and July 7, 2005 on Electricity Policy Issues.
[77] Testimony of Scott Cauchois, Office of Ratepayer Advocates, Transcript of the June 29, 2005 IEPR Committee workshop on the IOU Resource Plan Summary, pp. 116-128.
[78] Testimony of Stuart Hemphill, Southern California Edison, Transcript of the June 29, 2005 IEPR Committee workshop on the IOU Resource Plan Summary, pp. 20-30, and testimony of Harold LaFlash, Pacific Gas and Electric, pp. 11-20.
[79] Testimony of Robert Anderson, San Diego Gas and Electric, Transcript of the June 29, 2005 IEPR Committee workshop on the IOU Resource Plan Summary, p. 31-37.
[80] Testimony of Kevin Woodruff, The Utility Reform Network, Transcript of the June 29, 2005 IEPR Committee workshop on the IOU Resource Plan Summary, pp. 89-104.

Because the remaining uncertainty about departing load, especially return rights, is inhibiting investment in new generation, the Energy Commission makes the following recommendation:

- The CPUC should 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 recent solicitations. Since California faces both increasing electricity demand growth and an urgent need to modernize its generation fleet, it is critical that there are enough long-term commitments to bring new generation online and repower existing aging power plants. This is necessary to both 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 2000-2001 energy 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 applicable only to non-fuel aspects of the contracts. All that was truly locked-in was a reliance on outdated, inefficient generating technology and its chilling effect on new construction because of 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 make up 70 percent of the life cycle costs of a new combined-cycle power plant.[81] 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 longer than two years, the risk of gas price fluctuation is unavoidably absorbed by electricity ratepayers. Despite locking-in only 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 technologies 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 cost 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 with

[81] 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 is expressed here in year 2000 dollars, as it was reported in the *2003 Natural Gas Market Assessment* (August 2003, CEC-100-03-006).

$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.

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 RPS 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 IOUs.

Perversely, maintaining so many older plants on life support at low capacity factors has prevented construction of more efficient plants that would operate at higher capacities. Virtually all of the state's aging power plants operate at high heat rate capacities that would typically not be dispatched enough in the open market to cover their fixed costs and justify their 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 of about 10,550 Btu per kWh in 2003.[82] This compares with a 7,000 Btu per kWh heat rate for a modern combined-cycle power plant operating at a high capacity factor.[83] The lower the heat rate, the less natural gas burned, ultimately resulting in lower-cost electricity.

For the *2004 Energy Report Update,* the Energy Commission identified a group of older power plants for study of the current and anticipated roles of aging plants and their impacts on the state's resources.[84] This study used criteria based on a combination of several attributes including age, size, capacity factor, efficiency, and environmental considerations to produce the list of aging power plants in Appendix A. This group of 66 aging gas-fired power plants represents large plants with relatively high heat rates (low efficiencies) and high operation (capacity factors).[85] The Energy Commission strongly recommends development of an IOU procurement policy that would cover IOU net short positions as well as the retirement or replacement cost of this group of aging power plants.

While it is undoubtedly true that operation of some of these aging plants is critical to meet local reliability, the state would be better off repowering the plants that are locationally critical to the state's electricity system. Currently, these plants have RMR contracts, which are expensive mechanisms for ensuring system reliability. Utilities, the CPUC, and the FERC all agree that California should rapidly reduce its dependence upon these expensive contracts. The persistent dependence on RMR contracts more

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[82] *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.
[83] In 2003, new combined-cycle plants were operating at low capacity factors, around 21-22 percent, with lower than 7,000 Btu per kWh.
[84] *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.
[85] The study group included only natural gas-fired power plants of 10 MW or greater built before 1980. Peaking plants were excluded, as were plants known to be scheduled for retirement in the near term. Of the resulting 66 power plants, 16 are owned by publicly owned utilities.

than seven years after implementation of the state's restructuring law is an unfortunate indictment of California's regulatory effectiveness.

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

From the IOU perspective, as long as their resource adequacy requirements are met with a combination of RMR contracts and short-term contracts with aging power plants, IOU near-term costs are characterized as "reasonable" in the regulatory sense. However, it is not clear that anyone is adequately considering the cumulative long-term economic impact on ratepayers; the reliability risk from continued dependence upon older, less reliable plants; or increasing natural gas price exposure from perennial short-term contracts.

Future gas prices are highly uncertain and pose significant risks for 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.[86] When utilities are allowed to simply pass fuel costs through to ratepayers, as is the case today, they are likely to place less value on considering fuel price risk in their planning. This long-term risk exposure for ratepayers must be more effectively addressed in IOU long-term planning and procurement practices.

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

The Energy Commission recommends the following to ensure long-term contracts are signed that provide adequate electricity supplies for IOUs:

- The CPUC should require that IOUs procure enough capacity from long-term contracts to both meet their net short positions and allow for the orderly retirement or repowering of aging plants, by 2012.

[86] *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.

Portfolio Performance and Least-Cost, Best-Fit Criteria

In its December 2004 resource procurement decision,[87] the CPUC established its intended reliance upon a portfolio approach to balance adequate resources and procurement 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."[88] The CPUC found that a mixed portfolio of varying contract terms and lengths could prevent utilities from over-subscribing to long-term contracts that could crowd out future opportunities.[89]

IOUs currently use least-cost, best-fit criteria to select 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 and 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.[90]

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

> 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.[91]

Production cost simulations and benefit/cost ratios are extremely complex and involve literally hundreds of assumptions that are speculative and require judgment. Many parties have legitimate differences of opinion about the most appropriate assumptions to 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 claim.

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[87] CPUC Decision 04-12-048, December 16, 2004, p. 28.
[88] CPUC Decision 04-12-048, December 16, 2004 pp. 39 and 181.
[89] CPUC Decision 04-12-048, December 16, 2004, p. 180.
[90] 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, no one outside the procurement review group could tell 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 were disclosed within the group.
[91] Southern California Edison, 2005 Request for Proposals from Eligible Renewable Energy Resource Suppliers for Electric Energy: *Procurement Protocol.*

Developing a portfolio mix that economically meets baseload, intermediate, and peaking resource needs of utility load is the primary focus of the least-cost, best-fit criteria IOUs use for their resource procurement. The Energy Commission's review of this evaluation criteria indicated that there are significant limitations in market value and portfolio fit criteria currently being used by utilities.[92] The market valuation considers the present value of an asset compared with a market price assumption, while portfolio fit tries to compare an asset with its "short" or "long" positions. While these comparisons have value when evaluating a single asset, they are less valid when examining a larger portfolio since the portfolio then changes market price assumptions.

The state's energy objectives are broader than the IOU definition of least-cost, best-fit: they also include improving the security of a cost-effective supply under a range of uncertain but reasonably anticipated events, including:

- Major disruptions in supply or extreme volatility in the price 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 the following to address concerns about portfolio fits and least-cost, best-fit criteria:

- The CPUC, in collaboration with the Energy Commission, should pursue the additional development of portfolio approaches and risk assessment to create a more transparent and standardized method for determining what constitutes least-cost, best-fit. This would allow policy makers to better ensure that IOU resource selections reflect the state's interests in addressing future electricity risk and uncertainty.

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

- 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 provide both flexibility to control area operators when matching generators to load and reduce the number of power plants needed to meet system-wide demand. Operators would also have

[92] Presentation by Eric Toolson, Pinnacle Consulting, Transcript of the July 28, 2005 IEPR Committee Workshop on Transmission pp. 47-80, 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*.

greater flexibility to import electricity from cooler regions with generation surpluses during peak load conditions.

- 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 the state's energy decision making. The loading order decreases electricity demand by increasing both energy efficiency and demand response. It also meets new generation needs first with renewable and distributed generation resources and second 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 its foundation for recommended energy policies and decisions.

The state has outlined an aggressive strategy that combines energy efficiency and demand response programs to slow electricity demand growth. Governor Schwarzenegger recently affirmed his support for previous *Energy Report* recommendations "to ensure that efficiency maintains its preeminent place in preferred energy resource additions."[93] The Governor also recently signed legislation that requires investor-owned utility procurement plans to demonstrate that unmet resource needs will be met first with "all available energy efficiency and demand reduction resources that are cost effective, reliable, and feasible."[94] The legislation also adds a section to the Public Utilities Code placing a similar requirement on publicly owned utilities.

While California is on track to meet energy efficiency targets set 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 for reducing peak demand on the state's electricity system, have unfortunately failed to deliver energy savings targets established by state policy makers for each of the last three years. It appears that they will also fall short of next year's targets. The Governor has committed to using advanced meters and dynamic tariffs to meet demand response goals. He has also directed the CPUC to proceed promptly with plans by PG&E and SDG&E to provide meters to residential and commercial customers and recommended that SCE accelerate its planned efforts.[95]

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 RPS program is hampering the state's ability to meet its renewable targets. Additionally, neither distributed generation sources, including combined heat

[93] Letter from Governor Arnold Schwarzenegger to the Legislature, attachment: Review of Major Integrated Energy Policy Report Recommendations, August 23, 2005.
[94] SB 1037 (Kehoe), Chapter 366, Statutes of 2005.
[95] Letter from Governor Arnold Schwarzenegger to the Legislature, attachment: Review of Major Integrated Energy Policy Report Recommendations, August 23, 2005.

and power (CHP) facilities, nor renewable technologies have received the regulatory attention and encouragement necessary to meet the desires of policy makers to increase reliance on these resources. Governor Schwarzenegger has emphasized that the state should encourage distributed generation and CHP since "it can occur at load centers, reducing the need for further infrastructure additions."[96]

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 enough new generation online to meet future demand, the state must vigorously pursue preferred resources: renewables, distributed generation, and lastly conventional generation. At the same time, California's bulk transmission system must be enhanced and fortified to ensure that electricity can be delivered when and where it is most needed, as discussed in Chapter 5.

The following sections outline measures the state must urgently take to ensure achieving energy efficiency, demand response, and distributed generation goals. Renewable resource issues are addressed in Chapter 6. Collectively, these measures will help protect Californians against blackouts, ensure reliable long-term supplies, decrease the state's growing dependence on natural gas, and reduce electricity costs for both residential and business customers.

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. By decreasing peak demand, these programs also increase the reliability of the electricity system and reduce the environmental impact and cost of electricity.

California leads the nation in energy efficiency and conservation. As a result, electricity use per person in California has remained relatively flat over the past 30 years while the nation has seen a 45 percent increase. California's "energy intensity," the ratio of energy consumption to demand, is also well below that of the U.S. as a whole, as shown in Figure 13 on the following page. Through 2003, California's energy efficiency programs have saved more than 40,000 gigawatt hours (GWh) of electricity and 12,000 MW of peak demand, equivalent to more than two dozen 500 MW power plants. These programs, mainly mandatory efficiency standards, will continue to save energy in the future.

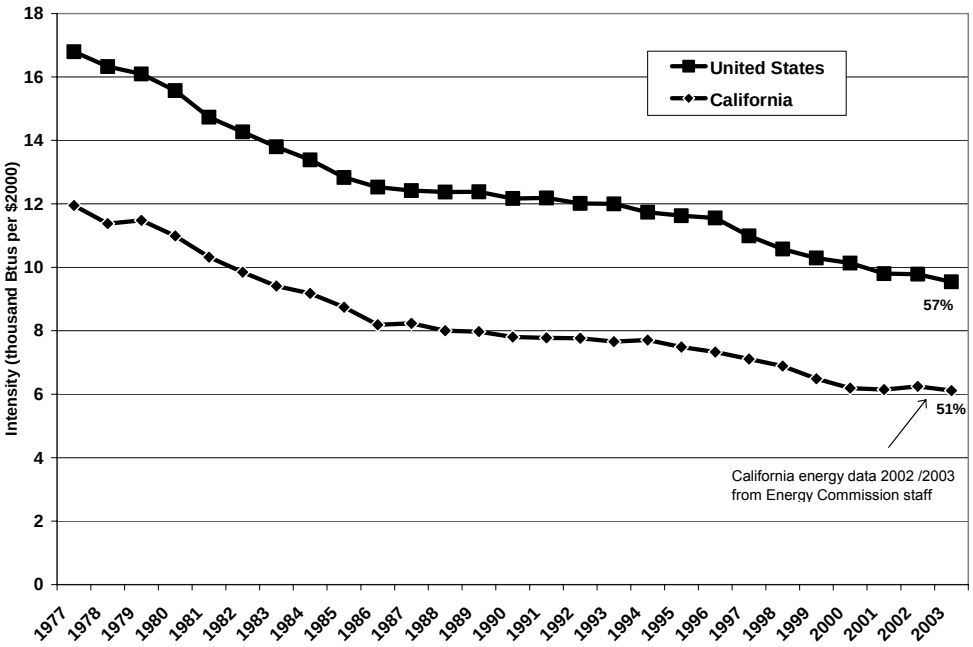
The *2003 Energy Report* concluded that 30,000 additional GWh represent the maximum achievable electricity savings from energy efficiency programs over the coming decade. The CPUC adopted aggressive energy savings goals in 2004 to reach this potential. When these goals are met, energy savings will represent more than half of IOU need for additional electricity between 2004 and 2013. To achieve these goals, the CPUC

[96] Ibid.

significantly increased IOU energy efficiency funding to $823 million for 2004-2005[97] and $1.98 billion for 2006-2008.[98]

California's building and appliance standards are the state's most cost-effective efficiency measures. Since the first round of standards was adopted in 1975, the state has saved 6,000 MW in peak demand and expects to save 10,000 MW by 2010. The Energy Commission also adopted new appliance efficiency standards in 2004 that will reduce consumer utility bills by $3.3 billion during the first 15 years they are in effect.[99] The Energy Commission will continue to evaluate energy-using technologies for incorporation into periodic updates to the state's building and appliance standards.

Figure 13: 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 and additions and alterations to existing buildings include energy efficiency in their design, there has been remarkably little regulatory attention to improving the energy efficiency of existing buildings. Although utility energy efficiency programs have generally promoted savings in existing buildings, there is still enormous potential for energy efficiency savings in existing buildings, which turn over very slowly and dominate energy consumption. The Energy Commission is developing a report to the Legislature in response to AB 549

[97] CPUC, Decision 03-12-060, issued December 22, 2003, Energy Efficiency Rulemaking 01-08-028.
[98] CPUC, Decision 05-09-043, issued September 27, 2005, Energy Efficiency Rulemaking 01-08-028.
[99] California Energy Commission, July 2005, *Implementing California's Loading Order for Electricity Resources*, CEC-400-2005-043.

(Longville), Chapter 905, Statutes of 2001, outlining options for upgrading existing buildings, including efficiency inspections when buildings are sold, and utility pilot programs like on-bill financing, building commissioning, and retro-commissioning. Close coordination with the benchmarking effort of the state's Green Buildings Initiative will improve the likelihood of 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 actually 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 administrators and program implementers to ensure that IOU intentions translate into real energy and peak demand savings. The Energy Commission and the CPUC should continue to work collaboratively to ensure the rigorous evaluation, measurement, and monitoring of energy efficiency programs. Doing so will give utility planners the accurate information they need for developing their procurement plans, while making certain that public funds are prudently spent. The recently enacted SB 1037 will add significant teeth to this process.

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

Energy efficiency program portfolios bid to non-utility third parties reflect a much-needed focus on programs that create peak demand energy savings. Energy efficiency programs must meet specific cost-effectiveness rules, which are typically measured by energy savings per dollar spent. This method can drive efficiency programs to focus on overall energy savings instead of on peak demand savings. Since California consistently experiences high peak summer demand, shaving those peaks is critical to reducing electricity price volatility, safeguarding reliability, and reducing the need for peaking power plants that operate only a few hours a year.

Residential space cooling contains the greatest potential for peak energy savings, followed by commercial space cooling and lighting.[100] The CPUC recognized that preliminary IOU efficiency portfolios were overly reliant upon high energy-using

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

measures, like lighting, at the expense of critical peak impact end uses like air conditioning. In its April 2005 Decision 05-04-051, 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."[101]

However, in its decision on 2006-2008 program funding, the CPUC rejected a proposal by The Utility Reform Network (TURN) that would have required utilities to rebalance their portfolios in favor of air conditioning savings. The CPUC reasoned that a large portion of the existing potential for these savings will be captured through efficiency increases in new residential air conditioners mandated by 2005 appliance standards, and that utility programs have already increased funding for residential air conditioning programs compared with previous years. TURN expressed concern that IOU portfolios overemphasize savings from residential lighting at the expense of savings from space cooling.

The CPUC has made some progress toward establishing an appropriate balance between energy and peak savings in energy efficiency programs. For example, the CPUC requires program administrators to demonstrate how their proposed portfolios will aggressively lower peak demand. Existing programs must also meet the standard that demand reductions equal 0.217 times the energy savings goals, based upon the historic relationship between energy and peak savings.[102] However, the Energy Commission remains concerned that IOU energy efficiency portfolios should focus more on programs that realize peak energy savings to reach the state's overall peak savings goals. This is especially critical in the near term in Southern California, where reliability margins are significantly tighter than in Northern California.

This emphasis on peak savings, however, should be balanced with another key reason for establishing energy efficiency goals: their potential contribution to global climate change targets established by Governor Schwarzenegger. Generally, getting the greatest energy savings from the program portfolio could make the single biggest contribution to reducing climate change gases from electricity generation. While much of California's electricity needs are met by natural gas-fired power plants, saving energy at different times of the day and year also affects generation from power sources of different efficiencies and fuel types. The Energy Commission should analyze the impact of energy savings during different hours on climate change goals and tailor programs to reduce both climate change gases and peak demand.

IOU energy efficiency programs have traditionally been established on an annual basis, and individual programs frequently generate a market response that ends up depleting

[101] 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, [http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/45783.htm].
[102] CPUC, September 27, 2005, Interim Opinion: Energy Efficiency Portfolio Plans and Program Funding Levels for 2006-2008 – Phase 1 Issues, [http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/49859-07.htm], accessed October 20, 2005.

the program's funds before by the end of the year. This has had two consequences. First, the state has not been able to capture the full amount of cost-effective peak demand and energy savings in that year, and utilities end up meeting their energy demand with resources lower in the loading order. Second, the businesses that provide energy efficiency services and equipment in California face the financial risk of annual boom and bust cycles. The CPUC should change this pattern by funding energy efficiency programs with enough budget flexibility to allow efficiency programs to meet market demand in a more timely fashion. In some cases, this may simply provide the ability to transfer funds within the overall target budget from one program with low demand to another program with higher demand.

Overall utility efficiency budgets should be established with a balancing account structure that accommodates the full market demand for any given program. Generation procurement flexibility — with utilities purchasing what is necessary to meet their demand — should also apply resources 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 25-30 percent of the electricity used in California, energy efficiency efforts by these entities are essential to the state's overall goal to reduce electricity demand. Although the state has adopted efficiency goals for IOUs, POUs are not required to match this level of performance. The recently enacted SB 1037 may go a long way toward changing that. The Energy Commission should work with POUs to establish goals similar to those required of IOUs by the end of 2006.

The Energy Commission needs better information about program plans and results to establish these goals. Without publicly available data, it is difficult to determine on a statewide basis how much POUs spend on efficiency or how much energy they save. The Energy Commission should create a reporting requirement as part of its Common Forecasting Methodology regulations for POUs to report the status and progress of their efficiency programs to allow transparent comparisons between IOU and POU program designs, costs, and effectiveness. This requirement is consistent with SB 1037 requirements for POUs to report annually to their customers and to the Energy Commission on their investments in energy efficiency and demand reduction programs, including descriptions of programs, expenditures, and expected and actual energy savings. This reporting requirement should not impose a cost burden on POUs but should still provide enough needed information for useful comparisons.

Recommendations for Energy Efficiency

- The Energy Commission should continue to evaluate energy-using technologies for possible incorporation in periodic updates to the state's building and appliance standards.
- The Energy Commission should develop an aggressive implementation plan for improving the energy efficiency of existing buildings as a follow up to its AB 549 report.
- The Energy Commission and the CPUC should continue to work together to ensure the rigorous evaluation, measurement, and monitoring of IOU energy efficiency programs.
- The Energy Commission should analyze the effect of energy savings on climate change goals, during different time periods, to reduce emissions of climate change gases.
- The CPUC should fund efficiency programs with enough budget flexibility to allow those programs to meet market demand in a timely way.
- Utilities should be required to procure as much cost-effective energy efficiency as the market can provide.
- The Energy Commission should create an efficiency reporting requirement for POUs as part of its Common Forecasting Methodology regulations.

Demand Response

The *2004 Energy Report Update* highlighted the importance of demand response programs to CPUC and Energy Commission goals.[103] Demand response programs reduce peak demand in two ways. First, price-sensitive programs provide customers with the financial incentives and metering technology to reduce electric loads when prices and electricity demand are high. Second, reliability programs provide customers with a non-price signal that clearly shows when system resources are strained and demand reduction would be most beneficial. Reducing system load before it reaches capacity constraints increases the reliability of California's electricity grid. By reducing the need for additional system infrastructure or peaking generation, demand response also lowers consumer electricity costs over the long term.

Price-sensitive and reliability programs are both key components of demand response. The state has historically relied on reliability programs in times of constrained supply, most recently during the summer of 2005 in Southern California. Advances in metering and communications technologies allow significant improvements to price-responsive and signal-responsive programs. It is important to recognize that new metering

[103] 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*.

technology will be the primary platform for the state's future demand response policies. Both types of programs are being designed to allow customer control – a key feature expected to increase participation by providing customers with greater choice over 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 the actual high price of electricity during periods of high demand, sending price signals to customers that will require them to either reduce energy use or pay the full cost of such service. Large customers already have advanced meters designed to take advantage of dynamic pricing rates. The state needs to establish and 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*.

The CPUC set demand reduction targets for the state's IOUs in 2003. Although the utilities did not meet their targets for 2004, they did reduce demand by 556 MW, 63 percent of the statewide target. In 2004, the CPUC ordered utilities to file applications for a new default rate with critical peak features. The proposed new rate addressed both the lack of enrollment in voluntary demand response programs by large customers and the limited customer performance 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. Instead of implementing these rates in time for summer 2005, the CPUC ordered new rate proposals for 2006 implementation.

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. IOUs will also develop customer education, assistance, and incentive plans to ease this rate transition for large customers. This effort could well 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 the Energy Commission reviewed these analyses and encouraged utilities to move forward with their applications.

PG&E and SDG&E filed plans aimed at quickly replacing their metering systems with advanced metering and communications systems capable of supporting time-based rates for all customers. In contrast, SCE simply filed a plan directed at development of a new metering infrastructure, with the replacement of its metering systems lagging

behind the other two IOUs. Governor Schwarzenegger recently urged the CPUC to require SCE to expedite its plans so that it will be on a par with the other utilities.[104]

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, simply curtail customers or appliances in response to a high-demand signal. Advanced communication technologies now permit less intrusive dispatchable demand reductions through two-way communication with customer thermostats and other equipment. Instead of completely shutting down groups of air-conditioners, managers can adjust air conditioner levels to both shape demand and allow customers greater control and choice. These new programs should be further explored and promoted as the state increases its reliance upon demand response.

POUs are also exploring advanced metering infrastructures and demand response programs. Advanced metering and demand response efforts by POUs will be essential for reaching the state's overall goal of reducing electricity demand and mitigating resource constraints and high prices. The Energy Commission should work with these POUs to better understand their demand response efforts and develop goals by the end of 2006 similar to those adopted for IOUs.

As part of this effort to develop POU goals, the Energy Commission again needs better information about these utilities' plans and results. The Energy Commission should include demand response information in the Common Forecasting Methodology reporting requirement recommended for energy efficiency programs without imposing an undue cost burden on these utilities, while still collecting the needed information to compare their performance with other demand response efforts in the state.

Advanced metering and dynamic pricing will likely be the foundation of California's future demand response programs. However, two pending efforts will affect the CPUC's ability 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 time periods. Moving to a real-time pricing approach will eliminate that cross-subsidization, resulting in higher overall electricity costs for some customers and lower costs for others.

Although demand response remains in some ways controversial, California must grapple with the state's increasing number of peak load hours to improve system reliability and moderate electricity price volatility. The Energy Commission and the CPUC need to make major efforts over the next few years to determine the best mix of voluntary and mandatory demand response programs, as well as the right mix of price-sensitive and reliability programs.

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

Recommendations for Demand Response

- The state needs to develop and implement dynamic rates for large customers.
- The state should develop an advanced metering infrastructure for all utility customers.
- By the end of 2006, the Energy Commission should work closely with POUs to better understand their demand response efforts, and develop goals similar to those required of IOUs.
- The Energy Commission should include demand response information in the Common Forecasting Methodology.

Distributed Generation and Combined Heat and Power

An important alternative to new central station fossil-fueled generation is distributed generation (DG), which includes both cogeneration and self-generation.[105] DG is broadly defined as electricity produced on-site or close to a load center that is also interconnected with a utility distribution system. California has approximately 2,500 MW of small-scale renewable and non-renewable DG and has added an average of 100 MW of new small-scale DG capacity every year since 2001.

The benefits of DG go far beyond actual generation. DG reduces the need for new transmission and distribution infrastructure and improves the efficiency of the state's electricity 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 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 totaling 9,000 MW,[106] with nearly 90 percent of this capacity from systems greater than 20 MW. CHP has significant market potential, as high as 5,400 MW, despite high natural gas prices.

California should particularly encourage CHP at the state's petroleum refineries to make them less vulnerable to power outages. An electricity outage on September 12, 2005, in Southern California caused the shutdown of three refineries in Wilmington. These

[105] This is a working definition for distributed generation used in various policy activities at the California Energy Commission and the CPUC.
[106] *Assessment of California CHP Market and Policy Options for Increased Penetration*, California Energy Commission, Publication #CEC-2005-060-D, April 2005.

shutdowns resulted in pressure buildups that forced refinery operators to flare excess gases, affecting air quality in the area. The shutdown also impacted gasoline production and supply, causing shortages and price spikes. Increased CHP use at refineries is an important strategy that can help insulate refineries from these kinds of electric grid problems and maintain gasoline production and refinery safety.

The *2003 Energy Report* highlighted the importance of DG and CHP in meeting California's growing energy needs and providing an essential element of customer choice. The *2003 Energy Report* called for the creation of a transparent distribution system planning process addressing the utility benefits 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 use of DG and CHP.

Despite policy preferences, DG and CHP in California still struggle with major barriers to market entry in the context of traditional utility cost-of-service grid management. In fact, many of the state's operating larger-scale CHP systems still run under the terms of generation contracts signed during the early 1980s following the national energy crisis of the late 1970s. These projects could shut down in the near future as their contracts expire. It is estimated as much as 2,000 MW could shut down between now and 2010 because project owners have been unable to renew their utility contracts.[107, 108]

The *2005 Energy Report* reaffirms its commitment to DG and CHP by separating the discussions of CHP and DG to provide more clarity for policy makers. As a first step, the Energy Commission funded the *Assessment of California CHP Market and Policy Options for Increased Penetration,* a study that identified a series of policy scenarios that could help focus policy direction on the effective deployment of future CHP.[109] The assessment produced a number of important findings.

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 generation delivered to the grid. CHP represents approximately 17 percent of the state's generation and is often key to preserving grid reliability. CHP systems smaller than 5 MW represent only about 3 percent of total CHP capacity in the state, though much of California's policy efforts over the past seven years have focused on these 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 over the next 15 years.

Current state policy must clearly change for California to take advantage of this valuable generation potential. It is equally important to retain the state's existing CHP that is so

[107] Public comments by Rod Aoki, representing Cogeneration Association of California and the Energy Producers and Users Coalition, IEPR Loading Order Workshop, July 25, 2005.
[108] Comments by Cogeneration Association of California and the Energy Producers and Users Coalition, Docket No. 04-IEP-1E, August 1, 2005.
[109] *Assessment of California CHP Market and Policy Options for Increased Penetration*, California Energy Commission, Publication #CEC-2005-060-D, April 2005.

critical to the current reliable operation of the electric grid. CHP developers seeking to install new generation are presently discouraged from sizing their systems to satisfy their full thermal loads because they would have to generate more electricity than they could use on site. These developers frequently have trouble finding customers interested in buying their excess power at wholesale prices. Lack of a robust, functioning wholesale market in California worsens CHP concerns about this risk.[110] Even if wholesale markets were functioning well, CHP owners would still struggle with the complexity and cost of complying with the California Independent System Operator's (CA ISO's) tariff requirements, including scheduling exports hour-by-hour, installing costly metering and reporting equipment, and other factors.

At the retail level, policy decisions (including suspension of direct access) have hampered CHP owners' ability to sell their excess power to customers. The lack of distribution wheeling tariffs and restrictions on "over the fence" transactions by Public Utilities Code Section 218 create additional barriers.[111] During the 2000-2001 energy crisis, Berry Petroleum needed additional steam for enhanced oil recovery and was willing to install additional CHP facilities to provide that steam. Berry was ultimately forced to install traditional boilers, however, because it could not secure a viable long-term contract for the excess electricity from the CHP facilities.[112] In another 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 trying to negotiate a new contract for more than two years.[113] In yet another example, Valero Refining Company has been trying to secure a contract for over a year with PG&E to sell its excess power, but has been unsuccessful because PG&E and the CA ISO are requiring Valero to execute a FERC jurisdictional interconnection agreement and pay the wholesale CA ISO tariff before selling power to the utility.[114] Equally troubling is the fact that Valero has received all necessary permits to install a second generating unit at its refinery but is reluctant to do so because of the "regulatory limbo" between the FERC and CPUC jurisdictions.[115]

Looking ahead to the future development of more workable CHP policies, California must recognize that CHP owners are not in the business of producing or selling electricity. CHP owners will choose to operate their businesses and simultaneously produce electricity only when the economics are favorable to them. CHP policy therefore must be different from the policies developed for traditional customer generators and merchant power plants. To illustrate this point, the CHP industry notes

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[110] Comments by Cogeneration Association of California and The Energy Producers and Users Coalition, Docket No. 04-IEP-01E, August 1, pp. 19-20.
[111] Comments by Kevin Duggan representing California Clean DG Coalition, Docket No. 04-IEP-1E, August 1, 2005, p. 2.
[112] Panel Discussion by Barry Lovell, Berry Petroleum Company, IEPR Combined Heat and Power Workshop, April 28, 2005 and comments filed, Docket No. 04-IEP-1E, October 11, 2005, p. 2.
[113] Comments by Cogeneration Association of California and The Energy Producers and Users Coalition, Docket No. 04-IEP-01E, August 1, p. 7.
[114] Ibid, p. 7.
[115] Panel discussion by David Dyck, Valero Energy Corporation, IEPR Combined Heat and Power Workshop, April 28, 2005.

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."[116] This may not be especially problematic since neither all merchant plants nor all IOU power purchases serve a single purpose in an IOU's generation portfolio. IOUs structure their portfolios to include resources with different terms, load shapes, and operational characteristics.[117]

Based on analyses conducted over the course of the *2005 Energy Report* and extensive input from the industry, utilities, the public, and others, the Energy Commission believes there are several key initiatives that California must pursue to encourage construction of additional cost-effective DG and CHP. CHP is of such unique value in meeting loading order efficiency and new generation objectives that CHP deserves its own place in the loading order. The Energy Commission and the CPUC should therefore separate CHP from DG in the next version of the *Energy Action Plan* so that CHP issues and strategies are not lost in broader DG issues and strategies.

The state also needs to improve access to wholesale energy markets and streamline the utilities' long-term contract processes so that CHP owners can easily and efficiently sell their excess electricity to their local utility. This would provide CHP owners with the certainty needed to guide their investment decisions to install or expand their CHP operations. By the end of 2006, the CA ISO should modify its CHP tariffs in recognition of the unique operational requirements of CHP and allow CHP owners to sell their power to the state's electric grid at reasonable prices. This is particularly important given the value CHP provides both IOUs and the CA ISO in reducing transmission congestion and increasing local reliability. 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 these barriers and ultimately loses these strategic generation resources. Natural gas resources and infrastructure would also feel the loss of this valuable generation, as would the environment, because of increases in boiler installations to meet thermal loads. If companies decide to leave California because of energy costs or reliability concerns, it would also mean the loss of well-paying industrial jobs.

Recent federal energy legislation suggests that the Public Utilities Regulatory Policies Act, enacted in 1978,will likely remain in effect in California because of the lack of a robust and functioning wholesale market. By the end of 2006, the CPUC should require IOUs to buy, through standardized contracts, all electricity from CHP plants in their service territories at their avoided cost, as defined by the CPUC in R.04-04-025.[118] The Legislature should pass legislation requiring similar requirements for POUs, irrigation districts, and other electricity service providers. These long-term contracts should be

[116] Comments by Cogeneration Association of California and The Energy Producers and Users Coalition, Docket No. 04-IEP-01E, August 1, p. 14.
[117] Ibid.
[118] CPUC, April 28, 2004, [http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/36203.htm], accessed November 6, 2005.

long enough for CHP owners to make well-informed investment decisions and provide assurances to the Energy Commission and the utilities of their long-term availability. The terms of these contracts should be at least 10 years; however, the Energy Commission and the CPUC should work together to evaluate whether these contracts should have terms with the same economic life as avoided resources.

IOUs also need an incentive to incorporate CHP into their systems and, more importantly, incorporate CHP into their system planning. The Energy Commission's recommendation is three-fold:

- As the Assessment of California CHP Market and Policy Options for Increased Penetration indicates, society as a whole benefits from CHP, though all CHP policy scenarios unfortunately produce utility revenue losses. For California to practically establish its societal preference for DG and CHP, IOUs should be compensated for their revenue shortfalls at least to the point of making them cost neutral. California should explore regulatory incentives to reward IOUs for promoting public- and utility-owned CHP and DG projects. Approaches like the Earned Rate Adjustment Mechanism, which have been successful in keeping IOUs revenue-neutral for energy efficiency programs, could also be implemented for both CHP and DG. California could additionally implement a regulatory approach similar to that of the United Kingdom, where utilities are provided incentives to interconnect DG and CHP projects. The United Kingdom provides even larger incentives to utilities for DG and CHP systems installed on constrained portions of their electricity systems. The CPUC should immediately develop a method to provide DG and CHP incentives to utilities and implement them by the end of 2006.
- The Assessment of California CHP Market and Policy Options for Increased Penetration determined the realistic goal of 5,400 MW of CHP by 2020, which will only be possible if the policies recommended here are actually implemented. By the end of 2006, the Energy Commission and CPUC should collaboratively translate this goal into annual IOU procurement targets. The Energy Commission and CPUC should establish mechanisms in this process to ensure that existing CHP systems retain their baseload positions in IOU portfolios. These mechanisms should rely upon cost/benefit methodologies being developed in CPUC Proceeding R.04-03-017 to make sure that California builds projects that provide the greatest societal benefit.
- California must carefully consider how additional DG and CHP facilities could affect distribution system operations, reliability, and safety. California utilities are planning to invest billions of dollars in their distribution systems in coming years to keep up with their load growth. Now is the time to require the infrastructure investment that will enable utilities to include DG and CHP in their distribution systems. A careful review of Denmark's system, where CHP and DG make up more than 50 percent of the country's generation capacity, shows that distribution system operations can become expensive, complicated, and unpredictable if they are not designed to accommodate DG and CHP.[119] California should require utilities to design and

[119] 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.

construct distribution systems that are DG and CHP compatible. These designs must recognize the system benefits DG and CHP provide, including voltage support, system restoration and reliability, and intentional islanding.

Initial research from the Energy Commission's Public Interest Energy Research program shows that DG and CHP can provide quantifiable benefits to utility systems. The results of recently completed research on Silicon Valley Power's system show that a majority of Silicon Valley Power's customers could install DG, providing various degrees of utility benefits.[120] In this case study, the optimal portfolio was made up of smaller DG systems, averaging less than 160 kW. Some locations on the utility system are also better than others for utility voltage variability, losses, and other factors. The CPUC should require utilities to implement comparable planning models to determine where DG and CHP is most beneficial from system transmission and distribution perspectives.

CHP effectively reduces greenhouse gas (GHG) emissions and both transmission and distribution congestion. CHP facilities are located in local load centers where system operators often struggle to maintain local reliability. CHP also provides significant resources during peak demand periods, which helps mitigate operational problems involved with meeting peak demand. To maintain these environmental and transmission benefits, California should explore production credits for CO_2 reductions and, by the end of 2006, the CPUC should direct utilities to provide transmission and distribution capacity payments to CHP projects in the state.

Recommendations for Distributed Generation and Combined Heat and Power

- California should encourage the use of CHP at California refineries to make them less vulnerable to power outages.
- The state should require utilities to design and build distribution systems that are more DG and CHP compatible.
- The CPUC should require utilities to develop and implement planning models to determine where DG and CHP would be most beneficial, from transmission and distribution perspectives.
- California should explore establishing production credits for CO_2 reductions from CHP.
- By the end of 2006, the CPUC should direct utilities to make transmission and distribution capacity payments to CHP projects.

[120] Presentation by Peter Evans, New Power Technologies, IEPR Distribution Planning Workshop, April 29, 2005.

Other Electricity Supplies

Advanced Coal Technologies

California ratepayers enjoy the economic benefits of relatively low-priced electricity generated by coal plants in other western states. In 2004, 21 percent of all retail electricity sales in California came from this out-of-state coal-fired generation. Most of this was from purchases by 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 POUs own almost all of the Intermountain pulverized coal project in Utah. LADWP, SCE, and other California POUs 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 (DWR) owns about a third of the Reid Gardiner pulverized coal project in Nevada. These and other 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 GHG regulation, and required California's IOUs to include an $8 per ton CO_2 adder when evaluating procurement contracts extending five years or longer. This has focused attention on California's interest in reducing ratepayer exposure to potential GHG retrofit (or offset) requirements, applied at some future date to coal-fired power plants, as well as on the role California utility procurement should play in influencing 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 when referring to plants with very low SO_2, NO_x, and particulate emissions, relative to conventional pulverized coal plants of that time. In the 1990s, researchers began to investigate processes for capturing 75-90 percent of the CO_2 at power plants from both combustion exhaust (flue gas) and processed fuel gas (synthesis gas). These technologies are very energy intensive, and their improvement is the goal of considerable research. This research now generally falls under the broad term "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, like 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 umbrella 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 its 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 lower-rank coal feed stocks with petroleum coke. Design changes or success with 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 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 they 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; future USC PC designs are projected to hit generating efficiencies above 45 percent and 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."[121]

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

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

hasten the deployment of current state-of-the-art advanced coal plants and spur development of technical and operational improvements. Such advances are intended to boost availability, lower heat rate, and reduce emissions in the near term and lead to the commercial introduction of next-generation plant designs that will be 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 online around 2010- 2012: the early deployment projects.
- Mid-term research and development 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 online between 2012-2015.
- Longer-term research and development on advanced concepts for IGCC, USC PC, and SC CFBC plants — including integration of CO_2 capture systems — for plants coming online after 2015-2020.

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 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 that 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 stated 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 achieving its GHG reduction goals and could be a critical driver of clean coal technology development in the West. As discussed more fully in Chapter 9, because of severe projected in-state impacts, California has a special interest in avoiding the consequences of severe climate change and a compelling motivation to reduce GHG emissions.

On October 6, 2005, the CPUC unanimously adopted a resolution directing its staff to develop a GHG performance standard for IOUs "that is no higher than the GHG emission levels of a combined-cycle natural gas turbine" for all procurement contracts that exceed three years in length and for all new generation. In the case of coal-fired generation, the capacity to capture and store carbon dioxide safely and inexpensively is necessary to meeting the standards. The CPUC resolution also directed its staff, working with the Energy Commission, to investigate "offset policies that are designed to ensure that the Governor's GHG goals are achieved," while noting that "any offset policy must include a reliable and enforceable system of tracking emissions reductions." Additionally, the CPUC resolution called on POUs to "reduce emissions that contribute to global warming by adopting energy efficiency and renewables goals that are comparable to the standards that the IOUs are required to meet under state law and regulation, as well as adopting an equivalent GHG performance standard."

The Energy Commission endorses the CPUC resolution with respect to non-PURPA baseload plants 50 MW and larger in size, and makes the following observations:

- There remains considerable uncertainty as to whether the $8 per ton CO2 adder adopted in the CPUC's Decision 04-12-048 adequately captures the financial risk faced by California ratepayers from future GHG regulation. Idaho utilities are required to use a $12 per ton adder for planning purposes, and the CPUC's decision acknowledged a plausible range of $8 - $25 per ton to quantify this risk.
- Sempra Global testified in the *Energy Report* hearings that its Granite Fox pulverized coal project planned for Nevada, when coupled with offsets to meet the proposed GHG procurement standard, could economically compete against a gas-fired combined-cycle plant assuming an $8 per ton adder, but was unlikely to be able to do so at a $25 per ton assumption. Sempra also expected that this financial risk would have to be contractually absorbed by the project developer rather than passed through to utility ratepayers.
- While the Energy Commission sees the cost-reducing benefits of an offsets approach to compliance, there are two fundamental prerequisites to such a policy being prudent. The first is establishing a GHG regulatory framework that provides complete assurance that such offsets will be recognized for compliance purposes and fully absorb the financial risk of future GHG regulation. The history of utility regulation, in California and elsewhere, suggests that inadequate vigilance on this point will ultimately result in a significant financial risk being borne by ratepayers.

The second fundamental prerequisite to a prudent reliance on offsets is the creation of a credible, transparent accounting system that can readily verify the environmental integrity of allowable offsets. The Energy Commission believes that the performance-/standards-based approach being developed by the California Climate Action Registry is a good foundation for such a system.

Recommendations:

- Without burdening interstate commerce or discriminating against particular technologies or fuels, the state should specify a GHG performance standard and apply it 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, if any, role GHG emission offsets should play in complying with such a performance standard.

Nuclear Resources

A significant portion (13 percent in 2004) 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, Arizona. In addition to operating in-state nuclear facilities, California's utilities are responsible for decommissioning older retired reactors at Humboldt Bay, Rancho Seco, and San Onofre, and for the safe storage of spent nuclear fuel from operating and retired plants until the federal government builds a permanent national repository for highly radioactive material. Operators of the state's nuclear plants therefore face many issues including the transportation and disposal of spent fuel, potential extensions of operating licenses, and major capital additions including the replacement of aging plant components like steam generators.

New nuclear power plant construction in California was suspended in 1976 pending assurances by the Energy Commission that the technology for the permanent disposal of high-level waste has been approved by the appropriate federal agency. In addition, for plants requiring reprocessing of spent fuel, the appropriate federal agency must approve a technology for reprocessing. In 1978, the Energy Commission determined that these conditions had not been met, so no new nuclear plants have been approved or built since that time.

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 to be 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.[122]

The Energy Commission must therefore reaffirm the finding made in 1978 that a high-level waste disposal technology has been neither demonstrated nor approved. The Energy Commission also finds that reprocessing remains substantially more expensive than waste storage and disposal and has substantial adverse implications for the U. S. effort to halt the proliferation of nuclear weapons. In addition, the Energy Commission recommends that some portion of the funds contributed by California ratepayers toward federal disposal efforts be returned to the state to defray the ongoing costs of long-term on-site spent fuel storage 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 indefinitely retain spent fuel in storage facilities at currently operating reactor sites. The state should evaluate the long-term implications of 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 versus transportation to offsite interim storage facilities.

Transporting spent fuel involves greater complexity, cost, and risk than leaving it in an on-site storage facility.[123] 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.[124] 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 could set for route selection of future shipments to Yucca Mountain.

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 covering state activities associated with spent fuel shipments.

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[122] Massachusetts Institute of Technology, 2003, *The Future of Nuclear Power*, p 86.
[123] 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.
[124] "Spent Nuclear Fuel Transportation to Yucca Mountain: Implications for California," pp. 37-38, Bob Halstead, Nuclear Issues Workshop, California Energy Commission, August 15, 2005.

California also has an ongoing role in protecting public health and safety and assuring the economic cost effectiveness of investing in electricity generation resources, including nuclear resources. The state must therefore consider the 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 additional 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 alone — it is likely that IOU owners will seek to extend operating licenses at these units to recover those costs.

Communities located near reactor sites continue to be concerned about public health and safety, particularly with today's heightened awareness of terrorism. 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 the release of large amounts of radioactive material.[125] Given these safety issues, as well as the long-term accumulation of spent fuel and adverse thermal impacts on the marine environment from once-through cooling at coastal nuclear plants, 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 the clear delineation of agency responsibilities, the scope of the evaluation, and the criteria for assessment.

Recommendations for Nuclear Resources:

- The Energy Commission recommends that some portion of the funds paid by California ratepayers for a permanent national repository be returned to the state to help defray the cost of long-term on-site spent fuel storage.
- The state should evaluate the long-term implications of the continuing accumulation of spent nuclear fuel at California's nuclear plants.
- The state should evaluate DOE's increasing use of California routes to transport nuclear waste to and from Nevada.
- The state should reexamine the adequacy of California's nuclear transport fees and federal funding programs to cover the state's costs of spent fuel shipments.
- The Legislature should develop a suitable framework for reviewing the costs and benefits of nuclear plant license extensions and clearly delineate agency responsibilities, scope of evaluation, and the criteria for assessment.

[125] 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 lines 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 Energy Commission strongly recommended improvements to transmission infrastructure in both the *2003 Energy Report* and the *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. After this summer's transmission-related outages in Southern California, fixing this problem should be afforded the highest priority by state policymakers.

Governor Schwarzenegger recently agreed with the 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."[126] 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 future transmission corridors so they will be available when needed.

California faces three urgent transmission issues:

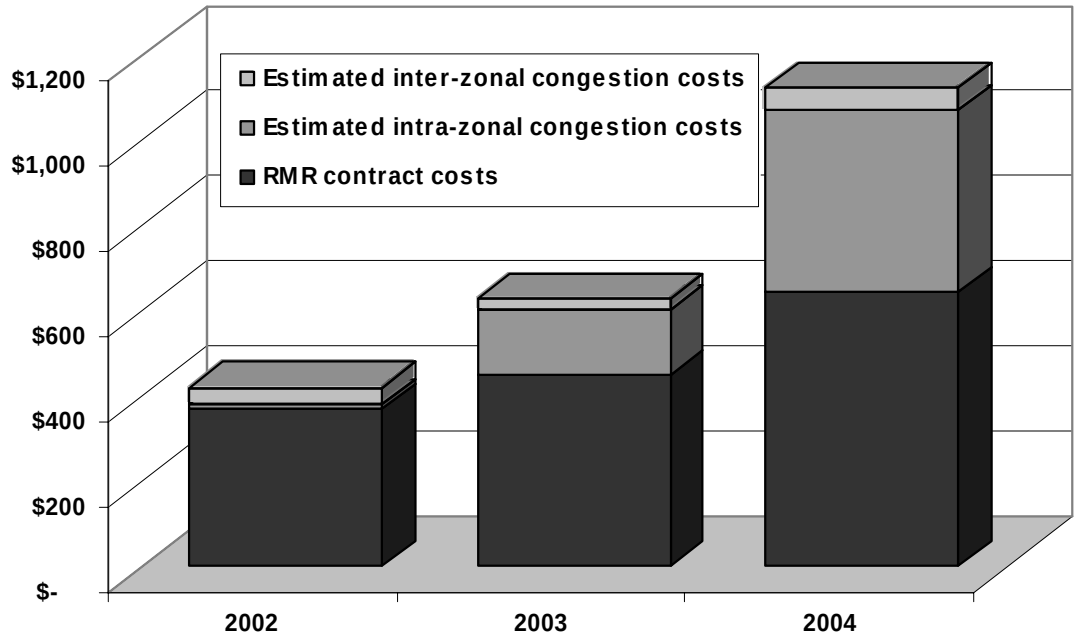
- The state lacks a well-integrated, proactive transmission planning and permitting process. Overlapping and often conflicting roles and responsibilities between state and federal agencies cripple California's ability to effectively secure the investment needed to address dramatic increases in congestion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

[126] 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.
- California needs major investments in new transmission infrastructure to interconnect with remote renewable resources in the Tehachapi and Imperial Valley areas, without which it will not be able to meet its 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 14, last year's total cost for transmission congestion and related reliability services in the CA ISO control area totaled over $1 billion, up from a total of $628 million in 2003.[127]

Figure 14: 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 Energy Commission, the CA ISO, and the CPUC to collaboratively solve this critical problem. Since the 2000-2001 energy crisis, the roles of these agencies have changed with the evolving regulation of the state's transmission system. These roles and

[127] 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.

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 SCE over the first segment of the Tehachapi transmission line graphically illustrate the challenge of effectively coordinating interagency planning objectives.[128]

In addition, changes in federal law giving the FERC transmission siting authority and conferring eminent domain powers for transmission projects in federally designed corridors present a clear threat to California's ability to make land-use and public health and safety decisions for transmission projects. Unless the state takes prompt action to establish an effective statewide corridor planning process and address permitting and planning problems, the federal government is prepared to take over where the state has failed to act. 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 tariff that recognize the unique characteristics of these projects.

This chapter addresses the actions that California policy makers must take to adequately plan for, permit, and construct crucial transmission upgrades and

[128] September 15, 2005 letter from the forest supervisor, Angeles National Forest, U.S. Forest Service to the supervisor for the California Environmental Quality Act, CPUC, on the SCE Antelope-Pardee Transmission Project.

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 five 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.[129] 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 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 duplicating others.

The *2004 Energy Report Update* recommended a collaborative process integrating transmission planning with electricity demand 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 intertwined with electricity forecasting, assessment, and resource procurement, the *2005 Strategic Transmission*

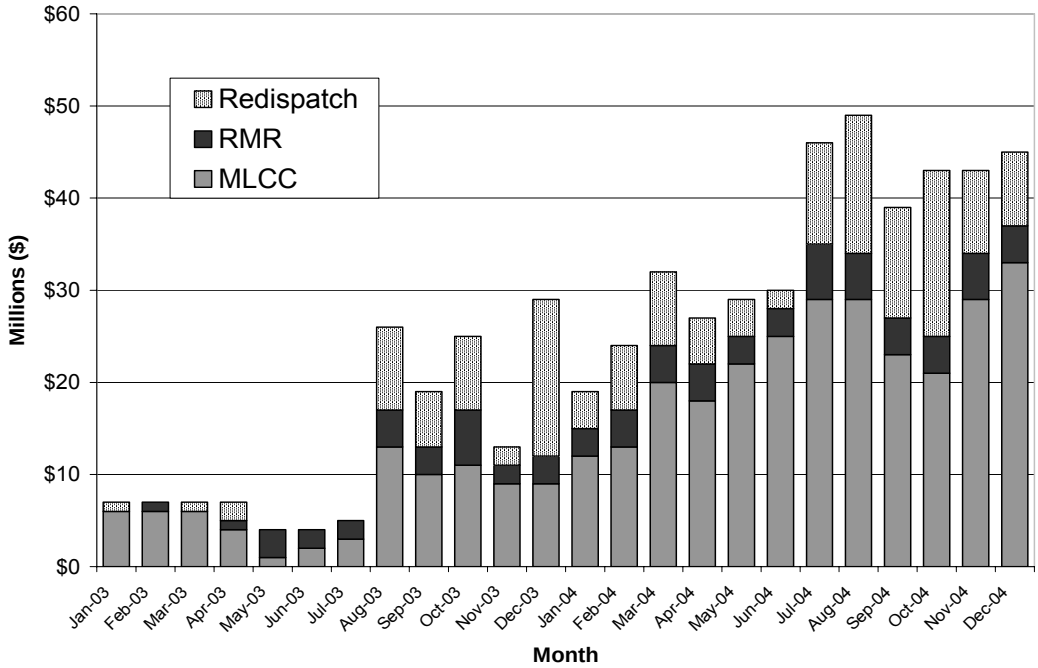
[129] SB 1565 (Bowen) Chapter 692, Statutes of 2004, was signed into law on September 22, 2004.

Plan provides the detailed assessment of transmission projects necessary for IOUs to effectively procure resources.[130]

Transmission Congestion and Reliability Concerns

In 2004, the cost of congestion and local reliability needs in the CA ISO system approximated $1.1 billion.[131] Figure 15 shows monthly intrazonal congestion costs for 2003 and 2004. 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 15: 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 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,

[130] 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."
[131] California Energy Commission, *Draft Committee Strategic Transmission Plan*, September 2005, CEC-100-2005-006CTD.

annual congestion costs totaled over $32 million, increasing to $48 million from July 2004 to July 2005.[132] Over the next year until the Mission-Miguel upgrade finally comes online, congestion costs are expected to exceed $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 is very precarious. As its representative noted, "We have to weigh the question of do we take a line out to try to repair it. And if we do, we're sitting on one other line. And if we lose that line we can be in a blackout situation." [133] 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. 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. Historically, local reliability on the CA ISO grid has been addressed either through transmission investment or reliability must run (RMR) contracts.[134] 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 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. The continuing central role of these contracts in reliability planning 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.

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. While the CPUC has not embraced the Energy Commission's *2003 Energy Report* and *2004 Energy Report Update* recommendations on consolidating transmission permitting authority at the Energy Commission, the CPUC's Office of Ratepayer Advocates has

[132] Testimony of James Avery, San Diego Gas and Electric, Transcript of the July 28, *2005 Integrated Energy Policy Report t*ransmission workshop, pp. 88-89.
[133] Ibid.
[134] The CA ISO conducts annual studies to identify power plants needed to meet reliability requirements and awards reliability must run contracts.

recently expressed its neutrality on the placement of permitting jurisdiction, noting its desire to have the same opportunity to participate and comment on transmission lines, with IOU reimbursement, wherever jurisdiction is ultimately placed.[135]

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.

California must also recognize the serious implications of changes at the federal level under the federal Energy Policy Act of 2005 regarding transmission planning and permitting.[136] Prior to this new law, transmission line permitting was exclusively a state function. The state power of eminent domain, which is especially important for transmission rights-of-way, was historically reserved for franchised utilities.

New federal law requires the U.S. Department of Energy (DOE) to designate within the next year corridors of national significance. The FERC can now authorize construction of a transmission line if an application is submitted to construct a project in a DOE-designated transmission corridor and the state has failed to approve a transmission project for more than one year or has conditioned its approval in a way that makes construction economically unfeasible. In cases where FERC grants a transmission permit, it can authorize the permit holder to acquire the right-of-way needed to construct the project upon payment of “just compensation” as determined by a federal court. Creation of a federal power of eminent domain represents a significant loss of state sovereignty and its application is likely to prove controversial with property rights advocates.

These changes in the federal landscape seriously threaten California’s ability to make land-use and public health decisions related to transmission projects. If California fails to immediately take the necessary actions to ensure adequate transmission infrastructure, the state will ultimately lose to the federal government its ability to determine how, where, and when to expand its bulk transmission grid, potentially thwarting the state’s energy, environmental, and economic policy goals.

[135] Testimony of Robert Kinosian, Office of Ratepayer Advocates, Transcript of September 23, 2005 hearing on the *Energy Report Committee Draft 2005 Strategic Transmission Investment Plan*, pp. 32-33.
[136] United States Code, 16 U.S.C. Section 824(e).

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 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 need for projects, as well as projects necessary for achievement of statewide policy goals including the 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 2005 *Energy Report* 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 transmission 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.[137]

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

[137] SCE 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.

reactivity, which is recounted in more detail in the *2005 Strategic Transmission Plan*.[138] 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 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 submit annual transmission assessment and expansion plans for the coming five years, which are then reviewed by the CA ISO.
- The CA ISO's management approves projects that meet its criteria and cost less than $20 million; projects costing more than $20 million are submitted to the CA ISO's board of directors for approval.
- The CA ISO performs an assessment of the combined participating transmission owner plans to make sure that projects do not "fall through the cracks."
- Finally, the CA ISO conducts studies to determine RMR generation requirements. [139]

The CA ISO notes it is forced to be reactive in part because it only acts upon projects submitted by participating transmission owners. It further notes that the decision either to pay RMR costs or build facilities to avoid RMR costs has been largely left to the participating transmission owners. 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.

The recent announcement that the CA ISO is proposing a new planning process, evolving from a reactive to a proactive role in transmission planning, offers a unique opportunity to better coordinate the activities of the three primary concerned state agencies: the CA ISO, the CPUC, and the Energy Commission.

[138] California Energy Commission, *2005 Strategic Transmission Plan, d*raft Committee report, November 2005, Apprndix A: Procedural History of PVD2.
[139] *New CA ISO Transmission Planning Process*, A.J. Perez, CA ISO, August 1, 2005.

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.

In the *2004 Energy Report Update,* the Energy Commission noted longstanding, continuing, and widespread criticism of California's permitting process and 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 transmission 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 online 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.[140]

While the CPUC has recently reduced extensive delays in some of its CPCN applications, 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 greatly 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 State of California Administration submitted a reorganization plan to the Little Hoover Commission and the Legislature which included implementing the *2003 Energy Report's* recommendation on transmission permitting.[141] 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.[142] The Attorney General went on to note that the reorganization statute would permit transfers of authority that do not interfere

[140] 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.
[141] *A Vision for California's Energy Future*, June 2005, p. 6.
[142] Letters from the Attorney General to the Little Hoover Commission regarding *Inquiry Regarding Governor's Energy Agency Reorganization Plan*, June 22 and 23, 2005.

with the CPUC's ratemaking function, citing as an example the Warren-Alquist State Energy Resources Conservation and Development Act, where the Energy Commission has responsibility for the siting of thermal energy plants and their related transmission lines.[143] 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 an Application for Certification, 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.

Recommendations to Improve Transmission Planning and Permitting

The Energy Commission recommends that a comprehensive planning process including the CA ISO, the CPUC, other key state and federal agencies, local and regional planning agencies, IOUs and POUs, 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.

To better align transmission with generation permitting and planning and ensure that needed transmission investments occur, the Energy Commission recommends that:

- The Legislature transfer transmission permitting responsibility from the CPUC to the Energy Commission using the framework laid out in the Warren-Alquist Act for generation siting that has worked successfully for the last 30 years.

[143] 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 should also make room for upfront environmental assessments that would streamline the current process and shorten lead times for bringing transmission online. 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.

The second element, designation of corridors, would allow corridor recommendations (and land use requirements) to be set aside for future use through a corridor designation process. Corridor designation would require local planning agencies to avoid incompatible uses and 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 retaining IOU investment of lands in the rate base is insufficient for long-term corridor planning, and needs to be extended.

The federal Energy Policy Act of 2005 directs the Secretaries of Agriculture, Commerce, Defense, Energy, and the Interior to designate under their respective authorities corridors on federal land in the 11 western states for energy corridors including transmission lines.[144] The agencies have determined that designating corridors as required by the Act constitutes a major federal action which may have a significant impact upon the environment within the context of the National Environmental Policy Act of 1969. For this reason, the agencies intend to prepare a programmatic environmental impact statement to address the environmental effects from the proposed action and the range of reasonable alternatives.[145] DOE and the Bureau of Land Management will lead this effort, with the U.S. Department of Agriculture's Forest Service participating as a cooperating agency. The Energy Commission plans to actively participate in this proceeding and other joint efforts involving federal land managers to ensure that future transmission corridors are adequately addressed by federal agencies.

Recommendations to Establish a Corridor Planning Process for California

The Energy Commission recommends the following actions to create a comprehensive corridor planning process that accommodates future needs for transmission:

- The Legislature should give the Energy Commission the statutory authority to establish a statewide corridor planning process and designate corridors for future use, enabling environmental reviews to begin earlier in the process and shortening the timeframe of the transmission infrastructure planning and permitting processes.
- In establishing a statewide corridor planning process, the Energy Commission should work collaboratively with the CPUC, the CA ISO, other key state and federal agencies, local and regional planning agencies, IOUs and POUs, generation owners and developers, the public, and other interested groups.
- The Energy Commission should actively participate in the recently initiated federal corridor planning efforts to evaluate issues associated with designation of energy corridors on federal lands in 11 western states, beginning with filing comments in the scoping of the programmatic environmental impact statement.

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 that were convened following recommendations in the *2004 Energy Report Update* are

[144] Section 368, Public Law 109-58 (H.R. 6), enacted August 8, 2005. The 11 western states include Arizona, California, Colorado, Idaho, Montana, Nevada, New Mexico, Oregon, Utah, Washington, and Wyoming. Energy corridors include oil and gas and hydrogen pipelines, as well as electricity transmission and distribution facilities.

[145] Programmatic environmental impact statement, *Designation of Energy Corridors on Federal Land in the 11 Western States,* (DOE/EIS-0386.

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, 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 did not approve 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."[146]

Current FERC policy effectively bars the advanced planning and construction of transmission facilities necessary through the "chicken and egg" nature of renewable transmission development: renewable projects cannot secure contracts under RPS procurement procedures without knowing whether existing transmission will be able to accommodate them; at the same time, utilities are wary of investing in renewable transmission without assurances of cost recovery, which is premised on the renewable generation being built. This poses a major impediment to renewable resource development.[147]

Even when a renewable developer requests new transmission capacity, the present system assigns the bulk of the 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 pre-building portions of transmission lines, currently not allowed under FERC regulation.

Recommendations to Encourage Transmission for Renewables

- Because of FERC's denial of the renewable trunk line concept, the Energy Commission strongly believes that its *2004 Energy Report* recommendation to implement changes to the CA ISO tariff is even more necessary today than it was a year ago for meeting California's renewable goals.[148] The Energy Commission, the

[146] *Southern California Edison Co.*, 112 FERC Section 61,014, 2005.
[147] The FERC's abandoned plant policy means that SCE 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, pp. 18-19.
[148] 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

CPUC, and the CA ISO should implement changes to the CA ISO tariff to encourage construction of transmission for renewables.

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 online by 2010. The Energy Commission has identified the five 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 Sunrise Powerlink Project

The Sunrise Powerlink Project is proposed as a 500 kV transmission line connecting Imperial Valley to the San Diego service territory. The proposed 500 kV project would provide significant near-term system reliability benefits to California, reduce system congestion and its resulting congestion costs, and provide interconnection to renewable resources located in the Imperial Valley, as well as lower-cost out-of-state generation. Without the proposed project, it is unlikely that SDG&E will be able to meet the state's RPS goals, ensure system reliability, or reduce RMR and congestion costs. A potential northern interconnection to the proposed project could strengthen the CA ISO grid by providing a 500 kV interconnection between the SDG&E and SCE service territories. Therefore, the Energy Commission believes the proposed project offers significant benefits and recommends that the project be moved 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.

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projects. Neither of the categories adequately accommodates the unique circumstances of renewable transmission projects.

Imperial Valley Transmission Upgrade Project

The Imperial Irrigation District and the Imperial Valley Study Group have developed transmission plans designed to deliver generation in the Imperial Valley to loads in California and the Western Electricity Coordinating Council (WECC). The Imperial Irrigation District plan, called the Green Path Initiative, is a phased transmission project that would connect generation in the Imperial Valley to SDG&E, SCE, the Western Area Power Authority, and Arizona. The Imperial Valley Study Group plan focuses on the delivery of power to California through SDG&E and SCE. The Imperial Valley Transmission Upgrade Project 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. In addition to providing a much needed interconnection to these renewable resources to support California's RPS goals, the Imperial Valley Transmission Upgrade Project would also 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 transmission development in the Imperial Valley region 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. 2 500-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 Energy Commission 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 current 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 ultimately allow interconnection with more than 4,000 MW of new wind generation and access 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 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 TCSG 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.

Trans-Bay Cable Project

The Trans-Bay DC Cable Project, proposed by the City of Pittsburg and Trans Bay Cable LLC, a subsidiary of Babcock and Brown, would consist of an approximately 50-mile-long underwater DC cable connecting the Pittsburg Substation to the Potrero Substation in San Francisco.[149] The Trans-Bay DC Cable Project would provide 400 MW of new import capacity into downtown San Francisco, eliminating the need for RMR contracts at the Hunters Point and Potrero power plants while ensuring electricity reliability beyond 2011. Along with other proposed strategies, the project has the potential to ensure the retirement of all older generation in San Francisco, resulting in

[149] PG&E, March 9, 2005, *San Francisco Phase II Study, Preliminary Cost Estimates and Discussion of Routes, Permitting and Schedules,* draft, p. 10.

significant environmental benefits. The proposed project would help ensure reliability, serve growing loads, and hasten retirement of aging generators in the San Francisco Peninsula area. Although the Trans-Bay DC Cable Project is not needed for reliability purposes until after 2011, the CA ISO has approved the project for early operation in 2009, consistent with Trans-Bay Cable LLC's plans.

The Energy Commission agrees with the CA ISO's assessment that the advanced in-service date provides insurance benefits that outweigh the net cost to CA ISO ratepayers. Therefore, the Energy Commission recommends that the Trans-Bay DC Cable Project be moved forward expeditiously in order for the San Francisco Peninsula and CA ISO control area to realize these reliability benefits.

Recommendations to Ensure Construction of Near-Term Transmission Projects

The Energy Commission recommends the following actions to ensure that new near-term transmission projects are online by 2010 to improve reliability, help mitigate congestion costs, access economic generation, and assist in meeting RPS goals:

- All five near-term transmission projects should move forward expeditiously so that Californians can begin to realize their benefits by 2010.
- Collaborative corridor study groups should be formed for the San Diego 500-kV Project and the Palo Verde-Devers No. 2 500-kV Transmission Project to quickly address concerns of local, state, and federal agencies, landowners, and other interested parties.
- The Imperial Valley Study Group should immediately coordinate with local, state, and federal agencies, landowners, and other interested parties to confront the significant land use constraints that must be resolved before completion of the Imperial Valley Transmission Upgrade 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, 10.2 percent of the state's electricity came from renewable sources, excluding large hydroelectric power.[150] 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.[151]

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

- The lack of progress in the RPS program.
- The need for new and/or upgraded transmission to access renewable resources in several 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 RPS program is central to meeting California's renewable resource goals. Established in 2002, the RPS was designed to address the lack of long-term power purchase agreements which prevent developers from getting the financing they need 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.[152]

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

[150] California Energy Commission, "California Electrical Energy Generation, 1995-2004," [http://www.energy.ca.gov/electricity/electricity_generation.html], accessed November 7, 2005.
[151] California Energy Commission, July 2005, *Implementing California's Loading Order for Electricity Resources*, CEC-400-2005-043, page 26.
[152] 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.

the Tehachapi wind and the Imperial Valley geothermal resource areas. Although the Tehachapi and Imperial Valley Transmission Groups have made progress in developing plans for transmission upgrades, the FERC recently rejected SCE's renewable trunk line proposal, thereby removing 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 volume 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 larger, more efficient turbines will not only increase the volume of renewable energy available to meet RPS goals, but will 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 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,*[153] 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 are needed to overcome barriers facing these resources and to ensure that the state meets its RPS goals.

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 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* 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

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

technical potential and had already reached 17.04 percent renewable by 2002,[154] the report recommended a new target for SCE of 35 percent by 2020.

The 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."[155] 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 or 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 25-30 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 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 facilities, particularly in the Altamont Pass area, and reducing the number of bird deaths associated with the operation of wind turbines. Repowered wind facilities with existing

[154] California Energy Commission, July 2005, *Implementing California's Loading Order for Electricity Resources*, CEC-400-2005-043, Appendix A, Section 14.
[155] 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.

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 limited 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

Figure 16 on the next page shows California's progress toward RPS goals as well as the amount of renewable generation needed to reach those 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 online until the end of 2006. The CPUC did not approve PG&E's first contracts from its 2004 RPS solicitation until July 2005, and SDG&E did not submit contracts from its 2004 solicitation for CPUC approval until September 2005. 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:

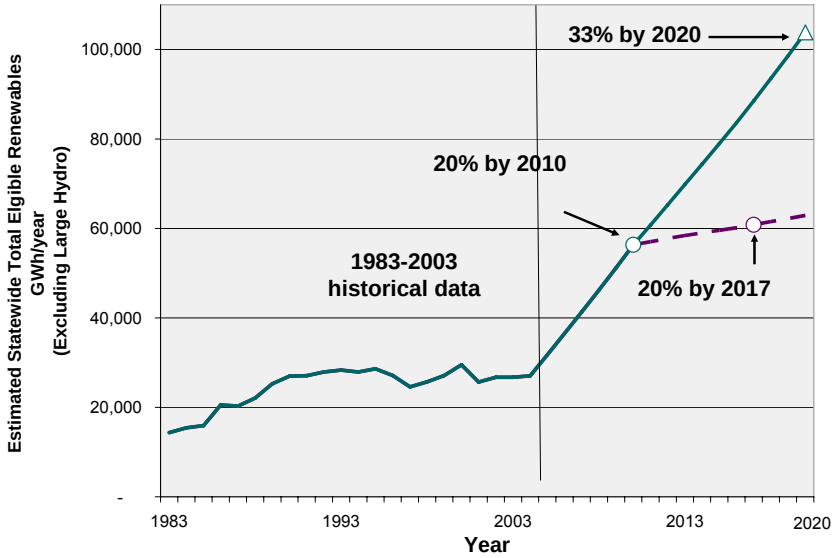
- The lack of transparency in the bidding, ranking, and contracting processes and the complexity in administering the program.
- The uneven application of RPS targets to all retail sellers in the state.

Too Little Transparency, Too Much Complexity

One of the main problems with the RPS program is the lack of transparency for program participants and the public. Transparency is necessary to ensure that all parties understand the allocation of the public funds that support the RPS program. The least-cost, best-fit method that IOUs use 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."[156] 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 aligned with the state's policy to provide long-term benefits to the system.

Figure 16: California's Renewable Energy Goals



Source: California Energy Commission

Transparency is also necessary in the bid evaluation process for contracts. Currently, bid results are confidential except to 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.

The administrative complexity of the RPS program is another deterrent to reaching renewable goals by 2010. 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.[157] This "market price referent" (MPR) is intended to be a proxy for the cost of developing conventional energy sources. The

[156] CPUC, June 19, 2003, Decision 03-06-071, "Order Initiating Implementation of the SB 1078 Renewable Portfolio Standard Program," p. 28, [http://www.cpuc.ca.gov/word_pdf/FINAL_DECISION/27360.pdf], accessed April 19, 2005.
[157] SB 1078 (Sher), Chapter 516, Statutes of 2002, codified in pertinent part in Public Utilities Code Section 399.15, Subdivision (c).

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.

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.

Several options could increase transparency and simplify administration of the RPS program. One option is to make RPS procurement the same as all-source procurement, eliminating the MPR and supplemental energy payment processes. To contain RPS program costs, the CPUC could apply the same reasonableness review to renewable contracts as it applies to non-renewable procurement.

Another option is to follow the structure used in interim RPS procurement. In the 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.

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.[158] 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 online. Several stakeholders have recommended a return to the auction process, citing its simplicity and success.

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.

Encouraging shaped or firmed renewable products could provide the necessary flexibility for renewable generators to structure their RPS contracts to keep transmission

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

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 that 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 the possibility of getting projects online before incentives are fully subscribed; and difficulty in securing financing. 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 standardized 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-available, and peaking) while commercial terms such as term, delivery point, contract price, and contract quantity would remain subject to negotiation.

Recommendations to Reduce Complexity and Increase Transparency:

- The RPS program is in need of a mid-course review and correction. After completion of the 2005 round of IOU solicitations, the CPUC and the Energy Commission should investigate whether a simpler and more transparent RPS process would better achieve the state's 2010 goals. A seminal question is the likely impact of the CPUC's "rebuttable presumption" for renewables directive for IOU all-source procurement. This review should be completed and transmitted to the Governor and Legislature by January 1, 2007.
- The CPUC should allow for changes to the current program that can be accomplished under existing RPS law, including inter-utility trades under flexible compliance, the use of shaped products, and more flexible delivery requirements, as well as changes to transmission cost adders, which are addressed later in this chapter.

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. Because POUs are not subject to the same implementation rules as IOUs, their RPS programs include varying targets, timelines, and eligibility standards. An analysis prepared for the Energy Commission by Kema-Xenergy, Inc. indicates that POU targets vary from 5 percent to 40 percent and dates vary from 2007 to 2017.[159] In addition, POUs do not have the same enforcement mechanisms as IOUs, so their targets are simply goals. Also, though most POUs include end targets, they do not include intermediate targets such as those faced by IOUs, ESPs, and CCAs. Finally, even though hydroelectric projects larger than 30 MW are not considered eligible renewable resources under the RPS program for IOUs, most POUs still count generation from these projects toward their renewable energy targets.

The Kema-Xenergy analysis also indicates that some California POUs are pursuing renewable goals that are reasonably consistent with the state's overall targets. However, other POUs are not taking such aggressive action. A number of other states with RPS policies impose more significant requirements on POUs than does California. Also, POUs in California 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 must be applied consistently to all POUs since these entities are expected to contribute to statewide renewable goals. The *2004 Energy Report Update* recognized that smaller POUs may have 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.

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 volume of renewables in California's electricity mix has actually dropped since 2002, from 11 percent to 10.2 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 and ESPs. Although a number of POUs already report more than 20 percent eligible renewables, in 2003 the state's largest POUs, LADWP and SMUD, reported

[159] Kema-Xenergy, "Publicly Owned Electric Utilities and the California RPS: A Summary of Data Collection Activities," November 2005, CEC-300-2005-023.

only 2 percent and 9 percent renewables, respectively, although the newly elected mayor of Los Angeles recently committed to reaching 20 percent by 2010.[160]

The lack of rules for RPS compliance is hampering the participation of ESPs and prospective CCAs 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 basic parameters for RPS participation by ESPs, CCAs, and small and multi-jurisdictional utilities.[161]

The CPUC draft decision proposes that ESPs and CCAs not needing public goods charge funds to meet their RPS requirements 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.

One way to facilitate the uniform 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 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, although some parties raise concerns that RECs could invite market manipulation or double counting.

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[160] "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.

[161] 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," June 29, 2005, [http://www.cpuc.ca.gov/word_pdf/COMMENT_DECISION/ 47469.doc], accessed July 5, 2005.

By allowing limited use of RECs in the near-term, California can gain experience and make necessary adjustments to ensure that RECs achieve their 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 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 rebundled 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.

Recommendations to Improve Consistency:

- The Legislature should apply the same RPS targets, timelines, and eligibility standards to POUs that it has established for IOUs. Consistent with the Energy Commission's 2004 recommendation, the state should establish an exemption process for small POUs to avoid the overly burdensome requirements that compliance with RPS goals may present to them.
- The Legislature should authorize the CPUC to allow limited use of renewable energy certificates for RPS compliance to facilitate uniform participation of all LSEs, with the associated electricity sold into the CA ISO real-time market or bilaterally to retail sellers.
- 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.

Addressing Other Issues Associated with 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 vital components 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.[162] 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 5 of this report.

California also needs a new approach for assessing transmission costs in RPS bid solicitations 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 many 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.[163] 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 erecting new barriers to renewable development.

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

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

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 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, the Energy Commission, and the CA ISO should investigate changes to the CA ISO tariff that would allow recognition of transmission needs not only for reliability and economic projects, but also for access to renewable projects to meet RPS goals.
- The CPUC, the Energy Commission, and the CA ISO should cooperate to revise the transmission cost adder process for RPS procurement 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.[164] 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.[165] Wind generators pay a forecasting service fee of $0.10 per MWh to the CA ISO to participate in the program.[166]

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[164] 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].

[165] 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.

[166] 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.

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 needed to support the state's goal of 20 percent renewables by 2010.[167] 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 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.[168] SDG&E has also announced plans for a 300-MW solar project using the same technology.[169] 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.

The overriding message from the CERTS work is "We've done this before. We've been successful. But it requires planning, coordination, practices, procedures, and action."[170] CERTS points out that utilities have overcome larger operational challenges in the past, such as subsynchronous resonance problems with remote coal plants, minimum load issues with the introduction of large nuclear plants, and absence of generation control when 10,000 MW of QFs came onto the grid.[171]

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 (PIER) program will build on the CERTS work. In the

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[167] 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].

[168] "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.

[169] "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.

[170] Testimony of Jim Dyer, Consortium for Electric Reliability Technology Solutions, Transcript of the February 3, 2005 IEPR Committee workshop on Renewable Transmission and Integration Issues, p. 9.

[171] Ibid, pp. 5-12.

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, the state has a vested interest in aggressively exploring energy storage opportunities to increase the operational flexibility of the state's electricity grid and accommodate the impacts of growing volumes of intermittent resources.

Recommendations for Research and Development Efforts:

- The CA ISO should undertake a research initiative addressing the attribute requirements of its system and focusing on defining current and future control area attribute requirements.
- 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, and integrate them 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.
- 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 smaller turbines that are less efficient and more costly to operate and maintain than the current generation of turbines. In its June 2003 decision on implementing the RPS, the CPUC supported repowering these facilities as "a common-sense approach to increasing procurement of renewable energy," and endorsed comments by The Utility Reform Network (TURN) that the CPUC should "require prompt negotiation to resolve

what [TURN] characterizes as a stalemate around repower of existing wind facilities."[172] Despite this directive, however, very little has been accomplished toward repowering these facilities.

To date, California has made only limited progress toward repowering wind facilities, with only 120-135 MW of repowered wind contracts submitted to or approved by the CPUC as of October 2005.[173] Repowering efforts in the Altamont Pass Wind Resource 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.[174]

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.[175] This provision discouraged wind operators from repowering because utility avoided costs are much lower than current contract prices.

As recommended in the *2004 Energy Report Update*, replacing 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. New turbines are also 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. 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.[176]

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[172] CPUC, "Order Initiating Implementation of the SB 1028 Renewable Portfolio Standard Program," Decision 03-06-071, June 19, 2003, pp. 57 and 60.

[173] This total includes 37 MW of SCE contracts and 84-99 MW of PG&E contracts. Energy Commission RPS staff and Ryan Wiser, Kevin Porter, Mark Bolinger and Heather Raitt, October 2005, "Does It Have To Be This Hard? Implementing the Nation's Most Complex Renewables Portfolio Standard," The Electricity Journal, Volume 18, Issue 8, Pages 55-67.

[174] 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.

[175] 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 early 1980s in response to the federal Public Utility Regulatory Policies Act of 1978.

[176] 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*

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 among 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. 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.

Recommendations for Repowering and Reducing Bird Deaths:

- Existing wind sites should be repowered to harness prime wind resources more efficiently and reduce or prevent bird deaths.
- The CPUC should quickly develop new standardized contracts to overcome impediments to repowering and take advantage of the Federal Production Tax Credit.
- Statewide protocols should be developed for studying avian mortality to address site-specific impacts in each individual wind resource area.

Recognizing the Value of Biomass Resources

California has approximately 1,000 MW of biomass-generated electricity, including some 600 MW from solid-fuel biomass (residues from forestry and agriculture) and about 400 MW from other sources such as landfill gas, biogas from wastewater treatment, direct burning of municipal solid waste, and anaerobic digestion of livestock manure. These feedstocks 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

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[http://www.energy.ca.gov/pier/final_project_reports/CEC-500-2005-005.html#ExecutiveSummary], accessed April 21, 2005.

problems at once: waste disposal and mitigating environmental problems such as increased fire risk, air pollution, and climate change.[177]

The volume of energy provided by biomass generating facilities in California has declined in recent years due to facility closures in the solid-fuel biomass sector. Prior to 1980, only a handful of solid-fuel biomass power plants were operating at lumber or pump mills to supply power for on-site use. The advent of standard offer contracts in the early 1980s, however, led to the development of 33 new biomass generating facilities between 1985 and 1990, bringing total statewide biomass capacity to 770 MW by the end of 1990.[178]

Faced with proposals by the CPUC to restructure the state's regulated electric utility industry in 1994, IOUs began offering to buy out standard offer contracts for biomass generators in their service territories. Because of concerns about long-term liabilities for firm capacity within these contracts, many biomass generators were willing to accept the IOU offers. As a result, 17 biomass facilities totaling 215 MW shut down.[179]

After California's electricity market was deregulated in 1996, the state's solid-fuel biomass energy industry entered a period of relative stability for the remainder of the 1990s, with 27 facilities representing 540 MW of capacity remaining in operation. Many of the existing biomass facilities received financial incentives from state public goods charge programs that helped to offset the end of the fixed-price periods in generators' standard offer contracts. Then, during the 2000-2001 energy crisis, several idle biomass facilities were able to restart and resume operations. However, 14 biomass plants are still idle, including 5 that have closed since the 2000-2001 energy crisis.[180]

California today has 28 biomass plants totaling about 600 MW of capacity.[181] Many of these facilities are operating under older standard offer contracts with fixed energy prices through mid-2006. The long-term prospects for these projects will depend on their ability to negotiate new contracts.

Current high diesel prices are affecting the prices paid by the biomass industry for fuel gathering, processing, and transportation. Biomass fuel prices have risen approximately 8 percent since the beginning of 2005, in part because of increasing diesel fuel prices. To help offset these increased costs and prevent biomass curtailment, the Energy Commission is considering increasing the incentive level and cap for biomass technologies under the Renewable Energy Program. Because biomass operators will realize the benefits of changes in the federal Production Tax Credit next year, the

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[177] California Energy Commission, *Biomass Strategic Value Analysis, June 2005.*
[178] *The Status of Biomass Power Generation in California*, July 31, 2003, G. Morris, Green Power Institute, under contract to National Renewable Energy Laboratory, publication number NREL/SR-510-35114.
[179] Ibid.
[180] Testimony of Julee Malinowski-Ball, California Biomass Energy Alliance, Transrcript of the October 6, 2005 IEPR Hearing on Demand Side Resources, Distributed Generation, Renewable Energy, and Other Electricity Resources, pp. 63-68.
[181] Ibid.

increased incentive level and cap are proposed to be in effect only through June of 2006.

Regarding future development of biomass resources in California, Governor Schwarzenegger, in his response to the *2003 Energy Report* and *2004 Energy Report Update*, 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.

Recommendations for Biomass Resources:

To realize the potential economic, social and environmental benefits of sustained biomass development, the state should:[182]

- 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.
- 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.

[182] 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.

Taking Advantage of California's Solar Resources

California has abundant solar resources that can be used to help meet the state's growing need for electricity. Solar thermal facilities can provide dispatchable power during periods of peak demand as well as help mitigate the impacts of integrating large amounts of intermittent wind resources into the system. Recent utility contracts for 800 MW of solar thermal electric capacity represent a major shift from previous perceptions that solar technologies are always more expensive than conventional generating sources, particularly since the contracts will not require any public subsidies. These contracts also represent the first major commercial applications of Stirling dish technology. While having two large contracts with a single small company may raise concerns about project risk, the increased focus on large solar technologies is promising for the future development and deployment of these technologies in California and elsewhere.

California is also a leader in the installation of solar photovoltaic (PV) systems, with more than 130 MW of rooftop PV systems installed since 1981.[183] Since taking office in 2003, Governor Schwarzenegger has indicated strong support for solar energy development, initially by proposing to make half of all new homes built in the state solar-powered and then by proposing a goal of one million solar roofs in California by 2018.[184] In his response to the *2003 Energy Report* and *2004 Energy Report Update,*[185] the Governor reinforced the goal of a million solar roofs by outlining principles to be used to achieve that goal. As a further indication of his commitment to solar energy, the Governor recently signed a law that would promote the installation of PV generation in open spaces above and along 660 miles of open canals and pipelines on the State Water Project.[186]

Although state PV incentive programs such as the CPUC's Self Generation Incentive Program and the Energy Commission's Emerging Buydown Program have provided important support for the installation of PV systems, installed solar costs in California are still high and the market is far from self-sustaining. The situation is exacerbated by the lack of a single, cohesive PV program in the state. Multiple and overlapping programs increase the risk of "double dipping" and the attendant monitoring and verification responsibilities of program administrators. Different programs with different

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[183] California Energy Commission, "Amount (MW) of Grid-Connected Solar Photovoltaics (PV) in California, 1981 to Present," [http://www.energy.ca.gov/renewables/emerging_renewables/GRID-CONNECTED_PV.XLS], forthcoming November 2005.
Implementing California's Loading Order for Electricity Resources, Staff Report, July 2005, CEC-400-2005-043.
[184] "Governor Announces Million Homes Solar Plan," press release, August 20, 2004, [http://www.governor.ca.gov/state/govsite/gov_htmldisplay.jsp?sCatTitle=Press%20Release&sFilePath=/govsite/spotlight/august20_update.html], accessed November 1, 2005.
[185] Letter from Governor Arnold Schwarzenegger to the Legislature, attachment: Review of Major *Integrated Energy Policy Report* Recommendations, August 23, 2005.
[186] AB 515 (Richman), Chapter 368, Statutes of 2005.

funding sources are also inefficient because of the inability to move funding from a program that may be underutilized to one that is oversubscribed.

In recent years, the Self Generation Incentive Program has provided incentive levels that greatly exceeded rebate levels provided by the Emerging Buydown Program. Despite repeated recommendations by the Energy Commission and the solar industry, the CPUC has failed to lower incentive levels to align with those in the Emerging Buydown Program. As a result, the Self Generation Incentive Program is chronically oversubscribed, while the high incentive levels may be causing distortion in the Emerging Buydown Program.

The principles outlined in the *2004 Energy Report Update* for a successful and rational PV program still apply today. Achieving the scale proposed by the Governor requires a broad program that includes all residential and commercial buildings, whether existing or new. Also, because leveraging energy efficiency improvements should be a key consideration in deploying PV, new homes should be required to exceed current building efficiency standards, while existing buildings should be required to improve their efficiency by a fixed percentage. Similarly, PV installations should be linked to dynamic pricing tariffs and advanced metering to use solar systems to meet peak load, thereby lowering electric system costs and rates. Further, to provide the most benefit, solar installations should be targeted to climate zones with high peak demands for air conditioning.

A sound solar program should also include consistent, long-term declining incentives to provide the volume of sales and commitment needed to bring manufacturing and other costs down. The failure of the state's PV incentive programs to bring costs down, and the severe oversubscription in those programs, indicates that up-front rebates may not be the most efficient use of public funds to achieve the goal of a sustainable solar industry. Instead, as articulated in the *2004 Energy Report Update,* the state should transition to performance-based incentives to promote more cost-effective public funding in terms of long-term energy generation per dollar of incentive support. A truly sustainable solar program will pay for kWhs produced rather than for system installation with no measure of performance to ensure that systems are appropriately installed and functioning correctly.

A consolidated solar program should also include solar hot water technologies. While PV systems can shave peak electricity demand, solar thermal technologies can displace natural gas use and help reduce California's overwhelming dependence on natural gas. Importantly, in designing a scaled-up PV program, the state needs to better understand the failure of previous solar water heating programs in the 1980s in order to learn from past mistakes.

Massive deployment of PV systems on the scale envisioned by Governor Schwarzenegger requires a willing partnership with the operators of the distribution system because of the volume of interaction with the electric grid entailed by such deployment. Development of a unified solar program therefore requires careful

exploration of a viable business role for utilities, as recommended in the *2004 Energy Report Update*.

The Energy Commission and the CPUC are working together to develop a unified PV program, with a proposed decision from the CPUC expected later in 2005. Such a program should have consistent funding levels and establish a performance-based incentive structure for both commercial and residential systems. In addition, the program should integrate energy efficiency and time-of-use rates to provide maximum benefits to PV purchasers and electricity consumers. The program must also be designed specifically to achieve the scale of PV penetration envisioned by the Governor. Most importantly, the overall aim of the program should be the efficient administration of funding to achieve the state's solar goals at the least possible cost.

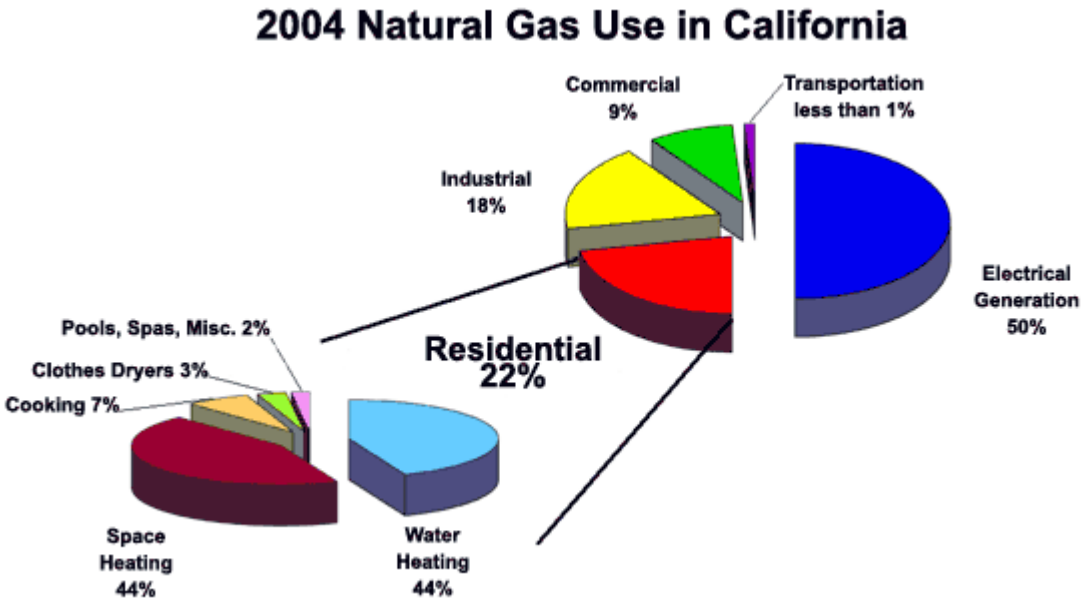
CHAPTER 7: THE CHALLENGES AND POSSIBILITIES OF NATURAL GAS

Introduction

California faces significant challenges in ensuring adequate natural gas supplies at reasonable prices to meet its growing natural gas demand. In the largely deregulated natural gas arena, California competes on a theoretically level playing field with the entire North American market. However, the state's geographic location — literally at the end of the interstate pipelines — poses significant challenges to securing adequate and reliable supplies of natural gas at reasonable prices.

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

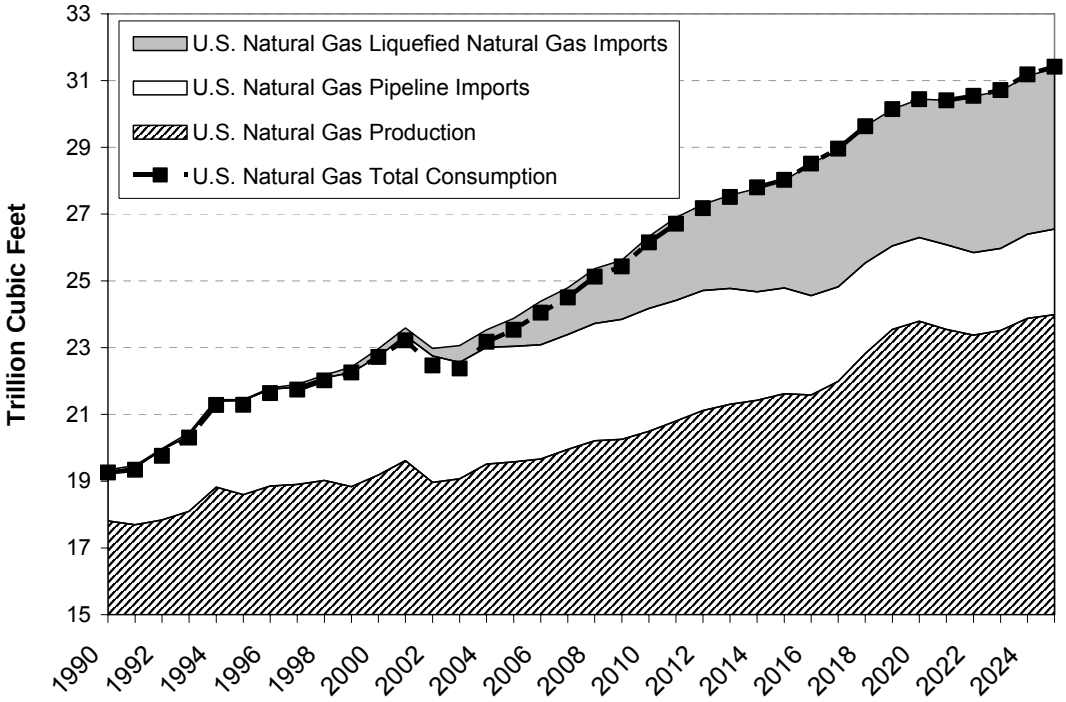
Figure 17



California's natural gas demand growth is expected to be slower than the rest of the nation's due largely to the state's energy efficiency programs and the use of renewable energy for electricity generation. Nevertheless, the demand growth is increasing steadily. In-state natural gas production 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, businesses, and economy. New natural gas supplies are increasingly difficult to find and

produce nationally, and the gap between U.S. demand and domestic supplies is widening each year, as shown in Figure 18.

Figure 18: Projected U.S. Natural Gas Supply and Demand



Source: U.S. Energy Information Administration.

Natural gas supplies to California are affected by 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 be unable to keep up with the growing demand for natural gas, further intensifying competition for already scarce supplies.

Recent infrastructure improvements have reinforced California's interstate and intrastate pipeline and storage capacity and its ability to bring in, distribute, and store available supplies to meet average annual demand. However, hurricanes Katrina and Rita reduced production in the Gulf of Mexico, demonstrating that even currently available supplies might not be accessible at all times.

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.[187] Higher natural gas prices inevitably mean higher electricity prices.

[187] California Energy Commission, *Revised Reference Case in Support of the 2005 Natural Gas Market Assessment,* September 2005, CEC-600-2005-026-REV.

The uncertainty of domestic 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 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.

Natural Gas Demand

Natural gas use in the power generation sector accounts for the bulk of the state's increasing demand. Although Californians continue 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.

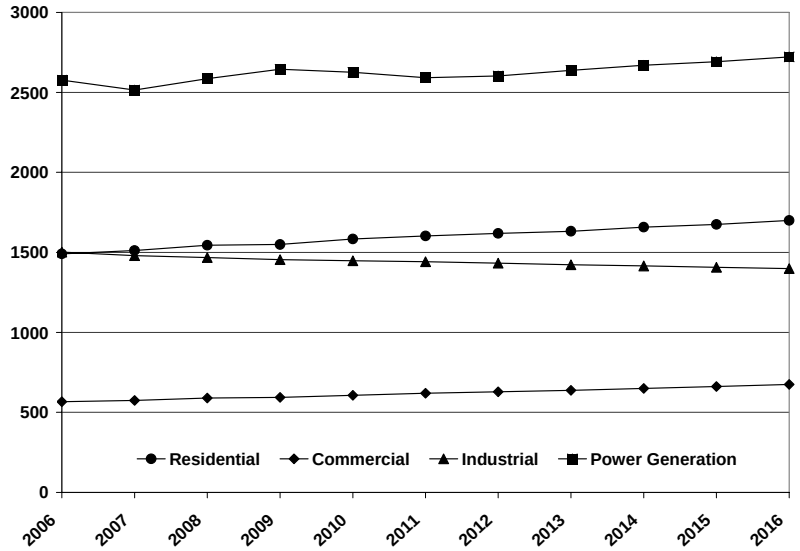
Electricity demand in the short term can fluctuate dramatically depending on the weather. Hot temperatures in the summer indirectly increase natural gas demand by increasing electricity demand for air conditioning; cold temperatures in the winter directly increase natural gas demand for heating. Variations 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. As shown in Figure 19, the Energy Commission expects residential natural gas use to increase by 1.3 percent per year and commercial natural gas use to increase by 1.8 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 likely to respond to currently rising natural gas prices. [188]

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 1.64 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.[189] Three-quarters of total demand growth in North America stems from increased natural gas consumption for power generation.

[188] California Energy Commission, *Revised Reference Case in Support of the 2005 Natural Gas Market Assessment*, September 2005, CEC-600-2005-026-REV.
[189] Ibid.

Figure 19: California Natural Gas Demand Projection by Sector (MMcfd)



Source: California Energy Commission

With the ongoing success of California's efficiency programs, natural gas demand growth in the state is expected to be lower than that in the rest of the nation over the next decade. California's energy efficiency programs over the last three decades have reduced natural gas use per household by more than half since 1975.[190] 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.

Past forecasts projected California's demand for natural gas for power generation to increase more quickly than demand in other sectors.[191] Now, however, the demand for gas in California's electricity sector is expected to grow at a relatively modest rate of 0.6 percent per year through 2016 as newly built power plants become operational and aggressive energy efficiency in electricity end uses and higher prices dampen demand. Without the addition of new, more efficient power plants to reduce the state's dependence on older, less efficient generation facilities that use more natural gas, California's dependence on natural gas for electricity generation would have grown much more rapidly. California's aggressive RPS will also reduce the electricity generating load from gas-fired facilities, 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

[190] Ibid.
[191] California Energy Commission, *Natural Gas Market Assessment*, CEC-100-03-006, August 2003.

resource plans for several western states, which could dampen projected natural gas demand growth for electricity generation in those states. Greater interest in renewable generation in other western states could also reduce their natural gas demand for power generation.

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.

Recommendation:

- 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 should therefore 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 traded in the markets exceed $9.85 per thousand cubic feet (Mcf).[192] 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 natural gas spot prices rose to over $14/mmBtu at the national pricing point at Henry Hub and over $16/mmBtu for delivery to the New York area in both late September and again in late October. During this same time, the wholesale natural gas market prices at the Southern California border were in the $10-11/mmBtu range, a significant savings under most national prices. Although California's wholesale prices increased due to the hurricane, they did not increase as much as those in the rest of the nation. The discount to the national average for California consumers widened from $0.90 per Mcf to $2.60 per Mcf during this same time period.

At the customer level, higher natural gas prices can mean higher natural gas bills if consumption stays the same, 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 50 to 70 percent higher than last winter, depending upon the region. At the wholesale level, higher natural gas prices also mean higher costs to generate electricity, which translate into higher costs for electricity ratepayers.

[192] Expressed in 2004 dollars converted from $10 per million British thermal units expressed in 2005 dollars.

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 could be a drop in natural gas prices over the next several years with the introduction of large new supplies into the market such as LNG and major pipeline additions, Energy Commission staff models project a general increase in national natural gas wellhead prices over the next decade. The general increase reflects the growing 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 $8.41 and $11.65 per Mcf.

Commercial customers can expect to pay between $7.57 and $9.72 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 $5.13 and $9.72 per Mcf over the next 10 years.

Natural gas prices for electricity generators are expected to fluctuate between $4.24 and $7.00 per Mcf over the next 10 years and vary based on whether or not the generator is served by a natural gas utility or takes its fuel supplies directly from another source, such as an interstate pipeline or local gas producer, as well as where the generator is located and when the facility began operation.

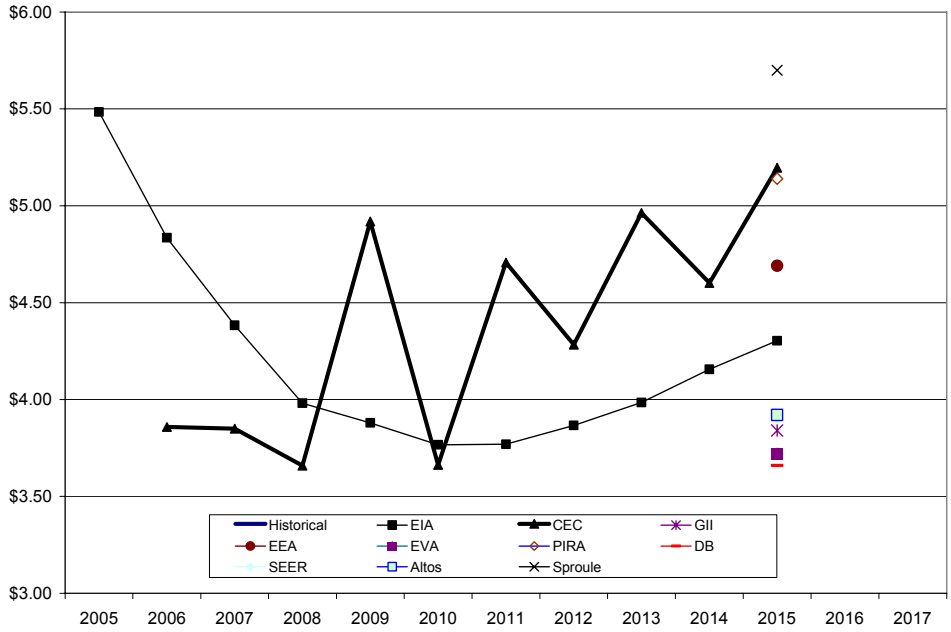
Since the energy crisis of 2001, natural gas prices that were anticipated to revert to the trends of the previous 10 to 15 years have instead consistently remained high. Global crude oil markets, a decreasing rate in finding new natural gas supplies, and events related to weather — most recently Hurricanes Katrina and Rita — have continued to put pressure on natural gas prices across the nation. Generally, when hurricanes impact the industry, producers and pipelines recover and resume normal operations within one to three months. However, the repeated and harsh impacts of this season's two major hurricanes have dramatically increased natural gas prices, with price and supply effects possibly lasting for more than six months. These trends will likely continue to place upward pressure on natural gas prices. It is the industry's anticipation that the prices may not back down from the high levels seen today for a significant period of time.

The Energy Commission staff forecast does not consider such unanticipated events in its price projections. The staff model is based on market fundamentals that normally drive the supply-demand balance in a well functioning market; this model and other

similar ones have a long history of providing reasonably accurate forecasts. Yet, clearly, today's market prices are substantially higher than the staff's forecasted prices.

In the past five years, numerous events have driven prices away from a fundamental forecast of future prices. In addition to the hurricanes, price manipulation documented in the Enron scandal and the misreporting of the natural gas price indices are examples of events that make comparing the staff forecast — or any other forecast — with natural gas market prices increasingly problematic. Existing equilibrium model forecasts relied on by Energy Commission staff and others cannot adequately capture such events in advance with any accuracy, but such events do have a very real effect on market prices. The Energy Commission notes that a fundamentals forecast may underrepresent future market prices.

Figure 20: Natural Gas Wellhead Price Forecast Comparison Lower 48 States (2005$/Mcf)



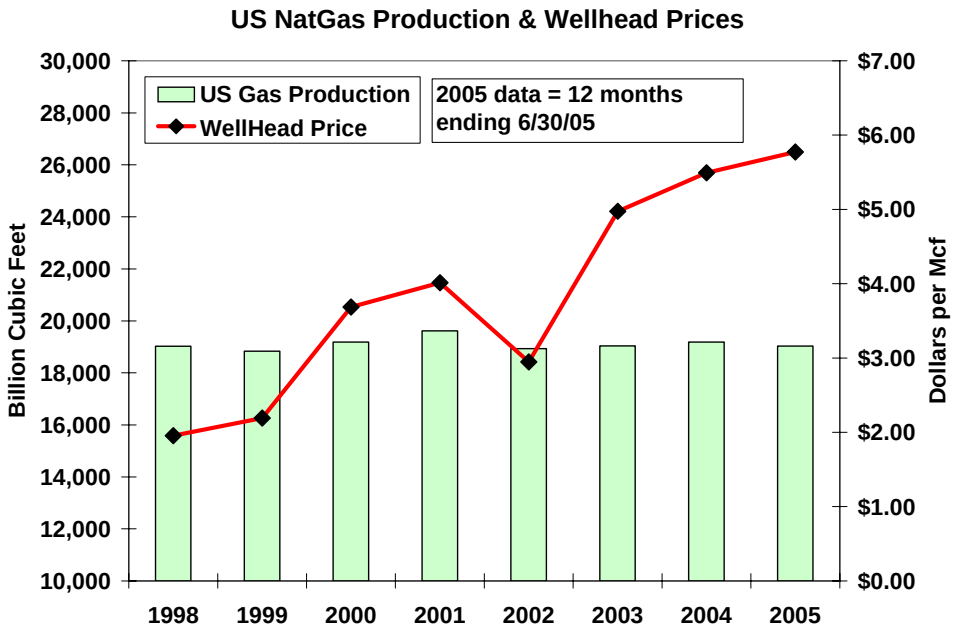
Source: California Energy Commission

The Center for Energy Efficiency and Renewable Technologies (CEERT) noted in its comments that current natural gas prices reflect large scarcity rents above the marginal costs of production that consumers are paying. It further notes that equilibrium models like the Energy Commission staff NARG model fail to capture this discrepancy.[193] While recognizing the difficulty in projecting what the scarcity price of natural gas will be in the future, CEERT points to this failure as a major shortcoming in staff's current approach to forecasting natural gas prices.

[193] Presentation by Rich Ferguson, Center for Energy Efficiency and Renewable Technologies, Transcript of the October 7, 2005 IEPR Hearing on Natural Gas Issues, pp.87-107.

As shown in Figure 21, despite the high prices being paid for gas over the last few years, U.S. production has not increased, and not, as CEERT points out, because the gas industry has not tried. In fact, the number of wells drilled per year has followed producer prices fairly well. CEERT further notes that if U.S. production hasn't increased at today's high prices, it is unlikely to increase in the foreseeable future, especially if LNG supplies reduce current well-head prices, as staff assumed in its assessment. The Commission noted that CEERT made a similar critique of staff's forecast in the *2003 Energy Report* process. While the Energy Commission shares concerns about this dilemma, it also notes that some parties provided comments that the Energy Commission's price forecast is too low, while others criticized it as too high.

Figure 21



Source: Center for Energy Efficiency and Renewable Technologies, Comments on the Draft IEPR Chapter 7: Natural Gas, October 14, 2005, based on EIA data.

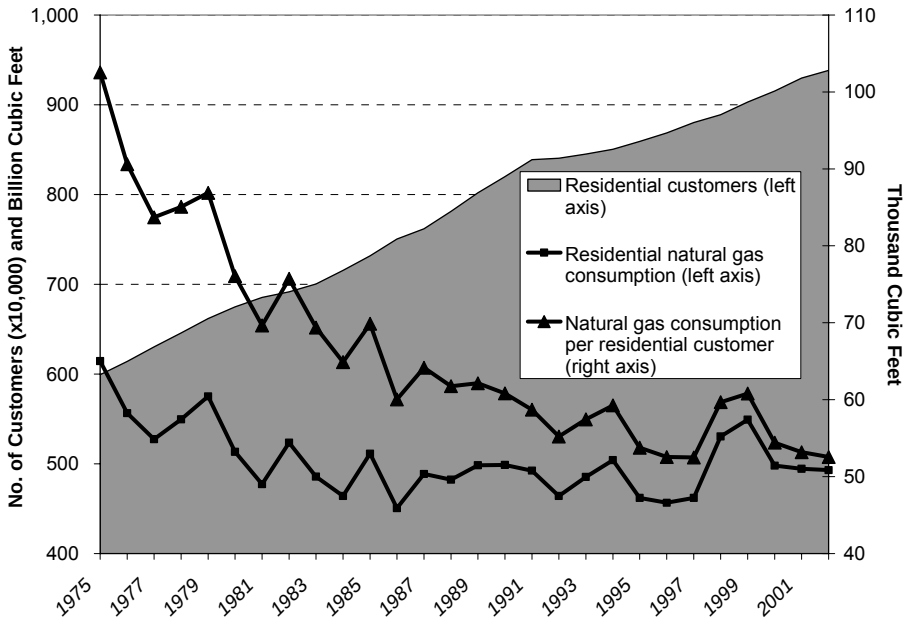
The Energy Commission will adopt the staff's forecast for the *2005 Energy Report* with the caveat that it should be augmented for its first two years by NYMEX prices. The Energy Commission should further investigate alternative forecasting methods in the *2007 Energy Report* cycle to better assess future natural gas prices.

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. Historically, energy efficiency has been highly effective as a means to reduce demand. As an example, today's households use almost one-half the natural gas that households used in 1977, as seen in Figure 22. This fact is even more impressive when considering that today's average

new home is considerably larger, and most new homes are being built in the harsher climates of the Central Valley, Inland Empire, and inland San Diego County.

Figure 22: Residential Natural Gas Consumption



Source: California Energy Commission

The *2003 Energy Report* recommended that the state decrease natural gas use by increasing funding for natural gas efficiency programs. In addition, the recently enacted SB 1037 requires gas utilities to first meet any unmet resource needs with all available energy efficiency and demand reduction resources that are cost-effective, reliable, and feasible.

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 2005 the CPUC authorized an additional $300 million in funding for natural gas efficiency programs for 2006-2008.[194] 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.[195]

[194] CPUC Decision 05-09-043, September 22, 2005, "Interim Opinion: Energy Efficiency Portfolio Plans and Program Funding Levels for 2006-2008 – Phase 1 Issues," http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/49859.htm], accessed October 24, 2005.
[195] 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 (CHP) 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. Additional savings may be available from the use of pressure drops in pipelines, flared gas, and "recycled energy," in which energy is recovered from industrial off-gases. To take full advantage of CHP facilities and recycled energy, however, California needs to address a number of policy and institutional barriers, as identified in Chapter 4.

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.[196] In 2005, the Energy Commission, with the concurrence of the CPUC, initiated a Public Interest Energy Research program on natural gas (PIERNG). 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.

Recommendation:

In light of the current high wholesale prices for natural gas, the CPUC's goals may not capture the maximum potential cost-effective savings. The Natural Resources Defense Council has indicated that the CPUC's natural gas savings targets represent only about 40 percent of the achievable potential.[197] The Energy Commission recommends:

- The CPUC should increase natural gas savings targets beyond their current level during its next goal revision.
- The CPUC and the Energy Commission should rigorously evaluate, measure, and monitor natural gas efficiency programs to ensure that they produce the intended savings and that public funds are well spent.

[196] CPUC R.02-10-001.
[197] Testimony of Audrey Chang, Natural Resources Defense Council, Transcript of the October 7, 2005 IEPR Committee hearing on Challenges and Possibilities of Natural Gas, pp. 57-58.

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.[198] 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 and reductions in industrial demand due to flooded refineries and petrochemical complexes made up for the loss of production. Production resumed at half its normal pace, but full production is not expected to resume for many months.

Domestic natural gas production is expected to remain almost the same over the next decade and 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 by the state's reliance on 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 by almost 1 percent per year despite efforts by government and industry to increase production.

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 online 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

[198] California Energy Commission, *Revised Reference Case in Support of the 2005 Natural Gas Market Assessment*, September 2005, CEC-600-2005-026-REV.

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 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 unfavorable cost recovery rules at FERC precluded development of a proposed private storage facility near Phoenix. To address the problem, the FERC is exploring the option of granting market-based rates to new independent storage developers not affiliated with existing pipelines. A less direct solution would be the development of a storage facility inside California that is tied directly to one of the pipelines coming from Arizona. This solution, however, 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 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. LNG is one such potentially cost-competitive and reliable source. Chilling and pressurizing natural gas reduces it to a liquid form and condenses its volume by 600 percent. This significant reduction in volume enables bulk shipping and storage before the liquid gas is revaporized into its gaseous state without any change to its chemical properties. Condensation allows importers to transport the liquefied gas over water, exponentially expanding the supply of natural gas.

Currently, the U.S. imports LNG into five receiving and regasification terminals in the lower 48 states to balance demand with total supply. LNG import facilities in North America that are under construction will increase natural gas supplies available to the U.S. over the next 10 years and will help meet California's additional natural gas needs by increasing total domestic supplies. In 2004, LNG imports made up 3.3 percent of total U.S. supply. By 2016, the Energy Commission staff expects that LNG will provide up to 22 percent of the total U.S. supply.

Of the five existing LNG facilities in the U.S., none is 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 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, there are three proposed facilities including the Terminal GNL Mar Adentrode Baja and the Moss Maritime LNG, both of which are off-shore projects, and the Sonora LNG facility.

Construction has begun on a fourth project, Energia Costa Azul, expected to be online in 2007. For California to access new LNG supplies, however, additional or modified pipeline infrastructure may be necessary.

The costs to deliver natural gas to the West Coast via an LNG project could be 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 21 state, local, and federal agencies to ensure all the reviewing agencies have a common set of information and are able to resolve administrative issues quickly.

An example of this working group's effectiveness was recently demonstrated. The federal Energy Policy Act of 2005 allows for any coastal governor to designate an agency to consult with the FERC on LNG import terminal safety issues and to also prepare a Safety Advisory Report on active terminal applications. Governor Schwarzenegger designated the Energy Commission to coordinate its review with the working group. With this group's active cooperation, the Energy Commission was able to produce a lengthy report on Sound Energy Solutions' proposed LNG import terminal at the Port of Long Beach within the 30 days allowed by law. In fact, California was the only state to have exercised this option. The FERC is still considering the more than 100 issues identified in the Safety Advisory Report.

The types of issues raised in the Safety Advisory Report included safety concerns for the import terminal and tanker operations. In a separate letter to the U.S. Coast Guard regarding its Waterway Suitability Assessment for the Port of Long Beach project, the Energy Commission detailed additional concerns and requested a response to three major areas:

- 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.

In addition, the LNG Interagency Permitting Working Group is involved with the review of the offshore LNG import terminal applications. The Cabrillo Port LNG Import Terminal proposed by BHP Billiton is currently in the middle of its application review process. Members of the working group are supporting both the U.S. Coast Guard and the California State Lands Commission, the lead federal and state permitting agencies. The working group has an added responsibility to provide information directly to the Governor for his ultimate decision to approve, approve with conditions, or deny this project, an action allowed by federal law for offshore projects but not onshore projects.

Potential Supplies from Alternative Sources of Natural Gas

To 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 a 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 that could still be converted to useful energy. Each of these potential alternatives presents technological and cost challenges to ensure that produced gas meets quality specifications and environmental protection requirements. Fortunately, these challenges are appropriate subjects of the state's natural gas research and development program.

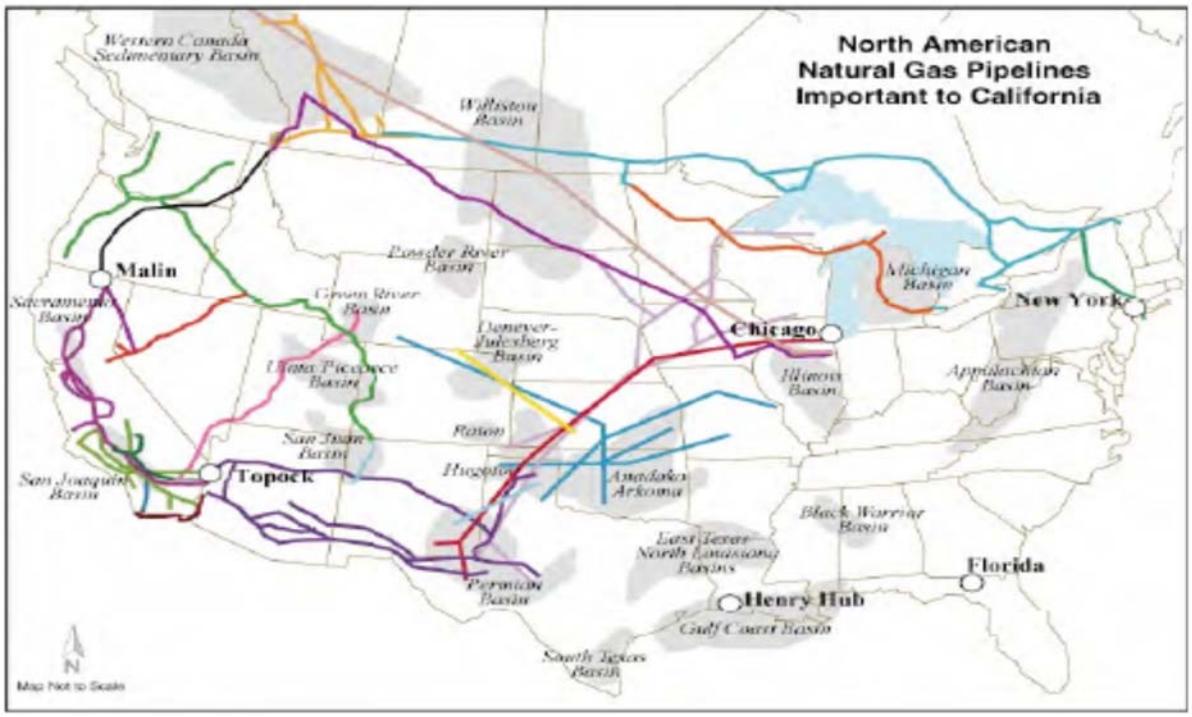
Using Infrastructure to Ensure Adequate Natural Gas Supplies

As 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 energy 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 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. It will also benefit from 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 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 they actually receive.

Figure 23: North American Natural Gas Pipelines



With 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.

The state is considering other projects 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. Total energy content, or heating value, is the component of gas quality that is of major concern. 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. The program plans further research efforts 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 ARB, 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, consumers, and LNG

project developers to accelerate resolution of natural gas quality issues in California. As a result, the ARB 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. Resolution of the issue of natural gas quality is expected 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 immediately recognizable aspect of this link is large-scale hydroelectric generation, the amount of energy used by the state's water infrastructure and water end-users is at least equally significant – and growing fast. The Energy Commission evaluated the relationship between water and energy systems to better understand this link and determine what, if any, mutually beneficial strategies can be developed to improve both the water and energy sectors. As a result of this initial work, the Energy Commission determined that much can be done to improve both systems.

California's water infrastructure uses a tremendous amount of energy to collect, move, and treat water; dispose of wastewater; and power the large pumps that move water throughout the state. California consumers also use energy to heat, cool, and pressurize the water they use in their homes and businesses. Together these water-related energy uses annually account for roughly 20 percent of the state's electricity consumption, one-third of non-power plant natural gas consumption, and about 88 million gallons of diesel fuel consumption.

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

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 not be able to meet the water needs of their customers. There are many opportunities to improve the performance of both systems by focusing on areas of mutual benefit. Particularly significant is the fact that Northern California receives two-thirds of the state's precipitation while two-thirds of the population lives in Southern California. Because of the distance and elevation involved in transporting water from Northern to Southern California, reducing water use in Southern California has more energy savings potential than reductions in other parts of the state.

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

Power plants use a significant volume of water, primarily for cooling. This water demand by power plants can have a significant effect on local water supplies. 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 in power plant cooling systems. California has a number of power plants along its bays and coastline that use once-through cooling. The state has the opportunity to more comprehensively study the impacts of once-through cooling on the marine environment as part of the Governor's California Ocean Protection Council efforts, as well as the State and Regional Water Quality Control Boards' review of impacts under Section 316(b) of the federal Clean Water Act.

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

Water Sources and Supplies

California receives its water from two sources: surface water and groundwater. Surface water includes natural lakes and streams as well as manmade reservoirs, canals, and aqueducts. Groundwater supplies about 30 percent of the state's average water demand but can supply as much as 60 percent during periods of extended drought. California's groundwater aquifers store several hundred million acre-feet of water, compared with approximately 45 million acre-feet stored in the state's 1,200 reservoirs.[199] Pumping groundwater uses significant amounts of energy. Many of the state's groundwater aquifers are in decline as water is pumped out faster than it is replaced so that the water must be pumped from greater depths, requiring even more energy.

Water storage in the state relies upon surface impoundments, especially in major water projects, the Sierra snowpack, and groundwater. The Sierra snowpack is a key element in both the state's water supply and energy production. The annual snowpack essentially "stores" water that is later released slowly during the spring and summer into reservoirs, some of which also serve for flood control. Stored water is also used later in the summer to generate hydroelectric electricity.

[199] 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.

California's growing population is putting great pressure on municipalities to secure enough water to meet that growth. Faced with limited fresh water, many agencies are using recycled water to meet their non-potable needs. The fastest-growing source of new water supplies is recycled wastewater from municipal and other systems. This water is treated to stringent health and quality standards before it is reused. Recycled water can substitute for fresh water in power plant cooling and other industrial processes, landscape irrigation, and to replenish groundwater aquifers.

Another option that many cities are considering to meet their future water demand is desalination, a process that removes salt from brackish water[200] or seawater. Because desalination is one of the very few options for increasing present water supplies, water agencies may build and operate many of these facilities in the future. Desalination facilities may make more economic sense in areas that have high energy and treatment costs for their current water supplies, like Southern California's urban areas.

California will face reduced water supplies in the future because of enforcement of the Colorado River Compact, which was signed in the early 1920s and apportions water from the Colorado River among several western states. California has historically used more than its allotted water because the other states were not using their full allotments. Since water demand in the Colorado River basin and Arizona is increasing dramatically, California can no longer use part of their water allotments. This will significantly impact water agencies in the southern part of the state.

Producing Energy from Water

Perhaps the most widely recognized aspect of the water-energy relationship is hydroelectric power generation in the state's hydroelectric power plants and pumped storage facilities. However, other opportunities exist to increase energy supplies from water and wastewater utilities. 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 full development of self-generation by water and wastewater utilities. Interconnection constraints and prohibitive market rules discourage customer self-generation. Limitations on net metering and constraints on service account aggregation also prevent self-generation for geographically remote customer loads.

[200] Fresh water aquifers containing salts, minerals or other contaminants that require high levels of treatment require only about one-third the energy to treat when compared to sea water desalination – Source: Inland Empire Utilities Agency and MWD 2005 water source energy intensity reports.

Hydroelectric Power

California is served by a vast network of reservoirs and dams, pumped storage, and run-of-river facilities. These facilities are operated by IOUs, POUs, state and federal agencies, irrigation districts and other entities, mostly for multiple purposes including power generation, water supply, recreation, and flood control. California's combined total hydroelectric capacity is more than 14,000 MW,[201] or about 25 percent of in-state generating capacity in an average precipitation year. In 2004, hydroelectric generation was about 29,000 GWh, or 13 percent of in-state generation.[202] California's hydroelectric system provides valuable peaking reserve capacity, spinning reserve capacity, load following capacity, and transmission support, all at low overall production cost since there is no associated fuel cost.[203]

Opportunities for construction of new hydroelectric plants and pumped storage projects are extremely limited in California. Most economically viable sites have already been developed, and development of 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 FERC between 2000 and 2015. FERC normally issues licenses for a period of 30-50 years, after which facilities must apply for relicensing. The five-year public relicensing period offers an excellent opportunity to reduce or resolve the ecological impacts of these facilities. The *2003 Energy Report* recommended that the Energy Commission continue its efforts to help state and federal agencies more fully understand the effects of these facilities on regional and statewide electricity supply.

The most contentious relicensing issue for the state's hydroelectric projects is the competing allocation of water between the in-stream flows needed to sustain a healthy aquatic ecosystem and the amount of water diverted to 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 available water for hydroelectric generation. The Energy Commission's Public Interest Energy Research (PIER) program has proposed research to improve the process of determining in-stream flows through the development and demonstration of new tools or the enhancement of existing tools. This research promises to ensure better environmental protection while reducing unnecessary curtailments of hydroelectric generation.

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[201] California Energy Commission, *2003 Environmental Performance Report. Appendix D, California Hydropower System: Energy and Environment*, CEC-100-03-018, March 2003, p. D-6.
[202] 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.
[203] California Energy Commission staff report, *California Hydropower System: Energy and Environment, Appendix D, 2003 Environmental Performance Repor";* 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.

There are opportunities to enhance existing hydroelectric generation without causing further environmental damage through improved runoff forecasting and decision support models. Hydroelectric operators can benefit from a 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 other generating devices installed in conduits (pipelines, canals, and aqueducts) to generate electricity from water flowing 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. [204] The potential was split fairly evenly between municipal and irrigation district systems. This electricity production could be used to offset the energy demand of the conveyance system itself or sold into the grid.

In-conduit hydropower facilities are attractive because they are generally easier to license, tend to have fewer environmental impacts compared with other hydroelectric facilities, and, because they are generally small, are more likely to meet requirements of the state's RPS program.[205] In most cases, in-conduit hydropower potential ranges from 1-2 kW to about 1 MW. However, many existing in-conduit facilities are facing the future challenge of the expiration of their standard offer power purchase contracts with the state's IOUs.

Existing rules do not credit power produced against a water or wastewater utility's total energy bills. Instead, wherever 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 small generators. Many of the arguments made on behalf of combined heat and power in Chapter 4 apply equally well to water agency self-generation.

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

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[204] California Energy Commission, *California Small Hydropower and Ocean Wave Energy Resources*, Mike Kane, Public Interest Energy Research program, April 2005.
[205] The RPS limits eligibility of hydroelectric facilities to 30 MW or less.

Biogas Recovery

Some of the electricity needed to process wastewater can be used to produce digester biogas from anaerobic digesters installed at or near wastewater treatment facilities 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 than 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 the discharge of air and groundwater pollutants.

Current rules discourage the full use of available biogas for either 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 by wastewater agencies.

Recommendation for Increasing Energy Production from Water:

- 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 selfgenerate and use the produced electricity to offset power requirements at their other locations and for multiple accounts 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.
  - Evaluating potential incentives to support the development and/or operation of in-conduit hydroelectric facilities.

Energy Use in California's Water Use Cycle

California uses about 14 trillion gallons of water in a normal year, with about 79 percent going to agriculture and the remainder to the urban sector.[206] Once water is collected or extracted from a source, it is transported to water treatment facilities and distributed to end users. Wastewater from urban end uses is collected and treated before it is discharged back into the environment, where it becomes a source for other uses. In

[206] California Department of Water Resources, Bulletin 160-2005 provides the breakdown of urban and agricultural water use.

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 as runoff into natural waterways or groundwater basins. As mentioned above, there is a growing trend to recycle some portion of the wastewater stream and redistribute it for non-potable end uses.

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.[207] As shown in Table 3, total water-related energy consumption is large, using roughly 19 percent of all electricity used in California, approximately 32 percent of all natural gas, and 88 million gallons of diesel fuel. These numbers are, however, preliminary, and are being refined through a 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

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

Source: California Energy Commission, *California's Water-Energy Relationship*, Final Staff Report, 2005.

Each element of the water use cycle has a unique "energy intensity," which is the amount of energy consumed per unit of water to perform water management-related actions such as desalting, pumped storage, groundwater extraction, conveyance, or treatment. The less energy required to perform such actions, the lower the energy intensity. Table 4 illustrates the considerable variability in the range of these intensities, followed by a description of each segment of the water cycle.

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

Table 4: Energy Intensities in the Water Cycle[208]

	Range of Energy Intensity (kilowatt hours/MG)	
Water Cycle Segments	Low	High
Supply and Conveyance	0	14,000
Treatment	100	16,000
Distribution	700	1,200
Wastewater Collection and Treatment	1,100	4,600
Wastewater Discharge	0	400
Recycled Water Treatment and Distribution	400	1,200

Source: California Energy Commission, *California's Water-Energy Relationship*, Final Staff Report, 2005.

Supply and Conveyance — Water must be transported long distances and over great elevations to reach the urban centers of the state, especially 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 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. Some portions of this energy can be recaptured through hydroelectric generation that uses the gravity of descending water to generate electricity.

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, refined chemicals, and hazardous compounds. Proposed regulations[209] 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 upon 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 pump both liquids and solids. Recycled wastewater requires even more energy.

Recycled Water Treatment and Distribution — Most wastewater treatment facilities in the state treat their effluent to a secondary standard, making it possible to further treat

[208] The energy intensities in Table 4 are non-additive and reflect ranges of recorded energy use by water cycle function.
[209] To comply with the federal Safe Drinking Water and Clean Water Acts.

the effluent to recycled water standards and expand available water supplies for non-potable uses.

Energy Consumption by Water End Users

Together, agricultural, residential, commercial, and industrial water-related end uses account for 58 percent of all water-related electricity and 99 percent of water-related natural gas use in California. The remaining 42 percent of water-related electricity is used to get the water to the end user at usable quality and to treat the discharged wastewater.

Agriculture

Each year California's agricultural sector consumes more than 10,000 GWh of electricity along with significant amounts of diesel fuel and natural gas to pump and move roughly 34 million acre-feet of water. Although most of that electricity use occurs during the summer, 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, an important air quality strategy, will also increase electricity use.

Residential, Commercial, and Industrial

Urban water use in California tends to be more energy intensive than in the agricultural sector because urban water systems use energy for pre-treatment as well as wastewater treatment, which is not generally required for agriculture, and because interbasin transfer systems are used primarily for urban water supplies.

The residential sector accounts for 48 percent of the electricity and natural gas consumption associated with urban water use. Residential energy uses include everything from water filtering and softening to heating and cooling to circulating water in a spa pump and, in some cases, pumping groundwater from private wells. In the residential sector, the major water-related electricity end uses are water heating and clothes drying. Water heating is also the major user of 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 used 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.

Water is used by California's petroleum industry for refining and enhanced oil recovery operations. A typical refinery uses an average 65-90 gallons of water per barrel of crude oil processed, and produces about 50-60 gallons of wastewater that generally must be treated prior to reuse or disposal; the difference is lost through evaporation.[210]

Recommendations for Energy Savings by End Users:

- The Energy Commission, the California Department of Water Resources, the CPUC, water agencies, POUs, and other stakeholders should explore and pursue cost-effective water efficiency opportunities that could result in significant energy savings to decrease the energy intensity of the water sector.
- These opportunities 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 IOU energy efficiency portfolios.

Storing Electricity for Peak Generation and Peak Load Shifting

California has a number of pumped storage hydro facilities. In pumped storage facilities, water is pumped from a lower to a higher reservoir during off-peak times and is used to generate electricity when peaking power is needed. Pumped storage is generally considered the only commercially viable method for the large-scale storage of electricity. California has more than 4,000 MW of pumped hydro storage capacity, with about 2,700 MW in the CA ISO control area.[211] Two pumped storage projects that would add as much as 900 MW of generating capacity are in the FERC permitting stage but face opposition because of potential water resource, biological, visual, wilderness, and recreational impacts.

Pumped storage can minimize the system impact of integrating large volumes of intermittent wind resources into the state's power grid by absorbing electricity generation during high-wind periods that would otherwise cause operational problems for system operators.[212] Pumped storage can also be used in tandem with wind resources to shift delivery of wind energy from off-peak to on-peak periods during the

[210] CH2M HILL, July 2003, *Water Use in Industries of the Future*, prepared under contract to the Center for Waste Reduction Technologies for United States Department of Energy, Office of Energy Efficiency and Renewable Energy, Industrial Technologies Program.
[211] CA ISO, "Role of Energy Storage in California ISO Grid Operations," presented by David Hawkins, Manager, Special Projects Engineering at California Energy Commission/Department of Energy 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.
[212] 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].

day and smooth out production spikes.[213] One example is the SMUD's proposed 400 MW pumped storage hydro facility in El Dorado County, which is intended to make the utility's wind energy projects more dispatchable.[214] Outside of California, the Pacific Northwest's Bonneville Power Administration offers a storage and shaping service that integrates and stores hourly wind energy generation from 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 electricity. A U.S. Department of Energy (DOE) study has identified dozens of reservoir pairs in California that could yield as much as 1,800 MW of new pumped-storage generation. This option avoids construction of new reservoirs but still faces the challenges of siting and building large pipelines in difficult terrain on protected lands.

Water storage can also 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 with the creative use of water storage, including refilling water storage tanks during off-peak periods. Additional treated water storage in urban areas could also save 1,000 MW of peak demand. Together these savings would represent more than a third of the peak load from the water cycle.

Recommendations for Electricity Storage:

- The Energy Commission's PIER program should evaluate and conduct research to examine opportunities to shift loads off peak and integrate intermittent renewable generation by maximizing use of storage in existing pumped hydro facilities and increasing use of water storage tanks and conveyance systems.

Water for Power Plant Cooling

California's 21 coastal power plants provide nearly 24,000 MW of generating capacity. These plants use "once through cooling," which passes up to 17 billion gallons of seawater per day through a heat exchanger before returning it to the ocean. Recent studies indicate that this use of seawater for once-through cooling can contribute to the decline of fisheries and the degradation of estuaries, bay, and coastal waters.[215] When

[213] CA ISO, "Role of Energy Storage in California ISO Grid Operations," presented by David Hawkins, Manager, Special Projects Engineering at California Energy Commission/Department of Energy 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.
[214] SMUD, *Relicensing Hydro UARP FERC. No. 2101: Proposed Iowa Hill Pumped Storage Development*, [http://hydrorelicensing.smud.org/docs/docs_iowa.htm], accessed April 30, 2005.
[215] 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].

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 because it returns seawater to the ocean at a higher temperature after passing through plant heat exchangers, affecting the early life stages of fish and shellfish.

In 2004, Governor Schwarzenegger established the Ocean Protection Council 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 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 fragile 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 federal Clean Water Act to reduce the 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.

Recommendations for Once-Through Cooling

- The Energy Commission's PIER program should continue to collaborate 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 for assessing the ecological effects of once-through cooling.
- The Energy Commission should update its current Memoranda-of-Understanding Agreement with the State Water Quality Control Board, the 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 use of best-available retrofit technologies to minimize impacts on 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 should update current data adequacy regulations with respect to once-through cooling at the state's coastal power plants. 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.

The Impact of Water Efficiency on Energy Use

Agricultural Water Use Efficiency

Because of the large amount of energy consumed in California's water cycle, reducing water use also saves energy. Efficient irrigation techniques hold promise for substantially reducing the amount of water delivered. Agricultural water conservation can also increase on-farm energy demand, such as the energy required to pressurize drip and microspray irrigation systems, but this increase can be more than offset by greater on-farm irrigation system efficiency and operations, and by energy reductions associated with delivering less water. Utilities and agencies are also addressing agricultural energy use with several targeted 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 IOUs.

Large numbers of both PG&E and SCE agricultural customers have signed up for 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 half of the utility's 80,000 agricultural accounts.[216] In the SCE service area, 71 percent of agricultural kWh sales are on TOU rates, generated by 18 percent of customer accounts.[217]

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 maximize crop growth. Agricultural electricity end users would benefit from energy policies that allow customers to choose the demand response practices that best fit their businesses. The industry will be more inclined to invest in peak load reduction measures if given flexibility and 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 at about 651 billion gallons per year.[218] In early 2005, the California Urban Water Conservation Council (CUWCC) posted the results from 32 percent of the

[216] Communication between Ricardo Amon and Keith Coyne, PG&E, August 4, 2005.
[217] Communication between Ricardo Amon and Cyrus Sorooshian, SCE, August 11, 2005
[218] Waste Not, Want Not. The Potential for Urban Water Conservation in California. Pacific Institute. November 2004.

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.[219] 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, and 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%	

Source: California Energy Commission, *California's Water-Energy Relationship*, Final Staff Report, 2005.

Significant untapped potential for energy savings exists in programs focused on water use efficiency. Energy savings from these programs could produce 95 percent of the savings 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.[220]

Increasing Water and Wastewater Treatment Efficiency

[219] 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 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.

[220] 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 *California's Water-Energy Relationship*, Final 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.

All water and wastewater treatment processes have opportunities to reduce 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 of 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 including load shifting and installation of 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 energy 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 recently enacted 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

Despite some efforts targeted at improving the energy efficiency of heating water, the state's largest energy utilities have no authority to invest in programs that save cold water, regardless of whether the programs yield energy benefits. Because of the potential for reduced energy demand from these programs, the Energy Commission, the CPUC, utilities, and other 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 creates 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 single focus causes underinvestment in programs that would increase the energy efficiency of the water use cycle, agricultural and urban water use efficiency, and 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, and focus on identifying and implementing cost-effective retrofits in the water system that increase efficiency and provide both energy and peak savings. In addition, research should examine opportunities to increase savings through the development of TOU water tariffs and meters, along with increased flexibility in water deliveries.

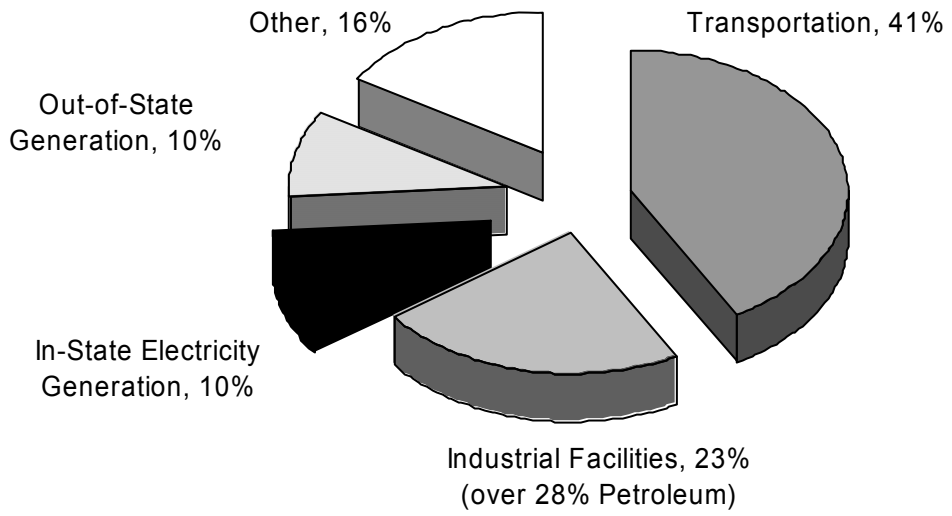
CHAPTER 9: GLOBAL CLIMATE CHANGE

Introduction

Climate change is a worldwide phenomenon with 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 seventeenth largest emitter of greenhouse gases (GHG) in the world,[221] with more emissions than any state in the nation except Texas.[222] 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 24: Greenhouse Gas Emissions



Source: California Energy Commission

The primary source of GHG emissions is the burning of fossil fuels in motor vehicles, refineries, industrial facilities, and power plants.[223] In California, the transportation sector is the largest source of GHG emissions, as shown in Figure 24, 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

[221] World Resources Institute, [http://cait.wri.org/], accessed October 28, 2005.
[222] California Energy Commission, *Inventory of California Greenhouse Gas Emissions and Sinks: 1990 to 2002 Update*, Publication CEC-600-2005-025, June 2005.
[223] 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 million metric tons of carbon dioxide ($MMTCO_2$) from in-state sources and 73 $MMTCO_2$ due to imported electricity.

about 28 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 about half 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 the result of two primary factors: aggressive building and appliance standards put in place over the years by the Energy Commission that have limited power plant generation growth and the stringent air quality standards applied to power plants that have resulted in power plants burning cleaner natural gas rather than oil.

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.[224]

Since 2003, state agencies have begun to take significant action in addressing these recommendations. Governor Schwarzenegger's recent Executive Order underscores the importance of addressing global climate change and provided specific targets.[225]

Resource Procurement

The CPUC, in a December 2004 decision, recognized the importance of reducing GHG emissions and directed the state's investor-owned utilities 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 carbon dioxide 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 risk associated with likely future regulation of GHG emissions. This adder encourages utilities to invest more in lower-emitting resources,

[224] California Energy Commission, *2003 Integrated Energy Policy Report*, Publication CEC-100-03-019, December 2003, p. 42.
[225] Executive Order S-3-05 by the Governor of the State of California, June 1, 2005, [http://www.climatechange.ca.gov].

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 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 and Universities, 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 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 agencies to develop 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,[226] establishing the following statewide GHG emissions targets:

[226] 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 ARB; 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 GHG targets established in the Executive Order. The first report is due to the Governor and the Legislature in January 2006 and bi-annually thereafter.

The Effects of Global Climate Change on Energy

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.[227] Increased winter flows could increase flood protection requirements, which could reduce storage for summer use.

Earlier snowmelts could result in water being diverted from hydropower facilities to avoid damage as well as water releases from reservoirs to prevent flooding. With reservoir capacity well below most generating capacity needs, less runoff will be captured for summer peaking power demand.

Increased runoff in winter would also result in increased hydro generation at a time when demand related to space heating, particularly in the Pacific Northwest, would be less due to overall warming trends. Conversely, decreased runoff in the summer would decrease hydro generation at a time when peak power is most needed to meet air conditioning loads that will be higher, also due to increased warming.

Preliminary studies suggest that hydroelectric generation may increase under wetter scenarios, but generation will decrease from 10 to 30 percent if 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.

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

Climate change could also increase the energy demand in California by increasing the demand for 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 by about $2 billion in 2020.[228] This net increase results from higher summer cooling demand that cancels any decrease in winter warming demand from warmer temperatures.

Increased energy demand would also 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 GWh of energy and by 2,000 MW of peak capacity in 2010.[229] 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 MW of peak electricity. Reducing this demand is possible by greater linkage between water conservation and energy efficiency programs, 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.[230]

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.

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 Public Interest Energy Research (PIER) program that evaluated measures to reduce high global warming potential gases in the landfill, natural gas, semi-conductor, dairy, and other sectors.

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[228] Mendelsohn, R., *The Impact of Climate Change on Energy Expenditures in California*. 2003, California Energy Commission, pp. 1–43.

[229] Baxter, L.W. and K. Calandri, "Global warming and electricity demand: A study of California." *Energy Policy* 1992: 233–244.

[230] 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.

In total, the measures analyzed have the potential to reduce GHG emissions by 44 million tons of CO_2 equivalent in 2010 and 117 million tons of Co_2 equivalent in 2020. These measures do not include the electric generation and oil refining sectors. These sectors contribute significantly to the state GHG inventory[231] 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.[232]

In all, based on a very preliminary baseline emissions estimate developed by the Energy Commission,[233] 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 SB 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.” The Advisory Committee’s 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 Environmental Protection Agency for use by the Climate Action Team. The following summarizes the recommendations from the respective subcommittees.

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[231] 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.

[232] Ned Helme, Center for Clean Air Policy, presentation in support of the *2005 Integrated Energy Policy Report,* July 11, 2005.

[233] 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, jet fuel, diesel, and natural gas demand. These projections should be considered placeholders until final state estimates are developed.

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 Western Electricity Coordinating Council. 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 role 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 program should be regional or national in design. A cap and trade at the state or focused on a single sector has inherent limitations.
- Any conversion of forest land to non-forest use should require a California Environmental Quality Act-level analysis.
- 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, and 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 is 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 as well as 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.[234]

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; 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 even while acknowledging 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 GHG 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.

[234] 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 fuel 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. 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

State agencies historically have not considered the impacts of climate change in their strategic planning. In the energy sector, the trade-offs and value of building and appliance efficiency standards are 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. This approach increases the need for coordination among agencies, common planning assumptions, and the integration of adaptation strategies across natural resources, a need that will only grow over time as more agencies anticipate climate change effects. Uncoordinated state planning efforts using disparate climate scenarios may result in the selection of contradictory policy options. 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 must 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.

The California Climate Change Center sponsored by the Energy Commission is developing probabilistic climate projections for California at an adequate level of geographical and temporal resolution 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 should:

- 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 and GHG standard in utility resource procurement.

CHAPTER 10: CALIFORNIA-MEXICO BORDER REGION ENERGY ISSUES

Introduction

The California – Baja California Norte border region extends about 60 miles (100 kilometers) north and south of the California-Mexico border and links the two countries in a complex network of trade, cultural, social, and institutional relationships. The region includes the San Diego and Imperial counties of California and the Mexican cities of Tecate, Tijuana, Mexicali, Rosarito, and Ensenada.

The border region's population and businesses are growing rapidly. This growth is driving energy demand, which is in turn driving the need for new power plants, transmission lines, and natural gas facilities. Generation from new natural gas-fired power plants in the region will predominantly meet this growing demand for electricity, though attention is increasingly focused on developing renewable energy resources. At least one liquefied natural gas (LNG) facility is also being built in Baja California Norte to meet energy demand both locally and in California.

The border region is becoming an energy corridor as both sides of the border develop facilities to meet local needs and export energy across state and international borders. The energy relationship between California and Baja California Norte is expected to become even more interdependent in the future as new generation, transmission lines, LNG facilities, and natural gas pipelines are built to meet the region's increasing energy needs.

The growing demand for energy in the border region is adding to already significant air pollution problems. Yet fundamental differences persist in regulatory approaches on both sides of the border. A binational policy is urgently 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 working together to address many energy and environmental issues and improve both the economic vitality and quality of life in the border region.

Border Region Growth

The current population of the border region is close to 5 million and expected to grow to more than 7.5 million over the next 25 years. The greatest population densities are in San Diego, Tijuana, and Imperial Valley-Mexicali.

The driving economic force in the region continues to be the companies on the Mexican side of the border that manufacture or assemble a variety of products and equipment, known as the maquiladora industry. The North American Free Trade Agreement

(NAFTA), passed in 1993, accelerated the growth of the maquiladora industry when U.S. companies subsequently located manufacturing plants in northern Mexico to reduce production costs and finish products for export either back to the U.S. or to other countries. NAFTA and other trade relationships with Mexico and Canada were also instrumental in San Diego's economic recovery from the recession of the first half of the 1990s. Over 700 maquiladora plants are now located in Baja California Norte.

Border Region Energy Demand

Electricity

Peak electricity demand in San Diego Gas and Electric's (SDG&E) service territory reached a record 4,065 MW in summer 2004. The Energy Commission estimates average annual growth rates of 2.1 percent for system peak load and 1.7 percent for electricity demand in SDG&E's service territory for 2004 - 2009. For the Imperial Irrigation District (IID), peak electricity demand is expected to increase from 840 MW in 2004 to about 1,000 MW by 2016.

The growth in electricity demand in Baja California Norte is expected to be the highest of any state in Mexico over the next 10 years. To meet this demand, Baja California Norte will need to almost double its electricity capacity.[235,236] In its official 2004-2013 electricity demand forecast, Mexico's Comisión Federal de Electricidad anticipates energy sales in Baja California Norte to increase an average of 7 percent and peak demand to continue to grow by 6.3 percent per year.

Natural Gas

Natural gas demand in SDG&E's service territory is forecast to grow 2.5 percent annually.[237] The primary driver for this gas demand in the near term is the natural gas needed to fuel new power plants. Demand for natural gas in Baja California Norte is driven mainly by power generation, a handful of industrial customers, and one local distribution company in Mexicali that serves about 25,000 customers.

Border Region Interdependencies

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 connections to Mexico's natural gas pipeline system and only limited connections to Mexico's national power grid.

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[235] *California-Mexico Border Energy Issues* staff report, prepared in support of the *2005 Integrated Energy Policy Report* Proceeding, July 2005.
[236] Western Governors' Association, April 2004, *Energy Efficiency in the Border Region: A Market Approach*, The Western Governors' Association, Denver, CO, pp. 6-10.
[237] California Energy Commission, *Revised Reference Case in Support of the 2005 Natural Gas Market Assessment,* September 2005, CEC-600-2005-026-REV.

Electricity

SDG&E consumes 3.5 times more power than Baja California Norte, cannot meet its customer demand solely with local generating capacity, and must import about 60 percent of its electricity from outside the region.[238] SDG&E's generating capacity is about 2,570 MW. Two new power plants are under construction in San Diego County, however, 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).[239] The CPUC approved the Miguel-Mission No. 2 230-kV Transmission Line in 2004, which is expected to be operational by June 2006. This project will increase the system's ability to transfer electricity from the two power plants in Mexicali, Mexico, and from new generation in Arizona that is scheduled into the CA ISO control area at Palo Verde.[240]

Conversely, IID has historically been a net exporter of electricity. IID provides 468 MW of capacity within the border region 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 also interconnects 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 the Comisión Federal de Electricidad's public service load and 1,210 MW for export to California. Baja California Norte also satisfies a significant portion of its energy needs with 720 MW of renewable geothermal energy with the balance of its generation coming from natural gas-fired combined-cycle units (985 MW), oil-fired steam-cycle plants (620 MW), and oil-fired gas turbines (326.9 MW). The Comisión Federal de Electricidad plans to build an additional 1,282 MW of generating capacity in Baja California Norte between 2008 and 2013. Most of this planned generation is expected to be natural gas-fired.

Path 45 is the backbone of the transmission system in Baja California Norte, connecting it 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 the Comisión Federal de Electricidad's Tijuana Substation, and the other between SDG&E's Imperial Valley Substation and the Comisión Federal de Electricidad's La Rosita Substation. Additional study is needed to

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[238] Western Governors' Association, April 2004, *Energy Efficiency in the Border Region: A Market Approach*, The Western Governors' Association, Denver, CO, p. 6.

[239] 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.

[240] 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.

determine the upgrade potential of the east-west transmission line in Baja California between the Path 45 cross border paths.

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 pipeline in Tijuana. 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 pipeline runs from Otay Mesa near Tijuana to Playas de Rosarito, where it supplies natural gas to the Presidente Juarez Power Plant. Sempra also supplies natural gas through a separate pipeline to the local distribution company in Mexicali.

Baja California Norte must import its gas from the U.S. through the Transportación de Gas Natural and Baja Norte pipelines since the region has no local sources of natural gas. The development of one or more proposed liquefied natural gas (LNG) gasification and storage facilities will increase natural gas supply sources for the region 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 and provide 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 online in 2007.

Sempra is planning to expand its Baja Norte and Transportación de Gas Natural pipelines to transport natural gas from the Energía Costa Azul LNG terminal. It is unclear, however, how SDG&E and Southern California Gas (SoCalGas) will plan and pay for future pipeline upgrades and coordinate cross-border delivery of gas into California. Other uncertainties include the amount and specific use (for example, power plants, commercial, residential) of the LNG supply dedicated for California, other parts of the U.S., and Baja California Norte.

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.[241] Accepting LNG supplies from Mexico at Otay Mesa will require infrastructure improvements allowing the reversal of the flow of the gas in the SDG&E system. Other improvements may also be necessary to the SDG&E system, depending upon the amount of LNG delivered to Otay Mesa.[242]

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[241] CPUC, November 2001, *California Natural Gas Infrastructure Outlook, 2002-2006*.
[242]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.

Border Region Renewable Resources

SDG&E is required by state law to have a 20 percent renewable portfolio mix by 2017. The utility has committed to achieving this goal sooner, by 2010. A recent study identified significant solar energy, biomass, geothermal, and wind power opportunities in the California-Mexico border region.[243] This study is an important first step, though more detailed assessments are needed to ultimately stimulate additional renewable resource development 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.

Facilities in Imperial County currently produce 635 MW of renewable energy, with an additional 270 MW of geothermal and 80 MW of biomass proposed for development. As a publicly owned utility (POU), IID is not required to meet the specific targets and timelines of the state's RPS. IID has, however, voluntarily adopted its own RPS. 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.[244]

Baja California Norte meets 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 additional potential both there and elsewhere in the region. The area also has promising potential for wind development, although further studies are needed to fully understand this resource potential. Mexico has set the national goal of bringing an additional 1,000 MW of renewable energy online by 2006.

Transportation

The 150-mile border between California and Mexico contains six points of entry: San Ysidro, Otay Mesa, and Tecate in San Diego County, and Calexico, Calexico East, and Andrade in Imperial County. In 2003 alone, 47 million people crossed the border northbound through San Ysidro, which is the busiest land crossing in the world. [245]

As noted earlier, cross-border trade between California and Mexico has increased substantially since the passage of NAFTA. In 2003, total trade activity totaled nearly $30 billion, with approximately 98 percent of this trade transported by truck through Otay Mesa, Tecate, and Calexico East.[246] There were 2,000,000 truck crossings at the border in 2003; this number is expected to increase to 5.6 million by 2030. Most of this truck

[243] *Potential for Renewable Energy in the San Diego Region*, San Diego Regional Renewable Energy Group, August 2005.
[244] 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].
[245] California/Mexico Border Briefing, p. ii.
[246] Ibid, p. V-3.

transport across the California-Mexico border at the three main entry points originates at or is destined for locations outside San Diego and Imperial counties, including the ports of Long Beach and Los Angeles and the Los Angeles and Ontario airports.[247]

Idling cargo trucks emit harmful pollutants that affect air quality on both sides of the border. These trucks usually refuel in Mexico with fuel that can contain many times more sulfur than fuel sold in California.[248] Shifting some of this cargo and freight to railroads and switching to cleaner-burning diesel and non-petroleum fuels could reduce both congestion and diesel use, ultimately improving air quality. The establishment of clean cities programs in the San Diego-Tijuana and Calexico-Mexicali areas and the imposition of per-truck border crossing fees could raise funding for cross-border transportation projects.

Air Quality and Cross-Border Emissions Trading

The transportation sector is the major source of emissions in the border region. Because the region is subdivided into two binational air sheds that span the international border, neither government alone is able to address regional air pollution. Air pollution in the border region violates most ambient air quality standards in both the U.S. and Mexico for ozone and particulate matter. Carbon monoxide levels on the Mexican side of the border also exceed established standards. Increasing population in the border region and the associated increase in the number of automobiles and cargo trucks will only exacerbate this problem over time.

Cross-border emission trading has been effective in reducing air pollution in other parts of the world and could potentially reduce emissions in the border region. This concept faces challenges, however, including the legality of establishing international air basins, the enforceability of international credits, the lack of an existing emission credit program in Mexico, and the inconsistency of air quality monitoring data on both sides of the border. Emission trading could well require additional air quality monitoring programs. More investigation of this issue is clearly needed, though available information indicates the strong potential for environmental and economic benefits for both countries.

Border Region Efficiency

There is significant potential for reducing the rate of growth in 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 that the potential energy efficiency savings for manufacturing facilities in Baja California

[247] Caltrans, pp. 2-3.
[248] 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.

Norte would be the highest in the region. [249] Average energy savings were estimated at 26 percent, and projected payback periods ranged from 1.3 to 6.0 years. The study also estimated that energy efficiency projects could reduce energy demand by as much as 10 percent in Baja California Norte.

While there is already awareness and active interest in both energy efficiency and load management in Baja California Norte, state and local energy efficiency assistance programs lack the technical and financial resources to have a significant overall impact on the supply-demand balance in the region.

Recommendations:

The state should establish a cross-border, binational policy to:

- Ensure that the planning, permitting, construction, and operation of electricity and natural gas infrastructure in the border region are coordinated and comply with the highest levels of environmental standards.
- Implement a common methodology to accurately forecast energy demand in the border region.
- Implement a loading order to encourage the development of the most efficient, clean, and cost-effective energy options.
- Develop programs to reduce demand and develop indigenous renewable resources.
- Develop and implement a cross-border emissions credit trading and offset program.
- Create opportunities to both improve the overall efficiency of transportation systems and expand the use of non-petroleum fuels.

[249] *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 online. The lack of available long-term power contracts has stalled the construction of more than 7,000 MW 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 energy 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,[250] 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).[251] 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.

[250] *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.

[251] 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.