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2008 INTEGRATED ENERGY POLICY REPORT UPDATE

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This report is dedicated to the memory of

JANE HUGHES TURNBULL

June 13, 1932 – October 18, 2008

With gratitude for her tireless devotion and invaluable contributions to the development of California's energy policies on behalf of the League of Women Voters and all the residents of California

Abstract

The *2008 Integrated Energy Policy Report Update* addresses the following five topics related to California's energy systems:

1. What physical, operational, and market changes will be needed for California's electric system to support a minimum of 33 percent renewables by 2020.

2. How the state's energy efficiency goals and programs interact with the Energy Commission's electricity and natural gas demand forecasting methods.

3. Recommended changes to electricity procurement practices to standardize assumptions, extend the period of analysis, and more adequately incorporate risk in the portfolio of projected resources.

4. Potential vulnerability of Diablo Canyon Power Plant and San Onofre Nuclear Generating Station nuclear power plants to a major disruption from a major seismic event or plant aging, as required by Assembly Bill 1632.

5. Evaluation of the California Public Utilities Commission's Self-Generation Incentive Program to determine the costs and benefits of providing ratepayers subsidies for renewable and fossil fuel "ultraclean and low-emission distributed generation" as required by Assembly Bill 2778.

6. Status report on recommendations made in past Integrated Energy Policy Reports.

Key Words

Renewables Portfolio Standard, Renewable Energy Transmission Initiative, renewable energy, energy efficiency, demand forecast, electricity procurement, portfolio planning, social discount rate, nuclear power plants, aging power plants, once-through cooling, Self-Generation Incentive Program, distributed generation, combined heat and power.

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Executive Summary

Senate Bill 1389 (Bowen, Chapter 568, Statutes of 2002) requires the California Energy Commission (Energy Commission) to "conduct assessments and forecasts of all aspects of energy industry supply, production, transportation, delivery and distribution, demand, and prices." The Energy Commission uses these assessments and forecasts to develop energy policies that conserve resources, protect the environment, ensure energy reliability, enhance the state's economy, and protect public health and safety. The Energy Commission prepares these assessments and associated policy recommendations every two years in the Integrated Energy Policy Report, with updates in alternate years.

The *2008 Integrated Energy Policy Report Update* assesses progress on the energy programs and policy recommendations that are critical to meeting California's energy and related environmental goals. The Energy Commission's Integrated Energy Policy Report Committee identified critical topics for the *2008 Integrated Energy Policy Report Update* at a public scoping hearing on April 28, 2008. After considering stakeholder feedback, the Committee focused on the following five areas:

1. Physical, operational, and market changes necessary for California's electric system to support a minimum of 33 percent renewables by 2020.

2. Evaluation of the interaction between the state's energy efficiency goals and programs with the Energy Commission's demand forecasting methods.

3. Status of recommended changes to electricity procurement practices to standardize assumptions, extend the period of analysis, and more adequately incorporate risk in the portfolio of projected resources.

4. Assessment of the Diablo Canyon Power Plant and San Onofre Nuclear Generating Station nuclear power plants, as required by Assembly Bill 1632 (Blakeslee, Chapter 722, Statutes of 2006), to determine potential vulnerabilities to a major disruption from a major seismic event or plant aging.

5. Evaluation of the California Public Utilities Commission's Self-Generation Incentive Program to determine the costs and benefits of providing ratepayer subsidies for renewable and fossil fuel "ultraclean and low-emission distributed generation" as required by Assembly Bill 2778 (Lieber, Statutes of 2006, Chapter 617).

The *2008 Integrated Energy Policy Report Update* also reports on the state's progress in implementing policy recommendations from past Integrated Energy Policy Reports. This review is intended to ensure that California is on track in meeting the state's energy policy goals while meeting California's need for affordable, safe, and environmentally acceptable energy choices.

California's Renewable Future

Since 2002, California has had a mandate to increase the use of renewable generation to 20 percent of retail electricity sales by 2010. On November 17, 2008, Governor Schwarzenegger signed Executive Order S-14-08, which raises California's renewable energy goals to 33 percent by 2020.[1] This enhanced target will help California meet the aggressive greenhouse gas emission reduction target of 1990 levels by 2020.

The Energy Commission believes the state can reach the 33 percent renewables target by 2020. There are, however, major barriers to achieving this goal, including: the need for transmission additions and upgrades to access renewable resource areas; the challenges associated with integrating large amounts of renewable resources into the state's electricity system; the impacts of renewable contract delays or cancellations; potential cost and rate impacts of adding renewables to the system; and permitting issues for renewable generation facilities in environmentally sensitive areas.

The Renewable Energy Transmission Initiative was established to help address transmission barriers by identifying and ranking renewable resource zones and broadly identifying the transmission needed to access those zones. Because environmental and land use issues can delay the development of transmission projects, the Energy Commission will continue to work closely with stakeholders in the Renewable Energy Transmission Initiative process to ensure that these issues are evaluated and considered. The Energy Commission also recognizes the importance and benefits of joint transmission projects between investor-owned and publicly owned utilities and will use the *2009 Integrated Energy Policy Report* forum to identify strategies to reduce barriers to these joint projects. In addition, the Energy Commission believes that transmission-related research, development, and demonstration efforts and funding should be significantly increased to identify technologies and strategies that can help integrate renewable resources.

Integrating large amounts of variable and intermittent resources like wind into California's electricity system is challenging. The state should focus on identifying energy storage technologies with the most promise of providing grid stability and improved operations, reducing the costs of those technologies, and accelerating their commercialization. Improved forecasting techniques are also needed to give grid operators information to make real-time decisions about electricity scheduling and dispatch. The state also needs to expand efforts to include renewable generation at the distribution level, such as community-scale photovoltaics or small wind, to reduce electricity loads and the need for upgrades to the transmission system. Similarly, increased use of renewable technologies for heating and cooling, like solar thermal water heating and geothermal ground-source heat pumps, could reduce electricity loads while also decreasing the use of fossil fuels and emissions of greenhouse gases.

Contract delays or cancellations for renewable projects continue to be a barrier to meeting California's renewable goals. Thirty five percent of the contracts signed under the Renewables Portfolio Standard have been either delayed (25 percent) or cancelled (10 percent). There also continues to be a need for greater transparency in the evaluation and selection of electricity providers. Independent parties, such as the California Public Utilities Commission or independent evaluators and not utilities, should review, select, and rank renewable procurement proposals. The investor-owned utilities should also be required to provide aggregated information on Renewables Portfolio Standard contract prices to assure policy makers that these contracts are meeting state energy policy goals and providing economic value to the state. In addition, the California Public Utilities Commission should make public the aggregate amount of above-market funds that are being allocated to Renewables Portfolio Standard contracts. To help encourage renewable development and provide price certainty to renewable developers, the California Public Utilities Commission should immediately implement a program to provide standardized contracts and prices for renewable projects smaller than 20 megawatts while continuing to evaluate expanding such a program to renewable projects larger than 20 megawatts.

The Energy Commission will evaluate impacts of a 33 percent renewable target on natural gas demand and prices, as well as the impacts of regional changes in natural gas supply and demand on California's natural gas market, to better understand the cost and price impacts of higher renewable targets. The Energy Commission will also continue to work on the Cost of Generation Model to regularly update changing technology costs over time. Finally, the Energy Commission will work with the California Public Utilities Commission to estimate potential price impacts of the 33 percent renewable target.

The number and size of proposed large-scale renewable power plants makes environmental permitting an increasing concern. Many of these new facilities are proposed in ecologically sensitive areas that could require habitat mitigation and restoration, which must be factored into the costs of the projects. Environmental mitigation issues can also affect project development schedules and project success. To help address these issues, Governor Schwarzenegger's Executive Order S-14-08 establishes the Renewable Energy Action Team to create a "one-stop" process for permitting renewable energy facilities. Also, the Energy Commission will continue participating in efforts with the Department of Energy and the Bureau of Land Management to evaluate environmental impacts associated with permitting solar thermal facilities in California. In addition, the California Public Utilities Commission should direct investor-owned utilities to consider the effect of the environmental permitting process on project schedules, milestones, and costs.

Energy Efficiency and Demand Forecasting

In the *2007 Integrated Energy Policy Report,* the Energy Commission identified the need to clarify and refine its California Energy Demand forecast. Accordingly, the *2008 Integrated Energy Policy Report Update* discusses the challenges involved in measuring and attributing electricity savings from energy efficiency programs and other market impacts, such as prices, within the Energy Commission's California Energy Demand Forecast process. It also provides

The Energy Commission staff has begun a process to make efficiency attribution and measurement more transparent to users of the demand forecast, refine and improve modeling methods, and develop efficiency measurement capabilities beyond what is part of the current forecasting process. During the 2009 Integrated Energy Policy Report cycle, staff will:

- **Develop standard definitions of terms encompassing all major concepts applying to efficiency potential studies and energy demand forecasts (September - November 2008).**
- **Organize and participate in a stakeholder working group designed to address technical efficiency issues and to develop consistent metrics for efficiency analysis across utilities and various agencies (Organized September 2008).**
- **Review and compare the modeling methods, inputs, and data sources used in Energy Commission forecasts of efficiency savings with the Itron Asset Model, and compare interim savings estimates from the Energy Commission's demand forecast and the Itron Asset Model for selected programs given common sets of input and modeling assumptions (September - November 2008).**
- **Refine and improve the Energy Commission's forecasting models to allow more detailed and complete output of committed efficiency savings (December - June, 2009).**
- **Investigate alternative forecasting methods (Ongoing).**
- **Develop the capability to make projections of uncommitted energy efficiency (June-July, 2009).**

an overview of methods currently used by Energy Commission staff to incorporate energy efficiency programs into the forecast. The chapter then identifies the approach staff will use to clarify the efficiency assumptions in the demand forecast within the *2009 Integrated Energy Policy Report* cycle and beyond as recommended in the *2007 Integrated Energy Policy Report*. Finally, the chapter reports on progress made by California utilities in fulfilling the efficiency requirements of Assembly Bill 2021 (Levine, Chapter 734, Statutes of 2006), which set a statewide goal of reducing total forecasted electricity consumption by 10 percent over the next 10 years.

To improve the Energy Commission's demand forecast in the future, the *2009 Integrated Energy Policy Report* should compare how end-use impacts are characterized in the Energy Commission's demand forecast and in efficiency program planning. Ignoring potential overlap will result in misleading estimates of how much can be achieved through future efficiency strategies. In addition, investor-owned utilities and publicly owned utilities, regulatory agencies, and other interested stakeholders should participate in the working group established in September 2008 that is focusing on technical issues and effectively communicating results to all interested stakeholders. Further, independent efforts to investigate and evaluate alternate forecasting methods should be continued in the *2009 Integrated Energy Policy Report* and focus on matching methods to the various purposes to which the demand forecast is applied.

The Energy Commission staff should continue to work with publicly owned utilities to understand the processes used by individual utilities to estimate their remaining economic energy efficiency potential and set efficiency targets. The Energy Commission staff should also continue to assist the publicly owned utilities in achieving their efficiency goals through workshops and collaborative efforts, while also encouraging them to identify all funding sources available to meet those goals to reflect the state's policy of energy efficiency as the top resource for meeting the state's energy needs.

Electricity Procurement Practices and Resource Planning Activities

The *2007 Integrated Energy Policy Report* raised concerns about electricity procurement in California and made recommendations to address those concerns. The *2008 Integrated Energy Policy Report Update* discusses progress made in implementing those recommendations. The report also outlines reliability and resource adequacy issues associated with moving away from the use of once-through cooling in power plants, as well as the relationship between electricity procurement and the Energy Commission's power plant siting process.

Every two years, the major investor-owned utilities must submit 10-year plans to the California Public Utilities Commission for procuring electricity. Various parties criticized the plans submitted in December 2006 for 2007 through 2016 because they did not allow for comparison across utilities, nor did they adequately evaluate high natural gas prices and greenhouse gas regulation that represent significant ratepayer risk. The California Public Utilities Commission acknowledged the shortcomings in the procurement planning process and in the 2008 long-term procurement plan proceeding is directing the investor-owned utilities to provide a set of plans in 2010 that can be compared and aggregated and that also consider ratepayer risks. The California Public Utilities Commission has developed a set of principles that reflect their desire to evaluate utility portfolios using a standardized, transparent methodology that reflects uncertainties like future natural gas prices and carbon costs.

The Energy Commission staff should continue to collaborate in the California Public Utilities Commission's long-term procurement plan proceeding. In addition, the *2009 Integrated Energy Policy Report* should assess longer-run (20-year) uncertainties related to electricity demand and natural gas prices and supply. As the California Public Utilities Commission's 2008 procurement proceeding moves forward, other issues related to resource planning beyond 2020 may also need to be included in the *2009 Integrated Energy Policy Report*, such as how to overcome utility constraints to reducing their portfolios' carbon footprint over the long run.

A second issue related to procurement that was identified in the *2007 Integrated Energy Policy Report* was how the discount rate used to estimate future natural gas fuel costs makes these costs appear unrealistically inexpensive. This could lead to increased dependence on natural gas-based generation because alternatives such as renewables and efficiency would be undervalued. The *2007 Integrated Energy Policy Report* recommended applying a 3 percent social discount rate (lower than the current discount rate which is based on a utility's cost of capital) to future natural gas costs to more accurately reflect the risks of cost volatility of natural gas-based generation. For the *2008 Integrated Energy Policy Report Update*, the Integrated Energy Policy Report Committee directed staff to explore the consequences of using a social discount rate.

There is general agreement about the importance of incorporating uncertainty and risk, including fuel price uncertainty, into the overall planning and decision-making process. The Energy Commission anticipates that the California Public Utilities Commission will require the next round of long-term procurement plans to incorporate risk-based portfolio analysis by reflecting a wide range of future natural gas prices and associated gas price risk. The Energy Commission staff will continue to collaborate with California Public Utilities Commission staff to ensure that fuel price risk is properly considered in constructing utility portfolios. The Energy Commission believes that the planning process is a more direct and transparent method to account for potential gas price risk than the adjustment of discount rates, and recommends that social discount rates should not be used to incorporate natural gas price risks. However, the California Public Utilities Commission should consider using risk-adjusted discount rates to compare projects selected in utility solicitations when they refine the bid evaluation process in the long-term procurement proceeding.

A third major issue related to electricity procurement is the potential effect on electricity reliability of retirement or repowering of aging power plants combined with restrictions on the use of once-through cooling in existing and new power plants. In March 2008, the State Water Resources Control Board issued a draft proposal calling for the phased elimination of once-through cooling between 2015 and 2021. A final proposal is expected in January 2009. Accomplishing this could require the refitting, repowering, replacement, or retirement of 19 power plants representing nearly 40 percent of the state's electricity generating capacity.

Aging plant retirement, or repowering and transmission line upgrades, are subjects of an ongoing California Independent System Operator study to be completed in early 2009. Additional analysis is needed on the implications of replacing much of the once-through cooling capacity with preferred resources, like renewables, and natural gas-fired generation that can be dispatched on demand to meet local capacity and grid stability needs. The *2009 Integrated Energy Policy Report* may need to evaluate how repowering, replacement or retirement of aging and once-through cooling plants interacts with the development of preferred resources like renewables, as well as the consequences of relying on once-through cooling and aging plants for energy and local capacity needs, particularly in the Los Angeles basin.

The final procurement issue relates to how utilities consider progress in the permitting process when evaluating what projects to select for procurement. In the past, investor-owned utilities selected some projects to receive contracts that later faced significant siting and environmental issues that threatened project viability, timely construction, or cost. Projects competing in a solicitation should understand the siting-related criteria that will be used to judge them. In addition, projects should have a high probability of being permitted in the required time frame without major environmentally-related modifications or cost increases.

The California Public Utilities Commission should develop and implement a fully transparent method of ranking projects in the bid evaluation phase of solicitations that is fair, objective, and transparent; considers environmental impacts, the likelihood of obtaining permits, and prior success of bidders in fulfilling contract offerings; encourages competitive offerings, is open to all bidders, and prevents circumvention; avoids unnecessary administrative and transaction costs; expressly identifies how project permitting is considered; and protects commercially competitive information.

Assessment of California's Operating Nuclear Plants

Assembly Bill 1632 directed the Energy Commission to assess the potential vulnerability of "large baseload generation facilities of 1,700 megawatts or greater" to a major disruption due to a seismic event or plant age-related issues. The Energy Commission was directed to adopt this assessment on or before November 1, 2008, and include it in the *2008 Integrated Energy Policy Report Update*.

The Energy Commission's Electricity and Natural Gas Committee developed the *AB 1632 Assessment of California's Operating Nuclear Plants: AB 1632 Report* based on a consultant report prepared by MRW & Associates that evaluated seismic and age-related issues along with other issues like reliability, economic impacts, and waste storage and disposal. The *2008 Integrated Energy Policy Report Update* includes a summary of the findings and recommendations from the *AB 1632 Report.*

California's two operating nuclear facilities, the Diablo Canyon Power Plant and the San Onofre Nuclear Generating Station, fall under the Assembly Bill 1632 requirement. Although two natural-gas fired facilities in California — Alamitos and Moss Landing — have a nameplate capacity greater than 1,700 megawatts, these facilities operate below a 60 percent capacity factor and are not considered baseload facilities.

Diablo Canyon and San Onofre represent 12 percent of California's overall electricity supply. A major disruption because of an earthquake or plant aging could shut down one or both plants anywhere from several months up to a year or even cause the retirement of a plant's reactor.

Each plant faces seismic hazards, which can include uncertainties about the type of fault zone near the plant, potential impacts from earthquakes directly below the plants, or ground motion resulting from an earthquake rupture. Non-safety related systems and structures, such as electrical switchyards, are the most vulnerable to damage from earthquake and could result in plant outages lasting weeks or months. A seismic event also poses a risk to spent fuel storage facilities at the plants.

Because of the importance of these facilities to the state's electricity supply, the Energy Commission believes Pacific Gas and Electric Company and Southern California Edison should report in the *2009 Integrated Energy Policy Report* on their seismic research efforts. In particular, Southern California Edison should develop an active seismic hazards research program similar to Pacific Gas and Electric's Long Term Seismic Program.

Age-related degradation is also a concern because these plants are approaching their fourth decade of operation. Effective maintenance programs and regulatory oversight are essential in identifying aging plant equipment and components since failure to do so could have serious long-term implications. The Energy Commission recommends that effective safety culture and plant maintenance programs be maintained at the nuclear plants along with enhanced oversight mechanisms by the Energy Commission, the Nuclear Regulatory Commission, and the Institute for Nuclear Power Operations.

An earthquake, age-related plant or equipment failure, or other event could lead to one or both of California's nuclear plants going off-line for extended periods, requiring replacement power from other sources. The reliability, cost, and environmental implications of using replacement power will depend on the time of the outage and type of replacement power available. The Energy Commission, the California Public Utilities Commission, and the California Independent System Operator should evaluate the uncertainties of losing the electricity supplied by the state's nuclear plants and modify the long-term planning and procurement processes to ensure that replacement resources are acquired in a timely way.

Diablo Canyon and San Onofre have been operating for roughly half of their 40-year initial license periods, and Pacific Gas and Electric and Southern California Edison are exploring the feasibility of seeking 20-year license renewals from the Nuclear Regulatory Commission. Diablo Canyon Unit 1's operating license expires in 2024 and Unit 2's expires in 2025, while San Onofre Nuclear Generating Station Units 2 and 3's operating licenses expire in 2022. If license renewals are granted, these facilities could continue to operate until the early to mid 2040s.

These plants produce significant quantities of radioactive waste in the form of spent fuel and other radioactively contaminated materials. The plants must carefully handle, store, transport, and dispose of the waste to protect humans and the environment from exposure to radioactive materials. As part of license renewal feasibility studies, Pacific Gas and Electric and Southern California Edison should evaluate the costs of disposing of low-level nuclear waste generated during a 20-year license extension and provide information on plans for storage and disposal of low-level waste and spent fuel through plant decommissioning.

In addition, the Energy Commission should work with the California Public Utilities Commission, as part of that agency's authority to fund and oversee plant relicensing feasibility studies, to develop a list of issues the utilities should address in those studies, including plant maintenance programs, safety cultures, waste storage, transport, and disposal; seismic hazards; life cycle comparison to alternative generating and transmission resources; contingency plans for prolonged outages; grid reliability; and overall economic and environmental costs and benefits of license extension. The utilities should report on the status and results of the feasibility studies in future Integrated Energy Policy Reports, beginning in 2009.

Evaluation of the Self-Generation Incentive Program

Assembly Bill 2778 requires the Energy Commission to include an evaluation in the Integrated Energy Policy Report of the California Public Utilities Commission's Self-Generation Incentive Program and the costs and benefits of expanding eligibility for the program to renewable and fossil fuel distributed generation. The evaluation is to be done in consultation with the California Public Utilities Commission and the California Air Resources Board.

The Self-Generation Incentive Program was established in 2001 and is one of the largest distributed generation incentive programs in the United States, with approximately 1,200 projects totaling 300 megawatts on-line at the end of 2007. The program originally included microturbines, small gas turbines, wind turbines, solar photovoltaics, fuel cells, and internal combustion engines; however, as of January 2008, only fuel cells and wind energy technologies are eligible for the program.

The Energy Commission selected TIAX, LLC to conduct the evaluation, which is presented in the consultant report *Cost Benefit Analysis of the Self-Generation Incentive Program*. Based on findings and information from that report, the Energy Commission recommends that eligibility for the Self-Generation Incentive Program should be based on the overall efficiency and performance of systems regardless of fuel type. In addition, the California Public Utilities Commission should consider re-instituting formerly eligible technologies that operate on landfill gas, digester gas from dairy waste or waste-water treatment processes, or biodiesel. TIAX's review of other technologies and fuel types also suggests that the California Public Utilities Commission should consider providing self-generation incentives for energy storage technologies, since these technologies provide capacity benefits.

Distributed generation can have location-specific grid benefits when sized correctly. The transmission and distribution costs avoided by installing such systems can be quantified with highly accurate customer and utility data. There should be further study in this area to better quantify the locational benefits of distributed generation, but in the meantime the California Public Utilities Commission should require investor-owned utilities to meet a portion of their distribution system upgrades by procuring distributed generation or combined heat and power in areas that provide these benefits to the distribution system.

State Progress on Key Integrated Energy Policy Report Recommendations

The *2008 Integrated Energy Policy Report Update* is a real-time, public forum for continuing dialog about California's energy policies. This update examines the progress the state has made in addressing 45 key recommendations made in past Integrated Energy Policy Reports on electricity and procurement issues, energy efficiency requirements, demand response, load management standards, renewable energy issues and goals, distribution system and combined heat and power, nuclear power, transmission, natural gas, transportation, petroleum infrastructure, land use, and water/energy. The *2008 Integrated Energy Policy Report Update* ranks the progress of each recommendation as "substantial," "on track," or "needs improvement," and describes progress to date on each recommendation.

Chapter 1

California's Renewable Energy Future

Introduction

California has made electricity generation from renewable resources a priority since the 1970s and leads the nation in biomass, geothermal, and solar capacity and generation. In addition to the environmental benefits from reducing the burning of fossil fuels, using renewable resources reduces the risks and costs associated with high and volatile natural gas prices while also decreasing the state's reliance on imported natural gas as a fuel for electricity generation. Renewable resources also provide other benefits such as economic development and new employment opportunities.

Renewable energy is an essential component of the state's loading order for meeting growing energy needs: first, with energy efficiency and demand response; second, with renewable energy and distributed generation; and third, with clean fossil-fueled sources and infrastructure improvements. California has had a Renewables Portfolio Standard (RPS) since 2002 that requires electric utilities to increase the use of renewable generation to 20 percent of retail electricity sales by 2010. On November 17, 2008, Governor Schwarzenegger signed Executive Order S-14-08 that raises California's renewable energy goals to 33 percent by 2020.[2] This higher target has been identified by the California Air Resources Board (ARB) as a key strategy for meeting the state's aggressive greenhouse gas (GHG) emission reduction target of 1990 levels by 2020.[3] To help meet the Governor's goal to reduce GHG emissions to 80 percent below 1990 levels by 2050,[4] California may need to achieve even higher renewable targets depending on the electricity sector's ultimate share of GHG reductions.

The *2007 Integrated Energy Policy Report* (*2007 IEPR)* found that "the 33 percent goal by 2020 is feasible, but only if the state commits to significant investments in transmission infrastructure and makes some key changes in policy." The priority now is to identify the obstacles to reaching that goal and determine how to overcome those obstacles. The state needs to develop an appropriate package of policy reforms that will help get it on track for meeting the 33 percent RPS target while continuing to deliver reliable and affordable power to Californians.

In the *2008 Integrated Energy Policy Report Update (2008 IEPR Update*), the Energy Commission concentrated on what useful information can be gleaned from prior or ongoing studies on this topic, what analysis is needed to better understand how the 2020 system should be structured to accommodate higher levels of renewables, identifying major barriers to renewable development, what research and development efforts will be needed to support higher renewable targets, and how the state's energy agencies can coordinate efforts to develop strategies to overcome barriers.

In addition to the investor-owned utilities' (IOUs) role in meeting the state's renewable energy goals, the role of publicly owned utilities is also extremely significant. These entities provide 25–30 percent of the retail electricity sold in California, making their participation essential to meeting statewide renewable and GHG reduction goals. There is, therefore, a need to work with the publicly owned utilities to understand their plans for helping the state to meet the 33 percent goal by 2020, and their views on challenges, opportunities, and changes needed to achieve even higher levels of renewables.

Barriers to Renewable Development

The primary barrier to increased development of renewable resources continues to be lack of transmission to access these resources, particularly in remote areas of the state. The Renewable Energy Transmission Initiative (RETI), discussed later in the chapter, was put in place to address this barrier by facilitating and coordinating the planning and permitting of transmission and generating projects that are needed to further the state's renewable policy goals.

There are also emerging technologies that can be used to improve the operation of the existing transmission system by increasing the carrying capacity of existing lines or by providing real-time information to grid operators about system outages or potential areas of congestion to allow better management of the grid. In addition, using a "smart grid" can improve efficiency, reliability, and cost-effectiveness of the transmission and distribution system by using advanced sensing, communication, and control technologies.

Another major barrier to meeting the 33 percent goal is how to integrate large amounts of variable and intermittent renewable resources, such as wind and solar, into California's electricity system. These technologies pose challenges to traditional reliability planning and resource adequacy requirements because they cannot be relied on to meet rapid changes in load and supply during peak hours and generally must be backed up with dispatchable resources. Also, wind resources can produce large amounts of energy during low demand times, which, when combined with generation from existing conventional baseload plants with must-run contracts and baseload nuclear power plants, can lead to an overgeneration problem. Energy storage technologies can help firm up variable technologies, while data management and display systems can give grid operators real-time information to allow them to respond to the unpredicted changes in output that are characteristic of some renewable technologies.

There is also the potential for wide-scale use of renewable generation at the distribution level, such as community-scale photovoltaics or small wind.

Behind-the-meter generation has the same effect as energy efficiency in reducing load and can help avoid or defer the need for transmission system upgrades. Similarly, using renewable technologies for heating and cooling, like solar thermal water heating and geothermal ground source heat pumps, can reduce electricity loads while also reducing the use of fossil fuels and their associated greenhouse gas emissions.

The risk of renewable contract delays or cancellations represents another barrier to renewable development. As of September 2008, the California Public Utilities Commission (CPUC) had approved 90 contracts for 6,800 megawatts (MW) of new, repowered, and re-started renewable generating capacity signed since 2002. However, only about 570 MW of that contracted capacity is operational. Approximately 35 percent of these contracts are not online because of delays (25 percent) or cancellations (10 percent), making it extremely unlikely that the state will meet the 2010 goals.[5]

A further barrier to renewable development is the concern that higher levels of renewables will result in higher costs to ratepayers. However, the issue here is how to compare the incremental costs of a 33 percent future with potential cost increases that may occur even without added renewables, depending on future natural gas prices, potential costs of carbon regulation, generation costs in general, and needed upgrades to the transmission and distribution system.

Environmental permitting issues related to large-scale renewable development remain a major concern. Many energy projects are being proposed on public lands overseen by the federal Bureau of Land Management (BLM). As of July 2008, the BLM had received 75 solar applications and 94 wind applications totaling about 1.3 million acres of land.[6] For comparison, 1,441 acres have been impacted by power plants (primarily natural-gas fired) currently operating or under construction that have been permitted by the Energy Commission since 1996. Given the sensitive nature of some of these lands, there may be significant habitat impacts requiring mitigation measures. Identifying enough habitat land to reduce the potential impacts of these projects will be a challenge depending on the species impacted, while uncertainty about how to account for the costs of mitigation measures is a major concern for renewable project developers.

In addition, with recent increased interest from investors in renewable energy as a result of climate change concerns and high fossil fuel prices, new and less-experienced developers may be entering the market who are unfamiliar with the California Environmental Quality Act, plant development issues, and the process for siting generating facilities in California. The CPUC has identified this risk in its quarterly reports to the Legislature on the RPS, and its April 2008 report noted that, "Many new, inexperienced developers have difficulty understanding and navigating the complex project development process…" and many approved contracts have been resubmitted with price reopeners possibly "…because the original bid had simply underestimated project development realities."[7]

Addressing Transmission Barriers

Every two years, the Energy Commission adopts a strategic plan for the state's electric transmission grid that identifies and recommends actions required to implement investments to ensure reliability, relieve congestion, and meet future growth in load and generation, including renewable resources.[8] The *2007 Strategic Transmission Investment Plan (2007 Strategic Plan)* recommended 10 specific near-term transmission projects that improve system reliability, reduce congestion, or interconnect renewable resources. Eight of those projects have the ability to interconnect renewables or provide operational flexibility to allow the transmission system to better integrate intermittent generation from renewables.[9]

The *2007 Strategic Plan* also identifies the need to remove transmission barriers to renewables. The plan recommended active Energy Commission participation in RETI, a three-phase process which was initiated in September 2007 with the goal of identifying preferred renewable resource zones for generating projects and the transmission infrastructure needed to access those zones.[10]

Phase 1 of RETI, to be completed in fall 2008, will screen and rank potential renewable resource zones and broadly identify transmission needed to access these zones. Phase 1 has been subdivided into two tasks: Phase 1A, to define the resource assessment method, study assumptions, and resources to be considered in the project-level analysis; and Phase 1B, to use the method developed in Phase 1A to group the identified resources into renewable energy zones. Phase 2, to be completed in spring 2009, will examine generation and transmission in more detail and will develop transmission plans in concept to access the top ranking zones. Phase 3, to be completed in 2010, will flesh out those conceptual plans and support transmission owners in developing detailed plans of service for commercially viable transmission projects and establish the basis for regulatory approvals of specific transmission projects.

The Energy Commission's participation in RETI is crucial in ensuring that the plans resulting from RETI reflect environmental, siting, and permitting perspectives to reduce impacts that could delay renewable energy projects.

The *2007 Strategic Plan* also recommended that the Energy Commission encourage corridor applications that would provide access to renewable resource areas. The Energy Commission is responsible for designating transmission corridors on non-federal lands in advance of need to help streamline future permitting of transmission projects and is the lead agency for preparing an environmental assessment of proposed transmission corridors.[11] In situations where RETI indicates the need for one or more transmission lines on non-federal land, the Energy Commission's transmission corridor designation process may designate one or more corridors to expedite the eventual permitting of such lines.

The Energy Commission staff held a workshop on July 23, 2008, to discuss transmission barriers for renewables and identify key issues for the *2009 Strategic Transmission Investment Plan*. Workshop participants identified two major transmission-related barriers to achieving the state's renewable goals. First, there is a need for mechanisms to remove barriers to joint transmission projects between publicly owned utilities and IOUs. Second, with regard to transmission siting, the state must continue to actively address environmental, land use, and local public opposition issues by working closely with stakeholders.

Stakeholders agreed that RETI is a valuable forum for reaching consensus on the high-priority renewable energy zones and the necessary transmission to reach them. Stakeholders also noted the potential for overlap between RETI and other forums and the limited amount of resources available to devote to the many forums, and encouraged coordination between efforts to avoid duplication. The Energy Commission agrees that RETI should be coordinated with all applicable transmission planning efforts, both in California and throughout the Western Electricity Coordinating Council's service territory.

Joint Transmission Projects

California's publicly owned utilities have raised concerns about obstacles to joint transmission development in the West between the state's publicly owned utilities and IOUs subject to the California Independent System Operator's (California ISO) tariffs. According to the publicly owned utilities, unless these concerns are resolved, they will not be able to develop joint transmission projects that could help achieve the state's renewable and GHG reduction policy goals. Parties discussed this issue at the July 23, 2008, IEPR staff workshop on transmission issues, and there was general consensus among multiple parties that this is an institutional barrier that needs to be addressed and resolved to achieve state policy objectives.[12]

Following the workshop, the California Municipal Utilities Association (CMUA), the Imperial Irrigation District (IID), the Los Angeles Department of Water and Power (LADWP), and the Sacramento Municipal Utility District (SMUD) filed joint comments describing some of the legal and market obstacles to joint ownership. The joint commenters noted that publicly owned utilities typically negotiate contract-based transmission rates for joint projects and contend that the constantly changing nature of the California

ISO tariff does not provide the same degree of cost certainty, rate predictability, and asset optimization as bilateral contract agreements. The joint commenters also noted that the California ISO is moving toward locational marginal pricing that uses financial rights, such as congestion revenue rights[13] that can be risky and speculative, rather than firm physical rights to a specified amount of transmission line capacity. Furthermore, publicly owned utilities are concerned about the California ISO's insistence on having full control of joint-ownership lines, as well as its requirement that all individual owner capacity and associated use must be subject to the California ISO tariff. The CMUA believes that this provision is being interpreted to bar joint ownership unless the line is within the electric footprint of the California ISO balancing authority.

The IID, LADWP, SMUD, Turlock Irrigation District (TID), and the Western Area Power Administration included their July 2008 white paper titled *Experiences with Joint Transmission-Project Development in the West* in their joint comments. The paper describes recent joint development challenges faced by the Green Path Southwest and Green Path North projects and proposes a hybrid model for bridging the differences between the California ISO tariff and a contract-based arrangement.

The joint parties' comments and white paper were the focus of a roundtable discussion at the August 21, 2008, joint IEPR and Renewables Committee workshop on achieving higher levels of renewables in California's electricity system. Roundtable participants included SMUD, LADWP, IID, TID, and California ISO representatives. The publicly owned utility panel participants described the difficulties with the Green Path Southwest and Green Path North projects and identified the California ISO tariff requirements as one reason for the failure of these projects to go forward as joint projects.

The California ISO noted that its mission is to ensure the full and efficient use of transmission assets and promote infrastructure expansion and development to achieve the greatest benefits for California and California ISO ratepayers. The California ISO accomplishes this mission through tariff provisions that incorporate system operations and planning goals based on transparent reliability and economic objectives, and simultaneously provide mechanisms to accommodate jointly owned projects governed by bilateral agreements between the California ISO or its participating transmission owners and other parties. It also noted that its Location Constrained Resource Interconnection tariff provisions require it to avoid duplication of facilities and to coordinate with neighboring control areas if the new transmission facility is in a region that also connects to the California ISO system.[14]

The California ISO also submitted written comments after the workshop to emphasize its position. In those comments, California ISO stated that key principles in carrying out its day-to-day operations and transmission responsibilities include: costs borne by California ISO ratepayers must provide commensurate benefits; existing transmission should be fully used before new transmission expands the environmental footprint; and continued cooperation across the West is critical. California ISO also stated that its tariff specifically provides for bilateral agreements between owners of transmission under the California ISO's control and other parties, including publicly owned utilities.

The Energy Commission recognizes the importance and benefits of joint projects, especially to access renewable resources. In the *2007 Strategic Transmission Investment Plan,* the Energy Commission noted its concern that SCE's Tehachapi Renewable Transmission Plan and LADWP's Tehachapi Project could be duplicative unless the plans are coordinated and encouraged the two utilities to work together to avoid any overlap. Because there are both legal and market obstacles that hinder the development of joint projects, the Energy Commission believes that the state should play a role in resolving these issues.

Environmental and Land Use Issues

At the July 23, 2008, IEPR staff workshop, the California ISO presented the results of its conceptual transmission planning study for connecting renewable generation to meet a 33 percent goal for the state's three IOUs.[15] The study identified the need for six new 500 kV transmission lines to meet the 33 percent goal through 2028 to 2030 at an estimated cost of about $6.5 billion.[16] Although these projects are conceptual only and will be refined as the RETI *Phase 1B Draft Resource Report* and Phase 2 results become available, they provide stakeholders with a sense of the scope, location, length, size, cost, and timing of possible transmission additions needed to meet the IOUs' portion of a statewide 33 percent renewables goal in 12 years.

However, many of the stakeholders at the workshop agreed that environmental and land use barriers are generally the biggest obstacles to the timely development of transmission projects. One stakeholder characterized the importance of understanding land use issues and environmental concerns during the transmission planning process this way: "…[W]e can all look at performing power flows till our faces are blue. But the real issue is going to be siting of that transmission facility."[17]

As noted earlier, in the *2007 Strategic Plan* the Energy Commission recommended that staff participate actively in RETI to ensure the resulting plan for preferred renewable resource zones for generation and electric transmission infrastructure reflects environmental, siting, and permitting perspectives. The Energy Commission will need to work closely with stakeholders during the RETI Phase 2 conceptual transmission planning process to ensure that they evaluate and consider land use issues and environmental concerns when planning conceptual projects to access renewable resource areas.

Other stakeholders at the workshop noted that local opposition at both individual and institutional levels can make it difficult, if not impossible, to permit transmission projects that would be necessary to meet statewide policy goals. Parties stressed the need to educate the public and local governments on the importance of achieving the state's renewable and GHG reduction goals and the difficult choices that must be made to accomplish those goals. Regarding transmission projects, parties noted the need to communicate and work with affected local agencies, stakeholders, and the public in the planning process, well before a route is proposed. In addition, local agency participants in the *2007 IEPR* emphasized their lack of expertise and experience with renewable energy development.[18] The League of Women Voters offered that its 70 local leagues could assist local governments in developing energy elements for their general plans.[19]

A coordinated and proactive effort to facilitate local land use planning for renewable energy-related transmission infrastructure would help reduce permitting difficulties and ensure that local planning efforts are informed by RETI and influenced by the state's renewable and greenhouse gas reduction strategies, goals, and requirements. For example, general plans containing energy and transmission elements could establish transmission corridors and energy zones that could facilitate the development of renewable energy at the local level, particularly in areas with the greatest potential for renewable energy. Informed local planning decisions regarding renewable energy development would be coordinated with the Energy Commission's Transmission Corridor Designation Program in order to preserve transmission corridors as necessary.

However, local agencies generally lack the funds, staffing, and expertise to carry out coordinated renewable energy, electric transmission, and local level land use planning. Therefore, technical and financial assistance to local governments would be required, particularly for local governments containing areas targeted for renewable development and related transmission corridors.

A priority should be placed on reactivating the Energy Commission's Local Agency Siting and Permit Assistance Program by re-establishing the Energy Resources Programs Account funding pursuant to Public Resources Code section 25616.[20] This program should be employed to assist local governments with the development of general plan transmission and energy elements that are consistent with RETI, recognize the importance of statewide renewable and greenhouse gas reduction requirements and goals, and are coordinated with the Transmission

Corridor Designation Program. It should target local governments having the greatest renewable energy development potential and the corridors most likely to support transmission infrastructure for interconnecting renewable energy development to the state's electric grid. Funding for this type of land use planning would allow local agencies to secure technical consultant support with Energy Commission oversight. Reactivation of the Siting and Permit Assistance Program should require full coordination with the existing Transmission Corridor Designation Program to help facilitate preservation of renewable energy-related transmission corridors. It should also require full consideration of RETI results and state renewable and greenhouse gas reduction strategy, goals, and requirements.

Addressing Integration Barriers

Another major barrier to increasing the amount of renewables in California is how to integrate large amounts of variable resources, like wind and solar, into the system while maintaining grid stability, operation, and reliability. Unexpected drops in energy production require quick-start units to cover the shortfall, while unexpected increases require the ability to absorb the unscheduled generation. Procuring additional resources to support intermittent renewable resources will be needed, as will better forecasting techniques for wind and solar generation.

It is important to remember that not all renewable resources are intermittent. Geothermal and biomass power plants provide reliable, baseload power and can be integrated into the system without any additional backup. However, adding large amounts of any type of renewables to the system can still be problematic because California's local reliability requirements call for load to be met primarily with local resources, and many renewable resources are located outside the state's 10 load centers.

One way to reduce the impacts of integrating renewables into the electricity system is through the use of distributed resources, which can reduce overall load, avoid or defer the need for transmission system upgrades, and reduce transmission and distribution losses. Using renewable resources to meet heating and cooling needs can also reduce electricity and natural gas loads while also reducing associated GHG emissions.

There are also a number of emerging technologies that can help integrate renewables into the electricity system, including energy storage technologies, better forecasting of variable resources, and technologies to improve the operation of the existing transmission system.

In the *2009 IEPR,* the Energy Commission intends to coordinate its analyses of integration issues with other efforts such as the California's ISO's study of the operational impacts of integrating 33 percent renewables and SCE's Renewable Integration and Advancement Project. The Energy Commission will also consider the costs of changes needed to integrate higher levels of renewables.

Results from Prior Integration Studies

At the IEPR workshops on achieving higher levels of renewables, Energy Commission staff summarized the findings from two recent studies on grid integration issues: the Energy Commission's *2007 Intermittency Analysis Project*[21] and the Consortium for Electric Reliability Technology Solutions/Electric Power Group's (CERTS/EPG) *Renewable Resource Integration Project – Scoping Study of Strategic Transmission, Operations, and Reliability Issues.*[22] The California ISO also discussed its November 2007 study on the transmission and operational requirements to meet the 20 percent by 2010 renewable goal and plans for a study on the requirements to meet a 33 percent renewable scenario.

The Energy Commission's *Intermittency Analysis Project Final Report* evaluated what is needed for the transmission system to accommodate generation from 33 percent renewables by 2020. The Intermittency Analysis Project (IAP) evaluated reliability, load following capability, voltage support, and regulation, among other characteristics, for an assumed resource mix of 12,700 MW of wind, 5,100 MW of geothermal, 3,100 MW of concentrating solar power, 2,900

MW of solar PV, and 2,000 MW of biomass.[23] The study found that with significant expansion of transmission by 2020, it is feasible to operate the electricity system with 33 percent renewables. However, the study suggests that strategies will be needed to address periods of high and low load and found that there may be small additional costs associated with regulation and load following.

At the July 23, 2008, IEPR staff workshop on transmission issues, CERTS/EPG presented the results of its study to identify transmission and operating issues associated with integrating renewables. CERTS/EPG calculated that California must integrate 20,000 MW of renewable capacity additions (relative to a 2006 base) to meet a statewide goal of 33 percent renewables by 2020. The study also suggested that 23,000 MW would be needed to continue to meet the 33 percent target in 2030 due to increased demand between 2020 and 2030. Furthermore, it found that a target of 50 percent renewables by 2030 would require 40,000 MW of renewable capacity additions. Based on these findings, the study focused on a mid-range value of 30,000 MW of additional renewables by 2030 as a reasonable starting point for examining system upgrades that would be necessary under that scenario.

CERTS/EPG observed that more than two-thirds of the 30,000 MW of additions would likely require delivery to transmission "gateways" surrounding the Los Angeles Basin Area.[24] The study concluded that gateway capacity would need to be tripled to integrate these renewable capacity additions, and other transmission links between regions would need to be expanded. From an operational perspective, local network reinforcements would also be required, including line upgrades, fault current limiters, breakers, and remedial action schemes.[25] The system would also need additional regulation and ramping ability, which could be addressed by energy storage, demand-side management, and automatic load control. Local voltage support could be enhanced by adding capacitors and dynamic voltage control devices. In addition, if plants in the Los Angeles Basin retire because of air or water restrictions, or if new non-renewable generation facilities are built outside the gateways, further increases in gateway capacity would be required.

The CERTS/EPG study made the following recommendations:

- Further studies should expand the focus from evaluating just the interconnection of remote renewable resources to the grid to delivering that renewable energy all the way to the respective load centers.
- Policy makers need to provide guidance on resource type and location to allow timely integration of renewables and support early planning and upgrades of transmission gateway capacity and deliverability to load centers, aided by the RETI effort currently underway.
- Transmission owners and the California ISO need to move the planning horizon out to 15 to 20 years to define long-term gateway requirements, long-term transmission requirements from gateways into load centers, and interregional transmission requirements.
- Transmission owners and the California ISO need to initiate studies to expand transmission gateways and beyond into the load centers.
- Policy makers need information associated with the complete transmission integration requirement and cost implications for delivering all remote resources (both renewable and non-renewable) to the local load centers.
- The California ISO needs to provide utilities and the CPUC with guidance on the resource attributes needed for reliable operability of the grid.
- The state should evaluate the transmission requirements for transfer of renewable energy from the L.A. Basin area to San Diego and Northern California.

In November 2007, the California ISO conducted a study on operational changes needed to accommodate 20 percent renewables and believes that it can accommodate that level.[26] According to the California ISO, to achieve higher levels of renewable penetration the following areas need further examination:

- Better wind and solar forecasting capability and better communication between forecasters and California ISO floor operators.
- Better understanding of the amount of ramping and regulation needed.
- Further information on the energy storage technologies that will be available.
- Changes to the California ISO market structure and tariffs to incentivize short-term storage for regulation flexibility.
- Whether the gas storage system can accommodate rapid swings in conventional generation needed to back up renewables, and how to quickly communicate the need for additional natural gas to the pipeline companies in response to weather-related drops in wind generation.

Recent initiatives at the California ISO and regional levels are designed to address many of these issues. The California ISO has initiated its Integration of Renewable Resources Program[27] with the goal of supporting the integration of renewable resources into the California power grid to fulfill state policy objectives. The program seeks to leverage the expertise and resources of agencies and market participants, including the Energy Commission. The program will address operational, market, and transmission planning issues to meet 20 percent renewables and beyond.

On October 21, 2008, the Joint Guidance Committee of the Western Electricity Coordinating Council (WECC) established the Variable Generation Subcommittee. The purpose of the subcommittee is to identify issues and opportunities related to variable generation sources (such as wind and solar) in the western interconnection and facilitate the development and implementation of solutions that add value to the WECC members. The subcommittee will focus on the regional reliability and market challenges of renewable energy integration and other emerging issues.

In addition, the California ISO suggested that more can be done to link renewables with demand side and thermal storage strategies. For example, the California ISO would like to see the ability to vary compressor loads for chillers in large buildings to help address variations in expected generation from wind or other variable renewable resources and suggested the state take a leadership role in retrofitting state buildings to provide this capability. This variable compressor load should be designed to allow the California ISO to send a signal requesting a building's compressor load to change in response to changes in expected generation.[28]

Resource Adequacy Requirements

California's resource adequacy requirements are intended to ensure uninterrupted electricity service to customers. There are two types of requirements, planning reserve margins and operating reserve margins. *Planning reserve margins* are long-term planning targets based on either the probability of a loss of load or the value of service. These targets are used to determine how much capacity is needed to maintain real-time operating reserves. *Operating reserve margins* relate to the ability to handle system fluctuations and disturbances. Operating reserve margins help balancing authorities, like the California ISO, ensure that voltage levels are maintained to prevent damage to transmission system components and uncontrolled cascading outages.[29]

Under the CPUC and California ISO resource adequacy requirement, each load-serving entity must demonstrate that it has enough generating capacity to cover 115 percent of expected monthly peak demand.[30] Generating resources have pre-established capacity values based on their performance, known as the net qualifying capacity, which is used by load-serving entities when shopping around for electricity generation to meet resource adequacy requirements. Load-serving entities must secure 90 percent of their requirements one year ahead, and then demonstrate they have acquired the balance of their requirements one month ahead of each calendar month. This approach helps ensure that the California ISO has enough resources to cover higher than expected loads, forced outages, and transmission outages.

This general framework has important implications for achieving high levels of renewable generation. Net qualifying capacity values for generating resources like wind and central station solar are established using a formula based on historic performance from hourly production data.[31] For wind resources, these values can be low because of the poor fit between performance and peak loads.[32] A low net qualifying capacity value means that load-serving entities will be reluctant to select these resources to meet their renewable requirements unless the economic costs and benefits are better than those of other resource types.

Another facet of resource adequacy requirements is that, beginning in 2007, load-serving entities must meet local capacity requirements to ensure that the capacity needed by the California ISO is available in 10 separate load centers or pockets throughout the state. As a general rule, about 75 percent of total resource adequacy requirements must be satisfied with resources within these load pockets. Because renewable resources are location-specific and often remote, this requirement highlights the disadvantages of wind, central solar, geothermal, and biomass resources outside of these load pockets. Renewable developers should therefore be encouraged to locate projects where they can meet local capacity requirements, when feasible and cost-effective.

Distributed Renewables

Distributed renewable resources do not directly address integration issues such as the need for load following, ramping, or regulation typically associated with higher levels of large-scale renewables. However, distributed resources do reduce overall electricity load and therefore the amount of large-scale renewable resources that will need to be integrated into the electricity system to meet the 33 percent goal. Several parties at the IEPR workshops on renewables asserted that there is tremendous opportunity for renewable generation at the distribution-level, at or near substations and on customer sites, or "behind the meter." However, most renewable generation from distributed resources, with the exception of facilities that are utility-owned or have specific power purchase contracts with a utility,[33] are not currently eligible for the state's RPS, though these technologies do reduce retail sales and therefore the amount of renewable energy that must be procured to meet the RPS. While the CPUC has determined that 100 percent of the renewable energy credits (RECs) associated with renewable "behind the meter" distributed generation projects belong to the system owners, generation from these systems cannot be counted toward RPS obligations until the CPUC authorizes the use of tradeable RECs for RPS compliance.

The California ISO has noted that when looking at a 33 percent goal, it is important to consider the contribution from behind-the-meter distributed solar installations that could provide enough energy to satisfy as much as 5 to 8 percent of that goal. In addition, GreenVolts, a developer of photovoltaic (PV) systems, referred to the RETI *Phase 1B Draft Resource Report* which identifies the potential for 27,500 MW of distributed solar PV projects, assuming 20 MW installations could be placed close to existing substations.[34] These projects could generate nearly 60,000 GWh annually, which is significant given that the current estimate of 33 percent of retail sales in 2020 is about 102,000 GWh.

In written comments submitted for the IEPR staff workshop on July 23, 2008, the Alliance for Responsible Energy Policy also stated that California's rush to identify competitive renewable energy zones and to permit new transmission lines has failed to adequately consider distributed generation and demand-side management alternatives.[35]

Distributed generation is a key component of the state's loading order for meeting new resource needs.[36] The California Solar Initiative has a target of 3,000 MW of new solar generating systems in the state by 2017.[37] In addition, the Governor's Bioenergy Action Plan calls for meeting 20 percent of the overall RPS target with biopower; all of the current biopower contribution to the RPS and most of the future contribution will come from power plants smaller than 50 MW. Many of these facilities, such as landfill gas generators and digester gas generators, are located in load pockets and can be connected at the distribution level. Further, the *2007 IEPR* recommended that all new residential buildings be net-zero energy by 2020 and all new commercial buildings be net-zero energy by 2030. Distributed generation resources are necessary to achieve this goal.

There is also increasing policy attention to the goal of sustainable communities. More California communities are considering renewable generation options as they explore strategies to become net-zero energy communities. Options include solar PV, solar thermal electric, biogas, and wind power plants in the 10 to 50 MW range. Examples of net-zero communities using renewable energy already exist in California on university campuses and in the operations of regional water agencies. The University of California at San Diego generates most of its own electricity and cold water for space cooling of campus buildings and is augmenting its natural gas cogeneration combined heat and power capacity with solar PV and other renewables.[38] Likewise, the Inland Empire Utilities Agency (IEUA), a regional water agency in San Bernardino County, recently announced the addition of 2 MW of PV capacity to its existing 3 MW of biopower generated from dairy manure and food waste.[39] IEUA is close to serving its total electricity demand for pumping and purification cost-effectively from renewable. Many California schools are also purchasing renewable electricity from solar electricity systems installed on school roofs.[40]

Widescale use of renewable generation at the distribution level could also reduce some reliability and operational concerns associated with meeting the 33 percent by 2020 goals by reducing overall load, avoiding or deferring transmission system upgrades, and reducing transmission and distribution losses. However, because integrating distribution level and customer-side renewable resources has received much less attention than integrating large central station renewable resources, it will be important to consider how to address distribution level integration of significant amounts of renewable generation. Also, there may be a need for day-ahead and hour-ahead solar and wind forecasting at the distribution level and even the building level and for new market mechanisms to effectively value distributed and customer-side renewables.

Renewable Energy Heating and Cooling

Like distributed renewable resources, renewable heating and cooling technologies can help reduce overall electric loads and therefore the ultimate amount of renewable electricity generating resources needed to meet California's RPS targets.

Heating and cooling demands by the industrial, commercial, and residential sectors account for 40 to 50 percent of total global energy use. Around the world, renewable heating and cooling technologies that use solar, biomass, and geothermal resources are used to reduce GHG emissions, electric and natural gas use, and fossil fuel dependency. Current annual GHG emissions in California from space, process, and water heating and cooling in the commercial, residential, and industrial sectors are about 25 percent of total statewide GHG emissions.[41] Using these technologies in California could therefore provide benefits beyond reducing electricity loads.

China accounts for 75 percent of annual solar water heating capacity additions, and Germany has installed the electric equivalent of nearly 5 GW of solar water heaters. In Europe and North America, there are more than 2 million ground source heat pumps in use, and about 30 percent of houses in Sweden have geothermal heat pumps with a combined equivalent electric capacity of nearly 4 GW. The solar share of Germany's residential space heating market is approaching 50 percent, while many countries and state and local jurisdictions are mandating solar water heating for all new residential and commercial buildings.

Although industries offering commercially ready technologies in California are underdeveloped and unprepared to deliver on a large scale, there are programs available to support renewable energy heating and cooling technologies. San Diego Gas & Electric Company (SDG&E) has a Solar Water Heating Pilot Program through December 31, 2009, with $1.5 million for incentives,[42] while the California Solar Initiative has budgeted $100.8 million in incentives for "non-PV electric displacing solar thermal," including solar water heating, solar-forced air heating and solar cooling or air conditioning, among other technologies. Specifications for eligible non-PV systems are under development.[43]

The potential value of renewable heating and cooling technologies could be very high, since California residential and commercial cooling accounts for approximately 30 percent of electric system peak load.[44] The National Renewable Energy Laboratory has estimated that 65 percent of residential and 75 percent of commercial buildings in California could be outfitted with solar collectors for hot water. Estimates by the Economic and Technology Advancement Committees suggest that as much as 20 percent of heating- and cooling-related GHG production could be eliminated using low-temperature solar collectors for solar water heating, plus advanced solar thermal collectors suitable for solar cooling and other higher temperature applications. Geothermal heat pumps can cut heating and cooling energy use by 70 percent, which would result in significant additional GHG emission reductions. Solar cooling can provide the added benefit of space cooling that displaces electricity generation needs.

To capture the potential GHG and load-reduction benefits of renewable heating and cooling technologies, California needs to strengthen the market for commercially mature technologies while also targeting research, development, and demonstration efforts for emerging technologies.

Emerging Technologies for Renewables Integration

Energy storage and transmission measurement and information systems can play an important role in helping to integrate renewables. Improvements in wind and solar forecasting and further development of the "smart grid" concept can provide additional benefits. The state needs to assess these new technologies and strategies to determine which are appropriate for near-term and long-term implementation, and what efforts should be undertaken to accelerate commercialization of the most promising potential solutions.

A recurring theme in IEPR workshops was the use of the "smart grid" concept to help reduce the impacts of integrating large amounts of renewables into the system. Smart grid uses advanced sensing, communication, and control technologies to improve overall efficiency, reliability, and cost-effectiveness of electrical transmission and distribution system operations, planning, and maintenance. Faster, more reliable, and more capable two-way communications systems will provide new energy management options to all levels of the utility grid system, including generation, transmission, distribution, and customer end use. A smart grid will provide the ability to aggregate customer loads for demand response, automatically locate utility system outages, quickly resolve utility system congestion issues, automatically control building and industrial loads in response to critical network needs, and the ability for all customers to have greater options to manage their energy needs.[45] As California moves to implement a smart grid system, more options will be available to manage and control renewable generation resources connected at the distribution level, as well as to enable the use of demand response measures to help address operational impacts of increased integration of renewable by balancing load and generation.

Based on discussions and input from the IEPR staff workshop on July 31, 2008, the following emerging technologies appear to have the highest potential to support the integration of renewables:

Energy Storage Technologies

These technologies have major potential to resolve grid stability and operations issues related to higher penetrations of renewables. Energy storage can be applied as generation, such as pumped hydroelectric storage; on the transmission or distribution system, to regulate fluctuations in generator output and maintain transmission system voltages at required levels; and even at the end-use customer's location. Smaller energy storage systems can provide significant grid support whether they are connected at the distribution or end-use customer level, and aggregating these systems can provide grid support when higher levels of renewables are introduced. Energy storage technologies are advancing rapidly in system performance, overall ability to address distribution and transmission level problems, and commercial viability. Field demonstrations and pilot projects are needed for larger energy storage systems (greater than 5 MW ratings for at least four hours) that can be connected to the distribution or transmission system. Additional research should evaluate very large energy storage systems, such as compressed air energy storage in comparison to pumped hydroelectric systems currently in use, for situations in which there is a need for storage systems that can store hundreds of MWs for several hours.[46]

High Temperature Thermal Energy Storage for Solar Thermal Electric Plants

Heat produced by a solar power plant collector field can be stored in a mixture of sodium and potassium salts, used to generate steam to produce electricity, and then reheated for reuse. Thermal storage has many potential applications, including increasing the capacity factor of a solar power plant, reducing the need for backup for the variable solar resource, shifting energy delivery to higher value periods, and even boosting energy production during peak periods. Determining the specification for storage applications in California and addressing risks before committing to commercial application in California will increase the economic performance of California's future fleet of solar power plants and allow them to better meet peak summer energy needs.

Increased Capability of Forecasting Tools

Higher penetration of wind and solar resources requires improved forecasting tools to inform electricity scheduling and dispatch decisions. Accurate forecasts also help address intermittence and unpredictability of resources and can increase the value of variable resources to the system. The California ISO has been using hour-ahead forecasting for wind resources successfully for several years but believes that forecasting tools need to be expanded to include day-ahead forecasting and forecasting capability for solar resources.[47] Toward this end, it is doing in-depth studies with three companies to improve wind forecasting ability. Research and development in this area should focus on increasing the accuracy and reliability of forecasts, expanding forecasting tools to encompass solar resources, and working with grid operators to understand their needs in displaying forecast results to allow real-time decisions to be made.

Synchrophasor Measurement Technologies

Phasor Measurement Units[48] can collect and report critical electrical measurements approximately 30 times per second, providing information about grid conditions to system operators so they can make time-sensitive decisions. As more renewable resources are integrated into the grid, operators need this kind of technology to respond to unpredicted changes in output that are characteristic of some renewable technologies. Additional demonstrations and pilot projects are needed along with continued and expanded research in this area.

Transmission Dynamic Thermal Rating Capability

Electricity transmission is limited by the thermal constraints of transmission lines. Resistance of the flow of electrons through transmission lines and equipment produces heat, and overheating can lead to loss of line strength or expansion and permanent sagging of the lines. New technologies can now monitor transmission lines and environmental conditions and calculate real-time line ratings. This allows existing transmission lines to be used to their full capability and reduces the need for new lines. Real-time transmission line ratings could provide more transmission capacity during periods of high system load, decreasing the need to use local generating resources. This could reduce capital expenditures for new transmission facilities and generating resources, while at the same time allow more efficient operation of the power grid, resulting in lower utility rates. The ability to monitor transmission lines in real-time would also improve system reliability and safety.

Addressing Contracting Issues

As of September 2008, the CPUC has approved 90 contracts signed since 2002 for about 6,800 MW of new, re-powered, or restarted RPS-eligible generating capacity. Only about 570 MW of that capacity is currently on-line and delivering energy. Approximately 35 percent of these contracts are not on-line because of delays (25 percent) or cancellations (10 percent).[49] A related issue is the small number of biomass contracts that have been signed through RPS solicitations, since the Governor's Bioenergy Action Plan sets a target for 20 percent of the state's RPS to be met with biomass.

The Energy Commission commends the CPUC for improvements made in the renewable procurement process, particularly increased access to certain procurement-related information and the use of an independent evaluator to provide third-party oversight of the RPS procurement process. However, renewable contract delays or cancellations continue to be a barrier to meeting California's renewable goals. This issue was raised in both the *2006 IEPR Update* and the *2007 IEPR*, with the *2006 IEPR Update* recommending that utilities procure a contract risk reserve margin of at least 30 percent above what would be needed to achieve the 20 percent by 2010 goal. In written comments for the July 21, 2008, IEPR staff workshop, Green Power Institute echoed this recommendation by noting that if retail providers continue to gear procurement toward getting just enough renewables to meet their requirements, they will not meet the 33 percent mandate because not all signed contracts will result in operating facilities.

In its July 2008 quarterly report to the Legislature on RPS procurement status,[50] the CPUC rated the risk associated with each project's RPS generation and noted that even if all 2010 generation that is now rated medium or high risk or under negotiation were to come on-line by that year, IOUs would still not meet the 20 percent by 2010 target. In that report, the CPUC identified the major risk factors for expected new 2010 RPS generation, with possible expiration of federal Production and Investment Tax Credits and transmission constraints being those affecting the largest percentage of new generation.[51]

At the August 21, 2008, IEPR joint committee workshop, the Independent Energy Producers Association stated that progress toward the state's RPS goals should not be determined based on signed contracts, but rather on projects delivering renewable megawatt hours to the grid. The association noted that it had filed a motion at the CPUC to investigate RPS procurement processes in California because of its concern that the IOUs are focused on selecting low-cost bidders rather than viable projects.[52]

Although lack of transmission continues to be identified as a major barrier to the development of new renewable projects, several parties at the IEPR workshops noted that, while RPS bid details and negotiations are confidential, they have heard anecdotally of projects not requiring major transmission upgrades that were not selected in RPS solicitations. PG&E stated that it has not seen any such projects bidding into its solicitations, while Green Power Institute warned against using transmission access as an excuse for failure to meet current RPS targets or as an argument against setting a 33 percent by 2020 target.

SDG&E submitted written comments for the July 21, 2008, IEPR staff workshop encouraging the Energy Commission to focus its IEPR efforts on determining what the state can do to promote the timely development of projects already under contract. At the August 21, 2008, IEPR joint committee workshop, Abengoa Solar suggested that the Energy Commission meet with project developers to discuss contract delays and analyze why contracts are failing.[53]

Potential Use of Feed-In Tariffs

The *2007 IEPR* recommended that the CPUC should immediately implement a feed-in tariff set initially at the market price referent for all RPS-eligible renewables up to 20 MW and that the Energy Commission should collaborate with the CPUC to develop feed-in tariffs for larger projects.[54]

Feed-in tariffs are essentially standardized contracts to sell energy delivered to the grid at a fixed price – although some feed-in tariffs step down in price over time – which can either be an all-inclusive rate or a fixed premium payment on top of the prevailing spot market price for power. The price paid is based on estimates of either the cost or value of renewable generation. The tariff is generally offered by the interconnecting utility and sets a standing price for each category of eligible renewable generator, with the price available to all eligible generators.

Assembly Bill 1969 (Yee, Chapter 731, Statutes of 2006) authorizes tariffs and standard contracts for the purchase of eligible renewable generation from public water and wastewater facilities. In February 2008, the CPUC made new feed-in tariffs available for the purchase of up to 480 MW of renewable generating capacity from small facilities (up to 1.5 MW) throughout California to provide a simple mechanism for small renewable generators to sell power to the utility at predefined terms and conditions, without contract negotiations.[55]

The Legislature introduced Assembly Bill 1807 (Fuentes, 2008) in 2008 to require the Energy Commission to examine the feasibility of feed-in tariffs for renewable facilities larger than 20 MW, but the legislation did not move forward. However, Senate Bill 380 (Kehoe, Chapter 544, Statutes of 2008) now requires IOUs to offer a standard tariff for RPS-eligible facilities up to 1.5 MW, capped at a statewide total of 500 MW, with eligibility contingent on the facility being owned and operated by a retail seller and strategically located for optimal delivery of electricity from the facility to load centers.

Energy Commission staff held a workshop on June 30, 2008, to discuss the challenges and opportunities associated feed-in tariffs. At that workshop, staff presented a consultant report by KEMA, Inc., to stimulate discussion and provide a primer on the issues surrounding the use of feed-in tariffs.[56] A second staff workshop was held October 1, 2008, to discuss potential paths for an expanded feed-in tariff with options ranging from full market implementation open to all technologies regardless of size to pilot scale options limited by technology and geographic area.[57] The IEPR and Renewables Committees will conduct the final joint Committee workshop on the topic of feed-in tariffs in early December 2008 with plans to publish a final report in early 2009.

Parties at the October 1 workshop generally supported feed-in tariffs for renewable projects up to 20 MW in size, but identified concerns about such tariffs for larger projects. IOUs continued to oppose expanding must-take feed-in tariffs, but described plans to offer standardized or "form" contracts designed to reduce transaction costs for smaller projects. The Energy Commission acknowledges IOU concerns that a feed-in tariff could result in higher energy costs to their customers, but notes that standard contracts could be financially burdensome and may not provide the same benefits in terms of encouraging increased and more timely renewable development.

The issue of feed-in tariffs also arose during other IEPR workshops. At the July 21, 2008, workshop, the Center for Resource Solutions discussed feed-in tariffs as a way to complement existing RPS procurement by providing another opportunity for large-scale (greater than 20 MW) renewable energy development projects that have transmission access, site control, and permitting to obtain RPS contracts. However, the California ISO stated that RPS procurement and contracting are not the main barriers to renewable development and that transmission, permitting, and siting are the key issues. The CPUC agreed that procurement is not the problem, but stated that perhaps feed-in tariffs for projects under 20 MW could play a role in increasing the amount of renewables in the state.

During the August 21, 2008, IEPR workshop, PG&E said that unless the state addresses permitting, the availability of the federal investment tax credit and production tax credit, and transmission issues, a feed-in tariff would not result in more renewable energy than the current approach to RPS procurement. PG&E noted that feed-in tariffs in Germany are much higher than California's market price referent set by the CPUC and said that if IOUs were required to pay an administratively set price higher than the price they can negotiate (which appears to be equal or close to the market price referent), the increased payment to the developers would represent a lost value to consumers and increased profit to suppliers.[58] However, as discussed in more detail in *Exploring Feed-In Tariffs for California: Feed-In Tariff Design and Implementation Issues and Options,*[59] feed-in tariffs can reduce uncertainty, which allows developers to obtain lower-cost financing and be less vulnerable to other costs related to delays in permitting, siting, interconnection, and equipment procurement.[60] The CPUC has identified project financing as one of the top four risk factors for renewable project development.[61]

At the August 21 workshop, GreenVolts, a developer of PV systems, discussed the benefits and large potential for PV less than 20 MW located near load[62] and stated that a feed-in tariff could energize the wholesale distributed generation market segment. To unlock this potential, GreenVolts suggested a feed-in tariff for projects 20 MW and below based on the CPUC's market price referent, plus time-of-use and locational benefits for generating close to load.[63]

In comments at the October 9 IEPR Committee hearing on the *Committee Draft 2008 IEPR Update*, the IOUs again raised concerns about feed-in tariffs, stating that the primary barriers to renewable development are transmission, siting, and permitting, and that feed-in tariffs do little to address these barriers. Although feed-in tariffs do not address every barrier to renewable development, they are still an important tool to allow numerous, small renewable projects into the system and help the state meet its renewable targets without the disproportionate administrative burden of responding to requests for offers or entering into standard offer contracts. Feed-in tariffs will provide additional certainty to developers seeking project financing, and will reduce transaction costs associated with proposing, negotiating, and signing RPS contracts.

Based on public comments received at the October 1 staff workshop on feed-in tariffs as well as at the October 9 IEPR Committee hearing, the Energy Commission recommends that the state focus its feed-in tariff efforts in the near-term on renewable projects of 20 MW or less. Over the long-term, it is essential for the CPUC and the Energy Commission to continue to evaluate the value of feed-in tariffs for renewable projects larger than 20 MW, using the Energy Commission's report on feed-in tariffs expected in early 2009.

Addressing Price Impacts

A continuing concern among parties is the potential for higher electricity costs as a result of moving to 33 percent renewables. Forecasts of electricity rates are very uncertain and depend on variables like future natural gas prices, costs associated with potential carbon regulation, the cost of necessary upgrades to the transmission and distribution grids, capital costs of building new facilities, and the cost of generation.

Natural gas prices remain volatile and prices over the long term will depend on the impacts of uncertain technological, economic, and political factors. Future costs of carbon regulation are unknown, but the *2007 IEPR* noted that, according to the Intergovernmental Panel on Climate Change, carbon prices could be as high as $100 per ton by 2030.[64] Construction costs for all generation resources continue to rise, with some estimates that the cost of building a natural gas power plant in the United States has increased by 92 percent since 2000.[65] Regarding the cost of new transmission investment, the *2007 IEPR* noted that investment will be needed to maintain system reliability and serve increasing electricity demand in any case, even if the state were not committed to 33 percent renewable generation by 2020.

In evaluating the impacts of higher levels of renewable penetration in California, cost assumptions will need to be made about renewable generation resources. The CPUC's 33 percent RPS implementation analysis is evaluating statewide cost and rate impacts, relying on RETI cost estimates as much as possible, and the Energy Commission will need to consider the conclusions from that study and from the RETI efforts in any cost evaluations.

In evaluating price impacts, however, it is important to remember the goals of increasing renewable generation, which include reducing dependence on natural gas as well as reducing GHG emissions. The potential costs associated with not meeting those goals, including higher electricity rates resulting from high natural gas prices as well as the economic effects of catastrophic climate change, must be considered in any evaluation of the costs of moving to higher levels of renewables.

Parties at the IEPR workshops noted that price impacts are an important issue but that future costs are extremely uncertain. SCE noted that the Energy Commission's *2007 IEPR Scenario Analysis Project* was a good beginning, but that actual price data is different from the assumptions used in that analysis, and believes that wholesale costs to all purchasers of power will increase by implementing a 33 percent goal.[66] Green Power Institute noted that because there is little doubt overall energy costs will increase in the future with the phasing out of fossil fuels, it may not matter if implementing the 33 percent target increases wholesale energy costs in and of itself given the importance of achieving that target to meet California's GHG reduction goals.[67]

Natural Gas Price Links to Renewable Energy

NYMEX natural gas futures have fluctuated greatly in the past 12 months, from about $6 per million British Thermal Units (MMBtu) to a peak of more than $13 per MMBtu.[68] In California, prices for renewable energy are linked to natural gas prices through the benchmark market price referent used in the RPS procurement process, which estimates market costs for a fixed-price, long-term contract for electricity generated from a new natural gas facility.

The IEPR workshop on July 21, 2008, summarized the findings from several studies on the potential effects of high levels of renewables on natural gas demand and prices. Lawrence Berkeley National Laboratory reviewed 13 studies of potential federal RPS programs ranging from 7.5 percent to 20 percent renewables and concluded that most studies showed net savings of $7 to $20 per MWh on electricity and natural gas bills across the United States. They also estimated changes in natural gas demand in California if IOUs met the 33 percent goal, and found that demand for natural gas could drop about 1 percent per year from 2011 to 2020, reaching about 9 percent below 2010 levels. This reduced demand could result in substantial natural gas savings (and associated CO_2 reductions) for California from 2011 through 2030, with the estimated net present value of natural gas savings in 2011 dollars between $0.8 billion and $2.0 billion.[69]

A 2005 report by the Center for Resource Solutions on achieving a 33 percent renewable energy target used the Lawrence Berkeley National Laboratory analysis to estimate natural gas price suppression effects and concluded that the incremental value of moving from 20 percent to 33 percent renewables in displacing natural gas can be from $3.5/MWh to $8.5/MWh.[70]

The 2007 Scenario Analysis Project conducted as part of the *2007 IEPR* also looked at the natural gas use and price impacts of increased levels of renewables. Based on a westwide scenario that included high efficiency, high renewables, and rooftop PV, the study indicated large reductions in gas use for electricity generation and price reductions in the range of 50 cents to $1 per MMBtu. The study, however, did not reflect likely behavioral changes from gas producers in response to reduced gas demand, such as reduced long-term capital investments. To incorporate those changes, staff ran the GPCM® model[71] and came up with expected price reductions of 10-25 cents per MMBtu.[72] Given the unproven assessment methods in the study, the *2007 IEPR* noted the existence of this natural price reduction effect, but said it could not be quantified well enough to be reliable.[73]

Several parties at the IEPR workshops noted that California may not see significant reductions in natural gas demand or price because of rising demand in other states as they move from coal to natural gas resources in response to GHG concerns. With the evolving global nature of natural gas markets, increased U.S. demand could offset any demand or price reductions in California from displacing natural gas resources with renewable resources.

The California ISO also stated that the need to back up variable wind renewable resources with natural gas plants may be exporting that variability to the natural gas system. Because resources like wind fluctuate in response to weather conditions, natural gas plants need to respond quickly to those variations, with associated impacts on the natural gas transmission and storage systems. In addition, it is unclear how to communicate the need for these rapid changes in supply to the gas pipeline companies.[74]

Clearly, there is a need for further evaluation of the links between natural gas demand and price and the increased use of renewable resources. Evaluation of this issue could include an examination of the regional price impacts from changes in natural gas demand and supply opportunities. Also, it will be necessary to better understand physical changes to natural gas supply, delivery, and storage systems to support a 33 percent renewable energy future. There may be a requirement for new natural gas transport capability to California and additional storage to support the cycling of natural gas-fired generation to back up intermittent renewable energy resources.

In addition, there is a need for continued evaluation of different mechanisms to decouple the price paid for renewable energy from the price of natural gas, including using feed-in tariffs that focus on the actual cost of generation of renewable resources.

Cost of Generation

The *2007 IEPR* recommended that the Energy Commission refine the input data used in its Cost of Generation Model in the *2009 IEPR* and establish a process to regularly update changing technology costs over time.[75] Because of the increasing role that newer technologies, particularly renewable technologies, are likely to play in the future, it is important that cost assumptions used in the various analyses on the effects of higher levels of renewables accurately reflect potential price changes for both conventional and renewable resources that may occur in the next decade.

Addressing Environmental Issues

Environmental permitting of large-scale renewable power plants is an increasing concern given the number, size, and potential locations of proposed plants. The Energy Commission has received applications for nearly 1,700 MW of new solar facilities. Another 1,100 MW of new facilities have been announced but not yet applied. The federal BLM has received applications for solar and wind facilities on public lands totaling about 1.3 million acres.[76]

There are several efforts underway related to the environmental permitting of renewable power in California. The U.S. Department of Energy (DOE) and the BLM are jointly preparing a solar energy programmatic environmental impact statement as a prelude to permitting or sponsoring large-scale solar electricity-generating installations in the western United States, including the Southern California desert. The BLM and DOE are evaluating whether installations of large-scale solar electric power plants on public lands could be facilitated by developing agency-specific programs that establish environmental policies and mitigation strategies for this solar development. In addition, the BLM and the Energy Commission have entered into a Memorandum of Understanding to more efficiently evaluate the environmental impacts of solar thermal projects above 50 MW in California by avoiding duplication of staff efforts, sharing staff expertise and information, and allowing public review by providing a joint environmental document.

An associated effort is the RETI, which is identifying renewable energy zones in California and neighboring states that can provide significant electricity to California consumers by 2020. RETI will identify zones that can be developed in the most cost-effective and environmentally benign manner.

More recently, Governor Schwarzenegger signed Executive Order S-14-08 on November 17, 2008, which establishes a Renewable Energy Action Team (REAT) to create a "one-stop" process for permitting renewable energy facilities. Among other things, the Executive Order calls for the REAT to undertake a variety of activities related to establishing long-term conservation plans, and to develop a best management practices manual to assist RPS project applicants in designing projects that minimize environmental impacts.

Much of the land where new renewable facilities will be located is ecologically sensitive and may require significant habitat mitigation. Solar facilities in particular require large amounts of land, and identifying enough ecologically appropriate land elsewhere to reduce potential impacts will be a challenge. At the IEPR joint committee workshop on August 21, 2008, the representative for BrightSource Energy, a developer of large-scale solar, suggested that clear information is needed on what constitutes adequate mitigation, recognizing that some locations are more ecologically valuable than others. Because the cost of mitigation and restoration must be factored into project finances, more information on these costs would assist developers.[77]

Environmental mitigation issues are also important in the selection and approval of RPS contracts because of the potential effects on developers' ability to bring projects on-line in a timely way. In selecting and approving renewable projects, IOUs and the CPUC need to make allowance for environmental impacts and mitigation not originally contemplated by project proponents and factor in the need for additional mitigation on project schedules and milestones. Inadequate consideration of these impacts will likely result in the project missing contract milestones due to a longer than expected permitting process, which can jeopardize the ultimate development of renewable projects. Project delays can also lead to higher costs both for developers and ratepayers because development costs can increase over time.

In written comments submitted after the October 9, 2008, IEPR Committee hearing on the draft *2008 IEPR Update*, the CPUC stated that, per Public Utilities Code section 399.14, the IOUs select contracts, and the CPUC then reviews those contracts for price reasonableness and consistency with each IOU's CPUC-approved renewable energy procurement plan. The CPUC asserts that environmental impacts are most appropriately considered later in the project development process, at the permitting stage. They note that consideration of project viability in the solicitation and contract review processes is an issue that will be addressed in R.08-08-009, one of the CPUC's two RPS Proceedings, where parties will have the opportunity to consider appropriate treatment of this issue.

Recommendations

Analysis Needed in 2009 Integrated Energy Policy Report

The *2009 IEPR* should include a thorough evaluation of the issues associated with transitioning to a higher renewable future. These should include:

- Evaluation of new fossil-fuel generation that may be needed while addressing once-through cooling concerns, aging power plant retirements, potential changes in the operation of existing power plants due to GHG emission regulations, and potential increased electrification of the transportation system that may affect the state's ability to meet higher renewable targets.

- Identifying transmission system improvements needed to reduce local capacity requirements for fossil-fuel generation.

- Identifying actions to increase the ability of load-serving entities to meet resource adequacy requirements with renewable energy.

- Working closely with the California ISO to better understand the amount of ramping and regulation needed for 33 percent renewable energy in 2020.

Transmission Barriers

The state should identify and implement ways to remove barriers to joint publicly owned utility and investor-owned utility transmission projects, including:

- The Energy Commission should work collaboratively with IOUs and publicly owned utilities in the RETI Phase 2 activity to develop conceptual transmission plans that will inform the *2009 IEPR/Strategic Transmission Investment Plan* process and provide information on potential high-priority transmission projects and corridors that may be necessary in the future to help achieve higher levels of renewables penetration. The RETI Phase 2 results, together with information on planned transmission projects and corridor needs that will be collected through the *2009 IEPR* process, will help identify opportunities for joint project collaboration.

- To promote joint transmission project opportunities, the Energy Commission should use the *2009 IEPR* and *2009 Strategic Transmission Investment Plan* processes as forums to identify and evaluate regulatory or policy changes that would reduce both legal and market obstacles to joint projects development

- The Energy Commission should work closely with stakeholders in the development of RETI Phase 2 conceptual transmission projects to ensure that land use issues and environmental concerns are evaluated and considered. To inform and build greater public support for achieving the state's renewable and greenhouse gas reduction goals, as well as the crucial role transmission projects play in providing access to renewable resources, the Energy Commission recommends reestablishing the Energy Resources Program Account funding to the Energy Commission's local assistance program established under Public Resources Code section 25616. This program can be used to assist local governments with the development of general plan transmission and energy elements that recognize the importance of these statewide goals.

Integration Issues

Grid Impacts

The Energy Commission should work collaboratively with the California ISO on its Integration of Renewable Resources Program and with the renewable integration efforts of the WECC Variable Generation Subcommittee to ensure that the potential impacts on grid operation of the RETI Phase 2 conceptual transmission projects are addressed. In addition, the state should continue to implement the key recommendations made by CERTS/EPG in its renewable resource integration work done for the Energy Commission, such as improved, long-term, and integrated transmission planning.

Local Capacity Requirements

Load-serving entities' procurement plans should demonstrate how their anticipated renewable, nonrenewable, demand response, and storage resource mix will address local capacity requirements to maintain system reliability.

Research and Development

The state should ensure sufficient funding for research and development efforts on:

- Identifying energy storage technologies such as grid-based electrical energy storage and high temperature thermal energy storage in solar thermal power plants with the most promise to resolve grid stability and operations issues related to higher penetrations of renewables, reduce the costs of those technologies, analyze their integration with solar and wind power plants, and accelerate their commercialization.

- Identifying, developing, and integrating transmission system improvements and technologies that can increase and control bulk power flows on the transmission system (like real-time power line rating technologies, synchronized phasor technologies, and advanced transmission conductors), provide real-time information to transmission operators to allow optimization of the existing transmission system (such as solar and wind production forecasts based on meteorological models and real-time measurements, real-time synchronized phasor situation displays, and real-time dynamic monitoring systems), and diminish local capacity requirements in load pockets.

- Expanding efforts on renewable integration issues to include technical and economic barriers and benefits of distribution-level and building-integrated renewable — with particular emphasis on feasible and cost-effective strategies for California communities to exploit local and nearby renewable resources — and analyzing the costs and benefits of installing 20 MW solar PV facilities at suitable distribution substations.

- Developing a targeted program to address technical and infrastructure barriers to deployment of emerging renewable heating and cooling technologies and to assess their current and future cost trajectories as well as how to strengthen the market for commercially mature technologies.

Transmission-related research, development, and demonstration activities to facilitate renewables integration will require a significant increase in research and development spending by the state. The CPUC and the Energy Commission should investigate potential sources of funding beyond what is already committed to current efforts such that transmission-related research and development is funded at no less than $60 million per year. In addition, the Legislature should require publicly owned utilities to expand their transmission research and development activities as well.

Contracting Issues

RPS Procurement

If a utility plans to build or purchase its own generating facilities, the RPS procurement proposals should be reviewed, selected, and ranked by independent parties. Selections should be based on publicly published selection criteria such as cost, locational benefits, and land use and environmental considerations, assisted by other non-market participants and the Energy Commission.

Increased Transparency

To assure policy makers that RPS contracts are providing the greatest strategic and economic value to the state, IOUs should be required to provide aggregated information on contract prices and the CPUC should make public the aggregate amount of above-market funds being allocated to RPS contracts.

Feed-In Tariffs

The CPUC should immediately implement a feed-in tariff program for all RPS-eligible generating facilities up to 20 MW in size. Such a program should include must-take provisions as well as cost-based technology-specific prices that generally decline over time and are not linked to the CPUC's market price referent.

The Energy Commission and CPUC should continue to evaluate feed-in tariffs for renewable projects larger than 20 MW using the information in the Energy Commission's report on feed-in tariffs expected to be completed in early 2009.

Price Impacts

Effects on Natural Gas

The Energy Commission should evaluate the effects of increased use of renewables and of changes in regional natural gas markets on natural gas demand and price in California.

Natural Gas Availability

The Energy Commission should evaluate the availability of natural gas in California based upon different scenarios and increasing worldwide demand.

Cost of Generation

The Energy Commission should continue efforts to refine the input data in the Cost of Generation Model and focus on regularly updating changing technology costs over time.

Cost of 33 Percent Target

Along with the CPUC's 33 percent RPS evaluation, the Energy Commission should estimate potential cost impacts of the 33 percent RPS target based on current contracts and scenarios using the Cost of Generation model.

Environmental Issues

Renewable Resource Zones

The Energy Commission should continue to work with the RETI Environmental Working Group to identify competitive renewable resource zones where renewable energy development is expected to be least damaging to the environment.

Permitting and Solar

The Energy Commission should continue participating in the Solar Programmatic Environmental Impact Statement (PEIS) efforts with DOE and the BLM and continue to work with the BLM to evaluate the environmental impacts associated with permitting solar thermal facilities in California.

Permitting and Procurement

The CPUC should direct the IOUs in their RPS solicitations to factor in and make allowance for the possibility of the permitting process affecting project schedules, milestones, and costs due to additional analysis and mitigation required for environmental impacts not originally covered in a developer's proposal.

Endnotes

1 Office of the Governor, Executive Order S-14-08, November 17, 2008, http://www.gov.ca.gov/executive-order/11072/.

2 Office of the Governor, Executive Order S-14-08, November 17, 2008, http://www.gov.ca.gov/executive-order/11072/.

3 Proposed Scoping Plan prepared by the California Air Resources Board as required by the Global Warming Solutions Act (Assembly Bill 32 [Núñez, Chapter 488, Statutes of 2006]), http://www.arb.ca.gov/cc/scopingplan/document/scopingplandocument.htm.

4 Governor's Executive Order S-3-05, June 2005, http://gov.ca.gov/executive-order/1861/.

5 California Energy Commission, Database of IOU Contracts for Renewable Generation, October 2008 update, www.energy.ca.gov/portfolio/IOU_CONTRACT_DATABASE.XLS.

6 Comments from Bob Doyel, Bureau of Land Management, July 23, 2008, IEPR staff workshop, http://www.energy.ca.gov/2008_energypolicy/documents/2008-07-23_workshop/2008-07-23_TRANSCRIPT.PDF, page 89.

7 California Public Utilities Commission, April 2008, *Renewables Portfolio Standard Quarterly Report to the Legislature,* http://www.cpuc.ca.gov/PUC/energy/electric/RenewableEnergy/documents.htm.

8 As required by Senate Bill 1565 (Bowen, Chapter 692, Statutes of 2004).

9 The eight projects are San Diego Gas & Electric's Sunrise Powerlink 500 kV Project; Southern California Edison's Tehachapi Renewable Transmission Plan (Segments 1 through 3 in the 2005 Strategic Plan plus the remaining segments in the 2007 Strategic Plan); the Imperial Valley Transmission Upgrade Project; Pacific Gas and Electric Company's Central California Clean Energy Transmission Project; the transmission component of the Lake Elsinore Advanced Pumped Storage Project; the Green Path Coordinated Projects; and the Los Angeles Department of Water and Power Tehachapi Project.

10 The Renewable Energy Transmission Initiative was initiated as a collaborative effort between the Energy Commission, the California Public Utilities Commission, the California Independent System Operator, the Northern California Power Agency, the Southern California Public Power Authority, and the Sacramento Municipal Utility District and has a diverse stakeholder committee composed of representatives from California's investor-owned and publicly owned utilities, renewable developers, environmental organizations, landowners, Native American representatives, transmission owners and providers, the military, and federal, state, and local agencies.

11 As authorized by Senate Bill 1059 (Escutia, Chapter 638, Statutes of 2006).

12 This issue was also identified by California ISO in its December 21, 2007, Order 890 Compliance Filing to the Federal Energy Regulatory Commission. In that filing, both Southern California Edison and the Transmission Agency of Northern California raised specific concerns with the language in Section 24.11 of the Draft Market Redesign and Technology Update tariff. California ISO's response in the December 21, 2007, Order 890 Compliance Filing indicated that it intended to revise the language in Section 24.11 to "reflect the appropriate level of flexibility to facilitate jointly-owned transmission projects."

13 Congestion revenue rights are financial instruments that enable holders to manage variability in congestion costs under MRTU based on locational marginal pricing. These rights are acquired primarily, although not solely, for the purpose of offsetting integrated forward market congestion costs that occur in the day-ahead market. http://www.caiso.com/1bb4/1bb4745611d10.html.

14 The Location Constrained Resource Interconnection tariff was developed by the California ISO to facilitate financing and construction of transmission facilities needed to develop location-constrained resources, such as renewables, http://www.caiso.com/1816/1816d22953ec0.html.

15 These results are contained in Chapter 3 of the California ISO's August 6, 2008, Report on Preliminary Renewable Transmission Plans, http://www.caiso.com/2007/2007d75567610.pdf.

16 Beyond the Southern California Edison Tehachapi Renewable Transmission Project and the San Diego Gas & Electric Sunrise Powerlink, which are currently undergoing review at the California Public Utilities Commission.

17 Comments from Jorge Chacon, Southern California Edison, July 23, 2008, IEPR workshop, http://www.energy.ca.gov/2008_energypolicy/documents/2008-07-23_workshop/2008-07-23_TRANSCRIPT.PDF,page 67.

18 Transcript of the April 17, 2007, IEPR Joint Committee Workshop on Removal of Transmission Barriers for Renewables and Examination of Transmission Corridor Initiatives. Page 290 Line 17 through Page 291 Line 21, http://www.energy.ca.gov/2007_energypolicy/documents/2007-04-17_workshop/2007-04-17_TRANSCRIPT.PDF.

19 Comments by Jane Turnbull, League of Women Voters, July 23, 2008, IEPR workshop on transmission issues, http://www.energy.ca.gov/2008_energypolicy/documents/2008-07-23_workshop/2008-07-23_TRANSCRIPT.PDF, pp. 121-122.

20 Public Resources Code section 25616 is a legislatively mandated but currently unfunded local assistance program that has been inactive for more than 10 years. It required the Energy Commission to encourage local agencies to expeditiously review permit applications to site energy projects, and to encourage energy project developers to consider all cost-effective and environmentally superior alternatives that achieve their project objectives. It also directed the Energy Commission, subject to the availability of funds, to provide technical assistance and grants-in-aid to assist local agencies in siting energy production or transmission projects which are not otherwise subject to the Energy Commission's power plant site certification process.

21 Final report available at: http://www.energy.ca.gov/2007publications/CEC-500-2007-081/CEC-500-2007-081.PDF.

22 The essential information in the report was summarized in the CERTS/EPG July 23, 2008, staff workshop presentation, available at: http://www.energy.ca.gov/2008_energypolicy/documents/2008-07-23_workshop/presentations/John_Ballance %20Renewables_Integration.pdf.

23 California Energy Commission, *Intermittency Analysis Project Final Report*, July 2007, page 18, http://www.energy.ca.gov/2007publications/CEC-500-2007-081/CEC-500-2007-081.PDF.

24 Major L.A. Basin gateways are Antelope-Mesa, Vincent-Mesa/Vincent Rio Hondo, Lugo-Mira Loma, Palo Verde/Harquahala-Devers, Coachella/Ramon-Mirage, and San Diego-San Onofre.

25 Automatic protection systems designed to detect abnormal transmission system conditions and take corrective action to maintain system reliability.

26 California Independent System Operator, November 2007, *Integration of Renewable Resources: Transmission and Operating Issues and Recommendations for Integrating Renewable Resources on the California ISO-controlled Grid*, http://www.caiso.com/1ca5/1ca5a7a026270.pdf.

27 California ISO website entitled Integration of Renewable Resources Program, http://www.caiso.com/1c51/1c51c7946a480.html.

28 Transcript of the July 21, 2008, IEPR Staff Workshop on Impacts of Higher Levels of Renewables on the Electricity System: Summary of Recent Studies, http://www.energy.ca.gov/2008_energypolicy/documents/2008-07-21_workshop/2008-07-21_TRANSCRIPT.PDF.

29 For more information, see California Energy Commission, May 2008, *Summer 2008 Electricity Supply and Demand Outlook, Staff Report*, CEC-200-2008-003, http://www.energy.ca.gov/2008publications/CEC-200-2008-003/CEC-200-2008-003.PDF.

30 The CPUC first adopted a broad resource adequacy requirement in D.04-01-050 as part of the series of decisions returning procurement authority to IOUs following the 2000-2001 electricity crisis. The initial framework for resource adequacy for CPUC-jurisdic-

tional entities (IOUs and Energy Service Providers) was established through D.04-10-035. Actual resource adequacy filing requirements began in late 2005 for the time period covering June – December 2006. A regular pattern of fall compliance filings for the subsequent calendar year was established, and has now been carried out for the 2007 and 2008 calendar years. Efforts for 2009 are underway. California ISO resource adequacy requirements paralleling those of the CPUC were established for the publicly owned utilities within its jurisdiction.

31 The California Energy Commission assesses individual project wind and solar performance data to compute the net qualifying capacity for these two resource types.

32 California Public Utilities Commission, Energy Division, *2006 Resource Adequacy Report*, March 2007, indicates that on the six-day period July 21-26, 2006, when the California ISO system peak record was established, wind achieved between 145 and 533 MW, its net qualifying capacity was 608 MW, and nameplate capacity was 2,298 MW (p. 35).

33 The Energy Commission will certify facilities as RPS-eligible that would have been considered distributed generation facilities except that they are participating in a standard contract and tariff under CPUC Decision 07-07-027. This decision adopts tariffs and standard contracts for water, wastewater, and other customers to sell generation from RPS-eligible renewable resources up to 1.5 MW, up to a cumulative statewide total of 250 MW. See California Energy Commission, *Renewables Portfolio Standard Eligibility Guidebook*, January 2008, page 18, http://www.energy.ca.gov/2007publications/CEC-300-2007-006/CEC-300-2007-006-ED3-CMF.PDF.

34 Black and Veatch, *Renewable Energy Transmission Initiative Phase 1B Draft Resource Report*, August 2008, page 1-6, http://www.energy.ca.gov/reti/documents/2008-08-16_PHASE_1B_DRAFT_RESOURCE_REPORT.PDF.

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36 As articulated in the State of California Energy Action Plan, http://www.energy.ca.gov/energy_action_plan/.

37 "California Solar Initiative" is often used to refer to all of the various solar incentive programs in the state that are addressed in Senate Bill 1 (Murray, Chapter 132, Statutes of 2006), and includes programs administered by the CPUC, the Energy Commission, and the publicly owned utilities.

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40 For example, Chevron Corp. is underway with a 14-site solar power and efficient energy project for the Milpitas Unified School District, http://www.bizjournals.com/sanfrancisco/stories/2008/06/23/daily31.html?ana=from_rss.

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43 Go Solar California, California Solar Initiative Program Handbook, November 2008, http://www.gosolarcalifornia.ca.gov/documents/CSI_HANDBOOK.PDF, p. 5, 9. See also California Public Utilities Commission Decision 06-12-033. http://docs.cpuc.ca.gov/published/FINAL_DECISION/63031.htm.

44 Lawrence Berkeley National Laboratory, *Electricity Use in California: Past Trends and Present Usage Patterns*, Richard E. Brown and Jonathan G. Koomey, May 2002, http://enduse.lbl.gov/info/LBNL-47992.pdf.

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working actively with representatives from all elements of the utility industry to identify the key codes, standards and protocols necessary to implement the "smart grid" of the future. The Energy Commission and the Public Utilities Commission are working together to help the California utilities develop a definition of the "smart grid" of the future that will work for and apply to all of California.

46 Unlike generation equipment ratings that are determined by power generation or electrical efficiency, the performance of energy storage systems is determined by the capacity and duration of the equipment.

47 Comments by David Hawkins, July 21, 2008, IEPR workshop, http://www.energy.ca.gov/2008_energypolicy/documents/2008-07-21_workshop/2008-07-21_TRANSCRIPT.PDF, page 124.

48 Devices capable of long-term recording of electrical characteristics and disturbances on transmission grids.

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50 California Public Utilities Commission, July 2008, *Renewables Portfolio Standard Quarterly Report to the Legislature*, http://docs.cpuc.ca.gov/word_pdf/REPORT/85936.pdf.

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Chapter 2

Energy Efficiency and Demand Forecasting

Introduction

With the state's adoption of the first *Energy Action Plan* in 2003, energy efficiency became the resource of first choice for meeting the state's future energy needs. Assembly Bill 2021 (Levine, Chapter 734, Statutes of 2006) set a statewide goal of reducing total forecasted electricity consumption by 10 percent over the next 10 years. Under AB 2021, the Energy Commission, along with the CPUC, is responsible for setting annual statewide efficiency targets in a public process using the most recent investor-owned and publicly owned utility targets. These targets, combined with California's greenhouse gas (GHG) emission reduction goals, make it essential for the Energy Commission to properly account for energy efficiency impacts when forecasting future electricity and natural gas demand.

This chapter discusses the challenges involved in measuring and attributing energy efficiency programs[78] and other market impacts within the Energy Commission's California Energy Demand Forecast process. It also provides an overview of methods currently used by Energy Commission staff to incorporate energy efficiency programs into the forecast. The chapter then identifies the approach staff will employ to better delineate the efficiency assumptions in the demand forecast within the *2009 IEPR* cycle and beyond as recommended in the *2007 IEPR*. Finally, the chapter reports on progress made by California utilities in fulfilling the efficiency requirements of AB 2021.

In forecasting future energy demand, isolating the effects of different sources of savings is a complex process that is sometimes subjective. Utilities and other stakeholders expressed concern during the *2007 IEPR* process about the lack of transparency in staff methods. In particular, parties requested clarification about the amount of uncommitted savings — savings from efficiency programs reasonably expected to occur but not yet implemented or funded — that are accounted for in the forecast. Prompted by these concerns, the *2007 IEPR* committed the Energy Commission in 2008 and beyond to examine the methods used to incorporate efficiency in the Energy Commission's demand forecast in a public process that includes the CPUC staff, utilities, and other stakeholders.

In its scoping order for the *2008 IEPR Update,* the IEPR Committee directed the Energy Commission staff to:

- Clearly explain how staff incorporated energy efficiency in the demand forecast, allowing parties to understand how the models include utility programs, standards, and other efficiency codes as inputs when developing the demand forecast.

- Evaluate price response, market trends, and other market effects, and how they are included or excluded from the demand forecast models.

- Clarify the amount of efficiency program savings or potential embodied in the forecast and how that will affect decisions to go forward with additional efficiency programs.

- Evaluate potential new projection capabilities to use along with the demand forecast to examine long-term alternative energy efficiency strategies, such as zero-emission building goals, in support of long-term GHG reduction goals.

- Identify what collaboration is needed or desirable among utilities, the CPUC, the Energy Commission, and others to refine demand forecasting methods and create the necessary energy efficiency projection capabilities.

Measurement and Attribution Challenges

Energy efficiency poses major challenges for energy forecasters. It is difficult to reliably estimate reduced consumption from efficiency measures for the following reasons:

- Efficiency results depend on consumer behavior, which alters with changes in energy prices, cultural practices, and technology. Changes in consumer behavior over time change the savings that result from energy efficiency measures in ways that are difficult to forecast.

- There are different ways to account for the impacts of efficiency programs taken in isolation, all of which are subject to uncertainty. Results from each method, even if considered reliable, may not directly translate into observable reduced demand due to simultaneous changes in technology and behavior.

- The effects of efficiency efforts depend on variations in program funding and authorization through time that cumulatively may have differential impacts equivalent to one or more large power plants.

With a generation facility, it is not difficult to accurately determine the amount of power generated at any given time. This is not the case for energy saved through efficiency programs. Forecasters estimate reduced demand from these programs relative to what would have happened if the programs were not in place. However, because there is overlap with

Table 1 – Efficiency Programs Explicitly Incorporated in the 2007 IEPR Forecast

Residential Model	
1975 HCD Building Standards	1988 Federal Appliance Standards
1978 Title 24 Residential Building Standards	1990 Federal Appliance Standards
1983 Title 24 Residential Building Standards	1992 Federal Appliance Standards
1991 Title 24 Residential Building Standards	OII-42 Solar Subsidies
2005 Title 24 Residential Building Standards	Pool Pump Timers
1976-82 Title 20 Appliance Standards	Miscellaneous Retrofit
1984 Title 20 Appliance Standards	
Commercial Model	
1978 Title 24 Nonresidential Building Standards	1998 Title 24 Nonresidential Building Standards
1978 Title 20 Equipment Standards	2001 Title 24 Nonresidential Building Standards
1984 Title 24 Nonresidential Building Standards	2004 Title 20 Equipment Standards
1984 Title 20 Nonresidential Equipment Standards	2005 Title 24 Nonresidential Building Standards
1985-88 Title 24 Nonresidential Building Standards	Federal Schools and Hospitals Program
1992 Title 24 Nonresidential Building Standards	
Summary Model	
Residential New Construction	Energy Extension Service
Residential Master Meter	Miscellaneous Commercial Retrofit
Commercial New Construction	

Source: California Energy Commission, *Energy Demand Forecast Method Report*, CEC-400-2005-036, June 2005.

effects from other program activities, voluntary actions, and market changes not directly attributable to those programs, it is difficult to determine the amount of reduced consumption that results from a specific efficiency program. Energy forecasters must often discount the estimated savings from efficiency programs, or allocate the savings among a variety of programs and market effects, when attempting to accurately predict what amount of energy will be used.[79] Forecasters do this when programs are not realizing expected savings or to avoid double-counting effects that are not clearly attributable to either programs or other market forces.

It is imperative that energy forecasters and program analysts refine and improve methods to quantify energy efficiency and conservation impacts to yield reliable results, while also accounting for processes already at work in the market.

Another challenge is in developing consistent measurement techniques. The Energy Commission's demand forecast, utility forecasts, and energy efficiency potential forecasts and models, such as Itron's Asset model,[80] often use different quantification methods when measuring the impacts of voluntary conservation and efficiency programs. Assumptions also differ about the impact of price and other market effects.[81] Sorting out these differences will require an increasing level of cooperation among the various interested parties.

Incorporating Efficiency in the Demand Forecast

The Energy Commission's demand forecast attempts to account for savings from committed efficiency programs, defined as programs that are either implemented or have approved funding, as well as savings resulting from market effects like increases in energy price. Efficiency programs incorporated in the demand forecast fall into three broad categories: building standards, appliance standards, and utility and public agency programs.

Committed efficiency programs are explicitly incorporated in the Residential Energy Demand Forecast Model, the Commercial Building Energy Demand Forecast Model, and the Energy Demand Summary Forecast Model,[82] but not in the models used for other sectors. The models used for the industrial, agricultural, transportation, communications and utilities, and street lighting sectors do not integrate specific programs, but do reflect past efficiency impacts because the models are calibrated to historic energy use.[83]

In the Residential and Commercial models, efficiency programs are accounted for by estimating changes in average energy consumption inputs at the end-use level for each "vintage" of efficiency program. For the Summary Model, program impacts that could not be modeled at the end-use level are estimated directly outside the model and then subtracted from aggregated total consumption. Table 1 lists the efficiency programs explicitly incorporated in these three models. The source provided at the bottom of the table gives information on the individual programs.

Staff forecasters attribute savings effects in the residential and commercial sectors by removing the estimated impacts of efficiency programs in reverse chronological order. This time-sequencing approach requires a series of model runs, with efficiency programs removed one at a time in the Residential and Commercial models. The incremental changes in output between model runs reflect the savings attributable to individual efficiency programs. Once all efficiency programs are removed, only market effects remain. Measuring market effects requires holding electricity prices constant at base year (1977) levels.

Table 2 shows the impact of committed efficiency programs, along with price and other market effects, on residential and commercial electricity use for the five major California utilities – Pacific Gas and Electric (PG&E), Southern California Edison (SCE), San Diego Gas and Electric (SDG&E), Sacramento Municipal Utility District (SMUD), and Los Angeles Department of Water and Power (LADWP) — from the *2007 IEPR* demand forecast.

The data in this table is drawn from the published 2007 demand forecast report (pages 25-29) in which there is a more detailed discussion of conservation accounting in the forecast for programs, standards, and price and market effects.[84] Additionally, the methods used to account for efficiency in the forecast are documented in the Energy Commission's Demand Forecast Methods Report, last published as part of the *2005 IEPR* cycle.[85] The table reflects the attribution of energy efficiency currently characterized in the demand model. Relative results are likely to change as the Energy Commission continues to refine and improve its energy efficiency measurement and attribution during the *2009 IEPR* process. This is part of the continuing effort to explain "all conservation reasonably expected to occur" over the Energy Commission's forecast period.

Table 2 also shows historical and projected residential and commercial electricity use from the *2007 IEPR* forecast, as well as historical and projected "unmanaged" use, that is, estimated use in the absence of these savings impacts. The last column shows the percentage reduction in use attributed to the impacts of efficiency programs plus market effects, calculated by dividing total savings by unmanaged use. The "Total Savings" column represents the amount

Table 2 - Residential plus Commercial Electricity Savings from the 2007 IEPR Forecast: Five Major California Utilities Combined

	Total Savings from Standards and Programs	Price and Other Market Effects	Total Savings	Elec. Use 2007 Adopted Forecast	Elec. Use 2007 Unmanaged Forecast	Percent Reduction in Use from Savings
Residential plus Commercial Consumption Impacts (GWH)						
1990	9,755	12,000	21,755	135,746	157,501	13.8
2000	20,988	8,273	29,261	169,421	198,682	14.7
2005	27,451	14,404	41,855	179,016	220,871	18.9
2008	31,255	16,198	47,453	193,233	240,686	19.7
2013	37,467	17,975	55,442	210,500	265,942	20.8
2018	43,789	19,381	63,170	226,616	289,786	21.8
Residential plus Commercial Coincident Peak Impacts (MW)						
1990	3,178	2,760	5,938	31,447	37,385	15.9
2000	6,001	1,903	7,904	38,320	46,223	17.1
2005	7,656	3,313	10,969	42,326	53,294	20.6
2008	8,536	3,725	12,261	45,557	57,818	21.2
2013	9,974	4,134	14,108	49,535	63,643	22.2
2018	11,486	4,458	15,944	53,485	69,428	23.0

Source: *California Energy Demand 2008-2018 Staff Revised Forecast*, CEC-200-2007-015-SF2, November 2007, various tables.

of savings due to efficiency programs and market effects explicitly accounted for in the demand forecast.

The level of price and market effects comes mainly from the impact of price in the commercial sector, where electricity rates have increased substantially since 1975. If the baseline were a later year, price and market effects would be lower.

In addition to electricity savings, natural gas efficiency programs and market effects in the residential and commercial sectors served by the three major California gas utilities (SDG&E, PG&E, and Southern California Gas) saved an estimated 4,337 million therms in 2005, increasing to an expected 5,716 million therms by 2018. Efficiency programs are estimated to contribute roughly 90 percent of savings impacts in both years. These savings are larger relative to total consumption than in the electricity sector; total gas consumption is estimated to be 6,695 million therms in 2005, increasing to 7,768 million therms by 2018.[86]

The Energy Commission's mandate to include energy savings reasonably expected to occur in its planning also includes impacts from efficiency programs that are uncommitted (not included in Table 2), such as future standards and unfunded programs. Staff currently treats such program impacts as an additional resource that can be compared to other options. However, this does not necessarily imply that estimates of savings from prospective standards and other efficiency programs can simply be subtracted from the demand forecast to measure impact on energy consumption. In other words, uncommitted savings, including savings related to adopted efficiency goals, may not be 100 percent incremental to the forecast.[87]

Indeed, during the 2006 CPUC Long-Term Procurement Planning and the *2007 IEPR* proceedings, SDG&E, PG&E, and SCE raised concerns about this possibility. The utilities claimed some of the estimated uncommitted savings related to CPUC efficiency goals would overlap with savings already included in the Energy Commission forecast, and subtracting all of the uncommitted impacts as though they were incremental would constitute double counting. Such double counting could occur for various reasons, for example:

- CPUC goal setting may allow proposed program savings to overlap with impacts from the Energy Commission's building standards or federal appliance standards.

- In meeting CPUC goals, investor-owned utilities (IOUs) can spend future efficiency program funds to replace measures that have expired, while the Energy Commission's forecast in some cases assumes that savings from those measures would continue without the inducement of any program, assigning the savings to market effects.

- CPUC goal setting may not account for the effect of underlying price and other market effects, which can induce some of the savings estimated from individual measures even in the absence of an efficiency program.

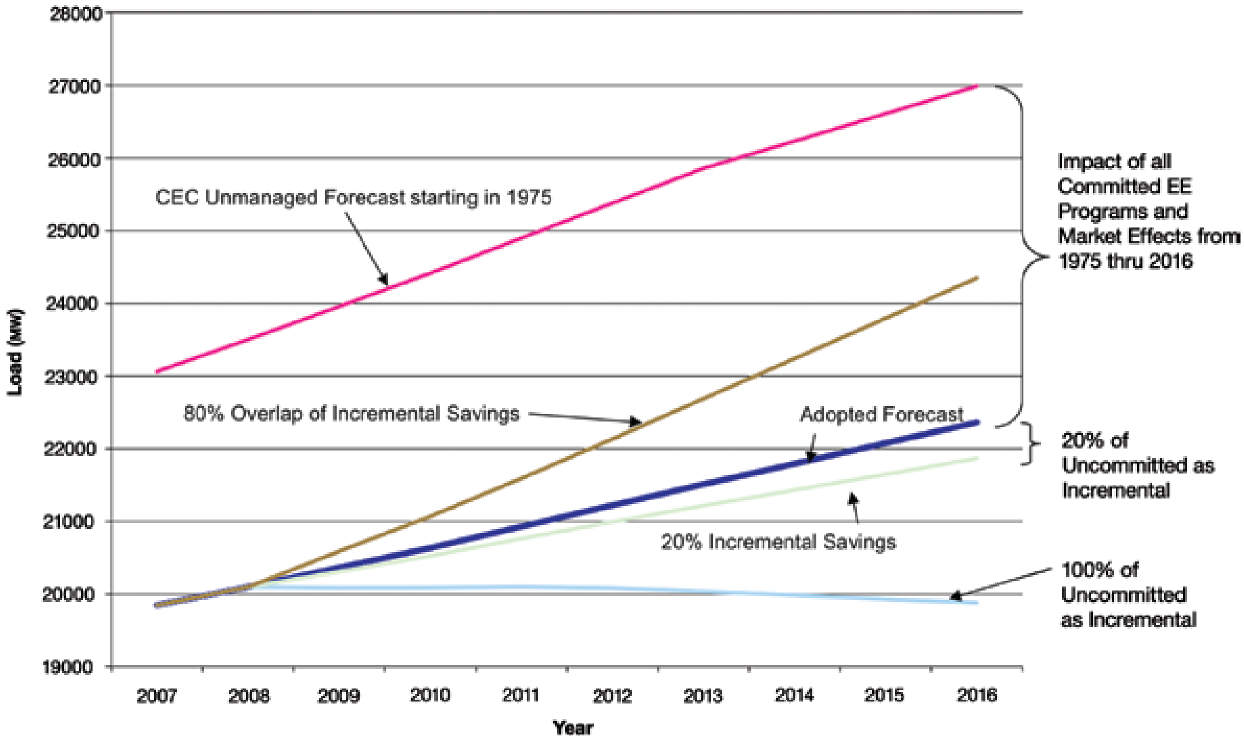
- Net-to-gross adjustments[88] and the life of program measures used in determining *ex ante* program impacts in CPUC goal setting are not always consistent with assumptions used in the Energy Commission's forecast.

The utilities' claim created a debate about what portion of uncommitted savings impacts could be considered incorporated in the Energy Commission's demand forecast, and what portion was incremental. As a temporary solution, the CPUC recommended an overlap factor of 80 percent of uncommitted savings be used for PG&E and SCE (20 percent considered incremental) and 100 percent for SDG&E.[89] The consequence of this decision is that only relatively small portions of uncommitted energy efficiency impacts are to be considered as a resource addition meant to diminish the need for supply-side resources.

Figure 1 shows the implications of this decision using PG&E as an example. The top-most curve shows the Energy Commission demand forecast for PG&E had there been no committed efficiency programs nor market effects from 1975 onward. The vertical distance between this curve and the one showing the actual adopted forecast (dark blue) represents the amount of committed savings and market effects incorporated in the forecast. Two additional lines show the implied impacts of an overlap factor for uncommitted savings of 80 percent. The distance between the curve labeled "80% Overlap of Uncommitted Savings" and the adopted forecast curve represents the amount of uncommitted savings impacts that would already be embedded in the forecast under the 80 percent assumption. The corresponding curve labeled "20% of Uncommitted as Incremental" shows the actual impact on the adopted forecast from uncommitted savings under this assumption. Note that the vertical distance between the "80% Overlap of Uncommitted Savings" and the "20% of Uncommitted as Incremental" curves represents the estimated gross savings from uncommitted efficiency programs for PG&E: the 80 percent that overlap with savings already accounted for in the forecast plus the 20 percent assumed to be incremental. If the split were assumed to be 60/40 rather than 80/20, the two curves would rotate downward, but the vertical distance between the two would remain the same.

As the figure shows, the magnitude of embedded uncommitted savings versus all committed savings and market effects would increase to an implausible level. In fact, embedded uncommitted programs would eventually become the largest single source of savings in the adopted forecast. On the other hand, assuming that no uncommitted savings are embed-

Figure 1: Illustration of CPUC Adjustments for Incremental Efficiency Savings (PG&E Service Area Values)



Source: California Energy Commission

ded in the forecast, meaning all uncommitted savings would be subtracted, yields a declining forecast (bottom curve) that some would consider unrealistic.

This figure and discussion are meant to illustrate the complexity of the uncommitted savings issue. Staff believes that a single percentage used for each year may be an inappropriate simplification. The CPUC has left improvement on this interim solution to the *2009 IEPR* process. Consequently, to address this issue, the Energy Commission has directed staff to refine efficiency measurement and attribution within the Energy Commission's demand forecast, as discussed in the next section.

An analysis of possible overlap between uncommitted efficiency impacts and savings already incorporated in the demand forecast must always consider price and market effects. More specifically, the savings from price and market effects forecasted to accumulate during the period of time uncommitted efficiency programs are in place represent potential overlap that must be accounted for when projecting incremental impacts from these programs. For example, consider a lighting program to be implemented in some future year. Any measurement of that program's impact on consumption in a given year would have to account for possible overlap with the effect of any projected rate increase (resulting in price-induced lighting efficiency improvement) that may occur from the time the program is implemented. As a more general example, using the most recent demand forecast, suppose a set of uncommitted programs in the residential and commercial sectors is to be implemented in 2013. By 2018, the amount of savings from price and market effects that must be accounted for is the addition in total accumulated price and market effects over this five-year period, or (from Table 2) 19,381 – 17,975 = 1,406 GWh. Additional overlap beyond price and market effects depends on the specific structure of the uncommitted programs.

Refining and Improving Efficiency Measurement and Attribution in the Demand Forecast

On March 11, 2008, the Energy Commission's IEPR Committee conducted a workshop on efficiency attribution and measurement and issues related to the incremental effect of near-term efficiency programs and long-term efficiency potential beyond the adopted demand forecast. As a result, the IEPR Committee agreed to better delineate the impacts of energy efficiency within the Energy Commission's demand forecast and to increase the ability to project the effects of energy efficiency programs.

On August 12, 2008, the IEPR Committee held a workshop to address these issues. Participants discussed a set of efficiency terms, concepts, and definitions, and staff presented a proposed approach to improve and refine efficiency attribution and measurement. The approach included plans to develop a working group dedicated to exploring technical issues related to efficiency measurement. In addition, a panel of utility representatives and Energy Commission staff discussed modeling issues related to efficiency at the workshop. Utility representatives were asked to provide details on their approaches to incorporating efficiency programs in their forecasts. Stakeholders at the workshop provided feedback on staff's approach and provided subsequent written comments. More details on the feedback and comments are given below.

To address the IEPR Committee's recommendations, as well as concerns voiced by stakeholders, Energy Commission staff has begun a process to make efficiency attribution and measurement more transparent to users of the demand forecast; refine and improve modeling methods; and develop efficiency measurement capabilities not currently part of the forecasting process.

The Energy Commission staff is to complete the following steps within the *2009 IEPR* cycle:

- Develop a standardized classification of terms encompassing all major concepts applying to efficiency potential studies and energy demand forecasts. (September–November 2008)

- Organize and participate in a stakeholder working group designed to address technical efficiency issues and to develop consistent measurement standards across utilities and various agencies for analyzing efficiency. (Organized September 2008)

- Review and compare the modeling methods, inputs, and data sources used in Energy Commission forecasts of efficiency savings with the Itron Asset Model. Compare interim savings estimates from the Energy Commission's demand forecast and Asset Model for selected programs given common sets of input and modeling assumptions. (September–November 2008)

- Refine and improve the Energy Commission's forecasting models to allow more detailed and complete output of committed efficiency savings. (December–June 2009)

- Investigate alternative forecasting methods. (Ongoing)

- Develop an uncommitted energy efficiency projection capability. (June–July 2009)

In addition, staff plans to develop an in-house method after 2009 for the analysis of high-efficiency scenarios. This method would support the analysis of efficiency goals within proceedings, such as those of AB 32.

A more detailed discussion of each step is presented below.

Develop Standardized Terms

Understanding the level of current and future efficiency program savings embedded in any forecast of future electricity demand requires precise definitions of efficiency-related concepts and methods.[90] However, little time has been spent updating and standardizing these concepts and methods across the Energy Commission's demand forecast and other forecasting methods. To resolve any differences among various organizations and to investigate the need for additional terminology, staff and Itron proposed a preliminary list of common terms and associated definitions to be used in Energy Commission forecasting, IOU-CPUC program impact reporting, and IOU-CPUC efficiency potential analyses at the August 12, 2008, IEPR workshop. Workshop participants supported the list's usefulness and necessity. Based on comments received from parties, staff will incorporate additional terminology, clarify certain definitions, and add contextual examples. The Energy Commission is organizing an efficiency working group to further refine and resolve such differences (see below).

Organize and Participate in an Efficiency Working Group

To address technical efficiency issues and establish common metrics for measuring savings impacts across the various forecasting methodologies, the Energy Commission is organizing a working group of utility forecasters and efficiency experts as well as Energy Commission and CPUC's Energy Division and Division of Ratepayer Advocates staff. The Energy Commission may also ask other organizations, such as the Natural Resources Defense Council and the California Air Resources Board, to participate. Staff has proposed the following set of tasks to be undertaken or reviewed by this working group:

- Develop a common set of efficiency concept and method definitions, as discussed above.
- Develop an efficiency measure saturation database showing saturation growth through time.[91]
- Develop an improved characterization of utility programs for lighting measures to determine how existing programs will help to achieve Assembly Bill 1109 (Huffman, Chapter 534, Statutes of 2007) lighting reduction goals.
- Develop and/or acquire a database showing marginal efficiency distribution through time for each major end-use.[92]
- Develop electricity rate projections incorporating new ranges of expected fuel prices, generation addition cost implications, and AB 32 GHG mitigation strategy implications.
- Compare models among various forecasts (Energy Commission, utility methodologies, and the Asset Model) investigating how each approach makes use of recorded consumption and peak data, efficiency measure impacts, saturation estimates, geographic location of customers, and weather phenomena, and how well outputs from each approach match the entire set of actual output data available.

Some of these group tasks are meant to support other steps discussed here. A kickoff meeting for the working group is planned for November 2008. At this meeting, staff plans to further refine the scope and goals of the group, develop a specific schedule, and form specialized teams within the group. A consultant will be hired to coordinate group activities. The Energy Commission expects the group to collaborate beyond the *2009 IEPR* cycle as new issues related to efficiency become apparent.

Review and Compare Efficiency Modeling Methods, Inputs, and Data Sources

The energy consulting firm Itron has developed the Asset Model to measure the effects of efficiency programs under various scenarios, and this model was used to support the CPUC's goal setting process. The Energy Commission, with consulting assistance from Itron[93], is comparing the modeling methods and input data used in the Energy Commission's demand forecast with those used in the Asset Model. Staff is initially focusing on the inputs and methods used to estimate the savings from utilities' 2006-2008 commercial and residential lighting programs, followed by new construction and heating, ventilation, and air conditioning programs. The analysis will also compare the techniques used to estimate incremental energy savings from new state or federal standards, and identify how each model estimates price and other market effects. The Energy Commission staff will highlight the major differences between the two approaches and, together with Itron, attempt to resolve them.

The analysis will then focus on defining a common set of inputs for selected end uses within each method and comparing the savings estimates produced by each. The analysis will also compare estimates of program-induced savings relative to naturally occurring and price-induced savings. This will help reveal the extent of differences between independent estimates of program savings and those occurring within a model that simultaneously estimates savings from efficiency programs, market effects, and technological changes. Stakeholders at the August 12 workshop supported this method to evaluate how well the forecast matches historical data. The Energy Commission staff will then propose adjustments to the demand forecasts or the reported program savings estimates so comparisons of savings between the two are consistent in the future.

Refine and Improve the Energy Commission's Forecasting Models

The Energy Commission staff will expand the capability to incorporate specific efficiency programs to sectors than residential and commercial. Staff is also working to improve the sets of inputs used to estimate baseline and program-induced energy intensities over time.[94] To this end, staff will further disaggregate end uses in the Energy Commission forecasting models to allow more detailed attribution of efficiency savings. For example, residential lighting, currently part of a miscellaneous category within the Residential Model, will be broken out into a separate category.

To help ensure that totally efficiency impacts are properly measured, staff will also review the analysis methods used in the energy demand forecast to ensure that simulated load forecasts that omit efficiency impacts truly capture the trends that would exist without these impacts. Staff will test completed refinements in a preliminary energy forecast early in 2009 that includes estimated impacts of committed savings programs. Any refinements not yet incorporated will be part of a revised forecast in the summer of 2009.

Investigate Alternative Forecasting Methodologies

An independent evaluation of the Energy Commission forecasting methodology is underway, referred to as the Demand Forecast Assessment Project.[95] This assessment will make recommendations for improvements in the Energy Commission's demand forecasting methods and is evaluating alternative methods for forecasting energy consumption and efficiency impacts, including econometric approaches. The results, due in the fall of 2008, may affect the efficiency measurement and refinement steps discussed here.

In their comments for the August 12 workshop, utilities supported the consideration of alternative forecasting methods. PG&E urged the Energy Commission to develop an econometric model to be used "either as a stand-alone forecasting model or be used in conjunction with the existing end-use modeling approach."[96] While SCE believed recommending any one approach was premature, it encouraged the Energy Commission to "seriously consider new, more contemporary models"[97] for forecasting energy efficiency impacts.

Develop Ability to Project Uncommitted Energy Efficiency

Historically, the Energy Commission has satisfied the regulatory requirement that its forecast include conservation "reasonably expected to occur" by incorporating only committed energy efficiency impacts in the baseline demand forecast and carrying uncommitted energy efficiency programs as supply-side resources. However, given the establishment of CPUC-required efficiency goals, which involve uncommitted programs, some of the utilities at the August 12 workshop questioned the need to distinguish between the two types of impacts with energy efficiency's cornerstone role under AB 32 in reducing

GHG emissions. The utilities contend that business as usual policies clearly expect high levels of energy efficiency program funding throughout the forecast horizon to meet goals adopted out to 2020 for both energy and capacity reductions.

The Energy Commission staff believe it is important to keep the distinction because uncommitted programs have no funding source or have not been passed into law, so there is no guarantee that these programs will actually materialize or what impact they would have. However, staff intends to develop a new capability to assess uncommitted energy efficiency impacts separately, and is considering two choices:

1. Inserting additional program characteristics into the Energy Commission demand forecasting models and making another run of the models. The difference between the baseline run with "committed" characteristics and the second run would develop "uncommitted" impacts.

2. Adapting the Itron Asset model to make two sets of runs, with the difference being the impacts of a set of programs considered to be "uncommitted."

The approach will be determined after a full comparison of the Energy Commission and Asset models, as described above.

Utility Progress Under Assembly Bill 2021

AB 2021 requires the Energy Commission and the CPUC to develop a statewide estimate of all potentially achievable cost-effective electricity and natural gas efficiency savings and establish targets for statewide annual energy efficiency savings and demand reduction for a 10-year period for both publicly owned utilities and IOUs.

Analysis and data of all cost-effective efficiency potential were prepared by Itron for the IOUs and by the Rocky Mountain Institute for the publicly owned utilities. The Energy Commission and the CPUC have adopted statewide savings goals consistent with these studies' measurement of all cost-effective efficiency potential.[98] The combined economic potential to save energy in 2016 for the IOUs and publicly owned utilities is estimated to be 39,500 gigawatt hours of electricity, 6,600 megawatts of peak electrical demand, and 750 million therms of natural gas.

It should be noted that progress reported by utilities for the 2006-2008 period were *ex-ante* impacts based on savings defined in the above mentioned studies and should not be assumed to equate to actual reductions in energy consumption or peak demand. Utilities are in the process of *ex-post* evaluation, measurement, and verification (EM&V) studies to determine the actual impact these programs have had on consumption and customer bills. The results of these studies may impact future assessments of progress in attaining the savings goals.

Investor-Owned Utility Energy Efficiency Progress

Table 3 provides the goals and *ex-ante* savings estimates reported by the combined IOUs for the 2006 and 2007 program years and the first six months of 2008.

The goals shown in the table are those defined by the CPUC, which represent about 74 percent of cost-effective potential for electricity savings, 98 percent of peak savings potential, and 73 percent of natural gas savings potential for the IOUs.[99]

After a ramp-up period in 2006 as new programs were getting underway for the CPUC's 2006-2008 efficiency cycle, the combined IOU efficiency portfolios report savings that exceed the CPUC-defined goals in 2007 and are on track to do so again for the 2008 goals.[100]

Publicly Owned Utility Energy Efficiency Progress

Estimated efficiency savings reported by publicly owned utilities increased substantially from 2006 to 2007.[101] The aggregate electricity consumption

Table 3 – IOU Reported Efficiency Savings and CPUC Annual Efficiency Goals for Electricity and Natural Gas

	2006			2007			2008		
	GWh	MW	MMTh	GWh	MW	MMTh	GWh	MW	MMTh
CPUC Goal	2,032	442	30	2,275	478	37	2,505	528	44
IOU Reported Savings	1,718	300	24	3,872	638	52	2,059	359	27
Percentage of Goal	85	68	80	170	133	141	82	68	61

Source: CPUC website (http://eega2006.cpuc.ca.gov) and CPUC Energy Division staff.

savings reported by publicly owned utilities reached 75 percent of AB 2021 adopted goals in 2007, while electricity peak savings reached 62 percent.[102] These results are noteworthy given that the publicly owned utilities' 2007 savings projections were developed prior to the actual adoption of the AB 2021 goals in December 2007.

Publicly owned utilities have demonstrated their commitment to increased efficiency savings over the past year by expanding both efficiency staffing and customer programs. Energy Commission staff is concerned, however, about the ability of the publicly owned utilities to meet adopted goals for 2008. To meet these goals, publicly owned utilities will require a substantial savings improvement from 2007. Savings for the 15 largest publicly owned utilities combined, for example, would have to increase by 130 percent over a one-year period. This seems a formidable task, particularly given the already substantial increase realized from 2006 to 2007.

In 2007, when publicly owned utilities submitted efficiency goals to the Energy Commission, staff expressed concern over unprecedented increases or "ramp-up rates," proposed between 2007 and 2011 that would be difficult to achieve. Efficiency planners likely had ramping in mind when they projected their efficiency goals for 2008. Of the large publicly owned utilities that fell short of their adopted goals in 2007, half project achieving or nearing their 2008 adopted goals. The remaining large publicly owned utilities made revised energy and peak savings projections for 2008 that are less than the goals adopted in 2007. While this may be more realistic when developing savings projections, it is in direct contradiction to the AB 2021 goals and a departure from *2007 IEPR* direction to achieve all cost-effective efficiency savings.

Publicly owned utilities need to continue to be proactive in meeting the adopted goals. It is clear from the cost-effectiveness data provided for each utility's portfolio that publicly owned utilities could expand their programs and benefit their customers and society as a whole. Such an expansion should be considered in light of the Legislature's mandate specifically requiring publicly owned utilities to give first consideration to energy efficiency when planning for energy resources to meet customer loads.

The publicly owned utilities have stated that their procurement investments are reserved for operational improvements (generation, transmission, and distribution upgrades), while efficiency expenditures are handled through public goods charge allocations. However, public goods charge allocations for the publicly owned utilities are insufficient to achieve the savings needed to meet all cost-effective energy efficiency. In addition, this practice contradicts the Energy Commission's stated policy to use procurement funds for expanding efficiency programs and requires exploration that should begin with more detailed reporting of sources for publicly owned utility investments in energy efficiency.

Senate Bill 1037 (Kehoe, Chapter 366, Statutes of 2005) requires the publicly owned utilities to describe their energy efficiency programs, expenditures, and expected and actual energy savings results to their customers and the Energy Commission each year. For the next SB 1037 report, the Energy Commission should work with the publicly owned utilities to identify all funding sources available to meet energy efficiency goals, with the intention of addressing the procurement issue stated above and to reiterate energy efficiency as the top resource for meeting the state's energy needs.

Conclusions

The recent focus on energy efficiency in California has heightened the need for proper accounting of efficiency and other savings impacts. This chapter has discussed the challenges involved in this accounting, including the uncertainties and lack of consistency among various organizations that must be addressed. Energy Commission staff has, as described in this chapter, undertaken a major effort to update and improve methods for the measurement and attribution of efficiency impacts within the Energy Commission's demand forecast, assisted by the CPUC through the work of Itron. Utilities have also offered their support and expressed their willingness to take part in a technical working group. Energy Commission staff plans on making substantial progress over the *2009 IEPR* cycle, although it is likely that at least some refinements will still be unfolding through the IEPR cycle in 2011.

Staff plans to release a preliminary energy forecast in February 2009, which will incorporate revisions to the forecasting methodology. A subsequent workshop will allow staff to present these revisions to stakeholders, who would be encouraged to provide comments and suggestions. A revised forecast, planned for May 2009, will incorporate feedback from public comment and other revisions discussed in the proposed staff plan not yet integrated into the forecasting models.

The publicly owned utilities are in the first year of AB 2021 mandated goals that have a 10-year time horizon (2007-2016). Energy Commission staff sees evidence that the publicly owned utility community is on the right long-term track. Goals will be reset in 2010 for 2011–2020. The ultimate resource value of these efficiency program savings will be determined through EM&V studies. Eleven publicly owned utilities are developing, or have contracted to develop, program evaluation plans to determine savings impacts, according to the March 2008 report. The publicly owned utilities have much to gain from EM&V; most importantly, these results will make their savings estimates more credible and reliable in statewide energy and climate change planning forums.

Recommendations

Understand Potential Overlap

The Energy Commission should analyze the relationship between end use efficiency impacts modeled in the Energy Commission's demand forecast and impacts characterized in efficiency program planning. This should be a high priority activity for the *2009 IEPR*. Ignoring potential overlap between efficiency program plans and savings impacts already incorporated in the demand forecast will give rise to misleading estimates of how much can be achieved through future efficiency strategies.

Working Group Participation

The Energy Commission encourages IOUs and publicly owned utilities, regulatory agencies, and other interested stakeholders to participate in the proposed working group to pursue the Demand Forecast-Energy Efficiency Quantification Project. The working group should focus both on technical issues and effectively communicating results to all interested stakeholders.

Independent Forecasting Methods

The Energy Commission recommends that independent efforts to investigate and evaluate alternate forecasting methods be continued in the *2009 IEPR*. These efforts should focus on matching appropriate methods to the various purposes to which the demand forecast is applied.

Working with POUs

The Energy Commission should continue to work with publicly owned utilities to understand the processes used by individual utilities to estimate their remaining economic potential and set targets.

The Energy Commission staff should work with the publicly owned utilities in the next report required in response to SB 1037 to identify all funding sources available to meet energy efficiency goals, with the intention of addressing procurement issues and to reiterate energy efficiency as the top resource for meeting the state's energy needs.

The Energy Commission staff should continue to assist the publicly owned utilities in achieving their efficiency goals through workshops and collaborative efforts that improve overall evaluation planning, develop program tracking systems, and improve savings reporting requirements for the next AB 2021 cycle.

Endnotes

77 Transcript of the August 21, 2008, IEPR Joint Committee Workshop on Achieving Higher Levels of Renewables in California's Electricity System. Page 200–211, http://www.energy.ca.gov/2008_energypolicy/documents/2008-08-21_workshop/2008-08-21_TRANSCRIPT.PDF.

78 In this context, "efficiency programs" refer to both programs and building and appliance standards.

79 For example, building standards aimed at reducing air conditioning load implicitly assume every household with air conditioning uses it in a certain pre-specified manner. Residential survey results make it apparent that there is a certain portion of the population with air conditioning that is never used. Energy Commission staff takes this into account when assigning air conditioning savings to standards in the residential forecast. In the case of appliance standards, staff considers take-back effects that may reduce the impact of standards (e.g., customers later buying a larger refrigerator with more amenities).

80 The Itron Asset Model, discussed later in this chapter, is used specifically to measure demand-side management program savings, incorporating measure costs and benefits over time.

81 "Other" market effects include changes to average energy consumption for an end use that are not directly the result of an efficiency program, such as a more efficient technology adopted for cost reasons.

82 The Summary Model combines the forecast for the individual sectors.

83 In these sectors, staff forecasts are similar to the aggregated econometric forecasts prepared by the utilities.

84 California Energy Commission, *California Energy Demand 2008–2018: Staff Revised Forecast - Final Staff Report*, 2nd Edition, November 2007, CEC-200-2007-015-SF2, http://www.energy.ca.gov/2007publications/CEC-200-2007-015/CEC-200-2007-015-SF2.PDF.

85 California Energy Commission, *Energy Demand Forecast Methods Report*, June 2005, CEC-400-2005-036, http://www.energy.ca.gov/2005publications/CEC-400-2005-036/CEC-400-2005-036.PDF.

86 California Energy Commission, *California Energy Demand 2008 - 2018: Staff Revised Forecast - Final Staff Report*, 2nd Edition, November 2007, CEC-200-2007-015-SF2, http://www.energy.ca.gov/2007publications/CEC-200-2007-015/CEC-200-2007-015-SF2.PDF.

87 The possibility of overlap applies to the Energy Commission's adopted efficiency goals under AB 2021, which are *gross*. On the other hand, the current AB 32 efficiency goal of 32,000 GWh savings statewide by 2020 is meant to be *net* of any overlap with committed savings incorporated in the Energy Commission forecast.

88 Adjustments to gross savings to account for free ridership and spillover effects from other programs.

89 D.07-12-052, CPUC, December 2007. The higher percentage applied to SDG&E reflects higher efficiency goals in percentage terms, so that a 20 percent incremental impact could lead to an unrealistically low projection of energy use for procurement purposes.

90 For example, "conservation" versus "efficiency" and "committed" versus "uncommitted" savings.

91 Saturation refers to the amount of diffusion or distribution within a market.

92 This refers to the efficiency of appliances or equipment sold in a given year, as opposed to average efficiency for all appliances or equipment currently being used.

93 Energy Commission staff wish to acknowledge and thank the CPUC for funding the assistance that Itron will provide.

94 Energy intensity is the energy required to meet a specific level of service or work within a given end use or building type.

95 Aspen Inc. and R.W. Beck are conducting the demand forecast assessment.

96 First Draft Written Comments of Pacific Gas and Electric Company Regarding Improvements to the CEC demand Forecast Following CEC IEPR Workshop of August 12, 2008, August 19, 2008, p.2.

97 Written Comments of Southern California Edison Company for the August 12, 2008, IEPR Workshop, p.3.

98 California Energy Commission, *Achieving All Cost-Effective Energy Efficiency for California*, Final Staff Report, CEC- 200-2007-019-SF, December 2007, http://www.energy.ca.gov/2007publications/CEC-200-2007-019/CEC-200-2007-019-SF.PDF.

99 The overall statewide goals for AB 2021 were equal to 100 percent of cost-effective potential. A portion of this overall goal was allocated as goals for the investor- and publicly owned utilities. The remaining portion was to be made up by savings activities from local governments in coordination with the utilities.

100 The savings estimates come from the CPUC website, http://eega2006.cpuc.ca.govhttp://eega2006.cpuc.ca.gov, and from CPUC Energy Division staff.

101 Savings estimates come from California Municipal Utilities Association, *Energy Efficiency in California's Public Power Sector: A Status Report*, March 2008.

102 There were no reported natural gas savings for publicly owned utilities in 2007. The City of Palo Alto's natural gas savings program is newly initiated and will not yield savings until 2008.

Chapter 3

Electricity Procurement Practices and Resource Planning Activities

Introduction

This chapter summarizes the recommendations in the *2007 Integrated Energy Policy Report (2007 IEPR)* regarding resource planning and procurement and describes progress to date in implementing those recommendations. It also provides recommendations for further activities, including analysis to be done for the *2009 IEPR*.

The *2007 IEPR* recommended that the Energy Commission and the California Public Utilities Commission (CPUC) work together to improve the analysis methods used by the state's investor-owned utilities (IOUs) to develop their long-term procurement plans. The *2007 IEPR* stated that the IOUs' analyses should use common assumptions as much as possible; adequately reflect significant ratepayer risks; extend over a 20- to 30-year period of analysis; incorporate environmental impacts and risks; and discount future fuel costs at a social discount rate to properly reflect risk associated with fuel cost volatility.

The IEPR Committee held two workshops focused on procurement issues on July 14 and August 18, 2008. The July 14 workshop focused on the use of procurement review groups in utility procurement. Members of these groups are subject to a non-disclosure agreement and consult with utilities to review procurement strategies, solicitations, and proposed contracts. The *2005 IEPR* recommended eliminating the use of procurement review groups in favor of a more open and transparent resource planning and procurement process, and the Energy Commission subsequently withdrew from participation in the procurement review groups.

The August 18 workshop focused on long-term procurement planning, including the status of collaborative efforts between the Energy Commission and the CPUC in the CPUC's 2008 long-term procurement proceeding, progress in implementing procurement recommendations from the *2007 IEPR*, and how to incorporate environmental impacts into long-term procurement. At that workshop, the Committee noted that while the CPUC is the agency with primary responsibility for electricity procurement activities, the Energy Commission shares the CPUC's interests and concerns that California's electricity supply is both reliable and least cost, as well as meeting other goals such as increasing the procurement of renewable energy.

Other issues related to procurement covered in this chapter include a discussion of reliability and resource adequacy issues associated with transitioning away from the use of once-through cooling in power plants and the relationship of electricity procurement to the Energy Commission's power plant siting process.

Long-Term Procurement Plans

During the past five years, the CPUC has developed processes for resource planning and procurement to be used by the state's major IOUs. This has been a gradual process, and not without difficulty given current dynamic market conditions, nascent market structure, and evolving legal and policy environments.

Since 2004, the CPUC has required the major IOUs to submit biennial 10-year plans for acquiring energy resources to meet demand growth and state targets for preferred resources – energy efficiency, demand response, and renewable energy – and for replacing expiring contracts. These long-term procurement plans (LTPPs) must balance the costs of meeting customer needs with state policy goals of minimizing environmental impacts and meeting state targets for preferred resources.

In preparing the plans, IOUs do two assessments, one to identify physical and contractual resources needed to meet bundled customer needs and one to identify new resources needed in their service territories to maintain adequate reserve margins. The latter assessment takes into account potential power plant retirements; for instance, the current assumption for PG&E is that aging plants in Northern California will be retired by 2015, while SCE assumes aging plants in Southern California will be retired by 2018.

After approving the LTPPs, the CPUC authorizes the IOUs to procure the resources needed to meet long-run growth in energy demand and cover the expiration of existing contracts. The CPUC sets targets over the next 10 years for energy efficiency, demand response and interruptible load programs, and renewable energy. The utilities provide estimates of the remaining need for energy and capacity in their LTPPs and then solicit long-term agreements through competitive requests for offers (RFOs) overseen by the CPUC.

In December 2006, the IOUs submitted plans for 2007 through 2016, which were approved by the CPUC in December 2007. Parties to the 2006 proceeding criticized the plans on several grounds, most notably that the assessment methods did not allow plans to be compared across utilities or adequately evaluate high natural gas prices and greenhouse gas (GHG) regulation, which are the most significant risks to ratepayers. The Energy Commission reflected these concerns in the *2007 IEPR* recommendations.

The CPUC acknowledged these shortcomings in its decision approving the 2006 plans.[103] That decision influenced the structure of the 2008 LTPP proceeding, which opened in February 2008 and in which the Energy Commission is collaborating. The 2008 LTPP proceeding is focusing primarily on the following two topics:

1. Standardized resource planning practices, assumptions, and analytic techniques applied in long-term procurement plans.

2. Interim standards and practices to evaluate the uncertain cost of future GHG regulations during AB 32 implementation and in anticipation of possible federal legislation.

The CPUC intends to resolve issues relating to these topics before issuing directions to the IOUs on preparing their 2010 LTPPs in April 2009. The CPUC expects to receive the IOUs' 2010 plans, covering 2011 through 2020, in late 2009 followed by CPUC approval in 2010.

The following sections discuss progress toward meeting the *2007 IEPR* procurement recommendations in more detail, including standardizing assumptions and looking at the portfolio of resources, incorporating environmental impacts and uncertainties, using a 20-year or longer analysis period, and discounting future fuel costs.

Portfolio Methodology

In the 2008 LTPP proceeding, the CPUC is directing the IOUs to provide a set of plans in 2010 that can be compared and aggregated and that also adequately considers ratepayer risks. The following principles reflect the CPUC's desire to evaluate utility portfolios using a standardized, transparent method that reflects uncertainties like future natural gas prices and carbon costs:

- The plans should use standardized inputs (where appropriate), formats for reporting outputs, and measures of performance, so that plans are based on consistent and well-reasoned assumptions regarding demand growth and fuel and resource development costs, and can be easily compared and aggregated.

- The plans should evaluate potential portfolios under a wide range of values for key variables that strongly influence costs (for example, natural gas prices or GHG costs) to determine the sensitivity of individual and aggregate portfolio costs to those key variables.

- The plans should use identical "scenarios," where portfolios are developed and evaluated using an internally consistent set of input assumptions that define specific futures (such as a "high natural gas cost world," or a "low carbon price world"). This allows parties to accurately evaluate and compare the cost and performance of utility portfolios under different sets of market conditions over the next 10 years.

- The plans should report on performance measures that incorporate risks, such as different cost ranges in the value of key variables and estimates of portfolio costs in different scenarios, to allow parties to evaluate both expected and potential costs.

The *2007 IEPR* discussed the Northwest Power and Conservation Council's (NWPCC) analytical software, which allows comparison of many more portfolios than will be possible in the 2010 proceeding. The software, however, cannot be applied to procurement decisions of an individual utility faced with numerous transmission and operating constraints. Enhanced development of the NWPCC's software, combined with review of the 2010 plans and clarification of future GHG regulations, will help determine the need for new software tools for evaluating resource planning decisions.

Incorporating Environmental Impacts and Uncertainties

In the 2006 LTPP proceeding, parties were concerned that the plans did not sufficiently analyze the potential effect of GHG regulations on utility portfolios and portfolio cost. In the 2008 LTPP proceeding, the CPUC asked parties how to best evaluate GHG regulations given uncertainties about possible regulatory regimes (like cap-and-trade), the relative costs of reducing GHG emissions across economic sectors, and the allocation of emission allowances across utilities.[104] Most parties replied that using a range of carbon costs to represent the potential impact of GHG regulation would be an adequate interim measure in the 2010 proceeding, but that the range must be wide enough to adequately reflect the risks faced by ratepayers.

Developing such a range of values will be somewhat subjective because there is little, if any, empirical data that can provide a sound basis for development of a range based on probability analysis. As more information becomes available regarding regulatory regimes and allocation of emission allowances, the LTPP analysis is expected to incorporate more explicit modeling of GHG regulation and any necessary software modifications.

Using 20-Year or Longer Analysis Period

Currently, the IOUs submit plans in the LTPP proceeding covering a 10-year planning horizon. The *2007 IEPR* recommended that this be extended to 20 or 30 years.

Stakeholder comments in the 2008 LTPP proceeding reflected a desire to have plans cover a period of 20 years or more. Utility responses were mixed, with Pacific Gas and Electric Company (PG&E) and San Diego Gas & Electric (SDG&E) contending that uncertainties associated with market conditions, regulation, and technology severely limit the value of analysis beyond 10 years. Southern California Edison, however, recommended extending the analysis period to 20 years, noting that investment decisions made in the near term could affect the mix of generating assets that is feasible in later years. The Center for Energy Efficiency and Renewable Technology (CEERT) called for an assessment of the GHG reductions possible from extrapolating energy efficiency and renewable energy procurement during 2010 – 2020 out to 2030. The Natural Resources Defense Council (NRDC) and Union of Concerned Scientists stated that sufficient data exists to develop least-cost utility portfolios through 2030, but that actions taken to meet 2020 GHG reduction targets may not be compatible with actions necessary to meet higher targets for 2050. For example, NRDC recommends that utilities might focus on the cheapest opportunities to reduce GHG emissions by 2020, which could improve subsequent LTPPs and increase the long-term costs and difficulties of attaining the 2050 goal. Also, while continued growing demand for low- or no-carbon resources may result in technological development and cost reductions, these could be discounted or underestimated if a shorter analysis period is used.

As analyses focus on longer planning horizons, there is greater uncertainty regarding the likely and potential values of the following key variables that drive the cost and potential content of utility portfolios:

- Electrification of the transportation sector and other sectors of the economy in response to GHG regulation may increase electricity demand in the post-2020 period and possibly alter the daily profile, increasing the need for energy in what are currently low load hours.

- Natural gas prices, and thus the cost of gas-fired generation, may climb dramatically because of increasing global demand. On the other hand, the development of shale reserves and increased reliance on renewable and clean coal technologies may moderate price increases beyond 2020.

- The absolute and relative costs of preferred resources (energy efficiency and renewable generation) will change as technologies mature and new ones are developed.

- Long-run GHG reduction targets may require disproportionate contributions from the electricity sector. This depends on the targets set and the cost of extracting emission reductions from the electricity sector and other parts of the economy. Other long-run issues and associated uncertainties identified in the 2008 LTPP proceeding include the development of smart grid technologies and their impact on the availability of clean generation connected at the distribution level, and the impact of interstate competition on the availability and cost of out-of-state renewable resources.

Currently, the CPUC has not decided on a planning horizon for the 2010 plans. The time and resources needed to complete the 2008 proceeding may preclude consideration of longer-term analysis in the 2010 plans, but the CPUC may consider this for subsequent filings. If the 2010 plans do look at a longer period than 10 years, it is possible that the post-2020 assessments will use a different set of analytical tools and methods and consider a different or smaller set of issues.

Discounting Future Fuel Costs at a Social Discount Rate

Discount rates are used to determine the present value of a future sum. Higher discount rates essentially place a low value on the future, while low discount rates represent a higher value on the future.

The *2007 IEPR* identified current methods for discounting future natural gas fuel costs as issues of concern because the discount rate that is used makes these costs appear unrealistically inexpensive. The concern is that this would lead to increased dependence on natural gas-based generation because alternatives, such as renewables and efficiency, would be undervalued.[105] Accordingly, the *2007 IEPR* recommended applying a 3 percent social discount rate (lower than the current discount rate, which is based on the utility's cost of capital) to future natural gas costs to more accurately reflect the risks of cost volatility of natural gas-based generation.

For the *2008 IEPR Update,* the IEPR Committee directed staff to identify the consequences of using a social discount rate.[106] Staff presented a paper, *Discounting Future Fuel Costs at a Social Discount Rate*, at the August 18, 2008, IEPR workshop and received comments on the use of social discount rates in economic analyses of electric generation projects.

There are two different views on how to use discount rates under conditions of uncertainty: discount rates should not be affected by the uncertain nature of the future cash flows and should be based on the cost of capital, or discount rates should be adjusted for risk to reflect the uncertainty of the cash flows in question, so that based on the market values of those cash flows, high-risk costs should be discounted at lower rates. These views reflect a difference in perspective (finance theory vs. decision analysis) when evaluating potential investments. Finance theory takes the investor's perspective and often applies a risk-adjusted discount rate to a single expected cash flow to estimate the market value of an investment. Decision analysis assumes the perspective of the corporate decision maker and considers project-specific risks by evaluating each of a number of uncertain cash flow scenarios using a risk-free (unadjusted) discount rate.

Some observers argue that discount rates should not be risk-adjusted because of a variety of analytical and conceptual problems. Others argue that unintended consequences could result from using discount rates that are lower than either the utility or ratepayer cost of capital, such that using a social discount rate could displace projects with higher benefits.

Under the CPUC's current energy efficiency incentives framework, using a social discount rate could allow utilities to receive greater incentives for the same amount of efficiency, with ratepayers paying more per unit of energy conserved. In its review of federal government discount rate policy, the White House Office of Management and Budget concluded that "in general, variations in the discount rate are not the appropriate method of adjusting net present value for the special risks of particular projects."[107]

There is general agreement about the importance of incorporating uncertainty and risk (including fuel price uncertainty) into the overall planning and decision-making process. In the *2007 IEPR*, the Energy Commission recognized the suitability of the IOUs' long-term planning process for considering the comparative risk of different utility investments when it "recommended making the development of a common portfolio analytic methodology a core focus of the *2008 IEPR Update*, with the clear objective of influencing the long-term procurement plans filed by the investor-owned utilities with the CPUC…"[108]

Since the adoption of the *2007 IEPR*, the CPUC issued Decision 07-12-052, which stated:

> *The methodology established in the Scoping Memo for long-term renewable resource planning was not as robust as we believe is necessary for effective resource planning decisions; therefore, we direct the IOUs to…refine this planning methodology. We anticipate a methodology that employs an integrated portfolio approach.*[109]

In February 2008, the CPUC convened the LTPP Rulemaking (R.08-02-007) to address analytical techniques applied in LTPPs based on an integrated resource planning framework. The Energy Commission anticipates that the CPUC will require the next round of LTPPs to be based on an integrated resource planning framework, incorporating risk-based portfolio analysis. The plans will incorporate a wide range of future natural gas prices and include the associated gas price risk. The Energy Commission staff will continue to collaborate with CPUC staff in R.08-02-007 to ensure that fuel price risk is properly considered in the long-term planning process.

The Energy Commission believes that the CPUC's Rulemaking could result in a planning process that properly incorporates long-term natural gas price risk in the construction of utility portfolios. The planning process is a more direct and transparent method to account for potential gas price risk than the adjustment of discount rates. The degree to which discount rates should be adjusted to reflect risk continues to be controversial and, under some conditions, could result in unintended consequences.

Aging Plants and Transitioning From Once-Through Cooling

The *2005* and *2007 IEPRs* called for the orderly retirement of more than 17,000 MW of aging gas-fired generation in the California fleet, and the State Water Resource Control Board (SWRCB) is proposing a statewide policy on Clean Water Act 316(b) regulations regarding the use of once-through cooling (OTC) by coastal power plants that has given new urgency to proactive fleet management. More than 21,000 MW of the state's generation fleet uses OTC, approximately 15,200 MW of which is aging capacity recommended for retirement in the *2005 IEPR*.[110] In March 2008, the SWRCB issued a draft proposal calling for the phased elimination of OTC between 2015 and 2021, with a final proposal expected in January 2009. Without alternative mitigation measures, accomplishing this will require the refitting, repowering, replacement, or retirement of 19 power plants, representing nearly 40 percent of the state's generation capacity.[111] A list of aging and OTC plants is shown in Appendix A.

As for complying with SWRCB's proposed policy, owners are unlikely to opt for refitting, repowering, and replacing the plant in the absence of long-term contracts, as they could not guarantee recovery of their substantial investment. Retirement, on the other hand, will likely require the construction of a new plant, since many of the OTC plants are located in California ISO-designated local reliability areas (the Greater San Francisco Bay Area, Los Angeles basin, and San Diego).

New plants would have to be located in the same or nearby location, unless transmission upgrades allow them to be built elsewhere. However, a recent superior court ruling preventing the South Coast Air Quality Management District from using compliance emissions credits from its priority reserve may without further environmental analysis delay the construction of new conventional power plants that would be necessary to replace retired OTC plants in the Los Angeles basin.[112]

The Energy Commission, the CPUC, and the California ISO face a challenge in facilitating compliance with the SWRCB's proposed policy quickly and at the least cost to ratepayers. The rule "in a least-cost fashion" requires that OTC plant owners have not only the "option" of retirement, but also of refitting, repowering, and so on, when these are lower-cost solutions for the ratepayer.

Because refitting, repowering, and associated permitting can take two years or more, plant owners must have the opportunity to bid for long-term contracts for energy and capacity products long before the SWRCB's compliance deadline. Transmission planning (to assess the extent to which transmission upgrades should substitute for local generation) and permitting require even longer lead times. Additional coordination will be required, since compliance options will require facilities to shut down, either partly or entirely, for prolonged periods while being modified. These shutdowns must be staggered to maintain system reliability.

Procurement and the Siting Process

Projects responding to a utility's RFO may be in various stages of development, ranging from those without permits to those that are fully operational. Projects in the earlier stages of development involve greater financial risk, primarily to the project owner, for bringing them to completion. Ultimately, however, the utility must consider both financial and reliability risks in evaluating bids. Unforeseen delays or project termination can affect system reliability and cost, either by requiring the procurement of replacement capacity at a late date, circumventing competitive procurement processes, or implementing more expensive solutions.

In evaluating bids, the utilities consider project viability, partly by considering the status of permits and certificate possession. For instance, PG&E listed the following project viability considerations in its April 1, 2008, All Source Long Term RFO (p. 14):

> *"The project's progress in the [Energy Commission] permitting process will also be evaluated, including its Environmental Characteristics such as Air Quality, Water Supply, Land Use, Hazardous Material usage, Wetlands & other Waters, Biological Resources, Cultural Resources, Socioeconomics, degree of control of property, and other aspects that would help ensure project completion. The project's progress in the gas and electric interconnection processes will be evaluated. The quantities and potential costs to PG&E and to society associated with all of these characteristics will be considered."*

Aside from these areas, there is no indication of how utilities evaluate progress in the permitting process, whether qualitatively or quantitatively, or how they rank projects that have not yet applied for permitting. In the past, some projects selected to receive contracts faced significant siting and environmental issues that threatened project viability, timely construction, and/or cost. Projects competing in an RFO should understand the siting-related criteria that will be used to judge them. In addition, projects should have a high probability of being permitted in the time frame required without major environmentally related modifications or cost increases. The Energy Commission's siting expertise could provide value to the procurement process.

Recommendations

Long-Term Procurement Planning

Continue Collaboration

Energy Commission staff should continue collaborating in the CPUC's LTPP proceeding to develop 2010 plans that adequately consider the significant risks facing ratepayers, and to further develop useful assessments of GHG evaluation and uncertainty in the resource planning and procurement processes.

Long-Run Uncertainties

The Energy Commission recommends assessing longer-run (20-year) uncertainties related to electricity demand and natural gas prices and supply in the *2009 IEPR*. As the 2008 Procurement proceeding moves forward, other issues related to resource planning for the period beyond 2020 may warrant inclusion in the *2009 IEPR*. These issues include evaluating the development of gas-fired power plants to meet near-term reliability needs to minimize subsequent need for gas-fired resources, and exploring how to overcome constraints faced by utilities in reducing the carbon footprint of their portfolios over the long run.

Risk-Adjusted Discount Rates

The Energy Commission recommends that social discount rates not be used to incorporate natural gas price risks in the CPUC's current Rulemaking, but that the subject of using risk-adjusted discount rates to compare projects selected in utility solicitations be considered by the CPUC when making refinements in how to evaluate RFO bids in the LTPP proceeding.

Aging Plants and Once-Through Cooling Issues

Aging plant retirement, or repowering and transmission line upgrades, are subjects of an ongoing California ISO study to be completed in early 2009.[113] Additional analysis is needed on the implications of replacing much of the OTC capacity with preferred resources, such as renewables, and gas-fired dispatchable generation to meet the need for local capacity and grid stability. Depending upon the ultimate scope and findings of the California ISO study, the following list contains possible topics for the *2009 IEPR*:

- Statistical assessment of relying on OTC and aging plants for energy and local capacity needs, including the Los Angeles basin.
- Summary of the California ISO study with issues and any obvious next steps, including (but not limited to) refining initial estimates of transmission costs for system expansion to allow OTC retirements, comparing transmission and generation costs and timeframes, devising a way to adapt a replacement plan as contingencies arise, and coordinating priorities among projects when multiple acceptable options exist.
- Examine power plant licensing and transmission line permitting issues.
- Interaction of OTC repowering/replacement/retirement and preferred resource development, system stability issues, and the potential of transmission upgrades to allow renewable capacity to replace OTC plants in transmission-constrained areas.
- Generator owners' reaction to SWRCB policy and the interaction among OTC policy, the procurement process, and the need for dispatchable conventional generation in local reliability areas.

Procurement

Procurement Principles

The Energy Commission recognizes that the CPUC has made several efforts to improve the IOU procurement process in the hybrid market. However, given that the current procurement was envisioned as a temporary solution, it is appropriate to now revamp the process to allow independent providers to fairly compete with IOUs. If a utility plans to build or purchase its own generation facility, the procurement proposals should be reviewed, selected, and ranked by independent parties. To create a robust procurement process that is fair to both merchant developers and utilities while assuring lowest cost to consumers, the Energy Commission recommends that the CPUC develop and implement a fully transparent method of ranking projects in the RFO bid process. As part of the *2009 IEPR*, the Energy Commission will conduct a public process and work with the CPUC to develop a bid evaluation and selection process that reflects the following principles:

- The procurement process should be conducted in a fair, objective, and transparent manner. Bids should be reviewed and selected or ranked by independent parties (for example, the CPUC or independent evaluators, not utilities) using publicly available selection criteria.
- Assessment of bids should be based upon appropriate cost and non-cost criteria and consider environmental impacts, likelihood of obtaining all required permits, and prior success of bidders in fulfilling contract offerings.
- The procurement process should encourage competitive offerings, be open to all bidders including utilities, and prevent circumvention of the competitive bidding process.

- The procurement process should be conducted in an efficient and timely manner and avoid unnecessary administrative and transaction costs that ultimately discourage market participants and impose greater costs on ratepayers.

- The procurement process should expressly identify how the bid evaluation phase will consider project permitting.

- The procurement process should protect commercially competitive information.

Siting Criteria

Siting-related criteria should apply to all projects that participate in an RFO, including those not under Energy Commission jurisdiction (under 50 MW or not thermally-based). The criteria should encompass all permitting issues that could result in project termination, delay, or cost increases. These should include, but not be limited to:

- Accurate determination of Energy Commission jurisdiction, especially for projects just under the 50 MW threshold

- Site control

- Consistency with city or county general plan land use designations and zoning

- Consistency with federal or state agency land use management plans

- Land under a Williamson Act contract

- Ability to obtain air permits

- Use of best available air pollution control technology, as applicable

- Availability or possession of adequate air pollution emission reduction credits, as applicable

- Status of California ISO interconnection studies

- Use of cooling technologies that avoid the use of fresh water

- Site location outside of prohibited, restricted, or limited-use lands[114]

- Affect on listed or endangered species

- Use and storage of hazardous materials on site

- Size, locational preference, and other important procurement criteria

Endnotes

103 California Public Utilities Commission, D.07-12-052, *Opinion Adopting Pacific Gas and Electric Company's, Southern California Edison Company's, and San Diego Gas & Electric Company's Long-Term Procurement Plans,* December 21, 2007.

104 Administrative Law Judge's Ruling Scheduling July 10, 2008, Workshop On Greenhouse Gas (GHG) Uncertainty And Requesting Comments, June 6, 2008.

105 California Energy Commission, *2007 Integrated Energy Policy Report,* CEC-100-2007-008-CMF, p. 64.

106 The social discount rate measures the rate at which a society would be willing to trade present for future consumption.

107 White House Office of Management and Budget, *Guidelines and Discount Rates for Benefit-Cost Analysis of Federal Programs*, Circular No. A-94, October 29, 1992, section 9.d.

108 California Energy Commission, *2007 Integrated Energy Policy Report*, p. 48.

109 California Public Utilities Commission, Decision 07-12-052, *Order Adopting Pacific Gas and Electric Company's Southern California Edison Company's, and San Diego Gas & Electric Company's Long-Term Procurement Plans*, December 20, 2007, page 76, http://docs.cpuc.ca.gov/word_pdf/FINAL_DECISION/76979.pdf.

110 The major facilities using OTC that were not nominated for retirement in the *2005 IEPR* are the nuclear facilities at Diablo Canyon (2,200 MW, in-service 1985) and San Onofre (2,254 MW, 1983), Moss Landing 1-2 (1,080 MW, 2002), Haynes 9-10 (575 MW, 2005), Huntington Beach 3-4 (450 MW, 2002), and Moss Landing 1-4 (1,060 MW, 2002).

111 "Refitting" refers to modifying the cooling technology used so as to comply with the rule; "repowering" involves replacing the boiler, but retaining the steam turbine. "Replacement" entails replacing both components, effectively erecting a new power plant on the site. In its comments on the SWRCB's preliminary draft policy, the Energy Commission asked that the licensing conditions for recently sited facilities be considered an alternative form of compliance. See California Energy Commission, *California Energy Commission Comment to State Water Resources Control Board Concerning its Coastal Power Plant Cooling Preliminary Draft Policy and Related Scoping Document*, May 20, 2008.

112 The aging merchant facilities that rely on OTC in SCAQMD include Alamitos (1,950 MW), El Segundo (670 MW), Huntington Beach (Units 1-2, 430 MW), and Redondo Beach (1,310 MW).

113 See California Independent System Operator, Mitigation of Reliance on Old Thermal Generation Including Those Using Once-Thru Cooling Systems Study Plan, http://www.caiso.com/1f52/1f529c671a380.pdf.

114 Wilderness areas or study areas, wildlife areas, wildlife management areas, wildlife refuges, roadless areas, ecological reserves, mitigation banks, habitat conservation areas, critical habitat areas for listed endangered and threatened species, species-specific conservation areas, state parks, Department of Defense lands, U.S. Forest Service lands, tribal lands.

Chapter 4

Assessment of California's Operating Nuclear Plants

Introduction

Assembly Bill 1632 (Blakeslee, Chapter 722, Statutes of 2006) directs the Energy Commission to assess the potential vulnerability of "large baseload generation facilities of 1,700 megawatts or greater" to a major disruption due to a seismic event or plant age-related issues. The Energy Commission is directed to adopt this assessment on or before November 1, 2008, and include it in the *2008 Integrated Energy Policy Report Update* (*2008 IEPR Update*).

This chapter summarizes the *AB 1632 Assessment of California's Operating Nuclear Plants: AB 1632 Committee Report,*[115] which was developed in parallel with the *2008 IEPR Update* and provides more detailed discussion of the topics and recommendations contained in this chapter.

The Energy Commission and its consultant, MRW & Associates, developed the original study plan for the *AB 1632 Assessment of California's Operating Nuclear Plants* in January 2008 based on public input at a December 2007 workshop. The Energy Commission released a draft consultant report for public comment on September 12, 2008, and held a public workshop on the report on September 25, 2008.[116] The Energy Commission's Electricity and Natural Gas Committee developed its draft Committee report, based on the consultant study and public comments received, which was discussed at a public workshop on the report on October 20, 2008. The Energy Commission expects to adopt the final *AB 1632 Assessment of California's Operating Nuclear Plants* in November 2008.

California's two operating nuclear facilities, the Diablo Canyon Power Plant (Diablo Canyon) and the San Onofre Nuclear Generating Station (SONGS), fall under the AB 1632 requirement. Although two natural-gas fired facilities, Alamitos and Moss Landing, have nameplate capacities greater than 1,700 MW, both of these facilities operate below a 60 percent capacity factor and are therefore not considered baseload facilities and not included in the AB 1632 assessment.

AB 1632 also directed the Energy Commission to assess the impacts of a major disruption on system reliability, public safety, and the economy; to assess the costs and impacts from nuclear waste accumulating at these plants; and to evaluate other major issues related to the future role of these plants in the state's energy portfolio.

Diablo Canyon and SONGS represent 12 percent of California's overall electricity supply.[117] A major disruption because of an earthquake or plant aging could result in a shutdown of several months up to more than a year or even cause the retirement of one or more of the plants' reactors. Because these plants are so important to the state's electricity supply, California needs a long-term plan should such a disruption occur. In addition, without license renewals, these plants will be permanently retired at the conclusion of their current operating licenses in the early to mid-2020s.

The U.S. Nuclear Regulatory Commission (NRC) regulates the radiological safety aspects of nuclear power, including plant licensing and license extensions. California has much broader authority to set electricity generation priorities based on economic, electricity reliability, and environmental concerns. The California Public Utilities Commission (CPUC) oversees the annual revenue required for each plant's decommissioning trust fund and determines revenue requirements for major capital projects at the plants. The CPUC establishes the framework for the cost effectiveness of plant license renewal and authorizes funding for license renewal feasibility studies.

In 2007, the CPUC authorized $16.8 million for PG&E to conduct a Diablo Canyon license renewal feasibility study and required PG&E to defer its study until after the Energy Commission issued its AB 1632 assessment and required them to incorporate the AB 1632 findings and recommendations into their study. The AB 1632 analytical effort was designed to fill current gaps in the public record regarding five major issues associated with California's nuclear plants: seismic issues, age-related plant degradation; waste accumulation, transport, storage and disposal; reliability, cost, and environmental issues with respect to replacement power; and future consideration regarding plant license renewal.

Seismic Vulnerability Assessment

The seismic vulnerability assessment in the consultant report prepared by MRW & Associates consists of three parts: assessment of the geology and seismic hazards in the vicinity of Diablo Canyon and SONGS; assessment of the seismic design of the power plants; and assessment of the seismic and other vulnerabilities of the spent fuel storage facilities located at the plants, of the transmission systems leading to and from the plants, and the access roadways for the plants.

Seismic Hazards

Diablo Canyon

The primary seismic hazard at Diablo Canyon is the offshore Hosgri Fault zone. There has been some uncertainty whether this is a lateral strike-slip fault or a thrust fault; a strike-slip fault is more vertically inclined, while a thrust fault has a shallower angle and extends diagonally beneath the surface. The importance of this distinction is the magnitude of ground motion at Diablo Canyon that could result from an earthquake. If the Hosgri Fault were a thrust fault with an eastward dip, then the fault would extend closer to the Diablo Canyon site and the ground motion could be greater.

PG&E and the NRC separately evaluated the seismic hazard at Diablo Canyon from the Hosgri Fault for probabilities of up to 33 percent thrust faulting. They found the plant's design had sufficient safety margin to accommodate the resulting ground motion, even though this motion was greater than had been anticipated when the plant was built. In addition, experts from the U.S. Geological Survey, the California Geological Survey, and the Southern California Earthquake Center have accepted the strike-slip characterization for the Hosgri Fault.

Another potential seismic hazard at Diablo Canyon is the possibility of an earthquake directly beneath the plant. In 2003, the San Simeon earthquake (magnitude 6.5) occurred about 35 miles north of the Diablo Canyon site, and the tectonic setting where this earthquake occurred appears similar to the local tectonic setting of Diablo Canyon. Better understanding of the fault zones where Diablo Canyon sits is significant for engineering vulnerability assessments. The Diablo Canyon seismic setting has been and continues to be extensively studied. Further study using advanced technology, such as three-dimensional geophysical seismic reflection mapping, could resolve questions about the characteristics of the Hosgri Fault and might change conclusions about seismic hazards at the plant. Since Diablo Canyon was built, scientists have learned more about ground motion that can result from an earthquake rupture. Recent studies have found that ground motion in close proximity to a fault could be stronger and more variable than previously thought. This could be important at Diablo Canyon since the plant lies within a few kilometers of the Hosgri Fault.

SONGS

Data that has become available since SONGS was built indicate that the site could experience larger and more frequent earthquakes than was originally anticipated when the plant was designed. A recent review by the California Coastal Commission states "there is credible reason to believe that the design basis earthquake approved by U.S. Nuclear Regulatory Commission (NRC) at the time of the licensing of SONGS 2 and 3 … may underestimate the seismic risk at the site."[118] Although new information does not necessarily imply that the facility is unsafe since the plant was engineered with a large safety margin, the possibility that the safety margin is shrinking does suggest that further study is necessary to characterize the seismic hazard at the site, especially since much less is known about the seismic setting of SONGS than the seismic setting of Diablo Canyon. While SCE periodically evaluates the implications of new seismic data that become available, there is no ongoing program at SONGS similar to PG&E's Long-Term Seismic Program at Diablo Canyon.

The major uncertainties relate to the earthquake potential of a nearby offshore fault zone (the South Coast Offshore Fault Zone) and the faulting that connects faults in the Los Angeles and San Diego regions. Additional seismic research, including well planned, high-quality three-dimensional seismic reflection data at strategically chosen locations, may resolve many of the remaining uncertainties and might change current estimates of the seismic hazard at the plant.

Like Diablo Canyon, SONGS is located within 10 kilometers of a fault, and new research on ground motion near an earthquake rupture is relevant to the seismic hazard of the plant. When SCE incorporated some of these developments into the seismic hazard assessment for SONGS, it found the plant's safety margins are less than previously believed. SCE is currently assessing the applicability of updated ground motion modeling for the SONGS site.

Tsunami Hazards at Diablo Canyon and SONGS

In addition to the direct hazard from earthquake ground motion, secondary seismic hazards like tsunami hazards could impact the nuclear plants. Currently available tsunami studies for both plants are at least 10 years old and do not take advantage of modern tools that could improve the quality of the assessments, such as probabilistic hazard assessments, inundation modeling, and new data from the National Oceanic and Atmospheric Administration. Second-generation tsunami run-up maps being prepared by the University of Southern California for evacuation planning purposes may also provide relevant information for tsunami hazard assessments at the plant sites.

SCE does not plan to reassess the tsunami hazard at SONGS and has not reassessed this hazard since the plant was designed. Since then, scientists have learned that submarine landslides can generate large local tsunamis. The tsunami run-up maps that are being prepared by the University of Southern California will incorporate expected hazards from such near-to-shore landslides. These new maps may or may not result in significantly revised estimates of the tsunami hazard at SONGS. However, even a moderate increase in the estimated maximum tsunami run-up could raise significant concerns about the adequacy of the site's seawall.

PG&E is currently conducting a study to reassess the tsunami hazard at Diablo Canyon. This study is a probabilistic tsunami hazard analysis that considers tsunamis triggered by local and distant earthquakes and by local submarine landslides. PG&E expects to complete this study by December 2008. The most recent study from the early 1990s concluded that the plant was designed to sustain the largest tsunami that can be expected at the site.

Vulnerability of Power Plant Buildings and Structures

The safety-related systems, structures, and components of Diablo Canyon and SONGS are designed to remain safe during "safe-shutdown earthquakes"[119] of magnitude 7.5 on the Hosgri Fault and 7.0 on the South Coast Offshore Fault Zone, respectively. These earthquakes are expected to be the largest that could impact the plants given what is currently known about the geology of local faults.

The largest earthquakes experienced at SONGS and Diablo Canyon have been significantly smaller than the plants' safe-shutdown earthquakes. A safe-shutdown earthquake could cause serious damage to the non-nuclear areas of Diablo Canyon or SONGS, but is not expected to seriously damage the safety-related portions of the plants—the reactor, primary steam supply, containment, and associated equipment.

The non-safety-related systems, structures, and components (SSC) of the plants are the most vulnerable to damage from earthquakes, compared with the safety-related systems, structures and components. The non-safety-related SSCs are the greatest source of seismic-related plant reliability risk for SONGS and Diablo Canyon and could result in plant outages lasting weeks or months. The risks to these parts of the plants are not well understood because the nuclear industry and the NRC historically have focused on safety-related systems. PG&E acknowledged this information gap at the Energy Commission's September 25, 2008, public workshop on the draft consultant report, and SCE confirmed in written comments to the Energy Commission that there are no studies that assess the seismic vulnerability of non-safety related systems at SONGS.

The electrical switchyards of the plants are particularly vulnerable to earthquake damage because the equipment configuration and the dispersed and interconnected nature of the switchyard facilities make them more vulnerable to ground motion and subsidence. An earthquake could cause damage resulting in failure of a switchyard, which could cause a loss of power from the plants to the transmission grid, but the reactor would continue to have a source of offsite power in addition to the onsite emergency diesel generators.

Following an earthquake, Diablo Canyon or SONGS could be shut down for as little as one week or for much longer for repairs or component replacement. Time estimates for repairing or replacing nuclear plant components are very uncertain, with the determining factors most likely being whether the repair is on the nuclear or non-nuclear side of the plant and the availability of appropriate replacement parts. Other factors affecting the duration of a shutdown include the time needed to investigate the plant for damage and the need for design and backfitting efforts. Public or regulatory concerns also could delay the restart of the power plant.

There are lessons to be learned from the effects of the 2007 Niigata Chuetsu-Oki earthquake on the Kashiwazaki-Kariwa Nuclear Power Plant in Japan. That facility experienced ground motions significantly higher than the design basis for the plant but suffered no significant damage to safety-related components. Nevertheless, more than a year after the earthquake, the facility remains shut down, apparently because of extensive investigations and reevaluation of the seismic design standards. This suggests that repairing or replacing damaged components may not be the primary driver of how long a nuclear power plant is shut down following a major seismic event. Research into this earthquake and the causes of damage at the plant are ongoing. The Energy Commission and California nuclear plant owners should stay informed as new information becomes available.

Vulnerability of Spent Fuel Storage Facilities

There are two general types of spent ("used") nuclear fuel storage: pool and dry cask storage. Diablo Canyon and SONGS currently use pools for spent fuel storage; SCE also uses dry cask storage facilities, and PG&E is constructing such facilities for future use. The greatest risk for spent fuel pools is the loss of water or active cooling, which could be caused by an earthquake or terrorist attack. If not mitigated, a loss of water or active cooling in the spent fuel pool could result in overheating of the pool, melting of the fuel cladding, and the subsequent release of radioactive material. Because of this risk, spent fuel pools are designed to reduce the possibility of drainage leading to water levels below the spent fuel. Diablo Canyon and SONGS' spent fuel pools are designed to the highest safety classification and are supported and partially embedded in the ground to increase their ability to withstand an earthquake. Spent fuel pools are not expected to suffer catastrophic loss of cooling as the result of an earthquake. However, an earthquake or other impact to a spent fuel pool could result in the release of radioactive materials if contaminated water spills from the pool, as occurred during the July 2007 Niigata Chuetsu-Oki earthquake in Japan. Spilled water in one reactor building leaked into the Sea of Japan from leaks in the reactor building floor. Although the SONGS and Diablo Canyon spent fuel pools are designed to curb the effects of sloshing, PG&E is investigating the water-tightness of conduits in its reactor buildings.

Because of the lack of a federal permanent spent fuel disposal facility, spent fuel pools at Diablo Canyon and SONGS have been "re-racked" to provide increased storage by placing the fuel assemblies closer together. The more-densely configured spent fuel pools are considered to have greater risk than a spent fuel pool with a more open racking arrangement. For example, a loss-of-coolant event from an earthquake or a terrorist attack in a re-racked spent fuel pool could result in extensive radiation release and contamination.

In general, a dry cask storage facility has a lower degree of overall risk than a spent fuel pool. Over the last 20 years, there have been no radiation releases from a dry cask storage facility that have affected the public, no radioactive contamination, and no known or suspected attempts of sabotage. However, the NRC's and the Electric Power Research Institute's risk analyses concluded that cask loading and transportation, which occur primarily during the first year of operation, pose a greater risk of an event or accident leading to public harm because spent fuel is exposed and in motion.

Diablo Canyon's dry cask storage facility incorporated a number of seismic safety features after an analysis of near-source fault ruptures showed the potential for types of ground motion to which the dry cask storage facility is more sensitive than the power plant. The SONGS dry cask storage facility was built to higher-than-required seismic standards. In reviewing the SONGS facility's seismic design, the California Coastal Commission concluded that ground shaking from an earthquake much larger or closer than the design earthquake would not exceed the facility's safety design.

Limited information is available on the vulnerability of dry cask storage to sabotage, which is consistent with the National Academies' finding in its study of spent fuel storage safety. While terrorist scenarios have been postulated that could release a significant amount of cesium into the environment, an assessment of the likelihood of such scenarios has not been publicly released.

Vulnerability of Roadways and Transmission Systems

The main concern with seismic vulnerability of roadways serving Diablo Canyon and SONGS is the ability for emergency personnel to reach the plants and for the local community and plant workers to evacuate. Diablo Canyon is served by a two-lane asphalt road and a separate emergency access road. During an emergency, this could result in traffic congestion and increase the potential for traffic accidents and further congestion. At SONGS, access roadways have a large capacity to bring in emergency supplies and relief personnel, but an emergency impacting nearby residents could cause congestion from traffic traveling through this corridor to escape a threatening situation. If the traffic overwhelmed the highway system, it could halt highway access and impede emergency response. To avert such a situation, SCE and state and local authorities have developed emergency plans. For example, during the October 2007 wildfires in southern California, state and local authorities coordinated access to the SONGS site for plant personnel.

The distributed nature of the transmission system makes it relatively more vulnerable than a nuclear plant to terrorist attack, but such an attack would not result in high human or environmental risk. Transmission towers and poles are not very susceptible to earthquake damage. However, as discussed earlier, switchyards are likely to be damaged during large earthquakes.

Aging Plant Issues

California's nuclear plants are approaching their fourth decade of operation and are subject to age-related degradation that could lead to a loss of function and impaired safety if not addressed. Effective maintenance programs and regulatory oversight are essential in identifying aging plant equipment and components, for example plant steam generators, that need to be repaired or replaced to maintain plant reliability and safety. Failure to do so could have serious long-term implications.

More than a dozen commercial nuclear power reactors have permanently shut down in the United States prior to the end of their operating license periods.[120] In many cases, the shut downs occurred unexpectedly. According to a study by the Union of Concerned Scientists, more than three dozen nuclear power reactors have experienced year-plus outages including reactors in California.[121]

The standard measurement of nuclear plant performance is the capacity factor, which is calculated by dividing how much energy a plant actually generates by the total possible energy produced during a given period. Reduced capacity factors over time may indicate age-related degradation. Capacity factors at Diablo Canyon and SONGS have actually increased since the early years of plant operation, and both plants achieved five-year average capacity factors of approximately 90 percent.[122] This does not necessarily indicate the absence of plant degradation; improved plant operations including reduced down time for plant maintenance and refueling may have compensated for possible degradation.

Not all nuclear plants have similar track records. Nuclear plants outside of California like Davis-Besse (Ohio), Vermont Yankee (Vermont), Oyster Creek (New Jersey), and Indian Point (New York) have all received increased scrutiny by the NRC, government agencies, or watchdog groups concerned that different types of age-related degradation are eroding the safety of the plants. The implications for Diablo Canyon and SONGS are twofold. First, the same unanticipated age-related degradation of plant components or systems could be occurring at the California plants. Second, a serious incident or a safety hazard at one plant could result in a regulatory requirement for more extensive inspections, repairs, and even shutdowns at similar plants nationwide.

Maintenance plays a central role in reducing age-related degradation and failure of components. A strong safety culture (that is, a strong "safety-first" dedication and accountability among plant workers) is a key element of an effective maintenance program, and problems with safety culture have been linked to the high-profile operational difficulties at the Palo Verde Nuclear Generation Station in Arizona and the extensive reactor vessel degradation uncovered at the Davis-Besse plant.

The NRC recently raised concerns about the safety culture at SONGS and required SCE to create a plan to improve safety culture at the plant. In addition, Energy Commissioner James Boyd, State Liaison Officer to the NRC, expressed concern to SCE regarding reports of lapses in the safety culture at SONGS. These reports include SONGS' unsatisfactory response to the failure of an emergency diesel generator at the plant, as well as certain willful violations of procedures including an employee who, over a five-year period, intentionally falsified records regarding required fire safety checks at SONGS.[123] The Institute for Nuclear Power Operations (INPO), an industry-funded oversight agency, has also identified safety concerns at SONGS, including an unusually high rate of employee injury.[124] Diablo Canyon, which has had no NRC violations since 1995, appears to have a relatively effective safety culture.

As the workforces at Diablo Canyon and SONGS get older, large numbers of employees will soon retire. Both PG&E and SCE have instituted programs to replace retiring workers and pass on their institutional knowledge. It is critical to the ongoing reliability and safety of the plant to implement such training programs and maintain strong safety cultures throughout this shift in workforce.

Impacts of Major Disruption

An earthquake, age-related plant or equipment failure, or other events could lead to one or both of California's nuclear plants going off-line for extended periods. Actions at other plants not directly related to the in-state nuclear plants could also result in a shutdown. For example, a major safety-related event at a nuclear power plant elsewhere in the country could lead to a general shutdown of other nuclear plants for an indefinite period.

In such an event, power from other sources would need to replace the power from the impaired units. The reliability, cost, and environmental implications of using replacement power would depend on what time of year the outage occurred and what replacement power was available. PG&E and SCE generally schedule refueling outages and other maintenance shutdowns to avoid periods of peak demand and reduce the cost of replacement power. Unplanned outages, however, can occur at any time. The experiences of nuclear plants nationwide indicate that while most unplanned outages last just a few days, many outages last a year or longer, mostly because of component degradation.

There are three scenarios that can be used to evaluate the consequences of an extended unplanned outage:

1. California and the rest of the Western Interconnection develop and implement comprehensive long-term resource adequacy standards.[125]

2. California utilities continue to use more ad hoc methods to estimate future capacity and energy requirements and continue to "muddle through" in procuring needed resources to cover likely conditions.

3. California ISO and the CPUC reform current resource adequacy requirements to extend current capacity planning into the 4-6 year ahead time horizon.

Each of these scenarios would lead to a different conclusion about the sudden disruption of output from one or both of the nuclear facilities, as described below.

West-Wide Resource Adequacy Scenario

Consultants to the Energy Commission simulated the operations of the electricity market for 2012 and beyond with and without one or both of the nuclear plants operating.[126] The simulations used a set of West-wide resource plans developed for the *2007 IEPR* Scenarios Analysis that assume supplies are always added to the system just in time to satisfy demand conditions and reserve requirements. The consultants found that no electricity supply shortages would occur as the result of either Diablo Canyon or SONGS being shut down for an extended period in 2012.

The consultant's simulations found that in the event of an extended outage at either nuclear plant, replacement power would be supplied mostly by combined cycle natural gas-fired plants. Approximately 55 to 62 percent of the increased generation would come from in-state gas-fired plants, while the remainder would come from out-of-state gas-fired plants along with a small amount of increased coal generation.

The cost of that replacement power would include the operating costs of in-state units and market costs to acquire power from out-of-state.[127] For a year-long loss of either nuclear plant, the simulations found that these costs would be $470 million higher than the cost to generate power from the nuclear plant. The added cost would increase average rates for customers of either PG&E or SCE/SDG&E by approximately half a cent per kilowatt-hour (kWh) while the outage continued. Plant repair costs likely would further increase rates.

An outage would also pose environmental consequences, since the replacement power would be largely natural gas-fired. The simulations found that a year-long outage at either nuclear plant would increase in-state GHG emissions from power generation by seven to eight percent, or roughly 4.3 to 4.7 million tons of CO_2. Out-of-state replacement generation would add an additional 2.2 to 2.8 million tons of CO_2, for a total GHG impact of approximately 7 million tons of CO_2.

Ad Hoc Planning Scenario

The Western Electricity Coordinating Council (WECC) collects electricity load and resource data from electrical system control areas (balancing authorities) and prepares an annual assessment of winter and summer electricity usage peak conditions. WECC counts resource additions only when they satisfy various criteria intended to screen out power plant proposals that are not considered committed. Because the purpose of the analysis is to reveal the extent to which peak planning needs are not satisfied by existing resources and committed additions, it is a very conservative view of what is actually expected to be in place in future years. Presumably by revealing deficits, it motivates independent generators to develop project proposals or move ahead toward contractual commitments with utilities and actually obtain needed permits and begin construction.

According to the WECC draft *2008 Power Supply Assessment*, reserve margins in both northern and southern California will decline over the next ten years if new plants are not built in addition to those currently undergoing regulatory review or already under construction.[128] The WECC study shows that by 2012 there will not be enough generating resources to maintain the CPUC-mandated 15 percent reserve margin in Southern California assuming SONGS is available; if SONGS were unavailable, reserve margins would fall below acceptable levels to nearly 5 percent – close to a Stage 2 Emergency. Northern California is just in balance (including a 15 percent reserve margin) in 2012 with Diablo Canyon in service, but is well below planning standards if Diablo Canyon were not available during summer peak electricity demand in California.

Actual reserve margins will depend on weather, economic conditions, and resource development. For example, tightening credit markets could delay construction of plants that are planned or currently under regulatory review, resulting in lower reserve margins. On the other hand, tightening credit markets could also reduce demand growth. Environmental constraints such as air quality requirements could limit new generation options, or once-through cooling restrictions could cause existing plants to retire more quickly than currently anticipated. Hotter than average peak weather would also worsen conditions. A planning reserve margin standard, such as the CPUC/California ISO requirement of 15 percent, would cover these contingencies. The WECC analysis indicates greatly increased reliability concerns if Diablo Canyon and SONGS were out of service in the (unlikely) environment that does not require utilities and other load serving entities (LSEs) to acquire resources to cover contingencies.

Extended Planning Time Horizon Scenario

Over the past two years, the CPUC and the California ISO have been examining alternatives that would extend the current one-year-ahead time horizon for planning electricity resource adequacy to something more like 4-6 years. The CPUC staff has recommended that this extended planning and commitment time horizon be adopted through bilateral markets or through a centralized capacity market mechanism administered by the California ISO. The CPUC is scheduled to make a decision on this by the end of 2008. If it does so, utilities and LSEs under the jurisdiction of the CPUC and the California ISO would need to acquire resources to cover loads and reserve requirements 4-6 years into the future on a rolling basis.

If this policy is adopted, an extended outage at Diablo Canyon or SONGS might be expected to have consequences somewhere in between the assessment of the two previous scenarios. It is possible that summer peak reliability could be assured, but providing enough energy to replace Diablo Canyon or SONGS would greatly strain the system. There are ways to cover energy deficits, but most are not easily accomplished or inexpensive. For example, the old steam generating units targeted for retirement or repowering by existing Energy Commission policy could generate more energy, albeit at much higher cost and emissions than would normally be considered acceptable. Few other resources have any “upside” energy generating capabilities.

Evaluating Local Reliability Implications and Other Transmission Issues

In evaluating alternative perspectives on the implications of unexpected, lengthy plant shutdowns, the Energy Commission must consider which, if any, is most appropriate, and whether additional factors that were not directly modeled are important. In the current energy agency planning processes, there does not appear to be an overt consideration of lengthy shutdowns for the nuclear units on reliability or other implications for customers. Further, the July 2008 court decision invalidating South Coast Air Quality Management District’s priority Reserve Rule 1309.1, without some immediate remedy to restore the rule, threatens power plant additions in the Southern California region. This makes all existing units more critical and less easily replaced. The pessimistic WECC scenario described above might be the most realistic, absent improvements to planning and regulatory processes.

Separate from the broad system perspective on resource adequacy are more detailed local assessments and procurement requirements that attempt to safeguard against outages in local load pockets. Such outages may require generation within the load pocket itself. These load pockets exist when the transmission system is inadequate to support all of the loads in an area.

None of the reliability assessments discussed above considered local transmission constraints that may restrict the delivery of power to such areas. SONGS is within the Los Angeles Basin load pocket but Diablo Canyon is not in any local load pocket, making SONGS more critical to reliability for most of Southern California than Diablo Canyon is to Northern California. More complete studies will be needed to reassess the need for replacement power at a system and local level given updated supply and demand conditions and local transmission constraints.

Previous studies have shown that while Diablo Canyon represents a significant generation resource and supports power flows through transmission Path 15 and Path 26, the plant is not needed to maintain reliable operation of the transmission system. During a year-long outage at Diablo Canyon, if replacement power is available it can be supplied to end-user loads without a disruption of the overall transmission system. Such replacement power may come at additional cost and with a greater environmental impact because most of the replacement power would come from natural gas-fired plants.

SONGS, on the other hand, is a more integral part of the Southern California transmission system, and when it is shut down, power flows of imports are also restricted. These restrictions affect Southern California by limiting imports from the Southwest, and also affect San Diego, which is interconnected with the Los Angeles portion of the California ISO through the SONGS units. Assuming replacement power for SONGS would be available (at similar costs and environmental impacts as for Diablo Canyon), a prolonged shutdown at SONGS could cause serious grid reliability shortfalls unless transmission system infrastructure improvements were made. The extent of the transmission system changes would depend on the transmission configuration in place at the time of the SONGS shutdown.

The Energy Commission believes that improvements in planning and reliability assessments are needed to fully understand reliability risks and other consequences of lengthy, unplanned outages of the nuclear plants.

Economic, Environmental, and Policy Issues

In 2003, California's principal energy agencies adopted a "loading order" that sets the priority for adding new energy resources to meet electricity use demands in the state: first is energy efficiency, second is renewable resources, third is distributed generation (electricity produced close to where it is used), and fourth is clean fossil fuel generation.

One of the challenges in replacing the nuclear plants with alternative energy resources would be the different impacts of this decision on communities and regions throughout California. If the new energy resources were built in California, the total economic benefit from employment and taxes statewide could be comparable to the benefits currently provided by the nuclear plants.[129]

Replacing the nuclear plants with renewable generating facilities would transfer economic benefits from the coastal communities near Diablo Canyon and SONGS to communities in inland southern California and other areas of the state that are rich in renewable resources. Recent announcements of several planned large-scale solar facilities in San Luis Obispo County suggest that the transfer of benefits away from the county could potentially be mitigated or offset by renewable power development in the area. In addition, the local economy could see gains from alternate uses of the plant site, other commercial or industrial development elsewhere in the county, or a potential increase in property values as a result of the plant closure. Without such potential offsets, the loss of Diablo Canyon would have a significant impact on the county's economy. The loss to the San Diego and Orange County economies from a closure of SONGS would be much less significant since these economies are more diversified and less dependent on the nuclear plant.

A key uncertainty in assessing the economic benefits to keeping Diablo Canyon and SONGS operating through a 20-year license extension is the reliability of the plants as they age. If the plants continue to operate reliably and do not require additional large capital improvements, the cost of power from the nuclear plants will likely remain lower than the cost of power from new renewable resources. However, significant equipment failures could result in extended outages and expensive repairs. As discussed earlier, effective plant maintenance and a strong safety culture are critical to keeping the plants operating safely and reliably as they age.

Nuclear Waste Disposal and Storage Issues

Diablo Canyon and SONGS produce significant quantities of radioactive waste in the form of spent fuel and other radioactively contaminated materials. The plants must carefully handle, store, transport, and dispose of the waste to protect humans and the environment from exposure to radioactive materials.

High-Level Radioactive Waste

Spent nuclear fuel or irradiated "used" fuel is extremely radioactive and remains radioactive for hundreds of thousands of years. Plants must store spent fuel assemblies in a water-filled pool for a minimum of five years following removal from the reactor core to shield against high levels of radiation. Once the spent fuel has cooled somewhat, it can be left in the pool or moved to dry cask storage facilities, consisting of metal or concrete outer shells with inner sealed metal cylinders, that contain the spent fuel. The plants store loaded casks on concrete storage pads in an on-site area away from the reactors.

In June 2008, the U.S. Department of Energy (DOE) filed a license application for a permanent geologic repository for spent fuel at Yucca Mountain, Nevada. If the license is granted, Yucca Mountain may begin operations sometime after 2020. In the absence of a permanent repository for spent fuel, utilities are using dry cask storage as an interim solution for waste disposal. Between spent fuel pool and dry cask storage, dry casks are generally considered to be the safer form. Over the last 20 years, there have been no radiation releases from a dry cask storage facility that have affected the public, no radioactive contamination, and no known or suspected attempts to sabotage spent fuel casks.

PG&E has designed and permitted a dry cask storage facility for Diablo Canyon that will allow the utility to transfer most of the spent fuel produced during the current operating license. SCE has designed and permitted and is constructing a dry cask storage facility for SONGS with capacity to store 36 percent of the spent fuel generated during the current license period (with additional storage available in the SONGS spent fuel pool). Both utilities may need to develop additional on-site storage or secure offsite storage to store all the spent fuel that will be produced over the plants' current operating licenses. Sufficient land area is available for the utilities to develop more storage capacity.

PG&E's dry cask storage is designed for a lifetime of 50 years and SCE's for a lifetime of 40 years. If the spent fuel is not transported off-site within the design lives of the dry cask storage system components, the utilities may need to repackage the spent fuel on-site and transfer it into new storage canisters, or bolster the current canisters or other storage system components. At this time there are no estimates how long the spent fuel will remain in interim dry-cask storage, and neither PG&E nor SCE are considering additional off-site or on-site interim fuel storage facilities.

If a federal repository is established, DOE plans to develop a special spent fuel packaging system for the transport, aging, and disposal (TAD) of spent fuel. DOE has proposed designing and developing a new TAD canister packing system, but the NRC has not yet established federal TAD packaging requirements. This forces nuclear plant owners, including PG&E and SCE, to move forward with onsite dry storage cask designs that may not be compatible with the federal TAD canister requirements. In addition, costs for transport of spent fuel to off-site storage or disposal facilities will be substantial, including costs for security, accident prevention, and emergency preparedness. Policies are being developed for federal spent fuel transportation and funding of state and county accident prevention and emergency response preparation programs; however, California has claimed that the proposed federal program may be insufficient, both in the planned timing of the grant program and potential inadequacies in the amount of the proposed grants for planning and for training emergency personnel to respond to potential accidents involving spent fuel shipments.

Low-Level Radioactive Waste

Low-level radioactive waste generated from nuclear power plants also requires care in handling, transport, and disposal. There are only three operating commercial low-level waste disposal facilities in the United States, located in South Carolina, Utah, and Washington state. Of those three facilities, only the Energy Solutions facility in Clive, Utah, is available to accept low-level waste from Diablo Canyon and SONGS. It is expected that Class A waste (the class of waste with the lowest radioactivity) will continue to be shipped to Clive, Utah. However, Class B and C waste (waste with higher levels of radioactivity) must be stored on-site at Diablo Canyon and SONGS until a new or existing facility can accept this waste. The NRC is reviewing its policies regarding on-site low-level waste storage and expects to complete this task by the end of 2008.

Low-level waste disposal costs are relatively modest during ongoing plant operations. However, the plants will need to dispose of a substantial quantity of low-level waste when they are decommissioned, and the cost to transport and dispose of this waste, presuming a disposal facility is available, is expected to be hundreds of millions of dollars, if not more. Low-level waste disposal costs have been rising in recent years, and current estimates of disposal costs during decommissioning are based on outdated cost information. Costs could be substantially higher than estimated during the most recent California regulatory proceeding on decommissioning costs.

Land Use and Economic Implications of On-Site Waste Storage

There is considerable uncertainty about if and when a geologic repository or other interim waste storage facility will become available to allow the removal of spent fuel from the Diablo Canyon and SONGS plant sites. The uncertainty regarding extended on-site waste storage raises concerns about the possible negative effect on future land uses, local property values, business, and tourism as a result of the perception of health and safety risks.

This concern is not supported by the experiences of other communities where nuclear power plants have been shut down and decommissioned but a dry cask storage facility remains onsite. Local communities near California's Rancho Seco nuclear power plant and Maine's Yankee nuclear power plant successfully converted the land and the area immediately around it into recreational or economically productive mixed use properties. The Connecticut Yankee nuclear plant site may also soon be developed.

Accordingly, Diablo Canyon and SONGS can establish alternate site uses after decommissioning, even with the presence of dry cask storage facilities after the plants are decommissioned. At Diablo Canyon, San Obispo County residents have expressed a strong preference for the plant site being converted to recreational use, but PG&E has not identified any priorities regarding future plans for the plant site. In the case of SONGS, the plant site is located on military land and will presumably remain under the control of the U.S. Navy. The Navy will have the option to use the land for military purposes, lease or sell to another party, or open it for recreational use.

Even for plant sites converted to alternate uses, the question remains whether the continued presence of the spent fuel has a negative impact on property values, business, and tourism in the area. Academic research does not lead to a strong conclusion that a dry cask storage facility would negatively affect nearby property values. However, the available analytical studies are extremely limited and only partially relevant, and the available surveys appear to be unreliable predictors of economic effects. An analysis of property sales data and other economic indicators in areas where a dry cask storage facility is operating would provide a useful starting point to assess potential economic impacts of extended spent fuel storage at California's nuclear plant.

Power Generation Options

The California legislature, through Assembly Bill 32 (Nuñez, Chapter 488, Statutes of 2006), has mandated greenhouse gas (GHG) reductions statewide. The California Air Resources Board, the CPUC, and the Energy Commission are integrating this mandate into the state's energy policies. Substantial economic, environmental, and regulatory barriers to developing new nuclear power plants in California mean that new nuclear plants cannot be relied on, at least in the near term, to meet California's AB 32 GHG emissions reduction goals for 2020.[130]

In the long term, renewable resources could be suitable replacement power options if either Diablo Canyon or SONGS were to be shut down. However, current renewable energy technologies cannot replace the operating characteristics of baseload nuclear plants. If either nuclear plant is shut down, ancillary services and regulating capability will most likely need to be increased. In addition, sufficient planning, siting, and construction time would be needed to develop these resources and any necessary transmission infrastructure. Moreover, the costs to develop renewable power resources and develop the transmission infrastructure needed to access them are uncertain, and a switch to renewable power resources away from nuclear power could result in an overall increase in the cost of electricity.

No power generation technology is free of environmental impacts. The total life cycle environmental impacts of alternative power generation technologies, including facility construction, operation and decommissioning, fuel, and waste disposal, must be considered. Life cycle analyses can provide decision makers a clearer and more complete understanding of the health and environmental impacts of different generating technologies. Moreover, GHG and other impacts from fossil fuel power plants that may be needed to support renewable facilities will also need to be considered.

Local economic impacts of generating facilities can also be important factors in policy decisions about resource options. Replacing the nuclear plants with an equal mixture of in-state wind, solar thermal, geothermal, and biomass power could result in roughly the same overall tax and employment benefits to the state as provided by the nuclear plants. However, these benefits would be conferred to different areas of the state. The communities currently benefiting from the nuclear plants would lose jobs and revenue unless the nuclear plants were replaced by other income-generating facilities.

Preliminary modeling suggests that replacing the state's two nuclear plants with renewable generation and using existing fossil-fuel units for reliability support could incur significant costs. Additional modeling is needed to fully understand the economic and environmental tradeoffs, as well as the implications on the California power grid, of long-term outages or permanently retiring Diablo Canyon and SONGS.

License Renewal Issues

Diablo Canyon and SONGS have been operating for roughly half of their 40-year initial license periods, and PG&E and SCE are exploring the feasibility of seeking 20-year license renewals from the NRC.[131] Diablo Canyon Unit 1's operating license expires in 2024 and Unit 2's expires in 2025, while SONGS Units 2 and 3's operating licenses expire in 2022. If license renewals are granted, Diablo Canyon and SONGS could continue to operate until the early to mid 2040s.

The NRC has approved extensions for approximately half of the nation's 104 commercial nuclear reactors (49 reactors) for 20 years beyond their original 40-year operating licenses and is reviewing license extension applications for another 19 reactors. To date, the NRC has not denied any license extension applications.

The role of the state in the license renewal decision is limited by the NRC's regulatory authority over all radiological safety aspects of nuclear power. However, the state has much broader authority to set electricity generation priorities based on economic, reliability, and environmental concerns. The CPUC relied on this authority in establishing a framework for considering the cost-effectiveness of the Diablo Canyon license renewal after PG&E sought approval for $16.8 million in ratepayer funding for a license renewal feasibility study.[132] The CPUC approved the requested funding and required that PG&E incorporate the Energy Commission's AB 1632 findings and recommendations in its feasibility study and submit the study to the CPUC no later than June 30, 2011, along with an application to the CPUC on whether to pursue license renewal.[133]

The CPUC further specified that the application should address: whether license renewal is cost effective and in the best interests of PG&E's ratepayers; the AB 1632 assessment; and any legislative framework that may be established for reviewing the costs and benefits of license renewal. The CPUC will then decide as part of PG&E's 2011 General Rate case whether PG&E should pursue a license renewal. This timeframe is intended to provide the state and PG&E with sufficient time (approximately 12 years) to develop alternate resources should the decision be to forego the Diablo Canyon license renewal.[134]

SCE requested approval of $17 million for a similar feasibility study for SONGS. A decision on this funding is expected in the coming months as part of SCE's 2009 General Rate Case. It is assumed that SCE will need to seek CPUC approval before proceeding with an NRC license renewal application, similar to PG&E.

If the CPUC determines that license renewal is not cost-effective for either Diablo Canyon or SONGS, the CPUC could use its rate authority to effectively restrict the operation of the plant through an extended license period, even if a license renewal is granted. Such an action would not conflict with the NRC's regulatory authority over the radiological aspects of nuclear power.

The decision whether or not to renew the Diablo Canyon and SONGS operating licenses will have a significant impact on the state's power supply portfolio and on the communities located near the reactors. The full implications of this decision are unknown. Even the most straightforward question of how much power would be impacted by this decision cannot be answered with certainty. While current production levels from the plants are known, it is unclear how performance will change as the plants age – no commercial reactor has yet operated for a full 60 years.

The cost of power from these plants over the license renewal period will be linked to their performance. If the plants maintain high levels of performance and safety without requiring significant repairs, the costs could remain comparable to current levels with relatively minor increases from higher nuclear fuel costs and potentially stricter security requirements. However, equipment failures or extended outages could result in much higher costs. In addition, the plants may have to retrofit their once-through cooling systems before a license renewal, at a cost of several billion dollars.

It is important to consider the environmental impacts from plant operations over an extended 20-year license period, including those from once-through cooling ocean impacts and continuing at-reactor waste accumulation. The extent of the impacts will depend on the outcomes of state and federal policies and requirements for once-through cooling and on whether a long-term solution to the waste disposal problem is found. The impact that shutting down one or both of the plants would have on the reliability of California's electricity grid is unclear at this time. In addition, these plants avoid using fossil generation plants that emit greenhouse gas emissions. The overall impact of shutting down one or both plants would depend on what other generating and transmission resources are built or retired over the next two decades and on the pattern of population growth in the regions near the plants. The plants' reliability and cost-effectiveness will depend largely on how well they are maintained, how well defective plant components are repaired and/or replaced, and the strength of plant workers' safety culture. These are some of the areas that should be investigated further before any decision on license renewal is made.

Recommendations

Seismic Hazards

Future Assessments

Both PG&E and SCE should report to the Energy Commission on the overall status and results of their seismic research efforts in future IEPR assessments, beginning with the most recent seismic vulnerability assessments for Diablo Canyon and SONGS in the *2009 IEPR*. In particular, SCE should develop an active seismic hazards research program for SONGS similar to PG&E's Long Term Seismic Program to assess whether there are sufficient design margins at the nuclear plant to avoid major power disruptions. SCE's research should prioritize and include further investigations into the seismic setting at SONGS and should assess whether recent or current seismic, geologic, or ground motion research in the vicinity of SONGS has implications for the long-term seismic vulnerability of the plant.

Advanced Seismic Research Techniques

The Energy Commission recommends that both PG&E and SCE should use three-dimensional geophysical seismic reflection mapping and other advanced techniques to supplement ongoing seismic research programs; the Energy Commission and other appropriate state agencies should evaluate whether these studies should be required as part of the Diablo Canyon and SONGS license renewal feasibility studies for the CPUC.

Diablo Canyon

PG&E should assess the implications of a San Simeon-type earthquake beneath Diablo Canyon, including expected ground motions and vulnerability assessments for safety- and non safety-related plant systems and components that might be sensitive to long-period motions in the vicinity of an earthquake rupture.

National Seismic Hazard Mapping Project

The Energy Commission, in cooperation with other appropriate state agencies, should consider the relevance of the USGS National Seismic Hazard Mapping Project models and the Uniform California Rupture Forecast, Version 2 data base in the context of studies required as part of the license renewal feasibility assessments for Diablo Canyon and SONGS for the CPUC.

Tsunami Hazards

PG&E and SCE should review the tsunami hazard at their nuclear plants in light of recent research and improved scientific understanding of tsunamis. SCE should assess SONGS' tsunami vulnerability after new data from the National Oceanic and Atmospheric Administration for the SONGS site and adjacent coastal areas become available. SCE should also assess the relevance of the University of Southern California second-generation tsunami run-up maps for the tsunami hazards at its nuclear plant sites. PG&E and SCE should provide to the Energy Commission the results of the updated Diablo Canyon and SONGS tsunami hazard study as part of future IEPR assessments beginning with the *2009 IEPR*.

Power Plant Buildings and Structures

PG&E and SCE should undertake the following actions and report on their progress as part of future IEPR assessments beginning with the *2009 IEPR*:

- Investigate and report findings on the how plant non-safety related systems, structures and components (SSCs) comply with current building codes and seismic design standards for non-nuclear power plants.

- Evaluate the seismic vulnerability and reliability implications for the nuclear plants' non-safety related SSCs from changes to seismic design standards that have occurred since the plants were designed and built, including consideration of the International Atomic Energy Agency Standards and Safety Reports and any retrofits, focusing on systems or components whose failure could lead to extended outages.

- Describe plant component repair/replacement plans including initial estimates of time needed to repair or replace key plant systems or components that could cause a prolonged plant outage as a result of being damaged from an earthquake. This should consider the fragility of components both in their operating positions and when relocated for refueling or plant maintenance.

Lessons Learned

As part of the license renewal feasibility analyses for the CPUC, PG&E and SCE should summarize the lessons learned from the Kashiwazaki-Kariwa plant experience in response to the 2007 earthquake and any implications for Diablo Canyon and SONGS, including whether any additional pre-planning or mitigation could minimize plant outage times following a major seismic event.

Spent Fuel Storage Facilities

Open Racking Arrangements

PG&E and SCE should return the spent fuel pools to open racking arrangements as soon as feasible, while maintaining compliance with NRC spent fuel cask and pool storage requirements, and report to the Energy Commission on their progress in doing so.

Security Clearances

The Energy Commission should continue to work with the NRC and the California Office of Homeland Security to obtain the necessary security clearances for selected California officials to review studies that assess the vulnerability of California's nuclear plants, spent fuel storage facilities, and spent fuel shipments to terrorist attacks or sabotage and the consequences of such attacks.

Access Roads

As part of license renewal feasibility studies and to protect plant assets and equipment, PG&E and SCE should reassess the adequacy of access roads to the plants and surrounding roadways for allowing emergency response personnel to reach the plants and local communities and plant workers to evacuate, taking into account changes to the local populations since the plants were constructed.

Age-Related Degradation

Maintenance Programs

To support long-term plant reliability, effective safety culture and plant maintenance programs must be maintained at Diablo Canyon and SONGS in conjunction with enhanced oversight mechanisms, including:

- The Energy Commission should work with federal and state regulators, nuclear plant owners, and INPO to develop a means for usefully incorporating results of INPO reviews and ratings of reactor operations into a meaningful public process while maintaining the value of these reviews as confidential and candid assessments.

- The Energy Commission should continue to closely monitor NRC actions and reviews of Diablo Canyon's and SONGS' performance. In particular, the state should monitor the NRC's responses to safety culture lapses at SONGS and require SCE to provide evidence of achieving and maintaining a strong plant safety culture prior to SCE's submitting a license renewal application. SCE, beginning with the *2009 IEPR*, should report on their progress on how they are addressing the SONGS safety culture issue.

- The Electric Power Research Institute's groundwater protection guidelines should be followed to prevent inadvertent releases of tritium due to degraded materials or operational failures.

Training and Recruiting

The CPUC should continue to recognize the importance of PG&E's and SCE's plant worker training and recruiting programs and approve adequate funding for such programs. On a periodic basis, the state should assess the adequacy and success of PG&E and SCE recruiting and training programs for replacing retiring plant workers and ensuring that knowledge and strong safety cultures are instilled in new workers.

Reliability Impacts of Major Disruption

Stakeholder Study

The existing California ISO-organized Stakeholder Study of Aging Power Plants and Once-Through Cooling Mitigation should be completed as quickly as feasible using sound analytic techniques, and the results should be closely reviewed to determine whether further studies are needed to understand the issues resulting from unplanned outages of Diablo Canyon and SONGS. To the extent such supplemental studies are needed, they should be commissioned and completed in a timely manner.

Ensuring Reliability

The Energy Commission, CPUC, and California ISO should further evaluate the unique uncertainties of losing the electricity provided by Diablo Canyon and SONGS over an extended period, identify how resources might be acquired that have an energy supply capability beyond that used in normal market conditions, and modify the long-term planning and procurement process at the CPUC to ensure that these resources are acquired in a timely manner.

Economic, Environmental, and Policy Issues

As part of the license renewal feasibility studies for Diablo Canyon and SONGS, the CPUC should require PG&E and SCE to conduct a detailed study of the local economic impacts of shutting down the nuclear plants compared with alternate uses of the site.

Nuclear Waste Accumulation

Estimated Amounts

During the upcoming CPUC proceeding on decommissioning costs, PG&E and SCE should provide estimates of the amounts of low-level waste to be generated and ultimately disposed of during plant operation and decommissioning and the cost of this disposal based on current and projected market prices.

Cost of Disposal

As part of license renewal feasibility studies, PG&E and SCE should assess the costs of disposing of low-level waste that will be generated during a 20-year license extension. The assessments should include the cost to dispose of low-level waste that would be generated from major capital projects that might be required over this period. PG&E and SCE should also provide information on their plans for storage and disposal of low-level waste and spent fuel through plant decommissioning.

Power Generation Options

As part of license renewal feasibility studies for Diablo Canyon and SONGS, the CPUC should require more detailed studies of alternative power generation options to quantify the reliability, economic, and environmental impacts of replacement power options.

License Renewal Issues

To help ensure plant reliability, the Energy Commission, working with the CPUC as part of the CPUC's authority to fund and oversee utilities' plant relicensing feasibility studies, should develop criteria and issues that the utilities will be asked to address in their license renewal feasibility studies to ensure that utilities fully evaluate the costs and benefits of nuclear plant license extensions. Further, such studies should address the following important considerations: the adequacy of the plants' maintenance programs and safety cultures; plans for waste storage, transport and disposal; seismic hazard and vulnerability assessments; the life cycle or cradle-to-grave evaluation of the nuclear plants compared with alternative generating and transmission resources; contingency plans in the event the state's nuclear power plants have prolonged outages; implications for grid reliability if these plants shut down; and the overall economic and environmental costs and benefits of license extension. The utilities should report on the status and results of their license renewal feasibility studies as part of the IEPR process, beginning with the *2009 IEPR*.

Endnotes

115 California Energy Commission, October 2008, *AB 1632 Assessment of California's Operating Nuclear Plants: AB 1632 Committee Report,* http://www.energy.ca.gov/2008publications/CEC-100-2008-009/CEC-100-2008-009-CTF.PDF.

116 MRW & Associates, September 2008, *AB 1632 Assessment of California's Operating Nuclear Plants*, draft consultant report, http://www.energy.ca.gov/2008publications/CEC-100-2008-005/CEC-100-2008-005-D.PDF.

117 California Energy Commission, April 2008, *2007 Net System Power Report*, pp. 4–5, http://www.energy.ca.gov/2008publications/CEC-200-2008-002/CEC-200-2008-002-CMF.PDF .

118 California Coastal Commission, http://www.coastal.ca.gov/energy/E-00-014-3mmi.pdf, page 19.

119 The Nuclear Regulatory Commission defines "safe-shutdown earthquakes" as the maximum earthquake potential for the respective plant sites based on the regional and local geology and seismology and the local subsurface material.

120 Nuclear Regulatory Commission, "Locations of Power Reactor Sites Undergoing Decommissioning." September 26, 2008. Accessed: October 2, 2008, http://www.nrc.gov/info-finder/decommissioning/power-reactor/.

121 Lochbaum, David. "Walking a Nuclear Tightrope: Unlearned Lessons of Year-Plus Reactor Outages." Union of Concerned Scientists. September 2006, pages 8-10.

122 California Energy Commission, *Nuclear Power in California: Status Report 2007*, October 2007, http://www.energy.ca.gov/2007publications/CEC-100-2007-005/CEC-100-2007-005-F.PDF.

123 Letter to Richard M. Rosenblum, Southern California Edison, from James D. Boyd, California Energy Commission, dated January 22, 2008.

124 The results of Institute for Nuclear Power Operations reviews are confidential, and the Energy Commission and the California Public Utilities Commission usually do not have access to information about these reviews. Recent limited information releases by SCE and PG&E are exceptions.

125 The Western Interconnection is one of the two major power grids in North America. The other major interconnection is the Eastern Interconnection. The three minor interconnections are the Québec Interconnection, the Texas Interconnection, and the Alaska Interconnection.

126 The simulations are described in more detail in the consultant report, *AB 1632 Assessment of California's Operating Nuclear Plants*.

127 The modeling assumes that incremental power from in-state resources can be acquired at the cost of service (i.e. are owned by the utilities or under a tolling contract) while incremental power from out of state must be purchased at market rates calculated internally within the MARKETSYM model.

128 New resources included in the analysis are under (or have completed) regulatory review with a completed facility study, are in active negotiations for (or possess) an interconnection agreement, and are projected to be in-service prior to January 2014. Western Electricity Coordinating Council. *2008 Power Supply Assessment - Draft.* September 29, 2008, page 11.

129 Assembly Bill 1451 (Leno, Chapter 538, Statutes of 2008) temporarily exempts certain renewable energy facilities from property tax assessments and will reduce the tax revenue generated from these facilities.

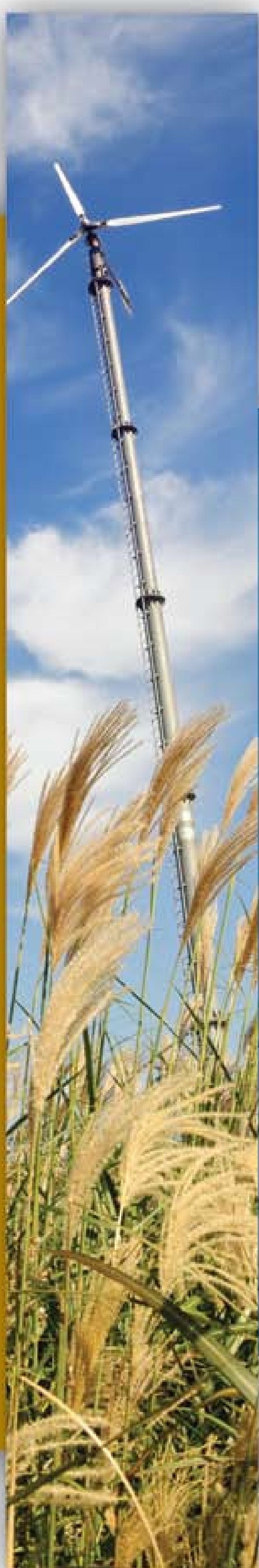
130 New nuclear power plant construction in California was suspended in 1976 pending a determination by the Energy Commission that a high-level federal nuclear waste disposal repository has been approved and built. In the *2005 IEPR*, the Energy Commission reaffirmed its finding made in 1978 that a "high-level waste disposal technology has been neither demonstrated nor approved." The *2007 IEPR* further discusses the status of the federal waste disposal and commercial reprocessing program and its implications for the California nuclear laws (pp. 67–69).

131 NRC is investigating the feasibility of a second 20-year license renewal option. See 10 CFR 54.31d and Federal Register Volume 56, No. 240, December 13, 1991, pp. 64964–64965. "Future Challenges for the Nuclear Science and Engineering Community." Remarks of NRC Chairman Dale Klein at the International Conference on Nuclear Engineering, Orlando. May 12, 2008.

132 The license renewal feasibility study consists of the following components: (1) screening Diablo Canyon's structures, systems, and components to determine if they are within the scope of a renewed license, (2) performing an aging analysis of plant systems and components to determine the need for additional monitoring programs, and (3) preparing a draft environmental impact report.

133 California Public Utilities Commission, Decision 07-03-044, *Opinion Authorizing Pacific Gas and Electric Company's General Rate Case Revenue Requirement for 2007–2010*, March 15, 2007, http://docs.cpuc.ca.gov/published/FINAL_DECISION/65852.htm.

134 California currently plans for long-term power procurement through the CPUC biennial adoption of a rolling 10-year long-term procurement plan, the purpose of which is to identify resource needs a decade in advance to provide sufficient time to plan for, and procure, new capacity in an orderly and cost effective manner.



Chapter 5

Evaluation of the Self-Generation Incentive Program

Introduction

Assembly Bill 2778 (Lieber, Chapter 617, Statutes of 2006) required the Energy Commission, in consultation with the California Public Utilities Commission (CPUC) and the California Air Resources Board (ARB), to evaluate the CPUC's Self-Generation Incentive Program and the costs and benefits of expanding eligibility for the program to renewable and fossil fuel "ultraclean and low-emission distributed generation."

The Energy Commission hired TIAX, LLC under contract to evaluate the Self-Generation Incentive Program. The results of TIAX's evaluation were presented at an Integrated Energy Policy Report (IEPR) staff workshop on September 3, 2008, and the final draft TIAX report was released for public review on October 29, 2008.[135] This chapter summarizes TIAX's report and findings and presents the Energy Commission's recommendations.

Assembly Bill 970 (Ducheny, Chapter 329, Statutes of 2000) directed the CPUC to adopt initiatives to reduce electricity demand, including providing incentives for distributed generation technologies. The CPUC created the Self-Generation Incentive Program to promote eligible distributed generation technologies under 5 megawatts (MW) to meet all or a portion of customers' electricity needs.[136] The Self-Generation Incentive Program is one of the largest distributed generation incentive programs in the United States, with approximately 1,200 projects totaling 300 MW on-line by the end of 2007. The total capacity is fairly evenly divided between cogeneration and solar photovoltaic projects.[137]

From 2001 through 2004, funding for the Self-Generation Incentive Program was set at $125 million per year, which was collected through a surcharge on electricity and natural gas bills.[138] Rebates from the Self-Generation Incentive Program are available to electric and/or gas customers of Pacific Gas and Electric (PG&E), Southern California Edison (SCE), Southern California Gas Company, and San Diego Gas & Electric (SDG&E).

The Self-Generation Incentive Program was extended through December 31, 2007, by Assembly Bill 1685 (Leno, Chapter 894, Statutes of 2003). AB 2778 subsequently extended the Self-Generation Incentive Program to January 1, 2012, and removed solar technologies from the program. Since January 1, 2007, the CPUC has offered incentives for photovoltaic technologies through the California Solar Initiative.[139] The program originally included microturbines, small gas turbines, wind turbines, solar photovoltaics, fuel cells, and internal combustion engines, but as of January 1, 2008, only fuel cells and wind energy technologies are eligible for the program.

Prior assessments of the Self-Generation Incentive Program by Itron, Inc., found that Self-Generation Incentive Program projects supply critical on-site electricity during peak demand, may reduce transmission and distribution system line loading and losses, reduced greenhouse gas (GHG) emissions in most instances compared to central station generation, and provide the most benefit to end-users and, in some instances, some benefit to the utilities.[140]

Analysis Approach and Method

One of the goals of the TIAX evaluation was to develop a clear and robust methodology to evaluate self-generation and distributed generation programs. Table 4 shows the benefits and costs considered in TIAX's analysis of the Self-Generation Incentive Program.[141]

TIAX's report separated the benefit and cost elements into the three core perspectives: participant, non-participant, and societal. Where possible, TIAX differentiated benefit and cost elements according to their respective perspectives; however, the report focused primarily on the societal perspective.

Data Sources

TIAX's report on the Self-Generation Incentive Program included the costs and benefits of installations interconnected between 2002 and December 31, 2006. TIAX did not include data from 2007 because of the time constraints imposed by the November 1, 2008, due date for the analysis. In May 2008, the CPUC formally requested the data needed for the TIAX analysis, including confidential customer data, from the investor-owned utilities (IOUs). These data included:

Metered Performance Data

Itron collected metered performance data for distributed generation systems supported by the Self-Generation Incentive Program from 2002 through 2006. For selected sites, the metered data include electric net generator output, fuel consumption, and useful recovered thermal energy (heat).

Cost Breakdown Worksheets

Self-Generation Incentive Program applicants are required to submit a Cost Breakdown Worksheet that details eligible and ineligible cost elements for the installation. For program years 2001 through 2004, the eligible costs were used to determine the value of the incentive, depending on the technology. For program years 2005 through 2008, incentives are calculated strictly on a kilowatt multiplied by $/kilowatt basis. Cost elements on the worksheets included engineering and design costs, permitting costs, equipment costs, interconnection fees, sales tax, and others.

Table 4. Benefits and Costs Considered in TIAX Evaluation of the Self Generation Incentive Program

	Benefits	Costs
PARTICIPANT	Electric bill savings	Capital costs (HV)
	Fuel-for-heat savings (HV)	Fuel costs – operational
	SGIP incentives (HV)	Operating and maintenance expenditures
	Customer reliability benefits (HV, NQ)	Standby charges (NQ)
	Tax credits (NQ)	
	Credits toward RPS (NQ)	
NON-PARTICIPANT	Energy commodity savings	Lost revenues
	Congestion charge savings	Administrative costs
	Transmission losses savings	SGIP incentives (HV)
	Avoided ancillary service charges	
	Avoided California ISO charges	
	Customer standby fees	
	Distribution capital deferral savings	
	Distribution loss savings	
	Congestion reduction savings (HV)	
	Local reliability benefits(NQ)	
SOCIETY (CALIFORNIA)	Congestion reduction savings	Fuel costs – operational
	Distribution capital deferral savings	O&M expenditures
	Economic impacts	Administrative costs
	Societal environmental benefits (HV)	
	Fuel-for-heat savings (HV)	
	Avoided energy costs (HV)	
	Avoided ancillary service charges (LV)	
	Avoided California ISO charges) (LV)	
	Distribution loss savings (LV)	
	Gas price moderation savings (LV)	
	Customer reliability benefits (HV, NQ)	
	Local reliability benefits (HV, NQ)	

HV = Highest value

NQ = Not quantified in report

LV = Low or very low monetized value, little effect on SGIP design or implementation

Source: TIAX, LLC.

Utility Tariff Data

The CPUC and IOUs provided electricity tariff data, including time-of-use rates and demand charges. Forecasts of retail prices for both gas and electricity rely on current tariffs as a starting point. Retail electricity and natural gas prices were escalated based on forecasts by the Energy Information Administration's Annual Energy Outlook. Retail gas rates were used to value both purchased generator input fuel and avoided purchases of natural gas resulting from recovered waste heat.

Transmission and Distribution System Data

This included substation size and physical locations, along with maximum line loads, transformer loads, and other system information.

Program Administration and Evaluation

The CPUC provided annual administration costs for the Self-Generation Incentive Program and the costs incurred by the administrators for evaluations conducted by third-party consultants.

Estimating Environmental Impacts

TIAX characterized environmental benefits by comparing the emissions of the self-generation installations to the emissions that would have otherwise come from centralized power generation. TIAX determined the emissions from centralized power generation on a marginal basis, assuming that the next installed watt of power would come from a natural gas-fired combined-cycle combustion turbine power plant. It is important to note that although self-generation installations often operate at peak demand (for instance, solar photovoltaic systems) and may displace emissions from dirtier generation sources (for example, peaker plants), TIAX made a simplifying assumption and presented the environmental benefits as a conservative estimate.

TIAX quantified emissions that impact air quality, volatile organic compounds (VOC), nitrogen oxides (NO_x), particular matter (PM2.5), and carbon monoxide (CO), and those that impact climate change, carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O), reported as carbon dioxide equivalents (CO_2-eq). Because air quality is driven primarily by local and regional chemistry and transport, TIAX used emission factors that accounted for all in-state emissions of air quality pollutants.[142] With climate change being a global phenomenon, TIAX employed life cycle emission factors that account for all upstream emissions of a fuel.[143]

TIAX used the damage cost of pollutants rather than the control cost to monetize emission reductions or increases.[144] The damage cost is typically measured on a per-ton basis and is a more accurate representation of the cost of a given pollutant to society. A control cost, on the other hand, reflects the cost of preventing that same pollutant from being emitted. The damage cost analysis included direct damages to humans as well as indirect damages to humans through ecosystem degradation and through nonliving systems.

TIAX used an estimate of the social cost of carbon dioxide as a proxy for damages related to GHG emissions. The Inter-Governmental Panel on Climate Change (IPCC) estimates this cost to be $43 per metric ton of carbon, which is equivalent to about $12 per metric ton of CO_2 (in 2006 dollars). The IPCC approximation is based on R.S.J. Tol's 2005 study, which reviewed 28 published studies containing 103 estimates.[145] Tol's work concluded that when only peer-reviewed studies are considered, "… climate change impacts may be very uncertain but it is unlikely that the marginal damage costs of carbon dioxide emissions exceed $50 per ton carbon." However, this estimate may be too low to stimulate the magnitude of GHG emissions reduction needed to avoid serious climate-related impacts.

The IPCC reports a 445–490 parts per million CO_2-eq as substantially reducing the expected magnitude, impact, and rate of climate change from business-as-usual scenarios by 2050 from 2000 emission levels and states that most individual studies for this category of reductions cluster around $100 per ton CO_2 by 2030.[146]

Table 5. Emission Factors for Centralized Power Generation Used in California and Corresponding Damage Costs

	Pollutant	Emission Factorsa (g/kWh)	$(2006)/ton
Air quality	VOC	1.0 x 10-3	8.9 x 10^3 [b,c]
			3.4 x 103 (gas phase) [b,c]
	NOx	4.5 x 10-3	19.0 x 103 (as PM)[c]
	CO	63 x 10-2	-[d]
	PM2.5	6.2 x 10-3	640 x 103 [c]
Climate Change	GHGs	505	12 [e]

a. Full Fuel Cycle Assessment, Well to Tank Energy Inputs, Emissions, and Water Impacts, Consultant Report, TIAX LLC, CEC-600-2007-003, June 2007

b. Delucchi, M. Annualized Social Cost of Motor Vehicle Use in the U.S., 1990-1991. Institute for Transportation Studies, University of California, Davis (UCD-ITS-RR-96-3)

c. Emission Reduction Plan for Ports and Good Movement, Appendix A: Quantification of the Health Impacts and Economic Valuation of Air Pollution from Ports and Goods Movement in California, California Air Resources Board, March 2006

d. Note that there is not a reliable estimate of the damage cost of carbon monoxide, CO. However, because CO is defined as a criteria air pollutant by the Environmental Protection Agency, TIAX quantified its emissions.

e. Tol, RSJ. The Marginal Damage Costs of Carbon Dioxide Emissions: An Assessment of the Uncertainties. Energy Policy, 33 (2005), 2064-2074 [per metric ton].

Source: TIAX

Estimating Macroeconomic Impacts

Jack Faucett Associates, a subcontractor with TIAX, estimated the macroeconomic impacts of the Self-Generation Incentive Program using an input-output model, IMPLAN.[147] To run IMPLAN, specific expenditures are allocated to a wide range of economic industries (509 total) to develop detailed estimates of economic impacts. Capital expenditure data by year and technology for each IOU were used to develop program level estimates of the benefits from program expenditures. To develop economic impact estimates from these expenditures it is necessary to classify them by the economic sectors utilized by the IMPLAN model. Preparing the data for IMPLAN analysis involves: identifying program expenditure categories, assigning program expenditure categories to IMPLAN sectors, aggregating expenditure categories assigned to the same sectors, and developing the expenditure levels to assign to each relevant sector in the model.

Sample data from 283 installations were available. The samples included examples of all the technologies except wind turbines. Among the 283 installations, 90 different cost categories were identified. The economic impacts of the program's expenditures included: value added, jobs created (full time equivalents), payroll compensation, federal tax revenue, and state and local tax revenue.

Grid Impacts

Rumla, Inc. (Rumla), a TIAX subcontractor, assessed the transmission and distribution grid impacts of the Self-Generation Incentive Program. The approach for assessing the grid impacts of self-generation investments must meet three basic criteria:

1. The focus has to be on the generation and distribution components of electric power service.

2. The approach must include a methodology that can assess self-generation performance in the future in accordance with the market structure and rules expected to prevail.

3. There should be a diligent effort to achieve the highest practicable spatial resolution of information on the costs and benefits of the self generation investments of interest.

Prior efforts have more or less recognized the importance of the generation factor. But with respect to distribution system benefits, the notion of transmission investment deferability continued to detract from the more realistic benefits associated with low-voltage opportunities. The achieved level of penetration of self-generation under the program is simply too low and too dispersed to be credibly tied to any past or future deferral of transmission upgrades. Rumla used General Electric's Multi Area Production Simulation Software program to analyze transmission congestion, marginal losses, and the grid locational value of the throughput of the Self-Generation Incentive Program installations. The model calculated hourly production costs while accounting for the system security constraints imposed by the transmission system on the economic dispatch of generation. Rumla included the following factors in its analysis of transmission system impacts:

- Zone-specific wholesale market transactions for assessing the value of Self-Generation Incentive Program generation for Zones North Path 15 and South Path 15 over 2002-2008.

- California ISO's Market Redesign and Technology Update (MRTU) as the pricing platform from 2009 onwards.

- Anticipated transmission upgrades.

- Anticipated generation additions in compliance with the CPUC's Resource Adequacy Requirements.

Together, the MRTU and the resource adequacy developments should, on average, determine more than 95 percent of the total value of the avoided costs for Self-Generation Incentive Program-supported systems.

For the distribution impacts, Rumla assessed the need for distribution system upgrades in the absence of Self-Generation Incentive Program installation on a case-by-case basis using utilities' circuit data.

Results

TIAX analyzed 1,062 installations, amounting to 263.1 MW of installed capacity, that were interconnected on or before December 31, 2006. To date, Self-Generation Incentive Program projects have delivered more than 610,000 MWh[148] to California's electric grid. Past Self-Generation Incentive Program-funded projects have reduced GHG emissions by displacing grid electricity, using waste heat through cogeneration, and generating electricity with biogas.

The environmental analysis indicates that the self-generation installations yielded a net reduction in both particulate matter (PM2.5) and GHGs when compared to a baseline of natural gas fired combined cycle combustion turbine power plant (Table 6). However, the reductions are small and largely attributable to photovoltaic installations that are no longer eligible for the program. Furthermore, the program's installations have net emissions of air quality pollutants including VOC, NO_x, and CO. For the sake of comparison, California emits VOC, NO_x, and CO on a statewide basis at a rate of 2,300, 12,500, and 3,600 short tons *per day*, respectively.[149] Table 6 indicates that fuel source significantly affects air emissions.

According to Energy Commission estimates, as of 2004 the state was emitting approximately 500 million metric tons of carbon dioxide equivalents on an annual basis. The installed capacity of the Self-Generation Incentive Program is small; however, the environmental benefits do indicate that engine and turbine technologies operating with a clean or renewable fuel, particularly those in efficient combined heat and power (CHP) applications, can reduce air quality pollutants and GHGs.

Table 6. Environmental Impacts of the Self-Generation Incentive Program

	Air quality [a] (cumulative short tons)				Climate change (cumulative million metric tons)
Technology	VOC	NOx	PM2.5	CO	GHGs
Photovoltaics	-5	-21	-28	-287	-2.09
Internal combustion engine [NR]	7799	3654	-157	19443	1.64
Internal combustion engine [R]	-4	-25	-10	-103	-0.43
Microturbine [NR]	24	38	-16	-175	0.45
Microturbine [R]	-4	-25	-8	-85	-0.26
Fuel cell [NR]	-6	-152	-14	-34	-0.13
Fuel cell [R]	0	-5	-1	-1	-0.02
Gas turbine [NR]	13	778	-11	815	0.26
Wind turbine	0	0	0	-4	-0.03
Total	7817	4242	-245	19569	-0.62

NR: non-renewable fuel
R: Renewable fuel

Note: Positive values indicate a net increase in emissions, negative values indicate a net decrease in emissions. Criteria pollutant reductions of less than 0.05 short tons are reported as zero.

Source: TIAX, LLC

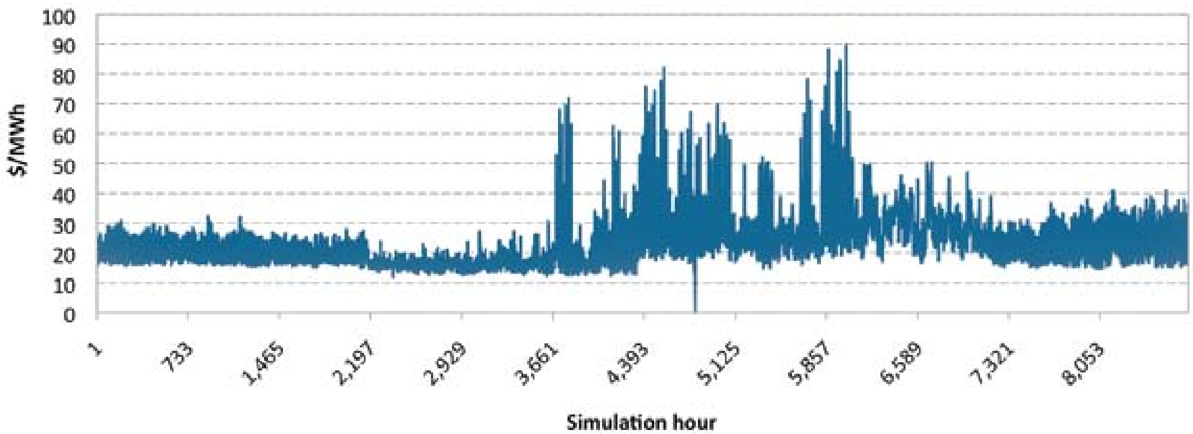
Table 7. Macroeconomic Impacts: Household Expenditures verses Self Generation Incentive Program Expenditures (per $100 million)

	Household	DG capital + O&M	% difference (DG/Household)
California Total Output	128.0	134.8	+5.3
California Total Value Added	75.8	65.6	-13.5
California Total Employment	938.7	588.8	-37.3
California Total Compensation	35.9	32.5	-9.4
California Compensation per FTE	38,251	55,271	+44.5

Note: all values reported in millions of 2006 dollars, except for total employment

Source: TIAX, LLC

Figure 2. Hourly Energy Price Spreads for Generators of the Self-Generation Incentive Program, 2009



Source: TIAX, LLC

The macroeconomic analysis indicates that Self-Generation Incentive Program expenditures resulted in an estimated $1.7 billion in total value added to the state, more than 15,000 full time equivalent jobs, and about $850 million in total compensation. On balance, the program resulted in an estimated $0.60 of output per dollar of project expenditure. Because incentives for the program are funded by ratepayers, it is important to compare the economic impacts of the program to the impacts of equivalent spending of household expenditure (Table 7). By comparison, the program results in slightly higher total output in California, and significantly higher compensation per full-time equivalent employment. However, the program spending has a lower total value added to California and lower total employment.

The grid impacts analysis focused on avoided energy costs, transmission and congestion savings, and distribution deferral savings. Rumla identified 94 buses to electrically anchor 94 self-generation clusters as miniature satellite generators. Note that the principle underlying this method is the geographic equivalency of two sources of energy: in the absence of differences due to transmission congestion and/or marginal losses, the market value of the electric commodity is the same, demonstrating an obvious prevalence of spatial price dispersion. The frequency of significant locational price variation among the clusters of self-generation is evident from Figure 2. The displayed dispersions indicate the prevalence of marginal losses and the frequency of transmission congestion. For example, there is a virtually ubiquitous price delta of $15-$20 per MWh. This gap indicates the presence of significant marginal losses.

Locational variation in prices means opportunities for cost effective investments in self-generation. For instance, if Location A is assigned a price of $70/MWh and Location B is given a price of $55/MWh, encouraging self generation investments at Location A is more effective than the other way around. Table 8 provides a hypothetical illustration of the value of commodity price differentiation for the Self-Generation Incentive Program. For example, depending on the discount rate used, a $20/MWh commodity price gap could translate into a benefit of $1.2 to $3.5 per Watt. This locational advantage has the potential to offset most of the program incentives.

Because distribution engineers have many options for managing heavily loaded circuits and transformers, and since customer generation may not be available when the system needs it, the positive results for distribution deferral are presented as potential cases of upgrade deferral savings. The analysis demonstrated that the Self-Generation Incentive Program, even without targeting the investments, did yield distribu-

Table 8. Geographic Energy Commodity Price Differentiation for the Self Generation Incentive Program

SGIP Price Differential Duration (% of Year)

SGIP Price Differential ($/MWh)	10%				20%			
	$/W/ yr	$/W (NPV) 2.8%	8%	15%	$/W/ yr	$/W (NPV) 2.8%	8%	15%
10	$0.88	$0.18	$0.10	$0.06	$1.75	$0.35	$0.20	$0.12
20	$1.75	$0.35	$0.20	$0.12	$3.50	$0.70	$0.39	$0.23
50	$4.38	$0.88	$0.40	$0.29	$8.76	$1.76	$0.99	$0.58
100	$8.76	$1.76	$0.99	$0.58	$17.52	$3.52	$1.97	$1.15

SGIP Price Differential ($/MWh)	50%				100%			
	$/W/ yr	$/W (NPV) 2.8%	8%	15%	$/W/ yr	$/W (NPV) 2.8%	8%	15%
10	$4.38	$0.88	$0.49	$0.29	$8.76	$1.76	$0.99	$0.58
20	$8.76	$1.76	$0.99	$0.58	$17.52	$3.52	$1.97	$1.15
50	$21.90	$4.41	$2.47	$1.44	$43.80	$8.81	$4.93	$2.88
100	$43.80	$8.81	$4.93	$2.88	$87.60	$17.62	$9.86	$5.75

Source: TIAX, LLC

tion deferral savings (Table 9), with 17 percent, 9 percent, and 20 percent of installations in the service areas of PG&E, SCE, and SDG&E, respectively, having the potential to defer distribution upgrade investments. The percentage of installations capable of deferring distribution investments could be increased significantly with a more targeted approach.

Limiting incentives to fuel cells and wind technologies has severely restricted the development, benefits, and use of the Self-Generation Incentive Program. The Energy Commission believes that ultraclean and low-emission distributed generation technologies using non-renewable and renewable fuels should be reinstated, especially those technologies used in CHP applications. Furthermore, depending on the reading of the original objectives of the program, which call for "incentives for distributed generation to be paid for enhancing reliability" and "differential incentives for renewable or super clean distributed generation resources," then even generation technologies that do not run on a renewable fuel may enhance reliability and add significant value to the program participant, the ratepayer, and society as a whole.

The *2007 IEPR* noted the value of CHP systems in reducing carbon emissions because of their efficient use of fossil fuel through the capture of waste heat for other uses (such as power plant cooling).[150] Fuel sources for CHP systems include natural gas, biomass, coal, biogas, or fuel oil, and CHP currently does not qualify for Self-Generation Incentive Program fund-

Table 9. Summary Results for Potential Distribution Upgrade Deferrals

	PGE	SCE	SDGE
Positive Cases	92	38	27
% of Total Candidate Cases	29%	13%	39%
% of Total # of All Cases	17%	4%	20%
Total kW of Positive Cases	15,748	9,700	5,157
% of All Candidate Cases Kw	35%	14%	45%
% of Total kW of All Cases	12%	4%	13%
Candidate Cases	318	297	70
Total kW of Candidate Cases	44,892	71,711	11,507
Total Number of Records	552	897	134
Total Number of kW in Records	132,185	253,797	39,882

Source: TIAX, LLC

ing. The Energy Commission believes that distributed generation, including CHP, continues to show value for customers seeking solutions in a fluctuating energy climate.

Recommendations

Eligibility

Eligibility for the Self-Generation Incentive Program should be based on the overall efficiency and performance of systems, regardless of fuel type.

Eligible Fuels and Technologies

Currently, renewable fuels are eligible for the Self-Generation Incentive Program only if used with a fuel cell system. The CPUC should consider re-instituting formerly eligible engine and turbine technologies that operate on non-renewable fuels, landfill gas, digester gas from dairy waste or wastewater treatment processes, or biodiesel.

Energy Storage

The CPUC should consider providing self-generation incentives for energy storage. Energy storage technologies can provide capacity benefits and should therefore be eligible for the program. Energy storage can be coupled with generation or installed as stand-alone systems. The U.S. Department of Energy has funded studies showing the benefits of hybrid photovoltaic-battery storage and fuel cell-battery storage systems in certain locations.

Transmission and Distribution Benefits

Locational Benefits

The CPUC should require that the IOUs meet a portion of their distribution system upgrades by procuring distributed generation or CHP in areas that provide locational benefits to the distribution system. The CPUC and Energy Commission should work collaboratively with the IOUs to identify locational benefits.

Distributed Generation

A 2007 study by the DOE and a forthcoming study with SCE and Navigant Consulting[151] find that distributed generation can have location-specific grid benefits when sized correctly. The transmission and distribution costs avoided by such systems can be quantified with highly accurate customer and utility data. The Energy Commission should work with the CPUC to define additional studies to assess the performance of distributed generation in circuit areas providing locational benefits.

Combined Heat and Power Systems

Previous IEPRs have recognized the value of distributed generation, particularly CHP, by encouraging policies that support market penetration in California. The CPUC has adopted some policies that permit the use of distributed generation, but economic barriers and the lack of incentives continue to hamper its development. The Energy Commission reiterates recommendations made in previous IEPRs that the CPUC should:

- Develop tariff structures that make distributed generation and CHP projects "cost and revenue neutral" while granting credit to owners for providing system benefits, such as reduced congestion.
- Eliminate all non-bypassable charges for distributed generation and CHP regardless of interconnection voltage and standby reservation charges.
- Work collaboratively with the Energy Commission to develop a method that estimates the value of Self-Generation Incentive Program-funded projects, as well as distributed generation costs and benefits.

Revise Program Incentive Structure

The Self-Generation Incentive Program should evolve to better support state policy and energy goals for distributed generation technologies. Since the program's creation in 2001, the state has enacted new legislation that increases incentives for distributed generation development in California. These bills include Assembly Bill 32 (Núñez, Chapter 488, Statutes of 2006), which sets GHG emission reduction goals, and Assembly Bill 1613 (Blakeslee, Chapter 713, Statutes of 2007), which requires electrical corporations to purchase excess electricity generated by CHP and provides a pay-as-you-save pilot program to finance the upfront costs of CHP for nonprofit entities. AB 1613 also requires the Energy Commission to develop CHP regulations for system size, efficiency standards, cost-effectiveness, technical feasibility, and environmental benefits by January 1, 2010. Finally, Senate Bill 1 (Murray, Chapter 132, Statutes of 2006) implemented incentive programs for consumers to install solar distributed generation systems. Therefore, the CPUC should develop an incentive structure for Self-Generation Incentive Program projects that meet specific targets for environmental, transmission and distribution, and economic benefits.

Endnotes

135 TIAX, LLC, *Cost Benefit Analysis of the Self Generation Incentive Program*, consultant report, October 2008, http://www.energy.ca.gov/2008publications/CEC-300-2008-010/CEC-300-2008-010-D.PDF.

136 For more information on the early implementation of the Self-Generation Incentive Program, see CPUC Decision D.01-03-073.

137 http://www.cpuc.ca.gov/PUC/energy/sgip/051005_sgip.htm.

138 California Public Utilities Commission Decision 01-03-073, http://docs.cpuc.ca.gov/WORD_PDF/FINAL_DECISION/6083.PDF, p. 7, 11–13, and 49–50.

139 For more information regarding the California Solar Initiative, see CPUC Decision 06-01-024. Incentives for the use of solar in new home construction is available through the California Energy Commission's New Solar Homes Partnership. Publicly owned utilities also offer solar incentive programs. See http://www.gosolarcalifornia.org/csi/index.html.

140 CPUC Self-Generation Incentive Program, *Sixth Year Impact Evaluation Final Report*, August 30, 2007.

141 Note that the benefits and costs listed in Table 5 were not all quantified or determined in TIAX's report; however, they were considered and discussed as appropriate.

142 Note that the in-state emission factors account for pollutant offsets that are required for both NOx and PM.

143 This approach was used by TIAX in a previous report prepared for the California Energy Commission: *Full Fuel Cycle Assessment, Well to Tank Energy Inputs, Emissions, and Water Impacts*, Consultant Report, TIAX LLC, CEC-600-2007-003, June 2007. Note that electricity is considered an alternative transportation fuel.

144 For further discussion of damage costs, see: U.S. EPA, Office of Air Quality Planning and Standards, Economic Analysis Resource Document, April 1999, http://www.epa.gov/ttnecas1/econdata/6807-305.pdf.

145 Tol, RSJ. The Marginal Damage Costs of Carbon Dioxide Emissions: An Assessment of the Uncertainties. Energy Policy, 33 (2005), 2064-2074.

146 California Energy Commission, 2007 Integrated Energy Policy Report, p. 67, Footnote 66, based on Intergovernmental Panel on Climate Change, 2007, Climate Change 2007: Mitigation. Contribution of Working Group III to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change. Metz, B., O. R. Davidson, P. R. Bosch, R. Dave, and L. A. Meyer (eds). Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA. http://www.ipcc.ch/pdf/assessment-report/ar4/wg3/ar4-wg3-chapter3.pdf, p. 198, Table 3.5 and p. 206.

147 Impact Analysis for PLANning (IMPLAN). For more information regarding this model, see http://www.economics.nrcs.usda.gov/technical/implan/implan-model.html and http://www.implan.com/.

148 Data from 2006

149 According the California Air Resources Board, 2006 Estimated Annual Average Emissions, Almanac Emission Projection Data, http://www.arb.ca.gov/ei/emissiondata.htm

150 California Energy Commission, An Assessment of California CHP Market and Policy Options for Increased Penetration, 2005, CEC -500-2005-173.

151 Prepared for the Department of Energy Office of Electricity Delivery and Energy Reliability, *Value of Distributed Energy Resources in Distribution Infrastructure Phase II – Operational Assessment*, expected to be published November 2008.

Chapter 6

State Progress on Key Integrated Energy Policy Report Recommendations

The *Integrated Energy Policy Report (IEPR)* is a real-time, public forum for continuing dialog about California's energy policies. This chapter examines the progress the state has made in addressing key recommendations made in past *IEPRs* (shown in italics) on electricity and procurement issues, energy efficiency requirements, demand response, load management standards, renewable energy issues and goals, distribution system and combined heat and power, nuclear power, transmission, natural gas, transportation, petroleum infrastructure, land use, and water/energy.

Electricity and Procurement

Beginning with the 2006 procurement proceeding, the California Public Utilities Commission (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.

(2005 IEPR)

Statewide Progress on Electricity/Procurement Recommendations

SUBSTANTIAL

Develop common portfolio analytic methodology to influence IOU long-term procurement plans

ON TRACK

Focus on portfolio analysis of future resource fuel types

IMPROVEMENT NEEDED

Statewide Progress on Electricity/Procurement Issues

The CPUC has only partially implemented these recommendations. In response to the *2005 IEPR* and concerns previously expressed by the Legislature in Senate Bill 1488 (Bowen, Chapter 690, Statutes of 2004), the CPUC opened a proceeding in 2006[152] to discuss issues related to confidentiality and utility procurement. In June 2006, the CPUC required the utilities to provide the public with detailed descriptions of utility least-cost, best-fit criteria used to select resources in the planning and procurement process.[153] However, the CPUC continued to hold a substantial amount of procurement-related materials confidential.

Since 2006, the CPUC has increased access to procurement-related information. Most notably, in D.07-12-052, the CPUC required discussions on resources procured by the investor-owned utilities (IOUs) to meet system needs (as opposed to bundled customer needs) to be open to electric service providers, who will be liable for a share of the costs. The decision also required greater transparency in Independent Evaluator[154] assessments and public notices about procurement review group (PRG) meetings and agendas.

The CPUC has decided to continue using the PRGs. The CPUC testified at an IEPR workshop on July 14, 2008, that it, the IOUs, and ratepayer advocates believe the PRGs are a necessary tool in allowing discovery in a timely fashion while preserving the confidentiality of market-sensitive information.

> ***The Energy Commission should ensure that portfolio analysis of future resource fuel types is a primary focus of the next Energy Report cycle.***
>
> **2005 IEPR**

The state has made some progress on this recommendation. As part of the *2007 IEPR*, Energy Commission staff investigated state-of-the-art utility portfolio-based planning and analysis. Staff examined how utilities in the western United States incorporate uncertainties like fuel price and carbon risk into their planning processes, described the current planning processes of the California IOUs, and evaluated several portfolio-based planning processes.

The Energy Commission published its findings in *Portfolio Analysis and its Potential Application to Utility Long-Term Planning*, which provided background material for workshops in June and July 2007. Based on the information presented, the *2007 IEPR* recommended developing a common portfolio method to influence the long-term procurement plans filed by the IOUs. As noted below, the CPUC's 2008 Long-Term Procurement Proceeding is focusing on the information needed from the IOUs to facilitate portfolio-based analysis as well as the analysis itself.[155]

> ***A common portfolio analytic methodology [be developed] to clearly influence the long-term procurement plans filed by the investor-owned utilities.***
>
> **2007 IEPR**

The state has made substantial progress on this recommendation. The Energy Commission staff has been collaborating with the CPUC in Phase I of the 2008 Long-Term Procurement Proceeding. This phase is developing a set of standard input assumptions and sensitivities, scenarios, and reporting formats and metrics for the 10-year plans that the IOUs submit to the CPUC every two years. The goal is to evaluate a number of potential resource plans under many and varied futures, including different assumptions about electricity demand, fuel prices, carbon costs, and so on, to adequately incorporate risk into the portfolio selection process.

Increased attention to the shortcomings of the 2006 procurement plans, in combination with recent volatility of major cost drivers and reactions to that volatility, has contributed to the emphasis on assessing risk in evaluating the 2010 procurement plans. Many decisions remain about sensitivities and scenarios to be modeled in the development of the 2010 plans, but the Energy Commission believes that the sensitivity values and scenarios selected for analysis will be diverse enough to allow regulators and stakeholders to assess the cost and risk tradeoffs in the IOUs' resource planning.

Energy Efficiency

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.

2005 IEPR

The state has made substantial progress on this recommendation. Senate Bill 1037 (Kehoe, Chapter 366, Statutes of 2005) required the publicly owned utilities, for the first time, to describe their energy efficiency programs, expenditures, and expected and actual energy savings results to their customers and the Energy Commission each year. Publicly owned utilities voluntarily provided the first of these annual reports in December 2006. The Energy Commission updated its data collection regulations in 2006 and established March 15 as the submittal date for the annual reports. The publicly owned utilities use methods similar to those used by the investor-owned utilities to report energy efficiency expenditures and savings. A CPUC consultant developed a standardized quantification method, the *Energy Efficiency Reporting Tool*, to estimate energy and peak reductions from efficiency programs.

Statewide Progress on Energy Efficiency Recommendations

SUBSTANTIAL

Establish reporting requirements for publicly owned utilities

Adopt statewide efficiency targets for 2016 equal to 100 percent of economic potential

Also in 2006, Assembly Bill 2021 (Levine, Chapter 734, Statutes of 2006) required publicly owned utilities to develop efficiency potential and targets in cooperation with the Energy Commission, which were adopted by the Energy Commission in December 2007. Staff is using the annual savings targets to keep track of energy efficiency progress of the publicly owned utilities and of all utilities toward meeting statewide goals set by the Energy Commission and CPUC under AB 2021. In March 2008, the California Municipal Utilities Association provided the Energy Commission with its first progress report since the energy efficiency targets were adopted in December 2007. Public utility spending on energy efficiency averages around 1 percent of revenue.

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

2007 IEPR

The state has made substantial progress on this recommendation. AB 2021 required the Energy Commission and the CPUC to develop statewide estimates of all cost-effective energy efficiency and demand reduction potential and savings targets for utilities (both publicly and investor-owned) for a 10-year period.

During 2007, the Energy Commission and the CPUC, together with the utilities, collaborated to fulfill the mandates of AB 2021. In the resulting report,[156] the Energy Commission analyzed data on energy efficiency potential submitted by the publicly owned utilities and by the CPUC for the investor-owned utilities. The Energy Commission adopted statewide goals equivalent to all cost-effective efficiency potential in December 2007. While these goals are higher than those proposed by the utilities, they were set with the understanding that California's utilities will cooperate in the future with private and public entities to maximize savings and fulfill 100 percent of the economic potential.

Demand Response

The CPUC and the Energy Commission must vigorously pursue actions to ensure that the state's demand response goals are met.

2005 IEPR

The state has made little progress on this recommendation. The *2005 IEPR* called for a 5 percent peak reduction from price-responsive demand response in the IOU service territories by 2007. In a CPUC proceeding concerning dynamic rates, commercial and industrial customers and trade groups resisted CPUC adoption of default rates. Rather than adopt rates that did not meet state policy goals, the CPUC decided to reintroduce default critical peak pricing (CPP) rates in the next general rate case cycle.

Another delay in meeting the 5 percent goal was the need for interval or advanced meters for customers with loads below 200 kilowatts. However, in 2002, the CPUC initiated a rulemaking to develop the analysis frameworks for the three major utilities' filings of the Advanced Metering Infrastructure (AMI) business case. To date, the CPUC has approved $4 billion of ratepayer funding to deploy a total 17 million of AMI meters over a 5-year period (2007-2012) in PG&E's, SCE's, and SDG&E's service territories (11.8 million electric meters and 5.1 million gas meters). Currently, about 700,000 AMI meters (electric and gas) have been installed. The CPUC is committed to meeting the state's 5 percent demand response goal, and the most recent timetable for the roll out of advanced meters shows installation being completed by 2012 for all three IOUs.

The CPUC has set timetables to introduce default CPP rates for large commercial and industrial customers with loads 20 kilowatts and above. In addition to these dynamic pricing programs, IOUs have also increased enrollments in incentive-based demand response programs. The upper estimate of enrolled MWs increased from 850 MWs in July 2005 to 1,136 MWs in April 2008, approximately 2.3 percent of system peak in 2007. However, this increase in non-emergency demand response still falls well short of the 5 percent goal.

Statewide Progress on Demand Response Recommendations

ON TRACK

Develop and implement dynamic rates for customers with advanced metering

Develop better understanding of publicly owned demand response efforts and goals similar to those of investor-owned utilities

Initiate formal rulemaking process for adoption of load management standards

IMPROVEMENT NEEDED

Pursue actions to ensure demand response goals are met

The CPUC needs to develop and implement dynamic rates for all customers with advanced metering.

2005 IEPR

The state has made substantial progress on this recommendation. In May 2008, SDG&E implemented default CPP rates for customers with loads of 20 kW and above. These rates offer an opt-out provision as well as an option to pay a capacity reservation charge to avoid high prices on a specified amount of load. In July 2008, the CPUC set a timetable for PG&E to develop a new "dynamic pricing" rate structure. This dynamic pricing decision can also be applied to the next general rate cases of SDG&E and SCE. SDG&E has also implemented a peak-time rebate tariff for commercial and residential customers, which provides a minimum credit of $0.75/kWh for each kWh of reduced consumption during a rebate event period. PG&E and SCE are also proposing peak-time rebate tariffs.

By the end of 2006, the Energy Commission should work closely with publicly owned utilities to better understand their demand response efforts, and develop goals similar to those required of investor-owned utilities.

2005 IEPR

The state has made progress on this recommendation. The Energy Commission did not begin this process before the end of 2006 as planned; however, in 2007 the Energy Commission held two workshops on demand response and the agency's load management authority, where publicly owned utilities and IOUs provided a status of their demand response efforts in California. These workshops, along with other conferences, meetings, and working groups held in 2006 and 2007, provided a venue for increased dialog, resulting in a better understanding of publicly owned utility demand response activities. Additional dialogue with the POUs has occurred in 2008 through the Load Management Standards Proceeding.

Initiate a formal rulemaking process involving the CPUC and California ISO in 2008 to pursue the adoption of load management standards under the Energy Commission's existing authority.

2007 IEPR

The state is on track with this recommendation. In January 2008, the Energy Commission approved an Order Instituting Informational and Rulemaking Proceeding on demand response equipment, rates, and protocols. The Energy Commission's Efficiency Committee hosted six workshops in Sacramento between March and July 2008 at which the CPUC, California ISO, all major utilities, and numerous other stakeholders participated.

Energy Commission staff is preparing a series of load management standards recommendations for public review and will prepare a proposed package of load management standards before the end of 2008 for initial review by the Office of Administrative Law, with adoption of the standards anticipated by spring of 2009.

Renewable Energy

The Legislature should apply the same RPS targets, timelines, and eligibility standards to publicly owned utilities that it has established for IOUs. Consistent with the Energy Commission's 2004 recommendation, the state should establish an exemption process for small publicly owned utilities to avoid the overly burdensome requirements that compliance with RPS goals may present.

2005 IEPR

The state has made slow progress on this recommendation. Currently, the RPS standards for IOUs do not apply to publicly owned utilities, but do require them to implement standards that encourage renewable resources. Some publicly owned utilities have recently adopted RPS targets or timeframes at least as aggressive as those for the retail sellers. For example, Los

Angeles Department of Water and Power, Riverside, Palo Alto, and Azusa have advanced their 20 percent renewable energy targets to 2010 or sooner.

Senate Bill 107 (Simitian, Chapter 464, Statutes of 2006) requires publicly owned utilities to annually report their status in implementing an RPS program and progress toward attaining RPS targets to their customers and to the Energy Commission. The law does not provide an exemption process for smaller publicly owned utilities in complying with RPS requirements.

The Energy Commission anticipates publishing a consultant report, *The Progress of California's Publicly Owned Utilities in Meeting the State's Renewables Portfolio Standard*, in fall 2008 based on data from the publicly owned utilities for 2003 through 2006. The report compares RPS targets, renewable deliveries, and renewables procurement efforts to those of the state's three major IOUs.

> *The Legislature should authorize the CPUC to allow limited use of renewable energy certificates for RPS compliance to facilitate uniform participation of all load serving entities, with the associated electricity sold into the California ISO real time market or bilaterally to retail sellers.*
>
> **2005 IEPR**

The state is making slow progress on this recommendation. Currently renewable energy credits (RECs) and the associated electricity generation must be procured as a bundled product to satisfy California's annual RPS targets. In 2006, SB 107 conditionally authorized the CPUC to allow unbundled RECs to satisfy RPS requirements once the CPUC and Energy Commission confirm that the RPS tracking system meets SB 107 requirements. SB 107 also allows the CPUC to limit the amount of unbundled (or tradable) RECs procured by a retail seller to meet its RPS requirements.

Statewide Progress on Renewable Energy Recommendations

ON TRACK

Begin collaborative process to develop feed-in tariffs for larger projects

Begin collaborative process to develop feed-in tariffs for larger projects

IMPROVEMENT NEEDED

Apply same RPS targets, timelines, and eligibility to publicly owned utilities as for investor-owned utilities

Allow limited use of renewable energy certificates for RPS compliance

Maintain penalties for RPS non-compliance and eliminate penalty cap

Implement feed-in tariff for RPS-eligible renewable up to 20 MW

In September 2007, the CPUC released a straw proposal of compliance rules for tradable RECs. The CPUC followed with a pre-hearing conference in December 2007. In July 2008, the CPUC issued a draft Proposed Decision on the definition and attributes of a REC. In addition, the Energy Commission and the CPUC developed the *Joint Commission Staff Report on Tracking System Operational Determination*. The Energy Commission released the first draft and held a staff workshop in March 2008. The CPUC released a revised draft in September 2008, with both commissions planning to adopt the final report in December 2008.

It is anticipated that once the CPUC adopts a final REC definition and both agencies adopt the *Joint Agency Staff Report*, the CPUC will continue its proceeding to consider authorizing retail sellers to use unbundled RECs for RPS compliance.

> ***The state should maintain the per-kilowatt-hour penalties for investor-owned utility non-compliance with Renewables Portfolio Standard goals consistent with California Public Utilities Decision 06-05-039, and eliminate the current per-utility cap on those penalties.***
>
> **2006 IEPR Update**

The state has maintained the authority to apply penalties of 5 cents per kilowatt-hour for IOU non-compliance with RPS goals, but has not made progress in eliminating the $25 million per-utility penalty cap established in the CPUC Decision 03-06-071.

The state has expanded the use of flexible compliance rules that allow retail sellers to carry a deficit in meeting their RPS targets. SB 107 modified the flexible compliance rules to include insufficient transmission, and in February 2008, the CPUC conditionally accepted the 2008 RPS Procurement Plans by stating that a deficit may be excused for up to three years if it results from insufficient transmission.[157]

SB 107 also applied the flexible compliance rules to all years, rather than up to 2009, and CPUC Decision 08-02-008 effectively extends the date for applying penalties for non-compliance beyond 2010 to 2013.

> ***The CPUC should immediately implement a feed-in tariff, set initially at the market price referent, for all RPS-eligible renewables up to 20 megawatts in size.***
>
> **2007 IEPR**

The state has made slow progress on this recommendation. In July 2007, the CPUC adopted what are essentially feed-in tariffs as well as standard contracts for up to 250 MW of RPS-eligible renewable energy from water, wastewater, and other customers sold to electrical corporations at the market price referent.[158] In Decision 07-07-027, the CPUC expanded this program to include SCE and PG&E customers other than water/wastewater and set a limit of 228.4 MW for this expansion, with feed-in tariffs available under this decision as of February 14, 2008.[159] On September 18, 2008, the CPUC issued Decision 08-09-033,[160] which expanded the program to include all SDG&E customers as well. As of October 2008, PG&E has signed contracts with 12 companies for a little over 9.5 MW. Four of the projects are hydro, one is wind, and the remaining seven are landfill gas. SDG&E has not yet signed any contracts.

In addition, through 2008 or until 250 MW are contracted, SCE is offering standard contracts for biogas and biomass generators not larger than 20 MW. The contracts are priced at the 2006 market price referent. As of October 2008, SCE has signed four contracts, all in the 1-5 MW category. Two have received CPUC approval and the other two are pending. All four projects are landfill gas and cumulatively equal 11 MW. Also, three landfill gas projects totaling 25 MW and one anaerobic digester project for 5 MW are under negotiation. SCE is currently restructuring their biomass program and will be offering two standard contracts for 1.5-5 MW and 5-20 MW beginning in January 2009.

Also, "[e]lectrical corporations are required to have a tariff/standard contract for the purchase of electricity from certain customers up to 20 MW (Public Utilities Code section 2840 et seq.; Assembly Bill 1613, effective January 1, 2008, requiring an electrical corporation to file a tariff/standard contract for the purchase of electricity delivered by a combined heat and power system up to 20 MW)."[161] Implementation of this requirement is being undertaken through CPUC Rulemaking 08-08-009.

> ***The Energy Commission should begin a collaborative process with the CPUC to develop feed-in tariffs for larger projects.***
>
> **2007 IEPR**

The state is making progress on this recommendation. The Energy Commission is developing a report that addresses the issues and options regarding feed-in tariffs for projects greater than 20 MW. In June 2008, the Energy Commission held a staff workshop on its draft consultant report, *Exploring Feed-In Tariffs for California: Feed-In Tariff Design and Implementation Issues and Options.*[162] A second staff workshop took place on October 1, 2008, and will be followed by a committee workshop on November 20, 2008. The CPUC is participating in the workshops and monitoring progress on the report. The final report is anticipated in early 2009.

> ***The Energy Commission and the CPUC should work together to establish an appropriate feed-in tariff for excess generation from customer-owned solar installations based upon the RPS market price referent and time-of-delivery adjustment.***
>
> **2007 IEPR**

The state is making progress on this recommendation. CPUC Decision 07-07-027 implemented feed-in tariffs for RPS-eligible renewable energy generated by customers up to 1.5 MW in size, including those using distributed generation solar installations. Participants may sell all their RPS-eligible renewable energy or just the excess energy not used on site. The price for customer generation of RPS-eligible renewable energy is set at the market price referent used for the RPS and includes a time-of-delivery adjustment.

Electric Distribution System and Combined Heat and Power

> ***The CPUC's self-generation program incentives should be based upon overall efficiency and performance of systems, regardless of fuel type.***
>
> **2007 IEPR**

The state has not implemented this recommendation. The Legislature introduced Senate Bill 1012 (Kehoe) and Assembly Bill 1064 (Lieber and Fuentes) that would have extended self-generation incentives based on overall efficiency and performance, regardless of fuel type, but neither bill passed during the 2007-2008 session.

> ***The CPUC should continue the work of the "Rule 21" industry/utility collaborative working group to refine interconnection standards, provide third party resolution of interconnection issues, and streamline permitting.***
>
> **2007 IEPR**

The state has made substantial progress on this recommendation by refining interconnection standards through the efforts of the Rule 21 Interconnection Working Group. In June 2008, the Energy Commission transferred leadership of the working group to the CPUC, which is working with stakeholders to get agreement on what additional issues (as identified by the Energy Commission) they should address. New issues may be referred to and discussed in existing and new distributed generation proceedings at the CPUC. The working group will carry on the collaborative process and mediation of interconnection issues as established by the Energy Commission. In the future, the Energy Commission will continue to provide support for additional research initiatives that the group identifies in the area of standards and smart grid.

> ***The CPUC should develop a distributed generation portfolio standard, including combined heat and power regardless of size or interconnection voltage, for electric utility procurement plans. Alternatively, the utilities could be required to treat distributed generation and combined heat and power, regardless of size or interconnection voltage, like efficiency programs.***
>
> **2007 IEPR**

The state is making progress on this recommendation. The Legislature enacted Assembly Bill 1613 (Blakeslee, Chapter 713, Statutes of 2007), which requires utilities to include export power from new combined heat and power (CHP) projects of 20 MW

Statewide Progress on Electric Distribution System and Combined Heat and Power Recommendations

SUBSTANTIAL

Continue work of Rule 21 collaborative working group on interconnection issues

ON TRACK

Develop distributed generation portfolio standard

IMPROVEMENT NEEDED

Self-Generation Incentive Program incentives should be based on overall efficiency and performance

Adopt revenue neutral programs to enable high efficiency combined heat and power to export power to utilities

and under in their long-term procurement plans. The CPUC must decide whether to limit the amount of exports the IOUs are required to purchase. However, the Energy Commission believes the state should implement AB 1613 and evaluate results before these limits are set. CHP developers face significant cost risks that include natural gas price volatility and increasing costs associated with equipment purchases. The CPUC should develop mechanisms to address these critical risk factors.

To meet the requirements of AB 1613, the Energy Commission will institute a rulemaking and establish operational requirements for qualified CHP facilities. The Energy Commission will also participate in a CHP Order Instituting Rulemaking (OIR) to be initiated by the CPUC to help resolve critical issues that hinder development of clean and efficient CHP projects in California. During this proceeding, the participants will discuss the issue of CHP projects that are 20 MW or larger.

The CPUC should adopt revenue-neutral programs that would enable high-efficiency combined heat and power to more easily export power to interconnected utilities.

2007 IEPR

These programs should not lead to additional non-bypassable charges and could include:

Providing the option for utilities to procure natural gas for combined heat and power plants at customer sites on the same basis they do for central power plants.

The state has made slow progress on this part of the recommendation. Regarding fuel costs, CHP customers or developers must absorb natural gas price swings immediately. Therefore, the success of AB 1613 depends on linking the fuel component of the price paid for excess energy to the market price of natural gas to allow CHP customers or developers timely recovery of their fuel costs. This issue and possible solutions will be discussed in the AB 1613 proceeding and in a subsequent CHP OIR.

Counting combined heat and power plant output toward energy efficiency goals for utilities.

The state has made slow progress on this part of the recommendation. AB 1613 and the CHP OIR will provide forums for discussing how to accomplish aligning the interests of CHP customer-generators, the utilities, and ratepayers similar to the way the state has aligned the interests of providers, utilities, and ratepayers in the area of energy efficiency. California's current energy efficiency programs should provide models and strategies that will support CHP development and goals.

Providing a portfolio standard with steadily increasing requirements for combined heat and power plant generation.

The state has made slow progress on this part of the recommendation. AB 1613 directs the CPUC to require the IOUs to establish tariffs and to require that electrical corporations purchase excess electricity from CHP systems (20 MW and under) that meet the efficiency standards adopted by the Energy Commission. This is a good first step but does not establish a portfolio standard that will include both large and small CHP.

The California Air Resources Board's (ARB) Climate Change Draft Scoping Plan estimates that CHP will substantially contribute to reducing greenhouse gas emissions. Increasing the deployment of CHP to meet these goals will require coordination between the Energy Commission, CPUC, and ARB to assure that barriers to development of clean and efficient CHP facilities in California will be addressed. Options to encourage widespread development of CHP systems in the Scoping Plan include a CHP portfolio standard, as well as utility-provided incentive payments, transmission and distribution payments, and feed-in tariffs. The ARB has formed a new CHP working group to explore these and other options. As a member of this group, the Energy Commission will work with all parties to support this goal.

Nuclear Power

The state should evaluate the long-term implications of the continuing accumulation of spent nuclear fuel at California's nuclear plants.

2005 IEPR

The state has made substantial progress on this recommendation. In 2007, the Energy Commission published the contractor report *Nuclear Power in California: 2007 Status Report*, which provided a status on nuclear storage issues. In addition, Assembly Bill 1632 (Blakeslee, Chapter 722, Statutes of 2006) requires the Energy Commission to assess the costs and impacts from nuclear waste accumulating at California's nuclear power plants. To meet these requirements, the Energy Commission hired a technical consultant to conduct this assessment, which was completed in September 2008. Following a public workshop on the draft report and consideration of public comments, the Energy Commission will prepare the *AB 1632 Committee Report* for adoption in November 2008.

Statewide Progress on Nuclear Power Recommendations

SUBSTANTIAL

Evaluate long-term implications of continuing accumulation of spent nuclear fuel

ON TRACK

Take an active role in Yucca Mountain licensing proceeding

To ensure that California's interests are protected, the state should take an active role in Yucca Mountain licensing proceeding and challenge the Department of Energy's inadequate response to potential impacts previously identified during the environmental impact statement and review process.

2007 IEPR

The state has made progress on this recommendation. The California Attorney General's Office and the Energy Commission have joined together in representing California in the U.S. Nuclear Regulatory Commission's (NRC) proceeding to review the Department of Energy's license application for the proposed Yucca Mountain repository in Nevada. The Energy Commission has established California's Web link whereby the state's documents are posted on the NRC's License Support Network.[163] The Energy Commission also co-chairs the Western Interstate

Energy Board (WIEB) High-Level Radioactive Waste Committee and participates on the Western Governors' Association (WGA) Waste Isolation Pilot Plant Advisory Group to continue working with other states and federal agencies in preparing for federal nuclear waste shipments.

The Energy Commission also coordinates a California Nuclear Transport Working Group to prepare for federal nuclear waste shipments in California and participates on the Department of Energy's Transportation External Coordination Group, which coordinates federal, state, industry and Indian tribe preparation for federal nuclear waste shipments. The Energy Commission will continue to participate in the state regional group planning activities for nuclear waste shipments through the WIEB and WGA activities.

Transmission

> *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.*
>
> **2005 IEPR**

The state has not implemented this recommendation. Although the CPUC has issued directives to streamline the permitting process and facilitate more efficient review of transmission projects, these internal changes have yet to result in timely project decisions.

The *2007 Strategic Transmission Investment Plan* recommended 10 specific near-term transmission projects that improve system reliability, reduce congestion, and/or interconnect renewable resources.[164] The status of those projects under the permitting jurisdiction of the CPUC is as follows:

- Phase I of the Tehachapi Transmission Plan consists of three segments. Segment 1 (Antelope-Pardee 500 kV Transmission Project) received unanimous Certificate of Public Convenience and Necessity (CPCN) approval on March 1, 2007. The United States Forest Service issued a Record of Decision on August 21, 2007, selecting its preferred alternative route and authorizing a 50-year special use permit for the project across Forest Service lands. Segments 2 (Antelope-Vincent 500 kV) and 3 (Antelope-Tehachapi 500 kV and 220 kV) received unanimous CPCN approval on March 15, 2007.

- SCE applied for a CPCN for Tehachapi Segments 4-11 on June 30, 2007. SCE anticipates project approval in early 2009, various segments under construction by 2011, and all segments completed by the end of 2013.

- The CPCN for the Palo Verde – Devers No. 2 500 kV line has been approved by the CPUC but the Arizona Corporation Commission (ACC) has denied permits for the Arizona portion of the project. As a result, SCE has requested approval from the CPUC to begin construction of the California-only portions of the project. In addition, SCE is pursuing two approaches for approval of the Arizona portions of the project, including a new project filing with the ACC and initiation of the prefiling process with the Federal Energy Regulatory Commission.

- SDG&E initially applied for a CPCN for the Sunrise Powerlink Project on December 14, 2005 and submitted an amended application on August 4, 2006. The CPUC and Bureau of Land Management (BLM) issued a Draft Environmental Impact Report (EIR)/Environmental Impact Statement (EIS) on January 3, 2008. A recirculated Draft EIR/EIS was released on July 11, 2008. It is expected that the CPUC will issue a decision by the end of 2008.

The Energy Commission recommends that a comprehensive transmission planning process is developed that includes the California ISO, the CPUC, other key state and federal agencies, local and regional planning agencies, IOUs and publicly owned utilities, generation owners and developers, and other interest groups to achieve statewide policy objectives.

2005 IEPR

The state has made substantial progress on this recommendation. In late 2005, the Energy Commission began working with the CPUC and the California ISO to better coordinate transmission and generation planning and procurement. In 2006, the Energy Commission and California ISO collaboratively developed a single transmission planning process to coordinate the Energy Commission's IEPR and Strategic Transmission Investment Plan proceedings with the California ISO's new grid planning process. As a result, the Energy Commission provides the IEPR's electricity load forecast and other planning assumptions to the California ISO for its analyses of transmission path upgrades and specific projects.

Lack of transmission has been identified as one of the primary barriers to achieving the state's renewable energy policy goals. In September 2007, the Energy Commission collaborated with the CPUC, the California ISO, investor-owned utilities, and publicly owned utilities to initiate the California Renewable Energy Transmission Initiative (RETI), a statewide, open, and transparent collaborative planning process. RETI is designed to facilitate and coordinate the planning and permitting of transmission and generation projects needed to accommodate the state's renewable policy goals, support future energy policy, facilitate transmission corridor designation, and minimize the duplication of efforts.

RETI involves a broad range of stakeholders who are assessing competitive renewable energy zones (CREZs) in California and neighboring states that can provide significant electricity to consumers by 2020 and be developed in the most cost-effective and environmentally benign manner. RETI will also prepare detailed transmission plans to reach CREZs identified for development and recommend the next transmission project or projects that should be developed to connect remote renewable energy resources to the grid.

Statewide Progress on Transmission Recommendations

SUBSTANTIAL

Develop comprehensive planning process

Establish statewide corridor planning process to designate corridors for future use

Work collaboratively with state, federal, local, and regional planning agencies, investor-owned utilities, publicly owned utilities, generators and developers, and the public

Participate in federal corridor planning efforts

Implement changes to California ISO tariff to encourage construction of transmission for renewables

IMPROVEMENT NEEDED

Transfer transmission permitting responsibility to Energy Commission

The Legislature should give the Energy Commission the statutory authority to establish a statewide transmission 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.

2005 IEPR

The state has made substantial progress on this recommendation. In 2006, Senate Bill 1059 (Escutia, Chapter 638, Statutes of 2006) authorized the Energy

Commission to lead both the transmission corridor planning and electricity transmission corridor zone designation processes, which are coordinated with local land use permitting activities. In early 2007, the Energy Commission initiated a rulemaking to establish regulations for the implementation of SB 1059 to further define the designation process and the informational requirements for future corridor designation applications. The Energy Commission adopted the final regulations in 2008.

Concurrent with the rulemaking, the Energy Commission's *2007 Strategic Transmission Investment Plan* encourages corridor applications requesting designations on non-federal lands to accommodate future transmission projects that would achieve one or more of the following objectives: provide access to renewable resource areas; interconnect with existing federal corridors or with proposed federal corridors identified under *Energy Policy Act of 2005* section 368; and preserve existing corridors that may be required for future facility upgrades.

> ***In establishing a statewide corridor planning process, the Energy Commission should work collaboratively with the CPUC, the California 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.***
>
> **2005 IEPR**

The state has made substantial progress on this recommendation. The state has executed a coordinated transmission planning process for renewable energy that includes a significant corridor planning component. The Energy Commission is also actively participating in the RETI process to ensure that environmental issues and land use constraints are addressed during the development of conceptual transmission plans for reaching high-priority CREZs. The Energy Commission's input helps make certain that any short-term, high-priority transmission plans developed in RETI consider these issues before development of project-specific Certificate of Public Convenience and Necessity applications to the CPUC. This helps projects submitted to the CPUC to have a greater likelihood of permitting success.

The Energy Commission's *2009 IEPR* and *2009 Strategic Transmission Investment Plan* will consider the results of RETI as part of a comprehensive evaluation of transmission investments needed to ensure reliability, relieve congestion, and meet future load growth and generation, including, but not limited, to renewable resources, energy efficiency, and other demand reduction measures. This will include an evaluation of potential transmission corridors that may be needed to help achieve state policy objectives.

> ***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.***
>
> **2005 IEPR**

The state has made substantial progress on this recommendation. In November 2005, the California Resources Agency requested the Energy Commission to represent California in the federal Programmatic Environmental Impact Statement (PEIS) effort to ensure that the PEIS considered the state's energy and infrastructure needs, renewable generation policy goals, and environmental concerns. In December 2005, the BLM designated the Energy Commission as a cooperating agency.

In coordination with the Department of Energy, the BLM, and the United States Forest Service (USFS), the Energy Commission established and coordinated the efforts of an interagency team of federal and state agencies to review proposals to designate new and/or expand existing energy corridors and examine alternatives on California's federal lands. Participating state agencies included the Department of Fish and Game, the Native American Heritage Commission, the Public Utilities Commission, and the Governor's Office of Planning and Research. In addition, the State Lands Commission and the Department of

Parks and Recreation provided input and monitored the interagency team's activities. In addition to the BLM and USFS, other federal agencies actively involved included the National Park Service, the Bureau of Indian Affairs, the United States Air Force, the United States Marine Corps, and other Department of Defense services.

The Energy Commission, the CPUC, and the California ISO should implement changes to the California ISO tariff to encourage construction of transmission for renewables.

The state has made substantial progress in implementing this recommendation. On April 19, 2007, the Federal Energy Regulatory Commission (FERC) granted the California ISO Petition for Declaratory Order, which created a new mechanism for facilitating the wholesale rate financing and development of renewable transmission lines, known as the "third category" of transmission. The FERC refers to these third category renewable transmission lines as interconnection facilities designed primarily to connect multiple location-constrained resources (remote renewable resources) to the California ISO-controlled grid.

In response to FERC's action, the California ISO developed an amendment to the tariff to include the Location Constrained Resource Interconnection (LCRI) policy for FERC's consideration. On October 17, 2007, the California ISO Board of Governors approved changes to its federal tariff language and filed the new tariff language with FERC on October 31, 2007. The LCRI policy was effective January 1, 2008.

Statewide Progress on Natural Gas Recommendations

ON TRACK

Incorporate new analytical tools in assessing and forecasting natural gas supplies and demand

Investigate alternative forecasting methods to better assess future natural gas prices

Examine feasibility of increasing natural gas production from renewable sources

Natural Gas

The Energy Commission will continue to incorporate new analytical tools such as scenario planning and portfolio analysis in assessing and forecasting the state's natural gas supplies and demand to meet reduced greenhouse gas (GHG) emission targets. The Energy Commission will encourage the Public Utilities Commission to participate in these analytic efforts.

2007 IEPR

The state has made progress on this recommendation. Staff is developing work plans for *2009 IEPR* that include as a main topic the impact of GHG reduction targets on coal use for electricity generation in the rest of the United States and the resulting impacts on demand for natural gas. Staff also plans to analyze the impact of these GHG targets on natural gas demand, supply, price, and infrastructure during the *2009 IEPR* cycle.

The Energy Commission should further investigate alternative forecasting methods in the 2007 Energy Report cycle to better assess future natural gas prices.

2005 IEPR

The state has made progress on this recommendation. To develop a natural gas assessment for the *2007 IEPR*, the Energy Commission hired consultants to assist in analyzing results from models staff used to derive natural gas prices. The consultants provided an alternative approach and highlighted uncertainties in the inputs and assumptions that could change the outcomes of the models. These views were reported in the *2007 Natural Gas Market Assessment Report*.

The Energy Commission has formed a team of technical staff to continue looking at methods used to derive supply, demand, and price parameters and is discussing new approaches to better assess the uncertainty of natural gas inputs, assumptions, and outputs derived from the models. The team will be analyzing different methods and studies on natural gas and is planning to incorporate findings in the *2009 IEPR*. Numerous entities currently forecast natural gas prices, and the team will examine some of those forecasts and provide an assessment to the IEPR Committee during the *2009 IEPR* process.

> *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.*
>
> **2007 IEPR**

The state has made progress on this recommendation. The Energy Commission, through its Public Interest Energy Research (PIER) Program, has recently funded research and development projects supporting the use of biomass as a feedstock for gasification technologies. For example, the Energy Commission provided a grant to Dixon Ridge Farms in Winters for the demonstration of a 50 kW modular gasification system using combined heat and power with biomass residue (walnut waste).

In 2008, the Energy Commission executed two biopower and two biofuels demonstration contracts. For biopower, Growpro, Inc., will demonstrate a simplified gasification technology using forest residue, and UC San Diego will demonstrate the integrated cogeneration of power from forest wood waste using an advanced thermochemical gasification process in parallel with the production of mixed alcohol (primarily ethanol) for blending with gasoline. Medcalf and Eddy and the San Francisco Public Utility Corporation will use fats, oils, and grease for biofuels production, and the Renewable Energy Institute International will use wood waste and rice straw.

The Energy Commission also executed four biomass research, development, and demonstration contracts in 2008 through its Natural Gas Replacement Program, which targeted advanced energy conversion technologies to replace natural gas.

Transportation Energy

> *The state should implement a public goods charge to establish a secure, long-term source of funding for comprehensive transportation program that provides funding for infrastructure investment, a broad range of technology and fuels research, analytical support, and incentive programs.*
>
> **2005 IEPR**

The state has made substantial progress on this recommendation. Assembly Bill 118 (Núñez, Chapter 750, Statutes of 2007) created the Alternative and Renewable Fuel and Vehicle Technology Program. The legislation increases vehicle registration, boat registration, and smog check fees and authorizes the Energy Commission to spend approximately $120 million per year over seven years to develop and deploy innovative technologies that transform California's fuel and vehicle types to help attain the state's climate change policies. The program will deploy alternative and renewable fuels in the marketplace without adopting any preferred fuel or technology.

> *Move quickly to implement AB 118, beginning with forming the advisory body as directed in the legislation; develop a strategic investment plan for alternative fuel and vehicle incentives, as required by AB 118 to be updated annually; develop and recommend sustainability standards to guide the future development of alternative fuels in California, in partnership with the Air Resources Board.*
>
> **2007 IEPR**

The state has made progress on these recommendations. The Energy Commission has begun implementing the Alternative and Renewable Fuels and Vehicle

Statewide Progress on Transportation Recommendations

SUBSTANTIAL

Implement public goods charge to provide funding for infrastructure, technology and fuels research, analytical support, and incentive programs

ON TRACK

Implement AB 118: form advisory body, develop investment plan, develop and recommend sustainability standards

Establish non-petroleum diesel fuel standard

Update full fuel cycle analysis working with relevant agencies and key stakeholders

IMPROVEMENT NEEDED

Work closely with other states to influence federal fuel efficiency standards

Technology Program. On January 30, 2008, the Energy Commission approved an Order Instituting Rulemaking (OIR 06-0130-05) to adopt guidelines, definitions, and other provisions necessary for the administration of the program. This rulemaking will develop and adopt regulations that are necessary to clarify ambiguities in statute and create certainty and transparency in the administration of the program. The Energy Commission expects to complete the rulemaking in spring 2009.

In addition, the Energy Commission has established an advisory committee to help develop an investment plan to establish priorities and identify opportunities for the program and describe how funding will complement existing public and private investments, including existing state programs. The Energy Commission prepared a draft investment plan that was discussed at the second advisory committee meeting on July 9, 2008, and expects to adopt the investment plan in early December 2008. The investment plan will be updated annually.

As part of the rulemaking for the Alternative and Renewable Fuels and Vehicle Technology Program, the Energy Commission is developing a set of "sustainability goals" as required in AB 118 that will be reflected in the investment plan and in funding solicitations. To assist in this effort, the Energy Commission established a sustainability working group. One of the key issues under discussion is indirect land use and how its impacts should be measured and considered in project evaluation.

> *The state should continue to work closely with other states to influence the federal government to double vehicle fuel efficiency standards and enact fleet procurement requirements that include super-efficient gasoline and diesel vehicles.*
>
> **2005 IEPR**

Indirectly, the state has made slow progress on this recommendation. From late 2004 to early 2005, the Energy Commission staff surveyed the level of interest among other states in working together to advocate to the federal government to double the existing the Corporate Average Fuel Economy (CAFE) standards, with many states indicating willingness to pursue this objective.

In October 2005, the Energy Commission filed comments to the docket of the U.S. Department of Transportation's National Highway Transportation Safety Administration (NHTSA), aimed at improving fuel economy of light trucks for model years 2008 to 2011. The Energy Commission requested NHTSA to adopt new CAFE standards for 2008 only and to conduct further analysis for developing higher fuel economy standards for later model years. The Energy Commission stated that the fuel cost used in current analysis was far too low and that using higher fuel costs would lead to higher fuel economy standards.

Although California has not successfully formed a state-level collaboration to directly influence the adoption of higher CAFE standards, the state has implemented landmark regulations that will indirectly improve efficiency of new vehicles sold in California. As directed by Assembly Bill 1493 (Pavley, Chapter 200, Statutes of 2002), the ARB in 2005 adopted regulations to limit GHG emissions from new vehicles sold in California, beginning in model year 2009. New vehicles fully complying with this regulation in 2016 will consume nearly 30 percent less fuel than vehicles built before 2009.

Further, the Federal Energy Independence and Security Act, enacted late last year, increases the CAFE standards from the current level of 27.5 miles per gallon for passenger cars and 22.2 miles per gallon for light trucks (minivans, sport minivans, sport utility vehicles, and pickups) to a combined fleet average of 35 miles per gallon by 2020. This increase is a significant improvement, but is not enough to attain the level of fuel economy that the Energy Commission and ARB determined in 2003 to be both achievable and cost-beneficial.

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.

2005 IEPR

The state has made progress on this recommendation. The ARB is developing regulations to establish a state Low Carbon Fuels Standard (LCFS) in its proceeding. These regulations will set standards to reduce the average fuel carbon intensity in the state's transportation fuel pool by 10 percent by 2020. Under the LCFS, the ARB is establishing separate standards for gasoline and diesel fuels. Like gasoline, diesel will be required to achieve a 10 percent reduction in its average fuel carbon intensity. The ARB currently considers biodiesel and renewable diesel to be fuels with lower carbon content. Blending in these fuels will increase the renewable content of petroleum fuel. The Energy Commission expects the LCFS to be adopted by spring 2009 and become effective January 2010. The ARB has designated the LCFS as a Discrete Early Action measure under its AB 32 proceedings.

Work collaboratively with the Air Resources Board, key stakeholders, and other relevant agencies to regularly update the full fuel cycle analysis in an open and transparent manner.

2007 IEPR

The state has made progress on this recommendation. The Energy Commission staff is working directly with ARB staff in the LCFS proceeding to document the full fuel cycle assessment conducted during the *AB 1007 State Alternative Fuels Plan* proceeding and to update the California-modified Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (GREET) model used in the assessment. The Energy Commission and ARB have agreed to jointly update the GREET model in the future and use the same version in the respective proceedings of the two agencies.

Also, in July 2008 the Energy Commission awarded two contracts to update the full fuel cycle assessment capabilities and assess how land use changes affect GHG emissions, evaluate water impacts associated with all alternative and renewable fuels, analyze new fuel pathways, and evaluate the sustainability of transportation fuels on a full fuel cycle basis. These enhancements to the GREET model and the collective understanding of the sustainability of transportation fuels options will improve the full fuel cycle assessment capabilities of the Energy Commission and ARB.

Petroleum Infrastructure

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

2005 IEPR

The state has made substantial progress on this recommendation. In May 2008, the Energy Commission published *2008 Best Permitting Practices Guidelines for Liquid Transportation Fuels Infrastructure.*[165] The report recommends guidelines to local, state, and federal agencies, as well as project proponents, for streamlining and coordinating the permitting process for petroleum and other liquid transportation fuel infrastructure projects without compromising environmental protection. The guidelines do not recommend changes to laws, regulations, or agency jurisdictions or responsibilities. The guidelines for the Energy Commission include: continuing and expanding active participation in petroleum and other transportation fuel infrastructure regulatory processes; and facilitating workshops and training forums for agency and stakeholder participants.

Next steps include:

- Provide input to and comments on the Pacific L.A. Marine Terminal LLC Pier 400, Berth 408 Project Supplemental Environmental Impact Statement/Subsequent Environmental Impact Report.

- Track, monitor progress, and provide comments on refinery upgrade and expansion projects, including the ConocoPhillips Rodeo Refinery Clean Fuels Expansion Project.

- Provide training to California Department of Fish and Game biologists and ecologists on permitting energy pipelines.

- Facilitate workshop discussion with agency and energy industry representatives on transportation fuels and related infrastructure issues for the CalFire Office of the State Fire Marshal and the California State Lands Commission.

Statewide Progress on Petroleum Infrastructure Recommendations

SUBSTANTIAL

Develop permitting guidelines based on best practices approach

ON TRACK

Monitor infrastructure impacts of State Lands Commission Marine Oil Terminal Engineering and Maintenance Standards

Monitor the impact on infrastructure development of the State Lands Commission Marine Oil Terminal Engineering and Maintenance Standards (MOTEMS), especially on clean fuels marine terminals in the Port of Los Angeles and Long Beach.

2007 IEPR

The state is on track with this recommendation. The Energy Commission continues to monitor petroleum industry progress in complying with MOTEMS and meet periodically with representatives of the State Lands Commission for status updates on implementing MOTEMS regulations. To date, there is no indication that operations at marine oil terminals would be significantly hindered or that importing fuel would be affected because of compliance.

A recent confidential survey of marine oil terminal operators included questions for oil importers about MOTEMS compliance. The results indicate that operators anticipate no problems. Later this year, the Energy Commission will survey marine terminal operators that import traditional and renewable transportation fuels. The survey will identify which marine terminals, if any, may not be able to comply with MOTEMS because of economic or business plan decisions, and how that will decrease their ability to import clean fuels.

The Energy Commission staff met with State Lands Commission representatives in September 2008 to obtain a report of compliance-to-date for all marine terminals, including those that import crude oil and clean refined products. The information from the survey and the State Lands Commission meeting will be presented at workshops held during the *2009 IEPR* workshop process.

Land Use

> ***The Air Resources Board should adopt regional greenhouse gas emission reduction levels to guide regional growth management plans in its AB 32 scoping plan. The state should require regional transportation planning agencies to adopt 25-year and 50-year regional growth plans that provide housing, transportation, and community services for expected population increases while reducing greenhouse gas emissions to state-determined climate change targets.***
>
> **2007 IEPR**

The state has made substantial progress with this recommendation. On September 30, 2008, Governor Arnold Schwarzenegger signed Senate Bill 375 (Steinberg, Chapter 728, Statutes of 2008) which establishes mechanisms for the development of regional targets for passenger vehicle greenhouse gas reductions.

Through the SB 375 process, regions will work to integrate development patterns, the transportation network, and other transportation measures and policies in a way that achieves greenhouse gas emission reductions while meeting regional planning objectives.

This new law reflects the importance of achieving significant additional greenhouse gas reductions from changed land use patterns and improved transportation to help achieve the goals of AB 32.

Statewide Progress on Land Use Recommendations

SUBSTANTIAL

Require regional transportation planning agencies to adopt regional growth plans that reduce greenhouse gas emissions to state-determined climate change targets

Form state agency working group to develop and implement efficient land use action plan for the state

ON TRACK

Provide clear guidance on greenhouse gas emissions accounting for urban land use activities and a local government protocol

Require local governments to develop GHG reduction plans

IMPROVEMENT NEEDED

Include energy element in local government general plans

Expand technical and financial assistance to regional agencies and local governments

Senate Bill 375 requires ARB to develop, in consultation with metropolitan planning organizations (MPOs), passenger vehicle greenhouse gas emission reductions targets for 2020 and 2035 by September 30, 2010. It sets forth a collaborative process to establish these targets, including the appointment by ARB of a Regional Targets Advisory Committee to recommend factors and methodologies to be considered for setting GHG emission reduction targets. The bill creates incentives for local governments and developers by providing relief from certain California Environmental Quality Act (CEQA) requirements for development projects that are consistent with regional plans that achieve the targets.

The ARB should include in the scoping plan clear guidance on greenhouse gas emissions accounting for urban land use activities and a local government protocol for assessing and tracking greenhouse gas emissions in jurisdictions.

2007 IEPR

The state is on track with this recommendation. ARB recently adopted the Local Government Operations Protocol which inventories emissions from government buildings, facilities, vehicles, wastewater and potable water treatment facilities, landfill and composting facilities, and other governments operations. ARB is also developing an additional protocol for community wide emissions. This protocol will go beyond just municipal operations and include emissions from the community as a whole including residential and commercial energy consumption and transportation activity.

The state's AB 32 plan should require local governments to develop GHG reduction plans and finance such efforts through the AB 32 administrative fee at a level commensurate with the GHG savings expected from improved land use planning.

2006 IEPR Update

The state is on track with this recommendation. On June 26, 2008, the ARB released its Climate Change Draft Scoping Plan, under AB 32. The draft plan encourages, but does not require, local governments to develop climate action plans. The scoping plan also calls for carbon fees that could be used "to pay for reductions or achieve other goals related to the program." The Energy Commission supports this plan but continues to believe that climate action plans should be required, not optional, for local governments.

The state should form a state agency working group to develop and implement an Efficient Land Use Action Plan for the state.

2006 IEPR Update

The state has made substantial progress on this recommendation. In January 2006, the Governor launched the Strategic Growth Plan (SGP), a proposed set of new policies to leverage partnerships with the private sector, increase synergy between public agencies, and educate thousands of new engineers to build the California of tomorrow. One of these policies was to create the Strategic Growth Council. This policy was enacted when the Governor recently signed Senate Bill 732 (Steinberg, Chapter 729, Statutes of 2008), which established a five-member Council to help state agencies allocate SGP money in ways that best promote efficiency, sustainability, and support the Governor's economic and environmental goals. Chaired by the Director of the Office of Planning and Research, the Council also consists of the Secretaries from the Resources Agency, CalEPA, the California Business, Transportation, and Housing Agency, and the California Department of Food and Agriculture.

The Council will award and manage grants and loans including $90 million from Proposition 84 funds, to support the development of sustainable communities. The Council's responsibilities include establishing application requirements and evaluation criteria for the grant program. It will also coordinate the four member state agencies as they undertake infrastructure and development projects meant to encourage sustainable land use; protect natural resources; improve air and water quality; increase the availability of affordable housing; improve transportation; and meet the goals of the Global Warming Solutions Act (AB 32). Furthermore, it will recommend policies to the Governor, the Legislature, and state agencies that encourage sustainable development, and will collect and provide data to local governments to help them develop and plan sustainable communities. While the state has little direct say in local land use planning, the Council will provide leadership and support for local governments.

> *Local governments should be required to include an energy element in their general plans.*
> **2006 IEPR Update**

The state has made little progress on this recommendation. No statewide legislation has emerged to require local governments to add an energy element to their general plans. The Governor's Office of Planning and Research is updating the 2003 version of the General Plan Guidelines and may update the section on optional energy elements, based on any new research on this topic.

In the absence of a mandate, the Energy Commission initiated a multi-year $400,000 contract with the San Diego Association of Governments (SANDAG) in June 2007. As part of the contract, SANDAG will develop a "how-to" guide on preparing an energy element for use by other regional and local governments. The Energy Commission is assembling a State Advisory Task Force to guide the project. The task force includes representatives from metropolitan planning organizations, councils of government, and state agencies. They will review and comment on all report drafts and will meet in 2009 to discuss energy and climate change planning at the Blueprint Learning Network workshops in Sacramento.

> *The state should expand efforts to provide technical and financial assistance to regional agencies and local governments to facilitate climate-friendly and energy-efficient planning and development.*
> **2007 IEPR**

The state has made little progress on this recommendation. The Land Use Subgroup of the Climate Action Team prepared a report detailing technical assistance the state provides for regional and local agencies to implement climate-friendly and energy-efficient planning and development. The subgroup submitted the report to ARB for consideration in its Climate Change Draft Scoping Plan. In the Draft Scoping Plan, the ARB states its intention to pursue and investigate strategies to provide stable funding for sustainable local planning and zoning updates.

Furthermore, in August 2008, the Energy Commission began updating the Energy-Aware Planning Guide. This update will provide detailed options for local governments seeking to reduce GHGs by conserving energy in transportation, buildings, and operations. The guide will explain the effects of energy policies on GHG emissions, prescribe more effective relationships between local and regional planning agencies, and describe recent best practices. The Energy Commission expects the updated document to be available in July 2009.

Water and Energy Use

> *The Energy Commission should update its current Memoranda-of-Understanding (MOU) Agreement with the State Water Resources Control Board (SWRCB), the Regional Water Quality Control Boards (RWQCB), 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 federal Clean Water Act Section 316(b) reviews of coastal power plant once-through cooling impacts.*

The state is on track with this recommendation. Since 2005, the Energy Commission has been working through the MOU Agreement process with the SWRCB, the RWQCBs, and the California Coastal Commission on a policy and regulatory approach to phase out once-through cooling for coastal power plants and increase the use of best available retrofit technologies such as large organism exclusion devices and modern screens at existing coastal power plants to minimize the marine environment impacts of using ocean water for once-through cooling of turbines.

With respect to the federal Clean Water Act Section 316(b) reviews, the SWRCB is California's lead agency. The Energy Commission is continuing to work closely with the SWRCB, the RWQCBs, and the

Statewide Progress on Water and Energy Use Recommendations

ON TRACK

Develop consistent regulatory approach for once-through cooling in power plants

Update data adequacy regulations with respect to once-through cooling at coastal power plants

Coastal Commission on a revision/implementation process for Section 316(b) regulations. In May 2008, the Energy Commission provided comments on the SWRCB's *Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling* (March 2008).

The Energy Commission is working with the SWRCB to address the once-through cooling issue from the perspective of maintaining the long-term efficiency and reliability of California's electrical system. The Energy Commission believes that, in most cases, retiring and replacing or repowering the existing plants using once-through cooling with new facilities using other cooling options would be most beneficial to the state.

Other recent Energy Commission activities in this area include:

- A once-through cooling impact analysis as part of the AB 1632 assessment of California's operating nuclear plants, which became available in September 2008.
- Staff participation in the California ISO's study of aging thermal power plants, including once-through cooling impacts.
- Ongoing staff work with the California Ocean Protection Council.
- PIER funding of a research contract on once-through cooling impacts at the Moss Landing Power Plant in Monterey County.

The Energy Commission should update current data adequacy regulations with respect to once-through cooling at the state's coastal power plants.

The state has made progress on this recommendation. In April 2007, the Energy Commission updated its data adequacy regulations for power plant licensing and site certification. The new requirement augments the biological resources information and applies to proposals for expanding or repowering existing coastal power plants if once-through cooling is involved. Applications for Certification (AFC) must now include recent studies to address the facility's current and expected impacts on marine species. The facility must have completed the studies within the last five years and include complete marine species impact information as required by federal Clean Water Act Section 316(b) regulations. Any proposals for new coastal generation facilities involving once-through cooling must also include these studies.

The Energy Commission approved the El Segundo project using once-through cooling in 2005; however, the project owner filed a 2007 amendment petition requesting a change to dry cooling technology, which is under Energy Commission review.

Since 2005, the Energy Commission has not received any AFCs for existing or new coastal power plants involving once-through cooling. There have been three applications for repowering/modernization projects at coastal power plants, the South Bay Replacement Project in Chula Vista, the Carlsbad Energy Center adjacent to the existing Encina plant in San Diego County; and the Humboldt Bay Replacement Project in Humboldt County. Each of these projects proposed use of dry cooling or reclaimed water rather than once-through cooling. The South Bay project withdrew its application because of land use and site control issues, and the Energy Commission is reviewing the Humboldt and Carlsbad projects.

Endnotes

152 California Public Utilities Commission, R.05-06-040, *Order Instituting Rulemaking to Implement Senate Bill No. 1488 (2004 Cal. Stats., Ch. 690 (Sept. 22, 2004)) Relating to Confidentiality of Information,* July 5, 2005, http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/47631.htm.

153 California Public Utilities Commission, D.06-06-066, *Interim Opinion Implementing Senate Bill No. 1488, Relating to Confidentiality of Electic Procurement Data Submitted to the* Commission, June 29, 2006, http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/57772.htm.

154 The California Public Utilities Commission requires an Independent Evaluator for each Renewable Portfolio Standard solicitation to provide third party oversight and a critical assessment of the procurement process.

155 California Public Utilities Commission, R.08-02-007, Order Instituting Rulemaking to integrate and refine procurement policies underlying long-term procurement plans, February 14, 2008.

156 California Energy Commission, Statewide Energy Efficiency Potential Estimates and Targets for California Utilities, August 2007, http://www.energy.ca.gov/2007publications/CEC-200-2007-019/CEC-200-2007-019-SD.PDF.

157 California Public Utilities Commission Decision 08-02-008; the retail seller must demonstrate that it has undertaken all reasonable efforts to use flexible delivery points, ensure availability of any needed transmission capacity, construct needed facilities (for electric corporations), and demonstrate that there is no conflict with any requirement relative to the retail seller's overall procurement plan.

158 California Public Utilities Commission, Decision 07-07-027, *Opinion Adopting Tariffs and Standard Contracts for Water, Wastewater, and Other Customers to Sell Electricity Generated from RPS-Eligible Renewable Resources to Electrical Corporations*, http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/70660.htm.

159 CPUC Resolution E-4137, http://docs.cpuc.ca.gov/WORD_PDF/FINAL_RESOLUTION/78934.PDF.

160 California Public Utilities Commission, September 18, 2008, http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/91159.htm.

161 CPUC, June 5, 2008, Amended Scoping Memo and Ruling of Assigned Commissioner Regarding Phase 2 of Tariff and Standard Contract Implementation for RPS Generators, in Rulemaking 06-05-027, p. A3, as cited by KEMA, Inc., 2008, *Exploring Feed-in Tariffs for California*, p. 5.

162 KEMA, Inc., 2008, Exploring Feed-in Tariffs for California: Feed-in Tariff Design and Implementation Issues and Options, Draft Consultant Report, prepared for the California Energy Commission, http://www.energy.ca.gov/2008publications/CEC-300-2008-003/CEC-300-2008-003-D.PDF.

163 Licensing Support Network, Nuclear Regulatory Commission, http://lsnnet.gov/.

164 The 10 projects are San Diego Gas & Electric's Sunrise Powerlink 500 kV Project; Southern California Edison's Tehachapi Renewable Transmission Plan (Segments 1 through 3 in the 2005 Strategic Plan plus the remaining segments in the 2007 Strategic Plan); the Imperial Valley Transmission Upgrade Project; Pacific Gas and Electric Company's Central California Clean Energy Transmission Project; the transmission component of the Lake Elsinore Advanced Pumped Storage Project; the Green Path Coordinated Projects; the Los Angeles Department of Water & Power Tehachapi Project; Southern California Edison's Palo Verde – Devers No. 2 500 kV Project; and the TransBay Cable Project.

165 California Energy Commission, May 2008, http://www.energy.ca.gov/2008publications/CEC-700-2008-002/CEC-700-2008-002-SF.PDF.

Glossary of Acronyms

AB	—	Assembly Bill
AFC	—	Applications for Certification
ARB	—	California Air Resources Board
BLM	—	Bureau of Land Management
CAFE	—	Corporate Average Fuel Economy
CalEPA	—	California Environmental Protection Agency
California ISO	—	California Independent System Operator
CERTS/EPG	—	Consortium for Electric Reliability Technology Solutions/ Electric Power Group
CH^4	—	Methane
CHP	—	Combined Heat and Power
CMUA	—	California Municipal Utilities Association
CO	—	Carbon Monoxide
CO_2	—	Carbon Dioxide
CPP	—	Critical Peak Pricing
CPUC	—	California Public Utilities Commission
CREZs	—	Competitive Renewable Energy Zones
DOE	—	(United States) Department of Energy
EIR/EIS	—	Environmental Impact Report/Environmental Impact Statement
FERC	—	Federal Energy Regulatory Commission
GHG	—	Greenhouse Gas
GW	—	Gigawatt
GWh	—	Gigawatt hours
IAP	—	Intermittency Analysis Project
IEPR	—	Integrated Energy Policy Report
IID	—	Imperial Irrigation District
IMPLAN	—	Input-output model
IOUs	—	Investor-Owned Utilities
LADWP	—	Los Angeles Department of Water and Power
LCFS	—	Low Carbon Fuel Standard
LTTPs	—	Long-Term Procurement Plans

MOTEMS	—	Marine Oil Terminal Engineering and Maintenance Standards
MOU	—	Memorandum of Understanding
MW	—	Megawatt
N_2O	—	Nitrous Oxide
NO_X	—	Nitrogen Oxides
NRC	—	Nuclear Regulatory Commission
NRDC	—	Natural Resources Defense Council
NWPCC	—	Northwest Power and Conservation Council
OTC	—	Once-Through Cooling
PG&E	—	Pacific Gas and Electric
PEIS	—	Programmatic Environmental Impact Statement
PIER	—	Public Interest Energy Research
PM2.5	—	Particulate Matter
PRG	—	Procurement Review Group
PV	—	Photovoltaic
REC	—	Renewable Energy Credit
RETI	—	Renewable Energy Transmission Initiative
RFO	—	Request for Offers
RPS	—	Renewables Portfolio Standard
RWQCB	—	Regional Water Quality Control Boards
SANDAG	—	San Diego Association of Governments
SCE	—	Southern California Edison
SDG&E	—	San Diego Gas and Electric Company
SMUD	—	Sacramento Municipal Utility District
SONGS	—	San Onofre Nuclear Generating Station
SWRCB	—	State Water Resource Control Board
TID	—	Turlock Irrigation District
USGS	—	United States Geological Survey
VOC	—	Volatile Organic Compounds
WIEB	—	Western Interstate Energy Board
WGA	—	Western Governors' Association

Appendix A

Aging and Once-through Cooling Power Plants, November 2008

	Unit	Year First in Service	OTC	Plant Original Capacity	2007 Capacity Factor (per cent)	County	LCR Area Name	Owner	Upgrades, Repower or Replacement Completed, Planned or In Process
Alamitos	1	1956	YES	175	2	Los Angeles	LA Basin	AES Southland/ Bear Energy	SCR installed.
Alamitos	2	1957	YES	175	2	Los Angeles	LA Basin	AES Southland/ Bear Energy	SCR installed.
Alamitos	3	1961	YES	320	19	Los Angeles	LA Basin	AES Southland/ Bear Energy	SCR installed.
Alamitos	4	1962	YES	320	10	Los Angeles	LA Basin	AES Southland/ Bear Energy	SCR installed.
Alamitos	5	1969	YES	480	9	Los Angeles	LA Basin	AES Southland/ Bear Energy	SCR installed.
Alamitos	6	1966	YES	480	7	Los Angeles	LA Basin	AES Southland/ Bear Energy	SCR installed.
Broadway	3	1965	NO	66	2	San Diego		City of Pasadena	None-slow start only used for long hot spell; SCR installed.
Carlsbad (Encina)	1	1954	YES	107	6	San Diego	San Diego	NRG	CEC AFC in process for a new 300 MW peaking power plant, air-cooled, low profile, where two old fuel tanks now sit at the Encina site. Units 1-3 to be shut down. Would use some ocean water.
Carlsbad (Encina)	2	1956	YES	104	5	San Diego	San Diego	NRG	
Carlsbad (Encina)	3	1958	YES	110	8	San Diego	San Diego	NRG	
Carlsbad (Encina)	4	1973	YES	293	8	San Diego	San Diego	NRG	SCR installed.

	Unit	Year First in Service	OTC	Plant Original Capacity	2007 Capacity Factor (per cent)	County	LCR Area Name	Owner	Upgrades, Repower or Replacement Completed, Planned or In Process
Carlsbad (Encina)	5	1978	YES	315	12	San Diego	San Diego	NRG	SCR installed.
Contra Costa	1,2,3	1951	YES	348	NA	Contra Costa	Bay Area	PG&E	Mirant Marsh Landing (930 MW) AFC declared data adequate September 2008. Plant will use recycled water and project includes water treatment facility. Plant to be constructed within the existing Contra Costa site, but will be a separate legal entity and not part of existing plant. Contra Costa 1-5 are retired. Units 6 and 7 sell into the wholesale market.
Contra Costa	4	1953	prev	117	NA	Contra Costa	Bay Area	Mirant	
Contra Costa	5	1953	prev	115	NA	Contra Costa	Bay Area	Mirant	
Contra Costa	6	1964	YES	340	1	Contra Costa	Bay Area	Mirant	The PG&E Gateway plant (formerly called Contra Costa 8) is NOT considered a repower or replacement; the new plant will be located adjacent to the existing Contra Costa site. CEC issued permit for the Gateway plant (Contra Costa 8) and it would have shared OTC facilities of Units 6-7. Permit amended August 2007 to use dry cooling. Unit 6 and 7 sell into wholesale market.
Contra Costa	7	1964	YES	340	3	Contra Costa	Bay Area	Mirant	Mirant has awarded a contract valued at $1.4 million for a turnkey process control upgrade at its Contra Costa Unit 7.
Coolwater	1	1961	NO	65	1	San Bernardino		Reliant	
Coolwater	2	1964	NO	81	1	San Bernardino		Reliant	
Coolwater	3	1978	NO	241	16	San Bernardino		Reliant	

	Unit	Year First in Service	OTC	Plant Original Capacity	2007 Capacity Factor (per cent)	County	LCR Area Name	Owner	Upgrades, Repower or Replacement Completed, Planned or In Process
Coolwater	4	1978	NO	241	21	San Bernardino		Reliant	
Diablo Canyon	1	1985	YES	1090	92	San Luis Obispo		PG&E	Steam Generator Replacement scheduled for 2009.
Diablo Canyon	2	1986	YES	1105	101	San Luis Obispo		PG&E	Steam Generator Replacement completed 2008.
El Segundo	1	1955	prev	175	NA	Los Angeles		NRG	CEC issued permit in 2005. Application to amend permit filed in 2007 will eliminate OTC. Repowered unit (560 MW). Demolition of old units approved August 2007. New combined cycle units will be called 5, 6, and 7.
El Segundo	2	1956	prev	175	NA	Los Angeles		NRG	
El Segundo	3	1964	YES	335	9	Los Angeles	LA Basin	NRG	SCR installed.
El Segundo	4	1965	YES	335	9	Los Angeles	LA Basin	NRG	SCR installed.
El Centro	3	1952	YES	44	11	Imperial		IID	CEC permit to repower issued January 2007; capacity increased to 128 MW; efficiency increased about 30% and water consumption reduced by about 60% for every MWH generated.
El Centro	4	1968	YES	74	20	Imperial	LA Basin	IID	Plan to repower to 240 MW in the future.
Etiwanda	1	1953	NO	132	NA	San Bernardino	LA Basin	Reliant	Retired 2004, last operated 2002.
Etiwanda	2	1953	NO	132	NA	San Bernardino	LA Basin	Reliant	

	Unit	Year First in Service	OTC	Plant Original Capacity	2007 Capacity Factor (per cent)	County	LCR Area Name	Owner	Upgrades, Repower or Replacement Completed, Planned or In Process
Etiwanda	3	1963	NO	320	14	San Bernardino	LA Basin	Reliant	Units 3 and 4 are equipped with SCR and use recycled water. (SCE 45 MW peaker plant installed in summer of 2007 is located adjacent to the Etiwanda plant.)
Etiwanda	4	1963	NO	320	9	San Bernardino	LA Basin	Reliant	
Etiwanda	5	1969	NO	NA	NA	San Bernardino	LA Basin	Reliant	Retired 2003.
Grayson	3	1953	NO	19	NA	Los Angeles		Glendale	Represents approximately 55% of the City's generation capacity, but used for intermediate and peaking; provides only 15% of the City's energy needs. Unit 3 retired January 2008. Units 6 & 7 declared obsolete 2005, replaced by Unit 9; September 2008 RFO for overhaul of Unit 8. Newer Magnolia plant is base load.
Grayson	4	1959	NO	44	5	Los Angeles		Glendale	
Grayson	5	1964	NO	42	30	Los Angeles		Glendale	
Grayson	8A & 1 or 2	1977	NO	32	NA	Los Angeles		Glendale	
Grayson	8B/C &1or 2	1977	NO	74	NA	Los Angeles		Glendale	
Harbor	1	1994	YES	227	9	Los Angeles		LADWP	No major repowering plans. Investigating possible use of reclaimed water
Haynes	1	1962	YES	200	29	Los Angeles		LADWP	Units 3 and 4 were repowered in 2005 using OTC. Units 5 and 6 will be replaced with six hybrid simple cycle turbines by late 2011. Then, Units 1 and 2 will be replaced with new technology.
Haynes	2	1963	YES	200	22	Los Angeles		LADWP	
Haynes	5	1967	YES	318	4	Los Angeles		LADWP	
Haynes	6	1967	YES	318	17	Los Angeles		LADWP	
Haynes	CC	2005	YES	575	50	Los Angeles		LADWP	

	Unit	Year First in Service	OTC	Plant Original Capacity	2007 Capacity Factor (per cent)	County	LCR Area Name	Owner	Upgrades, Repower or Replacement Completed, Planned or In Process
Humboldt Bay	1	1956	prev	52	90	Humboldt	Humboldt	PG&E	CEC permit for repower with Wartsila, 163 MW, due on-line October 2009; 35% more efficient diesel back-up. Replaces these four units and Unit 3 capacity. Permits for old units will be surrendered and OTC eliminated.
Humboldt Bay	2	1958	prev	53	28	Humboldt	Humboldt	PG&E	
Hunters Point	4	1958	prev	163	NA	San Francisco	Bay Area	PG&E	Units 2 and 3 converted to synchronous condensers in 2001; plant closed 2006. Plant demolished 2008.
Huntington Beach	1	1958	YES	215	21	Orange	LA Basin	AES Southland/ Bear Energy	SCR installed.
Huntington Beach	2	1958	YES	215	6	Orange	LA Basin	AES Southland/ Bear Energy	SCR installed.
Huntington Beach	3	1961	YES	215	25	Orange	LA Basin	AES Southland/ Bear Energy	2002 retool with OTC and mitigation-licensed for five years, then extended 5 years.
Huntington Beach	4	1961	YES	225	12	Orange	LA Basin	AES Southland/ Bear Energy	2002 retool with OTC and mitigation-licensed for five years, then extended 5 years.
Long Beach	8	1976	prev	303	NA	Los Angeles		NRG	CEC permit issued for 260 MW, 2007; replaced old capacity with CTs 1-4 peakers BACT, August 2007. No longer OTC.
Long Beach	9	1977	prev	227	NA	Los Angeles		NRG	
Mandalay	1	1959	YES	215	9	Ventura	Big Creek/ Ventura	Reliant	SCR installed. SCE plans to install a 45 MW peaker adjacent to, but separate from, the Mandalay site.
Mandalay	2	1959	YES	215	15	Ventura	Big Creek/ Ventura	Reliant	

	Unit	Year First in Service	OTC	Plant Original Capacity	2007 Capacity Factor (per cent)	County	LCR Area Name	Owner	Upgrades, Repower or Replacement Completed, Planned or In Process
Morro Bay	1	1956	YES	0	NA	San Luis Obispo		Dynegy/ LS Power	CEC issued permit in 2004 for replacement of the existing units with two new units that would continue to use OTC, relying on structures from old plants with habitat mitigation. Capacity increased to 1200 MW. Needs SWRCB permit for construction; AQ permit issued September 2008.
Morro Bay	2	1955	YES	0	NA	San Luis Obispo		Dynegy/ LS Power	
Morro Bay	3	1962	YES	338	11	San Luis Obispo		Dynegy/ LS Power	
Morro Bay	4	1963	YES	338	8	San Luis Obispo		Dynegy/ LS Power	
Moss Landing	1	1950	prev	116	68	Monterey		Dynegy/ LS Power	CEC issued permit in 2002 for new Units 1 & 2 (1,060 MW) replacing old units 1-5 (retired 1995). Uses OTC.
Moss Landing	2	1950	prev	115	71	Monterey		Dynegy/ LS Power	
Moss Landing	3	1951	prev	117	NA	Monterey		Dynegy/ LS Power	
Moss Landing	4	1952	prev	117	NA	Monterey		Dynegy/ LS Power	
Moss Landing	6	1967	YES	739	6	Monterey		Dynegy/ LS Power	SCR installed. New pilot project on site uses Calera process to sequester CO2 emissions as cement.
Moss Landing	7	1968	YES	739	10	Monterey		Dynegy/ LS Power	
Olive	1	1959	NO	46	1	Los Angeles		Burbank Water and Power	Retrofit in 2006, control systems upgraded. Used for load following and peaking. Expects to run until 2016.
Olive	2	1964	NO	55	NA	Los Angeles		Burbank Water and Power	
Ormond Beach	1	1971	YES	750	5	Ventura	LA Basin	Reliant	SCR installed.
Ormond Beach	2	1973	YES	750	9	Ventura	LA Basin	Reliant	SCR installed.

	Unit	Year First in Service	OTC	Plant Original Capacity	2007 Capacity Factor (per cent)	County	LCR Area Name	Owner	Upgrades, Repower or Replacement Completed, Planned or In Process
Pittsburg	1	1954	prev	163	NA	Contra Costa	Bay Area	Mirant	AFC for Willow Pass Generating Station (550 MW) declared data adequate in October 2008. Plant will be constructed entirely within the Pittsburg site replacing Units 1-4 that have been closed for years. New plant expected to run at about 50% CF.
Pittsburg	2	1954	prev	163	NA	Contra Costa	Bay Area	Mirant	
Pittsburg	3	1954	prev	163	NA	Contra Costa	Bay Area	Mirant	
Pittsburg	4	1954	prev	163	NA	Contra Costa	Bay Area	Mirant	
Pittsburg	5	1960	YES	325	3	Contra Costa	Bay Area	Mirant	Units 5 and 6 - SCR installed.
Pittsburg	6	1961	YES	325	2	Contra Costa	Bay Area	Mirant	
Pittsburg	7	1972	YES	720	1	Contra Costa	Bay Area	Mirant	
Potrero	3	1965	YES	207	26	San Francisco	Bay Area	Mirant	SCR installed. AFC for repower terminated by CEC, following SF decision for alternative plan. 2008, SFPUC rescinded contract for new peaker plants and voted for phased closure of the Potrero facility with possible retrofit of Units 4, 5, and 6 using Pratt Whitney Twin -Pacs.
Redondo Beach	5	1954	YES	175	1	Los Angeles	LA Basin	AES Southland /Bear Energy	SCR installed.
Redondo Beach	6	1957	YES	175	2	Los Angeles	LA Basin	AES Southland /Bear Energy	SCR installed.
Redondo Beach	7	1967	YES	480	6	Los Angeles	LA Basin	AES Southland /Bear Energy	SCR installed.
Redondo Beach	8	1967	YES	480	4	Los Angeles	LA Basin	AES Southland /Bear Energy	SCR installed.

	Unit	Year First in Service	OTC	Plant Original Capacity	2007 Capacity Factor (per cent)	County	LCR Area Name	Owner	Upgrades, Repower or Replacement Completed, Planned or In Process
San Onofre	2	1983	YES	1086	84	San Diego	LA Basin	SCE/SDGE	Steam Generator Replacement project begins in 2009.
San Onofre	3	1984	YES	1086	90	San Diego	LA Basin	SCE/SDGE	Steam Generator Replacement project begins in 2010.
Scattergood	1	1939	YES	179	16	Los Angeles		LADWP	SCR installed. Part of Industrial complex. 2007 feasibility study done; project to include new CT, then evaluation of repower of Units 1 and 2 could go forward.
Scattergood	2	1939	YES	179	25	Los Angeles		LADWP	
Scattergood	3	1939	YES	445	20	Los Angeles		LADWP	
South Bay	1	1960	YES	147	9	San Diego	San Diego	Dynegy/ LS Power	SCR installed. Application for repower withdrawn 2007.
South Bay	2	1962	YES	150	10	San Diego	San Diego	Dynegy/ LS Power	
South Bay	3	1964	YES	171	13	San Diego	San Diego	Dynegy/ LS Power	
South Bay	4	1971	YES	222	8	San Diego	San Diego	Dynegy/ LS Power	

Acronyms used in Table:

AFC – Application for Certification
AQ – Air quality
BACT – Best Available Control Technology
CF – Capacity Factor
CT – Combustion turbine
LCR – Local capacity requirements
OTC – Once-through cooling
RFO – Request for Offers
SCR – Selective catalytic reduction
SFPUC – San Francisco Public Utilities Commission
SWRCB – State Water Resources Control Board

2008 INTEGRATED ENERGY POLICY REPORT UPDATE

CALIFORNIA
ENERGY COMMISSION

ARNOLD SCHWARZENEGGER, GOVERNOR

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